Permit Application for Stationary Sources of Air Pollution

New Source Review (Revised)

CPV Towantic, LLC

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TETRA TECH

ATTACHMENT G – BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The following supplemental Best Available Control Technology (BACT) forms are provided with this application. Attachment G2, Cost/Economic Impact Analysis form DEEP-NSR-APP-214c, was only completed for those sources and pollutants for which the top-level of control was not selected.

- Attachment G - Analysis of Best Available Control Technology (DEEP-NSR-APP-214a)
    - AB – CO Emissions
    - AB – NO_x Emissions
    - AB – VOC Emissions
    - AB – PM Emissions
    - AB – SO_2 Emissions
    - AB – GHGs Emissions
    - AB – H_2SO_4 Emissions
    - CT#1 / DB#1 – CO Emissions
    - CT#1 / DB#1 – NO_x Emissions
    - CT#1 / DB#1 – VOC Emissions
    - CT#1 / DB#1 – PM Emissions
    - CT#1 / DB#1 – SO_2 Emissions
    - CT#1 / DB#1 – GHGs Emissions
    - CT#1 / DB#1 – H_2SO_4 Emissions
    - CT#1 / DB#1 – NH_3 Emissions
    - CT#2 / DB#2 – CO Emissions
    - CT#2 / DB#2 – NO_x Emissions
    - CT#2 / DB#2 – VOC Emissions
    - CT#2 / DB#2 – PM Emissions
    - CT#2 / DB#2 – SO_2 Emissions
    - CT#2 / DB#2 – GHGs Emissions
    - CT#2 / DB#2 – H_2SO_4 Emissions
    - CT#2 / DB#2 – NH_3 Emissions
- Attachment G1 - Background Search - Existing BACT Determinations (DEEP-NSR-APP-214b)
- Attachment G2 - Cost/Economic Impact Analysis (DEEP-NSR-APP-214c)
    - Auxiliary Boiler – CO Emissions
    - Auxiliary Boiler – NO_x Emissions
    - Auxiliary Boiler – VOC Emissions

  - Combustion Turbine #1/ Duct Burner #1 / Combustion Turbine #2/Duct Burner #2 – GHG Emissions
- Attachment G3 - Summary of Best Available Control Technology Review (DEEP-NSR-APP-214d)

Also provided is a control technology analysis to satisfy both the Lowest Achievable Emission Rate (LAER) and BACT requirements of the Project for nitrogen oxides (NO_x) emissions.

LOWEST ACHIEVABLE EMISSION RATE ANALYSIS

The Project is located in an area designated as non-attainment for ozone (O_3) and has potential NO_x emissions above the new source major source threshold. Therefore, the Project must implement LAER controls to minimize NO_x emissions.

Definition of LAER

LAER is defined under 40 Code of Federal Regulations (CFR) 51.165(a)(1)(xiii) as the more stringent rate of emissions based on the following:

1. The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or
2. The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources.

In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance.

LAER Process

As noted above, LAER is the more stringent of any limitation in a state's approved implementation plan or an emissions limitation which is achieved in practice by such class or category of stationary sources. For combined-cycle combustion turbine projects, the most stringent NO_x emission limitations can be found in previously permitted projects subject to Prevention of Significant Deterioration (PSD) or Nonattainment New Source Review (NNSR) requirements. In order to identify the "most stringent emissions limitation which is achieved in practice" by a combined-cycle combustion turbine facility, numerous sources of information were evaluated. These sources included the following:

- The United States Environmental Protection Agency's (USEPA's) Reasonably Achievable Control Technology (RACT), BACT, LAER Clearinghouse (RBLC);
- The California Air Resources Board (CARB) BACT Clearinghouse;
- USEPA regional air permitting websites; and
- State environmental agency websites.

In addition to these sources of information, additional publicly available information obtained through Tetra Tech's experience, such as permits for individual projects not listed in the RBLC or agency websites, were also included in the analysis. This research was conducted for the Project's emission sources that emit NO_x including:

- Combined-cycle combustion turbines and duct burners;
- Auxiliary boiler; and
- Emergency engines.

Following is a summary of the LAER determination for NO_x emissions for each of the above listed emission sources.

Combined-Cycle Combustion Turbines and Duct Burners

The LAER analysis for the combustion turbines and duct burners is combined, as the duct burners cannot operate without the combustion turbines in operation. Since the combustion turbines can operate with and without duct firing, LAER emission rates were reviewed for both of these operating scenarios. Provided in Table G-1 is a summary of recently permitted BACT and LAER NO_x emission limits for combined-cycle combustion turbine projects larger than 100 megawatts (MW) firing natural gas and, to the extent available, ultra-low sulfur distillate (ULSD). Projects with LAER permitted emission rates are noted as such in the table.

Table G-1: Combustion Turbine BACT and LAER NO_x Rate Emission Limits

Facility	Location	Permit Date	Turbine	NO_x[a,b] (ppm)
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	General Electric (GE) 7FA	2.0 (w/ and w/o DF) (LAER)
Brunswick County Power	Freeman, VA	05/23/2012	Mitsubishi M501 GAC	2.0 (w/ and w/o DF)
Carroll County Energy	Washington Twp., OH	11/5/2013	GE 7FA	2.0 (w/ and w/o DF)
Renaissance Power	Carson City, MI	11/1/2013	Siemens 501 FD2	2.0 (w/ and w/o DF)
Langley Gulch Power	Payette, ID	08/14/2013	Siemens SGT6-5000F	2.0 (w/ and w/o DF)
Kleen Energy (gas firing)	Middletown, CT	02/25/2008	Siemens SGT6-5000F	2.0 (w/ and w/o DF) (LAER)
Kleen Energy (ULSD firing)	Middletown, CT	02/25/2008	Siemens SGT6-5000F	5.9 (w/ and w/o DF) (LAER)
Oregon Clean Energy	Oregon, OH	06/18/2013	Siemens SCC6-8000H	2.0 (w/ and w/o DF)
TECO Polk Power 2	Mulberry, FL	05/15/2013	GE 7FA	2.0 (w/ and w/o DF)
Hess Newark Energy	Newark, NJ	11/01/2012	GE 7FA.05	2.0 (w/ and w/o DF) (LAER)
Cricket Valley Energy Center	Dover, NY	09/27/2012	"F" Class	2.0 (w/ and w/o DF) (LAER)
Pioneer Valley Generation Company (gas firing)	Westfield, MA	04-12-2012	Mitsubishi 501G	2.0 (w/o DF) (LAER)
Pioneer Valley Generation Company (ULSD firing)	Westfield, MA	04-12-2012	Mitsubishi 501G	5.0 (w/o DF) (LAER)

[a] Concentration in ppm is expressed in parts per million by volume, dry, (ppmvd) at 15 percent O_2.
[b] DF refers to duct firing

The lowest permitted NO_x emission rate during natural gas firing for all of the projects in Table G-1 is 2.0 ppmvd at 15% O_2 including a wide range of turbine models and sizes. This emission rate has been achieved in practice at several facilities, including the Kleen Energy facility in Connecticut. For these reasons, LAER for NO_x emissions from the two combined-cycle combustion turbines and duct burners was selected as 2.0 ppmvd at 15% O_2 during natural gas firing for all modes of operation.

For ULSD firing emission limits, there are far fewer recently permitted combined-cycle combustion turbine projects. The Pioneer Valley Generation project includes firing of ULSD as backup fuel and was required to meet LAER for NO_x emissions. The permitted NO_x emission rate for ULSD firing for the Pioneer Valley Generation project is 5.0 ppmvd at 15% O_2. The most recent Connecticut project (Kleen Energy) is permitted at 5.9 ppmvd during ULSD firing. The GE NO_x emissions guarantee for the Model 7HA.01 firing ULSD with installation of SCR and oxidation catalyst controls is 5.0 ppmvd at 15% O_2. This emission level is at or below the lowest permitted limits for ULSD firing and no additional control measures are available to reduce NO_x emissions from the combined-cycle combustion turbines and duct burners. For these reasons, LAER for NO_x emissions for ULSD firing was selected as 5.0 ppmvd at 15% O_2.

To meet the required LAER emission rates, the Project evaluated available NO_x control technologies for combined-cycle combustion turbines. All of the projects listed in Table G-1 employ selective catalytic reduction (SCR) to meet the permitted emission limits. SCR catalysts are made from a ceramic material, such as titanium oxide, and active catalytic components are oxides of base metals, typically vanadium, molybdenum or tungsten. Ammonia (NH_3) is used as the reagent in a chemical reaction that reduces NO_x to nitrogen (N_2) and water (H_2O).

Another technology that is marketed to control NO_x emissions from combustion turbines is EMx, formerly known as SCONOx. EMx has been installed on smaller combustion turbines; the largest combustion turbines installed with EMx control technology are two units at Redding Power in California. Redding Power operates two combustion turbines, a 43-MW unit (Unit 5) that is permitted at 2.5 ppmvd at 15% O_2, and a 45-MW unit (Unit 6) that is permitted at 2.0 ppmvd at 15% O_2. Although the 45 MW unit is permitted with an NO_x limit consistent with the proposed LAER limit for CPV Towantic, a review of USEPA's 2013 Acid Rain emission data for Unit 6 shows average NO_x emissions over the course of 2013 to be 0.0094 lb/MMBtu, which is equivalent to 2.55 ppmvd. Therefore, EMx has not demonstrated in practice that it can meet an NO_x emission rate of 2.0 ppmvd at 15% O_2 and is not able to meet the "most stringent emissions limitation" criteria required to satisfy LAER requirements. Furthermore, since EMx has never been utilized on a combustion turbine firing ULSD, its performance under this operating condition is unknown.

A review of EMx technology shows that there would be significant challenges to scaling up for the Project, which has combustion turbines that are six times larger than those installed at Redding Power. EMx consists of a platinum-based catalyst that oxidizes nitrogen oxide (NO) to nitrogen dioxide (NO_2) and carbon monoxide (CO) to carbon dioxide (CO_2). The catalyst is coated with potassium carbonate that converts the NO_2 to either potassium nitrite or potassium nitrate, and the potassium nitrite/nitrate collects on the surface of the catalyst. As potassium nitrite/nitrate builds up on the surface of the catalyst, it must be regenerated utilizing hydrogen that is created by reforming natural gas. The EMx catalyst is also extremely sensitive to fouling by sulfur, which requires a sulfur catalyst upstream of the NO_x catalyst to oxidize sulfur dioxide (SO_2) to sulfur trioxide (SO_3). The sulfur catalyst must be regenerated using hydrogen gas similar to the NO_x catalyst. Regeneration of the sulfur catalyst converts the SO_3 back to SO_2, so there is no reduction in overall SO_2 emissions. Catalyst regeneration must take place in an oxygen free environment, which requires a series of dampers upstream and downstream of each catalyst section to seal it off during regeneration. Therefore, sections of the EMx system are offline for regeneration at all times. Due to the buildup of nitrites, nitrates, and sulfates on the catalysts, they must be re-coated every six months to one year, which requires shutting down the unit and removing the catalyst modules from the system.

Due to all of the moving dampers, reliability and performance degradation due to leakage are significant issues with EMx that would be exacerbated on scale-up to a much larger combustion gas turbine. Therefore, EMx is not technically feasible for the Project and has failed to demonstrate in practice an NO_x control effectiveness equal to SCR. For these reasons, EMx was eliminated from consideration as LAER for NO_x.

SCR, in addition to dry-low NO_x combustors, has demonstrated that it can meet a NO_x emission limit of 2.0 ppmvd at 15% O_2 during natural gas firing at several operating large combined-cycle combustion turbine facilities firing natural gas. SCR, with water injection, has demonstrated that it can meet a NO_x emission limit of 5.0 ppmvd at 15% O_2 during ULSD firing. Therefore, SCR, dry-low NO_x combustors, and water injection are the only NO_x controls available that can meet the required LAER emission rates and CPV Towantic has selected these controls for the Project.

Auxiliary Boiler

Provided in Table G-2 is a summary of recently permitted BACT and LAER NO_x emission limits for auxiliary boilers rates less than 100 MMBtu/hr firing natural gas. Projects with LAER permitted emission rates are noted as such in the table.

Table G-2: Auxiliary Boiler BACT and LAER NO_x Rate Emission Limits

Facility	Location	Permit Date	Controls[a]	NO_x[b] (ppm)
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	Ultra-LNB	9.0 (LAER)
Brunswick County Power	Freeman, VA	05/23/2012	Ultra-LNB	9.0
Carroll County Energy	Washington Twp., OH	11/5/2013	LNB	16.4
Renaissance Power	Carson City, MI	11/1/2013	LNB	30
Kleen Energy	Middletown, CT	02/25/2008	LNB	37 (LAER)
Oregon Clean Energy	Oregon, OH	06/18/2013	LNB	16.4
Hess Newark Energy	Newark, NJ	11/01/2012	Ultra-LNB	9.0 (LAER)
Cricket Valley Energy Center	Dover, NY	09/27/2012	Ultra-LNB	9.0 (LAER)

[a] LNB = low NO_x burner.
[b] Concentration in ppm is parts per million by volume, dry, (ppmvd) at 3 percent O_2.

The proposed auxiliary boiler will fire natural gas as the sole fuel and will be equipped with ultra-low-NO_x burners (Ultra-LNB); this is the most stringent level of control identified in Table G-2. The vendor-guaranteed NO_x emission rate for this control scenario are 9.0 ppmvd at 3% O_2. The vendor-guaranteed NO_x emission rate is equal to the lowest permitted emission rate in Table G-2. For these reasons, LAER for NO_x emissions from the auxiliary boiler was selected as 9.0 ppmvd at 3% O_2.

Emergency Engines

The Project will include a diesel-fired emergency generator engine and a diesel-fired fire pump engine. These engines are subject to the NO_x and non-methane hydrocarbon emission standards under New Source Performance Standard (NSPS) Subpart IIII. A review of previously permitted projects did not identify any emergency engines permitted below the NSPS Subpart IIII emission standards. To satisfy LAER for the emergency engines, the Project will install engines that meet the NSPS Subpart IIII emission standards. These engines will also be operated in accordance with Regulations of Connecticut State Agencies (RCSA) Section 22a-174-3b(e), including firing ULSD and limiting operation to no more than 300 hours during any 12 month rolling period for each engine.

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The Project must install PSD BACT controls for emissions of NO_x, volatile organic compounds (VOC), CO, particulate matter (PM)/particulate matter with a diameter equal to or less than 10 microns (PM_{10})/particulate matter with a diameter equal to or less than 2.5 microns ($PM_{2.5}$), sulfuric acid mist (H_2SO_4), and greenhouse gases (GHG). Additionally, the Connecticut Department of Energy and Environmental Protection (DEEP) BACT must be satisfied for SO_2 and NH_3 emissions. For NO_x emissions, LAER controls will be installed, which are by definition the top level of control available and, therefore, satisfy BACT requirements. The following control technology analysis satisfies the BACT requirements for VOC, CO, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, GHGs, SO_2, and NH_3 emissions for the Project.

Definition of BACT

DEEP regulations define BACT under RCSA Section 22a-174-1 as:

> *"an emission limitation, including a limitation on visible emissions, based upon the maximum degree of reduction for each applicable air pollutant emitted from any proposed stationary source or modification which the commissioner, on a case-by-case basis, determines is achievable in accordance with section 22a-174-3a of the Regulations of Connecticut State Agencies. BACT may include, without limitation, the application of production processes, work practice standards or available methods, systems, and techniques, including fuel cleaning or treatment, the use of clean fuels, or innovative techniques for the control of such air pollutant."*

When determining whether or not an emission limitation is achievable, the DEEP must take into account the following factors in accordance with RCSA Section 22a-174-3a(j):

1. A previous BACT approval for a similar or a representative type of source;
2. Technological limitations; and
3. Energy, economic, and environmental impacts.

In no event shall the application of BACT result in emissions of any pollutant greater than an emission standard pursuant to 40 CFR Parts 60 and 61 or any State Implementation Plan (SIP).

BACT Process

USEPA provides guidance for conducting a BACT analysis in which all control technologies for a subject pollutant and emission source are identified and ranked from most to least efficient. An evaluation of each technology is then conducted to determine if it is technically feasible for the proposed project and if so, the resulting energy, environmental, and economic impacts from its application. The most efficient technology that is determined to be technically feasible, and does not result in adverse energy, environmental and/or economic impacts, is selected as BACT.

The BACT process is described in USEPA's draft document titled "*New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting*" (NSR Manual) (USEPA, 1990), which acts as a non-binding guidance document for USEPA, state permitting authorities and permit applicants during the permitting process. The process involves the following steps:

- Step 1: Identify all potential control technologies applicable to the pollutant and process.
- Step 2: Determine the technical feasibility of each control technology identified under Step 1 as applicable to the Project and eliminate those that are infeasible.
- Step 3: Rank the technically feasible control technologies based on overall control efficiency.

- Step 4: Evaluate the most effective control technology based on economic, energy, and environmental factors. If the most effective control technology causes unacceptable economic, energy, and/or environmental impacts, the next most effective technology is evaluated. This process continues until a technology is selected as BACT.
- Step 5: Select the most effective option not eliminated in Steps 2 – 4 above as BACT and determine the corresponding emission limit for the subject pollutant and emission source.

Per this guidance, if a project elects to implement the most efficient level of control that is technically feasible as identified in Steps 1 through 3, then no further analysis is required.

Sources Reviewed To Identify BACT

Steps 1 and 2 in the BACT process are the identification of all available control technologies and the top level of control for each subject pollutant from each source type for a given project. Per USEPA guidance, BACT may be achieved from a change in raw materials, a process modification, and/or add-on pollution controls. For the Project, the cleanest raw materials (natural gas and ULSD) and lowest emitting fossil-fuel generating process (combined-cycle combustion turbines) have been selected. Therefore, the identification of the top level of control focused on add-on pollution controls.

Per USEPA guidance, BACT is expressed as an emission rate and the top level of control is determined from the following:

- The most stringent emissions limitation that is contained in any SIP for such class or category of stationary source; or
- The most stringent emissions limitation that is achieved in practice by such class or category of stationary source.

In order to identify the "most stringent emissions limitation which is achieved in practice" by a combined-cycle combustion turbine facility, numerous sources of information were evaluated. These sources included the following:

- USEPA's RBLC;
- The CARB BACT Clearinghouse;
- USEPA regional air permitting websites; and
- State environmental agency websites.

In addition to these sources of information, additional publicly available information obtained through Tetra Tech's experience, such as permits for individual projects not listed in the RBLC or agency websites, were also included in the analysis. This research was conducted for the Project's emission sources that emit VOC, CO, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, GHGs, SO_2, and NH_3 including:

- Combined-cycle combustion turbines and duct burners;
- Auxiliary boiler;
- Emergency engines; and
- Fugitive GHG emissions.

Combined-Cycle Combustion Turbines and Duct Burners

The BACT analysis for the combustion turbines and duct burners is combined as the duct burners cannot operate without the combustion turbines in operation. Since the combustion turbines can operate with and without duct firing, BACT emission rates were reviewed for both of these operating scenarios. Provided in Table G-3 is a summary of recently permitted VOC, CO, $PM/PM_{10}/PM_{2.5}$, GHG, and NH_3 emission limits for combined-cycle combustion turbine projects larger than 100 MW. The emission limits provided in Table G-3 serve as the basis for determining the “most stringent emissions limitation that is achieved in practice” for large combined-cycle combustion turbines.

Volatile Organic Compounds

VOC is emitted from combustion turbines and duct burners as a result of incomplete oxidation of the fuel. The primary factors effecting VOC emission levels are the combustion temperature and residence time within the combustion zone.

Step 1: Identification of Potentially Feasible VOC Control Options

VOC emissions can be minimized by the use of proper combustor design and good combustion practices. Additional reductions in VOC emissions may be achieved through application of an oxidation catalyst, which is a passive reactor containing a platinum catalyst which oxidizes VOC in the exhaust stream to form CO_2 and H_2O. No other form of VOC control was identified and, therefore, proper combustor design, good combustion practices, and an oxidation catalyst were selected as BACT controls for VOC emissions. All of the VOC emission rates recently permitted for combined-cycle turbines and duct burners are based upon the turbine vendor-guaranteed emission rate with installation of an oxidation catalyst.

Step 2: Technical Feasibility of VOC Control Options

Combustion controls and oxidation catalysts have been demonstrated in practice for a number of combined-cycle turbine projects and are, therefore, considered technically feasible.

Step 3: Ranking of Technically Feasibility VOC Control Options

Combustion controls and oxidation catalyst systems are compatible technologies and not mutually exclusive. Together they represent the top level of VOC control for combined-cycle turbines and duct burners.

Step 4: Evaluation of the Most Effective VOC Control Options

Combustion controls in combined-cycle turbines utilize “lean combustion,” which entails sufficient air to create a balance of a cooler flame temperature to minimize formation of NO_x, while still achieving complete combustion of VOC.

Oxidation catalysts operate in a relatively narrow temperature range, generally between 700 to 1,100 degrees Fahrenheit (^oF). Above 1,200^oF, the catalyst may be damaged. Oxidation catalysts are, therefore, strategically placed within the optimal temperature zone in the heat recovery steam generator (HRSG), downstream of the turbine.

Step 5: Selection of VOC BACT

The GE-guaranteed maximum VOC emission rate for the Model 7HA.01 combined-cycle combustion turbine equipped with an oxidation catalyst is 1.0 ppmvd at 15% O_2 without duct firing and 2.0 ppmvd at 15% O_2 with duct firing. These VOC emission rates are consistent with the recently permitted BACT and LAER emission rates listed in Table G-3. These emission rates represent the lowest vendor emission guarantees provided for the GE Model 7HA.01 and will be achieved through good combustion practices and an oxidation catalyst. No additional control measures are available to reduce VOC emissions from the combined-cycle combustion turbines and duct burners. For these reasons, BACT for VOC emissions from the two combined-cycle combustion turbines and duct burners was selected as 1.0 ppmvd at 15% O_2 without duct firing and 2.0 ppmvd at 15% O_2 with duct firing.

Table G-3: Combustion Turbine Permitted CO, PM, GHG, and NH_3 Emission Rate Limits

Facility	Location	Permit Date	Turbine	VOC[a] (ppm)	CO[a] (ppm)	PM[b] (lb/MMBtu)	GHG (lb/MW-hr)	GHG (Btu/kW-hr)	NH_3[a] (ppm)
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	GE 7FA	1.0 (w/o DF[c]) 2.4 (w/ DF) LAER	2.0 (w/ & w/o DF)	0.00334 (w/ & w/o DF)	903	7,340[d] (gross, w/o DF) 7,780[d] (gross, w/ DF)	5.0 (w/ & w/o DF)
Brunswick County Power	Freeman, VA	05/23/2012	Mitsubishi M501 GAC	0.7 (w/o DF) 1.6 (w/ DF)	1.5 (w/o DF) 2.4 (w/ DF)	0.0033 (w/o DF) 0.0047 (w/ DF)	920	7,500[d] (net, w/o DF)	N/A
Carroll County Energy	Washington Twp., OH	11/5/2013	GE 7FA	1.0 (w/o DF) 2.0 (w/ DF)	2.0 (w/ & w/o DF)	0.0108 (w/o DF) 0.0078 (w/ DF)	859	7,350[d] (net, w/o DF)	N/A
Renaissance Power	Carson City, MI	11/1/2013	Siemens 501 FD2	2.0 (w/ and w/o DF)	2.0 (w/ & w/o DF)	0.0042 (w/ & w/o DF)	1,000	N/A	N/A
Langley Gulch Power	Payette, ID	08/14/2013	Siemens SGT6-5000F	2.0 (w/ and w/o DF)	2.0 (w/ & w/o DF)	0.0053 (w/ & w/o DF)	N/A	N/A	5.0 (w/ & w/o DF)
Kleen Energy (gas firing)	Middletown, CT	02/25/2008	Siemens SGT6-5000F	5.0 (w/ and w/o DF)	0.9 (w/o DF) 1.7 (w/ DF)	0.0051 (w/o DF) 0.0059 (w/ DF)	N/A	N/A	2.0 (w/ & w/o DF)
Kleen Energy (ULSD firing)	Middletown, CT	02/25/2008	Siemens SGT6-5000F	3.6 (w/ and w/o DF)	1.8	0.0269	N/A	N/A	5.0 (w/ & w/o DF)
Oregon Clean Energy	Oregon, OH	06/18/2013	Siemens SCC6-8000H	1.0 (w/o DF) 1.9 (w/ DF)	2.0 (w/ & w/o DF)	0.0047 (w/o DF) 0.0055 (w/ DF)	833	7,227[d] (net, w/o DF)	N/A
TECO Polk Power 2	Mulberry, FL	05/15/2013	GE 7FA	1.4 (no ox. cat)	4.1 (no ox. cat)	N/A	877	N/A	5.0 (w/ & w/o DF)
Hess Newark Energy	Newark, NJ	11/01/2012	GE 7FA.05	1.0 (w/o DF) 2.0 (w/ DF) (LAER)	2.0 (w/ & w/o DF)	0.0047 (w/o DF) 0.0058 (w/ DF)	887	7,522[d] (net, w/o DF)	5.0 (w/ & w/o DF)
Cricket Valley Energy Center	Dover, NY	09/27/2012	“F” Class	1.0 (w/o DF) 2.0 (w/ DF) (LAER)	2.0 (w/ & w/o DF)	0.005 (w/o DF) 0.006 (w/ DF)	910	7,605[d] (net, w/o DF)	5.0 (w/ & w/o DF)

Facility	Location	Permit Date	Turbine	VOC[a] (ppm)	CO[a] (ppm)	PM[b] (lb/MMBtu)	GHG (lb/MW-hr)	GHG (Btu/kW-hr)	NH_3[a] (ppm)
Pioneer Valley Generation Company (gas firing)	Westfield, MA	04/12/2012	Mitsubishi 501G	1.0 (w/o DF) (state BACT)	2.0 (w/ & w/o DF)	0.0040 (w/ & w/o DF)	895 (all fuels)	N/A	2.0 (w/ & w/o DF)
Pioneer Valley Generation Company (ULSD firing)	Westfield, MA	04/12/2012	Mitsubishi 501G	6.0 (w/o DF) (state BACT)	6.0	0.014			2.0

[a] Concentration in ppm is parts per million by volume, dry, (ppmvd) at 15 percent O_2.
[b] Concentration in pounds per million Btu heat input (HHV), except as noted, including front (filterable) and back-half (condensable) PM. All PM is considered to be $PM_{2.5}$.
[c] DF = duct firing.
[d] At full load and corrected to ISO conditions (59°F, absolute pressure of 14.696 kPa and 60% relative humidity)

For ULSD firing emission limits, there are far fewer recently permitted combined-cycle combustion turbine projects. The Pioneer Valley Generation project includes firing of ULSD and was required to meet state BACT requirements for VOC emissions. The permitted VOC emission rate for oil firing of the Pioneer Valley Generation project is 6.0 ppmvd at 15% O_2. The Kleen Energy project was permitted at a VOC emission rate for oil firing at 3.6 ppmvd at 15% O_2. The GE VOC emissions guarantee for the Model 7HA.01 firing ULSD with installation of an oxidation catalyst is 2.0 ppmvd at 15% O_2. This emission level is below the lowest permitted limits for ULSD firing and no additional control measures are available to reduce VOC emissions from the combined-cycle combustion turbines and duct burners. For these reasons, BACT for VOC emissions for ULSD firing was selected as 2.0 ppmvd at 15% O_2.

Carbon Monoxide

CO is emitted from combustion turbines and duct burners as a result of incomplete oxidation of the fuel. Like VOC, the primary factors effecting CO emission levels are the combustion temperature and residence time within the combustion zone.

Step 1: Identification of Potentially Feasible CO Control Options

CO emissions can be minimized by the use of proper combustor design and good combustion practices. The most stringent CO add-on pollution control technology is an oxidation catalyst, which is a passive reactor containing a platinum catalyst that oxidizes CO to CO_2. No other form of CO control was identified and, therefore, proper combustor design, good combustion practices, and an oxidation catalyst were selected as BACT for CO emissions. With the exception of the TECO Polk Power project, which was not required to install add-on controls for CO emissions, all of the projects listed in Table G-3 have been permitted with an oxidation catalyst to achieve the permitted CO emission levels; no other forms of CO control were identified. Accordingly, the Project is proposing to use an oxidation catalyst to control CO emissions from the combustion turbines and duct burners.

Step 2: Technical Feasibility of CO Control Options

Combustion controls and oxidation catalysts have been demonstrated in practice for a number of combined-cycle turbine projects and are, therefore, considered technically feasible.

Step 3: Ranking of Technically Feasibility CO Control Options

Combustion controls and oxidation catalyst systems are compatible technologies and not mutually exclusive. Together they represent the top level of CO control for combined-cycle turbines and duct burners.

Step 4: Evaluation of the Most Effective CO Control Options

Combustion controls in combined-cycle turbines utilize “lean combustion,” which entails sufficient air to create a balance of a cooler flame temperature to minimize formation of NO_x, while still achieving complete combustion of CO.

Oxidation catalysts operate in a relatively narrow temperature range, generally between 700 to 1,100^{o}F. At lower temperatures, CO control efficiency is greatly reduced. Above 1,200^{o}F, the catalyst may be damaged. Oxidation catalysts are, therefore, strategically placed within the optimal temperature zone in the HRSG, downstream of the turbine.

Step 5: Selection of CO BACT

A review of recently permitted projects shows that during natural gas firing, most are permitted at an emission rate at or above 2.0 ppmvd corrected to 15% O_2 on a 1-hour average basis during all operating periods. A few projects have marginally lower permitted limits without duct firing and one project has a lower limit with duct firing, but these projects have a different combustion turbine than the GE 7HA.01. The Kleen Energy project’s lower CO BACT limit comes at the expense of VOC, for which its BACT limit is considerably higher than most limits in the RBLC database.

Based upon GE guarantees, the proposed CO BACT emission rate during gas firing is 0.9 ppmvd at 15% O_2 without duct firing and 1.7 ppmvd at 15% O_2 with duct firing. Although this emission rate is marginally higher than a couple of recently permitted projects, the USEPA's Environmental Appeals Board (EAB) decision[1] on March 14, 2014 regarding the appeal of the La Paloma Energy Center, LLC PSD permit makes clear that minor differences in permitted PSD emission rates are allowable to account for different technologies, and that turbine model selection cannot be taken into account when determining BACT for a project. The proposed CO BACT emission rate during natural gas firing represents the vendor guarantee with an oxidation catalyst and is consistent with the majority of recently permitted projects.

Two CO BACT determinations for oil firing are provided in Table G-3. The Pioneer Valley Generation project is limited to 6.0 ppmvd at 15% O_2 and the Kleen Energy project is limited to 1.8 ppmvd at 15% O_2. The GE-guaranteed CO emission rate for oil firing with an oxidation catalyst is 2.0 ppmvd at 15% O_2. The GE guarantee is marginally higher than the Kleen Energy CO limit which, as discussed for natural gas firing, comes at the expense of a much higher VOC limit. Therefore, CO BACT for oil firing is proposed to be 2.0 ppmvd at 15% O_2.

Sulfur Dioxide and Sulfuric Acid Mist

SO_2 is formed in the combustion process as a result of oxidation of sulfur contained in the fuel. A portion of the SO_2 can be further oxidized to form SO_3, which will subsequently react with H_2O in the exhaust stream to form H_2SO_4. Therefore, the primary factor in the level of SO_2 and H_2SO_4 emissions is the sulfur content of the fuel. The Project will minimize SO_2 and H_2SO_4 emissions by utilizing pipeline quality natural gas as the primary fuel and ULSD as the backup fuel.

Step 1: Identification of Potentially Feasible SO_2 and H_2SO_4 Control Options

The only feasible method of controlling SO_2 and H_2SO_4 from combustion sources is limiting the sulfur content of the fuel and post-combustion controls. Based on a review of the RBLC database and other sources, post-combustion controls have not been applied to combustion turbines, or any other natural gas-fired source.

Step 2: Technical Feasibility of SO_2 and H_2SO_4 Control Options

The only technically feasible option for controlling SO_2 and H_2SO_4 is the use of low-sulfur fuels.

Step 3: Ranking of Technically Feasibility SO_2 and H_2SO_4 Control Options

The use of pipeline quality natural gas as the primary fuel and ULSD as the backup fuel are the only technically feasible options and represent the top level of control for SO_2 and H_2SO_4 emissions.

Step 4: Evaluation of the Most Effective SO_2 and H_2SO_4 Control Options

The most stringent level of control for SO_2 and H_2SO_4 emissions from combustion sources is the firing of pipeline quality natural gas. The USEPA defines pipeline quality natural gas in the Acid Rain regulations under 40 CFR 72.2 as natural gas that contains 0.5 grains or less of total sulfur per 100 standard cubic feet (gr S/100 scf). ULSD is proposed as backup fuel for the combustion turbines to ensure fuel availability at all times. The sulfur content of ULSD is limited to no greater than 15 parts per million (ppm) by weight, which is nearly equivalent to the sulfur content of pipeline quality natural gas. Therefore, the selection of these fuels results in the greatest level of SO_2 reduction and represents the top level of control. Implementing the top level of control for SO_2 emissions is also the top level of control for H_2SO_4 emissions.

[1] http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/PSD%20Permit%20Appeals%20(CAA)/687C700F9FD042F585257C9B006369CE/$File/La%20Paloma.pdf

Step 5: Selection of SO_2 and H_2SO_4 BACT

All projects identified in Table G-3 have utilized low-sulfur fuels in the forms of pipeline quality natural gas and ULSD to control SO_2 and H_2SO_4 emissions. This is the top level of control for these pollutants and, therefore, has been selected as BACT for the Project.

Particulate Matter

Emissions of particulate matter result from trace quantities of ash (non-combustibles) in the fuel, products of incomplete combustion and conversion of SO_2 in the exhaust to condensable salts. Conservatively, all PM emissions from the Project are presumed to be less than 2.5 microns in size ($PM_{2.5}$) and, therefore, emissions of PM, PM_{10}, and $PM_{2.5}$ are presumed to be equal for the Project. The Project will minimize particulate emissions by utilizing state-of-the-art combustion turbines firing fuels with the lowest sulfur and ash content.

Step 1: Identification of Potentially Feasible Particulate Control Options

Pipeline quality natural gas has the lowest ash and sulfur content of all fossil fuels. As previously discussed, the sulfur content of ULSD is nearly equivalent to that of pipeline quality natural gas and has a maximum allowable ash content of only 100 ppm by weight.

Post-combustion controls for particulate include electrostatic precipitators (ESPs) and fabric filters. These technologies have never been applied to combined-cycle combustion turbines and are considered technically infeasible.

Step 2: Technical Feasibility of Particulate Control Options

Add-on controls have never been applied to a combined-cycle combustion turbine project and are considered infeasible. The only feasible particulate control technology for this type of project is the use of low ash and sulfur content fuels.

Step 3: Ranking of Technically Feasibility Particulate Control Options

Use of pipeline quality natural gas as the primary fuel and ULSD as the backup fuel is the only technically feasible option and represents the top level of control for particulate emissions.

Step 4: Evaluation of the Most Effective Particulate Control Options

The most stringent level of control for particulate emissions from combustion turbines is the firing of pipeline quality natural gas. The USEPA defines pipeline quality natural gas in the Acid Rain regulations under 40 CFR 72.2 as natural gas that contains 0.5 gr S/100 scf. ULSD is proposed as backup fuel for the combustion turbines to ensure fuel availability at all times. The sulfur content of ULSD is limited to no greater than 15 ppm by weight, which is nearly equivalent to the sulfur content of pipeline quality natural gas. Therefore, the selection of these fuels results in the greatest level of particulate reduction and represents the top level of control.

Step 5: Selection of Particulate BACT

All projects identified in Table G-3 have utilized low sulfur fuels in the forms of pipeline quality natural gas and ULSD to control PM, PM_{10}, and $PM_{2.5}$ emissions. This is the top level of control for these pollutants and, therefore, has been selected as BACT for the Project.

ULSD firing will be limited to times when the natural gas supply is interrupted or for emissions or readiness testing, and in no case for more than 720 hours per 12-month period per turbine.

A review of the permitted emission limits in Table G-3 shows a wide range of values on a lb/MMBtu basis. Similar to VOC emissions, the permitted PM emission limit for a combustion turbine project is dependent upon the make and model of the combustion turbine selected and the vendor-guaranteed emission rate. Furthermore, turbine vendors typically have higher emissions guarantees at lower operating loads even though the emissions on a pound per hour basis are lower at the lower operating loads. A comparison of the recently permitted Green

Energy Partners project in Virginia to the Carroll County project in Ohio shows a permitted PM emission rate difference of a factor of three (on a lb/MMBtu basis) for the same model GE turbine. This difference results from the Green Energy Partners permitted emission rate being at full operating load while the Carroll County limit is at minimum operating load. For purposes of establishing PM BACT for the Project, lb/MMBtu emission levels at full load will be proposed to be consistent with the majority of recently permitted projects. Higher emission levels (on a lb/MMBtu basis) will occur at reduced operating loads, as presented in the calculations in Appendix A.

BACT for PM emissions from the Project is proposed to be good combustion practices, the use of natural gas as the primary fuel with a maximum sulfur content of 0.5 gr S/100 scf, limited firing of ULSD, and the guaranteed emission rates from GE. GE's guaranteed PM emissions on a lb/MMBtu basis change depending upon operating load and ambient conditions. In order to establish BACT as an emission rate, the following limits at full operating load are proposed for the Project, including filterable and condensable PM. The pound per hour (lb/hr) limits are absolute maximum values while the lb/MMBtu limit represents all scenarios at full operating load, including duct firing. Therefore, higher emissions at reduced operating loads may occur in terms of lb/MMBtu, but no increase in hourly mass emissions will result.

- 20.4 lbs/hr with duct firing natural gas;
- 9.7 lbs/hr without duct firing natural gas;
- 0.0081 lb/MMBtu at full load with duct firing on natural gas;
- 0.0041 lb/MMBtu at full load without duct firing on natural gas;
- 42.6 lbs/hr firing ULSD; and
- 0.020 lb/MMBtu at full load firing ULSD;

Full operating load limits are proposed to establish BACT since performance emissions testing will be conducted at full operating load. Emissions at reduced operating load will be lower on a lb/hr basis but higher on a lb/MMBtu basis.

Ammonia

NH_3 is injected into the exhaust of the combustion turbines prior to the SCR as the reagent in the conversion of NO_x to N_2 and H_2O. A small portion of the injected NH_3 does not react with NO_x and is exhausted to the atmosphere; this unreacted NH_3 is called "ammonia slip."

Step 1: Identification of Potentially Feasible Ammonia Control Options

Add-on controls for reducing ammonia slip have never been applied to combustion turbine projects. NH_3 emissions can be minimized by process controls to optimize the NH_3 injection rate and maximize the efficiency of the injection grid. This is the only feasible NH_3 control technology.

Step 2: Technical Feasibility of Ammonia Control Options

Add-on controls have never been applied to a combined-cycle combustion turbine project and are considered infeasible. The only feasible NH_3 control technology for this type of project is optimization of the SCR and NH_3 injection design.

Step 3: Ranking of Technically Feasibility Ammonia Control Options

SCR system optimization is the only technically feasible option for controlling NH_3 emissions. As such, it represents the top level of control.

Step 4: Evaluation of the Most Effective Ammonia Control Options

SCR optimization measures include careful design of the injection grid distribution pattern and number of injection nozzles, use of NO_x continuous emissions monitoring systems (CEMS), and process controls to optimize NH_3

injection rates. Additional catalyst volume would reduce the NO_x reduction reaction efficiency and reduce the NH_3 slip level, but would need to be balanced with the corresponding increase in back pressure and subsequent reduction in turbine efficiency. Increases in turbine back pressure would result in increased fuel use which would correspond to collateral increases in emissions of all pollutants and GHG.

Step 5: Selection of Ammonia BACT

A review of the recently permitted emission rates in Table G-3 for ammonia show that all of the projects are permitted at 5.0 ppmvd corrected to 15% O_2 with the exception of the Pioneer Valley and Kleen Energy projects. Based upon the great majority of recently approved projects, the Project proposes BACT for NH_3 emissions from the combustion turbines to be limited to 5.0 ppm corrected to 15% O_2 during normal operation. Ammonia will not be injected until the SCR catalyst reaches the vendor-recommended minimum operating temperature to ensure high reaction efficiency and to minimize ammonia slip.

Greenhouse Gases

USEPA issued a 2011 guidance document for completing GHG BACT analyses titled "*PSD and Title V Permitting Guidance for Greenhouse Gases.*"[2] This guidance is in addition to the 1990 USEPA BACT guidance document. Although the 2011 guidance document refers to the same top-down methodology described in the 1990 document, the 2011 guidance provides additional clarification and detail with regard to some aspects of the analysis. The following analysis has been conducted in accordance with both the 1990 and 2011 guidance documents for the combustion turbines, which account for more than 99% of the Project's GHG emissions. GHG BACT for other ancillary emission sources is discussed in subsequent sections.

Step 1: Identification of Potentially Feasible GHG Control Options

For a combined-cycle combustion turbine project, potential GHG controls include:

- Low carbon-emitting fuels;
- Energy efficiency and heat rate; and
- Carbon capture and storage (CCS).

Because these GHG control measures are not mutually exclusive, they are evaluated separately in Steps 2 through 5 of this analysis.

Low Carbon-Emitting Fuels

Low carbon-emitting fuels that can theoretically be fired in a combustion turbine include:

- Natural Gas
- ULSD
- Biodiesel

Step 2: Technical Feasibility of Low Carbon-Emitting Fuels

Both natural gas and ULSD are technically feasible control options for combustion turbines. Biodiesel was determined to not be a technically feasible control option for the GE 7HA.01 combustion turbines. The GE 7HA.01 combustion turbine has been designed to fire readily available commercial fuels including natural gas and ULSD. GE has not approved the use of biodiesel in the 7HA.01 turbine and, therefore, emissions from biodiesel

[2] http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

firing cannot be predicted or guaranteed. As a result, biodiesel was determined to be technically infeasible for the Project.

Step 3: Ranking of Low Carbon- Emitting Fuels

Based upon CO_2 emission factors provided by the USEPA in 40 CFR 98, Subchapter C, Table C-1, natural gas is the lowest CO_2-emitting fossil fuel and represents the top level of control with regard to fuel selection for the Project.

Step 4: Evaluation of Low Carbon-Emitting Fuels

As noted in Step 3, the top level of control with regard to fuel selection is firing natural gas. CPV Towantic has selected pipeline quality natural gas as the primary fuel for the Project to minimize GHG emissions. However, limiting the Project to a single fuel would preclude its operation if that fuel were to become unavailable. In order to preserve operational flexibility, CPV Towantic has proposed limited firing of ULSD in the combustion turbines. The firing of ULSD in lieu of natural gas will result in environmental, energy, and economic impacts. The following is a discussion of each of these impacts that will occur during ULSD firing in the combustion turbines.

Environmental Impacts

The firing of ULSD in the combustion turbines results in the following environmental impacts as compared to firing of natural gas:

- Increased emissions of NO_x, CO, PM_{10}/$PM_{2.5}$, VOC, and GHG; and
- Increased water consumption to operate water injection to minimize NO_x emissions.

Firing of ULSD increases the emission rates of NO_x, CO, PM_{10}/$PM_{2.5}$, VOC, and GHG from the combustion turbines compared to natural gas firing, as noted in the LAER and BACT emission limits summarized in Tables G-1 and G-3. Operation of water injection will require up to an additional 1 million gallons per day from the Heritage Village Water Company; consumption without water injection will range from approximately 50,000 to 150,000 gallons per day.

Energy Impacts

Firing ULSD in the combustion turbine will eliminate the potential for the greatest energy impact, that being the unavailability of natural gas and the total loss of generating capability of the Project. The Project will dispatch its electricity into the Independent System Operator-New England (ISO-NE) transmission system. ISO-NE regulates all generators that supply electricity into its system. The rules that govern the ISO-NE market include the declaration of an Energy Emergency where there is a national or regional shortage in fuel availability to the generators that supply the ISO-NE transmission system. In accordance with ISO-NE procedures, these fuel shortages may occur as a result of the following circumstances[3]; the list below is not meant to be all inclusive.

- One or more pipeline Operational Flow Orders (OFOs) have been declared
- Significant reductions of generation resource capability due to natural gas related issues
- Weather forecast for an extended period of cold or hot weather
- Fuel delivery to a significant number of fossil fuel-fired generating resources is, or may be, impaired
- Prolonged drought
- Adverse weather conditions within the Gulf of Mexico, Western Canada, or regional shale gas basins

[3] http://www.iso-ne.com/rules_proceds/operating/isone/op21/op21_rto_final.pdf

- Abnormal conditions at regional LNG import, satellite storage, or LNG trucking facilities
- Extreme cold weather conditions in Ontario and Quebec
- Extreme storm conditions off-shore in the Maritimes
- Any viable threat to one or more of the pipelines or LDCs supplying New England
- Any other serious threat to the integrity of the bulk electric system for which ISO determines that this procedure may mitigate the impact

In the event that ISO-NE declares an Energy Emergency, it will request that each dual-fuel generating facility switch to operation on the fuel source that is not in short supply. Although New England currently has a stable supply of natural gas, it is not possible to guarantee that this supply will be available at all times for the life of the Project.

In addition to an ISO-NE-declared Energy Emergency, there are additional circumstances that could affect the Project's ability to obtain natural gas on a given day. CPV Towantic expects to enter into an interruptible supply contract with the gas company; consistent with other electric generating facilities in New England. A firm gas transportation contract is currently not commercially available. Under the terms of an interruptible gas supply contract, gas supply is not guaranteed and the gas company may cutoff supply during periods of peak demand to ensure delivery residences and other sensitive end users. It is also possible that a local system failure could restrict delivery to the Project even though natural gas is available in the main supply pipeline.

The availability of ULSD as backup fuel would ensure that the facility's highly efficient advanced combined-cycle combustion turbine technology is available during times of emergency or natural gas shortage when its generation would be most needed. In the event the Project was shut down due to fuel shortage, this would result in the loss of 805 MW of generation, for a total of 19,320 MW-hours per day. Based upon data from the United States Energy Information Administration (EIA)[4], the average electricity consumption per household in Connecticut is 731 kilowatt-hours per month, equivalent to approximately 24 kilowatt-hours per day. Therefore, if the Project was offline due to a fuel shortage, this would remove enough electricity from the transmission system to power over 800,000 homes.

Economic Impacts

With an interruptible gas supply contract, there may be times when natural gas is available but due to market conditions, the costs for natural gas would prevent the Project from competing with ISO-NE market prices. During the 2013/2014 winter in New England, data from the EIA[5] shows that natural gas prices spiked from less than $5 per million BTU up to nearly $80 per million BTU. During these instances, the cost for ULSD would allow the Project to be competitive in the market while easing the burden on the region's congested natural gas transmission system[6].

CPV Towantic contacted the gas supplier to evaluate the terms of a firm gas contract for the Project. Based upon information provided by the gas supplier, a firm gas contract for the Project is not commercially available at this time; only an interruptible contract is available. Therefore, a firm gas contract is not technically feasible for the Project and was eliminated as a BACT option for the Project.

[4] http://www.eia.gov/electricity/sales_revenue_price/xls/table5_a.xls
[5] http://www.eia.gov/todayinenergy/detail.cfm?id=15111
[6] http://www.northeastgas.org/pipeline_expansion.php

Step 5: Selection of BACT for Low Carbon-Emitting Fuels

The analysis in Step 4 demonstrates that although the firing of ULSD would result in an increase in environmental impacts, this increase is more than offset by the energy and economic impacts that would result from ULSD fuel not being available to the Project. The loss of generating capacity of the Project would remove an equivalent of 800,000 households worth of generating capacity at a time of peak demand when this power is needed most. Further, a firm natural gas contract is not commercially available at this time, making it technically infeasible. Therefore, CPV Towantic proposes BACT to be the firing of natural gas as the primary fuel with limited firing of ULSD during periods when gas supply is curtailed or otherwise required to meet regulatory or plant readiness requirements. CPV Towantic proposes the following conditions for the firing of ULSD in the combustion turbines:

- ISO-NE declares an Energy Emergency and requests that the Project fire ULSD.
- The Project's interruptible natural gas supply is curtailed by its gas supplier. The natural gas supply is determined to be curtailed when the Project operator receives a communication from its supplier stating that the natural gas supply will be curtailed. The curtailment will end when the operator receives a communication from its supplier stating that the curtailment has ended.
- A blockage or breakage in the natural gas line delivery system limits or prohibits the use of natural gas.
- The Project operator is commissioning the combined-cycle turbines and, pursuant to the manufacturer's written instructions, the operator is required to fire ULSD during the commissioning process.
- The firing of ULSD is required for emission testing purposes as required by the DEEP.
- Routine maintenance and readiness testing of any equipment requires the owner/operator to fire ULSD.
- In order to maintain an appropriate turnover of the on-site fuel oil inventory, the owner/operator can fire ULSD when the last delivery of the oil to the tank was more than six months ago.

In addition to the above conditions, CPV Towantic will limit the total number of gallons of ULSD fired in any 12-month period to 13 million gallons per turbine, equivalent to 720 hours of operation at full load.

Energy Efficiency and Heat Rate

USEPA's 2011 GHG permitting guidance states:

> "*Evaluation of [energy efficiency options] need not include an assessment of each and every conceivable improvement that could marginally improve the energy efficiency of [a] new facility as a whole (e.g., installing more efficient light bulbs in the facility's cafeteria), since the burden of this level of review would likely outweigh any gain in emissions reductions achieved. USEPA instead recommends that the BACT analyses for units at a new facility concentrate on the energy efficiency of equipment that uses the largest amounts of energy, since energy efficient options for such units and equipment (e.g., induced draft fans, electric water pumps) will have a larger impact on reducing the facility's emissions..."*

USEPA also recommends that permit applicants:

> *"propose options that are defined as an overall category or suite of techniques to yield levels of energy utilization that could then be evaluated and judged by the permitting authority and the public against established benchmarks...which represent a high level of performance within an industry."*

Over the past 25 years there have been three types of proposed utility-scale electric fossil fuel-fired power generation projects: coal-fired steam electric generating units; simple-cycle combustion turbines; and combined-cycle combustion turbines. In addition, a limited number of smaller biomass-fired boilers and much smaller fuel cells have been permitted. There have been no known natural gas-fired boiler projects subject to PSD permitting during this period and, therefore, a comparison to a new natural gas-fired boiler project is not possible. However, the EIA lists the average heat rate of existing natural gas-fired steam electric power plants as 8,039 Btu/kWh.[7]

Advanced combined-cycle combustion turbine technology with natural gas firing is much more efficient than the other types of current fossil fuel-fired electric power generation projects. The EIA publication titled *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*[8] (April 2013) provides a comparison of heat rates for various electric utility-scale generating technologies. The listed heat rate for advanced combined-cycle generating technology of 6,430 Btu/kWh (higher heating value [HHV], net) is far superior to any of the other fossil fuel-fired generating technologies:

- Coal-fired boilers/IGCC – 8,700 to 12,000 Btu/kWh
- Simple-cycle combustion turbines – 9,750 to 10,850 Btu/kWh
- Biomass boilers – 12,350 to 13,500 Btu/kWh
- Fuel cells – 9,500 Btu/kWh

USEPA's Fact Sheet in support of the PSD permit issued for the Pioneer Valley Energy Center lists new and clean combined-cycle heat rates for various combustion turbine models ranging from 6,596 to 6,754 Btu/kWh (HHV, net).

The driving factor in the evaluation of energy efficiency is the core efficiency of the selected combustion turbine. However, in the EAB's recent decision in the La Paloma Energy Center case it was concluded that "combined-cycle combustion turbines with efficient turbine design is the most energy efficient way to generate electricity" and that minor differences in efficiency and GHG emission rates between different combustion turbine models are acceptable. The Project is proposing to install two "H" Class turbines in combined-cycle configuration, which are the most efficient class of combustion turbines commercially available. The proposed Project has a new and clean net heat rate at full load under ISO conditions of 6,402 Btu/kWh (HHV, net). This net heat rate is superior to the lowest value provided by the EIA as well as the efficiencies reviewed and approved by USEPA for the Pioneer Valley Energy Center project. Table G-3 shows that the proposed GHG BACT heat rate for Project is superior to all of the recently approved GHG BACT net heat rates.

With regard to energy efficiency considerations in combined-cycle combustion turbine facilities, the activity with the greatest effect on overall plant efficiency is the method of condenser cooling. As with all steam-based electric generation, combined-cycle plants can use either dry cooling or wet cooling for condenser cooling. Dry cooling uses large fans to condense steam directly inside a series of pipes, similar in concept to the radiator of a car. Wet cooling can either be closed-cycle evaporative cooling (using cooling towers), or "once-through" cooling using very large volumes of water. Wet cooling performance increases overall efficiency as it produces colder water as compared to dry cooling. Additionally, dry cooling requires more electricity than wet cooling, resulting in a higher parasitic load. As a result, operation of a dry cooling system requires approximately 1 to 5% more energy than a wet cooling system, depending on ambient conditions.

However, wet cooling systems utilize considerably more water than dry systems, which may not be suitable for all projects. Once-through cooling uses very large quantities of water that are returned to the receiving water body at a higher temperature. Wet mechanical draft cooling towers also require a significant quantity of water, mostly due

[7] U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report."

[8] http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

to evaporation to the atmosphere. The higher water demand of a wet cooling system is not suitable to the Project due to regional focus on minimizing water consumption. For this reason, a dry cooling system with an air-cooled condenser (ACC) was selected for the Project.

Advanced combined-cycle combustion turbine technology was determined to be the most efficient generating technology available. Therefore, the Project's proposal to use advanced combined-cycle combustion turbine technology is the most efficient process technically available to minimize GHG emissions and was selected as top case BACT for energy efficiency.

Carbon Capture and Storage

Step 2: Technical Feasibility of CCS

USEPA has specifically stated that CCS is technically achievable and must be considered in a GHG PSD BACT analysis. CCS is composed of three main components: CO_2 capture and compression, transport, and storage. While CCS is a promising technology and may be technically achievable for a specific project, it has never been applied on a facility near the size of the Project. Furthermore, USEPA has stated that at this time, CCS will be a technically feasible BACT option only in certain limited cases.

CCS can theoretically be applied as a pre-combustion or post-combustion control option. The application of CCS technology for pre-combustion control is applicable if the fuel contains significant concentrations of CO or CO_2. An example of pre-combustion CCS would be an Integrated Gasification Combined Cycle (IGCC) power plant or other type of gasification process. As the Project will fire pipeline quality natural gas with minimal amounts of CO and CO_2, pre-combustion CCS is not applicable to the Project.

As stated in the August 2010 *Report of the Interagency Task Force on Carbon Capture and Storage*[9], co-chaired by USEPA and the United States Department of Energy (USDOE), while amine- or ammonia-based CO_2 capture technologies are commercially available, they have only been implemented in non-combustion applications (i.e., separating CO_2 from field natural gas) or relatively small-scale combustion applications (e.g., slip streams from power plants with exhaust volumes that would correspond to approximately 1 MW of generating capacity). Scaling up these small-scale carbon capture systems for post combustion control of a nominal 805-MW combustion turbine generating plant such as the Project would represent a very significant technical challenge. In addition, integration of these technologies with the power cycle at generating plants presents significant cost and operating issues that would need to be addressed prior to widespread, cost-effective deployment of CO_2 capture. Current technologies are not ready for widespread commercial implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant applications. To date, United States power generating projects under consideration for using CCS technology have required significant government funding and have been limited to coal-fired boiler plants that have exhaust with higher CO_2 concentrations and lower exhaust volume as compared to a combustion turbine project. Furthermore, these proposed projects have experienced significant delays due to technical issues and dramatic increases in costs beyond original projections.

Once CO_2 is captured, it must be transported to a suitable sequestration site. As shown on Figure G-1, the nearest geological formation that is capable of storing CO_2 is located in western New York, more than 100 miles from the Project.[10] The USDOE database[11] of potential carbon storage formations provides a similar graphic of available carbon storage locations in the United States. A study was also conducted to evaluate the Newark

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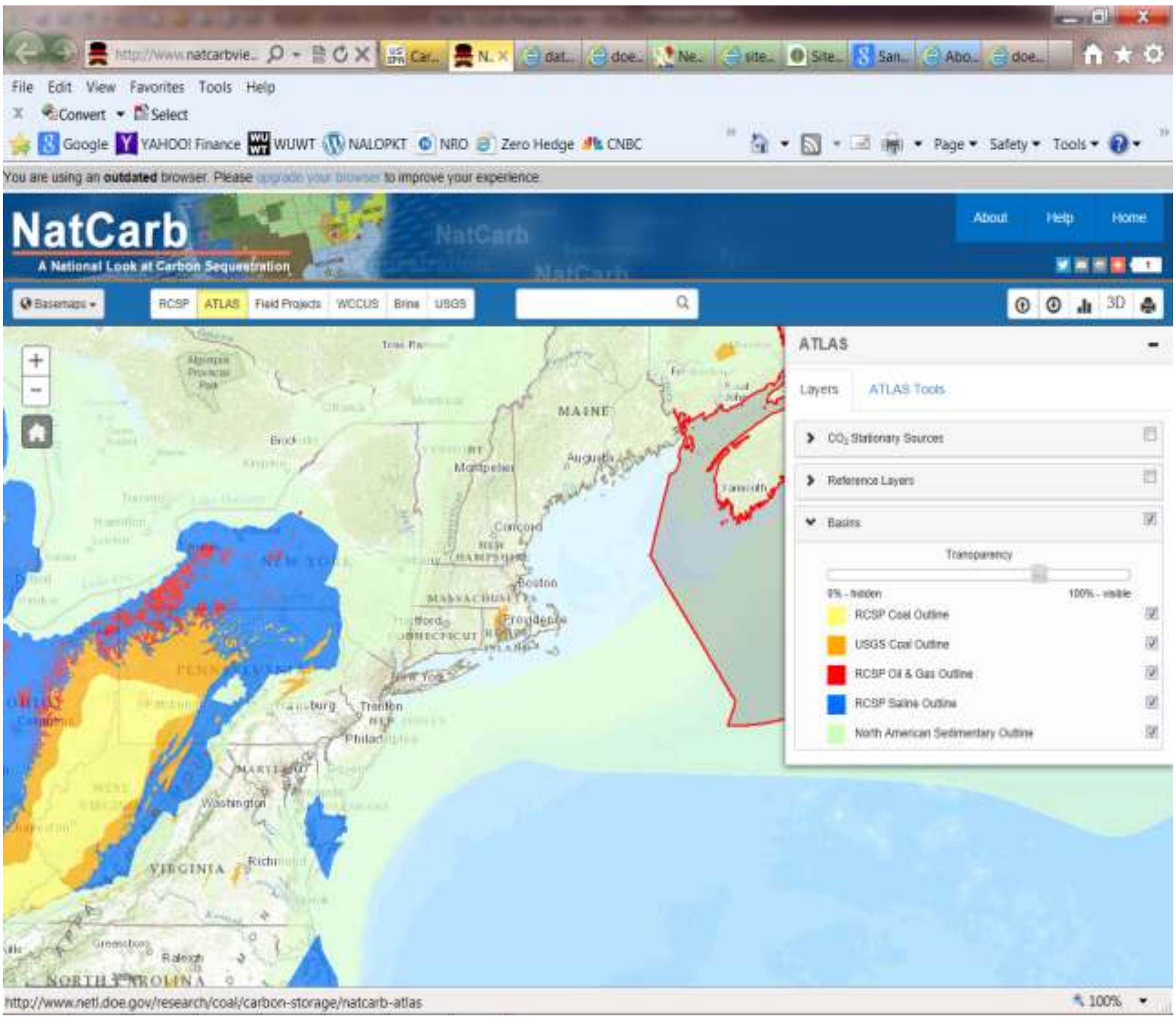
[9] http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf
[10] http://www.epa.gov/climatechange/ccs/
[11] http://www.natcarbviewer.com/

Basin[12], which extends into western Westchester County, for the potential to sequester CO_2. This project was scheduled to be completed in early 2013, but no reports have been issued to date. Since this area is not included in either the USEPA or USDOE databases as having the potential to sequester CO_2, it is not believed to be suitable. Therefore, western New York is believed to be the nearest location to the Project that is suitable for the sequestration of CO_2. A carbon storage facility does not currently exist in western New York and there are no existing CO_2 pipelines in that area.

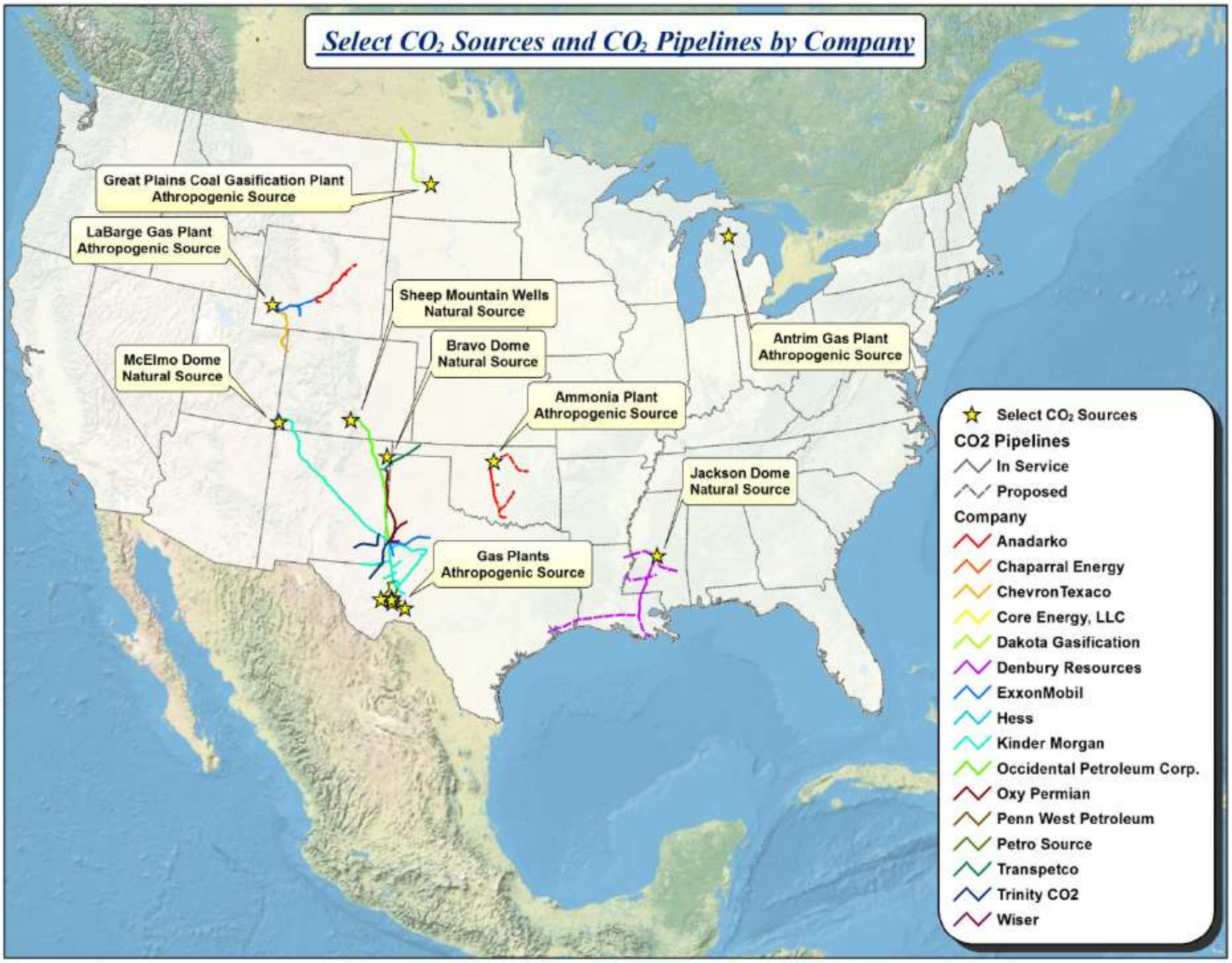
As shown on Figure G-2, the nearest existing CO_2 pipeline to the Project is in southern Mississippi; more than 1,000 miles from the Project in a straight line distance. In addition to the difficulties with implementing capture technology for the Project, there does not currently exist a carbon storage facility or a means of transport for captured CO_2 within more than 100 miles from the Project. Based upon this information, the application of CCS to the Project, while theoretically feasible, is not commercially available at this time.

Figure G-1. Suitable Geology for Carbon Sequestration



[12] http://www.tricarb.org/tricarb/default.aspx

Figure G-2: CO_2 Pipelines in the United States



Step 3: Control Effectiveness of CCS

Pilot-scale CCS projects have demonstrated removal efficiencies above 80 percent. Due to the absence of any demonstration data on a utility-scale generating plant, achieving this level of control on the Project with current technology is unlikely.

Step 4: Evaluation of CCS

The Interagency Task Force report showed that the costs to implement CCS technology on a natural gas combined-cycle combustion turbine generating project were excessive. The Interagency Task Force report provided an estimated capital cost for carbon capture equipment for a 550-MW natural gas-fired combined-cycle facility of \$340 million, an 80 percent increase in the capital cost of the plant. Scaling these costs up to nominal 805 MW for the Project yields an estimated capital cost for carbon capture equipment of approximately \$498 million dollars. These costs are excessive and would make the Project economically unviable.

In addition, the Interagency Task Force report states that CCS technology would result in an energy penalty of 15 percent, meaning that 15 percent more fuel would be required to meet the design criteria of 805 MW. This would result in a 15 percent increase in emissions of all other PSD subject pollutants for the Project.

After the CO_2 is captured it must be transported to a storage facility. As previously discussed and shown on Figure G-2, the nearest CO_2 pipeline to the Project is in southern Mississippi; more than 1,000 miles from the Project. The cost to construct a pipeline from the Project to Mississippi would more than double the cost of the Project.

As previously discussed and shown on Figure G-1, the nearest geological formation that is capable of storing CO_2 is located in western New York, more than 100 miles from the Project. However, a carbon storage facility does not exist at this location. Costing procedures provided by the National Energy Technology Laboratory (NETL) in *Carbon Dioxide Transport and Storage Costs in NETL Studies*[13] (March 2013) shows that construction of a 100-mile pipeline to western New York would cost $112 million dollars. Furthermore, the time necessary to acquire all required property rights, obtain regulatory approvals and construct the pipeline would take many years.

With regard to storage for CCS, the Interagency Task Force concluded that, while there is currently estimated to be a large volume of potential storage sites, "to enable widespread, safe, and effective CCS, CO_2 storage should continue to be field-demonstrated for a variety of geologic reservoir classes" and that "scale-up from a limited number of demonstration projects to wide-scale commercial deployment may necessitate the consideration of basin-scale factors (e.g., brine displacement, overlap of pressure fronts, spatial variation in depositional environments, etc.)." The cost to develop a carbon storage facility for the Project cannot be estimated given the limited demonstration projects completed to date.

From the cost data provided by the EIA, the capital costs for capture and transport equipment are estimated to be close to $600 million dollars, which would nearly double the cost of the Project and, therefore, be cost prohibitive.

Based upon the technical deficiencies of current CCS technology, the lack of suitable sequestration facilities near the Project, and its excessive cost, CCS was eliminated as a BACT option for GHG emissions from the combustion turbines.

Step 5: Selection of BACT for GHG Emissions

BACT for GHG emissions has been determined to be the application of advanced combined-cycle technology with natural gas firing as the primary fuel with USLD firing limited to certain operating periods. In accordance with BACT requirements, BACT must be established as a federally enforceable emission rate.

The recently permitted GHG emission rates in Table G-3 take into account degradation in turbine performance over the expected lifetime of each project. The majority of the GHG BACT decisions in Table G-3 apply several degradation factors initially established by the Bay Area Air Quality Management District for the permitting of the Russell City Energy Center. These degradation factors have been approved in numerous recent PSD permits issued by USEPA and other PSD-delegated agencies. As these degradation factors have been approved by USEPA, they are proposed to be applied for the Project to establish the GHG BACT emission rate. The following is a discussion of these factors and the proposed GHG BACT emission rate:

- The first factor accounts for design margin to reflect the likelihood that the equipment as constructed and installed may not fully achieve the optimal vendor specified design performance. A design margin of 3.3 percent is taken into account for this purpose.
- The second factor accounts for performance margin to reflect normal wear and tear of the combustion turbine over its useful life. A performance margin of 6.0 percent is taken into account for this purpose.

[13] http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev2_20130408.pdf

- The third factor accounts for degradation of auxiliary plant equipment to reflect normal wear and tear. An auxiliary equipment degradation margin of 3.0 percent is taken into account for this purpose.

These three factors are expected to compound upon each preceding factor such that the overall degradation in plant performance is estimated to be 12.8 percent over the useful life of the combustion turbines.

The DEEP has indicated that its preference is to establish GHG BACT in terms of a net heat rate. Several of the projects identified in Table G-3 have been permitted with a heat rate limit; the great majority of these limits have been established on a net-output basis. Additionally, most of these limits have been established solely for a natural gas-fired operating condition, without duct firing, at ISO conditions. The proposed GE 7HA.01 CTG has a new and clean designed heat rate of 6,241 Btu/kW-hr on a gross-output basis when firing natural gas at ISO conditions without duct firing. Taking into account a parasitic load of approximately 2.5 percent, the new and clean designed heat rate is 6,402 Btu/kW-hr on a net-output basis when firing natural gas at ISO conditions without duct firing. Applying the 12.8 percent performance degradation and margin factor discussed above, yields a net heat rate of 7,220 Btu/kW-hr when firing natural gas at ISO conditions without duct firing. This net heat rate is lower than any heat rate limit identified in Table G-3 and is proposed as GHG BACT for the Project.

Compliance with the proposed net heat rate limit will be demonstrated in accordance with ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996), or equivalent method approved by the DEEP. CPV Towantic proposes to complete this test with the initial performance testing and once every five years thereafter to verify compliance with the proposed net heat rate limit.

The operating data used to determine the GHG BACT emission rate are provided in Appendix A.

Start-up/Shutdown Emissions

Combustion turbines experience increased VOC, CO, and NO_x emissions during start-up and shutdown (SU/SD) operation. In addition, initial low operating temperatures during start-up preclude the use of the SCR and limit the efficiency of the oxidation catalyst. BACT for SU/SD is good operating practices by following the manufacturer's recommendations during start-up, and limiting the start-up time. The GE 7HA.01 combustion turbines proposed for the project are "fast start" units that can achieve compliance with steady-state emissions limits within one hour of start-up for all start types, further minimizing periods of increased emissions.

During SU/SD operation, VOC, CO, and NO_x emissions will be minimized during these short transitional periods by proper operational practices in accordance with manufacturer specifications. The vendor-specified SU/SD emissions for the combustion turbines are provided in Table G-4. Any increase in emissions during SU/SD operation is included in the potential annual emissions provided in Table E-3; detailed emission calculations are provided in Appendix A.

Table G-4: Start-up/Shutdown Emission Rates (lbs/hr)

Pollutant	Cold Start		Warm Start		Hot Start		Shutdown	
	Gas	ULSD	Gas	ULSD	Gas	ULSD	Gas	ULSD
NO_x	93	104	93	104	70	102	19	34
CO	242	230	242	230	238	231	121	18
VOC	37	87	37	87	36	90	60	23

For the purposes of Table G-4, the following definitions are applied:

- Cold Start-up refers to restarts made at least 72 hours or more after shutdown and shall not last longer than 60 minutes per occurrence.
- Warm Start-up refers to restarts made between 8 and 72 hours after shutdown and shall not last longer than 60 minutes per occurrence.
- Hot Start-up refers to restarts made between 0 and 8 hours after shutdown and shall not last longer than 60 minutes per occurrence.
- Shutdown refers to the period between the time the turbine load drops below 50 percent operating load and the fuel supply to the turbine is cut. Shutdown operation shall not last longer than 60 minutes per occurrence.

Auxiliary Boiler

The Project will include an auxiliary boiler rated at 92.4 MMBtu/hr fired exclusively with natural gas. The auxiliary boiler will provide steam to warm up the steam turbine in order to minimize the duration of plant start-ups. Annual operation of the auxiliary boiler will be limited to a full-load equivalent of 4,000 hours per year. Emissions from the boiler are subject to BACT requirements and a review was conducted of recently permitted emission rates from natural gas-fired boilers; the results of this review are provided in Table G-5. The emission limits provided in Table G-5 serve as the basis for determining the "most stringent emissions limitation which is achieved in practice" for natural gas-fired auxiliary boilers.

Volatile Organic Compounds

VOC is emitted from the auxiliary boiler as a result of incomplete oxidation of the fuel. VOC emissions can be minimized by the use of proper combustor design and good combustion practices. For the Auxiliary Boiler, the most advanced level of control identified in Table G-5 is good combustion practices achieved through state-of-the-art Ultra-LNB. Ultra-LNB can minimize VOC emissions and achieve an emission rate of 9.6 ppm corrected to 3% O_2, equivalent to 0.004 lb/MMBtu.

Table G-5: Summary of Recent PSD BACT Determinations for Natural Gas-Fired Auxiliary Boilers

Facility	Location	Permit Date	Controls	CO[a] (ppm)	VOC[a] (lb/MMBtu)	$PM_{10}/PM_{2.5}$[b] (lb/MMBtu)
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	Ultra-LNB	50	0.002 (LAER)	0.002
Brunswick County Power	Freeman, VA	05/23/2012	Ultra-LNB	50	0.006	0.0075
Dominion Warren County	Front Royal, VA	12/21/2010	Ultra-LNB	50	0.0053	0.005
Carroll County Energy	Washington Twp., OH	11/5/2013	Ultra-LNB	75	0.006	0.008
Renaissance Power	Carson City, MI	11/1/2013	LNB	50	0.005	0.005
Kleen Energy	Middletown, CT	07/2/2013	LNB	100	0.004	0.006
Oregon Clean Energy	Oregon, OH	06/18/2013	Ultra-LNB	75	0.006	0.008
Sunbury Generation	Sunbury, PA	04/01/2013	LNB	100	0.005	0.008
Hess Newark Energy	Newark, NJ	11/01/2012	Ultra-LNB	50	0.004	0.005

Facility	Location	Permit Date	Controls	CO[a] (ppm)	VOC[a] (lb/MMBtu)	$PM_{10}/PM_{2.5}$[b] (lb/MMBtu)
Cricket Valley Energy Center	Dover, NY	09/27/2012	Ultra-LNB	50	0.0015 (LAER)	0.005
Pioneer Valley Generation Company	Westfield, MA	04-12-2012	LNB	50	0.003	0.0048

[a] Concentration in ppm is parts per million by volume, dry, (ppmvd) at 3 percent O_2.
[b] Concentration in pounds per million Btu heat input (HHV), except as noted, including front (filterable) and back-half (condensable) PM.

Step 1: Identification of Potentially Feasible VOC Control Options

Potential control options for controlling VOC emissions from the auxiliary boiler include use of natural gas as the exclusive fuel, combustion controls, and an oxidation catalyst system.

Step 2: Technical Feasibility of VOC Control Options

Natural gas firing, combustion controls, and oxidation catalysts are considered technically feasible for controlling VOC emissions.

Step 3: Ranking of Technically Feasibility VOC Control Options

Combustion controls and oxidation catalyst systems are not mutually exclusive technologies. Therefore, no ranking of control options is necessary.

Step 4: Evaluation of the Most Effective VOC Control Options

Combustion controls include Ultra-LNB, which minimize emissions of NO_x while still achieving complete combustion of VOC. Use on an oxidation catalyst would be possible in addition to Ultra-LNB; however, VOC emissions from the natural gas-fired auxiliary boiler are expected to be straight chain alkanes, which are not efficiently controlled by an oxidation catalyst. Based upon speciated organic compound emission factors provided in AP-42 Section 1.4, Table 1.4-3, non-straight chain alkanes would be expected to contribute 0.00008 lb/MMBtu of the organic compound emissions, which is equal to 2 percent of the total VOC emissions. Therefore, while technically feasible, an oxidation catalyst is not expected to appreciably lower the VOC emissions below the vendor guaranteed emission rate. Further, as discussed later, installation of an oxidation catalyst system for CO control was determined to not be cost-effective.

Step 5: Selection of VOC BACT

The vendor-guaranteed VOC emission rate is at or below all of the permitted VOC limits in Table G-5 with the exception of the Green Energy Partners and Cricket Valley Generation projects, both of which were subject to LAER for VOC. None of the auxiliary boilers listed in the RBLC database have add-on controls; they all rely on low-NOx or Ultra-LNB burners and good combustion control to minimize VOC emissions. Therefore, use of natural gas as the exclusive fuel and good combustion controls has been selected as BACT for VOC from the auxiliary boiler.

Carbon Monoxide

CO is emitted from the auxiliary boiler as a result of incomplete oxidation of the fuel. CO emissions can be minimized by the use of proper combustor design and good combustion practices. For the auxiliary boiler, the most advanced level of control identified in Table G-5 is good combustion practices achieved through state-of-the-art Ultra-LNB. Ultra-LNB can minimize CO emissions and achieve an emission rate of 50 ppm corrected to 3% O_2.

Step 1: Identification of Potentially Feasible CO Control Options

CO control options for the auxiliary boiler include use of natural gas as the exclusive fuel, combustion controls, and an oxidation catalyst system.

Step 2: Technical Feasibility of CO Control Options

Natural-gas firing, combustion controls, and oxidation catalysts are considered technically feasible for controlling CO emissions.

Step 3: Ranking of Technically Feasibility CO Control Options

Combustion controls and oxidation catalyst systems are not mutually exclusive technologies. Therefore, no ranking of control options is necessary.

Step 4: Evaluation of the Most Effective CO Control Options

For the auxiliary boiler, the most advanced level of control identified in the RBLC database is good combustion practices. Further reductions in CO emissions could be achieved through installation of an oxidation catalyst; however, the installation of an oxidation catalyst on the auxiliary boiler would not be cost effective due to the already low CO emissions from the boiler. Potential CO emissions from the boiler are only 3.4 lbs/hr and limited to 6.8 tons per year due to the proposed operating restriction of 4,000 hours per year. The cost to control analysis in Attachment G2 shows a cost to control of over $7,400 per ton of CO removed for an oxidation catalyst on the auxiliary boiler. This cost to control is not economical and an oxidation catalyst was eliminated as a BACT option for this reason.

Step 5: Selection of CO BACT

The vendor guaranteed CO emission rate of 50 ppm corrected to 3 percent O_2 is at or below all of the permitted CO limits in the RBLC database. None of the auxiliary boilers listed in the RBLC database have add-on controls; they all rely on good combustion control to minimize CO emissions. Therefore, use of natural gas as the exclusive fuel and good combustion controls has been has been determined to be the most stringent level achieved in practice and is selected as BACT for CO from the auxiliary boiler.

Sulfur Dioxide and Sulfuric Acid Mist

Emissions of SO_2 from the auxiliary boiler result from oxidation of sulfur in the fuel. During combustion, a small percentage of SO_2 is further oxidized to SO_3 that subsequently reacts with moisture in the exhaust to form H_2SO_4.

Step 1: Identification of Potentially Feasible SO_2 and H_2SO_4 Control Options

As was discussed for the combustion turbines, use of low-sulfur fuels is the only feasible SO_2 and H_2SO_4 control technology for natural gas-fired boilers. Based on a review of the RBLC database and other sources, post-combustion controls have not been applied to natural gas-fired boilers; therefore, exclusive use of natural gas is considered the only feasible control option for SO_2 and H_2SO_4.

Step 2: Technical Feasibility of SO_2 and H_2SO_4 Control Options

The only technically feasible option for controlling SO_2 and H_2SO_4 is the use of low-sulfur fuels.

Step 3: Ranking of Technically Feasibility SO_2 and H_2SO_4 Control Options

The use of pipeline quality natural gas as the exclusive auxiliary boiler fuel is the only technically feasible option and represents the top level of control for SO_2 and H_2SO_4 emissions.

Step 4: Evaluation of the Most Effective SO_2 and H_2SO_4 Control Options

The most stringent level of control for SO_2 and H_2SO_4 emissions from combustion sources is the exclusive firing of pipeline quality natural gas. The USEPA defines pipeline quality natural gas in the Acid Rain regulations under

40 CFR 72.2 as natural gas that contains 0.5 gr S/100 scf. Implementing the top level of control for SO_2 emissions is also the top level of control for H_2SO_4 emissions.

Step 5: Selection of SO_2 and H_2SO_4 BACT

The most stringent level of control for SO_2 and H_2SO_4 emissions from combustion sources is the firing of pipeline quality natural gas. Therefore, BACT for SO_2 emissions from the auxiliary boiler is utilizing pipeline quality natural gas as the exclusive fuel. Implementing the top level of control for SO_2 emissions is also the top level of control for H_2SO_4 emissions.

Particulate Matter

Emissions of PM result from trace quantities of ash (non-combustibles) in the fuel, products of incomplete combustion, and conversion of SO_2 in the exhaust to condensable salts. Particulate emissions from a combustion source are minimized by utilizing state-of-the-art combustion technology while firing natural gas since natural gas has the lowest ash and sulfur content available.

Step 1: Identification of Potentially Feasible Particulate Control Options

Pipeline quality natural gas has the lowest ash and sulfur content of all fossil fuels. As previously discussed, post-combustion controls for particulates have never been applied to natural gas-fired boilers and are considered technically infeasible.

Step 2: Technical Feasibility of Particulate Control Options

Add-on controls have never been applied to natural gas-fired boilers and are considered infeasible. The only feasible particulate control technology for this type of project is the use of low ash and sulfur content fuels.

Step 3: Ranking of Technically Feasibility Particulate Control Options

Use of pipeline-quality natural gas as the exclusive auxiliary boiler fuel is the only technically feasible option and represents the top level of control for particulate emissions.

Step 4: Evaluation of the Most Effective Particulate Control Options

The most stringent level of control for particulate emissions from the auxiliary boiler is the firing of pipeline quality natural gas. The USEPA defines pipeline quality natural gas in the Acid Rain regulations under 40 CFR 72.2 as natural gas that contains 0.5 gr S/100 scf. Therefore, exclusive use of natural gas in the auxiliary boiler results in the greatest level of particulate reduction and represents the top level of control.

Step 5: Selection of Particulate BACT

The exclusive use of natural gas is proposed as BACT for particulates from the auxiliary boiler. The permitted PM emission rates in Table G-5 range from 0.002 to 0.008 lb/MMBtu. The reason for the difference in permitted PM emission from the auxiliary boiler is most likely due to differences in vendor specified emission rates. Based upon the boiler vendor emission guarantee, 0.007 lb/MMBtu was selected as BACT for the auxiliary boiler consistent with recent PSD BACT determinations.

Greenhouse Gases

As discussed for the combustion turbines and duct burners, there are three control mechanisms for reducing GHG emissions from combustion processes: (1) low carbon-emitting fuels; (2) energy efficiency; and (3) CCS. The combined-cycle combustion turbines account for greater than 99% of the facility's GHG emissions. As previously discussed, CCS is not technically or economically feasible for GHG emissions from combustion turbines. Since CCS becomes more feasible at larger scales, it is concluded that it is also not feasible for the auxiliary boiler. BACT for the auxiliary boiler is proposed to be firing natural gas as the sole fuel and efficient boiler design.

Step 1: Identification of Potentially Feasible GHG Control Options

The auxiliary boiler primarily provides low pressure steam to the steam turbine for warming prior to start-up of the combustion turbines. Operation of the auxiliary boiler reduces the start-up time of the combustion turbines and thereby reduces start-up emissions.

CPV has proposed an auxiliary boiler fired exclusively with natural gas. Other means of generating steam would be an auxiliary boiler fired with another fuel or an electric steam boiler. As for the combustion turbines, CCS could capture and store CO_2 emissions from the auxiliary boiler.

Step 2: Technical Feasibility of GHG Control Options

Electric steam boilers are not technically feasible for the Project. The auxiliary boiler proposed for the Project is rated at 92 MMBtu/hr; the largest commercially available electric steam boiler is more than an order of magnitude smaller than the proposed auxiliary boiler. Therefore, an electric steam boiler is considered technically infeasible. Although an auxiliary boiler using a different fuel is technically possible, natural gas has the lowest GHG emission rate, so use another fuel source would not be considered BACT.

Based upon the technical deficiencies of current CCS technology, the lack of suitable sequestration facilities near the Project, and its excessive cost, CCS was eliminated as a BACT option for GHG emissions from the combustion turbines. Since the combustion turbines represent over 99 percent of the total Project GHG emissions, CCS is not considered feasible for the auxiliary boiler.

Step 3: Ranking of Technically Feasibility GHG Control Options

Exclusive use of natural gas as the fuel for the auxiliary boiler is the only feasible GHG control option.

Step 4: Evaluation of the Most Effective GHG Control Options

As the only feasible GHG control option, a natural gas-fired auxiliary boiler is the lowest emitting BACT option for the Project.

Step 5 – Select BACT

BACT for the auxiliary boiler is firing natural gas as the exclusive fuel. The amount of natural gas fired in the auxiliary boiler will be limited to 359.6 million cubic feet per year, equivalent to 4,000 hours per year at full operating load.

Emergency Generator and Fire Pump Engines

The Project will include an emergency diesel generator engine and a diesel fire pump engine. Both engines will be fired with ULSD fuel. Both engines will be used only during emergency situations, with the exception of periodic maintenance/readiness testing, and will be limited to a maximum of 300 operating hours per rolling 12 month period.

Criteria Pollutants

No post-combustion controls have been demonstrated in practice for emergency internal combustion engines and the emergency nature of this equipment limits the fuel choice to ULSD. Therefore, the five-step BACT process is not warranted for determining BACT for VOC, CO, SO_2, H_2SO4, or $PM/PM_{10}/PM_{2.5}$. In order to satisfy GHG BACT requirements, CPV proposes that the engines meet NSPS 40 CFR 60 Subpart IIII requirements. Under 40 CFR 60 Subpart IIII, the emergency generator engine must meet the Tier 2 standards and the fire pump engine must meet the emission standards for fire pump engines in Table 4 of 40 CFR 60. Emissions will be controlled through the use of ULSD, engine design, good combustion practices, and limited annual operation. In accordance with NSPS Subpart IIII, operation of the engines for maintenance and readiness testing purposes shall be limited to no more than 100 hours per year. The engines will also be operated in accordance with Section 22a-174-3b(e) with total operating hours for all conditions of no more than 300 hours per year.

The Project has received vendor emission guarantees that are below the standards under NSPS Subpart IIII and proposes these emission guarantees as BACT. The emission guarantees are provided in Table G-6.

Table G-6: Emergency Engine Emission Guarantees

Pollutant	Emergency Generator Engine (g/bhp)	Fire Pump Engine (g/kW-hr)
NO_x	4.08	3.80
CO	0.44	0.90
VOC	0.11	0.10
$PM/PM_{10}/PM_{2.5}$	0.03	0.13
$SO2/H_2SO_4$ [a]	N/A	N/A

[a] SO_2/H_2SO_4 emissions will be limited based upon a maximum fuel sulfur content of 15 ppmw (0.0015 lb/MMBtu).

Greenhouse Gases

Step 1: Identification of Potentially Feasible GHG Control Options

The emergency engines provide electricity and/or fire protection during a loss of power or fire at the facility. In accordance with National Fire Protection Agency (NFPA) requirements under NFPA-20 (Standard for the Installation of Stationary Pumps for Fire Protection), emergency fire pump engines must be either diesel or electric engines and cannot be spark-ignited engines (i.e., natural gas, propane or gasoline). Furthermore, NFPA-20 emergency fire pump engines must have a dedicated diesel fuel tank. Spark ignition engines are not suitable for fire protection due to their unreliability as compared to diesel engines.

Similar to fire pump engines, a diesel generator is required for reliability purposes during an emergency. Unlike a fire pump engine, an electric engine cannot be used as an emergency generator as that equipment, by design, operates when electricity is not available.

Like the other Project sources, CCS could theoretically capture and store CO_2 emissions from the emergency engines.

Step 2: Technical Feasibility of GHG Control Options

Diesel-fired emergency engines are technically feasible. An electric fire pump engine was deemed technically infeasible as it could not operate if the power was out during an emergency.

Based upon the technical deficiencies of current CCS technology, the lack of suitable sequestration facilities near the Project, and its excessive cost, CCS was eliminated as a BACT option for GHG emissions from the combustion turbines. Since the combustion turbines represent over 99 percent of the total Project GHG emissions, CCS is not considered feasible for the emergency engines.

Step 3: Ranking of Technically Feasibility GHG Control Options

Since spark ignition engines were eliminated as technically infeasible, diesel engines are the lowest emitting technology available.

Step 4: Evaluation of the Most Effective GHG Control Options

As the only feasible GHG control option, diesel engines represent the lowest emitting BACT option for the Project.

Step 5 – Select BACT

BACT for the emergency diesel engines is compliance with the applicable NSPS and limited operation. The emergency engines will operate no more than 300 hours per rolling 12-month period and no more than 100 hours per rolling 12-month period for non-emergency operation (i.e., readiness testing).

Fugitive GHG Emission Sources

The Project will include natural gas handling systems and circuit breakers that contain sulfur hexafluoride (SF_6). Fugitive losses of natural gas and SF_6 will contribute to GHG emissions from the Project. Provided in Appendix A is an estimate of fugitive GHG emissions totaling 554 tpy, which represents less than 0.1% of the total GHG emissions for the Project.

Natural Gas Handling Systems

The proposed Project will include natural gas piping to transport fuel to all Project combustion equipment. Natural gas piping components, such as connections, valves, compressor seals, etc. are potential small sources of fugitive methane (CH_4). There are no specific control technologies to minimize fugitive emissions from natural gas handling beyond best operating practices; therefore, the five-step BACT process is not warranted for determining BACT for natural gas handling systems. In order to minimize fugitive GHG emissions from natural gas handling, the Project will implement current best operating practices for these emission sources, including the following:

- Implement an auditory/visual/olfactory leak detection program for the natural gas piping components and make daily observations; and
- Maintain records of all measurements and reports related to the fugitive emission sources including those related to maintenance as well as compliance with the Monitoring and QA/QC procedures defined under 40 CFR 98.304 Subpart DD.

Circuit Breakers

Circuit breakers utilize SF_6 as an arc-extinguishing medium for current interruption and for dielectric insulation between terminals. SF_6 has superior performance over all other materials for these purposes and, therefore, provides the greatest level of safety for this application.

Step 1: Identification of Potentially Feasible GHG Control Options

The available GHG control technologies for the circuit breakers are limiting the leakage of SF_6 and use of non-SF_6 containing circuit breakers.

Step 2: Technical Feasibility of GHG Control Options

The highest capacity non-SF_6 containing circuit breaker commercially available has a capacity of 72.5 kV. The Project will connect with Connecticut Light and Power's distribution system at 115 kV. Therefore, non-SF_6 containing circuit breakers are not technically feasible for the Project. Limiting the SF_6 leakage rate is technically feasible.

Step 3: Ranking of Technically Feasibility GHG Control Options

Limiting the SF_6 leakage rate is the only technically feasible GHG control option for the circuit breakers.

Step 4: Evaluation of the Most Effective GHG Control Options

As the only technically feasible GHG control option, limiting the SF_6 leakage rate is the top level of GHG control for high voltage circuit breakers.

Step 5 – Select BACT

BACT for GHG from the circuit breakers is limiting the SF_6 leakage rate. Each circuit breaker will be equipped with a low pressure alarm and low pressure lockout. SF_6 emissions from each circuit breaker will be calculated annually (calendar year) in accordance with the mass balance approach in Equation DD-1 of 40 CFR Part 98, Subpart DD. The maximum annual leakage rate for SF_6 will not exceed 0.5% of the total storage capacity of the plant's circuit breakers.