STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR RESOURCES

PRELIMINARY DETERMINATION FOR A MAJOR SOURCE PERMIT FOR THE CLEAR RIVER ENERGY CENTER

May 8, 2019

NAME OF SOURCE:	Clear River Energy Center
LOCATION:	Wallum Lake Road Burrillville, Rhode Island
APPLICATION PREPARED BY:	ESS Group, Inc. 401 Wampanoag Trail, Suite 400 East Providence, RI 02915 (401) 419-7749
OWNER OF SOURCE:	Invenergy Thermal Development, LLC One South Wacker Drive Suite 1900 Chicago, IL 60606

I. Description of the Proposed Project

Invenergy Thermal Development LLC proposes to construct and operate the Clear River Energy Center, a combined-cycle electrical power generating facility adjacent to the Spectra Energy Algonquin Compressor Station located along Wallum Lake Road (Route 100) in Burrillville, Rhode Island.

The proposed facility will include two General Electric Model 7H.02 combustion turbines, each capable of firing natural gas as the primary fuel and ultra-low sulfur diesel (ULSD) as a back-up fuel. Each combined-cycle combustion turbine will produce electricity and steam. The turbines will be operated in a single-shaft combined-cycle configuration. Each turbine will be equipped with a heat recovery steam generator (HRSG) with natural gas only fired duct burners. The steam produced by the two HRSGs will be used to power a single steam turbine. The steam passed through the system will be cooled and condensed back to water by the use of an air-cooled condenser (ACC).

Invenergy is proposing to install two selective catalytic reduction systems (SCR) for air pollution control of nitrogen oxide (NO_x) emissions, one for each combustion turbine and associated HRSG. SCR is a technology that achieves post-combustion reduction of NOx from flue gas within a catalytic reactor. The SCR system will utilize 19% aqueous ammonia (NH_3) as a reagent to reduce NOx emissions. The reagent is injected into and mixes with the flue gas and both components diffuse through a catalyst where the NOx in the flue gas is chemically reduced to molecular nitrogen (N_2) and water vapor (H_2O). The facility will store the aqueous NH3 in a 40,000-gallon aboveground storage tank.

Each combustion turbine and HRSG will be equipped with an oxidation catalyst (OC) for air pollution control of carbon monoxide (CO), volatile organic compounds (VOCs), and organic hazardous air pollutants (HAPs). Catalytic oxidation is a post-combustion technology, which does not rely on the introduction of additional chemical reagents to promote the desired reactions.

The maximum combined net power output of the facility be approximately 1,080 megawatt (MW) while firing with natural gas and 966 MW while firing ULSD.

The maximum heat input capacity for each combustion turbine is 3,448 million BTUs (MMBTU) per hour while firing natural gas and 3,692 MMBTU per hour while firing ULSD. Each natural gas only duct burner will each have a maximum heat input capacity of 446 MMBTU per hour.

The combustion turbine's total ULSD usage will be limited to a maximum of 18,987,429 gallons in any 12-month rolling period. This usage will apply to only those times when natural gas is unavailable or to maintain system readiness. Natural gas could be considered unavailable under the following situations that are declared by the Independent System Operator-New England (ISO NE), a federally-regulated independent organization who dispatches and directs the flow of electricity across the region to manage grid reliability: (1) If ISO NE has declared an Energy Emergency under ISO NE's Operating Procedure No. 21 (Actions During an Energy Emergency (OP-21)); or (2) a Capacity Emergency under ISO NE's Operating Procedure No. 4 (Actions During a Capacity Deficiency (OP-

4)); or (3) under extreme circumstances under ISO NE's Operating Procedure No. 7 (Actions in an Emergency (OP-7)).

Additional sources of air pollution emissions at the site will also include a 140.6 MMBTU (heat input) auxiliary boiler, a 15 MMBTU (heat input) dew point heater, a 2682 horse-powered (HP) diesel-fired compression ignition internal combustion engine/generator set for emergency purposes, and a 315 HP diesel-fired fire pump engine.

Potential Criteria Pollutant Emissions from the Proposed Facility

Combustion Turbines & Duct Burners

Table 1 summarizes the total maximum criteria pollutant emissions from both combustion turbines and their associated duct burners combined. The total ton per year emission rate is the maximum combined total if the facility was to utilize all the ULSD allowed and it also takes into consideration the maximum emission rates that could occur during startup and shutdown condition. The startup period is defined as the period beginning from the turbines initial firing and lasting until the minimum emissions compliant load is reached. The shutdown period is defined as the period beginning from the time the operating load goes below the minimum emissions compliance load and lasting until the fuel flow is completely off and combustion has ceased. The startup period will be limited to approximately 136 hours per year for both turbines combined. The shutdown period will be limited to approximately 16 hours per year for both turbines combined. The minimum emissions compliance load is defined at which the facility's continuous emissions monitors (CEMs) reports compliance with each of the permitted NOx, CO, and NH3 emission limit. The remaining 8,609 hours per year of operation is assumed to occur under steady state conditions.

CEMs will monitor emissions of nitrogen oxides, carbon monoxide, ammonia, oxygen and opacity.

Table 1- Potential Emissions from the Proposed Combustion Turbines & Duct Burners

Pollutant	**(tons/yr)**
Nitrogen oxides (NOx)	273.42
Carbon monoxide (CO)	227.34
PM-10/Particulates (PM)	153.90
Nonmethane hydrocarbons (VOC)	84.72
Sulfur dioxide (SO_2)	52.00
Carbon Dioxide (CO_2)	3,584,983

Auxiliary Boiler

The auxiliary boiler will supply gland sealing steam to the steam turbine, sparging steam to the HRSG steam drums, sparging steam to the ACC condensate tank, and motive steam to establish initial vacuum in the ACC and the steam turbine. It will be equipped with ultra-low NOx burners and flue gas recirculation for emissions control. The boiler will only fire natural gas and will be limited to operate at maximum capacity up to 2,400 hours per year.

Table 2- Potential Emissions from the Proposed Auxiliary Boiler	
Pollutant	**(tons/yr)**
Nitrogen oxides (NOx)	1.86
Carbon monoxide (CO)	6.07
PM-10/Particulates (PM)	1.18
Nonmethane hydrocarbons (VOC)	0.672
Sulfur dioxide (SO_2)	0.252
Carbon Dioxide (CO_2)	19,909

Dew Point Heater

The natural gas from the pipeline is under high pressure conditions and needs to be reduced to match the pressure required by the combustion turbines. This reduction in pressure will lead to a decrease in the temperature of the natural gas. The dew point heater will be used to maintain the temperature of the natural gas delivered to the gas turbines at a nominal 50°F above the hydrocarbon dew point of the natural gas. The heater will be equipped with ultra-low NOx burners and flue gas recirculation for emissions control. The heater will only fire natural gas and will be allowed to operate as needed.

Table 3- Potential Emissions from the Proposed Dew Point Heater	
Pollutant	**(tons/yr)**
Nitrogen oxides (NOx)	0.657
Carbon monoxide (CO)	1.01
PM-10/Particulates (PM)	0.315
Nonmethane hydrocarbons (VOC)	0.526
Sulfur dioxide (SO_2)	0.066
Carbon Dioxide (CO_2)	7,753

Emergency Generator

The proposed emergency generator will only operate when grid power is unavailable and for maintenance and readiness testing for up to 1 hour per week not to exceed 300 hours per year.

Table 4- Potential Emissions from the Proposed Emergency Generator	
Pollutant	**(tons/yr)**
Nitrogen oxides (NOx)	4.84
Carbon monoxide (CO)	0.266
PM-10/Particulates (PM)	0.027
Nonmethane hydrocarbons (VOC)	0.098

Sulfur dioxide (SO_2)	4.59×10^{-3}
Carbon Dioxide (CO_2)	481

Fire Pump Engine

The proposed fire pump engine will only operate during emergency situations and for maintenance and readiness testing for up to 1 hour per week not to exceed 300 hours per year.

Table 5- Potential Emissions from the Proposed Fire Pump Engine	
Pollutant	**(tons/yr)**
Nitrogen oxides (NOx)	0.257
Carbon monoxide (CO)	0.047
PM-10/Particulates (PM)	7.80×10^{-3}
Nonmethane hydrocarbons (VOC)	8.55×10^{-3}
Sulfur dioxide (SO_2)	4.95×10^{-4}
Carbon Dioxide (CO_2)	52.28

Potential Emissions from the Proposed Facility

The facility is classified as a major stationary source under the requirements for major stationary sources in nonattainment areas "Air Pollution Control Permits", 250-RICR-120-05-9.8 because potential emissions of nitrogen oxides and volatile organic compounds exceed 50 tons per year. The facility is also classified as a major stationary source under the requirements for major stationary sources in attainment or unclassifiable areas, also known as the PSD requirements in 250-RICR-120-05-9.9 because potential emissions of carbon monoxide and particulate matter less than 10 microns exceed 100 tons per year. As the facility is classified as a new major stationary source, the facility is subject to regulation for Greenhouse gases (GHGs) as defined under 250-RICR-120-05-9.5.1(B)(41) and the potential to emit is greater than 75,000 tons per year of carbon dioxide equivalents (CO_2e).

Table 6- Potential Emissions from the Proposed Facility		
	All Emission Units	**Major Source Thresholds**
Pollutant	**(tons/yr)**	**(tons/yr)**
Nitrogen oxides (NOx)	281.03	50
Carbon monoxide (CO)	234.73	100
PM-10/Particulates (PM)	155.42	100
Nonmethane hydrocarbons (VOC)	86.46	50
Sulfur dioxide (SO_2)	52.23	100
Carbon Dioxide (CO_2)	3,613,178	75,000 CO_2e

II. Requirements for Major Stationary Sources in Nonattainment Areas

The nonattainment area provisions of "Air Pollution Control Permits", 250-RICR-120-05-9 are applicable to the pollutant volatile organic compounds (VOC). The following is a discussion of the various provisions of 250-RICR-120-05-9.8 and how the applicant has demonstrated compliance with those provisions.

A. Lowest Achievable Emission Rate (LAER) (Air Pollution Control Permits, 250-RICR-120-05-9.8.1(B)(1))

250-RICR-120-05-9.8.1(B)(1) requires that a new major stationary source must meet an emission limitation that is considered the lowest achievable emission rate (LAER). The lowest achievable emission rate will be based on technological factors and can be in the form of a numerical emission standard or a design, operational or equipment standard. It is the responsibility of the applicant to present and defend the technology chosen to represent LAER.

LAER is the most stringent emission limitation derived from either of the following:

(1) the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or

(2) the most stringent emission limitation achieved in practice by such class or category of source.

By definition LAER cannot be less stringent than any applicable new source performance standard (NSPS).

As part of the review of this permit application, the Office of Air Resources reviewed recent air permits for similar projects issued by other state and local air pollution control agencies. Table 7 summarizes our findings.

The Office of Air Resources believes that LAER for the proposed Clear River Energy Center facility is a NO_x emission limitation of 2 ppm, dry, by volume (ppmdv) corrected to 15% O_2 (1-hour average) while firing natural gas and 5 ppmdv corrected to 15% O_2 (1-hour average) while firing ULSD. The applicant proposes to meet this emission limitation by using selective catalytic reduction (SCR) to reduce the concentration of NO_x in the exhaust gases from the turbines and duct burners.

Selective catalytic reduction (SCR) is a post combustion or flue gas treatment technique. The process involves the injection of ammonia into the flue gases upstream of a catalyst bed. The ammonia, mixed with the combustion products, passes over a catalyst bed and the nitrogen oxides (NO_x) in the flue gas are reduced to nitrogen (N_2) and water vapor (H_2O). The catalyst requires an operating temperature between 600ºF and 750ºF for optimum performance and is therefore installed in the heat recovery steam generator (HRSG).

The Department is not aware of any air pollution control rule or regulation contained in the implementation plan of any State that would require a combined cycle combustion turbine firing natural gas or ULSD that would result in lower emissions than that proposed here. Additionally, the Department is not aware of any combined cycle combustion turbine firing natural gas or ULSD in place that will result in lower emissions than that proposed here.

Therefore, the Office of Air Resources believes that the proposed emission rate of 2 ppmvd NOx, corrected to 15 percent O_2 represents LAER for the proposed facility.

Table 7- NO_x Emission Limitations for Recently Permitted Projects Firing Natural Gas				
Facility	Location	Permit Status	Date	NO_x Emission Limit Gas Firing
CPV Towantic, LLC	CT	Final	2/19/16	2 ppmvd corrected to 15% O_2
MATEP Limited Partnership	MA	Final	7/1/16	2 ppmvd corrected to 15% O_2
MIT	MA	Draft	11/27/17	2 ppmvd corrected to 15% O_2
CPV Valley Energy Center	NY	Final	9/28/17	2 ppmvd corrected to 15% O_2
Stonegate Power	NJ	Final	11/3/16	2 ppmvd corrected to 15% O_2
Mattawoman Energy Center	MD	Final	11/13/15	2 ppmvd corrected to 15% O_2
Palmdale HyBrid Power	CA	Final	1/27/14	2 ppmvd corrected to 15% O_2
Footprint Power	MA	Final	1/10/14	2 ppmvd corrected to 15% O_2

Table 8- NO_x Emission Limitations for Recently Permitted Projects Firing ULSD				
Facility	Location	Permit Status	Date	NO_x Emission Limit ULSD Firing
CPV Towantic, LLC	CT	Final	2/19/16	5 ppmvd corrected to 15% O_2
MATEP Limited Partnership	MA	Final	7/1/16	6 ppmvd corrected to 15% O_2
MIT	MA	Draft	11/27/17	6.8 ppmvd corrected to 15% O_2
Stonegate Power	NJ	Final	11/3/16	4.0 ppmvd corrected to 15% O_2

B. *Compliance Status of Existing Major Stationary Sources (250-RICR-120-05-9.8.1(B)(2))*

250-RICR-120-05-9.8.1(B)(2) requires that the applicant certify that all existing major stationary sources owned or operated by the applicant located within the state are in compliance with all applicable state and federal air pollution rules and regulations under the Clean Air Act and federally enforceable compliance schedules.

The applicant, Clear River Energy Center does not own or operate any existing major stationary sources in the state.

C. *Emission Offsets (250-RICR-120-05-9.8.1(B)(3))*

250-RICR-120-05-9.8.1(B)(3) requires the applicant to provide evidence that the total tonnage of emissions of the nonattainment air pollutant allowed from the proposed new source, shall be offset by a greater reduction in the actual emissions of such air pollutant from the same or other sources. The facility must demonstrate that all the requirements below are satisfied prior to startup[1].

Clear River Energy Center has executed contracts to purchase NO_x and VOC offsets to satisfy this requirement. These offsets were generated by the shutdown of a facility located in New York.

Potential NO_x emissions from the proposed Clear River Energy Center facility is 281 tons per year. Clear River Energy Center must purchase 337 tons of offsets. This will be a requirement in any permit issued pursuant to this preliminary determination. The offset ratio is 337/281 = 1.2.

Potential VOC emissions from the proposed Clear River Energy Center facility is 86 tons per year. Clear River Energy Center must purchase 104 tons of offsets. This will be a requirement in any permit issued pursuant to this preliminary determination. The offset ratio is 104/86 = 1.2.

It is well documented that emissions from "upwind" states, such as New York, contribute to the formation of ozone in Rhode Island. Since the offset ratio is greater than 1:1 there will be a net reduction in NO_x emissions. Therefore, all of the requirements of 250-RICR-120-05-9.8.1(B)(3) and 9.8.1(B)(4) pertaining to emission offsets are satisfied.

250-RICR-120-05-9.8.1(B)(4) lists six criteria that emission offsets must satisfy. The emission offsets must:

(a) be approved by the Director, and be part of a federally enforceable permit, or part of an operating permit issued pursuant to 40 CFR Part 71 or under regulations approved pursuant to 40 CFR Part 70, or made part of the federally approved State Implementation Plan.

(b) be federally enforceable prior to the issuance of the Major Source Permit

(c) actually occur at the source of the offsets prior to the start-up of the new source

(d) be at an offset ratio of at least 1.2 to 1 for nitrogen oxides

(e) be obtained from a source in the same nonattainment area or in another nonattainment area provide that:

(1) The other nonattainment area has an equal or higher nonattainment area classification than the area in which the source is to be located;

[1] The Office of Air Resources currently is under sanctions from the USEPA for failing to submit required SIP provisions. The outcome of the sanctions is that the offset ratio is 2 to 1. The OAR is working with EPA to rectify the situation prior to finalizing the proposed permit.

and

(2) Emissions from such other area contribute to a violation of the national ambient air quality standard in the nonattainment area in which the source is to be located.

(f) when considered in conjunction with the proposed emissions increase, have a net air quality benefit in the area.

D. Alternatives Analysis (250-RICR-120-05-9.8.1(B)(5))

250-RICR-120-05-*9.8.1(B)(5)* requires the applicant to prepare an analysis of alternative sites, sizes, production processes, and environmental control techniques that demonstrate the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction or modification.

The applicant states that suitable locations must have access to a large natural gas pipeline, access to high voltage transmissions lines, be properly zoned, and have a suitable buffer to any nearby residential properties. The only industrial parcels that cross a natural gas pipeline are the parcels owned by Algonquin Gas Transmission (AGT) and the Ocean State Power plant site. Other parcels near to the pipeline are surrounded by residential properties and were deemed to be much less ideal. AGT's parcel includes not only the pipeline but also a double circuit 345 kV transmission line. The parcel is also located with frontage on Wallum Lake Road, so no additional right-of-way is needed.

The applicant has concluded that the proposed location is the best location.

The "Study of Alternatives" that was submitted with the EFSB application evaluates seven alternative production technologies and/or fuels which include; (1) coal-fired (2) reciprocating engines (3) simple cycle turbines; (4) solar; (5) geothermal; (6) biomass; and (7) wind energy.

These technologies were evaluated with respect to technical maturity, reliability, siting/permitting feasibility, cost effectiveness, local resource potential and environmental impact. This evaluation concluded that the chosen-combined cycle gas turbine technology is superior to each of the identified alternatives in terms of cost, environmental impact and reliability.

E. NO_x Air Quality Impact (250-RICR-120-05-9.8.1(B)(6))

250-RICR-120-05-9.8.1(B)(6) requires that the applicant demonstrate compliance with the conditions in 250-RICR-120-05-9.9.1(A)(2) through (4) and 9.9.2(A). See Section III of this document for a complete discussion of these requirements.

F. Air Toxics Regulation and CAALs (250-RICR-120-05-9.8.1(B)(7))

250-RICR-120-05-*9.8.1(B)(7)* requires the applicant to demonstrate that the emission from the proposed facility will not cause an increase in the ground level ambient concentration at or beyond the property line in access of that allowed by Air Toxics, 250-RICR-120-05-

22 and any Calculated Acceptable Ambient Levels. See Section III of this document for a complete discussion of these requirements.

G. Health Risks from Proposed Air Pollution Sources (250-RICR-120-05-9.8.1(B)(8))

250-RICR-120-05-*9.8.1(B)(8)* requires the applicant to conduct any studies required by the Guidelines for Assessing Health Risks from Proposed Air Pollution Sources and meet the criteria therein.

The proposed source was required to conduct the studies required under the Guidelines and submitted a Health Risk Assessment on January 27, 2016.

H. Applicable Air Pollution Control Regulations (250-RICR-120-05-9.8.1(B)(9))

250-RICR-120-05-*9.8.1(B)(9)* requires the applicant to demonstrate that the facility will be in compliance with all applicable state and federal air pollution control regulations at the time the source commences operation. See section III. G of this document for a complete discussion of these requirements.

III. Requirements for Major Stationary Sources in Attainment or Unclassifiable Areas

The following is a discussion of the various provisions of 250-RICR-120-05-9.9 and how the applicant has demonstrated compliance with those provisions.

A. Best Available Control Technology (BACT) (250-RICR-120-05-9.9.1(A)(1)

250-RICR-120-05-*9.9.1(A)(1)* requires that a stationary source shall apply BACT for each pollutant it would have the potential to emit. Best available control technology is defined as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each air pollutant which would be emitted from any proposed stationary source or modification which the Director, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable state or federal air pollution control rule or regulation. If the Director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of air emissions standards infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement of best available control technology. Such standard shall to the degree possible set forth the emission reduction achievable by implementation of such design, equipment, work practice or operation and shall provide for compliance by means which achieve equivalent results."

The Office of Air Resources requires the use of the "top down" approach in a BACT analysis. The first step in the "top down" approach is to determine, for the source category being evaluated, the most stringent level of control available. If it can be shown that this level of control is technically or economically infeasible, then the next most stringent level of control is determined and similarly evaluated. Such an evaluation would continue until the level of control under consideration could not be ruled out by any technical, environmental or economic considerations.

The purpose of the BACT analysis is to determine the lowest emission limits that can be met by the source, in light of energy, economic and environmental impacts. The following is an evaluation of the applicant's BACT analysis.

1. Carbon Monoxide (CO)

The most stringent control technology identified for reducing carbon monoxide emissions on a natural-gas fired turbine is catalytic oxidation. As with SCR, catalytic oxidation is a post combustion or flue gas treatment technique. The technology is an extension of that used for automotive emission control. The technology is relatively simple requiring only the flow of flue gases over a catalyst bed. Nothing is added to the flue gases and given the temperature operating range of the catalyst, it is usually placed in the heat recovery steam generator, upstream of an SCR system. CO oxidation catalyst technology has been used on gas turbine installations in several locations.

The applicant has proposed the use of an oxidation catalyst for the control of CO emissions. The emissions from the proposed gas-fired turbines and duct burners will not exceed a CO exhaust gas concentration of 2 ppmvd, corrected to 15 percent O_2 regardless of the load on the turbine while firing natural gas and 5 ppmvd, corrected to 15 percent O_2 regardless of the load on the turbine while firing ULSD.

2. Sulfur dioxide (SO_2)

The only means of controlling SO_2 emissions from a combustion turbine is to limit the sulfur content of the fuel. Flue gas desulfurization systems have not been applied to natural gas-fired combustion turbines. The applicant is proposing to burn natural gas in the combustion turbine and ULSD during periods of gas curtailments. The proposal to limit fuel use to natural gas would represent BACT and the most stringent level of control for this pollutant.

Sulfur is added as an odorant by the natural gas supplier for safety reasons. SO_2 emissions during natural gas firing are expected to be minimal. The natural gas to be combusted at this facility is expected to contain, no greater than, 2.0 grains of sulfur per 100 standard cubic feet of gas which is equivalent to an allowable sulfur dioxide emission rate of 0.0054 lbs per MMBtu heat input.

BACT for sulfur dioxide is therefore represented by limiting fuel use to natural gas and ULSD. The emission limit chosen to represent BACT for SO_2 is: 0.00167 lbs per MMBTU heat input while firing the combustion turbines only; 0.00168 lbs per MMBTU heat input while firing the combustion turbines with the duct burners; and 0.0015 while firing ULSD.

3. Particulate Matter less than 10 microns (PM-10)

The Office of Air Resources is not aware of any combustion turbine installations where flue gas controls are used to reduce particulate emissions. Additionally, the Office of Air Resources believes that the concentration of particulate matter in the flue gases from a gas turbine, during combustion of natural gas is not sufficient to warrant consideration of flue gas controls as a BACT option. The effectiveness of flue gas controls at such a low loading would be minimal. Therefore, flue gas controls are not considered a practical option.

BACT for particulate emissions is good combustion practices to minimize particulate emissions. The emission limits chosen to represent BACT for PM-10 emissions is: *0.00368 lb/MMBTU heat input while firing the combustion turbines only*; *0.00445 lbs per MMBTU heat input while firing the combustion turbines with the duct burners; and 0.019 while firing ULSD.*

4. Nonmethane Hydrocarbons (NMHC)

The most stringent control technology identified for reducing NMHC emissions was catalytic oxidation. This is the same technology described previously for control of carbon monoxide emissions.

Therefore, the Office of Air Resources believes that the proposed emission rates represent LAER or BACT for the proposed facility: 2 ppmvd NMHC corrected to 15 percent O_2 while firing the combustion turbines with the duct burners; and 5 ppmvd NMHC corrected to 15 percent O_2 while firing ULSD in the combustion turbines.

5. Ammonia (NH_3)

The SCR process involves the injection of ammonia into the flue gases. Due to a number of factors, it is impractical to inject ammonia at the theoretical quantity needed to remove all the NO_x and therefore an excess of ammonia over the theoretical quantity is necessary to achieve high conversion efficiencies. As a result, some unreacted ammonia passes through the system and is discharged to the atmosphere. This unreacted ammonia emission is commonly referred to as "ammonia slip."

Ammonia slip could, theoretically, be reduced through the use of flue gas controls such as a specially designed ammonia decomposition catalyst. However, the Office of Air Resources is not aware of any commercial applications of this technology, or any other flue gas control technique, for combustion turbines. Therefore, we do not consider flue gas controls an available BACT option.

The applicant has proposed to limit ammonia slip to 2 ppm ppmvd, corrected to 15 percent O_2 or less during natural gas and ULSD firing.

Therefore, the Office of Air Resources concluded that BACT for ammonia slip is represented by an SCR system design and good operating practices to minimize emissions.

B. Air Quality Impact Analysis (250-RICR-120-05-9.9.1(2))

The Office of Air Resources requested that the applicant model the criteria pollutants from the Algonquin Compressor Station, Ocean State Power, and the Tennessee Gas Compressor Station together with the background concentrations for compliance with EPA's National Ambient Air Quality Standards (NAAQS). The applicant's air dispersion modeling analysis was reviewed with respect to the methodology required under the Rhode Island Air Dispersion Modeling Guidelines. The modeling demonstrated that the combined emissions from the proposed facility along with the Algonquin Compressor Station, Ocean State Power, and the Tennessee Gas Compressor Station will not exceed the NAAQS.

Multi-Source Criteria Pollutant Modeling Results ($\mu g/m^3$)

Pollutant	Averaging Time	Maximum Predicted Multi-Source Impact	Background Concentrations	Total	NAAQS
SO_2	1-hour	41	36.0	77.0	195
	3-hour	45.2	45.0	90.2	1300
	24-hour	22.7	21.0	43.7	365
	Annual	0.4	3.69	4.1	80
CO	1-hour	164	2346	2510	40000
	8-hour	142	1495	1637	10000
NO_2	1-hour	44.7	80	124.7	188
	Annual	3.7	19.7	23.4	100
PM-10	24-hour	7.5	17.0	24.5	150
PM-2.5	24-hour	4.5	13.1	17.6	35
	Annual	0.69	5.17	5.9	12
Lead	24-hr/Quarterly	0.00078	0.0	0.00078	0.15

250-RICR-120-05-9.9.1(2)(a) requires the applicant to demonstrate, by means of air quality modelling, that allowable emissions from the proposed source only would also not cause or contribute to:

1. air pollution in violation of any national ambient air quality standard; or,

2. any increase in ambient concentrations exceeding the remaining available increment for the specified air contaminant.

The Office of Air Resources' review of the applicant's air quality impact analysis consists of three parts:

1. A review of the modeling methodology used to predict the ambient impacts of the facility;

2. A review of the emission rates used as input to the air quality models to predict the ambient impacts of the facility; and

3. A comparison of the predicted impacts for criteria pollutants to the applicable significant impact levels and a comparison of the predicted impacts for non-criteria pollutants to acceptable ambient levels.

Therefore, the following is a summary of the Office of Air Resources findings with respect to each of these reviews.

1. Modeling Methodology

The applicant prepared an air quality modeling protocol. The protocol discusses, in detail, the methodology used to conduct the air quality impact analysis. The Office of Air Resources reviewed this protocol and determined that the protocol represents acceptable methodology to conduct this particular air quality impact analysis. The key components of the modeling methodology are as follows:

a. Discussion of Emission Sources

The applicant identified eight emission sources that have the potential to cause a moderate impact of 1,3-Butasdiene, Acetaldehyde, Acrolein, Ammonia, Arsenic, Barium, Benzene, Cadmium, Chromium, Cobalt, Copper, Ethyl Benzene, Formaldehyde, Hexane, Manganese, Mercury, Naphthalene, Nickel, Propylene, Propylene Oxide, Selenium, Sulfuric Acid, Toluene, Vanadium, Xylene, Zinc, NO_2, CO, SO2, PM10, PM2.5, and Lead to surrounding air quality.

The facility-wide sources including:
Combustion turbine/HRSG-1 & 2 (natural gas)
Combustion turbine/HRSG-1 & 2 (ULSD)
Auxiliary Boiler
Dewpoint Heater
Diesel emergency generator
Fire pump engine

b. Model Selection

The AMS/EPA Regulatory Model Improvement Committee's (AERMIC) AERMOD model, version 15181 was selected. The Rural option was selected for Burrillville, RI NED (National Elevation Dataset) coverage location for 1-hour, 3-hr, 8-hr, 24-hour, and Annual averages.

c. Meteorology

The meteorological data used by the applicant to predict the pollutant air impacts are consistent with EPA's recommended procedures for AERMET. The AERMET data covered a five-year period of surface and upper air data from 2007 to 2014. Surface data were collected at T. F. Green Airport and upper air data were collected at Chatham, Mass. These stations are the closest and most representative national weather service stations to the site of the proposed project.

d. Receptor Locations

The applicant used the NED coverage for the Burrillville area to create a domain and to show the exact location of the modeling structures in relation to the surrounding topography. The AERMAP terrain data used by the applicant to create Clear River's facility-wide building domain is consistent with EPA recommended procedures for AERMAP.

The applicant placed one polar receptor grid centered at the GT/HRSG 1 stack location. Receptors were placed at 25-meter intervals out to 1,000 meters from the center, 100-meter intervals out to 2,000 meters, 200-meter intervals out to 5,000 meters, 500-meter intervals out to 10,000 meters, and 1000-meter intervals out to 50,000 meters. The receptor grid was used to construct the domain used to produce the final concentrations around and beyond the facility. The recommended 10 meter spacing property line receptor was used by the consultant. The construction of the polar grid and the selection of distances are consistent with procedures specified in EPA's "Guideline on Air Quality Model" (40 CFR Part 51, Appendix W).

e. Model Options

The applicant selected the Rural option of AERMOD as requested under protocol approval dated July 27, 2015. EPA's Tier II Ambient Ratio Method (ARM) for determining conversion of NO to NO_2 emissions of 0.80 was used, as per the approved modeling protocol. The protocol requested urban modeling, which was not included, to also be performed. The regulatory options for point sources selected by ESS are consistent with those recommended for regulatory use in EPA's "Guideline for Air Quality Models" (40 CFR Part 51, Appendix W).

f. Good Engineering Practice (GEP) Stack Height and Building Downwash Parameters

The emissions of concern were the point sources that emit 1,3-Butasdiene, Acetaldehyde, Acrolein, Ammonia, Arsenic, Barium, Benzene, Cadmium, Chromium, Cobalt, Copper, Ethyl Benzene, Formaldehyde, Hexane, Manganese, Mercury, Naphthalene, Nickel, Propylene, Propylene Oxide, Selenium, Sulfuric Acid, Toluene, Vanadium, Xylene, Zinc, NO_2, CO, SO2, PM10, PM2.5, and Lead to the atmosphere. Since the analysis contains non-GEP point sources, building downwash effects were considered in the modeling.

g. Cavity Impacts

AERMOD has been developed to incorporate the PRIME downwash algorithm, which calculates impact concentrations in all cavity regions from the controlling buildings and structures within the modeled domain. This modeling study included a cavity analysis of the nearby buildings from the modeled point sources. The highest cavity impacts provided by the model were below applicable NAAQS, SILS, AALs and were localized southeast inside the property boundary. The applicant's analysis of the cavity regions of this modeling study is consistent with EPA's "Guideline for Air Quality Models" (40 CFR Part 51, Appendix W).

h. Class I Areas

The nearest Class I area is the Lye Brook Wilderness Area in southern Vermont located approximately 170 km northwest of the facility. The model predicts that visibility will not be impacted by the proposed project.

The applicant applied AERMOD to determine the possible extent of facility impacts greater than the Class I SILs, out to a maximum distance of 50 kilometers. Receptors beyond 10 kilometers were located at 1-kilometer increments.

The maximum distances from the Facility at which the modeled Facility impact concentrations were greater than the Class I SILs were as follows:

- 3-hour SO2: 5 kilometers
- 24-hour SO2: 5 kilometers
- 24-hour PM10: 48 kilometers
- Annual NO2: 3 kilometers
- Annual SO2: 0.875 kilometers
- Annual PM10: 1.2 kilometers

As shown above, the Facility will not produce any ambient air impacts which exceed a Class I SIL in any Class I area.

2. Emission Rates

The nitrogen oxide, carbon monoxide, NMHC, particulate matter, ammonia, and sulfuric acid emission rates used by the applicant are based on emission rate given for General Electric Model 7H.02 combustion turbines combustion turbines at various load conditions and for varying ambient temperatures. General Electric also provided the emission rates for formaldehyde firing natural gas only. The applicant provided metal emission factors for the combustion turbines while firing ULSD from the document "Survey of Ultra-Trace Metals in Gas Turbine Fuels". All other emission rates for non-criteria pollutants were from EPA's AP-42 emission factors.

Gas Turbines Firing Natural Gas			
Number of Sources:		2	
Maximum Unit Heat Input (MMBtu/hr):		3,435	
Annual Operation (hrs/yr):		8400	
RIDEM PART 22 Air Toxic Chemical	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Factor Source
Ammonia	3.00E-03	20.60	GE Emissions Estimates
Sulfuric Acid	1.21E-03	8.30	GE Emissions Estimates
1,3-Butadiene	4.30E-07	2.95E-04	AP-42 Table 3.1-3
Acetaldehyde	4.00E-05	2.75E-02	AP-42 Table 3.1-3
Acrolein	6.40E-06	4.40E-03	AP-42 Table 3.1-3
Benzene	1.20E-05	8.24E-03	AP-42 Table 3.1-3
Ethylbenzene	3.20E-05	2.20E-02	AP-42 Table 3.1-3
Formaldehyde	2.18E-04	1.50	GE Emissions Estimates
Naphthalene	1.30E-06	8.93E-04	AP-42 Table 3.1-3
PAH	2.20E-06	1.51E-03	AP-42 Table 3.1-3
Propylene Oxide	2.90E-05	1.99E-02	AP-42 Table 3.1-3
Toluene	1.30E-04	8.93E-02	AP-42 Table 3.1-3
Xylenes	6.40E-05	4.40E-02	AP-42 Table 3.1-3

Gas Turbines Firing ULSD			
Number of Sources:		2	
Maximum Unit Heat Input (MMBtu/hr):		ULSD	
Annual Operation (hrs/yr):		3669	
RIDEM PART 22 Air Toxic Chemical		360	
Ammonia	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Factor Source
Sulfuric Acid	2.78E-03	20.40	GE Emissions Estimates
1,3-Butadiene	9.78E-04	7.18	GE Emissions Estimates
Benzene	1.60E-05	1.17E-02	AP-42 Table 3.1-4
Formaldehyde	5.50E-05	4.04E-02	AP-42 Table 3.1-4
Naphthalene	2.80E-04	2.05	AP-42 Table 3.1-4
PAH	3.50E-05	2.57E-02	AP-42 Table 3.1-4
Arsenic	4.00E-05	2.94E-02	AP-42 Table 3.1-4
Beryllium	4.62E-08	3.39E-04	Ultra-Trace Metal Survey
Cadmium	3.10E-07	2.27E-03	Ultra-Trace Metal Survey
Chromium	5.13E-09	3.76E-05	Ultra-Trace Metal Survey

Lead	2.24E-06	1.64E-02	Ultra-Trace Metal Survey
Manganese	7.69E-07	5.64E-03	Ultra-Trace Metal Survey
Mercury	2.82E-07	2.07E-03	Ultra-Trace Metal Survey
Nickel	1.03E-08	7.56E-05	Ultra-Trace Metal Survey
Selenium	1.48E-06	1.09E-02	Ultra-Trace Metal Survey
		1.88E-03	Ultra-Trace Metal Survey

HRSG Duct Burners			
Number of Sources:		2	
Fuel Fired:		Natural Gas	
Maximum Unit Heat Input (MMBtu/hr):		403.0	
Annual Operation (hrs/yr):		6,100	
RIDEM PART 22 Air Toxic Chemical	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Factor Source
Lead	4.90E-07	3.95E-04	AP-42 Table 1.4-2
Benzene	2.06E-06	1.66E-04	AP-42 Table 1.4-3
Formaldehyde	7.35E-05	5.93E-02	AP-42 Table 1.4-3
Hexane	1.76E-03	1.42E-01	AP-42 Table 1.4-3
Naphthalene	5.98E-07	4.82E-05	AP-42 Table 1.4-3
Toluene	3.33E-06	2.69E-04	AP-42 Table 1.4-3
Arsenic	1.96E-07	1.58E-04	AP-42 Table 1.4-4
Barium	4.31E-06	3.48E-03	AP-42 Table 1.4-4
Beryllium	1.18E-08	9.48E-06	AP-42 Table 1.4-4
Cadmium	1.08E-06	8.69E-04	AP-42 Table 1.4-4
Chromium	1.37E-06	1.11E-03	AP-42 Table 1.4-4
Cobalt	8.24E-08	6.64E-05	AP-42 Table 1.4-4
Copper	8.33E-07	6.72E-04	AP-42 Table 1.4-4
Manganese	3.73E-07	3.00E-04	AP-42 Table 1.4-4
Mercury	2.55E-07	2.05E-04	AP-42 Table 1.4-4
Molybdenum	1.08E-06	8.69E-04	AP-42 Table 1.4-4
Nickel	2.06E-06	1.66E-03	AP-42 Table 1.4-4
Selenium	2.35E-08	1.90E-05	AP-42 Table 1.4-4
Vanadium	2.25E-06	1.82E-03	AP-42 Table 1.4-4
Zinc	2.84E-05	2.29E-02	AP-42 Table 1.4-4
2-Methylmaphthalene	2.35E-08	1.90E-06	AP-42 Table 1.4-3
3-Methylchloranthrene	1.76E-09	1.42E-07	AP-42 Table 1.4-3
7,12-Dimethylbenz(a)anthracene	1.57E-08	1.26E-06	AP-42 Table 1.4-3
Acenaphthene	1.76E-09	1.42E-07	AP-42 Table 1.4-3
Acenaphthylene	1.76E-09	1.42E-07	AP-42 Table 1.4-3

Anthracene	2.35E-09	1.90E-07	AP-42 Table 1.4-3
Benz(a)anthracene	1.76E-09	1.42E-07	AP-42 Table 1.4-3
Benzo(a)pyrene	1.18E-09	9.48E-08	AP-42 Table 1.4-3
Benzo(b)fluoranthene	1.76E-09	1.42E-07	AP-42 Table 1.4-3
Benzo(g,h,i)perylene	1.18E-09	9.48E-08	AP-42 Table 1.4-3
Benzo(k)fluoranthene	1.76E-09	1.42E-07	AP-42 Table 1.4-3
Butane	2.06E-03	1.66E-01	AP-42 Table 1.4-3
Chrysene	1.76E-09	1.42E-07	AP-42 Table 1.4-3
Dibenzo(a,h)anthracene	1.18E-09	9.48E-08	AP-42 Table 1.4-3
Dichlorobenzene	1.18E-06	9.48E-05	AP-42 Table 1.4-3
Ethane	3.04E-03	2.45E-01	AP-42 Table 1.4-3
Fluoranthene	2.94E-09	2.37E-07	AP-42 Table 1.4-3
Fluorene	2.75E-09	2.21E-07	AP-42 Table 1.4-3
Indeno(1,2,3-cd)pyrene	1.76E-09	1.42E-07	AP-42 Table 1.4-3
Pentane	2.55E-03	2.05E-01	AP-42 Table 1.4-3
Phenanthrene	1.67E-08	1.34E-06	AP-42 Table 1.4-3
Propane	1.57E-03	1.26E-01	AP-42 Table 1.4-3
Pyrene	4.90E-09	3.95E-07	AP-42 Table 1.4-3

Auxiliary Boiler			
Number of Sources:		1	
Fuel Fired:		Natural Gas	
Maximum Unit Heat Input (MMBtu/hr):		140.6	
Annual Operation (hrs/yr):		2,400	
RIDEM PART 22 Air Toxic Chemical	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Factor Source
Lead	4.90E-07	6.89E-05	AP-42 Table 1.4-2
Benzene	2.06E-06	2.89E-04	AP-42 Table 1.4-3
Formaldehyde	7.35E-05	1.03E-02	AP-42 Table 1.4-3
Hexane	1.76E-03	2.48E-01	AP-42 Table 1.4-3
Naphthalene	5.98E-07	8.41E-05	AP-42 Table 1.4-3
Toluene	3.33E-06	4.69E-04	AP-42 Table 1.4-3
Arsenic	1.96E-07	2.76E-05	AP-42 Table 1.4-4
Barium	4.31E-06	6.07E-04	AP-42 Table 1.4-4
Beryllium	1.18E-08	1.65E-06	AP-42 Table 1.4-4
Cadmium	1.08E-06	1.52E-04	AP-42 Table 1.4-4
Chromium	1.37E-06	1.93E-04	AP-42 Table 1.4-4
Cobalt	8.24E-08	1.16E-05	AP-42 Table 1.4-4
Copper	8.33E-07	1.17E-04	AP-42 Table 1.4-4
Manganese	3.73E-07	5.24E-05	AP-42 Table 1.4-4
Mercury	2.55E-07	3.58E-05	AP-42 Table 1.4-4
Molybdenum	1.08E-06	1.52E-04	AP-42 Table 1.4-4
Nickel	2.06E-06	2.89E-04	AP-42 Table 1.4-4
Selenium	2.35E-08	3.31E-06	AP-42 Table 1.4-4

Vanadium	2.25E-06	3.17E-04	AP-42 Table 1.4-4
Zinc	2.84E-05	4.00E-03	AP-42 Table 1.4-4
2-Methylmaphthalene	2.35E-08	3.31E-06	AP-42 Table 1.4-3
3-Methylchloranthrene	1.76E-09	2.48E-07	AP-42 Table 1.4-3
7,12-Dimethylbenz(a)anthracene	1.57E-08	2.21E-06	AP-42 Table 1.4-3
Acenaphthene	1.76E-09	2.48E-07	AP-42 Table 1.4-3
Acenaphthylene	1.76E-09	2.48E-07	AP-42 Table 1.4-3
Anthracene	2.35E-09	3.31E-07	AP-42 Table 1.4-3
Benz(a)anthracene	1.76E-09	2.48E-07	AP-42 Table 1.4-3
Benzo(a)pyrene	1.18E-09	1.65E-07	AP-42 Table 1.4-3
Benzo(b)fluoranthene	1.76E-09	2.48E-07	AP-42 Table 1.4-3
Benzo(g,h,i)perylene	1.18E-09	1.65E-07	AP-42 Table 1.4-3
Benzo(k)fluoranthene	1.76E-09	2.48E-07	AP-42 Table 1.4-3
Butane	2.06E-03	2.89E-01	AP-42 Table 1.4-3
Chrysene	1.76E-09	2.48E-07	AP-42 Table 1.4-3
Dibenzo(a,h)anthracene	1.18E-09	1.65E-07	AP-42 Table 1.4-3
Dichlorobenzene	1.18E-06	1.65E-04	AP-42 Table 1.4-3
Ethane	3.04E-03	4.27E-01	AP-42 Table 1.4-3
Fluoranthene	2.94E-09	4.14E-07	AP-42 Table 1.4-3
Fluorene	2.75E-09	3.86E-07	AP-42 Table 1.4-3
Indeno(1,2,3-cd)pyrene	1.76E-09	2.48E-07	AP-42 Table 1.4-3
Pentane	2.55E-03	3.58E-01	AP-42 Table 1.4-3
Phenanthrene	1.67E-08	2.34E-06	AP-42 Table 1.4-3
Propane	1.57E-03	2.21E-01	AP-42 Table 1.4-3
Pyrene	4.90E-09	6.89E-07	AP-42 Table 1.4-3

Dewpoint Heater			
Number of Sources:		1	
Fuel Fired:		Natural Gas	
Maximum Unit Heat Input (MMBtu/hr):		15.0	
Annual Operation (hrs/yr):		8,760	
RIDEM PART 22 Air Toxic Chemical	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Factor Source
Lead	4.90E-07	7.35E-06	AP-42 Table 1.4-2
Benzene	2.06E-06	3.09E-05	AP-42 Table 1.4-3
Formaldehyde	7.35E-05	1.10E-03	AP-42 Table 1.4-3
Hexane	1.76E-03	2.65E-02	AP-42 Table 1.4-3
Naphthalene	5.98E-07	8.97E-06	AP-42 Table 1.4-3
Toluene	3.33E-06	5.00E-05	AP-42 Table 1.4-3
Arsenic	1.96E-07	2.94E-06	AP-42 Table 1.4-4
Barium	4.31E-06	6.47E-05	AP-42 Table 1.4-4
Beryllium	1.18E-08	1.76E-07	AP-42 Table 1.4-4
Cadmium	1.08E-06	1.62E-05	AP-42 Table 1.4-4

Chromium	1.37E-06	2.06E-05	AP-42 Table 1.4-4
Cobalt	8.24E-08	1.24E-06	AP-42 Table 1.4-4
Copper	8.33E-07	1.25E-05	AP-42 Table 1.4-4
Manganese	3.73E-07	5.59E-06	AP-42 Table 1.4-4
Mercury	2.55E-07	3.82E-06	AP-42 Table 1.4-4
Molybdenum	1.08E-06	1.62E-05	AP-42 Table 1.4-4
Nickel	2.06E-06	3.09E-05	AP-42 Table 1.4-4
Selenium	2.35E-08	3.53E-07	AP-42 Table 1.4-4
Vanadium	2.25E-06	3.38E-05	AP-42 Table 1.4-4
Zinc	2.84E-05	4.26E-04	AP-42 Table 1.4-4
2-Methylmaphthalene	2.35E-08	3.53E-07	AP-42 Table 1.4-3
3-Methylchloranthrene	1.76E-09	2.65E-08	AP-42 Table 1.4-3
7,12-Dimethylbenz(a)anthracene	1.57E-08	2.35E-07	AP-42 Table 1.4-3
Acenaphthene	1.76E-09	2.65E-08	AP-42 Table 1.4-3
Acenaphthylene	1.76E-09	2.65E-08	AP-42 Table 1.4-3
Anthracene	2.35E-09	3.53E-08	AP-42 Table 1.4-3
Benz(a)anthracene	1.76E-09	2.65E-08	AP-42 Table 1.4-3
Benzo(a)pyrene	1.18E-09	1.76E-08	AP-42 Table 1.4-3
Benzo(b)fluoranthene	1.76E-09	2.65E-08	AP-42 Table 1.4-3
Benzo(g,h,i)perylene	1.18E-09	1.76E-08	AP-42 Table 1.4-3
Benzo(k)fluoranthene	1.76E-09	2.65E-08	AP-42 Table 1.4-3
Butane	2.06E-03	3.09E-02	AP-42 Table 1.4-3
Chrysene	1.76E-09	2.65E-08	AP-42 Table 1.4-3
Dibenzo(a,h)anthracene	1.18E-09	1.76E-08	AP-42 Table 1.4-3
Dichlorobenzene	1.18E-06	1.76E-05	AP-42 Table 1.4-3
Ethane	3.04E-03	4.56E-02	AP-42 Table 1.4-3
Fluoranthene	2.94E-09	4.41E-08	AP-42 Table 1.4-3
Fluorene	2.75E-09	4.12E-08	AP-42 Table 1.4-3
Indeno(1,2,3-cd)pyrene	1.76E-09	2.65E-08	AP-42 Table 1.4-3
Pentane	2.55E-03	3.82E-02	AP-42 Table 1.4-3
Phenanthrene	1.67E-08	2.50E-07	AP-42 Table 1.4-3
Propane	1.57E-03	2.35E-02	AP-42 Table 1.4-3
Pyrene	4.90E-09	7.35E-08	AP-42 Table 1.4-3

Emergency Diesel Generator			
Number of Sources:		1	
Fuel Fired:		ULSD	
Maximum Unit Heat Input (MMBtu/hr):		19.5	
Annual Operation (hrs/yr):		300	
RIDEM PART 22 Air Toxic Chemical	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Factor Source
Benzene	7.76E-04	1.51E-02	AP-42 Table 3.4-3
Toluene	2.81E-04	5.48E-03	AP-42 Table 3.4-3
Xylenes	1.93E-04	3.76E-03	AP-42 Table 3.4-3

Propylene	2.79E-03	5.44E-02	AP-42 Table 3.4-3
Formaldehyde	7.89E-05	1.54E-03	AP-42 Table 3.4-3
Acetaldehyde	2.52E-05	4.91E-04	AP-42 Table 3.4-3
Acrolein	7.88E-06	1.54E-04	AP-42 Table 3.4-3
Naphthalene	1.30E-04	2.54E-03	AP-42 Table 3.4-4
Acenaphthylene	9.23E-06	1.80E-04	AP-42 Table 3.4-4
Acenaphthene	4.68E-06	9.13E-05	AP-42 Table 3.4-4
Fluorene	1.28E-05	2.50E-04	AP-42 Table 3.4-4
Phenanthrene	4.08E-05	7.96E-04	AP-42 Table 3.4-4
Anthracene	1.23E-06	2.40E-05	AP-42 Table 3.4-4
Fluoranthene	4.03E-06	7.86E-05	AP-42 Table 3.4-4
Pyrene	3.71E-06	7.23E-05	AP-42 Table 3.4-4
Benz(a)anthracene	6.22E-07	1.21E-05	AP-42 Table 3.4-4
Chrysene	1.53E-06	2.98E-05	AP-42 Table 3.4-4
Benzo(b)fluoranthene	1.11E-06	2.16E-05	AP-42 Table 3.4-4
Benzo(k)fluoranthene	2.18E-07	4.25E-06	AP-42 Table 3.4-4
Benzo(a)pyrene	2.57E-07	5.01E-06	AP-42 Table 3.4-4
Indeno(1,2,3-cd)pyrene	4.14E-07	8.07E-06	AP-42 Table 3.4-4
Dibenz(a,h)anthracene	3.46E-07	6.75E-06	AP-42 Table 3.4-4
Benzo(g,h,l)perylene	5.56E-07	1.08E-05	AP-42 Table 3.4-4
PAH	2.12E-04	4.13E-03	AP-42 Table 3.4-4

Fire Pump Engine			
Number of Sources:		1	
Fuel Fired:		ULSD	
Maximum Unit Heat Input (MMBtu/hr):		2.1	
Annual Operation (hrs/yr):		300	
RIDEM PART 22 Air Toxic Chemical	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	Emission Factor Source
Benzene	9.33E-04	5.88E-01	AP-42 Table 3.3-2
Toluene	4.09E-04	2.58E-01	AP-42 Table 3.3-2
Xylenes	2.85E-04	1.80E-01	AP-42 Table 3.3-2
Propylene	2.58E-03	1.63	AP-42 Table 3.3-2
Formaldehyde	1.18E-03	7.43E-01	AP-42 Table 3.3-2
Acetaldehyde	7.67E-04	4.83E-01	AP-42 Table 3.3-2
Acrolein	9.25E-05	5.83E-02	AP-42 Table 3.3-2
Naphthalene	8.48E-05	5.34E-02	AP-42 Table 3.3-2
1,3-Butadiene	3.91E-05	2.46E-02	AP-42 Table 3.3-2
Acenaphthylene	5.06E-06	3.19E-03	AP-42 Table 3.3-2
Acenaphthene	1.42E-06	8.95E-04	AP-42 Table 3.3-2
Fluorene	2.92E-05	1.84E-02	AP-42 Table 3.3-2
Phenanthrene	2.94E-05	1.85E-02	AP-42 Table 3.3-2
Anthracene	1.87E-06	1.18E-03	AP-42 Table 3.3-2
Fluoranthene	7.61E-06	4.79E-03	AP-42 Table 3.3-2
Pyrene	4.78E-06	3.01E-03	AP-42 Table 3.3-2

Benz(a)anthracene	1.68E-06	1.06E-03	AP-42 Table 3.3-2
Chrysene	3.53E-07	2.22E-04	AP-42 Table 3.3-2
Benzo(b)fluoranthene	9.91E-08	6.24E-05	AP-42 Table 3.3-2
Benzo(k)fluoranthene	1.55E-07	9.77E-05	AP-42 Table 3.3-2
Benzo(a)pyrene	1.88E-07	1.18E-04	AP-42 Table 3.3-2
Indeno(1,2,3-cd)pyrene	3.75E-07	2.36E-04	AP-42 Table 3.3-2
Dibenz(a,h)anthracene	5.83E-07	3.67E-04	AP-42 Table 3.3-2
Benzo(g,h,l)perylene	4.89E-07	3.08E-04	AP-42 Table 3.3-2
PAH	1.68E-04	1.06E-01	AP-42 Table 3.3-2

3. Impact Analysis

The applicant provided a written Significant Impact Area (SIA) analysis impact certification that demonstrated that the 1-hr NO2 SIA had a radius distance from the source out to 3.56 kilometers. The SIA analysis also demonstrated that the 24-hr PM10 extended out to 1.85 kilometers from the source.

No AAL adjustments were used for the air toxics analysis in this modeling study. AERMOD reported the highest impact concentrations for NO_2 and PM10 to be localized southeast inside properly limits.

The applicant has satisfactorily demonstrated that the proposed facility will not cause or contribute to air pollution in violation of the NAAQS for these pollutants or in excess of the allowable PSD increments for criteria pollutants.

C. *Additional Impacts Analysis (250-RICR-120-05-9.9.1(A)(3))*

250-RICR-120-05-9.9.1(A)(3) requires the applicant to provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source and general commercial, residential, industrial and other growth associated with source. Additionally, this subsection requires the applicant to provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source.

1. Visibility Analysis

Any source located more than 50 km from any Class I area is exempt from the Class I visibility analysis if its total annual emissions of SO2, NOx, PM10, and H2SO4 in tons divided by the distance in kilometers from the sources to the nearest Class I area (Q/D factor) is 10 or less.

The total potential annual emissions of SO2, NOx, PM10, and H2SO4 are approximately 525 tons. The distance to the nearest Class I area, Lye Brook, is approximately 170 km. The Q/D factor is therefore 3.1. Because the Q/D factor is less than 10, no Class I visibility impairment analysis is required.

2. Soils and Vegetation Analysis

The applicant has presented an assessment of the impacts on soils and vegetation as a result of emissions from the proposed facility. This assessment compared predicted project impacts with the background concentrations and comparing the results to the vegetation sensitivity screening levels presented in Table 3.1 of EPA's A Screening Procedure for the Impacts of Air Pollution on Plants, Soils, and Animals (EPA, 1981).

This analysis concluded that emissions from the proposed facility will not cause or contribute to air pollution that would adversely impact soils and vegetation in the area.

3. Growth Analysis

The applicant's analysis concluded that there is not expected to be any significant, direct, industrial, commercial or residential growth associated with this facility that would adversely affect air quality in the vicinity of the project. It is not anticipated that any industrial, commercial, or residential growth will occur to support the people which will constitute the peak construction work force.

D. Welfare Impacts (250-RICR-120-05-9.9.1(A)(4))

250-RICR-120-05-*9.9.1(A)(4)* requires the applicant to apply the applicable procedures of the Guidelines for Assessing the Welfare Impacts of Proposed Air Pollution Sources and meet the criteria therein.

The Office of Air Resources "Guidelines for Assessing the Welfare Impacts of Proposed Air Pollution Sources" specify the procedures to be followed for evaluating a facility's impact on plants, animals and soil. Applicants must apply the procedures and comply with the screening concentrations in EPA's A Screening Procedure for the Impacts of Air Pollution on Plants, Soils, and Animals (EPA, 1981). The applicant has correctly applied the procedure in this assessment and met the criteria therein.

E. Air Toxics Regulation (250-RICR-120-05-9.9.1(A)(5))

250-RICR-120-05-*9.9.1(A)(5)* requires the applicant to demonstrate that the emission from the proposed facility will not cause an increase in the ground level ambient concentration at or beyond the property line in access of that allowed by "Air Toxics", 250-RICR-120-05-22 and any Calculated Acceptable Ambient Levels.

See III.B of the document for the details of the Air Quality Impact Analysis submitted by the applicant. The applicant demonstrated compliance with all Acceptable Ambient Levels under Table 1 of 250-RICR-120-05-22.

F. Health Risks from Proposed Air Pollution Sources (250-RICR-120-05-9.9.1(A)(6))

250-RICR-120-05-9.9.1(A)(6) requires that the applicant to conduct any studies required by the Guidelines for Assessing Health Risks from Proposed Air Pollution Sources and meet the criteria therein.

The proposed source was required to conduct the studies under the Guidelines and submitted a Health Risk Assessment on January 27, 2016.

G. *Applicable Air Pollution Control Regulations (250-RICR-120-05-9.9.1(A)(7))*

250-RICR-120-05-*9.9.1(A)(7)* requires the applicant to demonstrate that the facility will be in compliance with all applicable state and federal air pollution control regulations at the time the source commences operation. The following is list of all applicable regulations.

1. Applicable Federal Air Pollution Control Rules and Regulations

a. 40 CFR 60 Subpart A – General Provisions
b. 40 CFR 60 Subpart Db – Industrial, Commercial, Institutional Steam Generating Units
c. 40 CFR 60 Subpart IIII – Stationary Compression Internal Combustion Engines
d. 40 CFR 60 Subpart KKKK - Standards of Performance for Stationary Gas Turbines
e. 40 CFR 60 Appendix B – CEM Performance Specification
f. 40 CFR 60 Appendix F – Quality Assurance Procedures
g. 40 CFR 60 Subpart TTTT– Greenhouse Gas Emissions for Electric Utility Generating Units
h. 40 CFR 63 Subpart A – General Provisions
i. 40 CFR 63 Subpart YYYY – Stationary Combustion Turbines
j. 40 CFR 63 Subpart ZZZZ – Stationary Compression Internal Combustion Engines
k. 40 CFR 63 Subpart JJJJJJ – Industrial, Commercial, Institutional Boilers Area Sources
l. 40 CFR 64 – Compliance Assurance Monitoring
m. 40 CFR 68 – Chemical Accident Prevention Provisions- General Duty Clause
n. 40 CFR 70 & 71 – Operating Permit Program
o. 40 CFR 72 – Acid Rain Permits
p. 40 CFR 73 – Acid Rain Program Sulfur Dioxide Allowance System
q. 40 CFR 75 – Acid Rain Program Continuous Emissions Monitoring
r. 40 CFR 99 – Mandatory Greenhouse Gas Reporting

2. Applicable State Air Pollution Control Rules and Regulations

a. Part 1 – Visible Emissions
b. Part 5 – Fugitive Dust
c. Part 6 – Opacity Monitors
d. Part 7 – Emission of Air Contaminants Detrimental to Person or Property
e. Part 8 – Sulfur Content of Fuels
f. Part 9 – Air Pollution Control Permits
g. Part 10 – Air Pollution Episodes
h. Part 11 – Petroleum Liquids Marketing and Storage
i. Part 13 – Particulate Emissions from Fuel Fired Steam or Hot Water Generation Units
j. Part 14 – Recordkeeping and Reporting
k. Part 16 – Operation of Air Pollution Control Systems
l. Part 17 – Odors
m. Part 22 – Air Toxics

n. Part 27 – Control of NOx Emissions
o. Part 28 – Operating Permit Fees
p. Part 29 – Operating Permits
q. Part 45 – RI Diesel Anti-Idling Program
r. Part 46 – CO2 Budget Trading Program

VI. Additional Issues

A. Applicability of 250-RICR-120-05-9.7.3(B) of Air Pollution Control Regulation Part 9

250-RICR-120-05-9.7.3(B) provides that no person shall construct a 112(g) source unless:

(1) The source in question has been specifically regulated or exempted from regulation under a standard in 40 CFR Part 63, issued pursuant to Section 112(d), Section 112(h) or Section 112(j) of the Clean Air Act and the owner and operator has fully complied with all procedures and requirements for preconstruction review established by that standard, including any applicable requirements set forth in subpart A of 40 CFR part 63; or

(2) The Office of Air Resources has made a final and effective case-by-case determination pursuant to the provisions of 40 CFR 63.43 such that emissions from the constructed or reconstructed 112(g) source will be controlled to a level no less stringent than the maximum achievable control technology emission limitation for new sources.

As defined in 250-RICR-120-05-9.5.A.9, "construct a 112(g) source" means to fabricate, erect, or install at any greenfield site an emissions unit or group of emissions units which is located within a contiguous area and under common control and which emits or has the potential to emit 10 tons per year of any Hazardous Air Pollutant (HAP) or 25 tons per year of any combination of HAP.

The applicant has demonstrated that the source will not have the potential to emit 10 tons per year or any one HAP or 25 tons per year of any combination of HAPs, therefore, the source is not a 112(g) source.

VI. Conclusion

Based on the information supplied by the applicant and the Office of Air Resources' review of the proposed project, the Office of Air Resources believes that the applicant has satisfied all of the applicable provisions of “Air Pollution Control Permits”, 250-RICR-120-05-9.8 relative to the requirements for issuance of a Major Source Permit to a major stationary source in a nonattainment area and 250-RICR-120-05-9.9 relative to the requirements for issuance of a Major Source Permit to a major stationary source in an attainment area. As such, the Office of Air Resources is proposing approval of the Major Source Permit application for the subject to the permit conditions and emission limitations contained in the draft permit.