Appendix 10-1

Information Request Letter from The Delaware Division of Air Quality to Calpine Corporation - Garrison

April 30, 2019

STATE OF DELAWARE
DEPARTMENT OF NATURAL RESOURCES
& ENVIRONMENTAL CONTROL
DIVISION OF AIR QUALITY
100 W. Water Street
DOVER, DELAWARE 19904

Telephone: (302) 739 - 9402
Fax No.: (302) 739 - 3106

April 30, 2019

Gerald Kissel
Plant Manager
Calpine Mid-Atlantic Generation, LLC
500 Delaware Avenue, Suite 600
Wilmington, DE 19801

Certified Mail # 7018 2290 0002 1278 0328
RETURN RECEIPT REQUESTED

Subject: Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule

Dear Mr. Kissel:

The federal Clean Air Act (CAA) and Regional Haze Rule (40 CFR 51.308 (f)(2)(i) through (iv)) requires States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment. Under the Regional Haze Rule, States are required to develop a series of state implementation plans (SIP) to address visibility impairment in Class I areas and progress made toward achieving natural visibility conditions.

As part of its Regional Haze SIP, Delaware must consider emission reductions measures identified by Class I states as being necessary to make reasonable progress in any Class I area. Delaware is part of the Mid-Atlantic Northeast Visibility Union (MANE-VU), a regional planning organization in which member states work collaboratively to develop emission control strategies to address visibility impairment in Class I areas.

MANE-VU proposed six (6) emission management strategies (Asks) in order to meet the 2028 reasonable progress goal for regional haze (Attachment 1). While many of the strategies are directed at states to adopt, there are some strategies that required input from Calpine Corporation (Calpine). Therefore, the Delaware Department of Natural Resources and Environmental Control (DNREC) is requesting information regarding an emission unit that meets the applicability criteria for one of the MANE-VU Asks: Ask # 1 – Year-Round NO_X and SO_2 Controls for large

Electric Generating Units (EGUs)[1]. DNREC requests that Calpine submit the following information by June 14, 2019:

Unit CT1

Garrison operates a combustion turbine (CT1) which uses Low NOx burners, a Selective Catalytic Reduction (SCR) system, and a Water Injection (WI) system as a NOx control devices. Unit CT1 combusts distillate fuel oil and natural gas. Garrison's Regulation 1102 Operating Permit does not require that the WI system be operated when burning natural gas. Ask #1 for NOx emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI system when burning natural gas, on a year-round basis.

Thank you in advance for your cooperation. If you have any questions or wish to further discuss this request, please contact Renae Held of the Division of Air Quality at (302) 739-9402 or renae.held@delaware.gov.

Sincerely,

David Fees

David F. Fees, P.E.
Director
Division of Air Quality

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[1] For the purposes of the MANE-VU Ask, a large EGU is defined as having a nameplate capacity larger than or equal to 25 MW.

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. Fish and Wildlife Service
U.S. Forest Service

MANE-VU Class I Areas
ACADIA NATIONAL PARK ME
BRIGANTINE WILDERNESS NJ
GREAT GULF WILDERNESS NH
LYE BROOK WILDERNESS VT
MOOSEHORN WILDERNESS ME
PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH
ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

Mid-Atlantic/Northeast Visibility Union

MANE-VU

Reducing Regional Haze for Improved Visibility and Health

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION WITHIN MANE-VU TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP. This Ask by the MANE-VU Class I states, was developed through a collaborative process with all of the MANE-VU states. It is designed to identify reasonable emission reduction strategies which must be addressed by the states and tribal nations of MANE-VU through their regional haze SIP updates. This Ask has been developed and presented at this time so that SIPs may be developed and submitted between July of 2018 and July of 2021.

In addressing the emission reduction strategies in the Ask, the MANE-VU states will need to harmonize any activity on the strategies in the Ask with other federal or state

requirements that affect the sources and pollutants covered by the Ask. These federal and state requirements include, but are not limited to:

- The 2010 SO_2 standard,
- The Regional Greenhouse Gas Initiative (RGGI), if applicable,
- The Mercury and Air Toxics Standards (MATS), and
- The new 2015 ozone standard.

Because of this need for cross-program harmonization and because of the formal public process required by the federal CAA and state rulemaking processes, it is expected that there will be opportunities for stakeholders and the public to comment on how states intend to address the measures in the Ask.

Many of the MANE-VU states are also members of RGGI. RGGI is a market based cap-and-invest program designed to cost effectively reduce greenhouse gas emissions from the energy sector while returning value to rate-payers. One of the co-benefits of RGGI is that it will also significantly reduce SO_2 and NOx emissions, the two most important haze precursors. Because of this, the RGGI states, regionally, will likely achieve greater emission reductions than those envisioned in this Ask.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

Therefore, the course of action for pursuing the adoption and implementation of measures necessary to meet the 2028 reasonable progress goal for regional haze include the following "emission management" strategies:

1. Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or SO_2 controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;
2. Emission sources modeled by MANE-VU that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution

analyses (see attached listing) - perform a four-factor analysis for reasonable installation or upgrade to emission controls;

3. Each MANE-VU State that has not yet fully adopted an ultra-low sulfur fuel oil standard as requested by MANE-VU in 2007 - pursue this standard as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:
    a. distillate oil to 0.0015% sulfur by weight (15 ppm),
    b. #4 residual oil within a range of 0.25 to 0.5% sulfur by weight,
    c. #6 residual oil within a range of 0.3 to 0.5% sulfur by weight.
4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels – pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;
5. Where emission rules have not been adopted, control NOx emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:
    a. Striving to meet NOx emissions standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NOx emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or
    b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or
    c. Obtaining equivalent alternative emission reductions on high electric demand days.

High electric demand days are days when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet. Peaking combustion turbine is defined for the purposes of this "Ask" as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016;

(Note: SO_2 emissions for fuel oil units are addressed with Ask item 3.a. above)

6. Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 control measures.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

Listing of emission units that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area using actual 2015 emissions for EGUs and 2011 for other emission sources). The complete contribution analyses report is available at http://www.otcair.org/manevu.

State	Facility Name	Facility/ ORIS ID	Unit IDs	Max Extinction
MA	Brayton Point	1619	4	4.3
MA	Canal Station	1599	1	3.0
MD	Herbert A Wagner	1554	3	3.8
MD	Luke Paper Company	7763811	001-0011-3-0018	6.0
MD	Luke Paper Company	7763811	001-0011-3-0019	5.9
ME	The Jackson Laboratory	7945211	7945211	10.2
ME	William F Wyman	1507	4	5.6
ME	Woodland Pulp LLC	5974211		7.5
NH	Merrimack	2364	2	3.3
NJ	B L England	2378	2,3	5.6
NY	Finch Paper LLC	8325211	12	5.9
NY	Lafarge Building Materials Inc	8105211	43101	8.1
PA	Brunner Island	3140	1,2	4.0
PA	Brunner Island	3140	3	3.8
PA	Homer City	3122	1	9.3
PA	Homer City	3122	2	8.1
PA	Homer City	3122	3	3.3
PA	Keystone	3136	1	3.2
PA	Keystone	3136	2	3.1
PA	Montour	3149	1	4.4
PA	Montour	3149	2	4.1
PA	Shawville	3131	3,4	3.6

Information Request Response for Calpine – Garrison

June 14, 2019

CALPINE CORPORATION

500 DELAWARE AVENUE
SUITE 600
WILMINGTON, DE 19801

FedEx # 7877 7319 3061

June 14, 2019

Mr. David F. Fees, P.E.
Director
Division of Air Quality
100 W. Water Street
Dover, Delaware 19904

Reference: **April 30, 2019 Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule – Garrison Energy Center**

Dear Mr. Fees:

This is in response to the above-referenced Request for Information (RFI) letter from the Delaware Department of Natural Resources and Environmental Control (DNREC) requesting information regarding emission reduction measures to reduce visibility impairment in Class I areas. It is our understanding that the request is related to the federal Regional Haze Rule [40 CFR 51.308 (f)(2)(i) through (iv)] that is designed to reduce visibility impairment in Class I Areas. Delaware's State Implementation Plan (SIP) includes Reasonable Progress goals for 2028, consistent with federal requirements. Guidance developed with a group of other states and tribal nations under the Mid-Atlantic / Northeast Visibility Union (MANE-VU) issued on August 25, 2017 includes six emission management strategies ("Asks") designed to help meet the 2028 reasonable progress goal for regional haze.

DNREC's RFI letter is seeking input for one of the Asks as it relates to Unit CT1 at Calpine's Garrison Energy Center in the State of Delaware: Ask# 1 - Year-Round NO_x and SO_2 Controls for large Electric Generating Units (EGUs). The specific request is outlined below for CT1, along with information that Calpine is providing in response to the request.

As you are aware, Calpine has already taken significant steps as a company to reduce emissions that contribute to visibility impairment within the Mid-Atlantic Northeast Visibility Union (MANE-VU) footprint. Calpine supports the collaborative efforts to address visibility impairment Class I areas including the Brigantine Wilderness Area, in Atlantic County, New Jersey, that is most likely to be impacted by emissions from Delaware. Calpine has achieved significant reductions in NO_x and SO_2 emissions as a result of switches to cleaner fuels, unit shutdowns, and emission control technology retrofits.

Calpine acquired the Deepwater Energy Center (Deepwater) in Salem County, New Jersey and Edge Moor Energy Center (Edge Moor) in New Castle County, Delaware in 2010, and promptly transitioned the primary fuel at both facilities from coal to natural gas. In 2008–2009, the two years immediately prior to Calpine's acquisition of Deepwater, the facility's coal-fired boiler Unit 6/8 averaged 387 tons per year (tons/year) of NO_x and 998 tons/year of SO_2. After the transition to natural gas, the facility achieved NO_x and SO_2 emission reductions of 85% and over 99%, respectively for Unit 6/8. Deepwater permanently shut down in 2014, effectively eliminating 100% of its NO_x and SO_2 emissions.

Similarly, in 2008 and 2009, the two years immediately prior to the Calpine's acquisition of Edge Moor, the facility's coal-fired boiler Units 3 and 4 averaged 1,152 tons/year of NO_x and 4,539 tons/year of SO_2. In 2011 and 2012, the first two full years after Calpine's acquisition of the units and transition to natural gas

[1] Pulled from MANE-VU Emissions Inventory dated 11 September 2018.

firing, SO_2 emission reductions of 76% and over 99%. The capacity factors of these units have since fallen to below 10% with the discontinuation of a steam supply contract with a nearby DuPont facility.

Calpine reduced emissions in Southern New Jersey with the shutdown of peaking combustion turbines at Middle Energy Center (Cape May County), Missouri Avenue Energy Center (Atlantic County), and Cedar Energy Center (Ocean County) in May 2015.

Two peaking combustion turbine stations in Southern New Jersey owned by Calpine, Carlls Corner Energy Center in Cumberland County and Mickleton Energy Center in Gloucester County, were retrofitted with Selective Catalyst Reduction (SCR) in 2015 to reduce NO_x emissions. These retrofits resulted in lower NO_x emission rates for peaking power in the region.

You may also be aware that recently (May 2019), the BL England Generating Station in Upper Township, New Jersey, owned by RC Cape May Holdings, was permanently retired. This shutdown further reduces emissions that potentially contributed to visibility impairment within the Class I affected area and MANE-VU footprint. In fact, in the materials provided with the RFI letter identify the BL England Generating Station units among those having the potential for visibility impacts of 3.0 Mm^{-1} or greater at any MANE-VU Class I area using actual 2015 emissions for EGUs.

These emission reduction actions are summarized in the table below.

Prior Regional Emission Reductions

Calpine Facility	Description of Reductions	Estimated NO_x Emissions Reductions (tons/year)	Estimated SO_2 Emissions Reductions (tons/year)
Deepwater Energy Center	Switched Unit 6/8 from coal to natural gas firing	328	998
	Permanent shutdown of Unit 6/8	79	0.2
Edge Moor Energy Center	Switched Units 3 and 4 from coal to natural gas firing	898	4,513
	Reduced capacity factor	217	25
Middle, Missouri Avenue, & Cedar Energy Centers	Permanent shutdown	145	20
Carlls Corner & Mickleton Energy Centers	SCR retrofits	230	N/A
Non-Calpine Facility	**Description of Reductions**	**Estimated NO_x Emissions Reductions (tons/year)**	**Estimated SO_2 Emissions Reductions (tons/year)**

BL England Generating Station	Permanent shutdown	1,328	1,937

The above-described emissions reductions reasonably contribute to the MANE-VU strategy for visible impairment reduction. Further reduction or elimination of emissions from remaining Calpine assets within Delaware will not provide meaningful reductions in visible emissions. Delaware is consistently one of the lowest emitting states within the MANE-VU group, and from 2002 to 2014[1], reduced NO_x and SO_2 emissions by 52% and 95%, respectively. In 2014, stationary source NO_x and SO_2 emissions from the entire state of Delaware were 8,500 tons and 4,330 tons, respectively. Calpine sources were only a fraction of those totals, and as noted, there have been further reductions in Calpine's emissions since 2014. In 2017-2018, Calpine's collective annual NO_x and SO_2 emissions from sources in Delaware averaged 610 tons/year and 120 tons/year, respectively.

Calpine Response to the DNREC Request for Information

In response to the April 30, 2019 Request for Information (RFI), Calpine is pleased to provide the requested information below.

Ask #1 – Evaluation of Technical & Economic Feasibility of Year Round WI on NG

Garrison Energy Center Unit CT1 is a nominal 309-megawatt (MW) combined cycle combustion turbine generating system including one General Electric (GE) Model 7FA combustion turbine generator, along with a Heat Recovery Steam Generator (HRSG) and a steam turbine generator (STG). The facility is located in Dover, Kent County, Delaware, and started commercial operation in June 2015. The unit burns natural gas as its primary fuel, with ultra-low sulfur distillate (ULSD) fuel oil as a back-up fuel, and is equipped with power augmentation generation (PAG), evaporative cooling (EC) and duct burning (DB). Emissions of nitrogen oxides (NO_x) are controlled by dry low-NO_x combustion (DLNC) on natural gas and water injection (WI) on ULSD, as well as Selective Catalytic Reduction (SCR) post-combustion control in the HRSG. NO_x emission limits for the unit are consistent with current Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) requirements for similar units:

- 2.0 ppmvd at 15% O_2 (1-hour average) for natural gas fired base load operation without PAG, EC, or DB;
- 2.0 ppmvd at 15% O_2 (3-hour average) for natural gas-fired non-base load operation with PAG, EC, or DB;
- 2.5 ppmvd at 15% O_2 (3-hour average) for natural gas fired peak load operation with PAG, EC, or DB; and
- 6 ppmvd at 15% O_2 (3-hour average) for ULSD oil firing.

Despite the unit's large size and high annual capacity factor, its annual NO_x emissions since initial commercial operation in 2015 have been quite low, ranging from 14.3 tons in 2015 (part-year operation) to 43.9 tons in 2017. This is due to the unit's state-of-the-art NO_x emission controls.

DNREC's letter for Garrison Energy Center is specific to Ask #1 for NO_x only:

Garrison's Regulation 1102 Operating Permit does not require that the WI system be operated when burning natural gas. Ask #1 for NO_x emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI system when burning natural gas, on a year-round basis.

Calpine Response:

The Garrison Energy Center CT is equipped with dry low-NO_x combustion (DLNC) when firing natural gas, and water injection (WI) when firing ULSD. DLNC is a technology that is specifically designed to reduce NO_x emissions from combustion turbines without injecting a diluent such as water or steam to reduce combustion temperatures.

The amount of NO_x produced by a combustion turbine depends on combustion temperatures. When combustion occurs at lower temperatures, NO_x emissions are reduced. DLNC technology was developed to achieve lower emissions without using water or steam as diluents to reduce combustion temperatures. DLNC uses the principle of lean combustion, and requires an advanced control system with a large number of burners. DLNC results in lower NO_x emissions because the process is operated with less fuel and air, and combustion occurs at lower temperatures.[2]

There are two types of combustion processes in combustion turbines: diffusion flame combustion and lean-staged combustion. In diffusion flame combustion, both fuel and oxidizer (i.e. air) are supplied to the reaction zone in an unmixed state. The fuel/air mixing and combustion occur simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high, resulting in elevated levels of thermal NO_x emissions. At the inception of combustion turbine development, the primary design goal was to optimize performance (i.e. output) while complying with applicable emission requirements. Initially, emphasis was placed on maximizing combustion efficiency while minimizing the emission of unburned hydrocarbons and carbon monoxide (CO). It was possible to achieve these design goals by providing the diffusion flame with a relatively high combustion chamber volume in which all chemical reactions were allowed to occur without the addition of dilution air. This combustion chamber design yielded optimum thermodynamic properties with low pressure losses and a combustion efficiency of practically 100%.

In the early 1970's, when emission controls were introduced, the pollutant of primary concern shifted to NO_x. For the relatively low levels of NO_x reduction initially required, the injection of water or steam into the combustion zone produced the required reduction in NO_x emissions with minimal performance impact. In addition, the emissions of other pollutants [CO, volatile organic compounds (VOC)] remained low. To comply with more stringent NO_x emission standards that began to be imposed in the 1980's, further attempts were made to increase water/steam injection rates to ensure compliance. These attempts proved detrimental to cycle performance and equipment life, and the emission rates of other pollutants (i.e. CO, VOC) rose significantly. Other control methodologies needed to be developed, which led to the introduction of DLNC.

With DLNC, air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustors. Mixing may occur before or in the combustion chamber. A turbine using DLNC may operate in diffusion flame mode during operating conditions such as startup and shutdown, low or transient loads, and cold

[2] "Dry Low Emission." Wikipedia. December 01, 2018. Accessed June 06, 2019. https://en.wikipedia.org/wiki/Dry_low_emission.

ambient temperatures. The lean mixture prevents local "hot spots" within the combustor that can lead to significant thermal NO_x formation. Atmospheric nitrogen from the combustion air acts as a diluent, because fuel is mixed with air upstream of the combustor at deliberately fuel-lean conditions. The fuel to air ratio typically approaches one-half of the ideal stoichiometric level, meaning that approximately twice as much air is supplied as is actually needed to burn the fuel. This excess air is a key to limiting NO_x formation, because very lean conditions cannot produce the high temperatures that create thermal NO_x.

DLNC requires sophisticated hardware features and operational methods that simultaneously allow the stoichiometry and residence time in the flame zone to be low enough to achieve low NO_x emissions, while maintaining acceptable levels of combustion dynamics, stability at part-load conditions, and sufficient residence time to achieve low CO and VOC emissions. In principle, the DLNC strategy is simple: keep the combustion process lean at all operating conditions. In practice, this is not easily achieved. If the engine is already near the limit of lean operation at full power, then it is not possible to reduce the combustor temperature rise on all of the fuel injectors, because the flame may become unstable or be extinguished. To solve this problem, some of the fuel or air is rerouted (i.e. staged) to keep the flame within its operating boundaries. Products from a first combustion zone are mixed with fuel and air in a subsequent combustion zone, providing leaner operation of the second zone. This approach maintains the desired combustion zone temperatures at all operating conditions, but adds to the complexity of controlling the large volumes of combustion air.[3]

In short, the DLNC utilized on the Garrison Energy Center CT when firing natural gas is specifically designed to control NO_x emissions without the need to inject a diluent such as water or steam to reduce combustion temperatures. Their inherent design and operating principle is incompatible with modification or retrofit to accommodate water injection. The combustion turbines are specifically designed to utilize the existing water injection systems only when combusting oil, which is a different type of combustion mode. Therefore, it is not technically feasible to operate the existing WI systems when burning natural gas, on a year-round basis. The use of DLNC in combination with post-combustion SCR results is extremely low NO_x emissions when firing natural gas.

We trust that you will find this information useful and responsive. Please reach out to James Klickovich at 302-354-2839 or james.klickovich@calpine.com if you have any questions or need additional information.

Yours sincerely,

Gerald Kissel FOR
Plant Manager

Cc:
James Klickovich, Calpine
Sarah Deater, Calpine
David Shotts, ERM

[3] Bender, William R. "3.2.1.2 Lean Pre-Mixed Combustion." Accessed June 5, 2019. https://netl.doe.gov/coal/turbines/handbook

Information Request Letter from The Delaware Division of Air Quality to Calpine Corporation –
Hay Road, Edge Moor, Christiana, Delaware City and West Energy Centers

April 30, 2019

STATE OF DELAWARE
DEPARTMENT OF NATURAL RESOURCES
& ENVIRONMENTAL CONTROL
DIVISION OF AIR QUALITY
100 W. Water Street
DOVER, DELAWARE 19904

Telephone: (302) 739 - 9402
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April 30, 2019

Eric Graber
General Manager
Calpine Mid-Atlantic Generation, LLC
198 Hay Road
Wilmington, DE 19809

Certified Mail # 7018 2290 0002 1278 0311
RETURN RECEIPT REQUESTED

Subject: Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule

Dear Mr. Graber:

The federal Clean Air Act (CAA) and Regional Haze Rule (40 CFR 51.308 (f)(2)(i) through (iv)) requires States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment. Under the Regional Haze Rule, States are required to develop a series of state implementation plans (SIP) to address visibility impairment in Class I areas and progress made toward achieving natural visibility conditions.

As part of its Regional Haze SIP, Delaware must consider emission reductions measures identified by Class I states as being necessary to make reasonable progress in any Class I area. Delaware is part of the Mid-Atlantic Northeast Visibility Union (MANE-VU), a regional planning organization in which member states work collaboratively to develop emission control strategies to address visibility impairment in Class I areas.

MANE-VU proposed six (6) emission management strategies (Asks) in order to meet the 2028 reasonable progress goal for regional haze (Attachment 1). While many of the strategies are directed at states to adopt, there are some strategies that required input from Calpine Corporation (Calpine). Therefore, the Delaware Department of Natural Resources and Environmental Control (DNREC) is requesting information regarding emission units that meet the applicability criteria for two of the MANE-VU Asks: Ask # 1 – Year-Round NO_X and SO_2 Controls for large Electric Generating Units (EGUs)[1] and Ask # 5 – NOx Emission Limits for

[1] For the purposes of the MANE-VU Ask, a large EGU is defined as having a nameplate capacity larger than or equal to 25 MW.

Peaking Combustion Turbines[2]. DNREC requests that Calpine submit the following information by June 14, 2019:

Hay Road

Units 1, 2, and 3

Hay Road operates three combustion turbines (Units 1, 2, and 3) which use Low NOx Burners and a Water Injection (WI) system as NOx control devices. The Units combust primarily natural gas, and low sulfur light petroleum product (LSLPP) as a secondary fuel. Hay Road's Title V Permit does not require that the WI systems be operated when burning natural gas. Ask #1 for NOx emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI systems when burning natural gas, on a year-round basis.

Units 5, 6, and 7

Hay Road operates three combustion turbines (Units 5, 6, and 7) which use Low NOx Burners, a Water Injection (WI) system, and Selective Catalytic Reduction as NOx control devices. The Units combust primarily natural gas, and low sulfur light petroleum product (LSLPP) as a secondary fuel. Hay Road's Title V Permit does not require that the WI systems be operated year-round. Ask #1 for NOx emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI systems on a year-round basis.

Edge Moor

Unit 3, 4 and 5

Edge Moor operates three boilers (Unit 3, 4, and 5) which use Low NOx burners and Selective Non-Catalytic Reduction (SNCR) systems as NOx control devices. The Units combust primarily natural gas and distillate and residual fuel oil, landfill gas, digester gas, re-refined oil as secondary fuels. Edge Moor's Title V Permit does not require that the SNCR systems be operated at all times for the Unit. Ask #1 for NOx emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing SNCR systems on a year-round basis.

Christiana Energy Center

Units CH11 and CH14

Christiana Energy Center operates two distillate fired combustion turbines (Units CH11 and CH14) which use Water Injection (WI) systems as NOx control devices. The Units combust distillate fuel oil. Christiana's Title V Permit does not require that the WI systems be operated at all times for the Units. Ask #1 for NOx emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC

[2] For the purposes of the MANE-VU Ask, a peaking combustion turbine is defined as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016.

requests that Calpine evaluate the technical and economic feasibility of operating the existing WI systems on a year-round basis.

In addition, these Units have also been identified as a peaking combustion turbines that do not have stringent enough NOx limits, as compared to the year-round limits set forth in MANE-VU's Ask # 5 (Attachment 1). Therefore, DNREC also requests that Calpine perform a Four-Factor Analysis for reasonable installation or upgrade to year-round NOx emission controls for Unit CH11 and CH14[3]. A Four-Factor Analysis takes into consideration:

1) Cost of compliance[4];
2) Time necessary for compliance;
3) Energy and non-air quality environmental impacts of compliance; and
4) Remaining useful life of any potentially affected sources. (40 CFR 51.308(f)(2)(i))

West Energy Center

Unit 10

West Energy Center operates a distillate fuel fired turbine (Unit 10) which uses a Water Injection system as a NOx control device. The Unit combusts distillate fuel oil. The Unit has been identified as a peaking combustion turbine that does not have stringent enough NOx limits, as compared to the year-round limits set forth in MANE-VU's Ask # 5 (Attachment 1). Therefore, DNREC requests that Calpine perform a Four-Factor Analysis, as referenced above, for reasonable installation or upgrade to year-round NOx emission controls for the Unit[3].

Delaware City Energy Center

Unit 10

Delaware Energy Center operates a distillate fuel fired turbine (Unit 10) which uses a Water Injection system as a NOx control device. The Unit combusts distillate fuel oil. The Unit has been identified as a peaking combustion turbine that does not have stringent enough NOx limits, as compared to the year-round limits set forth in MANE-VU's Ask # 5 (Attachment 1). Therefore, DNREC requests that Calpine perform a Four-Factor Analysis, as referenced above, for reasonable installation or upgrade to year-round NOx emission controls for the Unit[3].

Thank you in advance for your cooperation. If you have any questions or wish to further discuss this request, please contact Renae Held of the Division of Air Quality at (302) 739-9402 or renae.held@delaware.gov.

Sincerely,

David Fees

David F. Fees, P.E.
Director
Division of Air Quality

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[3] DNREC requests that Calpine perform a four-factor analysis for installation or upgrade to year-round NOx controls necessary to meet both of the proposed fuel oil emission limits listed in Ask #5: 96ppm at 15% O_2 and 42ppm at 15% O_2.

[4] EPA's Control Cost Manual is a potential resource for determining the cost of compliance, it provides guidance for the development of accurate and consistent costs for air pollution control devices. https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. Fish and Wildlife Service
U.S. Forest Service

MANE-VU Class I Areas
ACADIA NATIONAL PARK ME
BRIGANTINE WILDERNESS NJ
GREAT GULF WILDERNESS NH
LYE BROOK WILDERNESS VT
MOOSEHORN WILDERNESS ME
PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH
ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

Mid-Atlantic/Northeast Visibility Union
MANE-VU

Reducing Regional Haze for Improved Visibility and Health

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION WITHIN MANE-VU TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP. This Ask by the MANE-VU Class I states, was developed through a collaborative process with all of the MANE-VU states. It is designed to identify reasonable emission reduction strategies which must be addressed by the states and tribal nations of MANE-VU through their regional haze SIP updates. This Ask has been developed and presented at this time so that SIPs may be developed and submitted between July of 2018 and July of 2021.

In addressing the emission reduction strategies in the Ask, the MANE-VU states will need to harmonize any activity on the strategies in the Ask with other federal or state

requirements that affect the sources and pollutants covered by the Ask. These federal and state requirements include, but are not limited to:

- The 2010 SO_2 standard,
- The Regional Greenhouse Gas Initiative (RGGI), if applicable,
- The Mercury and Air Toxics Standards (MATS), and
- The new 2015 ozone standard.

Because of this need for cross-program harmonization and because of the formal public process required by the federal CAA and state rulemaking processes, it is expected that there will be opportunities for stakeholders and the public to comment on how states intend to address the measures in the Ask.

Many of the MANE-VU states are also members of RGGI. RGGI is a market based cap-and-invest program designed to cost effectively reduce greenhouse gas emissions from the energy sector while returning value to rate-payers. One of the co-benefits of RGGI is that it will also significantly reduce SO_2 and NOx emissions, the two most important haze precursors. Because of this, the RGGI states, regionally, will likely achieve greater emission reductions than those envisioned in this Ask.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

Therefore, the course of action for pursuing the adoption and implementation of measures necessary to meet the 2028 reasonable progress goal for regional haze include the following "emission management" strategies:

1. Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or SO_2 controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;
2. Emission sources modeled by MANE-VU that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution

analyses (see attached listing) - perform a four-factor analysis for reasonable installation or upgrade to emission controls;

3. Each MANE-VU State that has not yet fully adopted an ultra-low sulfur fuel oil standard as requested by MANE-VU in 2007 - pursue this standard as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:
    a. distillate oil to 0.0015% sulfur by weight (15 ppm),
    b. #4 residual oil within a range of 0.25 to 0.5% sulfur by weight,
    c. #6 residual oil within a range of 0.3 to 0.5% sulfur by weight.
4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels – pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;
5. Where emission rules have not been adopted, control NOx emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:
    a. Striving to meet NOx emissions standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NOx emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or
    b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or
    c. Obtaining equivalent alternative emission reductions on high electric demand days.

    High electric demand days are days when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet. Peaking combustion turbine is defined for the purposes of this "Ask" as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016;

    (Note: SO_2 emissions for fuel oil units are addressed with Ask item 3.a. above)

6. Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 control measures.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

Listing of emission units that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area using actual 2015 emissions for EGUs and 2011 for other emission sources). The complete contribution analyses report is available at http://www.otcair.org/manevu.

State	Facility Name	Facility/ ORIS ID	Unit IDs	Max Extinction
MA	Brayton Point	1619	4	4.3
MA	Canal Station	1599	1	3.0
MD	Herbert A Wagner	1554	3	3.8
MD	Luke Paper Company	7763811	001-0011-3-0018	6.0
MD	Luke Paper Company	7763811	001-0011-3-0019	5.9
ME	The Jackson Laboratory	7945211	7945211	10.2
ME	William F Wyman	1507	4	5.6
ME	Woodland Pulp LLC	5974211		7.5
NH	Merrimack	2364	2	3.3
NJ	B L England	2378	2,3	5.6
NY	Finch Paper LLC	8325211	12	5.9
NY	Lafarge Building Materials Inc	8105211	43101	8.1
PA	Brunner Island	3140	1,2	4.0
PA	Brunner Island	3140	3	3.8
PA	Homer City	3122	1	9.3
PA	Homer City	3122	2	8.1
PA	Homer City	3122	3	3.3
PA	Keystone	3136	1	3.2
PA	Keystone	3136	2	3.1
PA	Montour	3149	1	4.4
PA	Montour	3149	2	4.1
PA	Shawville	3131	3,4	3.6

Information Request Response for Calpine –

Hay Road, Edge Moor, Christiana, Delaware City and West Energy Centers

June 14, 2019

CALPINE CORPORATION

500 DELAWARE AVENUE
SUITE 600
WILMINGTON, DE 19801

FedEx # 7877 7308 3208

June 14, 2019

Mr. David F. Fees, P.E.
Director
Division of Air Quality
Department of Natural Resources & Environmental Control
100 W. Water Street
Dover, Delaware 19904

Reference: **April 30, 2019 Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule – Hay Road, Edge Moor, Christiana, Delaware City, and West Energy Centers**

Dear Mr. Fees:

This is in response to the above-referenced Request for Information (RFI) letter from the Delaware Department of Natural Resources and Environmental Control (DNREC) requesting information regarding emission reduction measures to reduce visibility impairment in Class I areas. It is our understanding that the request is related to the federal Regional Haze Rule [40 CFR 51.308 (f)(2)(i) through (iv)] that is designed to reduce visibility impairment in Class I Areas. Delaware's State Implementation Plan (SIP) includes Reasonable Progress goals for 2028, consistent with federal requirements. Guidance developed with a group of other states and tribal nations under the Mid-Atlantic / Northeast Visibility Union (MANE-VU) issued on August 25, 2017 includes six emission management strategies ("Asks") designed to help meet the 2028 reasonable progress goal for regional haze.

DNREC's RFI is seeking input for two of the Asks as they relate to Calpine's energy centers in the State of Delaware: Ask# 1 - Year-Round NO_x and SO_2 Controls for large Electric Generating Units (EGUs) and Ask# 5 - NO_x Emission Limits for Peaking Combustion Turbines. The specific requests are outlined below for Hay Road Units 1, 2, 3, 5, 6, and 7, Edge Moor Units 3, 4 and 5, Christiana Units 11 and 14, West Unit 10, and Delaware City Unit 10, along with information that Calpine is providing in response to the requests.

As you are aware, Calpine has already taken significant steps as a company to reduce emissions that contribute to visibility impairment within the Mid-Atlantic Northeast Visibility Union (MANE-VU) footprint. Calpine supports the collaborative efforts to address visibility impairment Class I areas including the Brigantine Wilderness Area, in Atlantic County, New Jersey, that is most likely to be impacted by emissions from Delaware. Calpine has achieved significant reductions in NO_x and SO_2 emissions as a result of switches to cleaner fuels, unit shutdowns, and emission control technology retrofits.

Calpine acquired the Deepwater Energy Center (Deepwater) in Salem County, New Jersey and Edge Moor Energy Center (Edge Moor) in New Castle County, Delaware in 2010, and promptly transitioned the primary fuel at both facilities from coal to natural gas as the primary fuel. In 2008–2009, the two years immediately prior to Calpine's acquisition of Deepwater, the facility's coal-fired boiler Unit 6/8 averaged 387 tons per year (tons/year) of NO_x and 998 tons/year of SO_2. After the transition to natural gas, the facility achieved NO_x and SO_2 emission reductions of 85% and over 99%, respectively. Deepwater permanently shut down in 2014, effectively eliminating 100% of its NO_x and SO_2 emissions.

[1] Pulled from MANE-VU Emissions Inventory dated 11 September 2018.

Similarly, in 2008 and 2009, the two years immediately prior to the Calpine's acquisition of Edge Moor, the facility's coal-fired boiler Units 3 and 4 averaged 1,152 tons/year of NO_x and 4,539 tons/year of SO_2. In 2011 and 2012, the first two full years after Calpine's acquisition of the units and transition to natural gas firing, emissions dropped to 254 tons/year of NO_x and 25 tons/year of SO_2. This represents NO_x and SO_2 emission reductions of 76% and over 99%, respectively. The capacity factors of these units have since fallen with the discontinuation of a steam supply contract with a nearby DuPont facility. As a result, Edge Moor Units 3 and 4 now operate with annual capacity factors below 10%. Consequently, their emissions have decreased further, to just 36.6 tons/year of NO_x and 0.38 tons/year of SO_2, on average for 2017 and 2018.

Calpine reduced emissions in Southern New Jersey with the shutdown of peaking combustion turbines at Middle Energy Center (Cape May County), Missouri Avenue Energy Center (Atlantic County), and Cedar Energy Center (Ocean County) in May 2015.

Two peaking combustion turbine stations in Southern New Jersey owned by Calpine, Carlls Corner Energy Center in Cumberland County and Mickleton Energy Center in Gloucester County, were retrofitted with Selective Catalytic Reduction (SCR) in 2015 to reduce NO_x emissions. These retrofits resulted in lower NO_x emission rates for peaking power in the region.

You may also be aware that recently (May 2019), the BL England Generating Station in Upper Township, New Jersey, owned by RC Cape May Holdings, was permanently retired. This shutdown further reduces emissions that potentially contributed to visibility impairment within the Class I affected area and MANE-VU footprint. In fact, in the materials provided with the RFI letter identify the BL England Generating Station units among those having the potential for visibility impacts of 3.0 Mm^{-1} or greater at any MANE-VU Class I area using actual 2015 emissions for EGUs.

These emission reduction actions are summarized in the table below.

Prior Regional Emission Reductions

Calpine Facility	Description of Reductions	Estimated NO_x Emissions Reductions (tons/year)	Estimated SO_2 Emissions Reductions (tons/year)
Deepwater Energy Center	Switched Unit 6/8 from coal to natural gas firing	328	998
	Permanent shutdown of Unit 6/8	79	0.2
Edge Moor Energy Center	Switched Units 3 and 4 from coal to natural gas firing	898	4,513
	Reduced capacity factor	217	25
Middle, Missouri Avenue, & Cedar Energy Centers	Permanent shutdown	145	20
Carlls Corner & Mickleton Energy Centers	SCR retrofits	230	N/A
Non-Calpine Facility	**Description of Reductions**	**Estimated NO_x Emissions Reductions (tons/year)**	**Estimated SO_2 Emissions Reductions (tons/year)**
BL England Generating Station	Permanent shutdown	1,328	1,937

The above-described emissions reductions reasonably contribute to the MANE-VU strategy for visible impairment reduction. Further reduction or elimination of emissions from remaining Calpine assets within Delaware will not provide meaningful reductions in visible emissions. Delaware is consistently one of the lowest emitting states within the MANE-VU group, and from 2002 to 2014[1], reduced NO_x and SO_2 emissions by 52% and 95%, respectively. In 2014, stationary source NO_x and SO_2 emissions from the entire state of Delaware were 8,500 tons and 4,330 tons, respectively. Calpine sources were only a fraction of those totals, and as noted there have been further reductions in Calpine's emissions since 2014. In 2017-2018, Calpine's collective annual NO_x and SO_2 emissions from sources in Delaware averaged 610 tons/year and 120 tons/year, respectively.

Calpine Response to the DNREC Request for Information

In response to the April 30, 2019 Request for Information (RFI), Calpine is pleased to provide the requested information below.

Ask #1 – Evaluation of Technical & Economic Feasibility of Year Round WI on NG (Hay Road, Edge Moor, Christiana)

<u>Hay Road Units 1, 2, 3</u>

Hay Road Units 1, 2, and 3 (HR1, HR2, and HR3) are combined cycle combustion turbine (CT) units that began operation in 1989. Each unit consists of one Siemens V84.2 CT, nominally rated at 100 megawatts (MW) at base load and equipped with a Heat Recovery Steam Generator (HRSG). The three CTs share a single ABB steam turbine generator (STG), Unit 4. The CTs burn natural gas, with restricted use of low sulfur light petroleum Product (LSLPP) as a back-up fuel. The CTs are equipped with dry low-NO_x combustion (DLNC) when firing natural gas in premix mode, the primary operating mode. Water injection (WI) is used when firing in gas diffusion mode and when firing LSLPP.

The CTs meet the following NO_x emission limits:

- 25 ppmvd at 15% O_2 (ppm) on natural gas in pre-mix mode;
- 42 ppm on natural gas in diffusion mode or at peak load;
- 77 ppm in diffusion mode on LSLPP up to base load; and
- 88 ppm on LSLPP at peak load.

For Hay Road Units 1, 2, and 3, the RFI pertains to Ask #1:

> Hay Road's Title V Permit does not require that the WI systems be operated when burning natural gas (in premix mode). Ask #1 for NO_x emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI systems when burning natural gas, on a year-round basis.

<u>Calpine Response:</u>

The Hay Road CTs are equipped with dry low-NO_x combustion (DLNC) when firing natural gas in premix mode, and water injection (WI) when firing natural gas or LSLPP in diffusion mode. DLNC is a technology that is specifically designed to reduce NO_x emissions from combustion turbines without injecting a diluent such as water or steam to reduce combustion temperatures.

The amount of NO_x produced by a combustion turbine depends on combustion temperatures. When combustion occurs at lower temperatures, NO_x emissions are reduced. DLNC technology was developed to achieve lower emissions without using water or steam as diluents to reduce combustion temperatures. DLNC uses the principle of lean combustion, and requires an advanced control system with a large number of burners. DLNC results in lower NO_x emissions because the process is operated with less fuel and air, and combustion occurs at lower temperatures.[2]

There are two types of combustion processes in combustion turbines: diffusion flame combustion and lean-staged combustion. In diffusion flame combustion, both fuel and oxidizer (i.e. air) are supplied to the reaction zone in an unmixed state. The fuel/air mixing and combustion occur simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures

[2] "Dry Low Emission." Wikipedia. December 01, 2018. Accessed June 06, 2019. https://en.wikipedia.org/wiki/Dry_low_emission.

are very high, resulting in elevated levels of thermal NO_x emissions. At the inception of combustion turbine development, the primary design goal was to optimize performance (i.e. output) while complying with applicable emission requirements. Initially, emphasis was placed on maximizing combustion efficiency while minimizing the emission of unburned hydrocarbons and carbon monoxide (CO). It was possible to achieve these design goals by providing the diffusion flame with a relatively high combustion chamber volume in which all chemical reactions were allowed to occur without the addition of dilution air. This combustion chamber design yielded optimum thermodynamic properties with low pressure losses and a combustion efficiency of practically 100%.

In the early 1970's, when emission controls were introduced, the pollutant of primary concern shifted to NO_x. For the relatively low levels of NO_x reduction initially required, the injection of water or steam into the combustion zone produced the required reduction in NO_x emissions with minimal performance impact. In addition, the emissions of other pollutants [CO, volatile organic compounds (VOC)] remained low. To comply with more stringent NO_x emission standards that began to be imposed in the 1980's, further attempts were made to increase water/steam injection rates to ensure compliance. These attempts proved detrimental to cycle performance and equipment life, and the emission rates of other pollutants (i.e. CO, VOC) rose significantly. Other control methodologies needed to be developed, which led to the introduction of DLNC.

With DLNC, air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A turbine using DLNC may operate in diffusion flame mode during operating conditions such as startup and shutdown, low or transient loads, and cold ambient temperatures. The lean mixture prevents local "hot spots" within the combustor that can lead to significant thermal NO_x formation. Atmospheric nitrogen from the combustion air acts as a diluent, because fuel is mixed with air upstream of the combustor at deliberately fuel-lean conditions. The fuel to air ratio typically approaches one-half of the ideal stoichiometric level, meaning that approximately twice as much air is supplied as is actually needed to burn the fuel. This excess air is a key to limiting NO_x formation, because very lean conditions cannot produce the high temperatures that create thermal NO_x.

DLNC requires sophisticated hardware features and operational methods that simultaneously allow the stoichiometry and residence time in the flame zone to be low enough to achieve low NO_x emissions, while maintaining acceptable levels of combustion dynamics, stability at part-load conditions, and sufficient residence time to achieve low CO and VOC emissions. In principle, the DLNC strategy is simple: keep the combustion process lean at all operating conditions. In practice, this is not easily achieved. If the engine is already near the limit of lean operation at full power, then it is not possible to reduce the combustor temperature rise on all of the fuel injectors, because the flame may become unstable or be extinguished. To solve this problem, some of the fuel or air must be rerouted (or staged) to keep the flame within its operating boundaries. Products from a first combustion zone are mixed with fuel and air in a subsequent combustion zone, providing for leaner operation of the second zone. This approach maintains the desired combustion zone temperatures at all operating conditions, but adds to the complexity of controlling the large volumes of combustion air.[3]

In short, the DLNC utilized on the Hay Road Units 1, 2, and 3 CTs when firing natural gas in premix mode are specifically designed to control NO_x emissions without the need to inject a diluent such as water or steam to reduce combustion temperatures. Their inherent design and operating principle is incompatible with

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[3] Bender, William R. "3.2.1.2 Lean Pre-Mixed Combustion." Accessed June 5, 2019. https://netl.doe.gov/coal/turbines/handbook

modification or retrofit to accommodate water injection. The combustion turbines are specifically designed to utilize the existing water injection systems only when combusting oil or natural gas in diffusion mode, which is a different type of combustion mode. Note that NO_x emissions when combusting natural gas in diffusion mode are substantially (68%) higher than in premix mode (i.e. 42 ppm vs. 25 ppm). Therefore, it is not technically feasible to operate the existing WI systems when burning natural gas, on a year-round basis.

Hay Road Units 5, 6, and 7

Hay Road Units 5, 6, and 7 (HR5, HR6, and HR7) are also combined cycle CT units that began operation in 2001. Each unit consists of one Siemens V84.2 CT, nominally rated at 122 MW at base load and equipped with a HRSG. The three CTs share a single Alstom STG. The CTs burn natural gas, with restricted use of LSLPP as a back-up fuel. Units 5, 6, and 7 are Siemens V84.2 CT combined cycle units, each equipped with HRSG, and sharing one Alstom STG (Unit 8). The CTs are equipped with DLNC on gas premix mode, WI on gas diffuse mode and LSLPP, and post-combustion Selective Catalytic Reduction (SCR) to meet the following NO_x emission limits:

- 3 ppm on natural gas in pre-mix mode at base load;
- 9 ppm on natural gas in pre-mix mode at peak load;
- 14 ppm on natural gas in diffusion mode at base or peak load; and
- 14 ppm on LSLPP in diffusion mode at base or peak load.

For Hay Road Units 5, 6, and 7, the RFI pertains to Ask #1:

> Hay Road's Title V Permit does not require that the WI systems be operated year-round. Ask #1 for NO_x emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI systems on a year-round basis.

Calpine Response:

Please see the response pertaining to Hay Road Units 1, 2, and 3 above.

Edge Moor Units 3, 4 and 5

Edge Moor consists of three boilers, Units 3, 4, and 5 (EM3, EM4, and EM5) that are capable of firing natural gas, distillate oil and residual fuel oil. Units 3, 4, and 5 have nominal heat input ratings of 983 MMBtu/hr, 1,793 MMBtu/hr, and 4,551 MMBtu/hr, respectively. Units 3, 4, and 5 were originally installed in 1954, 1966, and 1973, respectively. The units are equipped with low-NO_x burners (LNB) and Selective Non-Catalytic Reduction (SNCR) to control NO_x emissions to the following levels:

- Units 3 and 4 are limited to 0.1 lb/MMBtu on gas and 0.125 lb/MMBtu on oil; and
- Unit 5 is limited to 0.125 lb/MMBtu on gas, oil, or other fuels.

For Edge Moor Units 3, 4, and 5, the RFI pertains to Ask #1:

> Edge Moor's Title V Permit does not require that the SNCR systems be operated at all times for the Unit. Ask #1 for NO_x emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the

technical and economic feasibility of operating the existing SNCR systems on a year-round basis.

Calpine Response:

It is technically feasible to operate the existing SNCR systems on a year-round basis. The economic feasibility of doing so depends on its cost-effectiveness in reducing NO_x emissions. To assess the cost-effectiveness of year-round operation of the SNCR systems, Calpine utilized a simplified version of the approach outlined in EPA's Control Cost Manual, a resource for determining the cost of compliance that provides guidance for the development of accurate and consistent costs for air pollution control devices. Chapter 1 of the Control Cost Manual specifically pertains to SNCR. As the manual indicates, most of the cost of using SNCR is operating expense, and the primary operating expense is for the NO_x reduction reagent which, in this case, is aqueous urea (50% by weight).

For Units 3 and 4, which burn natural gas only, the SNCR systems were originally installed to control NO_x emissions from coal firing, when coal was the primary fuel for these units. No coal has been combusted in these units since 2010. Calpine estimates capital costs of $500,000 per unit to reconfigure the SNCR systems for natural gas firing. The flue gas temperatures are compatible with effective SNCR operation only at high (> 80%) load operation. Marginal (30%) NO_x reductions are expected with SNCR use on units with such limited operation. SNCR operation also carries with it the negative impacts of ammonia slip emissions, as well as the deleterious effects on unit heat rate, cost, and dispatch.

Unit 5 is a 450 MW boiler that burns both natural gas and oil. Firing natural gas alone, the maximum output is limited to about 250 MW; at this point, oil firing must be added to achieve higher loads. The furnace temperature at the SNCR urea injection location does not reach the temperatures needed for effective SNCR operation until the boiler reaches loads of about 300 to 350 MW. Due to these limitations and with the limited recent operation of the boiler in general, the SNCR has been only rarely used. There is a significant expense with the current operation associated with keeping fresh urea on-site and making demineralized water for the urea solution in case operation of the unit is needed. At optimum (high-load) conditions, the SNCR provides about 30% NO_x reduction, which is needed to meet the NO_x limit while firing oil.

Calpine's operators believe that the SNCR could be modified to provide some degree of NO_x reduction when firing natural gas and at lower loads. Calpine estimates capital costs of $300,000 to reconfigure the SNCR system for lower loads and the associated lower flue gas temperatures. Calpine also estimates costs of $4,000 per day (urea + water + air) to operate the SNCR. As noted, the operation of Unit 5 has been limited in recent years, to about 5% capacity factor with NO_x emissions averaging about 81 tons/year for the 2017-2018 period. Based on the annualized capital cost to reconfigure the SNCR, plus the operating and maintenance costs, the cost-effectiveness of using SNCR for incremental NO_x reduction above what is currently achieved is estimated to be in the range of $10,000/ton of NO_x removed. This is not considered to be cost-effective for NO_x reduction on a unit that operates as little as Unit 5. The additional cost would also negatively impact dispatch of the unit, making it likely that it would operate even less than it presently does.

SNCR operation also carries with it the negative impacts of ammonia slip emissions. Ammonia slip emissions from Unit 5 are limited to 7 ppm. Ammonia is not a criteria pollutant with direct air quality impacts, but it can convert to a fine particle in the atmosphere and thus has potential to impact visibility in the same manner as emissions of NO_x and SO_2.

Christiana

Christiana consists of two General Electric Frame 5 simple cycle peaking CTs, Units 11 and 14 (CH11 and CH14), that fire distillate oil (ULSD). Each CT has a peak nameplate rating of 22.3 MW and a rated heat input of 391 MMBtu/hr, and is equipped with WI to control NO_x emissions to 88 ppm during the ozone season. The CTs were originally installed in 1973, and are black start units, designated generators that Calpine has committed to PJM[4] are able to restore electricity to the grid without using an outside electrical supply, and assist with restoring grid reliability. The facility's Title V operating permit limits Units 11 and 14 to a capacity factor of 5% either annually or during the period of April 1 through October 31, inclusive. In the period 2008 through 2018, inclusive, actual annual capacity factors for Unit 11 ranged from 0.05% (2014) to 0.37% (2018), and actual annual capacity factors for Unit 14 ranged from 0.02% (2013) to 0.88% (2014). Annual NO_x emissions in this period ranged from 0.20 tons (2014) to 7.3 tons (2018) for Unit 11, and from 0.14 tons (2013) to 16.8 tons (2014) for Unit 14.

For Christiana, the RFI pertains to Ask #1 and Ask #5. Ask #1 is:

> Christiana's Title V Permit does not require that the WI systems be operated at all times for the Units. Ask #1 for NO_x emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI systems on a year round basis.

Calpine Response:

It is technically feasible to operate the existing WI system on a year-round basis. The economic feasibility of doing so depends on its cost-effectiveness in reducing NO_x emissions. Currently, Calpine rents water demineralization units to supply demineralized water for WI to each unit during the ozone season. Calpine would need to incur the additional annual cost of renting the water demineralization units for the balance of each year. This cost is estimated at $12,000 per year per unit. Also, there is currently no insulation or heat tracing of WI system above-ground storage vessels and piping, which could affect the reliability of WI during the colder weather months, particularly during extreme cold weather events, such as the polar vortices that have occurred several times over the past few years. Calpine estimates that the capital cost of insulating and heat tracing of storage vessels and piping, along with a suitable heated shelter building, easily exceeds $150,000 ($75,000 per unit) at Christiana. Applying a capital recovery factor of 0.1424 based on an interest rate of 7% and a remaining useful life of 10 years, the annualized capital cost of heat tracing at Christiana exceeds $10,700 (per unit). Summing the annual costs of demineralized water and heat tracing yields annual costs exceeding $22,700 per year per unit.

As mentioned above, the worst-case annual NO_x emissions in the 2008-2018 period were 7.3 tons (2018) for Unit 11, and 16.8 tons (2014) for Unit 14. The non-ozone season component of these emissions was 7.2 tons for Unit 11, and 16.6 tons for Unit 14. Assuming that the water injection systems can reduce non-ozone season NO_x emissions by 60%, this would result in NO_x emission reductions of 4.3 tons for Unit 11, and 9.9 tons for Unit 14. At an total annual operating cost of $22,700, this results in a cost-effectiveness of about $5,300/ton of NO_x removed for Unit 11, and $2,300/ton of NO_x removed for Unit 14. These estimates are conservatively low because they only take into account the rental cost of the water demineralization unit,

[4] PJM Interconnection LLC is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states, including Delaware, and the District of Columbia.

and insulation/ heat tracing of demineralized water storage and piping, assume a NO_x reduction efficiency on the higher end of the typical range for WI systems, and use the highest NO_x emissions from the units over an 11 year period, whereas average NO_x emissions are significantly lower. For example, average non-ozone season NO_x emissions were 1.6 tons for Unit 11, and 2.5 tons for Unit 14, which alone would increase the cost-effectiveness values to \$23,900/ton of NO_x removed for Unit 11 and \$14,900/ton of NO_x removed for Unit 14.

In short, Calpine concludes that year-round utilization of WI is not economically feasible for the extremely low capacity factor CTs at Christiana. In addition to its dubious cost-effectiveness, WI presents several technical and operational challenges. Of primary concern with WI is the possibility of flame stability issues during operation in low ambient temperature conditions. Also, at smaller, traditionally unmanned sites such as Christiana, there are significant space constraints associated with placing new structures on the properties, as well as the challenges of procuring appropriate state and local approvals for such structures. In addition, having been in commercial operation for nearly 50 years, the units also have limited remaining useful life.

Ask# 5 - NO_x Emission Limits for Peaking Combustion Turbines: Four Factor Analysis for NO_x Emissions Control Technology (Christiana, West, Delaware City)

The Christiana units are described above.

West consists of one Pratt & Whitney/Turbo Power & Marine FT4 A-8 simple cycle peaking CT, Unit 10 (W10), that fires distillate oil (ULSD). The CT has a nameplate rating of 19 MW and a rated heat input of 264 MMBtu/hr, and is equipped with WI to control NO_x emissions to 88 ppm during the ozone season. The CT was originally installed in 1965, and is a black start unit, a designated generator that Calpine has committed to PJM is able to restore electricity to the grid without using an outside electrical supply, and assist with restoring grid reliability. The facility's Title V operating permit limits Unit 10 to a capacity factor of 5% either annually or during the period of April 1 through October 31, inclusive. In the period 2010 through 2018, inclusive, actual annual capacity factors have been much lower than this, ranging from 0.11% (2010) to 0.49% (2018). Annual NO_x emissions in this period ranged from 0.29 tons (2010) to 2.6 tons (2018).

Delaware City consists of one Pratt & Whitney/Turbo Power & Marine FT4 A-8 simple cycle peaking CT, Unit 10 (DC10), that fires distillate oil (ULSD). The CT has a peak nameplate rating of 20.4 MW and a rated heat input of 270 MMBtu/hr, and is equipped with WI to control NO_x emissions to 88 ppm during the ozone season. The CT was originally installed in 1968, and is a black start unit, a designated generator that Calpine has committed to PJM is able to restore electricity to the grid without using an outside electrical supply, and assist with restoring grid reliability. The facility's Title V operating permit limits Unit 10 to a capacity factor of 5% either annually or during the period of April 1 through October 31, inclusive. In the period 2010 through 2018, inclusive, actual annual capacity factors have been much lower than this, ranging from 0.01% (2018) to 0.14% (2013). Annual NO_x emissions in this period ranged from 0.14 tons (2012) to 3.2 tons (2014).

For Christiana, West, and Delaware City, the RFI pertains to Ask #5:

> The Units have been identified as peaking combustion turbines that do not have stringent enough NO_x limits, as compared to the year-round limits set forth in MANE-VU's

Ask #5. Therefore, DNREC requests that Calpine perform a Four Factor Analysis for reasonable installation or upgrade to year-round NO_x emission controls for the Units.

Calpine Response:

Two NO_x emission reduction technologies, WI and SCR, are considered technically feasible for the Christiana, Delaware City, and West CTs.

WI is already installed on these units and used during the ozone season. Hence, it is technically feasible to operate the existing WI systems on a year-round basis. The economic feasibility of doing so depends on its cost-effectiveness in reducing NO_x emissions.

The estimated cost-effectiveness and technical and operational challenges of year-round WI operation at Christiana is discussed above.

Currently, at West and Delaware City, Calpine rents a water demineralization unit at each site to supply demineralized water for WI during the ozone season. Calpine would need to incur the additional annual costs of renting the water demineralization unit at each site for the balance of each year. This cost is estimated at $12,000 per year per unit. Also, there is currently no insulation or heat tracing of WI system storage vessels or piping, which could affect the reliability of WI during the colder weather months, particularly during extreme cold weather events, such as the polar vortices that have occurred several times over the past few years. Calpine estimates that the capital cost of insulating and heat tracing of above-ground storage vessels and piping, along with a suitable heated shelter building, easily exceeds $100,000 per unit at West and Delaware City. Applying a capital recovery factor of 0.1424 based on an interest rate of 7% and a remaining useful life of 10 years, the annualized capital cost of heat tracing at West and Delaware City exceeds $14,240 per unit. Summing the annual costs of demineralized water and heat tracing yields annual costs exceeding $26,240 per year per unit.

For West, the worst-case annual NO_x emissions in the 2010-2018 period were 2.6 tons (2018). The non-ozone season component of these emissions was 2.3 tons. Assuming that the water injection systems can reduce NO_x emissions by 60%, this would result in NO_x emission reductions of 1.4 tons. At an annual operating cost of $26,240, this results in a cost-effectiveness of about $19,000/ton of NO_x removed. Again, these estimates are conservatively low because they only take into account the rental cost of the water demineralization unit, assume a NO_x reduction efficiency on the higher end of the typical range for WI systems, and use the highest NO_x emissions from the units over a 9 year period, whereas average NO_x emissions are significantly lower. For example, average non-ozone season NO_x emissions were less than 0.8 tons, which alone would increase the cost-effectiveness value to over $59,000/ton of NO_x removed.

For Delaware City, the worst-case annual NO_x emissions in the 2010-2018 period were 3.2 tons (2014). The non-ozone season component of these emissions was 3.0 tons. Assuming that the water injection systems can reduce NO_x emissions by 60%, this would result in NO_x emission reductions of 1.8 tons. At an annual operating cost of $26,240, this results in a cost-effectiveness of $14,700/ton of NO_x removed. Again, these estimates are conservatively low because they only take into account the rental cost of the water demineralization unit, assume a NO_x reduction efficiency on the higher end of the typical range for WI systems, and use the highest NO_x emissions from the units over a 9 year period, whereas average NO_x emissions are significantly lower. For example, average non-ozone season NO_x emissions were 0.5 tons, which alone would increase the cost-effectiveness value to $94,500/ton of NO_x removed.

In short, Calpine concludes that year-round utilization of WI is not economically feasible for the extremely low capacity factor CTs at Christiana, Delaware City, and West. In addition to its lack of cost-effectiveness, WI presents several technical and operational challenges. Of primary concern with WI is the possibility of flame stability issues during operation in low ambient temperature conditions. Also, at smaller, traditionally unmanned sites such as Christiana, Delaware City, and West, there are significant space constraints associated with placing new structures on the properties, as well as the challenges of procuring appropriate state and local approvals for such structures. In addition, having been in commercial operation for 45 to over 50 years, the units also have limited remaining useful life.

Aside from WI, the most common and technically feasible retrofit NO_x emission control technology for peaking combustion turbines is SCR, although SCR is not without its technical and operational challenges at Christiana, Delaware City, and West. In addition to sharing the space constraint issues associated with permitting and placing new structures on the properties, as well as limited remaining useful life, SCR presents the additional challenges of managing operations and maintenance for the complex new control systems associated with SCR at what have traditionally been unmanned sites, along with the operational and safety challenges or aqueous ammonia storage and handling. SCR also involves disposal and handling of spent precious metal catalyst materials.

Like SNCR, SCR operation also carries with it the negative impacts of ammonia slip emissions. Ammonia slip emissions are typically limited to 5 to 10 ppm. Ammonia is not a criteria pollutant with direct air quality impacts, but it can convert to a fine particle in the atmosphere and thus has potential to impact visibility in the same manner as emissions of NO_x and SO_2.

In 2015, Calpine evaluated retrofitting SCR on its New Jersey peaking combustion turbines in response to regulations that tightened NO_x emission standards for turbines. SCR retrofits were evaluated at five New Jersey sites: Carlls Corner, Cedar, Mickleton, Middle, and Missouri Avenue Energy Centers. The combustion turbines at Carlls Corner, Cedar, Middle, and Missouri Avenue are Pratt & Whitney/Turbo Power & Marine FT4 "aeroderivative" combustion turbines are similar to those at Delaware City and West. The combustion turbine at Mickleton is a Westinghouse Model W501-AC "frame" combustion turbine similar to the GE Frame 5 turbines at Christiana.

As part of this evaluation, Calpine obtained bids from five SCR vendors for each of the sites. Based on these bids, the installed capital costs ranged from \$146,000/MW to \$197,000/MW. Conservatively using the lower of these values, \$146,000/MW, and scaling it to the MW ratings of the Christiana, Delaware City, and West CTs, the estimated installed capital cost for each of the 22.3 MW CTs at Christiana is approximately \$3.2 million. For Delaware City's 20.4 MW CT, the cost is approximately \$3.0 million, and for the 19 MW CT at West the cost is approximately \$2.8 million. Applying a capital recovery factor of 0.1424 based on an interest rate of 7% and a remaining useful life of 10 years, the annualized capital costs at Christiana (per unit), Delaware City, and West are \$463,000, \$423,000, and \$394,000, respectively. Worst-case annual NO_x emissions in the 2008-2018 period were 7.3 tons for Christiana Unit 11, 16.8 tons for Christiana for Unit 14, 3.2 tons for Delaware City, and 2.6 tons for West.

Assuming 90% control of these worst-case NO_x emissions with SCR, the amounts of NO_x reduced would be 6.6 tons for Christiana Unit 11, 15.2 tons for Christiana for Unit 14, 2.9 tons for Delaware City, and 2.3 tons for West. Dividing the annualized capital costs by the amounts of NO_x reduced results in cost-effectiveness values of \$71,000/ton of NO_x removed for Christiana Unit 11, \$31,000/ton of NO_x removed for Christiana for Unit 14, \$147,000/ton of NO_x removed for Delaware City Unit 10, and \$171,000/ton of NO_x removed for West Unit 10. These cost-effectiveness values are conservatively low in they use the lowest of the five bids, and highest historical actual emissions over the last 11 years. Yet they are still excessive even without *taking into account additional annual operating and maintenance costs including staffing for SCR O&M, aqueous ammonia reagent, power consumption, and power loss from reduced heat rate and back pressure across the catalysts. The additional costs would also negatively impact dispatch of the units, making it likely that they would operate even less than they do presently. Therefore, Calpine concludes that retrofitting SCR is not economically feasible for the CTs at Christiana, Delaware City, and West.*

Calpine considered other potential NO_x controls for retrofit to the Christiana, Delaware City, and West CTs. These other technologies include SCONOx™ (also known as EMx™), SNCR, and XONON™.

EMx™ uses a single catalyst to remove NO_x emissions from combustion turbine exhaust gas by oxidizing nitric oxide (NO) to nitrogen dioxide (NO_2) and then absorbing the NO_2 onto a catalytic surface using a potassium carbonate (K_2CO_3) absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx™ catalyst is from 300 °F to 700 °F.

When all of the potassium carbonate absorber coating has been converted to N_2 compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N_2. Carbon dioxide (CO_2) in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst. Calpine's understanding is that the demonstrated application for EMx™ is currently limited to natural gas fired combined cycle combustion turbines under approximately 50 MW in size. Therefore, EMx™ is not considered technically feasible for the oil-fired simple-cycle CTs at Christiana, Delaware City, and West.

SNCR, to be effective in reducing NO_x emissions, requires a temperature window that is significantly higher than the exhaust temperatures from the combustion turbines. Therefore, SNCR is not considered technically feasible for the Christiana, Delaware City, and West CTs.

XONON™ is a catalytic combustion technology that has apparently been successfully demonstrated in a 1.5 MW simple-cycle combustion turbine pilot facility, and is commercially available for combustion turbines rated at up to 10 MW. However, catalytic combustors such as XONON™ have not been demonstrated as a retrofit technology on 19 to 22 MW CTs such as those at Christiana, Delaware City, and West. Therefore, the XONON™ is not considered technically feasible for these units.

We trust that you will find this information useful and responsive. Please reach out to James Klickovich at 302-354-2839 or james.klickovich@calpine.com if you have any questions or need additional information.

Yours sincerely,

for

Eric Graber
General Manager
Calpine Mid-Atlantic Generation, LLC

Cc:
James Klickovich, Calpine   Robert Lattomus, Calpine   David Shotts, ERM

Information Request Letter from The Delaware Division of Air Quality to Calpine Corporation – Christiana, Delaware City and West Energy Centers

June 26, 2020

STATE OF DELAWARE
DEPARTMENT OF NATURAL RESOURCES AND
ENVIRONMENTAL CONTROL
DIVISION OF AIR QUALITY
STATE STREET COMMONS
100 W. WATER STREET, SUITE 6A
DOVER, DELAWARE 19904

DIRECTOR'S
OFFICE

PHONE
(302) 739-9402

June 26, 2020

Eric Graber
General Manager
Calpine Mid-Atlantic Generation, LLC
198 Hay Road
Wilmington, DE 19809

Certified Mail # 7011 3500 0003 2400 0640
RETURN RECEIPT REQUESTED

Subject: Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule

Dear Mr. Graber:

This letter is a follow-up to the Regional Haze information request letter that the Delaware Department of Natural Resources and Environmental Control (DNREC) sent to Calpine (Calpine) regarding the Christiana, West, and Delaware City Energy Center facilities on April 30, 2019.

As part of its Regional Haze SIP, Delaware must consider emission reductions measures identified by Class I states as being necessary to make reasonable progress in any Class I area. Delaware is part of the Mid-Atlantic Northeast Visibility Union (MANE-VU), a regional planning organization in which member states work collaboratively to develop emission control strategies to address visibility impairment in Class I areas.

MANE-VU proposed six (6) emission management strategies (Asks) in order to meet the 2028 reasonable progress goal for regional haze. While many of the Asks are directed at states to adopt, there are some strategies that require input from companies. Therefore, DNREC sent the above-mentioned information request to Calpine regarding the facilities that fell under the MANE-VU Asks.

In its information request, DNREC asked Calpine to perform a Four-Factor Analysis for reasonable installation or upgrade to year-round NOx emission controls for the following combustion distillate fired turbines which use a Water Injection system as a NOx control device:

- Christiana – Units CH11 and CH14
- West – Unit 10
- Delaware City – Unit 10

DNREC thanks Calpine for its subsequent response, submitted on June 14, 2019. Water injection is currently used on the units during the ozone season (May – September), to meet the NOx standards set forth in 7 DE Admin. Code 1148 – Control of Stationary Combustion Turbine Electric Generating Unit Emissions. Calpine replied that it was technically feasible to operate the Water Injection on a year-round basis, it would not be economically feasible to do so.

Calpine rents water demineralization units to supply water to the units during the ozone season. In addition, the above ground components of the Water Injection systems do not currently have insulation or heat tracing of the components. Calpine also responded that in order for the Water Injection to be operated during cold weather events, it would be necessary to install insulating and heat tracing of storage vessels and piping, along with a heated shelter building. Therefore, additional capital and operating costs would be incurred in order to extend Water Injection beyond the ozone season.

To better evaluate Calpine's response, DNREC is requesting that Calpine provide the following additional information:

- The procedures and timing for shutdown of water injection system each fall, after the ozone season (operational/pipework modifications, draining of pipework, removal of demineralization units, etc.).
- The procedures and timing for bringing the water injection system back into operation each spring, before the start of the ozone season (operational/pipework modifications, instillation of demineralization units, removal of insulation of systems, etc.).
- The technical feasibility and cost of weatherization systems (pipe insulation, heat tracing, etc.) that could be installed without the use of a heated shelter building, to potentially extend the use of the Water Injection system to the months adjacent to the ozone season (April and October).
- Potential maintenance or operational improvements (cleaning, tuning of components, etc.) that could be made on the units to improve the NOx reduction.
- A breakdown of the following costs for each new control system or existing control system upgrade that was evaluated for cost effectiveness, if applicable[1]:
    - Capital Costs: Purchased Equipment, Direct Instillation, Indirect Instillation, Indirect Capital
    - Annualized costs: Operating and Maintenance, Utilities, Indirect Annual, Capital Recovery.

[1] EPA's Control Cost Manual contains information regarding the different types of cost categories: https://www3.epa.gov/ttn/catc/dir1/c_allchs.pdf

DNREC requests that Calpine submit the requested supplemental information by July 23, 2020.

Thank you in advance for your cooperation. If you have any questions or wish to further discuss this request, please contact Renae Held of the Division of Air Quality at (302) 739-9402 or renae.held@delaware.gov.

Sincerely,

David Fees

David F. Fees, P.E.
Director
Division of Air Quality

Information Request Response for Calpine –

Christiana, Delaware City and West Energy Centers

July 23, 2020

CALPINE CORPORATION

500 Delaware Avenue
Suite 600
Wilmington, DE 19801

FedEx# 3950 4807 4406

July 23, 2020

Mr. David F. Fees, P.E.
Director
Division of Air Quality
Department of Natural Resources & Environmental Control
100 W. Water Street
Dover, Delaware 19904

Reference: June 26, 2020, Supplemental Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule –Christiana, Delaware City, and West Energy Centers

Dear Mr. Fees:

This is in response to the above-referenced "Supplemental" Request for Information (SRFI) letter from the Delaware Department of Natural Resources and Environmental Control (DNREC) requesting information regarding emission reduction measures to reduce visibility impairment in Class I areas. It is our understanding that the request is related to the federal Regional Haze Rule [40 CFR 51.308 (f)(2)(i) through (iv)] that is designed to reduce visibility impairment in Class I Areas. Delaware's State Implementation Plan (SIP) includes Reasonable Progress goals for 2028, consistent with federal requirements. Guidance developed with a group of other states and tribal nations under the Mid-Atlantic / Northeast Visibility Union (MANE-VU) issued on August 25, 2017 includes six emission management strategies ("Asks") designed to help meet the 2028 reasonable progress goal for regional haze.

As you are aware, and as provided in Calpine's response (June 14, 2019 – attached for your convenience) to DNREC's initial Request for Information dated April 30, 2019, Calpine has already taken significant steps as a company to reduce emissions that contribute to visibility impairment within the Mid-Atlantic Northeast Visibility Union (MANE-VU) footprint. Calpine supports the collaborative efforts to address visibility impairment Class I areas including the Brigantine Wilderness Area, in Atlantic County, New Jersey, that is most likely to be impacted by emissions from Delaware. Calpine has achieved significant reductions in NO_x and SO_2 emissions as a result of switches to cleaner fuels, unit shutdowns, and emission control technology retrofits. .

DNREC's SRFI (June 26, 2020) is seeking input related to Calpine's Energy Centers in the State of Delaware. The SRFI is specific to Christiana Units 11 and 14 (2 units), West Unit 10 (1 unit), and Delaware City Unit 10 (1 unit), each unit at these Energy Center's are simple cycle combustion turbines that generate electricity. Note that these units have historically had low operating/generating hours on an annual basis. The operating/generating hours for each unit for the past 5 years is provided herein.

Annual Operating/Generating Hours

	2015*	2016	2017	2018*	2019	2020 (YTD)
Christiana 11	31.3	3.78	5.75	30.37	8.97	1.02
Christiana 14	17.4	2.57	5.33	36.92	8.00	1.43
Delaware City 10	6.00	4.00	9.00	6.00	11.00	0.00
West 10	7.00	24.00	3.00	47.00	6.00	0.00

*Polar Vortex

<u>In response to DNREC's SRFI dated June 26, 2020, Calpine provides the following:</u>

SRFI # 1: The procedures and timing for shutdown of water injection system each fall, after the ozone season (operational/pipework modifications, draining of pipework, removal of demineralization units, etc.).

<u>Response</u>:
Each unit has a large permanent demineralized water storage tank at the Energy Center. Each unit requires 2 portable ion exchange resin vessels (demin system) that are skid mounted and rented. The demin system connects to the city water supply by flexible piping. The demin system connects to the permanent piping to the tank by flexible piping. Permanent piping from the tank supplies the demineralized water to the water injection system forwarding/injection pumps by flexible piping.

Following the ozone sseason the following occurs:

1) Drain down portable ion exchange resin vessels and return to supplier.
2) Disconnect flexible hoses, drain and place into storage.
3) Drain down storage tanks.
4) Drain all associated water injection system piping, pumps and install any required blanks.
5) Secure the water injection system associated pumps (prevent inadvertent operation).

SRFI #2: The procedures and timing for bringing the water injection system back into operation each spring, before the start of the ozone season (operational/pipework modifications, instillation of demineralization units, removal of insulation of systems, etc.).

<u>Response</u>:

Setup before ozone season – Typically the 3rd week in April

1) Secure (rent) 2 portable ion exchange resin vessels for each unit from the supplier and install at the sites.
2) Flush the system.
3) Connect flexible hoses to ion exchange resin vessels and permanent piping (city water supply, storage tanks).

4) Remove any installed blanks.
5) Inspect water injection nozzles.
6) Energize the water injection system pumps.
7) Test system.

SRFI #3: The technical feasibility and cost of weatherization systems (pipe insulation, heat tracing, etc.) that could be installed without the use of a heated shelter building, to potentially extend the use of the Water Injection system to the months adjacent to the ozone season (April and October).

Response:

In a collaborative effort, Calpine is willing to voluntarily operate water injection to reduce NOx emissions during the months adjacent to the ozone season (April and October) assuming any resulting permit conditions are mutually agreeable.

SRFI #4: Potential maintenance or operational improvements (cleaning, tuning of components, etc.) that could be made on the units to improve the NOx reduction.

Response:

Calpine maintains and operates the units with due care, conforming to industry standards, recognized industry practices and manufacturer recommendations. Calpine routinely inspects the units to assure that components are in sound working condition including the water injection system (water injection nozzles, water injection system forwarding/injection pumps, etc.).

SRFI #5: A breakdown of the following costs for each new control system or existing control system upgrade that was evaluated for cost effectiveness, if applicable[1]:

- Capital Costs: Purchased Equipment, Direct Instillation, Indirect Instillation, Indirect Capital
- Annualized costs: Operating and Maintenance, Utilities, Indirect Annual, Capital Recovery

Response:

Calpine believes that this SRFI was covered in responses provide in Calpine's response (June 14, 2019) to the initial RFI. Calpine believes that due to the limited annual hours of operation/generation (see above) that one would conclude that installing heat tracing on each tank for each unit, heat tracing for permanent and flexible piping and a heated shelter would not be cost effective.

We trust that you will find this information useful. If you have any questions or need additional information please call me at 304-354-2839 or email me at james.klickovich@calpine.com.

Sincerely,

James Klickovich
Manager Environmental Health and Safety

Cc:

E. Graber, Calpine
R. Lattomus, Calpine

CALPINE CORPORATION

500 DELAWARE AVENUE
SUITE 600
WILMINGTON, DE 19801

FedEx # 7877 7308 3208

June 14, 2019

Mr. David F. Fees, P.E.
Director
Division of Air Quality
Department of Natural Resources & Environmental Control
100 W. Water Street
Dover, Delaware 19904

Reference: **April 30, 2019 Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule – Hay Road, Edge Moor, Christiana, Delaware City, and West Energy Centers**

Dear Mr. Fees:

This is in response to the above-referenced Request for Information (RFI) letter from the Delaware Department of Natural Resources and Environmental Control (DNREC) requesting information regarding emission reduction measures to reduce visibility impairment in Class I areas. It is our understanding that the request is related to the federal Regional Haze Rule [40 CFR 51.308 (f)(2)(i) through (iv)] that is designed to reduce visibility impairment in Class I Areas. Delaware's State Implementation Plan (SIP) includes Reasonable Progress goals for 2028, consistent with federal requirements. Guidance developed with a group of other states and tribal nations under the Mid-Atlantic / Northeast Visibility Union (MANE-VU) issued on August 25, 2017 includes six emission management strategies ("Asks") designed to help meet the 2028 reasonable progress goal for regional haze.

DNREC's RFI is seeking input for two of the Asks as they relate to Calpine's energy centers in the State of Delaware: Ask# 1 - Year-Round NO_x and SO_2 Controls for large Electric Generating Units (EGUs) and Ask# 5 - NO_x Emission Limits for Peaking Combustion Turbines. The specific requests are outlined below for Hay Road Units 1, 2, 3, 5, 6, and 7, Edge Moor Units 3, 4 and 5, Christiana Units 11 and 14, West Unit 10, and Delaware City Unit 10, along with information that Calpine is providing in response to the requests.

As you are aware, Calpine has already taken significant steps as a company to reduce emissions that contribute to visibility impairment within the Mid-Atlantic Northeast Visibility Union (MANE-VU) footprint. Calpine supports the collaborative efforts to address visibility impairment Class I areas including the Brigantine Wilderness Area, in Atlantic County, New Jersey, that is most likely to be impacted by emissions from Delaware. Calpine has achieved significant reductions in NO_x and SO_2 emissions as a result of switches to cleaner fuels, unit shutdowns, and emission control technology retrofits.

Calpine acquired the Deepwater Energy Center (Deepwater) in Salem County, New Jersey and Edge Moor Energy Center (Edge Moor) in New Castle County, Delaware in 2010, and promptly transitioned the primary fuel at both facilities from coal to natural gas as the primary fuel. In 2008–2009, the two years immediately prior to Calpine's acquisition of Deepwater, the facility's coal-fired boiler Unit 6/8 averaged 387 tons per year (tons/year) of NO_x and 998 tons/year of SO_2. After the transition to natural gas, the facility achieved NO_x and SO_2 emission reductions of 85% and over 99%, respectively. Deepwater permanently shut down in 2014, effectively eliminating 100% of its NO_x and SO_2 emissions.

[1] Pulled from MANE-VU Emissions Inventory dated 11 September 2018.

Similarly, in 2008 and 2009, the two years immediately prior to the Calpine's acquisition of Edge Moor, the facility's coal-fired boiler Units 3 and 4 averaged 1,152 tons/year of NO_x and 4,539 tons/year of SO_2. In 2011 and 2012, the first two full years after Calpine's acquisition of the units and transition to natural gas firing, emissions dropped to 254 tons/year of NO_x and 25 tons/year of SO_2. This represents NO_x and SO_2 emission reductions of 76% and over 99%, respectively. The capacity factors of these units have since fallen with the discontinuation of a steam supply contract with a nearby DuPont facility. As a result, Edge Moor Units 3 and 4 now operate with annual capacity factors below 10%. Consequently, their emissions have decreased further, to just 36.6 tons/year of NO_x and 0.38 tons/year of SO_2, on average for 2017 and 2018.

Calpine reduced emissions in Southern New Jersey with the shutdown of peaking combustion turbines at Middle Energy Center (Cape May County), Missouri Avenue Energy Center (Atlantic County), and Cedar Energy Center (Ocean County) in May 2015.

Two peaking combustion turbine stations in Southern New Jersey owned by Calpine, Carlls Corner Energy Center in Cumberland County and Mickleton Energy Center in Gloucester County, were retrofitted with Selective Catalytic Reduction (SCR) in 2015 to reduce NO_x emissions. These retrofits resulted in lower NO_x emission rates for peaking power in the region.

You may also be aware that recently (May 2019), the BL England Generating Station in Upper Township, New Jersey, owned by RC Cape May Holdings, was permanently retired. This shutdown further reduces emissions that potentially contributed to visibility impairment within the Class I affected area and MANE-VU footprint. In fact, in the materials provided with the RFI letter identify the BL England Generating Station units among those having the potential for visibility impacts of 3.0 Mm^{-1} or greater at any MANE-VU Class I area using actual 2015 emissions for EGUs.

These emission reduction actions are summarized in the table below.

Prior Regional Emission Reductions

Calpine Facility	Description of Reductions	Estimated NO_x Emissions Reductions (tons/year)	Estimated SO_2 Emissions Reductions (tons/year)
Deepwater Energy Center	Switched Unit 6/8 from coal to natural gas firing	328	998
	Permanent shutdown of Unit 6/8	79	0.2
Edge Moor Energy Center	Switched Units 3 and 4 from coal to natural gas firing	898	4,513
	Reduced capacity factor	217	25
Middle, Missouri Avenue, & Cedar Energy Centers	Permanent shutdown	145	20
Carlls Corner & Mickleton Energy Centers	SCR retrofits	230	N/A
Non-Calpine Facility	**Description of Reductions**	**Estimated NO_x Emissions Reductions (tons/year)**	**Estimated SO_2 Emissions Reductions (tons/year)**
BL England Generating Station	Permanent shutdown	1,328	1,937

The above-described emissions reductions reasonably contribute to the MANE-VU strategy for visible impairment reduction. Further reduction or elimination of emissions from remaining Calpine assets within Delaware will not provide meaningful reductions in visible emissions. Delaware is consistently one of the lowest emitting states within the MANE-VU group, and from 2002 to 2014[1], reduced NO_x and SO_2 emissions by 52% and 95%, respectively. In 2014, stationary source NO_x and SO_2 emissions from the entire state of Delaware were 8,500 tons and 4,330 tons, respectively. Calpine sources were only a fraction of those totals, and as noted there have been further reductions in Calpine's emissions since 2014. In 2017-2018, Calpine's collective annual NO_x and SO_2 emissions from sources in Delaware averaged 610 tons/year and 120 tons/year, respectively.

<u>Calpine Response to the DNREC Request for Information</u>

In response to the April 30, 2019 Request for Information (RFI), Calpine is pleased to provide the requested information below.

Ask #1 – Evaluation of Technical & Economic Feasibility of Year Round WI on NG (Hay Road, Edge Moor, Christiana)

Hay Road Units 1, 2, 3

Hay Road Units 1, 2, and 3 (HR1, HR2, and HR3) are combined cycle combustion turbine (CT) units that began operation in 1989. Each unit consists of one Siemens V84.2 CT, nominally rated at 100 megawatts (MW) at base load and equipped with a Heat Recovery Steam Generator (HRSG). The three CTs share a single ABB steam turbine generator (STG), Unit 4. The CTs burn natural gas, with restricted use of low sulfur light petroleum Product (LSLPP) as a back-up fuel. The CTs are equipped with dry low-NO_x combustion (DLNC) when firing natural gas in premix mode, the primary operating mode. Water Injection (WI) is used when firing in gas diffusion mode and when firing LSLPP.

The CTs meet the following NO_x emission limits:

- 25 ppmvd at 15% O_2 (ppm) on natural gas in pre-mix mode;
- 42 ppm on natural gas in diffusion mode or at peak load;
- 77 ppm in diffusion mode on LSLPP up to base load; and
- 88 ppm on LSLPP at peak load.

For Hay Road Units 1, 2, and 3, the RFI pertains to Ask #1:

> Hay Road's Title V Permit does not require that the WI systems be operated when burning natural gas (in premix mode). Ask #1 for NO_x emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI systems when burning natural gas, on a year-round basis.

Calpine Response:

The Hay Road CTs are equipped with dry low-NO_x combustion (DLNC) when firing natural gas in premix mode, and water injection (WI) when firing natural gas or LSLPP in diffusion mode. DLNC is a technology that is specifically designed to reduce NO_x emissions from combustion turbines without injecting a diluent such as water or steam to reduce combustion temperatures.

The amount of NO_x produced by a combustion turbine depends on combustion temperatures. When combustion occurs at lower temperatures, NO_x emissions are reduced. DLNC technology was developed to achieve lower emissions without using water or steam as diluents to reduce combustion temperatures. DLNC uses the principle of lean combustion, and requires an advanced control system with a large number of burners. DLNC results in lower NO_x emissions because the process is operated with less fuel and air, and combustion occurs at lower temperatures.[2]

There are two types of combustion processes in combustion turbines: diffusion flame combustion and lean-staged combustion. In diffusion flame combustion, both fuel and oxidizer (i.e. air) are supplied to the reaction zone in an unmixed state. The fuel/air mixing and combustion occur simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures

[2] "Dry Low Emission." Wikipedia. December 01, 2018. Accessed June 06, 2019. https://en.wikipedia.org/wiki/Dry_low_emission.

are very high, resulting in elevated levels of thermal NO_x emissions. At the inception of combustion turbine development, the primary design goal was to optimize performance (i.e. output) while complying with applicable emission requirements. Initially, emphasis was placed on maximizing combustion efficiency while minimizing the emission of unburned hydrocarbons and carbon monoxide (CO). It was possible to achieve these design goals by providing the diffusion flame with a relatively high combustion chamber volume in which all chemical reactions were allowed to occur without the addition of dilution air. This combustion chamber design yielded optimum thermodynamic properties with low pressure losses and a combustion efficiency of practically 100%.

In the early 1970's, when emission controls were introduced, the pollutant of primary concern shifted to NO_x. For the relatively low levels of NO_x reduction initially required, the injection of water or steam into the combustion zone produced the required reduction in NO_x emissions with minimal performance impact. In addition, the emissions of other pollutants [CO, volatile organic compounds (VOC)] remained low. To comply with more stringent NO_x emission standards that began to be imposed in the 1980's, further attempts were made to increase water/steam injection rates to ensure compliance. These attempts proved detrimental to cycle performance and equipment life, and the emission rates of other pollutants (i.e. CO, VOC) rose significantly. Other control methodologies needed to be developed, which led to the introduction of DLNC.

With DLNC, air and fuel are thoroughly mixed to form a lean mixture before delivery to the combustor. Mixing may occur before or in the combustion chamber. A turbine using DLNC may operate in diffusion flame mode during operating conditions such as startup and shutdown, low or transient loads, and cold ambient temperatures. The lean mixture prevents local "hot spots" within the combustor that can lead to significant thermal NO_x formation. Atmospheric nitrogen from the combustion air acts as a diluent, because fuel is mixed with air upstream of the combustor at deliberately fuel-lean conditions. The fuel to air ratio typically approaches one-half of the ideal stoichiometric level, meaning that approximately twice as much air is supplied as is actually needed to burn the fuel. This excess air is a key to limiting NO_x formation, because very lean conditions cannot produce the high temperatures that create thermal NO_x.

DLNC requires sophisticated hardware features and operational methods that simultaneously allow the stoichiometry and residence time in the flame zone to be low enough to achieve low NO_x emissions, while maintaining acceptable levels of combustion dynamics, stability at part-load conditions, and sufficient residence time to achieve low CO and VOC emissions. In principle, the DLNC strategy is simple: keep the combustion process lean at all operating conditions. In practice, this is not easily achieved. If the engine is already near the limit of lean operation at full power, then it is not possible to reduce the combustor temperature rise on all of the fuel injectors, because the flame may become unstable or be extinguished. To solve this problem, some of the fuel or air must be rerouted (or staged) to keep the flame within its operating boundaries. Products from a first combustion zone are mixed with fuel and air in a subsequent combustion zone, providing for leaner operation of the second zone. This approach maintains the desired combustion zone temperatures at all operating conditions, but adds to the complexity of controlling the large volumes of combustion air.[3]

In short, the DLNC utilized on the Hay Road Units 1, 2, and 3 CTs when firing natural gas in premix mode are specifically designed to control NO_x emissions without the need to inject a diluent such as water or steam to reduce combustion temperatures. Their inherent design and operating principle is incompatible with

[3] Bender, William R. "3.2.1.2 Lean Pre-Mixed Combustion." Accessed June 5, 2019. https://netl.doe.gov/coal/turbines/handbook

modification or retrofit to accommodate water injection. The combustion turbines are specifically designed to utilize the existing water injection systems only when combusting oil or natural gas in diffusion mode, which is a different type of combustion mode. Note that NO_x emissions when combusting natural gas in diffusion mode are substantially (68%) higher than in premix mode (i.e. 42 ppm vs. 25 ppm). Therefore, it is not technically feasible to operate the existing WI systems when burning natural gas, on a year-round basis.

<u>Hay Road Units 5, 6, and 7</u>

Hay Road Units 5, 6, and 7 (HR5, HR6, and HR7) are also combined cycle CT units that began operation in 2001. Each unit consists of one Siemens V84.2 CT, nominally rated at 122 MW at base load and equipped with a HRSG. The three CTs share a single Alstom STG. The CTs burn natural gas, with restricted use of LSLPP as a back-up fuel. Units 5, 6, and 7 are Siemens V84.2 CT combined cycle units, each equipped with HRSG, and sharing one Alstom STG (Unit 8). The CTs are equipped with DLNC on gas premix mode, WI on gas diffuse mode and LSLPP, and post-combustion Selective Catalytic Reduction (SCR) to meet the following NO_x emission limits:

- 3 ppm on natural gas in pre-mix mode at base load;
- 9 ppm on natural gas in pre-mix mode at peak load;
- 14 ppm on natural gas in diffusion mode at base or peak load; and
- 14 ppm on LSLPP in diffusion mode at base or peak load.

For Hay Road Units 5, 6, and 7, the RFI pertains to Ask #1:

> Hay Road's Title V Permit does not require that the WI systems be operated year-round. Ask #1 for NO_x emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI systems on a year-round basis.

<u>*Calpine Response:*</u>

Please see the response pertaining to Hay Road Units 1, 2, and 3 above.

<u>Edge Moor Units 3, 4 and 5</u>

Edge Moor consists of three boilers, Units 3, 4, and 5 (EM3, EM4, and EM5) that are capable of firing natural gas, distillate oil and residual fuel oil. Units 3, 4, and 5 have nominal heat input ratings of 983 MMBtu/hr, 1,793 MMBtu/hr, and 4,551 MMBtu/hr, respectively. Units 3, 4, and 5 were originally installed in 1954, 1966, and 1973, respectively. The units are equipped with low-NO_x burners (LNB) and Selective Non-Catalytic Reduction (SNCR) to control NO_x emissions to the following levels:

- Units 3 and 4 are limited to 0.1 lb/MMBtu on gas and 0.125 lb/MMBtu on oil; and
- Unit 5 is limited to 0.125 lb/MMBtu on gas, oil, or other fuels.

For Edge Moor Units 3, 4, and 5, the RFI pertains to Ask #1:

> Edge Moor's Title V Permit does not require that the SNCR systems be operated at all times for the Unit. Ask #1 for NO_x emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the

technical and economic feasibility of operating the existing SNCR systems on a year-round basis.

Calpine Response:

It is technically feasible to operate the existing SNCR systems on a year-round basis. The economic feasibility of doing so depends on its cost-effectiveness in reducing NO_x emissions. To assess the cost-effectiveness of year-round operation of the SNCR systems, Calpine utilized a simplified version of the approach outlined in EPA's Control Cost Manual, a resource for determining the cost of compliance that provides guidance for the development of accurate and consistent costs for air pollution control devices. Chapter 1 of the Control Cost Manual specifically pertains to SNCR. As the manual indicates, most of the cost of using SNCR is operating expense, and the primary operating expense is for the NO_x reduction reagent which, in this case, is aqueous urea (50% by weight).

For Units 3 and 4, which burn natural gas only, the SNCR systems were originally installed to control NO_x emissions from coal firing, when coal was the primary fuel for these units. No coal has been combusted in these units since 2010. Calpine estimates capital costs of $500,000 per unit to reconfigure the SNCR systems for natural gas firing. The flue gas temperatures are compatible with effective SNCR operation only at high (> 80%) load operation. Marginal (30%) NO_x reductions are expected with SNCR use on units with such limited operation. SNCR operation also carries with it the negative impacts of ammonia slip emissions, as well as the deleterious effects on unit heat rate, cost, and dispatch.

Unit 5 is a 450 MW boiler that burns both natural gas and oil. Firing natural gas alone, the maximum output is limited to about 250 MW; at this point, oil firing must be added to achieve higher loads. The furnace temperature at the SNCR urea injection location does not reach the temperatures needed for effective SNCR operation until the boiler reaches loads of about 300 to 350 MW. Due to these limitations and with the limited recent operation of the boiler in general, the SNCR has been only rarely used. There is a significant expense with the current operation associated with keeping fresh urea on-site and making demineralized water for the urea solution in case operation of the unit is needed. At optimum (high-load) conditions, the SNCR provides about 30% NO_x reduction, which is needed to meet the NO_x limit while firing oil.

Calpine's operators believe that the SNCR could be modified to provide some degree of NO_x reduction when firing natural gas and at lower loads. Calpine estimates capital costs of $300,000 to reconfigure the SNCR system for lower loads and the associated lower flue gas temperatures. Calpine also estimates costs of $4,000 per day (urea + water + air) to operate the SNCR. As noted, the operation of Unit 5 has been limited in recent years, to about 5% capacity factor with NO_x emissions averaging about 81 tons/year for the 2017-2018 period. Based on the annualized capital cost to reconfigure the SNCR, plus the operating and maintenance costs, the cost-effectiveness of using SNCR for incremental NO_x reduction above what is currently achieved is estimated to be in the range of $10,000/ton of NO_x removed. This is not considered to be cost-effective for NO_x reduction on a unit that operates as little as Unit 5. The additional cost would also negatively impact dispatch of the unit, making it likely that it would operate even less than it presently does.

SNCR operation also carries with it the negative impacts of ammonia slip emissions. Ammonia slip emissions from Unit 5 are limited to 7 ppm. Ammonia is not a criteria pollutant with direct air quality impacts, but it can convert to a fine particle in the atmosphere and thus has potential to impact visibility in the same manner as emissions of NO_x and SO_2.

Christiana

Christiana consists of two General Electric Frame 5 simple cycle peaking CTs, Units 11 and 14 (CH11 and CH14), that fire distillate oil (ULSD). Each CT has a peak nameplate rating of 22.3 MW and a rated heat input of 391 MMBtu/hr, and is equipped with WI to control NO_x emissions to 88 ppm during the ozone season. The CTs were originally installed in 1973, and are black start units, designated generators that Calpine has committed to PJM[4] are able to restore electricity to the grid without using an outside electrical supply, and assist with restoring grid reliability. The facility's Title V operating permit limits Units 11 and 14 to a capacity factor of 5% either annually or during the period of April 1 through October 31, inclusive. In the period 2008 through 2018, inclusive, actual annual capacity factors for Unit 11 ranged from 0.05% (2014) to 0.37% (2018), and actual annual capacity factors for Unit 14 ranged from 0.02% (2013) to 0.88% (2014). Annual NO_x emissions in this period ranged from 0.20 tons (2014) to 7.3 tons (2018) for Unit 11, and from 0.14 tons (2013) to 16.8 tons (2014) for Unit 14.

For Christiana, the RFI pertains to Ask #1 and Ask #5. Ask #1 is:

> Christiana's Title V Permit does not require that the WI systems be operated at all times for the Units. Ask #1 for NO_x emissions, seeks to ensure that control technologies are used on a year-round basis. Therefore, DNREC requests that Calpine evaluate the technical and economic feasibility of operating the existing WI systems on a year round basis.

Calpine Response:

It is technically feasible to operate the existing WI system on a year-round basis. The economic feasibility of doing so depends on its cost-effectiveness in reducing NO_x emissions. Currently, Calpine rents water demineralization units to supply demineralized water for WI to each unit during the ozone season. Calpine would need to incur the additional annual cost of renting the water demineralization units for the balance of each year. This cost is estimated at $12,000 per year per unit. Also, there is currently no insulation or heat tracing of WI system above-ground storage vessels and piping, which could affect the reliability of WI during the colder weather months, particularly during extreme cold weather events, such as the polar vortices that have occurred several times over the past few years. Calpine estimates that the capital cost of insulating and heat tracing of storage vessels and piping, along with a suitable heated shelter building, easily exceeds $150,000 ($75,000 per unit) at Christiana. Applying a capital recovery factor of 0.1424 based on an interest rate of 7% and a remaining useful life of 10 years, the annualized capital cost of heat tracing at Christiana exceeds $10,700 (per unit). Summing the annual costs of demineralized water and heat tracing yields annual costs exceeding $22,700 per year per unit.

As mentioned above, the worst-case annual NO_x emissions in the 2008-2018 period were 7.3 tons (2018) for Unit 11, and 16.8 tons (2014) for Unit 14. The non-ozone season component of these emissions was 7.2 tons for Unit 11, and 16.6 tons for Unit 14. Assuming that the water injection systems can reduce non-ozone season NO_x emissions by 60%, this would result in NO_x emission reductions of 4.3 tons for Unit 11, and 9.9 tons for Unit 14. At an total annual operating cost of $22,700, this results in a cost-effectiveness of about $5,300/ton of NO_x removed for Unit 11, and $2,300/ton of NO_x removed for Unit 14. These estimates are conservatively low because they only take into account the rental cost of the water demineralization unit,

[4] PJM Interconnection LLC is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states, including Delaware, and the District of Columbia.

and insulation/ heat tracing of demineralized water storage and piping, assume a NO_x reduction efficiency on the higher end of the typical range for WI systems, and use the highest NO_x emissions from the units over an 11 year period, whereas average NO_x emissions are significantly lower. For example, average non-ozone season NO_x emissions were 1.6 tons for Unit 11, and 2.5 tons for Unit 14, which alone would increase the cost-effectiveness values to \$23,900/ton of NO_x removed for Unit 11 and \$14,900/ton of NO_x removed for Unit 14.

In short, Calpine concludes that year-round utilization of WI is not economically feasible for the extremely low capacity factor CTs at Christiana. In addition to its dubious cost-effectiveness, WI presents several technical and operational challenges. Of primary concern with WI is the possibility of flame stability issues during operation in low ambient temperature conditions. Also, at smaller, traditionally unmanned sites such as Christiana, there are significant space constraints associated with placing new structures on the properties, as well as the challenges of procuring appropriate state and local approvals for such structures. In addition, having been in commercial operation for nearly 50 years, the units also have limited remaining useful life.

Ask# 5 - NO_x Emission Limits for Peaking Combustion Turbines: Four Factor Analysis for NO_x Emissions Control Technology (Christiana, West, Delaware City)

The Christiana units are described above.

West consists of one Pratt & Whitney/Turbo Power & Marine FT4 A-8 simple cycle peaking CT, Unit 10 (W10), that fires distillate oil (ULSD). The CT has a nameplate rating of 19 MW and a rated heat input of 264 MMBtu/hr, and is equipped with WI to control NO_x emissions to 88 ppm during the ozone season. The CT was originally installed in 1965, and is a black start unit, a designated generator that Calpine has committed to PJM is able to restore electricity to the grid without using an outside electrical supply, and assist with restoring grid reliability. The facility's Title V operating permit limits Unit 10 to a capacity factor of 5% either annually or during the period of April 1 through October 31, inclusive. In the period 2010 through 2018, inclusive, actual annual capacity factors have been much lower than this, ranging from 0.11% (2010) to 0.49% (2018). Annual NO_x emissions in this period ranged from 0.29 tons (2010) to 2.6 tons (2018).

Delaware City consists of one Pratt & Whitney/Turbo Power & Marine FT4 A-8 simple cycle peaking CT, Unit 10 (DC10), that fires distillate oil (ULSD). The CT has a peak nameplate rating of 20.4 MW and a rated heat input of 270 MMBtu/hr, and is equipped with WI to control NO_x emissions to 88 ppm during the ozone season. The CT was originally installed in 1968, and is a black start unit, a designated generator that Calpine has committed to PJM is able to restore electricity to the grid without using an outside electrical supply, and assist with restoring grid reliability. The facility's Title V operating permit limits Unit 10 to a capacity factor of 5% either annually or during the period of April 1 through October 31, inclusive. In the period 2010 through 2018, inclusive, actual annual capacity factors have been much lower than this, ranging from 0.01% (2018) to 0.14% (2013). Annual NO_x emissions in this period ranged from 0.14 tons (2012) to 3.2 tons (2014).

For Christiana, West, and Delaware City, the RFI pertains to Ask #5:

> The Units have been identified as peaking combustion turbines that do not have stringent enough NO_x limits, as compared to the year-round limits set forth in MANE-VU's

Ask #5. Therefore, DNREC requests that Calpine perform a Four Factor Analysis for reasonable installation or upgrade to year-round NO_x emission controls for the Units.

Calpine Response:

Two NO_x emission reduction technologies, WI and SCR, are considered technically feasible for the Christiana, Delaware City, and West CTs.

WI is already installed on these units and used during the ozone season. Hence, it is technically feasible to operate the existing WI systems on a year-round basis. The economic feasibility of doing so depends on its cost-effectiveness in reducing NO_x emissions.

The estimated cost-effectiveness and technical and operational challenges of year-round WI operation at Christiana is discussed above.

Currently, at West and Delaware City, Calpine rents a water demineralization unit at each site to supply demineralized water for WI during the ozone season. Calpine would need to incur the additional annual costs of renting the water demineralization unit at each site for the balance of each year. This cost is estimated at $12,000 per year per unit. Also, there is currently no insulation or heat tracing of WI system storage vessels or piping, which could affect the reliability of WI during the colder weather months, particularly during extreme cold weather events, such as the polar vortices that have occurred several times over the past few years. Calpine estimates that the capital cost of insulating and heat tracing of above-ground storage vessels and piping, along with a suitable heated shelter building, easily exceeds $100,000 per unit at West and Delaware City. Applying a capital recovery factor of 0.1424 based on an interest rate of 7% and a remaining useful life of 10 years, the annualized capital cost of heat tracing at West and Delaware City exceeds $14,240 per unit. Summing the annual costs of demineralized water and heat tracing yields annual costs exceeding $26,240 per year per unit.

For West, the worst-case annual NO_x emissions in the 2010-2018 period were 2.6 tons (2018). The non-ozone season component of these emissions was 2.3 tons. Assuming that the water injection systems can reduce NO_x emissions by 60%, this would result in NO_x emission reductions of 1.4 tons. At an annual operating cost of $26,240, this results in a cost-effectiveness of about $19,000/ton of NO_x removed. Again, these estimates are conservatively low because they only take into account the rental cost of the water demineralization unit, assume a NO_x reduction efficiency on the higher end of the typical range for WI systems, and use the highest NO_x emissions from the units over a 9 year period, whereas average NO_x emissions are significantly lower. For example, average non-ozone season NO_x emissions were less than 0.8 tons, which alone would increase the cost-effectiveness value to over $59,000/ton of NO_x removed.

For Delaware City, the worst-case annual NO_x emissions in the 2010-2018 period were 3.2 tons (2014). The non-ozone season component of these emissions was 3.0 tons. Assuming that the water injection systems can reduce NO_x emissions by 60%, this would result in NO_x emission reductions of 1.8 tons. At an annual operating cost of $26,240, this results in a cost-effectiveness of $14,700/ton of NO_x removed. Again, these estimates are conservatively low because they only take into account the rental cost of the water demineralization unit, assume a NO_x reduction efficiency on the higher end of the typical range for WI systems, and use the highest NO_x emissions from the units over a 9 year period, whereas average NO_x emissions are significantly lower. For example, average non-ozone season NO_x emissions were 0.5 tons, which alone would increase the cost-effectiveness value to $94,500/ton of NO_x removed.

In short, Calpine concludes that year-round utilization of WI is not economically feasible for the extremely low capacity factor CTs at Christiana, Delaware City, and West. In addition to its lack of cost-effectiveness, WI presents several technical and operational challenges. Of primary concern with WI is the possibility of flame stability issues during operation in low ambient temperature conditions. Also, at smaller, traditionally unmanned sites such as Christiana, Delaware City, and West, there are significant space constraints associated with placing new structures on the properties, as well as the challenges of procuring appropriate state and local approvals for such structures. In addition, having been in commercial operation for 45 to over 50 years, the units also have limited remaining useful life.

Aside from WI, the most common and technically feasible retrofit NO_x emission control technology for peaking combustion turbines is SCR, although SCR is not without its technical and operational challenges at Christiana, Delaware City, and West. In addition to sharing the space constraint issues associated with permitting and placing new structures on the properties, as well as limited remaining useful life, SCR presents the additional challenges of managing operations and maintenance for the complex new control systems associated with SCR at what have traditionally been unmanned sites, along with the operational and safety challenges or aqueous ammonia storage and handling. SCR also involves disposal and handling of spent precious metal catalyst materials.

Like SNCR, SCR operation also carries with it the negative impacts of ammonia slip emissions. Ammonia slip emissions are typically limited to 5 to 10 ppm. Ammonia is not a criteria pollutant with direct air quality impacts, but it can convert to a fine particle in the atmosphere and thus has potential to impact visibility in the same manner as emissions of NO_x and SO_2.

In 2015, Calpine evaluated retrofitting SCR on its New Jersey peaking combustion turbines in response to regulations that tightened NO_x emission standards for turbines. SCR retrofits were evaluated at five New Jersey sites: Carlls Corner, Cedar, Mickleton, Middle, and Missouri Avenue Energy Centers. The combustion turbines at Carlls Corner, Cedar, Middle, and Missouri Avenue are Pratt & Whitney/Turbo Power & Marine FT4 "aeroderivative" combustion turbines are similar to those at Delaware City and West. The combustion turbine at Mickleton is a Westinghouse Model W501-AC "frame" combustion turbine similar to the GE Frame 5 turbines at Christiana.

As part of this evaluation, Calpine obtained bids from five SCR vendors for each of the sites. Based on these bids, the installed capital costs ranged from \$146,000/MW to \$197,000/MW. Conservatively using the lower of these values, \$146,000/MW, and scaling it to the MW ratings of the Christiana, Delaware City, and West CTs, the estimated installed capital cost for each of the 22.3 MW CTs at Christiana is approximately \$3.2 million. For Delaware City's 20.4 MW CT, the cost is approximately \$3.0 million, and for the 19 MW CT at West the cost is approximately \$2.8 million. Applying a capital recovery factor of 0.1424 based on an interest rate of 7% and a remaining useful life of 10 years, the annualized capital costs at Christiana (per unit), Delaware City, and West are \$463,000, \$423,000, and \$394,000, respectively. Worst-case annual NO_x emissions in the 2008-2018 period were 7.3 tons for Christiana Unit 11, 16.8 tons for Christiana for Unit 14, 3.2 tons for Delaware City, and 2.6 tons for West.

Assuming 90% control of these worst-case NO_x emissions with SCR, the amounts of NO_x reduced would be 6.6 tons for Christiana Unit 11, 15.2 tons for Christiana for Unit 14, 2.9 tons for Delaware City, and 2.3 tons for West. Dividing the annualized capital costs by the amounts of NO_x reduced results in cost-effectiveness values of \$71,000/ton of NO_x removed for Christiana Unit 11, \$31,000/ton of NO_x removed for Christiana for Unit 14, \$147,000/ton of NO_x removed for Delaware City Unit 10, and \$171,000/ton of NO_x removed for West Unit 10. These cost-effectiveness values are conservatively low in they use the lowest of the five bids, and highest historical actual emissions over the last 11 years. Yet they are still excessive even without *taking into account additional annual operating and maintenance costs including staffing for SCR O&M, aqueous ammonia reagent, power consumption, and power loss from reduced heat rate and back pressure across the catalysts. The additional costs would also negatively impact dispatch of the units, making it likely that they would operate even less than they do presently. Therefore, Calpine concludes that retrofitting SCR is not economically feasible for the CTs at Christiana, Delaware City, and West.*

Calpine considered other potential NO_x controls for retrofit to the Christiana, Delaware City, and West CTs. These other technologies include SCONOx™ (also known as EMx™), SNCR, and XONON™.

EMx™ uses a single catalyst to remove NO_x emissions from combustion turbine exhaust gas by oxidizing nitric oxide (NO) to nitrogen dioxide (NO_2) and then absorbing the NO_2 onto a catalytic surface using a potassium carbonate (K_2CO_3) absorber coating. The potassium carbonate coating reacts with NO_2 to form potassium nitrites and nitrates, which are deposited onto the catalyst surface. The optimal temperature window for operation of the EMx™ catalyst is from 300 °F to 700 °F.

When all of the potassium carbonate absorber coating has been converted to N_2 compounds, NO_x can no longer be absorbed and the catalyst must be regenerated. Regeneration is accomplished by passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the gas reacts with the nitrites and nitrates to form water and N_2. Carbon dioxide (CO_2) in the gas reacts with the potassium nitrite and nitrates to form potassium carbonate, which is the absorbing surface coating on the catalyst. The regeneration gas is produced by reacting natural gas with a carrier gas (such as steam) over a steam-reforming catalyst. Calpine's understanding is that the demonstrated application for EMx™ is currently limited to natural gas fired combined cycle combustion turbines under approximately 50 MW in size. Therefore, EMx™ is not considered technically feasible for the oil-fired simple-cycle CTs at Christiana, Delaware City, and West.

SNCR, to be effective in reducing NO_x emissions, requires a temperature window that is significantly higher than the exhaust temperatures from the combustion turbines. Therefore, SNCR is not considered technically feasible for the Christiana, Delaware City, and West CTs.

XONON™ is a catalytic combustion technology that has apparently been successfully demonstrated in a 1.5 MW simple-cycle combustion turbine pilot facility, and is commercially available for combustion turbines rated at up to 10 MW. However, catalytic combustors such as XONON™ have not been demonstrated as a retrofit technology on 19 to 22 MW CTs such as those at Christiana, Delaware City, and West. Therefore, the XONON™ is not considered technically feasible for these units.

We trust that you will find this information useful and responsive. Please reach out to James Klickovich at 302-354-2839 or james.klickovich@calpine.com if you have any questions or need additional information.

Yours sincerely,

For

Eric Graber
General Manager
Calpine Mid-Atlantic Generation, LLC

Cc:
James Klickovich, Calpine   Robert Lattomus, Calpine   David Shotts, ERM

Information Request Letter from The Delaware Division of Air Quality to NRG – Indian River

April 30, 2019

STATE OF DELAWARE
DEPARTMENT OF NATURAL RESOURCES
& ENVIRONMENTAL CONTROL
DIVISION OF AIR QUALITY
100 W. Water Street
DOVER, DELAWARE 19904

Telephone: (302) 739 - 9402
Fax No.: (302) 739 - 3106

April 30, 2019

David Burton
Plant Manager
NRG
29416 Power Plant Road
Dagsboro, DE 19939

Certified Mail # 7018 2290 0002 1278 0304
RETURN RECEIPT REQUESTED

Subject: Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule

Dear Mr. Burton:

The federal Clean Air Act (CAA) and Regional Haze Rule (40 CFR 51.308 (f)(2)(i) through (iv)) requires States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment. Under the Regional Haze Rule, States are required to develop a series of state implementation plans (SIP) to address visibility impairment in Class I areas and progress made toward achieving natural visibility conditions.

As part of its Regional Haze SIP, Delaware must consider emission reductions measures identified by Class I states as being necessary to make reasonable progress in any Class I area. Delaware is part of the Mid-Atlantic Northeast Visibility Union (MANE-VU), a regional planning organization in which member states work collaboratively to develop emission control strategies to address visibility impairment in Class I areas.

MANE-VU proposed six (6) emission management strategies (Asks) in order to meet the 2028 reasonable progress goal for regional haze (Attachment 1). While many of the Asks are directed at states to adopt, there are some strategies that required input from NRG Energy, Inc. (NRG). Therefore, the Delaware Department of Natural Resources and Environmental Control (DNREC) is requesting information regarding an emission unit that meets the applicability criteria for one of the MANE-VU Asks: Ask # 5 – NOx Emission Limits for Peaking Combustion Turbines[1].

[1] For the purposes of the MANE-VU Ask, a peaking combustion turbine is defined as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016.

DNREC requests that NRG submit the following information for the Indian River Generating Station (Indian River) by June 14, 2019:

Emission Unit 5 (IR Unit 10)

Indian River operates a combustion gas turbine (Emission Unit 5) which uses a Water Injection system as a NOx control device. Unit 5 combusts distillate fuel oil. The Unit has been identified as a peaking combustion turbine that does not have stringent enough NOx limits, as compared to the year-round limits set forth in MANE-VU's Ask # 5 (Attachment 1). Therefore, DNREC requests that NRG perform a Four-Factor Analysis for reasonable installation or upgrade to year-round NOx emission controls for the Unit[2]. A Four-Factor Analysis takes into consideration:

1) Cost of compliance[3];
2) Time necessary for compliance;
3) Energy and non-air quality environmental impacts of compliance; and
4) Remaining useful life of any potentially affected sources. (40 CFR 51.308(f)(2)(i))

Thank you in advance for your cooperation. If you have any questions or wish to further discuss this request, please contact Renae Held of the Division of Air Quality at (302) 739-9402 or renae.held@delaware.gov.

Sincerely,

David Fees

David F. Fees, P.E.
Director
Division of Air Quality

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[2] DNREC requests that NRG perform a four-factor analysis for installation or upgrade to year-round NOx controls necessary to meet both of the proposed fuel oil emission limits listed in Ask #5: 96ppm at 15% O_2 and 42ppm at 15% O_2.

[3] EPA's Control Cost Manual is a potential resource for determining the cost of compliance, it provides guidance for the development of accurate and consistent costs for air pollution control devices. https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Mid-Atlantic/Northeast Visibility Union

MANE-VU

Reducing Regional Haze for Improved Visibility and Health

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. Fish and Wildlife Service
U.S. Forest Service

MANE-VU Class I Areas
ACADIA NATIONAL PARK ME
BRIGANTINE WILDERNESS NJ
GREAT GULF WILDERNESS NH
LYE BROOK WILDERNESS VT
MOOSEHORN WILDERNESS ME
PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH
ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION WITHIN MANE-VU TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP. This Ask by the MANE-VU Class I states, was developed through a collaborative process with all of the MANE-VU states. It is designed to identify reasonable emission reduction strategies which must be addressed by the states and tribal nations of MANE-VU through their regional haze SIP updates. This Ask has been developed and presented at this time so that SIPs may be developed and submitted between July of 2018 and July of 2021.

In addressing the emission reduction strategies in the Ask, the MANE-VU states will need to harmonize any activity on the strategies in the Ask with other federal or state

requirements that affect the sources and pollutants covered by the Ask. These federal and state requirements include, but are not limited to:

- The 2010 SO_2 standard,
- The Regional Greenhouse Gas Initiative (RGGI), if applicable,
- The Mercury and Air Toxics Standards (MATS), and
- The new 2015 ozone standard.

Because of this need for cross-program harmonization and because of the formal public process required by the federal CAA and state rulemaking processes, it is expected that there will be opportunities for stakeholders and the public to comment on how states intend to address the measures in the Ask.

Many of the MANE-VU states are also members of RGGI. RGGI is a market based cap-and-invest program designed to cost effectively reduce greenhouse gas emissions from the energy sector while returning value to rate-payers. One of the co-benefits of RGGI is that it will also significantly reduce SO_2 and NOx emissions, the two most important haze precursors. Because of this, the RGGI states, regionally, will likely achieve greater emission reductions than those envisioned in this Ask.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

Therefore, the course of action for pursuing the adoption and implementation of measures necessary to meet the 2028 reasonable progress goal for regional haze include the following "emission management" strategies:

1. Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or SO_2 controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;
2. Emission sources modeled by MANE-VU that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution

analyses (see attached listing) - perform a four-factor analysis for reasonable installation or upgrade to emission controls;

3. Each MANE-VU State that has not yet fully adopted an ultra-low sulfur fuel oil standard as requested by MANE-VU in 2007 - pursue this standard as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:
    a. distillate oil to 0.0015% sulfur by weight (15 ppm),
    b. #4 residual oil within a range of 0.25 to 0.5% sulfur by weight,
    c. #6 residual oil within a range of 0.3 to 0.5% sulfur by weight.
4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels – pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;
5. Where emission rules have not been adopted, control NOx emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:

    a. Striving to meet NOx emissions standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NOx emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or
    b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or
    c. Obtaining equivalent alternative emission reductions on high electric demand days.

    High electric demand days are days when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet. Peaking combustion turbine is defined for the purposes of this "Ask" as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016;

    (Note: SO_2 emissions for fuel oil units are addressed with Ask item 3.a. above)

6. Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 control measures.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

Listing of emission units that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area using actual 2015 emissions for EGUs and 2011 for other emission sources). The complete contribution analyses report is available at http://www.otcair.org/manevu.

State	Facility Name	Facility/ ORIS ID	Unit IDs	Max Extinction
MA	Brayton Point	1619	4	4.3
MA	Canal Station	1599	1	3.0
MD	Herbert A Wagner	1554	3	3.8
MD	Luke Paper Company	7763811	001-0011-3-0018	6.0
MD	Luke Paper Company	7763811	001-0011-3-0019	5.9
ME	The Jackson Laboratory	7945211	7945211	10.2
ME	William F Wyman	1507	4	5.6
ME	Woodland Pulp LLC	5974211		7.5
NH	Merrimack	2364	2	3.3
NJ	B L England	2378	2,3	5.6
NY	Finch Paper LLC	8325211	12	5.9
NY	Lafarge Building Materials Inc	8105211	43101	8.1
PA	Brunner Island	3140	1,2	4.0
PA	Brunner Island	3140	3	3.8
PA	Homer City	3122	1	9.3
PA	Homer City	3122	2	8.1
PA	Homer City	3122	3	3.3
PA	Keystone	3136	1	3.2
PA	Keystone	3136	2	3.1
PA	Montour	3149	1	4.4
PA	Montour	3149	2	4.1
PA	Shawville	3131	3,4	3.6

Information Request Response for NRG – Indian River

June 19, 2019

David Bacher
Indian River Power LLC
29416 Power Plant Road
Dagsboro, Delaware 19939

An NRG Energy Company

June 19, 2019

Renae Held
Environmental Scientist
Airshed Planning & Inventory Program
Delaware Division of Air Quality
100 Water Street
Dover, Delaware 19904

Ms. Held,

I am writing in response to your inquiry of April 30, 2019 in regard to Delaware's Regional Haze State Implementation Plan and pending amendments, in association with the Indian River Generating Station, Emission Unit 5, Indian River Unit 10 (IR10). We appreciate Delaware's commitment to Regional Haze and it partnership with the Mid Atlantic North East Visibility Union (MANE-VU) to collectively develop regional emission control strategies to address visibility impairment in Class 1 areas. As requested, please accept our "Four Factor analysis" response to you inquiry for evaluating year round NOx control emission reduction technology on IR10. In addition, our discussion includes "Ask #5" to include technologies reviewed and determined infeasible.

The MANE-VU initiative is based on achieving reasonable progress goals by 2028 and participating states are asked to evaluate potential from qualified emission sources for reductions that can be quantified within a SIP revision. The initiative targets units 25MW or greater seeking operation near 25ppm at 15% O2 for natural gas and 42ppm at 15% O2 for distillate fuel and a request that each state adopt an ultra low sulfur in fuel content standard. Further states are requested to complete a four factor analysis to evaluate reduction potential, specifically for units 15 MW or more that operate equivalent to a 20% or less capacity factor or 1752 hours per year during 2014 to 2016.

Unit 10 Combustion Turbine
Indian River Unit 10 (Regulation 30 Unit 5) is a 366 MMBTU/hr Turbo-Jet Pratt & Whitney FT4-9LF combustion turbine installed in 1967 that operates on distillate fuel (the -9 refers to the internal cooling of the engine turbine nozzle vanes, LF refers to a liquid fueled engine) equipped with a fuel manifold and Delavan Fuel nozzles for Water Injection. The unit has a summer rating of 17MW and a winter rating of 21MW.

The unit was designed for black start capability and to serve as a critical resource and peaking unit available to the facility and the Independent System Operator (ISO) for reliability reasons.

In 2009 the unit was equipped with water injection to comply with an 88ppm NOx emission limit during the Ozone Season and achieved an average of 52.8ppm, verified by stack testing.

Since that time the facility has taken action to further reduce emissions including cleaning and tuning of other components of the fuel system and improving the control logic for water injection. As a result, our emission profile has improved based on stack testing with a reduction from 2009 at 52.8 ppm and 2013 at 56.8 ppm to 22.8 ppm in 2018, better than a 50% reduction.

From an operational perspective, the unit is typically "out of market" and only operates when called by PJM or for completing PJM capacity verification or DNREC emissions testing. Over the past 10 years the unit has operated for an average of 28 hours per year which is comparable to a capacity factor of 0.32% annually. Within this 10 year range, the highest operating hours of 76 hours occurred in 2014 followed by 61 hours in 2028 (most for testing). However, more typical, the unit operated only 7 hours in 2017 and 6 hours in 2016. These values are well below the MANE-VU target of units operating around 1752 hours and why Indian river is not included on the MANE-VU list of units that have a potential for improving visibility.

Analysis

1. **Cost of Compliance**
   Indian River conducted an evaluation to modify the current system for annual operation, specifically to utilize water injection. The initial cost is based on converting the water system for winter operation which required constructing a stand alone building for water injection system, new water tanks, transformers and electrical system modifications, heat tracing, heating systems, piping, foundation work, and control system modifications. The current estimate for this conversion is $205,200 however not based on actual contracts or bidder solicitation. Using this value and a high CF value such as 2018 at 61hours and a 25% reduction from the 4.28 tons emitted in 2018 (based on 50/50 summer winter operations and a 50% emissions reduction in winter), this equates to $192,000 per ton. However, a more realistic evaluation would be based on our average at 28 hours, this equates to $418 per ton. Data from 2016 and 2017 equates to about $2M per ton note the annual emissions would be around .5 tons or less and the reduction only 0.12 tons).
2. **Time Necessary for Compliance**
   The project would need to be completed in the non-ozone season. Most likely this could be achieved in about a year.
3. **Energy and Non-Air Quality Environmental Impacts of Compliance**
   We have not fully evaluated the added operating cost of the heat trace system or heating the building housing the equipment. Further, we have not calculated emissions generated provide power for these systems or the emission profile of any unit that would provide the power to the equipment as it would not be provided by the plant itself.
4. **Remaining Useful Life of Any Potentially Affected Sources**
   NRG has not determined any timeline for taking Unit 10 out of service and does not have any plans to replace Unit 10. Further, the unit would remain in service as long as it is economical and needed for reliability within PJM. However, for the purpose of considering any retrofit, the unit was installed in 1967 and has been in operation for 52 year, exceeding the typical operating range of 30-40 years for this type of unit.
5. **Technologies Reviewed**
   Indian River had considered replacement of the unit if associated with a natural gas conversion. In inability to bring a natural gas supply to the area has prohibited that

option. Because of the operating profile and lack of other fuel options, water injection is the only reduction technology available.

As stated, appreciate the initiative for DNREC and MANE-VU to improve air quality. Based on our review, it is not practical or feasible to initiate further emissions reduction on Unit 10 primarily because of our operating profile, the cost of the project, the cost per ton, and the very minimal NOx reduction that would actually occur. We do not anticipate the unit to operate more that it currently operates, maintaining our current operating profile. Further, looking at 2 or the last 3 years, the unit operated less than 10 hours per year and the years with higher hours are typically because of stack testing or an extreme weather event.

Please recognize NRG and Indian River have already support this initiative in our recent AQCS project to significantly reduce SO2, NOx, Hg, and PM emissions, an investment of almost $400M in Delaware and in our air quality. Further, while further reductions are not feasible, our 2009 and 2013 test have exceeded our permit limit on average by 35%, exceeds the minimum standard of 96ppm, and are within 20% of the maximum MANE-VU target of 42ppm. Further, our previous emission test in 2018 yielded an average of 22.77ppm that exceeded the maximum MANE-VU target of 42 ppm.

After your review, please feel free to contact me on (302) 540-0327 or by E-Mail on david.bacher@nrgenergy.com.

Respectfully submitted,

David Bacher
Regional Manager, NRG Environmental Business

CC:	D. Fees	(DNREC)
	A. Carter	(Indian River)
	D. Burton	(Indian River)

Information Request Letter from The Delaware Division of Air Quality to NRG – Indian River

June 26, 2020

STATE OF DELAWARE
DEPARTMENT OF NATURAL RESOURCES AND ENVIRONMENTAL CONTROL
DIVISION OF AIR QUALITY
STATE STREET COMMONS
100 W. WATER STREET, SUITE 6A
DOVER, DELAWARE 19904

DIRECTOR'S OFFICE

PHONE
(302) 739-9402

June 26, 2020

David Burton
Plant Manager
NRG
29416 Power Plant Road
Dagsboro, DE 19939

Certified Mail # 7011 3500 0003 2400 0633
RETURN RECEIPT REQUESTED

Subject: Request for Additional Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule

Dear Mr. Burton:

This letter is a follow-up to the Regional Haze information request letter that the Delaware Department of Natural Resources and Environmental Control (DNREC) sent to NRG Energy, Inc. (NRG) regarding Indian River Generating Station on April 30, 2019.

As part of its Regional Haze SIP, Delaware must consider emission reductions measures identified by Class I states as being necessary to make reasonable progress in any Class I area. Delaware is part of the Mid-Atlantic Northeast Visibility Union (MANE-VU), a regional planning organization in which member states work collaboratively to develop emission control strategies to address visibility impairment in Class I areas.

MANE-VU proposed six (6) emission management strategies (Asks) in order to meet the 2028 reasonable progress goal for regional haze. While many of the Asks are directed at states to adopt, there are some strategies that require input from companies. Therefore, DNREC sent the above-mentioned information request to NRG for Indian River regarding the MANE-VU Asks.

In its information request, DNREC asked NRG to perform a Four-Factor Analysis for reasonable installation or upgrade to year-round NOx emission controls for Unit 10. DNREC thanks NRG for its subsequent response, submitted on June 19, 2019. Water injection is currently used on the units during the ozone season (May – September), to meet the NOx standards set forth in 7 DE Admin. Code 1148 – Control of Stationary Combustion Turbine Electric Generating Unit

Emissions. NRG replied that it was technically feasible to modify the current Water Injection system to operate on a year-round basis, it would not be economically feasible to do so.

NRG replied that the system would need to be converted for winter operation. This would include constructing a standalone building for the water injection system, new water tanks, heat tracing, heating systems and piping. Therefore, additional capital and operating costs would be incurred in order to extend Water Injection beyond the ozone season.

To better evaluate NRG's response, DNREC is requesting that NRG provide the following additional information:

- The procedures and timing for shutdown of water injection system each fall, after the ozone season (operational/pipework modifications, draining of pipework, etc.).
- The procedures and timing for bringing the water injection system back into operation each spring, before the start of the ozone season (operational/pipework modifications, removal of insulation of systems, etc.).
- The technical feasibility and cost of weatherization systems (pipe insulation, heat tracing, etc.) that could be installed without the use of a heated shelter building, to potentially extend the use of the Water Injection system to the months adjacent to the ozone season (April and October).
- For each of the individual control technologies that NRG evaluated and found not to be technologically feasible: a more detailed description of the specific operational reasons why they are not feasible for the Unit.
- Stack test result numbers listed in initial response at a NOx value adjusted to 15% O_2.
- A breakdown of the following costs for each new control system or existing control system upgrade that was evaluated for cost effectiveness, if applicable[1]:
    - Capital Costs: Purchased Equipment, Indirect Instillation, Indirect Capital
    - Annualized costs: Operating and Maintenance, Utilities, Indirect Annual, Capital Recovery.

DNREC requests that NRG submit the requested supplemental information by July 23, 2020.

Thank you in advance for your cooperation. If you have any questions or wish to further discuss this request, please contact Renae Held of the Division of Air Quality at (302) 739-9402 or renae.held@delaware.gov.

Sincerely,

David Fees

David F. Fees, P.E.
Director
Division of Air Quality

[1] EPA's Control Cost Manual contains information regarding the different types of cost categories: https://www3.epa.gov/ttn/catc/dir1/c_allchs.pdf

Information Request Response for NRG – Indian River

July 21, 2020

David Bacher
Indian River Power LLC
29416 Power Plant Road
Dagsboro, Delaware 19939

An NRG Energy Company

July 21, 2020

Renae Held
Environmental Scientist
Airshed Planning & Inventory Program
Delaware Division of Air Quality
100 Water Street
Dover, Delaware 19904

Ms. Held,

I am writing in response to your inquiry of June 26, 2020 in regard to Delaware's Regional Haze State Implementation Plan and pending amendments, in association with the Indian River Generating Station, Emission Unit 5, Indian River Unit 10 (IR10) and your additional information request regarding our four factor analysis which included your additional Ask #5 regarding technologies reviewed.

We appreciate Delaware's commitment to Regional Haze and it's partnership with the Mid Atlantic North East Visibility Union (MANE-VU) to collectively develop regional emission control strategies to address visibility impairment in Class 1 areas. As requested, please accept our additional information.

MANE-VU Goals

The MANE-VU initiative is based on achieving reasonable progress goals by 2028 and participating states are asked to evaluate potential from qualified emission sources for reductions that can be quantified within a SIP revision, we appreciate Delaware's desire to seek any possible reductions. Please note, the initiative targets units 25MW or greater seeking operation near 25ppm at 15% O2 for natural gas and 42ppm at 15% O2 for distillate fuel and a request that each state adopt an ultra low sulfur in fuel content standard. Further, states were requested to complete a four factor analysis to evaluate reduction potential, specifically for units 15 MW or more that operate equivalent to a 20% or less capacity factor or 1752 hours per year during 2014 to 2016. Indian River Unit 10 at 17-21MW and a capacity factor of < 1% completed the four factor analysis as required in 2019.

Unit 10 Combustion Turbine

Indian River Unit 10 (Regulation 30 Unit 5) is a 366 MMBTU/hr Turbo-Jet Pratt & Whitney FT4-9LF combustion turbine installed in 1967 that operates on distillate fuel (the -9 refers to the internal cooling of the engine turbine nozzle vanes, LF refers to a liquid fueled engine) equipped with a fuel manifold and Delavan Fuel nozzles for Water Injection. The unit has a summer rating of 17MW and a winter rating of 21MW. The unit was designed for black start capability and to serve as a critical resource and peaking unit available to the facility and the Independent System Operator (ISO) for reliability reasons. In 2009 the unit was equipped with water injection to comply with an 88ppm NOx emission limit during the Ozone Season and achieved an average of 52.8 ppm, verified by stack testing at that time. Since the installation of the water injection system, the facility has already taken action to further reduce emissions including cleaning and tuning of other components of the fuel system and improving the control logic for water injection. The 2013 and 2018 stack tests verified compliance of our permit limit reporting 56.8 ppm (O2 corrected) and 63 ppm (O2 corrected) respectively. I have included our most recent 2013 and 2018 stack test results as requested.

As reported in our 2019 information request, the unit only operates when called by PJM, for completing PJM capacity verification, or DNREC required emissions testing. In 2019 we reported averaging 28 hours per year over 10 years or comparable capacity factor of 0.32%, we can report the operating hours are trending down. In fact in 2019 the unit operated only 2.79 hours within two operations, one for a PJM capacity test in April and the when called to run for 1.5 hours in July. As typical, the unit operated only 7 hours in 2017 and 6 hours in 2016. The 61 hours of operation in 2018 were primarily stack testing as required by our permit and unusual system demand. These values are well below the MANE-VU target of units operating around 1752 hours and why Indian river is not included on the MANE-VU list of units that have a potential for improving visibility and why we believe other than eliminating stack testing, Unit 10 should not be considered as a NOx reduction option in Delaware's SIP.

DNREC Information Request

1. **Operational Procedures for Fall Shutdown** – The procedure is attached.
2. **Operational Procedure for Ozone Season Startup** – The procedure is attached.
3. **Technical Feasibility and Cost for extending use to include April and October** – In regard to capital expenditures there would be no additional costs associated with expanding water injection operations to include April and October. However, because the demineralized water is required and the water source is rented, adding operations in April and October would result in an added expense in the range of $10,000. Because the probability of the unit operating during these months is extremely low, we do not believe any expense can be justified. Further, from a technical feasibility aspect, there is concern with cold weather occurring in early April or in October that could damage the system. For these reasons, we do not believe expanding water injection operations to include April or October are viable.
4. **Technologies not Feasible** – Indian River had considered replacement of the unit if associated with a natural gas conversion. The inability of third-party companies to bring a natural gas supply to the area has prohibited that option. As a result, we do not have cost information available for this option. Other than replacing the unit which is not an economically viable option because of its operating profile and lack of other fuel options, water injection is the only reduction technology evaluated available and there were no other technologies reviewed for NOx reduction. As a result, we installed water injection at a cost of near $0.5M because it was the only option feasible and because it satisfied the emissions limits defined by regulation and in our operating permit.
5. **Stack Test Data** – 2018 Stack Test Data Attached.
6. **Capital and Annualized Costs for any New or Existing Upgraded System** – We have not conducted any analysis on these parameters because they are not options and analysis has not been required.

Summary
Please recognize NRG and Indian River have already supported this initiative in our recent AQCS project to significantly reduce SO2, NOx, Hg, and PM emissions, an investment of almost $400M in Delaware and in our air quality as well as the shut down of Units 1, 2, and 3. For Unit 10, any additional capital operating expenditures to try and further reduce NOx are not technically or economically feasible given the operating profile and limited potential any reductions of emissions. Our most recent emission test in 2018 yielded compliance of our permit limit and on a ton per year basis, we anticipate the unit to maintain its current operating profile, the only exceptions being stack testing or an extreme weather event.

Hopefully this additional information satisfies your information request. What we do suggest is that the Department seriously consider the elimination of stack testing for Unit 10, or at least expand the duration to one test every ten years. This is something that would avoid real emissions and something that can be quantified in your SIP as a real quantifiable reduction.

After your review, please feel free to contact me on (302) 540-0327 or by E-Mail on david.bacher@nrgenergy.com.

Respectfully submitted,

David Bacher

David Bacher
Regional Manager, NRG Environmental Business

CC:	A. Carter	(Indian River)
	D. Burton	(Indian River)

Water Injection System

Installation and Removal Procedure

APPROVED

____ _______________

System Owner Date

____ _______________

Operations Manager Date

RECORD OF REVISIONS		
Revision	**Explanation**	**Date**
Rev. Draft	Initial Issue	November 10, 2009
Rev. CC	Client Comments	November 18, 2009
Rev. 0	Final	January 14, 2010

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1.0 SYSTEM DESCRIPTION

Function

The primary function of the high pressure water injection system is to reduce NOx emissions from Unit 10. Unit 10 is a Pratt & Whitney FT4 A8 LF gas turbine generator with a nominal output of 22 megawatts. During the ozone non-attainment period (May through September), DNREC regulations require that the unit be operated at NOx emission rates less than 88 PPM NOx. To meet this requirement a NOx reduction process was added to the unit. During the remainder of the year Unit 10 is operated without the high pressure water injection so the HPWI system is drained to prevent freezing damage to components.

System Overview

The High Pressure Water Injection system takes demineralized water stored in a dedicated tank and supplies it at high pressure to a mixing device in the jet fuel supply just prior to the fuel inlet manifold. The system consists of redundant, two pump, parallel flowpaths. The self contained system consists of the following major components:

- Storage tank
- Inlet duplex strainer
- Booster pumps - 2
- High pressure water pumps – 2
- Pressure relief valve
- Mixing tee
- PLC controller

The high pressure water injection system is located west of the jet. The pumps and controls are located in a metal building and the storage tank is located north of the building. A rollup door on the west wall of the building and a personnel door on the east side of the building allow access to the interior.

Primary HPWI Flowpath

The storage tank provides suction to the booster pump through a duplex strainer. The booster pump discharges to the suction of the high pressure pump providing an elevated suction pressure. The high pressure pump provides a variable flow, high pressure water source to the mixing tee where the water and fuel oil are mixed then injected into the combustion chamber.

Refer to Section 8 for a Flow Diagram of the Indian River High Pressure Water Injection system.

1.1 Water Storage Tank

Function

The function of the water storage tank is to receive demineralized water from the demineralizer effluent, store the water, and supply demineralized water at adequate suction head to the booster pump suction.

Detailed Description

A 6000 gallon composite vertical cylindrical tank is located north of the HPWI Building. The tank, shown in **Figure 2**, is constructed for non-potable water of a non-metallic composite and coated with 2” thick Polyfoam 460 insulation with Mastic coating for protection. A 24” safe-surge manway is installed on the top for access. A 6” PVC goose neck overflow, mounted in the domed top, acts as a vent to prevent over-pressurization when filling and prevent tank collapse during draw-down. The tank is mounted on a concrete pad and anchored to the pad with a seismic zone 3 restraint system consisting of metal cable tie downs for protection during high winds and flooding.

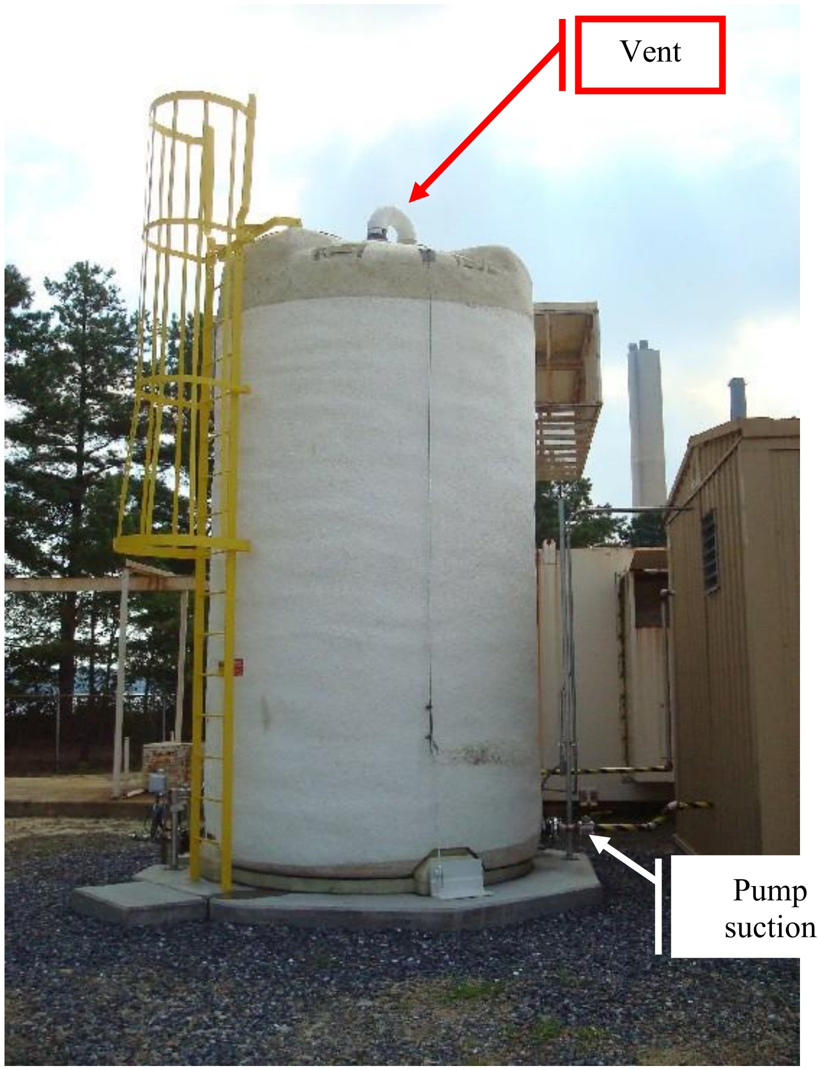


Figure 1 – Water Storage Tank

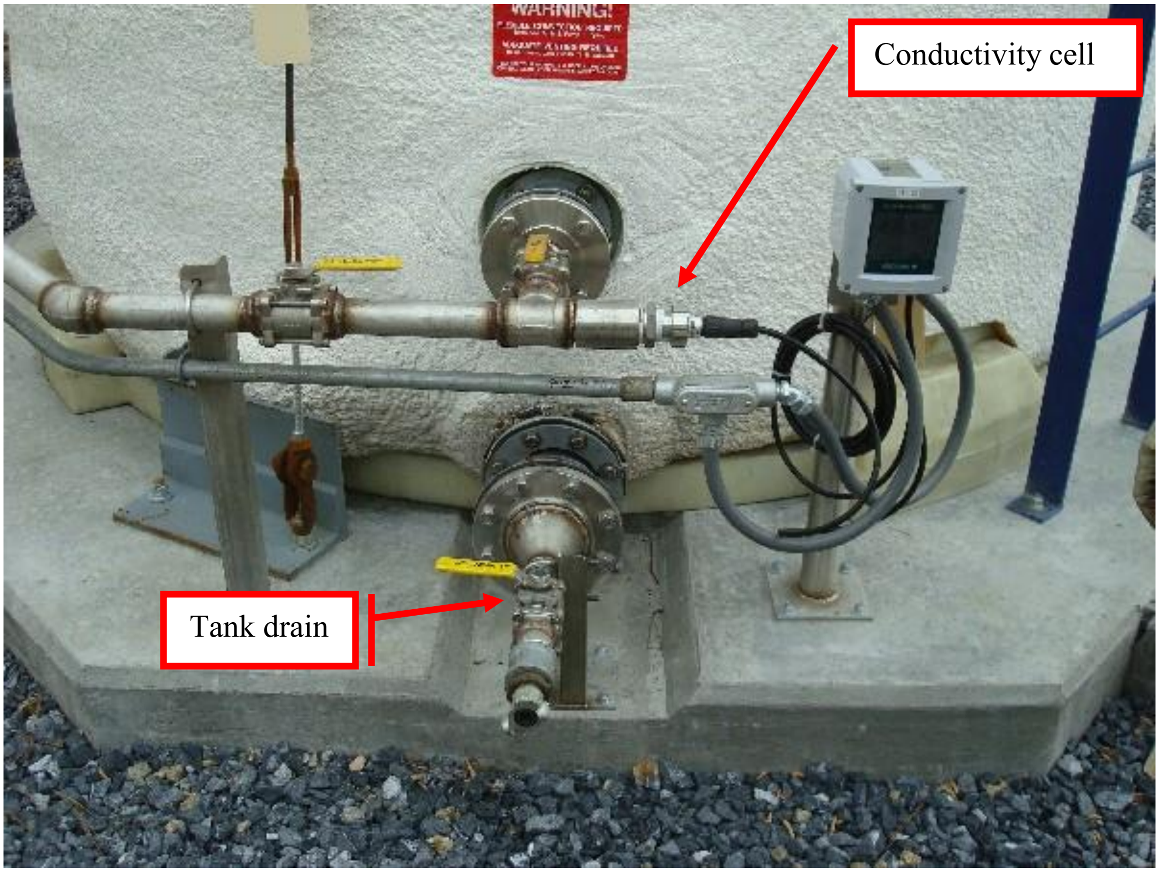


Figure 2 – Water Storage Tank fill connection

The tank has two connections on the north side, shown in **Figure 2,** one for filling and one for draining. A conductivity probe, with local readout, is mounted in the tank fill penetration. Isolation valves allow for conductivity probe removal. A drain connection, located below the inlet, is used to completely empty the tank of all water to prevent freezing damage during winter conditions. A hose connection permits directing the water away from the tank foundation.

The fill line is used to direct the effluent of the demineralizer outlet to the tank for filling and for periodic cleanup. Water is circulated by the installed pumps through the demineralizers and returned to the tank. Cleanup occurs periodically as described in the controls section.

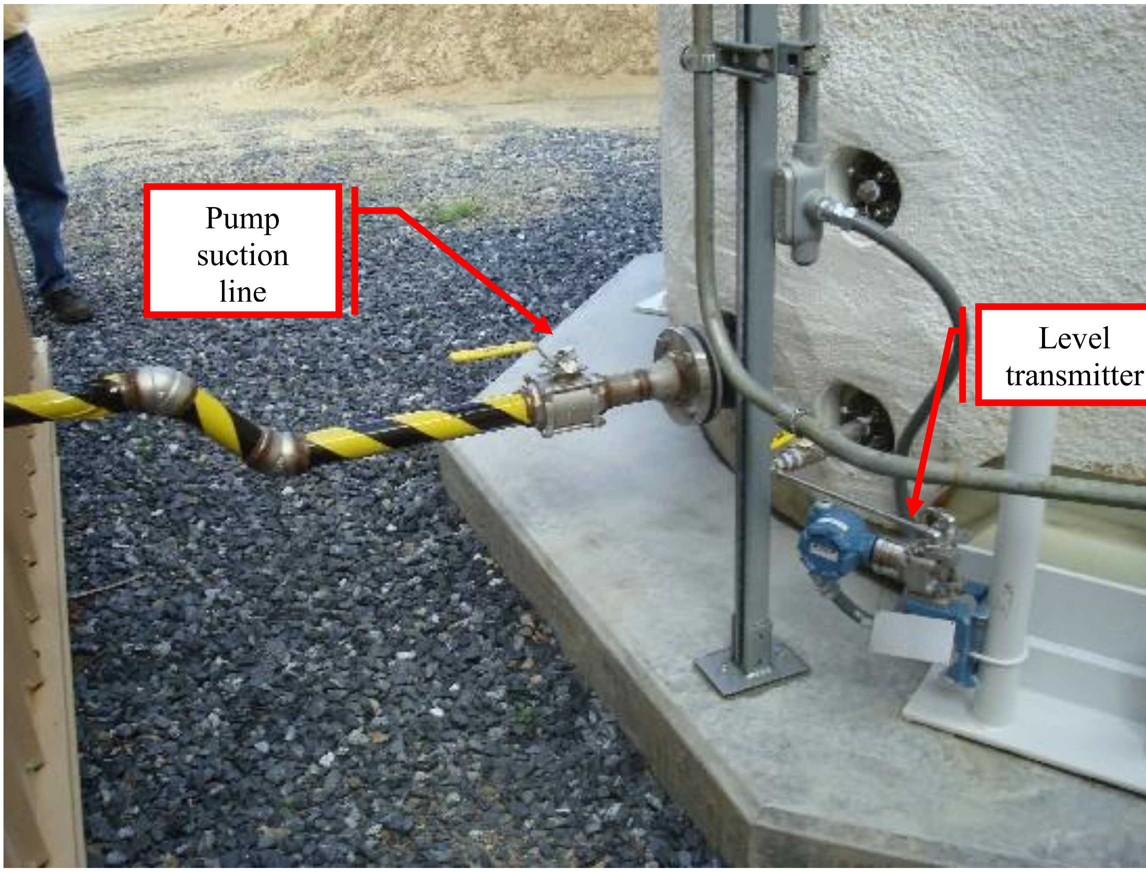


Figure 3 – Pump suction

The tank fill line is on the north side of the tank along with a tank drain. The pump suction from the tank, shown in **Figure 3**, is on the south side of the tank. A level transmitter is located near the pump suction line.

Flowpath

Flow into the tank for initial filling and replenishment is from the fire main through a manual isolation valve. When open, fire main water is admitted to the demineralizer through a motor operated valve controlled by the PLC. A manual bypass valve can be used to bypass the motor operated valve. Demineralizer effluent is directed to the storage tank. A relief valve set to open at 100 psig is installed for system protection. The tank is normally filled to 165 inches.

Design Data

Demineralized Water Storage Tank	
Nominal capacity	6000 gal
Design capacity	6115 gal
Total volume	6350 gal
Height	16’ 3”
Diameter	8’ 6”
Design pressure	atmospheric

1.2 Booster Pump

Function

The function of the booster pumps is to supply the needed suction head to the high pressure pumps.

Detailed Description

The booster pumps, shown in **Figure 4** are Goulds centrifugal pumps driven by 3 HP single speed motors. The booster pumps take suction from the storage tank, through the duplex strainer, and provide positive pressure at the inlet to the HP Pumps. The booster pump maintains a minimum suction pressure of 20 psi to the high pressure pump it supplies. Booster pump shaft seals are supplied cooling water by a line tapping off the pump casing.

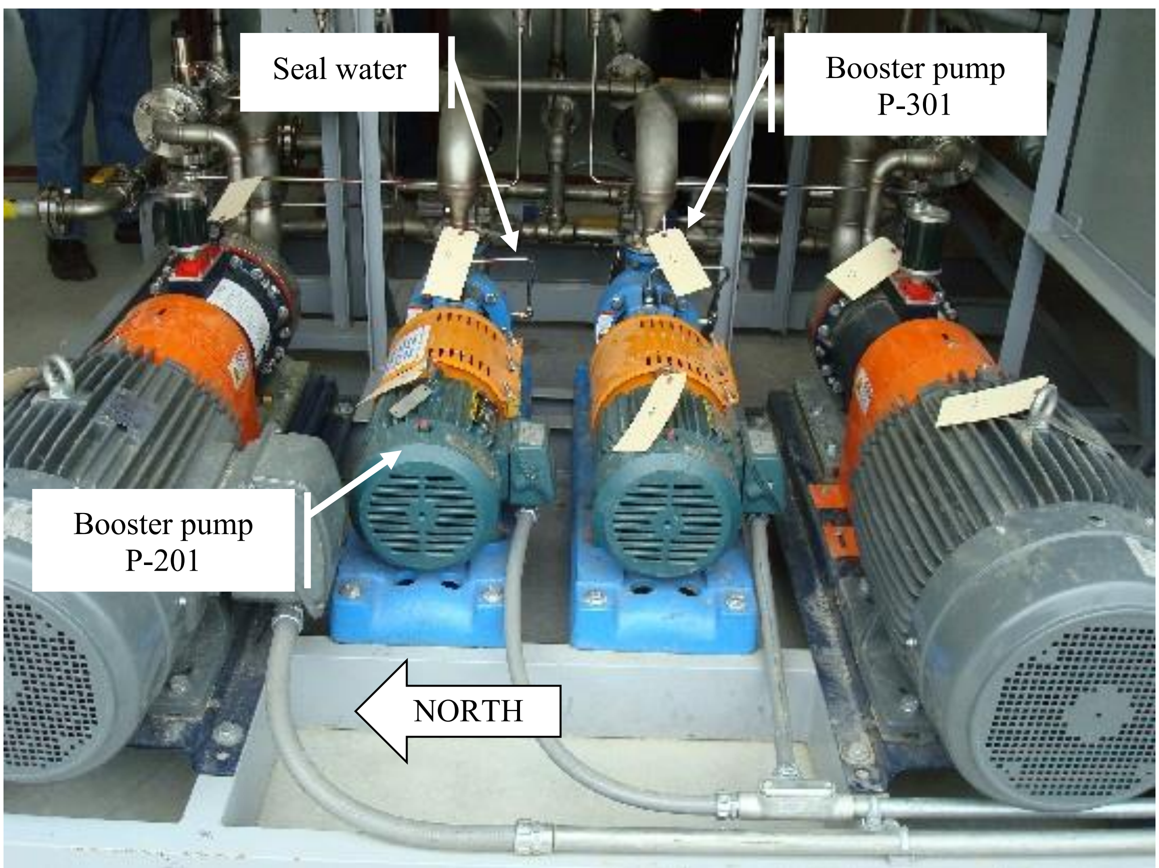


Figure 4 – Skid mounted pumps

The booster pump motor is connected to the pump shaft through a speed changer gear box shown in **Figure 5**. The gear box output shaft speed is increased above motor speed. Gear box oil level should be monitored through the sight glass on the north side of the gear box.

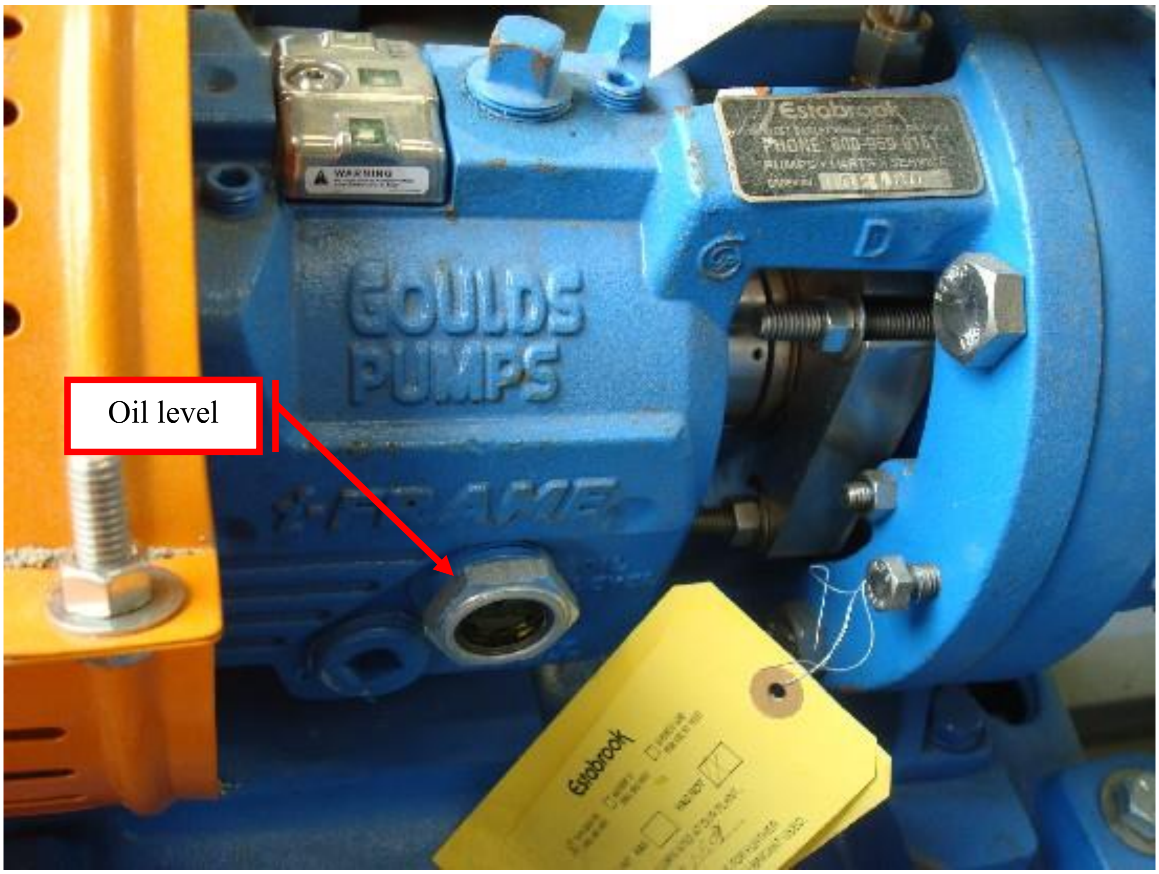


Figure 5 – Booster pump gear box

Figure 6 – Duplex strainer

The inlet duplex strainer, shown in **Figure 6**, is equipped with two, 100 mesh strainers. The strainer body covers are held down with two hold down handles per strainer. The operating handle on top is used to shift from one strainer basket to the other. This is done to place a clean strainer in service. The handle is positioned over the strainer basket in service allowing removal of the dirty basket. Drain plugs can be removed to drain the water from the strainer during winter conditions to prevent freezing damage. The strainer is equipped with a differential pressure gauge and transmitter. The transmitter will alarm if a differential pressure exceeding 2 PSI exists during operation. The alarm will be logged on the HPWI skid HMI display

Flowpath

Water is drawn from the storage tank through a manual isolation valve to the duplex strainer. After passing through the clean strainer basket, water is supplied to the booster pump suction where pressure is increased then supplied to the high pressure pump suction.

Design Data

Booster pumps	
Pump/Gear box manufacture	Goulds
Motor manufacture	Baldor Relience
Motor shaft speed	3520 rpm
Gear box output shaft speed	TBD rpm
Minimum suction required	TBD feet
Discharge pressure	TDB psig

1.3 High Pressure Water Pumps

Function

The function of the high pressure water pumps is to supply water at a variable high pressure and variable flow rate to the mixing tee in the jet fuel supply.

Detailed Description

Variable speed, piston type, positive displacement pumps, shown in **Figure 7**, supply water to the mixing tee at a pressure dictated by jet engine power output. A variable speed, variable frequency drive, motor is connected to a hydraulic driven piston type pump. Oil in the reservoir is used to force the pistons forward delivering water at a volume and pressure determined by motor speed. Motor speed is determined by the control system that monitors generator load and exhaust temperature. At full discharge pressure, 100 rpm will deliver 2.5 gpm and 1050 rpm will deliver 36.5 gpm. Maximum discharge pressure of the pump is 1200 psi. Normal operating pressure varies from 250 psi at low load to 750 psi at full load.

Figure 7 – High pressure pumps

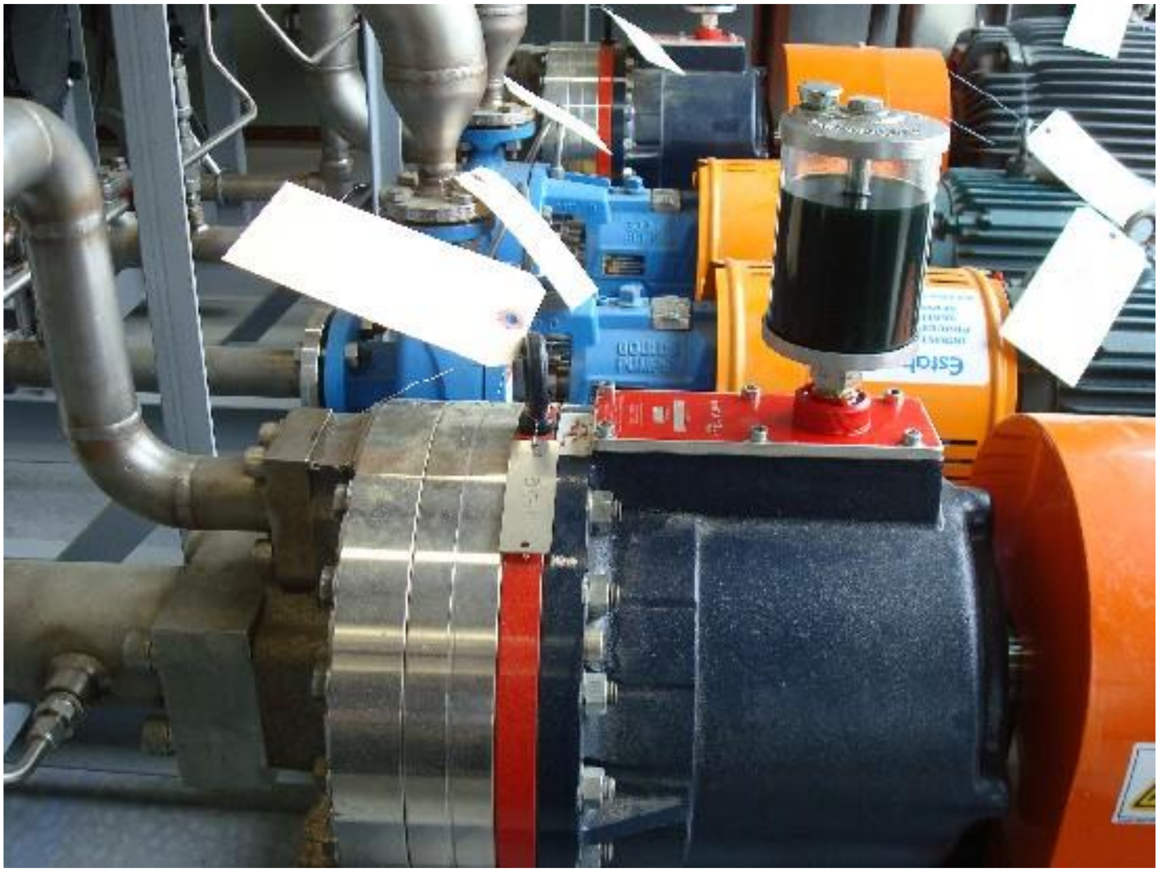


Figure 8 – High pressure pump oil level

Oil level should be checked periodically before and during operation. The type and viscosity of oil is critical to proper hydraulic end operation. The reservoir mounted on the top of the hydraulic end, shown in **Figure 8**, is at the correct level. Oil should be added to keep level at least 1" from the bottom of reservoir.

To prevent exceeding the design pressure of the HPWI and fuel system piping and components a recirculation pressure control valve will open at 950 psig returning water to the storage tank. The recirc pressure control valve is shown in **Figure 9**.

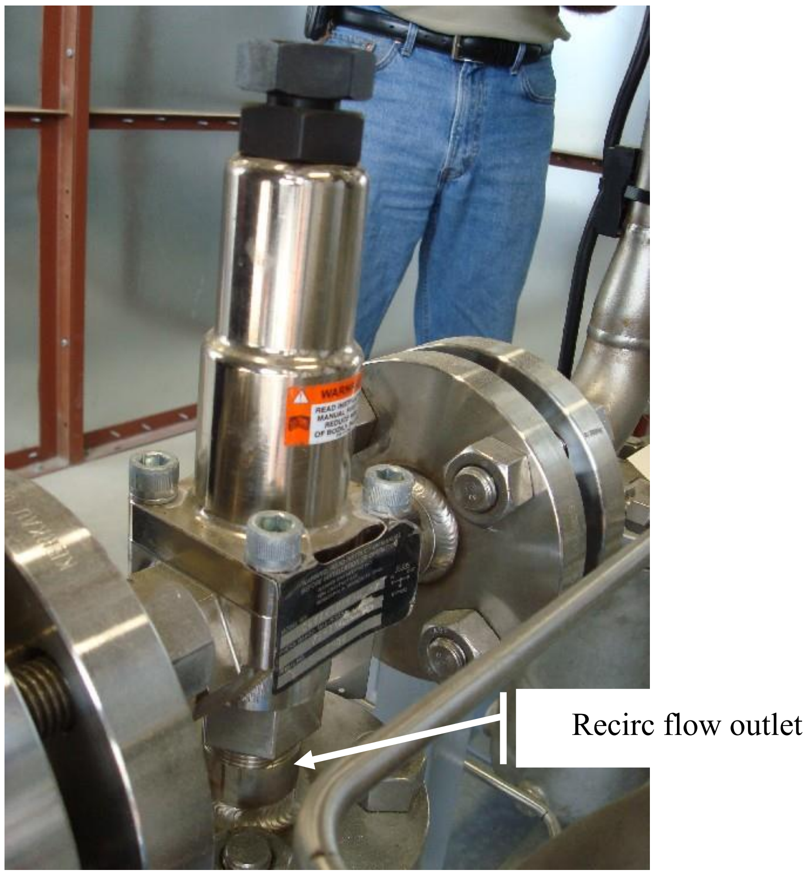


Figure 9 – Pressure control recirculation valve

Flowpath

The discharge of the booster pump enters the suction of the high pressure pump where pressure is increased and discharged to the header leading to the mixing tee located in the jet engine housing. If pressure increases to 950 psi the recirc valve will begin opening to return water to the storage tank.

Design Data

High pressure pumps	
Quantity	2
Manufacturer	Wanner Engineering, Hydra-cell Industrial Pumps
Model	D-35
Type	Positive displacement piston
Capacity	36.5 gpm @ 1050 rpm
Delivery at max pressure	1 gallon every 29 revolutions

1.4 Mixing Tee

Function

The function of the mixing tee is to create a homogenous mixture of water and jet engine fuel.

Detailed Description

The mixing tee, shown in **Figure 10**, is a double helix mixer that mixes the jet engine fuel and demineralized water into a homogenous fluid. The fluid passing through the mixer provides motive force for the double helix mixing mechanism. A check valve at the water inlet prevents fuel oil contamination of the water system during periods of operation when the high pressure water injection system is not operating, <10 megawatts. The mixing tee is located in the engine compartment on the east side of the engine.

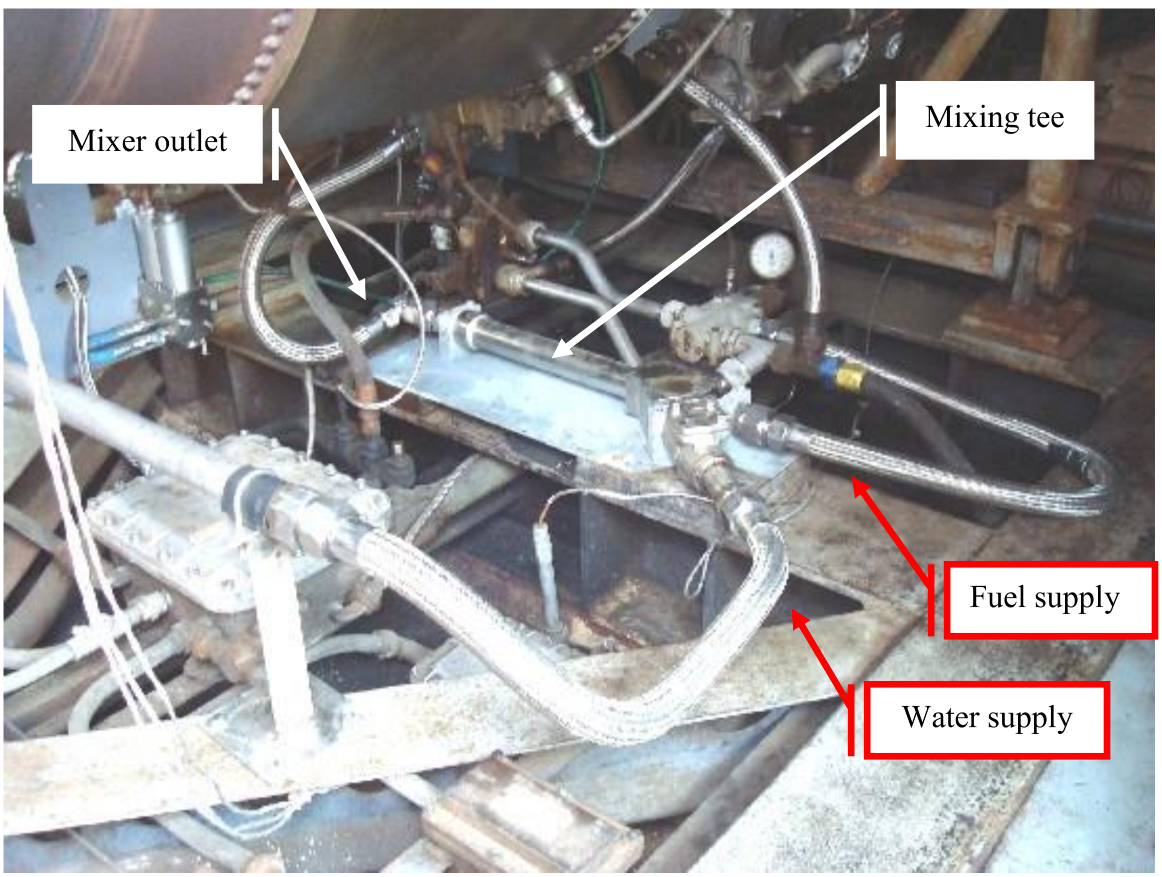


Figure 10 – Mixing tee

Flowpath

Water and fuel oil enter the mechanism on the east end and exit on the west end after forming a homogenous mixture.

Design Data

None available.

1.5 Demineralizers

Function

The function of the demineralizer is to provide demineralized water to the high pressure water injection system and maintain the purity of the water in the storage tank.

Detailed Description

Demineralized water is supplied to the storage tank from connections on the south wall of the metal building. A separate skid mounted demineralizer is connected to the fire main via hoses. Fire main water is admitted through the manual valve identified in **Figure 11**. The fire main should be flushed through the flush connection until the water is clear before admitting to the demineralizer. Extremely dirty water as influent to the demineralizer will exhaust the demineralizer resin after processing a small quantity of water. Storage tank contents are periodically re-circulated through the demineralizer to reduce conductivity.

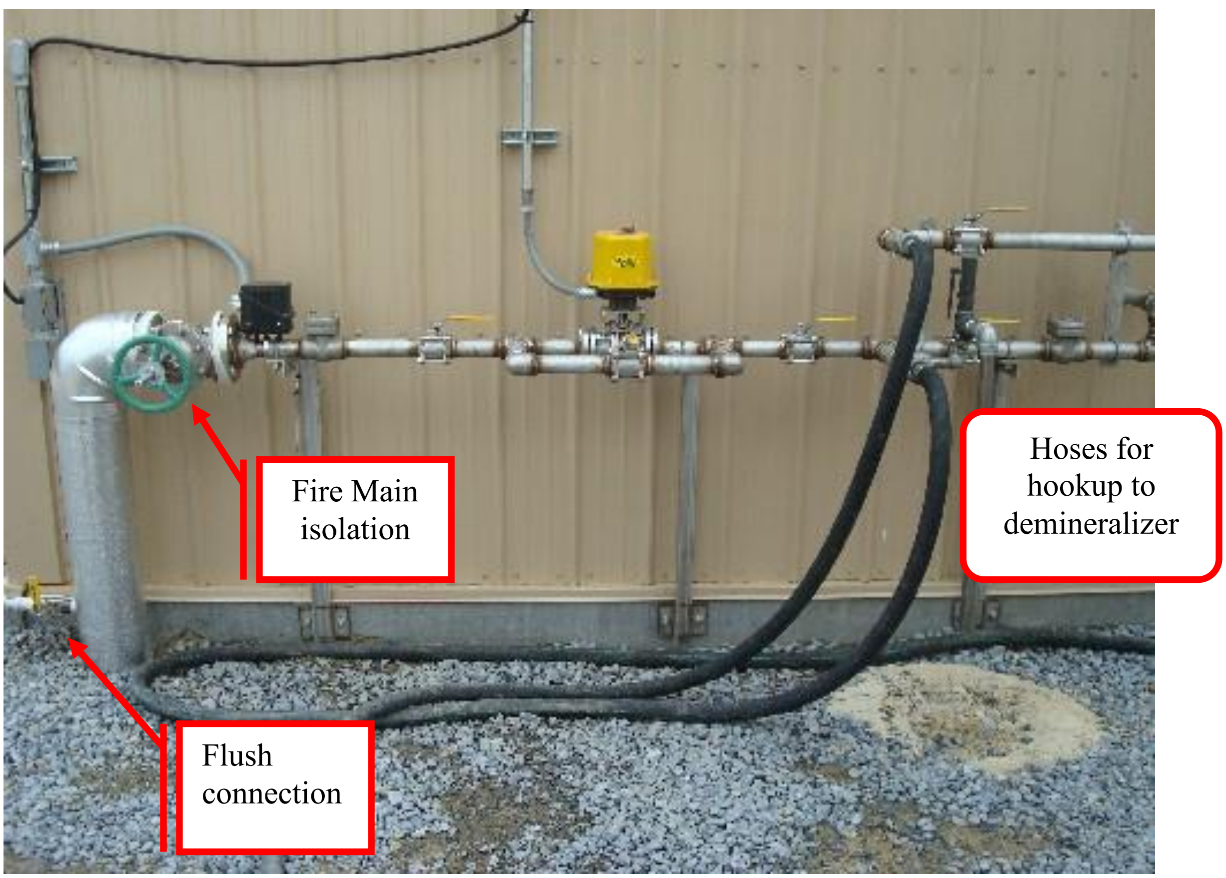


Figure 11 – Fire main water supply

Recirculation occurs when a high conductivity is detected in the tank or at a preset time interval. Tank contents are pumped by the installed pumps, through a solenoid valve, to the inlet of the demineralizer. A relief valve, in the permanent piping on the south side of the building, prevents over-pressurization by opening at 100 psi.

The fire main that supplies the substation also provides the supply to the high pressure water injection system. The part of the piping above ground is heat traced and insulated. The heat trace controller can be seen to the right of the fire main isolation valve. A motor operated makeup valve allows automatic makeup based on storage tank level. A bypass valve allows manual operation. Check valves are installed but the internals have been temporarily removed.

Figure 12 - Demineralizers

The demineralizers, shown in **Figure 12**, are located south of the HPWI building. Two identical 500,000 gallon capacity mixed bed demineralizer trains are provided. The expected water use is less than 100,000 gallons annually. Recirculation for periodic cleanup of the storage tank should not exhaust the demineralizers during the summer NOx period. A valve manifold allows manual selection of the north or south train. The demineralizers and valve manifolds are removed during the period when they are not needed.

Figure 13 – Demineralizer inlet and control panel

The demineralizer inlet manifold, shown in **Figure 13**, receives fire main water at full system pressure through a hose connected to the permanent piping mounted on the HPWI building. A pressure reducing valve set to begin closing at 85 psig prevents over-pressurization of downstream components. A motor operated valve located in the inlet manifold is controlled by the demineralizer controller located above the manifold. There is a safety valve in the permanent piping set to open at 100 psig.

The outlet manifold contains manual valves used to align the north or south demineralizers for service and a conductivity cell. Outlet conductivity is monitored and used by the control system to close the inlet valve should outlet conductivity be unacceptable.

Flowpath

Fire main water from the permanent piping mounted on the building enters the demineralizer train in service through manual valves, a pressure reducing valve, and a motor operated valve on the inlet manifold. After passing through the demineralizer train in service, water exits through the outlet manifold passing by a conductivity cell. A hose connects the outlet manifold to the permanent piping connected to the storage tank. The water passes by another conductivity cell at the tank inlet.

Design Data

Demineralizer System	
Quantity	2 string of 4 canisters each
Capacity	500,000 gallons per string
Maximum operating pressure	100 psig

1.6 HPWI Power Supply

Function

The function of the HPWI power supply is to provide AC and DC power to the high pressure water injection system.

Detailed Description

480 volt, 3Φ power for the HPWI system components is provided through a 100 amp breaker located in the Relay Control House south of the HPWI building. The 480 volt panel, shown in **Figure 14**, is located in the north east corner of the Relay House. The breaker is the second 3 pole breaker on the right side of the panel, marked "IR 10 WATER INJECTION SKID. 480 volt power enters the VFD cabinet at the HPWI skid. The VFD cabinet has a 480 volt disconnect switch, which can be used to isolate all 480 volt, 240 volt and 120 volt AC power to the HPWI enclosure.

Power is taken from the VFD cabinet to a 480/240/120V AC step-down transformer mounted on the west wall of the building. The output of this transformer provides power to the building heater, vent fan, lighting, power receptacles, MOVs, and heat tracing. There is also 120 VAC power located in a receptacle box located inside the PLC building. This receptacle is to provide power to the PLC cabinet air conditioner. 240/120VAC power is distributed through the circuit breaker panel mounted above the step-down transformer. If the 480 volt disconnect switch is opened, the step-down transformer will be de-energized, and 240VAC and 120 VAC power will be de-energized in the building as well as external power receptacles.

125 VDC power is used to supply the PLC with operating power. The 125 V DC power source is located in the 125 VDC distribution panel located in the Unit 10 Control house. The 125V DC power is supplied from breaker position 4, on the right side of the panel. Opening this supply will isolate 125 VDC to the HPWI Skid. Instrument loops are powered by 25 V DC from the PLC cabinet. Alarm power is provided by the PLC power source.

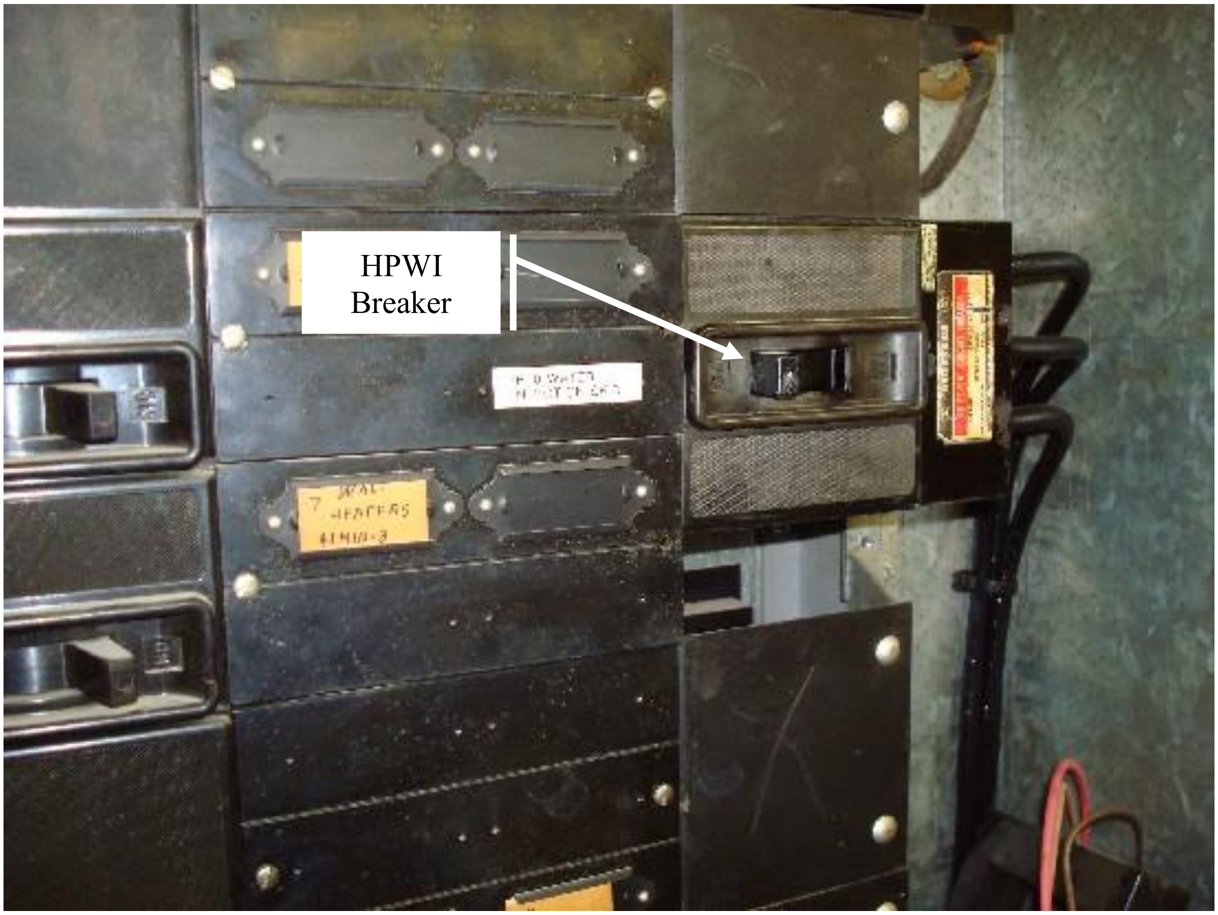


Figure 14 – 480 volt supply breaker

Flowpath

480 volt AC power passes through a 100 amp breaker in the Relay Control House of the switch yard. From there it is passed through a disconnect switch before entering a step-down transformer and distribution panels.

Design Data

N/A

2.0 SYSTEMS CONTROLS

The controls, alarms, and instrumentation for the high pressure water injection system are located at the skid mounted control panel, Unit 1&2 control room, and demineralizer control panel.

The HPWI System controls consist of an ICS Programmable Logic Control (PLC) system and its interface with the Jet Unit 10 control system. The PLC is located at the HPWI skid in the HPWI building. The PLC and associated computer are housed in a steel cabinet suitable for power plant environment. Displays and controls at the control panel are used to operate and monitor the HPWI System.

2.1 System Controls

Function

The function of the PLC is to initiate and control the high pressure water flow rate to the mixing tee over the prescribed range of jet engine power output. The PLC monitors storage tank contents maintaining adequate inventory and water quality.

Detailed Description

An ICS programmable logic control system is mounted in a cabinet in the HPWI building on the south side of the skid. The cabinet contains the display screen on the door, an emergency stop button on the door and a Dell computer inside the cabinet.

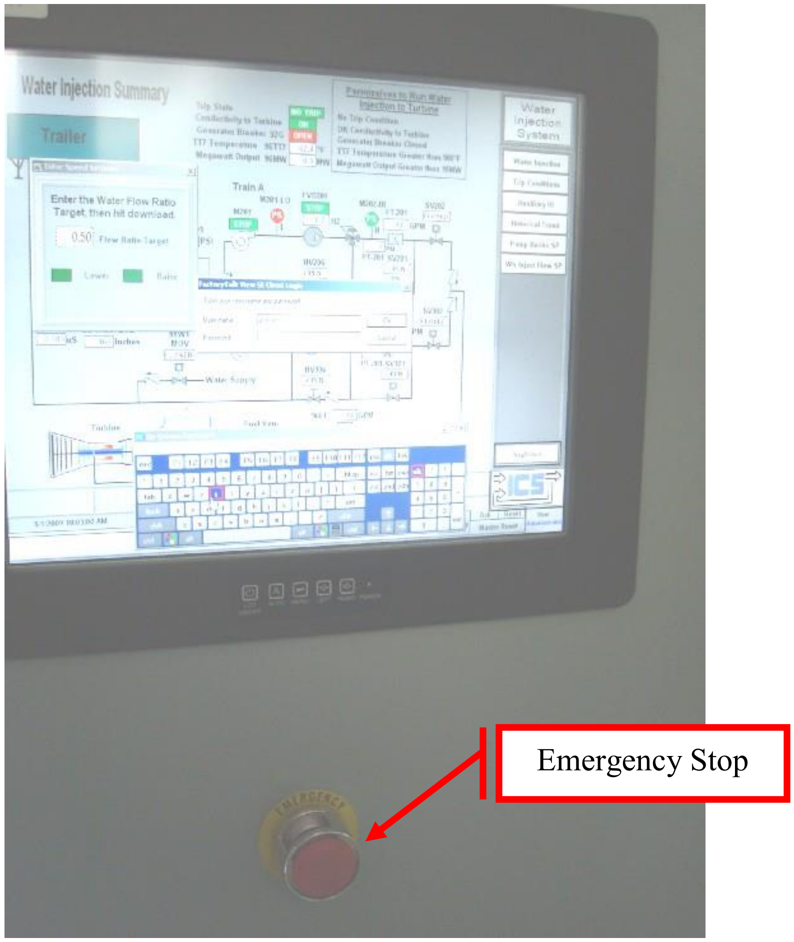


Figure 15 – Local panel control screen

The local control panel display, shown in **Figure 15**, contains a system diagram which displays active values of measured parameters and a menu bar on the right side. The menu allows selection of the following displays:

- Water injection
- Trip conditions
- Auxiliary IO
- Historical trends
- Pump recirc SP
- Wtr inject flow SP
- Keyboard

Water storage tank level is measured by a Rosemount level transmitter mounted low on the south side of the tank. The range of the instrument covers full capacity of the tank. At 0" indicated level the actual water level is 25" above the instrument ensuring pump suction is always covered. If level should be allowed to decrease to 0" indicated the pumps would be stopped and prevented from starting until inventory is recovered. Normal level is controlled between 120" and 165" by operation of a motor operated inlet valve. A high level alarm actuates at 168". Actual water level at 168" is 12" from the top of the vertical tank walls.

Train operation is rotated to equalize equipment wear. If the 201 train is operating and the jet is secured, on the next startup the 301 train will be started. If the 301 train does not supply adequate pressure, the 201 train will be placed in service and the 201 train secured. If the 201 and 301 trains fail to meet setpoint the Skid Not Ready to Run alarm will actuate.

Duplex strainer differential pressure is indicated on a local indicator and on the PLC Water Injection summary display screen. A high differential pressure alarm will be registered at >2 psid.

Individual train flow is measured by sonic flow detectors mounted in the pump discharge. Flow transmitters FT-201 and FT-302 provide local flow indication and PLC indication. They provide input to the control system for comparison to the flow setpoint. High pressure injection pump speed will be modified according to a comparison of actual flow to setpoint flow. High pressure pump discharge pressure is detected by PT-201 and PT-301 with local indication and PLC readout. Pressure, temperatures and flow are displayed on the Water Injection display.

Solenoid valves are operated by the PLC to establish specific flowpaths. Solenoid valves SV-201 and SV-301 will open to place the system in a storage tank recirculation mode. During this mode water from the tank is re-circulated through the demineralizer to reduce conductivity. During normal water injection mode the solenoid valve SV-202 or SV-302 will open to admit high pressure pump discharge to the mixing tee for injection.

A seasonal operation selector switch located on the Vibration and Temperature Panel in the Unit 10 Control House provides for the selection of operation of the high pressure water injection system. During the Ozone Non-Attainment period (May 1-September 30) the switch is positioned to ON. When ON is selected the high pressure injection system will startup at an exhaust temperature of 900 °F on TT7. If the system does not initiate injection the output of the engine will be limited to 900 °F on TT7 or about 10 megawatts. For the balance of the year the switch will be in the OFF position. Load will not be limited and the injection system will not be started.

The engine controls are also set to reduce the load on the engine to less than 900°F TT7 temperature if the HPWI system should fail to maintain flow. Once HPWI system alarms have been cleared, the system will allow the engine to load up to full load when water flow has been established at the current setpoint of the control system.

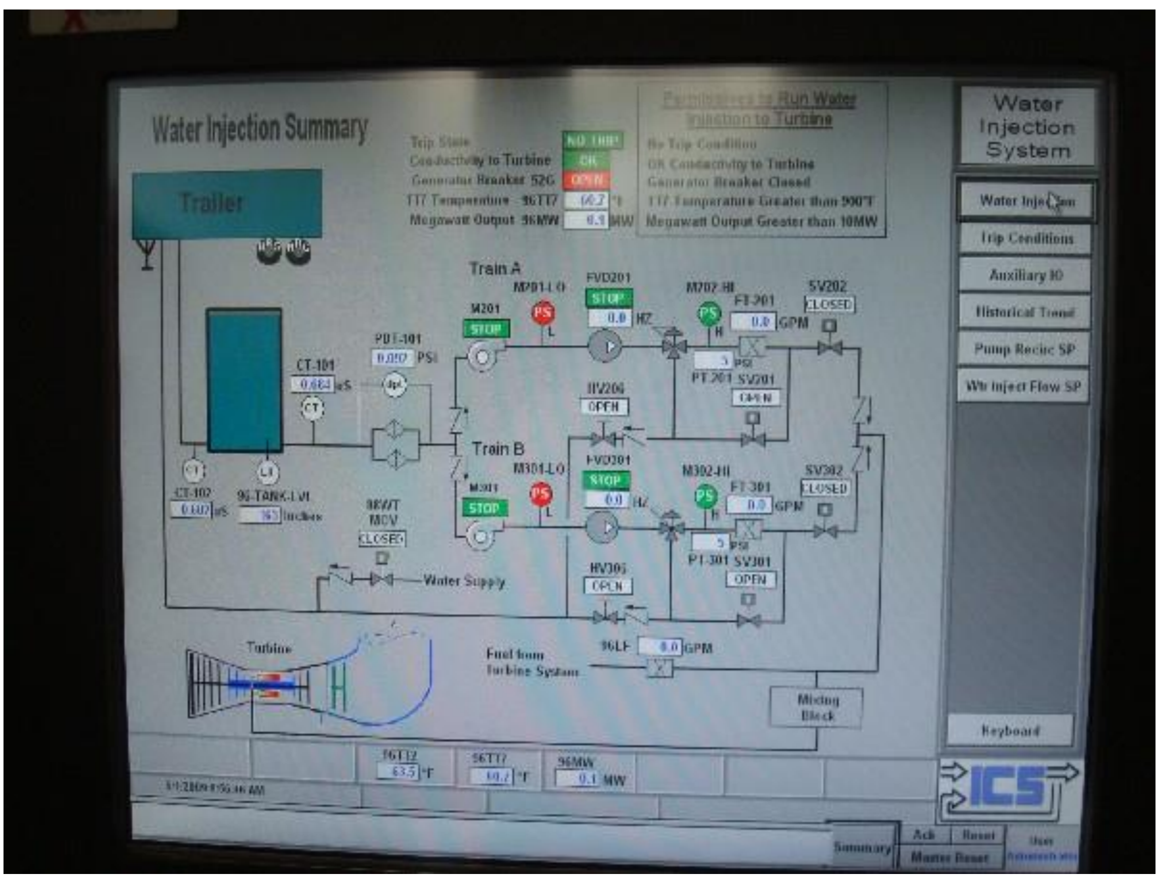


Figure 16 – PLC Water Injection Summary

The water injection summary display allows access to the remainder of the display pages and continuously displays live values of pertinent parameters. Alarms are displayed at the bottom of the page with acknowledge and reset touch points.

The trip condition display lists system trips:

- Both trains failed
- Both isolation valves are closed
- Emergency stop
- CT102 tank conductivity high
- Recirc time has been exceeded due to high conductivity
- Fuel flow fault
- Pressure was exceeded during recirculation

The auxiliary I/O and D/O screen, shown in **Figure 17** can be useful in the diagnosis of system problems. The green box to the right of the displayed digital input and digital output will show the state of the device; green when OFF, red when ON.

Figure 17 – PLC Auxiliary I/O screen

DIGITAL INPUT	DIGITAL OUTPUT
Network switch No. 1 fault	Energize remote alarm
Local emergency stop	Energize train A booster pump
PLC panel temperature high alarm	Energize train B booster pump
Train A VFD fault	Stop train A main pump
Train B VFD fault	Stop train B main pump
Train A booster pump overload	Start train A main pump
Train B booster pump overload	Start train B main pump
Silence alarm	Flow control train A main pump
24 VDC power supply PS-1 failed alarm	Flow control train B main pump
	Open demin water tank fill MOV
	Ready to run
	Not ready to run
	Open train A water injection supply valve
	Open train B water injection supply valve
	Close train A water injection bypass valve
	Close train B water injection bypass valve

The demineralizer control panel, located between the demineralizer tanks and the HPWI building control the motor operated valve shown in **Figure 18**. The control panel contains a conductivity meter indicating the demineralizer outlet conductivity. The inlet MOV can be placed in the open position, closed position or operated in automatic. Automatic will close the valve on high conductivity, which is reset by the high conductivity reset switch to the right of the high conductivity red light.

Figure 18 – Demineralizer control panel

<u>Flowpath</u>

Not applicable

<u>Design Data</u>

None available

3.0 SYSTEM PREPARATION

3.1 HPWI Ozone Season

Step	Location	Description	Initials
NOTE:	**The Location column specifies where the step is performed. A "C" indicates that the step is performed in the control room; an "L" indicates that the step is performed locally, and an "LP" indicates that the step is performed from a local panel.**		
1.	L	INSTALL all low point drain plugs in the strainer basket chambers.	
2.	L	INSTALL low point drain plugs in the inlet header low point drain.	
3.	L	INSTALL low point drain plugs in the recirculation header.	
4.	L	INSTALL low point drain plugs in the high pressure header.	
5.	L	CLOSE High Pressure Low Point valve and drain plug at Engine Compartment	
6.	L	CLOSE supply header ball valve downstream of 3" Gate Valve	
7.	L	REMOVE tags and lock from 3" Gate Valve	
8.	L	OPEN 3" supply valve	
9.	L	INSTALL hose on supply header discharge	
10.	L	Slowly OPEN supply header ball valve, and flush line and hose until water is clear.	
11.	L	CLOSE supply header ball valve	
12.	L	CONNECT supply hose to demineralizer inlet.	
13.	L	CONNECT return hose to demineralizer outlet.	
14.	L	OPEN supply header ball valve to fill demineralizer and flush in accordance with vendor requirements.	
15.	L	CLOSE supply header ball valve	
16.	L	CLOSE MOV Bypass Valve	
17.	L	CONNECT return hose to Tank Fill line.	
18.	L	CLOSE ball valve at tank fill inlet.	
19.	L	REMOVE conductivity probe from end of line	
20.	L	Slowly OPEN supply header ball valve and flush water through trailer, and tank fill line.	
21.	L	After water has flushed line for 1 minute, CLOSE supply header ball valve.	
22.	L	RE-INSTALL conductivity probe	

Step	Location	Description	Initials
23.	L	OPEN tank fill ball valve.	
24.	L	OPEN supply header ball valve	
25.	L	FLUSH tank for 1-2 minutes, or until water exiting tank appears to be clean	
26.	L	CLOSE supply header ball valve	
27.	L	CLOSE tank drain ball valve.	
28.	L	CLOSE tank outlet ball valve	
29.	L	VERIFY that level control transmitter valve is OPEN, and that line to transmitter is tight	
30.	L	VERIFY PLC and PC are energized.	
31.	L	VERIFY tank fill MOV is OPEN.	
32.	L	SLOWLY OPEN supply header ball valve.	
33.	L	VERIFY flow of water through demineralizer to the tank.	
34.	L	VERIFY tank fill MOV CLOSES at 165”.	
35.	L	OPEN tank outlet valve.	
36.	L	OPEN skid inlet valve.	
37.	L	CYCLE strainer selector valve to fill strainer chambers.	
38.	L	REMOVE high point vent plugs on HP Pump Discharge piping.	
39.	L	CRACK OPEN booster pump to HP pump piping vent valves	
40.	L	OPEN booster pump inlet valves	
41.	L	VENT air from Booster pump to HP Pump vents and high pressure drains	
42.	L	When air is vented from HP Vents, INSTALL vent plugs.	
43.	L	VERIFY that HP header discharge ball valves are open.	
44.	L	VERIFY that Recirculation discharge ball valves are open.	
45.	L	VERIFY that Recirculation ball valve on supply header is in the OPEN Position.	
46.	L	VERIFY that the Demineralizer inlet valve is in the OPEN Position.	
47.	L	RE-VERIFY that valves are in the proper position to allow recirculation of water.	
48.	L	LOG ON to PLC Panelview as Administrator	
49.	L	SELECT Manual Recirculation	
50.	L	INITIATE manual recirculation.	
51.	L	VERIFY that HP Pump discharge pressure is no higher than 80 PSI.	

Step	Location	Description	Initials
52.	L	VENT air out of booster pump to HP Pump piping vent valve.	
53.	L	VERIFY flow is established through demineralizer, and that flow shown agrees with flow shown on PLC Panelview.	
54.	L	STOP manual recirculation.	
55.	L	START manual recirculation. This will initiate operation of the other train of pumps.	
56.	L	VENT air out of booster pump to HP pump piping vent valve.	
57.	L	VERIFY flow is established through demineralizer, and that flow shown agrees with flow shown on PLC Panelview.	
58.	L	VERIFY that water conductivity at inlet to skid is <1 uS/cm.	
NOTE: If water conductivity is >1 uS/cm recirc until the conductivity falls below 1uS/cm or drain water from tank and refill.			
59.	L	REMOVE Cap from Mixing Tee.	
60.	L	REMOVE plug from end of hose	
61.	L	INSTALL a new conical seal on the mixing tee male JIC connector.	
62.	L	INSTALL female JIC Hose connector onto mixing tee fitting. Tighten fitting, using care to ensure that the hose is not subjected to significant torque as the fitting is tightened.	
63.	L	VERIFY that low point drain valve is closed and plug is tight.	
64.	L	In Administrator Mode on panel, SELECT a low (0.15 to 0.2) water/fuel ratio.	
65.	L	SELECT ON position on the NOx Season Switch.	
66.	L	START Engine, LOAD engine to 10 to 12 MW and until TT7 exceeds 900 F	
67.	L	RUN engine until water injection has been established. Once air has been purged out of line, reset water/fuel ratio to 0.5 water/fuel ratio.	
68.	L	CLEAR all alarms.	
69.	L	LOG ON to system as user.	
70.	L	LOAD engine to full load (base), and observe water injection rates and fuel consumption rates are consistent with previous runs.	
71.	L	REDUCE load and verify that water injection stops below TT7 is below 900°F	

4.0 SYSTEM OPERATION

4.1 HPWI System Normal Operation

Step	Location	Description	Initials
NOTE:	**The Location column specifies where the step is performed. A "C" indicates that the step is performed in the control room; an "L" indicates that the step is performed locally, and an "LP" indicates that the step is performed from a local panel.**		
1.	L	VERIFY tank level is being maintained.	
2.	L	VERIFY tank conductivity is being maintained.	
3.	LP	VERIFY system seasonal switch is in the correct position.	

4.2 HPWI System Shutdown

4.2.1 HPWI Non-Ozone Season

Step	Location	Description	Initials
NOTE:	**The Location column specifies where the step is performed. A "C" indicates that the step is performed in the control room, an "L" indicates that the step is performed locally, and an "LP" indicates that the step is performed from a local panel.**		
1.	LP	SELECT OFF on Ozone Season Switch.	
2.	LP	PRESS Emergency-Stop on HPWI Skid PLC Cabinet door.	
3.	L	CLOSE, LOCK and TAG the 3” Fire Main Water supply valve.	
4.	L	VERIFY satisfactory condition of heat tracing on 3” fire main water supply valve and above ground fire header.	
5.	L	SELECT ON Heat tracing to 3” fire main water supply line and valve.	
6.	L	SET enclosure heater thermostat to maintain at least 40°F.	
7.	L	SELECT ON for the HPWI Enclosure Heater.	
8.	L	DISCONNECT and DRAIN the hoses from the water supply header, and the recirculation line to and from demineralizer skid.	
9.	L	Coil up and store hoses in the HPWI enclosure.	
10.	L	OPEN and tag power supply breaker for MOV in 240/120 V Power Panel. (breaker #8)	
11.	L	OPEN the following valves: • ball valves on the water supply line • MOV isolation ball valves • MOV bypass valves • Manually open the MOVs.	
12.	L	DRAIN all water from water supply header.	
13.	L	OPEN all ball valves on the recirculation line.	
14.	L	REMOVE recirculation line check valves (4) internals, allow line to drain, and then reinstall internals and covers.	
15.	L	DRAIN water out of the tank.	
16.	L	OPEN the tank outlet valve.	

Step	Location	Description	Initials
17.	L	OPEN the skid inlet valve.	
18.	L	OPEN each inlet strainer basket then flush basket with water.	
NOTE: Store all drain plugs for re-installation in spring time.			
19.	L	REMOVE drain plugs from inlet strainer housings.	
20.	L	VERIFY strainer body is empty of water.	
21.	L	RE-INSTALL strainer baskets and replace covers.	
22.	L	REMOVE low point drain plug from inlet header.	
23.	L	REMOVE check valves internals, allow line to drain, and then reinstall internals and covers.	
24.	L	REMOVE low point drain plug from Recirc. Header.	
25.	L	REMOVE cap, open, and drain water from low point drain valve outside Engine Compartment.	
26.	L	REMOVE low point drain plug from HP Header.	
27.	L	REMOVE check valves internals, allow line to drain, and then reinstall internals and covers.	
28.	L	REMOVE HP Pump A vent valve.	
29.	L	REMOVE HP Pump B vent valve.	
30.		REMOVE HP Pump A suction pressure gauge line allowing line to drain and then reconnect.	
31.		REMOVE HP Pump B suction pressure gauge line allowing line to drain and then reconnect.	
32.		REMOVE HP Water line flex hose from mixing tee and drain water.	
33.		INSTALL 1-1/2” Conical (Vorshon) seal on end of male fitting.	
34.		INSTALL 1-1/2” Stainless JIC Cap on Mixing tee water connection leg.	
35.		DRAIN all water from the 1-1/2” flexible hose.	
36.		INSTALL plug in end of hose.	
37.		SECURE Hose to engine mounting frame.	

4.3 HPWI System Abnormal Operation

4.3.1 Alarm Fails to Clear

Step	Location	Description	Initials
NOTE:	**The Location column specifies where the step is performed. A "C" indicates that the step is performed in the control room; an "L" indicates that the step is performed locally, and an "LP" indicates that the step is performed from a local panel.**		
NOTE:	**The purpose of this procedure is to clear an alarm or trip condition that isn't clearing using the normal method.**		
1.	L	On the PLC WATER INJECTION SUMMARY display PUSH the SUMMARY button.	
2.	L	On the SUMMARY display PUSH the DIAGNOSTICS ALARMS button.	
3.	L	PUSH the DIAGNOSTICS RESET to reset the alarm or trip.	
4.	L	PUSH the RESET or MASTER RESET button to reset the alarm or trip.	
NOTE:	**If the above does not reset the alarm or trip proceed to restart the HMI as outlined below.**		
5.	L	OPEN the PLC cabinet and slide out the keyboard.	
6.	L	PRESS the Windows key on the keyboard to access the Start Menu.	
7.	L	From the Start Menu PUSH the Shutdown button.	
8.	L	When the Shutdown Menu appears SELECT Restart then press OK.	
NOTE:	**The Water Injection program should restart and all alarms should clear.**		

5.0 SYSTEM ALARMS AND RESPONSES

Location	Alarm Description
PLC	SKID NOT READY TO RUN
PLC	STRAINER DIFFERENTIAL PRESSURE HIGH
PLC	TRAIN A IS SELECTED AND THE ISOLATION IS CLOSED
PLC	HP PUMP LOW SUCTION PRESSURE
PLC	TRAIN B IS SELECTED AND THE ISOLATION IS CLOSED
PLC	TRAIN A WAS SELECTED AND FAILED
PLC	TRAIN B WAS SELECTED AND FAILED
PLC	CT101 SKID CONDUCTIVITY HIGH HIGH TO TURBINE
PLC	CT102 TANK CONDUCTIVITY HIGH
PLC	TRAIN A BOOSTER PUMP NOT RUNNING
PLC	TRAIN B BOOSTER PUMP B NOT RUNNING
PLC	TRAIN A BOOSTER PUMP OVERLOAD
PLC	TRAIN B BOOSTER PUMP OVERLOAD
PLC	TRAIN A MAIN PUMP FAULT
PLC	TRAIN B MAIN PUMP FAULT
PLC	TRAIN A SUPPLY TO TURBINE NOT CLOSED
PLC	TRAIN B SUPPLY TO TURBINE NOT CLOSED
PLC	TRAIN A SUPPLY FAILED TO OPEN TO TURBINE
PLC	TRAIN B SUPPLY FAILED TO OPEN TO TURBINE
PLC	TRAIN A HIGH PRESSURE AT MAIN PUMP OUTLET
PLC	TRAIN B HIGH PRESSURE AT MAIN PUMP OUTLET
PLC	CT101 SKID CONDUCTIVITY HIGH
PLC	DEMINERALIZED WATER TANK LOW LEVEL
PLC	DEMINERALIZED WATER TANK HIGH LEVEL
PLC	DEMINERALIZED WATER TANK HIGH HIGH LEVEL
PLC	NETWORK SWITCH NO.1 FAULT
PLC	24VDC POWER SUPPLY PS-1 FAILED
PLC	PLC PANEL TEMPERATURE HIGH

Location	Alarm Description
PLC	TRAIN A BYPASS VALVE FAILED TO CLOSE
PLC	TRAIN B BYPASS VALVE FAILED TO CLOSE
PLC	MOV WATER SUPPLY VALVE HAS BEEN OPEN AN EXTENDED AMOUNT OF TIME.

Alarm Title: SKID NOT READY TO RUN
Initiating Device: PLC
Setpoint: Both trains disabled

Possible Causes:

1. System valves closed
2. Low tank level
3. System controls not in automatic

Consequences:

1. Loss of water injection
2. Load limited to 900 ^{O}F TT7 or approximately 10 Megawatts if NOx is selected

Initial Operator Actions:

1. Verify local indications
2. Verify system lineup
3. Fill tank to >120”.

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason train malfunction
3. Notify system desk if load limit imposed
4. Restore System to normal as soon as possible

Alarm Title: STRAINER DIFFERENTIAL PRESSURE HIGH
Initiating Device: PDT-101
Setpoint: 2 psid

Possible Causes:

1. In-service strainer basket fouled

Consequences:

1. Loss of pump suction resulting in system shutdown
2. Load limited to 900 ^{O}F TT7 or approximately 10 Megawatts if NOx is selected

Initial Operator Actions:

1. Verify local indication
2. Select the clean strainer basket

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for strainer clogging
3. Clean the dirty strainer
4. Notify system desk if load limit imposed
5. Restore System to normal as soon as possible

Alarm Title: HP PUMP LOW SUCTION PRESSURE
Initiating Device: PS M201-LO/PS M301-LO
Setpoint: 20 psig

Possible Causes:

1. Duplex strainer clogging
2. Low level in water storage tank
3. Cavitation in the booster pump

Consequences:

1. High pressure pump shutdown
2. Automatic start of the standby train

Initial Operator Actions:

1. Verify local indication
2. Verify correct operation of the standby train

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for the low pressure
3. Notify system desk if load limit imposed
4. Restore System to normal as soon as possible

Alarm Title: TRAIN A IS SELECTED AND THE ISOLATION IS CLOSED
Initiating Device: DI-33SV202
Setpoint: N/A

Possible Causes:

1. Isolation valve closed
2. Faulty limit switch

Consequences:

1. Loss of injection
2. Load limited

Initial Operator Actions:

1. Open train A isolation valve
2. Verify train B is operational
3. Select train B for operation

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for incorrect valve position
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN B IS SELECTED AND THE ISOLATION IS CLOSED
Initiating Device: DI-33SV302
Setpoint: N/A

Possible Causes:

1. Isolation valve closed
2. Faulty limit switch

Consequences:

1. Loss of injection
2. Load limited

Initial Operator Actions:

1. Open train B isolation valve
2. Verify train A is operational
3. Select train A for operation

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for incorrect valve position
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN A WAS SELECTED AND FAILED
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Pump failed to start
2. Low pump suction pressure

Consequences:

1. Train B will be selected automatically

Initial Operator Actions:

1. Check for additional alarms
2. Verify train B is selected for operation
3. Determine cause for train A failure

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Ensure at least one train is operational
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN B WAS SELECTED AND FAILED
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Pump failed to start
2. Low pump suction pressure

Consequences:

1. Train A is automatically selected

Initial Operator Actions:

1. Check for additional alarms
2. Verify train A is selected for operation
3. Determine cause for train B failure

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Ensure at least one train is operational
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: CT101 SKID CONDUCTIVITY HIGH HIGH TO TURBINE
Initiating Device: C_HIGH_COND_TO_TURBINE_DO
Setpoint: 1.8

Possible Causes:

1. System has failed to maintain low conductivity
2. Conductivity probe needs cleaning or replaced

Consequences:

1. Loss of injection
2. Load limited

Initial Operator Actions:

1. Verify local indication
2. Flush system

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason system failed to recirc storage tank
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: LOW SUPPLY PRESSURE TO MAIN PUMP A
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Strainer clogged
2. Low storage tank level
3. Improper valve lineup

Consequences:

1. Train B selected for operation
2. Failure of injection system
3. Load limited

Initial Operator Actions:

1. Verify local indications
2. Verify train B automatically selected
3. Shift strainer to clean basket
4. Check for additional alarms

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for the low pressure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: LOW SUPPLY PRESSURE TO MAIN PUMP B
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Strainer clogged
2. Low storage tank level
3. Improper valve lineup

Consequences:

1. Train A selected for operation
2. Failure of injection system
3. Load limited

Initial Operator Actions:

1. Verify local indications
2. Verify train A automatically selected
3. Shift strainer to clean basket
4. Check for additional alarms

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for the low pressure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: CT102 TANK CONDUCTIVITY HIGH
Initiating Device: C_TANK_HI_COND
Setpoint: 1.0

Possible Causes:

1. System has failed to maintain low conductivity
2. Conductivity probe needs cleaning or replaced

Consequences:

1. Loss of injection
2. System initiates tank recirculation through demineralizer

Initial Operator Actions:

1. Verify local indication
2. Flush system
3. Manually initiate cleanup cycle

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Instruct laboritorian to take local sample
3. Determine reason system failed to recirc storage tank
4. determine if opposite demineralizer string needs placed in service
5. Generate a work order if necessary
6. Restore System to normal as soon as possible

Alarm Title: TRAIN A BOOSTER PUMP NOT RUNNING
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Power supply failure

Consequences:

1. Train B selected for operation

Initial Operator Actions:

1. Verify local indication
2. Check for additional alarms

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for loss of booster pump
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN B BOOSTER PUMP B NOT RUNNING
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Power supply failure

Consequences:

1. Train A selected for operation

Initial Operator Actions:

1. Verify local indication
2. Check for additional alarms

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for loss of booster pump
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN A BOOSTER PUMP OVERLOAD
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Binding of pump/motor internals
2. High system flow

Consequences:

1. Train B selected for operation

Initial Operator Actions:

1. Verify local indication
2. Verify opposite train selected for operation

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for pump failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN B BOOSTER PUMP OVERLOAD
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Binding of pump/motor internals
2. High system flow

Consequences:

1. Train A selected for operation

Initial Operator Actions:

1. Verify local indication
2. Verify opposite train selected for operation

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for pump failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN A MAIN PUMP FAULT
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Binding of pump/motor internals
2. High system flow

Consequences:

1. Train B selected for operation

Initial Operator Actions:

1. Verify local indication
2. Verify opposite train selected for operation

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for pump failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN B MAIN PUMP FAULT
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Binding of pump/motor internals
2. High system flow

Consequences:

1. Train A selected for operation

Initial Operator Actions:

1. Verify local indication
2. Verify opposite train selected for operation

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for pump failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN A SUPPLY TO TURBINE NOT CLOSED
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. SOV failed to close

Consequences:

1. System disabled – not ready to operate

Initial Operator Actions:

1. Verify local indication

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for valve failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN B SUPPLY TO TURBINE NOT CLOSED
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. SOV failed to close

Consequences:

1. System disabled – not ready to operate

Initial Operator Actions:

1. Verify local indication

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for valve failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN A SUPPLY FAILED TO OPEN TO TURBINE
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. SOV failed to open

Consequences:

1. System disabled – not ready to operate
2. Train B selected for operation

Initial Operator Actions:

1. Verify local indication

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for valve failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN B SUPPLY FAILED TO OPEN TO TURBINE
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. SOV failed to open

Consequences:

1. System disabled – not ready to operate
2. Train A selected for operation

Initial Operator Actions:

1. Verify local indication

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for valve failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN A HIGH PRESSURE AT MAIN PUMP OUTLET
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Pressure relief valve failure
2. Pressure relief valve flowpath isolated
3. Improper main pump speed control

Consequences:

1. System failure

Initial Operator Actions:

1. Verify local indication
2. Stop the train operating at high pressure
3. Check valve lineup on recirc path
4. Select train B for operation

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Generate a work order if necessary
3. Restore System to normal as soon as possible

Alarm Title: TRAIN B HIGH PRESSURE AT MAIN PUMP OUTLET
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Pressure relief valve failure
2. Pressure relief valve flowpath isolated
3. Improper main pump speed control

Consequences:

1. System failure

Initial Operator Actions:

1. Verify local indication
2. Stop the train operating at high pressure
3. Check valve lineup on recirc path
4. Select train B for operation

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Generate a work order if necessary
3. Restore System to normal as soon as possible

Alarm Title: CT101 SKID CONDUCTIVITY HIGH
Initiating Device: C_CT101_COND_H_SP
Setpoint: 1.0

Possible Causes:

1. System has failed to maintain low conductivity
2. Conductivity probe needs cleaning or replaced

Consequences:

1. Loss of injection
2. Load limited

Initial Operator Actions:

1. Verify local indication
2. Flush system

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason system failed to recirc storage tank
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: DEMINERALIZED WATER TANK LOW LEVEL
Initiating Device: C_TANK_LOW_LVL_SP
Setpoint: 49 inches

Possible Causes:

1. Automatic makeup initiation failed
2. Fire main pressure inadequate
3. Valves not aligned per procedure

Consequences:

1. Insufficient water to support operation
2. System leakage

Initial Operator Actions:

1. Verify tank level locally
2. Verify system integrity
3. Verify fire main pressure >100 psig
4. Initiate system fill

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason level was not maintained automatically
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: DEMINERALIZED WATER TANK HIGH LEVEL
Initiating Device: DI_71LS102_HI
Setpoint: 165 inches

Possible Causes:

1. Automatic makeup failed open
2. Tank level transmitter failure

Consequences:

1. Tank overflows to ground

Initial Operator Actions:

1. Verify tank level locally
2. Verify system integrity
3. Manually stop makeup

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason level was not maintained automatically
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: DEMINERALIZED WATER TANK HIGH HIGH LEVEL
Initiating Device: C_TANK_HIHI_LVL_SP
Setpoint: 167 inches

Possible Causes:

1. Automatic makeup failed open or stuck partially open
2. Level transmitter failure

Consequences:

1. Tank overflows to the ground

Initial Operator Actions:

1. Verify tank level local indication
2. Verify system integrity
3. Manually stop makeup

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for level control failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: NETWORK SWITCH NO.1 FAULT
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. TBD

Consequences:

1. TBD

Initial Operator Actions:

1. TBD
2.
3.

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Generate a work order if necessary
3. Restore System to normal as soon as possible

Alarm Title: 24VDC POWER SUPPLY PS-1 FAILED
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Internal fault

Consequences:

1. Manufacturing defect
2. System fault

Initial Operator Actions:

1. Verify local indication

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: PLC PANEL TEMPERATURE HIGH
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. Air conditioning failure
2. Filter dirty

Consequences:

1. High temperature shutdown of PLC

Initial Operator Actions:

1. Verify high temperature
2. Start/restart air conditioning
3. Install temporary air conditioning
4. Shutdown system before PLC damage

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for high temperature
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN A BYPASS VALVE FAILED TO CLOSE
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. SOV failure

Consequences:

1. Unable to reach required system pressure and flow
2. System not ready for service

Initial Operator Actions:

1. Check the system for additional alarms
2. Check the valve for obstruction

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for valve failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: TRAIN B BYPASS VALVE FAILED TO CLOSE
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. SOV failure

Consequences:

1. Unable to reach required system pressure and flow
2. System not ready for service

Initial Operator Actions:

1. Check the system for additional alarms
2. Check the valve for obstruction

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for valve failure
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

Alarm Title: MOV WATER SUPPLY VALVE HAS BEEN OPEN AN EXTENDED AMOUNT OF TIME.
Initiating Device: N/A
Setpoint: N/A

Possible Causes:

1. TBD
2.

Consequences:

1. TBD

Initial Operator Actions:

1. TBD
2.
3.

Follow-up Operator Actions:

1. Inform Shift Supervisor
2. Determine reason for
3. Generate a work order if necessary
4. Restore System to normal as soon as possible

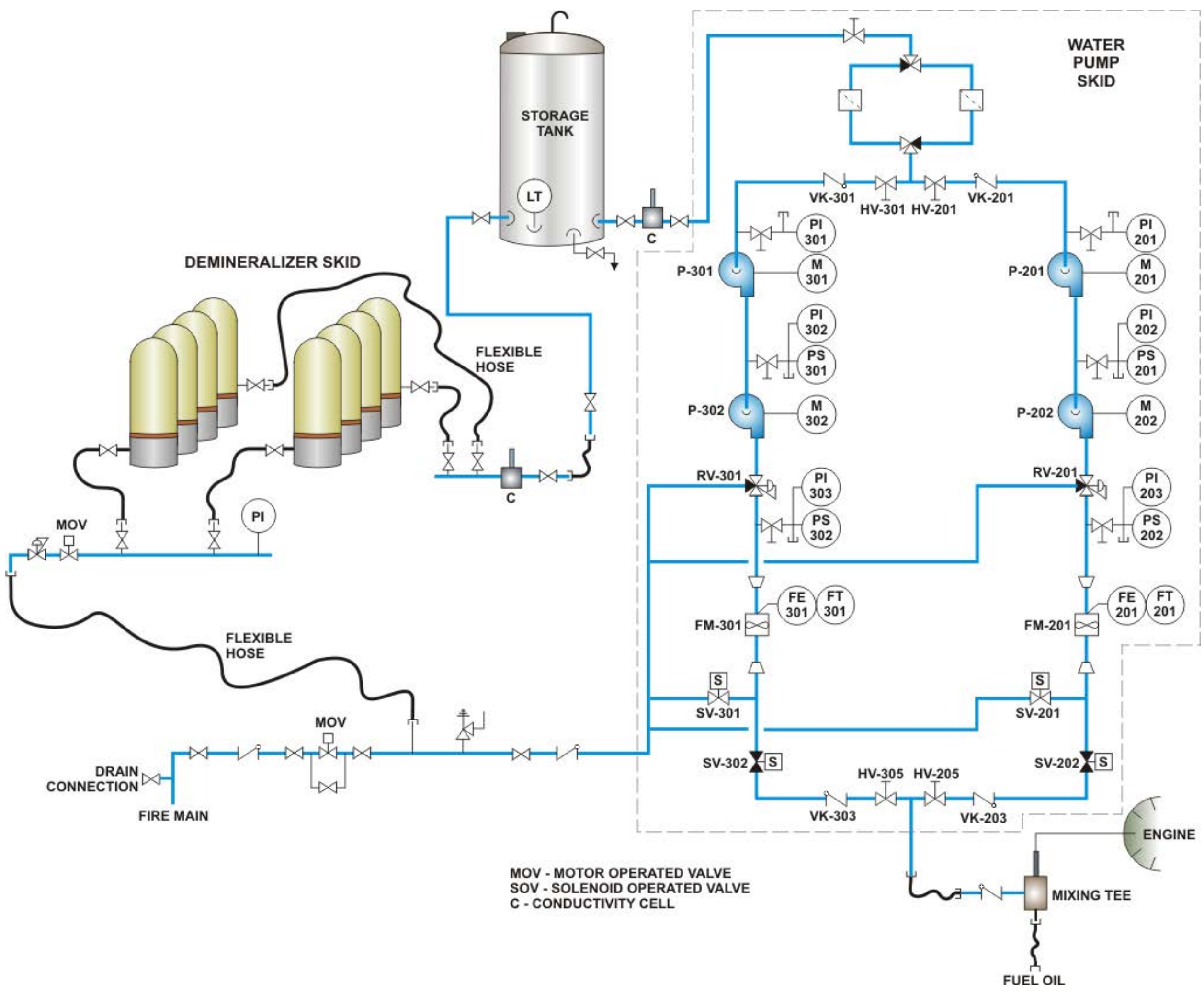
6.0 SYSTEM TESTS

N/A

7.0 SYSTEM LIMITATION

- Do not enter the engine housing with the engine in operation.

8.0 SIMPLIFIED DIAGRAM



2018 Stack Testing Report

NOx COMPLIANCE
TEST REPORT
FOR
INDIAN RIVER GENERATING STATION
DAGSBORO, DELAWARE
CT10
August 9, 2018

Indian River Generating Station
29416 Power Plant Rd.
Dagsboro, DE 19939

Job # 18-606

Test Report Date: 09-07-18

Grace Consulting, Inc.
Emissions Testing Services

September 7, 2018

I, Michael Whitt, hereby certify that the data obtained for Indian River Generting Station, CT10 is in accordance with procedures set forth by the USEPA. This report accurately represents the data obtained from the testing procedures and analysis of this data.

Michael Whitt, QSTI
Crew Chief

I, Carl Vineyard, hereby certify that I have reviewed this report and to the best of my knowledge, the data presented herein is complete and accurate.

Carl Vineyard, P.E., QSTI
Test Engineer

Grace Consulting, Inc.
1855 Sipe Road
Conover, NC 28613

Toll Free: 1-877-GCI-TEST
Phone: 828-855-0217
Fax: 828-855-2311
gcitest.com

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INTRODUCTION

INTRODUCTION

This report presents the results of the compliance tests performed for Indian River Generting Station, CT.

The purpose of the tests was to determine compliance of the plant CEMS of each unit. The results can be found in the Summary of Test Results section of this report.

The testing was performed by Grace Consulting, Inc., located at 1855 Sipe Road, Conover, NC 28613. Present during the testing were Michael Whitt, Josh Brittain, and Ben Stafford from Grace Consulting, Inc. Also present to observe the testing were Eric Roland on behalf of the Indian River Generting Station and Mark Lutrzykowski from the Delaware Department of Natural Resources and Enviornmental Control (DNREC).

The tests were performed on August 9, 2018. The testing was completed in accordance with USEPA test methods as published in the Federal Register.

The sampling and analytical procedures can be found in the Methods and Discussion section of this report. The raw field data and the equations used to determine the final results are presented in the Appendix section.

SUMMARY OF TEST RESULTS

SUMMARY OF TEST RESULTS

The following presents the results of the compliance tests performed for Indian River Generting Station, CT10.

GASEOUS EMISSIONS

Run	Date	NOx ppm	NOx lb/mmBtu	NOx ppm @ 15% O_2	O_2 percent
1	08-09-18	19.20	0.245	62.93	19.10
2	08-09-18	22.40	0.245	62.93	18.80
3	08-09-18	26.70	0.245	63.01	18.40
Avg.		**22.77**	**0.245**	**62.96**	**18.77**

The Compliance Limit for NOx ppm @ 15% O2 = 88.0 ppm

Three 1-hour NOx emission tests were conducted while the unit was operating at maximum load for the ambient conditions observed during the test day conditions.

The complete results can be found on the computer printouts following.

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Indian River
- Unit CT 10

Date: 8/9/2018
Pollutant: NOx
Monitor Span: 97.56

Run Number	Average Measured Value	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Calibration Gas	Corrected Value, Dry Basis
1	19.6	0.33	0.70	0.38	50.20	50.00	-0.21	50.01	19.20
2	22.8	0.70	0.70	0.00	50.00	50.00	0.00	50.01	22.40
3	26.9	0.70	0.80	0.10	50.00	49.60	-0.41	50.01	26.70

Cgas = (Cavg - Co) * Cma / (Cm - Co)   Eq. 6C-1

where:
Cgas = Effluent gas concentration, dry basis, ppm
Cavg = Average gas concentration indicated by gas analyzer, dry basis, ppm
Co = Average of initial and final system calibration bias check responses for the zero gas, ppm
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, ppm
Cma = Actual concentration of the upscale calibration gas, ppm

Grace Consulting, Inc.

Sampling System Bias Check and Measured Value Correction

Indian River
- Unit CT 10

Date: 8/9/2018
Pollutant: O2
Monitor Span: 21.95

Run Number	Average Measured Percent	Initial Zero Gas Bias	Final Zero Gas Bias	Zero Gas Drift	Initial Upscale Gas Bias	Final Upscale Gas Bias	Upscale Gas Drift	Calibration Gas	Corrected Percent, Dry Basis
1	19.1	0.10	0.00	-0.46	11.10	11.10	0.00	11.08	19.10
2	18.8	0.00	0.00	0.00	11.10	11.10	0.00	11.08	18.80
3	18.4	0.00	0.00	0.00	11.10	11.11	0.05	11.08	18.40

Cgas = (Cavg - Co) * Cma / (Cm - Co)   Eq. 6C-1

where:
Cgas = Effluent gas concentration, dry basis, percent
Cavg = Average gas concentration indicated by gas analyzer, dry basis, percent
Co = Average of initial and final system calibration bias check responses for the zero gas, percent
Cm = Average of initial and final system calibration bias check responses for the upscale calibration gas, percent
Cma = Actual concentration of the upscale calibration gas, percent

SAMPLING AND ANALYTICAL PROCEDURES

Test Methods used at Indian River Generating Station – CT10

Method 3A

O_2 concentrations were determined with 3 Method 3A test runs on each unit. GCI used a monitor range of 0-21.95% for O_2.

Method 7E

NO_x emissions were determined with 3 Method 7E test runs on each unit. GCI used a monitor span of 97.56 ppm for NOx.

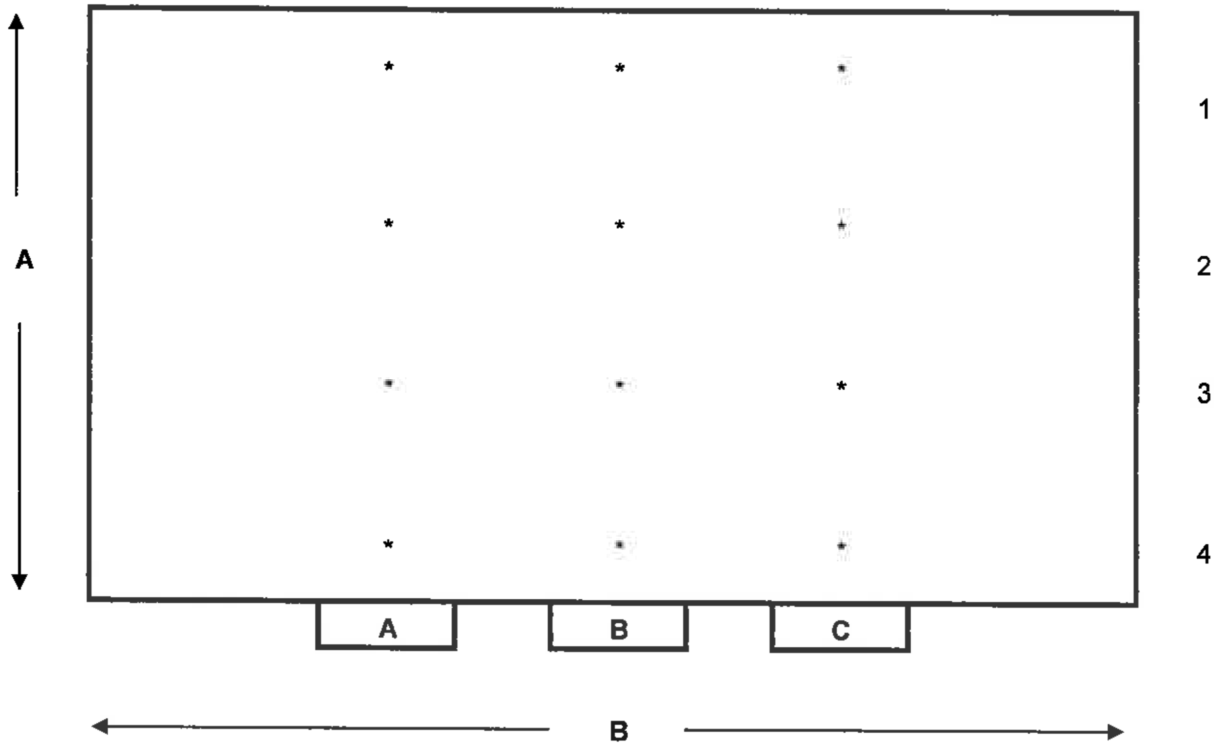
Sampling was conducted with 4 points sampled on each of 3 ports for a total of 12 points per test run.

Discussion

Environmental conditions did not adversely affect the test results.

Each run was traversed due to it not being able to pass a stratification test.

Testing was completed by following GCI's Internal Site Specific Test Plan #18-606 with no deviations.



POINTS	DISTANCE FROM WALL
1	9.2'
2	6.6'
3	3.9'
4	1.3'

Indian River
CT10

A = 126.0"
B = 133.3"
Area = 116.6 ft^2

Grace Consulting, Inc.
Emissions Testing Services

APPENDIX

Sample Calculations

Indian River Generating Station
CT10
08-09-18
Run 1

NO_x CALCULATION
(O_2 Based)

lb/dscf = $1.194 \times 10^{-7} \times$ PPM

2.29E-06 = $1.194 \times 10^{-7} \times 19.2$

lb/mmBtu = $\text{lb/dscf} \times \text{F-Factor} \times \frac{20.9}{(20.9-\%O2)}$

0.245 = $2.29\text{E-}06 \times 9190 \times \frac{20.9}{(20.9-19.10)}$

NO_x CALCULATION AT 15% O_2

NO_x ppm at 15% O_2 = corrected ppm x $\frac{20.9-15}{20.9-O2}$

62.93 = 19.2 x $\frac{20.9-15}{20.9-19.10}$

*Sample calculations use rounded numbers and computer printouts carry all decimal places.

SAMPLING SYSTEM BIAS CORRECTION

EMISSION CALCULATION
(CFR 40, Part 60, Appendix A)

Eq. 6C-1

$$C_{gas} = \left(\overline{C} - C_o\right)\frac{C_{ma}}{C_m - C_o}$$

Where:

C_{gas} = Effluent gas concentration, dry basis, ppm.
$\overline{C}$ = Average gas concentration indicated by gas analyzer, dry basis, ppm.
C_o = Average of initial and final system calibration bias check responses for the zero gas, ppm.
C_m = Average of initial and final system calibration bias check responses for the upscale calibration gas, ppm.
C_{ma} = Actual concentration of the upscale calibration gas, ppm.

Test Data Sheets

ANALYZER DATA

Client	Indian River	Project #	18-606
Unit	10	Date	8/9/2018
		Operator	M.Whitt

Run 1

Port A	Time	O2 %	NOx ppm
	10:17	19.8	12.3
	10:18	19.9	12.1
1	10:19	18.9	14.1
	10:20	18.1	27.3
	10:21	18.1	29.0
	10:22	18.5	28.1
	10:23	18.5	25.8
2	10:24	18.5	25.4
	10:25	18.5	25.3
	10:26	18.5	25.3
	10:27	19.6	15.0
	10:28	19.9	12.0
3	10:29	19.9	12.0
	10:30	19.8	12.0
	10:31	19.9	12.1
	10:32	20.5	5.8
	10:33	20.6	5.3
4	10:34	20.6	5.4
	10:35	20.5	5.5
	10:36	20.5	5.7

Port B			
	10:39	18.1	29.4
	10:40	18.2	29.5
1	10:41	18.2	28.9
	10:42	18.1	28.7
	10:43	18.1	29.2
	10:44	18.1	29.6
	10:45	18.1	29.5
2	10:46	18.1	29.5
	10:47	18.2	29.8
	10:48	18.2	29.8
	10:49	19.3	17.1
	10:50	19.4	16.8
3	10:51	19.4	16.6
	10:52	19.5	16.6
	10:53	19.5	16.5
	10:54	20.4	6.8
	10:55	20.4	6.8
4	10:56	20.5	6.4
	10:57	20.5	6.2
	10:58	20.4	6.9

	Time	Run 1 O2 %	NOx ppm
Port C	11:00	17.8	32.7
	11:01	17.8	33.1
1	11:02	17.8	33.3
	11:03	17.8	33.2
	11:04	18.1	32.6
	11:05	18.1	30.1
	11:06	18.1	29.3
2	11:07	18.1	29.1
	11:08	18.2	29.2
	11:09	18.2	29.2
	11:10	19.3	16.8
	11:11	19.3	17.1
3	11:12	19.3	17.3
	11:13	19.3	17.1
	11:14	19.3	17.1
	11:15	20.1	9.9
	11:16	20.1	10.5
4	11:17	20.1	10.3
	11:18	20.1	9.6
	11:19	20.1	9.7
	Average	**19.1**	**19.6**

ANALYZER DATA

Client	Indian River	Project #	18-606
Unit	10	Date	8/9/2018
		Operator	M.Whitt
		Run 2	

	Time	O2 %	NOx ppm
Port C	11:21	17.7	32.0
	11:22	17.7	34.1
1	11:23	17.7	34.6
	11:24	17.7	34.5
	11:25	18.0	33.3
	11:26	18.4	27.0
	11:27	18.4	26.7
2	11:28	18.4	26.7
	11:29	18.4	26.5
	11:30	19.1	24.7
	11:31	19.7	13.5
	11:32	19.7	13.7
3	11:33	19.7	13.6
	11:34	19.8	12.9
	11:35	19.8	12.4
	11:36	20.1	9.6
	11:37	20.1	9.5
4	11:38	20.1	9.5
	11:39	20.1	9.4
	11:40	20.1	9.4

Port B	11:42	18.0	30.0
	11:43	18.1	29.9
1	11:44	18.0	30.1
	11:45	17.9	30.2
	11:46	18.0	30.1
	11:47	18.4	28.7
	11:48	18.4	27.6
2	11:49	18.4	27.2
	11:50	18.3	27.7
	11:51	18.4	27.8
	11:52	18.6	26.5
	11:53	18.6	25.4
3	11:54	18.7	25.0
	11:55	18.7	24.7
	11:56	18.7	24.8
	11:57	19.3	17.2
	11:58	19.2	17.0
4	11:59	19.3	16.5
	12:00	19.3	17.4
	12:01	19.2	17.0

	Time	Run 2 O2 %	NOx ppm
Port A	12:03	17.9	33.0
	12:04	17.8	33.0
1	12:05	17.9	33.2
	12:06	17.9	33.0
	12:07	18.3	30.9
	12:08	18.4	26.6
	12:09	18.4	26.4
2	12:10	18.4	26.2
	12:11	18.4	27.0
	12:12	18.7	26.8
	12:13	19.1	20.5
	12:14	19.1	19.7
3	12:15	19.1	20.1
	12:16	19.2	19.9
	12:17	19.5	18.2
	12:18	19.9	11.9
	12:19	19.9	11.8
4	12:20	19.9	11.9
	12:21	19.9	11.6
	12:22	20.0	11.6
	Average	**18.8**	**22.8**

ANALYZER DATA

Client	Indian River	Project #	18-606
Unit	10	Date	8/9/2018
		Operator	M.Whitt
		Run 3	

	Time	O2 %	NOx ppm
Port A	12:27	17.5	36.3
	12:28	17.5	36.2
1	12:29	17.5	36.5
	12:30	17.5	36.6
	12:31	18.0	35.4
	12:32	18.4	27.3
	12:33	18.4	26.5
2	12:34	18.4	26.9
	12:35	18.4	27.0
	12:36	18.6	26.9
	12:37	19.1	21.1
	12:38	19.1	20.0
3	12:39	19.0	19.6
	12:40	19.0	20.2
	12:41	19.2	20.3
	12:42	19.9	14.3
	12:43	19.9	12.0
4	12:44	19.8	12.0
	12:45	19.7	12.4
	12:46	19.9	12.9

Port B	12:48	18.1	29.9
	12:49	18.1	29.8
1	12:50	18.1	28.8
	12:51	18.0	28.8
	12:52	18.1	28.8
	12:53	18.4	27.6
	12:54	18.4	27.7
2	12:55	18.5	26.5
	12:56	18.5	25.5
	12:57	18.5	25.6
	12:58	18.4	27.2
	12:59	18.4	27.1
3	13:00	18.4	27.3
	13:01	18.5	26.9
	13:02	18.7	26.4
	13:03	19.2	18.7
	13:04	19.1	18.9
4	13:05	19.2	19.2
	13:06	19.2	19.0
	13:07	19.1	19.0

Port C	Time	Run 3 O2 %	NOx ppm
	13:09	17.4	28.7
	13:10	17.4	38.1
1	13:11	17.4	38.4
	13:12	17.4	38.5
	13:13	17.4	38.5
	13:14	17.6	37.6
	13:15	17.7	35.5
2	13:16	17.6	35.1
	13:17	17.6	34.9
	13:18	17.7	34.8
	13:19	18.1	31.5
	13:20	18.1	29.5
3	13:21	18.1	29.5
	13:22	18.2	29.3
	13:23	18.2	29.0
	13:24	18.8	25.6
	13:25	18.8	22.5
4	13:26	18.8	22.3
	13:27	18.8	22.3
	13:28	18.8	22.6
	Average	**18.4**	**26.9**

GCI Calibration Data

Client	Indian River	Test Date	8/9/2018
		Project #	18-606
Source Identification	10	Operator	M.Whitt

Calibration Data For Sampling Runs: 1-3 Gas Type: NOx Span: 97.56	Cylinder Number	Cylinder Value % or PPM	Analyzer Response	Absolute Difference % or PPM	Difference % of Span	
Zero Gas	CC189278	**0.00**	0.30	0.30	0.308	
NO2 to NO Converter Check	CC504734	**43.69**	**42.10**	1.59	96.36%	**PASS**
Mid-Range Gas	CC504920	**50.01**	50.05	0.04	0.041	
High-Range Gas	CC46075	**97.56**	97.31	0.25	0.256	

Run #: 1 Gas Type: NOx Span: 97.56	Analyzer Response	Initial Values		Final Values		Drift % of Span
		System Response	System Cal. Bias % of Span	System Response	System Cal. Bias % of Span	
Zero Gas	0.30	0.33	0.03	0.70	0.41	0.38
Upscale Gas	50.05	50.20	0.15	50.00	-0.05	-0.21

Run #: 2 Gas Type: NOx Span: 97.56	Analyzer Response	Initial Values		Final Values		Drift % of Span
		System Response	System Cal. Bias % of Span	System Response	System Cal. Bias % of Span	
Zero Gas	0.30	0.70	0.41	0.70	0.41	0.00
Upscale Gas	50.05	50.00	-0.05	50.00	-0.05	0.00

Run #: 3 Gas Type: NOx Span: 97.56	Analyzer Response	Initial Values		Final Values		Drift % of Span
		System Response	System Cal. Bias % of Span	System Response	System Cal. Bias % of Span	
Zero Gas	0.30	0.70	0.41	0.80	0.51	0.10
Upscale Gas	50.05	50.00	-0.05	49.60	-0.46	-0.41

$$\text{System Calibration Bias} = \frac{\text{System Cal. Response - Analyzer Cal. Response}}{\text{Span}} \times 100$$

$$\text{Drift} = \frac{\text{Final System Cal. Response - Initial System Cal. Response}}{\text{Span}} \times 100$$

Client	Indian River		Test Date	8/9/2018	
			Project #	18-606	
Source Identification	10		Operator	M.Whitt	

Calibration Data For Sampling Runs: 1-3 Gas Type: O2 Span: 21.95		Cylinder Number	Cylinder Value % or PPM	Analyzer Response	Absolute Difference % or PPM	Difference % of Span	
Zero Gas		CC189278	**0.00**	0.10	0.10	0.456	
Low-Range Gas							
Mid-Range Gas	**NC**	CC92098	**11.08**	11.00	0.08	0.364	
High-Range Gas	**NC**	XC023912B	**21.95**	21.73	0.22	1.002	

Run #:	1		Initial Values		Final Values		
Gas Type:	O2	Analyzer Response	System Response	System Cal. Bias % of Span	System Response	System Cal. Bias % of Span	Drift % of Span
Span:	21.95						
Zero Gas		0.10	0.10	0.00	0.00	-0.46	-0.46
Upscale Gas		11.00	11.10	0.46	11.10	0.46	0.00

Run #:	2		Initial Values		Final Values		
Gas Type:	O2	Analyzer Response	System Response	System Cal. Bias % of Span	System Response	System Cal. Bias % of Span	Drift % of Span
Span:	21.95						
Zero Gas		0.10	0.00	-0.46	0.00	-0.46	0.00
Upscale Gas		11.00	11.10	0.46	11.10	0.46	0.00

Run #:	3		Initial Values		Final Values		
Gas Type:	O2	Analyzer Response	System Response	System Cal. Bias % of Span	System Response	System Cal. Bias % of Span	Drift % of Span
Span:	21.95						
Zero Gas		0.10	0.00	-0.46	0.00	-0.46	0.00
Upscale Gas		11.00	11.10	0.46	11.11	0.50	0.05

$$\text{System Calibration Bias} = \frac{\text{System Cal. Response - Analyzer Cal. Response}}{\text{Span}} \text{ X 100}$$

$$\text{Drift} = \frac{\text{Final System Cal. Response - Initial System Cal. Response}}{\text{Span}} \text{ X 100}$$

Gas Certification Sheets

Airgas.
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
630 United Drive
Durham, NC 27713
Airgas.com

MW

CERTIFICATE OF ANALYSIS

Grade of Product: CEM-CAL ZERO

Part Number:	NI CZ15ACT	Reference Number:	122-401135858-1
Cylinder Number:	CC189278	Cylinder Volume:	142.0 CF
Laboratory:	124 - Durham (SAP) - NC	Cylinder Pressure:	2000 PSIG
Analysis Date:	Feb 23, 2018	Valve Outlet:	580
Lot Number:	122-401135858-1		

16-59

Expiration Date: Feb 23, 2026

ANALYTICAL RESULTS

Component	Requested Purity		Certified Concentration
NITROGEN	99.9995 %		99.9995 %
CARBON DIOXIDE	< 1.0 PPM	<LDL	0.031 PPM
NOx	< 0.1 PPM	<LDL	0.023 PPM
SO2	< 0.1 PPM	<LDL	0.077 PPM
THC	< 0.1 PPM	<LDL	0.024 PPM
CARBON MONOXIDE	< 0.5 PPM	<LDL	0.031 PPM

Permanent Notes: Airgas certifies that the contents of this cylinder meet the requirements of 40 CFR 72.2

Impurities verified against analytical standards traceable to NIST by weight and/or analysis.

Approved for Release

Airgas.
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
630 United Drive
Durham, NC 27713
Airgas.com

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

MW

Part Number:	E02NI99E15WC042	Reference Number:	122-124579647-1
Cylinder Number:	CC504734	Cylinder Volume:	146 Cubic Feet
Laboratory:	124 - Durham - NC	Cylinder Pressure:	2015 PSIG
PGVP Number:	B22016	Valve Outlet:	660
Gas Code:	NO2,BALN	Certification Date:	Oct 14, 2016

16-74

Expiration Date: Oct 14, 2019

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NITROGEN DIOXIDE	44.50 PPM	43.69 PPM	G1	+/- 1.7% NIST Traceable	10/04/2016, 10/14/2016
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
GMIS	0512201605	CC503250	30.07 PPM NITROGEN DIOXIDE/NITROGEN	+/- 1.6%	May 12, 2019
PRM	12365	5604119	30.03 PPM NITROGEN DIOXIDE/AIR	+/- 1.5%	Jun 05, 2016

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
MKS NO2 018176583	FTIR	Oct 13, 2016

Triad Data Available Upon Request

PERMANENT NOTES:OXYGEN ADDED TO MAINTAIN STABILITY

A Williams
Approved for Release

Page 1 of 122-124579647-1

Airgas
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
630 United Drive
Durham, NC 27713
Airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

18-79

Part Number:	E02NI99E15AC416	Reference Number:	122-401200223-1
Cylinder Number:	CC504920	Cylinder Volume:	144.3 CF
Laboratory:	124 - Durham (SAP) - NC	Cylinder Pressure:	2015 PSIG
PGVP Number:	B22018	Valve Outlet:	660
Gas Code:	NO,NOX,BALN	Certification Date:	May 18, 2018

Expiration Date: May 18, 2021

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NOX	50.00 PPM	50.01 PPM	G1	+/- 0.9% NIST Traceable	05/11/2018, 05/18/2018
NITRIC OXIDE	50.00 PPM	49.95 PPM	G1	+/- 1.0% NIST Traceable	05/11/2018, 05/18/2018
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	16060611	CC442568	50.42 PPM NITRIC OXIDE/NITROGEN	+/- 0.8%	Jun 27, 2020
PRM	12367	APEX1099237	10.00 PPM NITROGEN DIOXIDE/AIR	+/- 1.5%	May 29, 2016
GMIS	1114201603	CC506722	4.965 PPM NITROGEN DIOXIDE/NITROGEN	+/- 2.0%	Nov 14, 2019

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 AHR0801549 NO	FTIR	Apr 26, 2018
Nicolet 6700 AHR0801549 NO	FTIR	Apr 26, 2018

Triad Data Available Upon Request

Approved for Release

Airgas.
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
630 United Drive
Durham, NC 27713
Airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E02NI99E15A3615	Reference Number:	122-401135857-1A
Cylinder Number:	CC46075	Cylinder Volume:	144.3 CF
Laboratory:	124 - Durham (SAP) - NC	Cylinder Pressure:	2015 PSIG
PGVP Number:	B22018	Valve Outlet:	660
Gas Code:	NO,NOX,BALN	Certification Date:	Mar 13, 2018

18-32

Expiration Date: Mar 13, 2026

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NOX	100.0 PPM	97.56 PPM	G1	+/- 1.1% NIST Traceable	03/06/2018, 03/13/2018
NITRIC OXIDE	100.0 PPM	97.53 PPM	G1	+/- 1.1% NIST Traceable	03/06/2018, 03/13/2018
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	17060238	EB0079232	100.3 PPM NITRIC OXIDE/NITROGEN	+/- 1.0%	May 11, 2019
PRM	12367	APEX1099237	10.00 PPM NITROGEN DIOXIDE/AIR	+/- 1.5%	May 29, 2016
GMIS	1114201603	CC506722	4.965 PPM NITROGEN DIOXIDE/NITROGEN	+/- 2.0%	Nov 14, 2019

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 AHR0801549 NO	FTIR	Mar 01, 2018
Nicolet 6700 AHR0801549 NO	FTIR	Mar 01, 2018

Triad Data Available Upon Request

Approved for Release

Airgas.
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
630 United Drive
Durham, NC 27713
Airgas.com

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E02NI89E15A0235	Reference Number:	122-401082810-1
Cylinder Number:	CC92098	Cylinder Volume:	145.3 CF
Laboratory:	124 - Durham (SAP) - NC	Cylinder Pressure:	2015 PSIG
PGVP Number:	B22017	Valve Outlet:	590
Gas Code:	O2,BALN	Certification Date:	Dec 19, 2017

18-00

Expiration Date: Dec 19, 2025

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
OXYGEN	11.00 %	11.08 %	G1	+/- 0.4% NIST Traceable	12/19/2017
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	09060230	CC263091	9.961 % OXYGEN/NITROGEN	+/- 0.3%	Nov 08, 2018

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Horiba MPA510 O2 41499150042	Paramagnetic	Nov 29, 2017

Triad Data Available Upon Request

Approved for Release

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E03NI60E15A1069	Reference Number:	122-124401458-1
Cylinder Number:	XC023912B	Cylinder Volume:	158.2 CF
Laboratory:	ASG - Durham - NC	Cylinder Pressure:	2015 PSIG
PGVP Number:	B22013	Valve Outlet:	590
Gas Code:	CO2,O2,BALN	Certification Date:	Oct 25, 2013

13-173

Expiration Date: Oct 25, 2021

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
CARBON DIOXIDE	18.00 %	17.70 %	G1	+/- 0.6% NIST Traceable	10/25/2013
OXYGEN	22.00 %	21.95 %	G1	+/- 0.4% NIST Traceable	10/25/2013
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	12061551	CC354889	19.87 % CARBON DIOXIDE/NITROGEN	+/- 0.6%	Jan 27, 2018
NTRM	09061416	CC273522	22.53 % OXYGEN/NITROGEN	+/- 0.4%	Mar 08, 2019

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Horiba VIA510 CO2 42399380022	Nondispersive Infrared (NDIR)	Oct 24, 2013
Horiba MPA510 O2 41499150042	Paramagnetic	Oct 24, 2013

Triad Data Available Upon Request

Signature on file

Approved for Release

Plant Data Sheets

Operating Data Averages

Operating Data	Average
Inlet Temperature (F)	96.1
Exhaust Temperature (F)	1020.9
Gross Megawatts (GMW)	14.8
Fuel Flow (GPM)	26.5
Water Flow (GPM)	10.6

8/9/18 CTIO op. DATA (EDT)

(EDT) Time	Inlet Temp (F) TI2	Exhaust Temp (F) TI7	GMW	FF (GPM)	WF (GPM)
1017	88.8	1021.1	15.2	26.9	10.8
1032	91.6	1021.1	15.1	26.9	10.7
1047	92.6	1021.1	14.9	26.6	10.6
1102	94.5	1019.4	14.9	26.7	10.7
1117	94.8	1019.5	14.9	26.6	10.6
1132	96.3	1021.1	14.8	26.4	10.6
1147	96.3	1021.1	14.8	26.5	10.6
1202	97.9	1021.1	14.7	26.3	10.5
1217	98.8	1021.1	14.7	26.4	10.5
1232	98.4	1021.1	14.7	26.2	10.5
1247	98.4	1021.2	14.6	26.2	10.4
1302	99.5	1021.1	14.5	26.1	10.4
1317	100.9	1021.2	14.5	26.1	10.4

1328 – TEST END RUN #3

Accreditation

American Association for Laboratory Accreditation

Accredited Air Emission Testing Body

A2LA has accredited

GRACE CONSULTING, INC.

In recognition of the successful completion of the joint A2LA and Stack Testing Accreditation Council (STAC) evaluation process, this laboratory is accredited to perform testing activities in compliance with ASTM D7036:2004 - Standard Practice for Competence of Air Emission Testing Bodies.

Presented this 7th day of November 2017

President and CEO
For the Accreditation Council
Certificate Number 3727.01
Valid to September 30, 2019

This accreditation program is not included under the A2LA ILAC Mutual Recognition Arrangement.

Grace Consulting, Inc.
Emissions Testing Services

Qualified Individual

LET IT BE KNOWN THAT

Michael Whitt

HAS SUCCESSFULLY PASSED A COMPREHENSIVE EXAMINATION AND SATISFIED EXPERIENCE REQUIREMENTS IN ACCORDANCE WITH THE GUIDELINES SET FORTH IN ASTM D 7036 FOR QUALIFIED INDIVIDUALS FOR

GROUP I – GAS FLOW, ISOKINETIC SAMPLING, AND PARTICULATE MATTER TESTING

EXAM COMPLETED ON MARCH 11, 2016 AND EFFECTIVE UNTIL MARCH 10, 2021

TYSON STILES, QUALITY MANAGER

SCOTT TEAGUE, QSTI I-IV, PRESIDENT

Grace Consulting, Inc.
Emissions Testing Services

Qualified Individual

LET IT BE KNOWN THAT

Michael Whitt

HAS SUCCESSFULLY PASSED A COMPREHENSIVE EXAMINATION AND SATISFIED EXPERIENCE REQUIREMENTS IN ACCORDANCE WITH THE GUIDELINES SET FORTH IN ASTM D 7036 FOR QUALIFIED INDIVIDUALS FOR

GROUP III – MEASURING GASEOUS POLLUTANT CONCENTRATIONS WITH INSTRUMENTAL TEST METHODS AND CONDUCTING CEMS RATAS

EXAM COMPLETED ON JANUARY 8, 2016 AND EFFECTIVE UNTIL JANUARY 7, 2021

TYSON STILES, QUALITY MANAGER

SCOTT TEAGUE, QSTI I-IV, PRESIDENT

This is the Last Page Of This Report

Grace Consulting, Inc.
Emissions Testing Services

2013 Stack Testing Report

NRG Energy, Inc.
121 Champion Way
Canonsburg, PA 15317

2013 Nitrogen Oxides (NO_X) Monitoring Test Report

Combustion Turbine 10
Indian River Generating Station
29416 Power Plant Road
Dagsboro, Delaware
19939

September, 2013

Testing Performed by NRG Energy Services ART
Test Team

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2013 Indian River Combustion Turbine 10 NO_X Test

Test Date: August 14, 2013

<u>ECMPS Air Emissions Testing Data XML Elements:</u>

AETB Name: NRG Energy Air Resources Test Team
5027 River Road
Mt. Bethel, PA 18343
AETB Phone Number: (570) 897-2140
QI Name: Shaun C. Stenlake
AETB Email: Shaun.Stenlake@nrgenergy.com
QSTI Exam Date: April 12, 2013
QSTI Exam Provider Name: Source Evaluation Society
QSTI Exam Provider Email: qstiprogram@gmail.com

2013 Indian River CT10 NO_X Test

Statement of Compliance

Indian River Power LLC has reviewed the 2013 Indian River CT10 NO_X Test Report, conducted by NRG Energy Services on September 10th, 2013, and agrees with the findings that Combustion Turbine 10 (IR10) is in compliance with the NO_X permit limit found in Air permit AQM-005/00001 (Renewal 2), Condition 3- Table 1, d. Emission Unit 5, Section 3.

Paul A. Straub
Environmental Specialist
Indian River Power LLC
NRG Indian River Generating Station

Chapter

1

2013 Indian River CT10 NO_X Test

1 Summary of Test Results

The average NO_X ppm corrected to 15% oxygen measured during the test was 56.8, below the permitted level of 88. **The emission Unit demonstrates compliance with the applicable NO_X permit limit.** A summary of the measured emissions is documented below. The emission limit is found in Air permit AQM-005/00001 (Renewal 2), Condition 3- Table 1, d. Emission Unit 5, Section 3. All reference method test results are contained in Appendix A.

Parameter	Unit	Date	Value	Limit
NO_X	**ppm@15% O_2**	**9/10/2013**	**56.8**	**88**
	ppm	9/10/2013	18.8	N/A
	lb/MMBtu	9/10/2013	0.22	N/A
O_2	percent (%)	9/10/2013	18.9%	N/A

Chapter

2

2013 Indian River CT10 NO_X Test

2 Abstract

A compliance emissions test was performed at the NRG Indian River Generating Station for Combustion Turbine 10 (IR10) on September 10th, 2013. Air permit AQM-005/00001 (Renewal 2) requires testing for nitrogen oxides from this source with a frequency based on annual capacity factor. At the current capacity factor, testing is required once every five years. The purpose of the test was to demonstrate compliance with the permit limit for nitrogen oxides corrected to 15% oxygen while firing No. 2 fuel oil with water injection for nitrogen oxides control. Testing was performed using USEPA test methods and in accordance with the DNREC approved test protocol and as outlined in Section 3 of this test report. Compliance was demonstrated through the performance of three one-hour test runs.

IR10 is a simple cycle electric generating unit manufactured by Pratt and Whitney, model FT4A-9 Turbo Jet Power Pak. IR10 is designated as Emission Unit 5 in the facilities air permit. IR10 fires No. 2 fuel oil and utilizes water injection for NO_X control. IR10 was operated in normal configuration and fired to base load during the compliance test. Measured gross megawatts (GMW), water flow (gpm), fuel flow (gpm), and other process parameters were hand recorded during the test program. A summary of the process data is located in Appendix B.

The field test crew consisted of Eric Roland (QSTI) and Shaun Stenlake (QSTI) from NRG Energy Services. Mr. Paul Straub and Jim Sadowski from the Indian River Generating Station were present during testing. The emission testing program was witnessed by Mr. Ed Jackson from DNREC.

Chapter

3

2013 Indian River CT10 NO_X Test

3 Test Process

The following section summarizes the general sampling procedures and the specific RMs utilized for the IR10 compliance test. Deviations from the EPA test methods / protocol are noted in Section 3.4. No test abnormalities or operational difficulties were encountered.

3.1 Reference Method System Overview

The RM test system consisted of a conventional extractive-type gas conditioning and delivery system and microprocessor-based source-level NO_X, and O_2 analyzers and data logger. Figure 3-1 depicts a functional representation of the test arrangement.

A hot, wet sample was extracted continuously from the exhaust stream according to the sample locations depicted in Figure 3-2 (cross-sectional sample point diagram). The sample flowed through an Inconel probe to a heated Teflon line and into the combination condenser/pump. The temperature of the sample was maintained above the dew point until the inlet of the condenser. Valving in the pump controlled the sample flow rate. Upon exiting the pump, the sample dew point was reduced to 40^o F. The sample was transported through a clean Teflon sample line to the flow controller in the test trailer. The flow controller, upon automated command from the data logger, directed a constant flow of filtered, dry exhaust gas sample or calibration standards to the instrumentation for analysis. An ESC 8816 data logger scanned the measured concentrations once a second, digitally recorded and reduced to one-minute averages. The data resolution was less than or equal to 0.5% of the analyzer full scale range. Data from the logger was electronically downloaded into the test summary computer program where the run averages and emission rates are calculated. Hardcopy printouts of the RM test data are included in Appendix A.

Calibration of the system was accomplished by flowing reference gases either directly into the analyzers or through a tee at the end of the sampling probe. All calibration gases used were EPA Protocol 1 gases meeting the required minimum uncertainty. The gas cylinder certifications are included in Appendix D. Calibration gas was sampled in the same manner as the stack gas and the system response was recorded automatically without any adjustment to the measurement system.

Prior to conducting the RM test runs, a system response time check was conducted and is documented in Appendix A. Calibration durations and system recovery events were timed to allow at least two times the longest parameter response time to ensure adequate system transition equilibration.

The calibration sequence was initiated with a three (3) point linearity check injected directly into the analyzers by the flow controller. The level of each gas used conformed to the specific requirement of the respective RM. The system passed the linearity check requirements of less than 2% of span deviation from expected for each parameter. Following the linearity check, a system bias test was conducted with low-level gas and an upscale gas by flowing the gas through the entire gas sampling and conditioning system. The upscale gas was selected to most closely match the stack concentrations from the linearity check mid and high gases. The results were within 5% of span from the linearity check results. Following each test run, the bias test was repeated. The difference in the pre to post-run bias check calibrations was verified to be less than the allowable 3% of span per run drift limitation. Sample flow rate was maintained constant (within 10%) during analyzer calibration error, system response time check, bias / drift checks, and during sampling.

The average of each test run was corrected according to the results of the bias test calibrations immediately prior to, and following each test run. All measurements made by the system are on a dry basis.

3.2 Sample Point Selection

A three point long line traverse was conducted prior to Test Run 1 with sample points located at 16.7%, 50% and 83.3% (21.0”, 63.0”, 105.0”) of the duct width per RM 7E Section 8.1.2. Sampling for Test Run 1 was conducted with a 12 point traverse, four points per three test ports located at 15.75”, 47.25”, 78.75” and 110.25”. The results of the 12 point traverse sampled for Test Run 1 determined that Test Runs 2 and 3 could be sampled at the three point long line, as oxygen was minimally stratified (maximum 7.6% difference from mean).

3.3 Nitrogen Oxides (NO_X)

NO_X concentrations were measured using a Teledyne API Model 200EH chemiluminescence analyzer according to RM 7E. The analyzer is certified to meet the interference response check of RM 7E. As specified in RM 7E Section 8.2.4, an NO_2 to NO conversion efficiency test was successfully performed during the test program using the procedure outlined in RM 7E Section 8.2.4.1. The converter efficiency check is documented in Appendix A.

NO_X pounds per million British thermal units (lb/MMBtu) were determined using the average measured concentrations for NO_X and O_2 for each test run and applying the appropriate F_d factor (9,190 scf/MMBtu for distillate fuel oil) and equations in RM 19.

3.4 Oxygen (O_2)

Oxygen concentrations were measured using a Servomex Model 1400 oxygen analyzer in accordance with RM 3A. The analyzer incorporates a paramagnetic O_2 sensor to determine gas O_2 percentage and provides the signal via microprocessor control to the data logger.

3.5 Test Method / Protocol Deviations

Oxygen calibration gasses were selected based upon previous test data. Measured oxygen exceeded the calibration span of 18.05% during the test program at several sample points. Because higher level oxygen calibration gas concentrations were unavailable on the test day, testing proceeded using the 18.05% oxygen span gas. However, the analyzer and data logger were ranged 0 to 25% oxygen, and concentrations above 18.05% were recorded. As discussed with Mr. Ed Jackson during the test, ambient readings of oxygen were recorded showing acceptable linearity above 18.05%. The average oxygen recorded during the test program was 18.9%, near the calibration and bias test gas concentration of 18.05%. As a result of the linear response of the paramagnetic analyzer and acceptable results measuring ambient oxygen, the oxygen content of the exhaust gas from IR10 was measured accurately during the program.

FIGURE 3-1 RM TRAILER FUNCTIONAL DIAGRAM

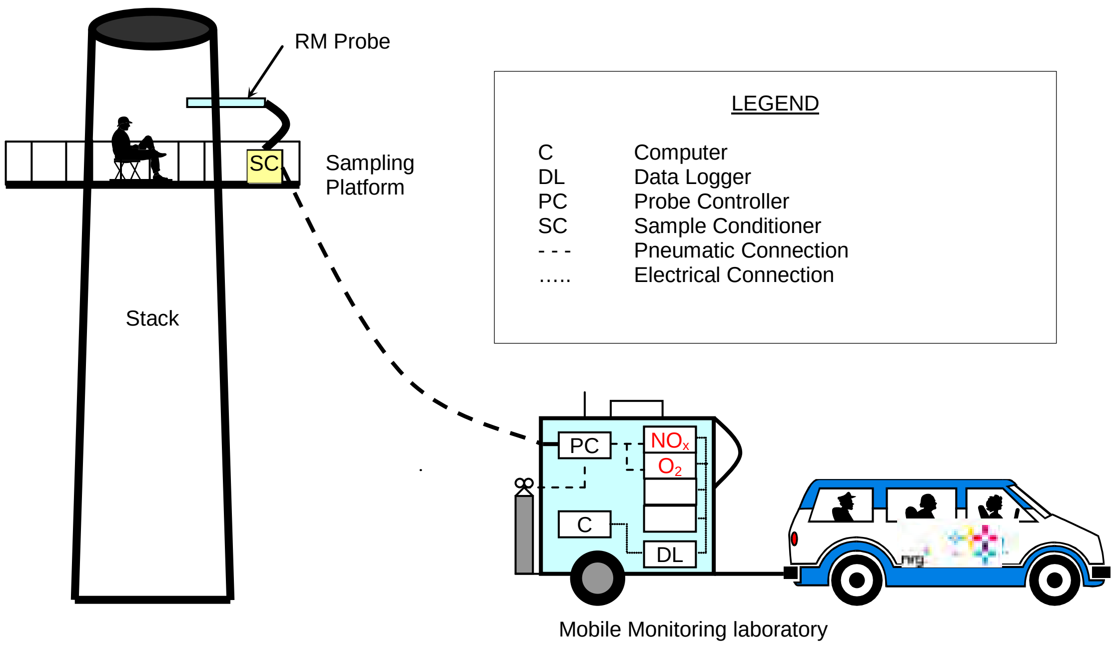
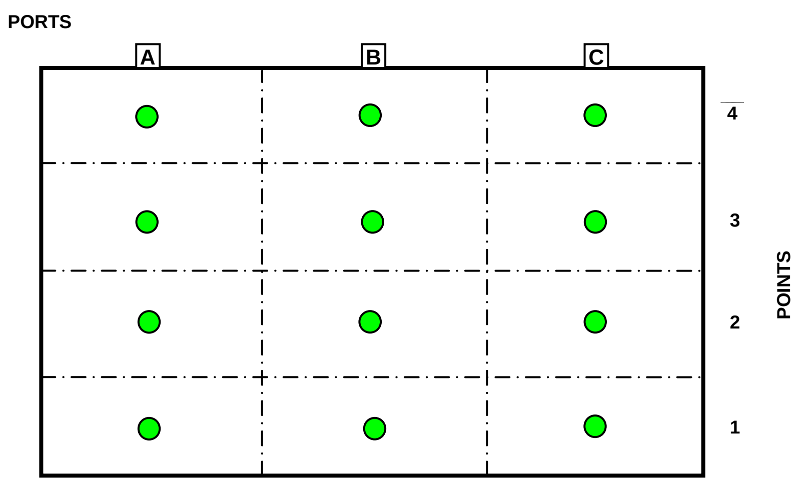


FIGURE 3-2 CROSS-SECTIONAL SAMPLE POINT DIAGRAM
Indian River Combustion Turbine (IR10)



RM STRATIFICATION TRAVERSE POINTS

1) 110.25 Inches
2) 78.75 Inches
3) 47.25 Inches
4) 5.75 Inches

(Long line, not shown), Port B

1) 105.0 Inches
2) 63.0 Inches
3) 21.0 Inches

INSIDE DIMENSION

Port Side	133.3 feet
Adjacent Side	126.0 feet

Appendix

A

APPENDIX A TEST SUMMARY FIELD DATA AND RM PRINTOUTS

Emissions Test Summary

Indian River CT 10	2013 NOx Testing	September 10, 2013			
		Run 1	**Run 2**	**Run 3**	***Average:***
Measured Stack Oxygen (%):		18.9	19.1	18.9	*18.9*
F-factor O2 (Fd, scf/mmbtu):		9190	9190	9190	
Fuel:		No. 2 Fuel Oil	No. 2 Fuel Oil	No. 2 Fuel Oil	
Measured megawatts (MW):		16.1	15.8	15.6	*15.8*
Exhaust Temperature (deg. F):		1021	1022	1021	*1021*
Water Flow (gpm):		14.6	14.4	14.3	*14.4*
Fuel Flow (gpm):		27.9	27.6	27.4	*27.6*
Nitrogen Oxides (as NO2) via EPA Method 7E				**Molar Mass = 46.01**	
ppmv, dry:		19.7	17.7	19.1	*18.8*
pounds/MMBtu O2:		0.22	0.22	0.22	*0.22*
ppmv, dry @	15 % O2	57.7	56.5	56.1	*56.8*

IR 10
EPA Method 7E stratification calculations

Point	Oxygen A concentration %, vd	Oxygen |D| difference %, v/v	Oxygen |D| difference % of average
A1	18.31	0.53	2.82%
A2	18.56	0.28	1.51%
A3	18.72	0.12	0.66%
A4	20.27	1.43	7.60%
B1	17.62	1.22	6.47%
B2	17.98	0.86	4.57%
B3	18.93	0.09	0.47%
B4	20.32	1.47	7.82%
C1	19.10	0.25	1.35%
C2	18.48	0.37	1.94%
C3	18.63	0.21	1.13%
C4	19.19	0.35	1.86%
average	18.84		
5% of average (**0.05A**)	0.94		
10% of average (**0.10A**)	1.88		

Number of stratification check points	Criteria for all point	Number of sample traverse points
3 or 12	$\|D\| \leq 0.05A$ (NOx, CO, SO_2, O_2, CO_2) or	1 (most representative of average)
	$\|D\| \leq 0.5$ ppmv (NOx, CO, SO_2) or	
	$\|D\| \leq 0.3$ %v/v (O_2, CO_2)	
3	$0.05A \leq \|D\| \leq 0.1A$ (NOx, CO, SO_2, O_2, CO_2) or	3 at 16.7%, 50.0%, and 83.3% of diameter
	0.5 ppmv $\leq \|D\| \leq$ 1.0 ppmv (NOx, CO, SO_2) or	
	0.3 %v/v $\leq \|D\| \leq$ 0.5 %v/v (O_2, CO_2)	
12	$0.05A \leq \|D\| \leq 0.1A$ (NOx, CO, SO_2, O_2, CO_2) or	3 on the line with the highest concentration, located at:
	0.5 ppmv $\leq \|D\| \leq$ 1.0 ppmv (NOx, CO, SO_2) or	16.7%, 50.0%, and 83.3% of diameter (stack diameter <7.8 feet)
	0.3 %v/v $\leq \|D\| \leq$ 0.5 %v/v (O_2, CO_2)	16”, 39” and 79” from stack wall (stack diameter >7.8 feet)
3 or 12	$\|D\| \geq 0.1A$ (NOx, CO, SO_2, O_2, CO_2) or	12 located per EPA Method 1
	$\|D\| \geq 1.0$ ppmv (NOx, CO, SO_2) or	
	$\|D\| \geq 0.5$ %v/v (O_2, CO_2)	

Indian River
CT 10
Reference Method Data Summary
2013 NOx Testing

Date / Time		NO_x	O_2	
10-Sep	9:33	23.32	18.24	A1
10-Sep	9:34	23.31	18.29	
10-Sep	9:35	23.2	18.26	
10-Sep	9:36	23.42	18.28	
10-Sep	9:37	22.92	18.48	
10-Sep	9:38	22.1	18.47	A2
10-Sep	9:39	22.23	18.44	
10-Sep	9:40	21.99	18.6	
10-Sep	9:41	20.95	18.93	
10-Sep	9:42	20.09	18.35	
10-Sep	9:43	21.64	18.49	A3
10-Sep	9:44	21.83	18.76	
10-Sep	9:45	20.25	18.78	
10-Sep	9:46	19.7	18.81	
10-Sep	9:47	19.38	18.75	
10-Sep	9:48	19.62	19.06	A4
10-Sep	9:49	8.338	20.52	
10-Sep	9:50	4.117	20.59	
10-Sep	9:51	3.669	20.63	
10-Sep	9:52	3.675	20.57	
10-Sep	9:55	29.63	17.63	B1
10-Sep	9:56	29.53	17.63	
10-Sep	9:57	29.61	17.65	
10-Sep	9:58	29.89	17.59	
10-Sep	9:59	30.14	17.62	
10-Sep	10:00	30.2	17.71	B2
10-Sep	10:01	29.6	17.72	
10-Sep	10:02	27.93	18.09	
10-Sep	10:03	22.73	18.42	
10-Sep	10:04	26.6	17.97	
10-Sep	10:05	26.93	17.92	B3
10-Sep	10:06	26.64	18.18	
10-Sep	10:07	16.13	19.43	
10-Sep	10:08	13.32	19.61	
10-Sep	10:09	13	19.51	
10-Sep	10:10	12.55	19.76	B4
10-Sep	10:11	5.431	20.51	
10-Sep	10:12	5.04	20.34	
10-Sep	10:13	5.501	20.48	
10-Sep	10:14	4.96	20.49	
10-Sep	10:17	18.59	19.07	C1
10-Sep	10:18	18.48	19.11	
10-Sep	10:19	17.64	19.11	
10-Sep	10:20	17.19	19.1	
10-Sep	10:21	17.18	19.09	

10-Sep	10:22	16.93	19.04	C2
10-Sep	10:23	20.27	18.57	
10-Sep	10:24	24.15	18.22	
10-Sep	10:25	24.32	18.34	
10-Sep	10:26	23.82	18.21	
10-Sep	10:27	24.3	18.4	C3
10-Sep	10:28	23.23	18.64	
10-Sep	10:29	21.13	18.67	
10-Sep	10:30	20.27	18.75	
10-Sep	10:31	20.39	18.69	
10-Sep	10:32	20.61	18.81	C4
10-Sep	10:33	18.8	19.27	
10-Sep	10:34	16	19.31	
10-Sep	10:35	15.06	19.28	
10-Sep	10:36	15.01	19.29	

Average concentration	19.6	18.8
Bias Correction		
zero initial (Zi)	0.30	-0.01
zero final (Zf)	0.31	-0.01
span initial (Si)	53.90	17.99
span final (Sf)	54.04	18.02
Actual Conc. (Cma)	54.81	18.05
Corrected value	**19.7**	**18.9**

Corrected value = (**Average Concentration**-(@avg(Zi,Zf))) x Cma / (@avg(Si,Sf)-@avg(Zi,Zf))

Indian River
CT 10
Reference Method Data Summary
2013 NOx Testing

Date / Time		NO_x	O_2
10-Sep	10:47	25.51	18.06
10-Sep	10:48	25.56	18.08
10-Sep	10:49	25.67	18.08
10-Sep	10:50	25.77	18.08
10-Sep	10:51	25.94	18.08
10-Sep	10:52	26.11	18.09
10-Sep	10:53	25.79	18.12
10-Sep	10:54	25.68	18.08
10-Sep	10:55	26.06	18.07
10-Sep	10:56	26.26	18.08
10-Sep	10:57	26.14	18.09
10-Sep	10:58	26.16	18.07
10-Sep	10:59	26.24	18.08
10-Sep	11:00	26.17	18.06
10-Sep	11:01	26.23	18.04
10-Sep	11:02	26.59	18
10-Sep	11:03	26.66	18.07
10-Sep	11:04	26.35	18.07
10-Sep	11:05	26.32	18.07
10-Sep	11:06	22.57	18.61
10-Sep	11:08	21.67	18.46
10-Sep	11:09	21.98	18.54
10-Sep	11:10	21.82	18.54
10-Sep	11:11	21.62	18.55
10-Sep	11:12	21.75	18.51
10-Sep	11:13	22.01	18.53
10-Sep	11:14	21.85	18.58
10-Sep	11:15	21.52	18.59
10-Sep	11:16	21.43	18.62
10-Sep	11:17	21.27	18.66
10-Sep	11:18	21.09	18.63
10-Sep	11:19	21.11	18.59
10-Sep	11:20	21.28	18.63
10-Sep	11:21	21.18	18.64
10-Sep	11:22	20.83	18.69
10-Sep	11:23	20.52	18.75
10-Sep	11:24	20.1	18.74
10-Sep	11:25	20.03	18.73
10-Sep	11:26	20.21	18.7
10-Sep	11:27	20.37	18.72
10-Sep	11:29	5.979	20.39
10-Sep	11:30	5.663	20.45
10-Sep	11:31	5.262	20.42
10-Sep	11:32	5.098	20.44
10-Sep	11:33	5.146	20.34

10-Sep	11:34	5.261	20.39
10-Sep	11:35	5.328	20.38
10-Sep	11:36	5.433	20.34
10-Sep	11:37	5.216	20.35
10-Sep	11:38	5.285	20.32
10-Sep	11:39	5.327	20.43
10-Sep	11:40	4.873	20.39
10-Sep	11:41	4.866	20.35
10-Sep	11:42	5.804	20.09
10-Sep	11:43	6.646	20.33
10-Sep	11:44	5.712	20.46
10-Sep	11:45	4.799	20.38
10-Sep	11:46	5.175	20.22
10-Sep	11:47	6.034	20.08
10-Sep	11:48	7.157	20.21

Average concentration	17.5	19.0
Bias Correction		
zero initial (Zi)	0.31	-0.01
zero final (Zf)	0.18	0.00
span initial (Si)	54.04	18.02
span final (Sf)	53.72	18.01
Actual Conc. (Cma)	54.81	18.05
Corrected value	**17.7**	**19.1**

Corrected value = (**Average Concentration**-(@avg(Zi,Zf))) x Cma
/ (@avg(Si,Sf)-@avg(Zi,Zf))

Indian River
CT 10
Reference Method Data Summary
2013 NOx Testing

Date / Time		NO_x	O_2
10-Sep	11:58	3.522	20.44
10-Sep	11:59	4.184	20.42
10-Sep	12:00	4.698	20.33
10-Sep	12:01	5.029	20.28
10-Sep	12:02	5.693	20.26
10-Sep	12:03	5.98	20.35
10-Sep	12:04	5.479	20.37
10-Sep	12:05	5.079	20.41
10-Sep	12:06	5.298	20.14
10-Sep	12:07	6.92	20.01
10-Sep	12:08	7.177	20.34
10-Sep	12:09	5.957	20.29
10-Sep	12:10	5.712	20.38
10-Sep	12:11	5.282	20.42
10-Sep	12:12	4.828	20.4
10-Sep	12:13	5.028	20.19
10-Sep	12:14	5.833	20.32
10-Sep	12:15	6.187	20.32
10-Sep	12:16	5.741	20.4
10-Sep	12:17	5.147	20.4
10-Sep	12:19	20.83	18.5
10-Sep	12:20	21.04	18.47
10-Sep	12:21	21.65	18.45
10-Sep	12:22	22.03	18.48
10-Sep	12:23	22.1	18.46
10-Sep	12:24	22.27	18.44
10-Sep	12:25	22.31	18.47
10-Sep	12:26	22.3	18.43
10-Sep	12:27	22.5	18.41
10-Sep	12:28	22.59	18.39
10-Sep	12:29	22.63	18.41
10-Sep	12:30	22.63	18.43
10-Sep	12:31	22.52	18.44
10-Sep	12:32	22.51	18.44
10-Sep	12:33	22.47	18.44
10-Sep	12:34	22.55	18.4
10-Sep	12:35	22.73	18.44
10-Sep	12:36	22.64	18.47
10-Sep	12:37	22.46	18.45
10-Sep	12:38	22.55	18.43
10-Sep	12:40	28.92	17.69
10-Sep	12:41	30.07	17.7
10-Sep	12:42	29.71	17.74
10-Sep	12:43	29.24	17.73
10-Sep	12:44	29.16	17.73

10-Sep	12:45	29.1	17.73
10-Sep	12:46	28.99	17.7
10-Sep	12:47	29.06	17.75
10-Sep	12:48	28.98	17.75
10-Sep	12:49	29.01	17.72
10-Sep	12:50	29.15	17.71
10-Sep	12:51	29.29	17.69
10-Sep	12:52	29.44	17.71
10-Sep	12:53	29.49	17.66
10-Sep	12:54	29.68	17.67
10-Sep	12:55	29.64	17.68
10-Sep	12:56	29.47	17.71
10-Sep	12:57	29.45	17.75
10-Sep	12:58	29.35	17.74
10-Sep	12:59	29.29	17.72

Average concentration	19.0	18.8
Bias Correction		
zero initial (Zi)	0.18	0.00
zero final (Zf)	0.38	0.00
span initial (Si)	53.72	18.01
span final (Sf)	54.26	17.97
Actual Conc. (Cma)	54.81	18.05
Corrected value	**19.1**	**18.9**

Corrected value = (**Average Concentration**-(@avg(Zi,Zf))) x Cma
/ (@avg(Si,Sf)-@avg(Zi,Zf))

STATION: Indian River			2013 NOx Testing											9/10/2013		
Parameter	Value	Response	Cal Error	Bias, Start R1		Bias, End R1		Bias, End R3		Bias, End R3						
Oxygen	20.9	20.97	0.4%													
	18.05	18.14	0.5%	17.99		18.02		18.01		17.97						**Upscale**
	9.976	10.04	0.4%													
	0.00	0.00	0.0%	-0.01		-0.01		0.0		0.0						**Low Level**
	Span: Bias | Drift			0.8%		0.7%	0.2%	0.7%	0.1%	0.9%	0.2%					
Range: 0 - 18.02	Zero: Bias | Drift			0.1%		0.1%	0.0%	0.1%	0.1%	0.1%	0.0%					
NOx	103.5	105	1.4%													
	54.81	54.56	0.2%	53.9		54.04		53.72		54.26						**Upscale**
	0.00	-0.05	0.0%	0.30		0.31		0.18		0.38						**Low Level**
	Span: Bias | Drift			0.6%		0.5%	0.1%	0.8%	0.3%	0.3%	0.5%					
Range: 0 - 103.5	Zero: Bias | Drift			0.3%		0.3%	0.0%	0.1%	0.1%	0.1%	0.2%					
Run No.						R1		R2		R3						
Time:				9:23		9:33	10:36	10:47	11:48	11:58	12:59					

Converter Efficiency Test

Date	**09/10/13**	Highest Stable Peak	**49.78**	ppm
Time	**07:39**	Expected Value	**51.14**	ppm
Cylinder	**D41651**			

Converter Efficiency **97.3%** **PASS** (Limit 90%)

Appendix

B

APPENDIX B PROCESS DATA

Indian River Generating Station
IR 10 NOx compliance test

Time	Tank Level	Pump Pressure	TT2 Temperature	TT7 Temperature	Generator	Fuel Flow	Water Flow
	Inches	psi	Degrees F	Degrees F	MW	gpm	gpm
9:40	139	545	75	1021	16.2	28	14.7
9:50	136	545	75	1021	16.1	28	14.6
10:00	132	543	77	1021	16	27.9	14.6
10:10	128	544	79	1020	16.1	27.9	14.6
10:20	123	543	79	1021	16	27.7	14.5
10:30	125	541	79	1021	16	27.7	14.5
Test Run 1 Average:	***131***	***544***	***77***	***1021***	***16.1***	***27.9***	***14.6***
10:50	157	541	81	1021	15.8	27.7	14.5
11:00	164	542	81	1021	15.9	27.7	14.5
11:10	156	540	81	1020	15.9	27.7	14.5
11:20	153	538	82	1024	15.9	27.7	14.5
11:30	148	540	82	1023	15.6	27.4	14.3
11:40	142	540	82	1020	15.8	27.5	14.4
11:50	140	537	82	1022	15.7	27.5	14.4
Test Run 2 Average:	***151***	***540***	***82***	***1022***	***15.8***	***27.6***	***14.4***
12:10	132	539	84	1021	15.6	27.5	14.3
12:20	128	540	84	1020	15.6	27.4	14.3
12:30	121	537	84	1021	15.5	27.3	14.3
12:40	123	540	84	1020	15.7	27.4	14.4
12:50	142	538	84	1020	15.6	27.4	14.4
13:00	155	534	84	1023	15.4	27.3	14.2
Test Run 3 Average:	***134***	***538***	***84***	***1021***	***15.6***	***27.4***	***14.3***

Appendix

C

APPENDIX C HANDWRITTEN LOGS

STATION: Indian River CT 10 DATE: September 10, 2013

Parameter	Value	CAL	R1 Start BIAS	END R1	END R2	END R3
NO_x	103.5	105.0				
	54.81	54.56	53.9	54.04	53.72	54.26
	* 51.14	49.78				
Range:	Zero	-0.05	0.30	0.31	0.18	0.38
O_2	18.05	18.14	17.99	18.02	18.01	1797
	9.976	10.04				
	20.9 Ambient	20.97				
Range:	Zero	-0.01	-0.01	-0.01	0.00	0.00
Range:						
Range:			923			
Run No.			1		2	3
Time:		0713	0933-1036		1047-1148	1158-1259

Notes: High NO_x: CC27117 High O_2: XC016255B * NO_2: D41651

Mid NO_x: SG882929 Mid O_2: CC273660

PREPARED BY SCS
DATE 9-10-13

IR 10 NOx TEST

Begin CAL @ 713
Conv. Check Stable @ 0737 ≃ 738

Response time test - 6.5 lpm Sample Flow RATE

	NOx	O_2	
855:00	26.15	18.03	STACK to Zero O_2 / Span NOx
855:30	25.09	2.82	
856:00	52.98	0.05	← 95% change 1min
856:30	53.28	0.00	
857:00	53.09	0.00	
857:30	53.14	0.00	
858:00	53.22	0.00	
859:00	53.37	0.00	
859:30	53.44	0.00	
80900:00	53.45	0.00	
			STACK To
0903:00	26.54	17.79	SPAN O_2 / Zero NOx
0903:30	20.01	17.85	
0904:00	1.02	17.96	← 95% change 1min
0904:30	0.76	17.99	
0905:00	0.57	18.02	
0905:30	0.56	18.02	
0906:00	0.54	18.05	
0906:30	0.42	18.05	
0907:00	0.36	18.05	
0908:00	0.34	18.04	

→ START STRAT CHECK

PREPARED BY SCS

DATE 9-10-13

IR10 Con't

STRAT CHECK 83.3, 50%, 16.7%

Pt. 1 0910, 0911, 0912 (83.3%) = 105.0"

Pt. 2 0914, 0915, 0916 (50%) = 63.0"

Pt. 3 0917, 0918, 0919 (16.7% = 21.0"

Run 3 ports - 12 pts ~~per test~~ R1

A 1 933 - ~~938~~ 937 END

2 0938 - ~~0943~~ 0942 END

3 ~~0944~~ 0943 - 0947 END

4 0948 - 0952

B 1 0955 - 959

2 1000 - 1004

3 1005 - 1009

4 1010 - 1014

C 1 1017 - 21

2 22 - 26

3 27 - 31

4 32 - 36

Sample Runs 2 and 3 at 3 pt. Longline middle port:

Run 2: 1047 - 1106 pt. 1 1108 - 1127 pt. 2 1129 - 1148 pt. 3

Run 3: 1158 - 1217 pt. 3 1219 - 38 pt. 2 1240 - 1259

Appendix
D

APPENDIX D CALIBRATION GAS CERTIFICATES

Airgas

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Airgas Specialty Gases
600 Union Landing Road
Cinnaminson, NJ 08077
(856) 829-7878 Fax: (856) 829-6576
www.airgas.com

Part Number:	E03NI99E15AC0H6	Reference Number:	82-124341427-1
Cylinder Number:	SG882929	Cylinder Volume:	144 Cu.Ft.
Laboratory:	ASG - Riverton - NJ	Cylinder Pressure:	2015 PSIG
PGVP Number:	B52012	Valve Outlet:	660
Gas Code:	NC	Analysis Date:	Oct 29, 2012

Expiration Date: Oct 29, 2020

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty
CARBON MONOXIDE	55.00 PPM	55.43 PPM	G1	+/- 1% NIST Traceable
NITRIC OXIDE	55.00 PPM	54.81 PPM	G1	+/- 1% NIST Traceable
NITROGEN	Balance			
Total oxides of nitrogen		55.00 PPM		For Reference Only

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Expiration Date
NTRM	11060538	CC331935	101.2PPM NITRIC OXIDE/NITROGEN	Feb 16, 2017
NTRM	12060501	CC353893	49.53PPM CARBON MONOXIDE/NITROGEN	Dec 20, 2017

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 APW1100391 CO	FTIR	Oct 13, 2012
Nicolet 6700 APW1100391 NO	FTIR	Oct 20, 2012

Triad Data Available Upon Request

Permanent Notes:Shaun Stenlake

Notes:O2<0.05PPM LDL

Approved for Release

Airgas

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E03NI99E15A00L5	Reference Number:	82-124266532-1
Cylinder Number:	CC27112	Cylinder Volume:	144.4 CF
Laboratory:	ASG - Riverton - NJ	Cylinder Pressure:	2015 PSIG
PGVP Number:	B52011	Valve Outlet:	660
Gas Code:	CO,NO	Analysis Date:	Jun 02, 2011

Expiration Date: Jun 02, 2019

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty
NITRIC OXIDE	105.0 PPM	103.5 PPM	G1	+/- 1% NIST Traceable
CARBON MONOXIDE	115.0 PPM	115.9 PPM	G1	+/- 1% NIST Traceable
NITROGEN	Balance			
Total oxides of nitrogen		104.2 PPM		For Reference Only

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Expiration Date
NTRM	11060107	CC330497	248.4 PPM NITRIC OXIDE/NITROGEN	Jan 11, 2017
NTRM	09060511	CC280456	98.88 PPM CARBON MONOXIDE/NITROGEN	Feb 01, 2013
NTRM	09060515	CC280685	98.88 PPM CARBON MONOXIDE/NITROGEN	Feb 01, 2013

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 APW1100391 CO	FTIR	May 05, 2011
Nicolet 6700 APW1100391 NO	FTIR	May 16, 2011

Triad Data Available Upon Request

Notes:

Signature on file

Approved for Release

Airgas

Airgas Specialty Gases
600 Union Landing Road
Cinnaminson, NJ 08077
(856) 829-7878 Fax: (856) 829-6576
www.airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E02NI90E15AC006	Reference Number:	82-124380518-1
Cylinder Number:	CC273660	Cylinder Volume:	145.2 CF
Laboratory:	ASG - Riverton - NJ	Cylinder Pressure:	2015 PSIG
PGVP Number:	B52013	Valve Outlet:	590
Gas Code:	O2,BALN	Certification Date:	Jun 24, 2013

Expiration Date: Jun 24, 2021

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
OXYGEN	10.00 %	9.976 %	G1	+/- 0.4% NIST Traceable	06/24/2013
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	09060215	CC262427	9.961 % OXYGEN/NITROGEN	+/- 0.3%	Nov 08, 2018

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Siemens Oxymat 6E-O2-N1-M1-0603	Paramagnetic	Jun 21, 2013

Triad Data Available Upon Request

Permanent Notes:Shaun Stenlake

Notes:
NO <0.02ppmLDL
CO <0.03ppmLDL

Approved for Release

Airgas

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Airgas Specialty Gases
600 Union Landing Road
Cinnaminson, NJ 08077
(856) 829-7878 Fax: (856) 829-6576
www.airgas.com

Part Number:	E02NI82E15AC000	Reference Number:	82-124341424-1
Cylinder Number:	XC016255B	Cylinder Volume:	146 Cu.Ft.
Laboratory:	ASG - Riverton - NJ	Cylinder Pressure:	2015 PSIG
PGVP Number:	B52012	Valve Outlet:	590
Gas Code:	O2	Analysis Date:	Oct 22, 2012

Expiration Date: Oct 22, 2020

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty
OXYGEN	18.00 %	18.05 %	G1	+/- 1% NIST Traceable
NITROGEN	Balance			

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Expiration Date
NTRM	09061436	CC282500	22.53% OXYGEN/NITROGEN	Aug 01, 2013

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Siemens Oxymat 6E-O2-N1-M1-0603	Paramagnetic	Oct 15, 2012

Triad Data Available Upon Request

Permanent Notes:Shaun Stenlake

Notes:CO <0.03ppm LDL
NO <0.02ppm LDL

Approved for Release

Page 1 of 82-124341424-1

Airgas

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Airgas Specialty Gases
600 Union Landing Road
Cinnaminson, NJ 08077
(856) 829-7878 Fax: (856) 829-6576
www.airgas.com

Part Number:	E03NI97E33AC000	Reference Number:	82-124341425-1
Cylinder Number:	D41651	Cylinder Volume:	32 Cu.Ft.
Laboratory:	ASG - Riverton - NJ	Cylinder Pressure:	2216 PSIG
PGVP Number:	B52012	Valve Outlet:	660
Gas Code:	APPVD	Analysis Date:	Oct 31, 2012

Expiration Date: Oct 31, 2015

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a volume/volume basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty
NITROGEN DIOXIDE	50.00 PPM	51.14 PPM	G1	+/- 1% NIST Traceable
OXYGEN	2.000 %	2.010 %	G1	+/- 1% NIST Traceable
NITROGEN	Balance			

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Expiration Date
NTRM	09060117	CC262450	2.000% OXYGEN/NITROGEN	Jan 15, 2013
GMIS	124288126116	CC344710	59.90PPM NITROGEN DIOXIDE/NITROGEN	Jul 16, 2014

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Thermo 42i-HL-NOx-0627218610	Chemiluminescence	Oct 01, 2012
Siemens Oxymat 6E-O2-N1-M1-0603	Paramagnetic	Oct 15, 2012

Triad Data Available Upon Request

Permanent Notes: Shaun Stenlake

Notes:

Dana Mason

Approved for Release

Appendix

E

APPENDIX E EXAMPLE CALCULATIONS

Example Calculations

A. Bias Corrected Run Concentration

C gas = (C – Co) x (Cma / (Cm – Co))

C gas = Bias Corrected concentration
C = Average analyzer concentration
Co = Average of pre and post run zero calibration responses
Cm = Average of pre and post run upscale calibration responses
Cma = Expected upscale gas concentration

Example: C = 1118.5 ppm, Co = 0.048845 ppm, Cma = 1048 ppm, Cm = 1072 ppm

C gas = (1118.5 ppm-(-0.48845 ppm))x(1048 ppm/ (1072 ppm-(-0.48845 ppm))
C gas = 1093.438 ppm

B. Pollutant Concentration Corrected to Standard Oxygen

Ppm cor = Cgas x ((20.9–O2 std) / 20.9 – O2))

C gas = Bias corrected concentration
O2 std = Oxygen standard (%)
O2 = Average bias-corrected test run Oxygen (%)

Example: Cgas = 13.840 ppm, O2 std = 15%, O2 = 15.146 %

Ppm cor = 13.840 x ((20.9 – 15) / (20.9 – 15.146))
Ppm cor = 14.190 ppm

C. Fd Based Emission Rate (lb/MMBtu*)*

E = Cgas x MW x 2.595E-9 x Fd x (20.9 / (20.9 - %O2))

E = Emission rate in lb/MMBtu
MW = Pollutant molecular weight (wet lb/lb mole)
Fd = Oxygen based F factor (EPA RM19 in dscf/MMBtu)

Example: NOx=29.678 ppm, O2=15.146%, MW(NOx as NO2)=46 lb/lb mole
Fd = 8710 dscf/MMBtu (natural gas)

E = 29.678 x 46 x 2.595E-9 x 8710 x (20.9 / (20.9 – 15.146))
E = 0.112 lb/MMBtu

Appendix

F

APPENDIX F TEST PROTOCOL AND ACCEPTANCE LETTER

STATE OF DELAWARE
DEPARTMENT OF NATURAL RESOURCES
& ENVIRONMENTAL CONTROL
DIVISION OF AIR QUALITY
655 S. Bay Road, Suite 5N
DOVER, DELAWARE 19901

Telephone: (302) 739 - 9402
Fax No.: (302) 739 - 3106

June 20, 2013

NRG Energy
Indian River Generating Station
29416 Power Plant Road
Dagsboro, Delaware 19939

Attention: Paul Straub
Environmental Specialist

REGARDING: STACK TEST and PROTOCOL for a Combustion Turbine (IR 10)
Permit: <u>AQM-005/00001 (Renewal 2)</u>

Dear Mr. Straub:

<u>Emissions Test Protocol and Guidance</u>
The Department received the stack test protocol dated May 30, 2013 submitted by NRG Energy. The protocol for testing the Combustion Turbine (IR 10) for nitrogen oxides (NOx) at the Dagsboro Facility (Indian River Generating Station) has been reviewed.

The submitted test protocol is determined to be acceptable by the Department.

The testing shall be conducted in accordance with EPA Reference Methods. It is the responsibility of the tester to identify and list any exceptions to the methods in the protocol. All exceptions to the methods must be approved by the Department prior to the start of the test. Failure to comply with this requirement may result in a delayed or invalid test. There were no exceptions listed in the protocol.

<u>Stack Test Report</u>
Two hard copies of the full stack test report shall be submitted within 60 days of completion of the test as follows:

<u>Original to:</u>
Thomas I. Lilly, P.E.
Division of Air Quality
Blue Hen Corporate Center
655 S. Bay Road, Suite 5 N
Dover, DE 19901

<u>1 copy to:</u>
Edward Wm. Jackson
Engineering & Compliance Branch
Source Testing Group
715 Grantham Lane
New Castle, DE 19720

This full report shall include the stack tester report (including raw data from the test as given below) as well as a summary of the results.

<u>Report from Stack Testing Firm</u>
The operating and sampling data shall be recorded legibly in ink and copies of the raw data sheets shall be

submitted in the final test report. All raw analyzer data shall be included on a disk in an Excel format and submitted with the final test report. Raw data includes: 1-minute data points, run averages, instrument calibrations, system bias/calibration drift checks, chromatographs, and production rates.

Summary of Results and Statement of Compliance or Non-Compliance
The Company shall supplement the report from the stack testing firm with a summary of results that includes the following information:

- Statement that the Company has reviewed the report from the stack tester and agrees with the findings
- Permit number and condition(s)
- Summary of results for each permit condition
- Statement of compliance or non-compliance with each permit condition

Test Schedule
Testing shall be scheduled with Edward Wm. Jackson at (302)323-4542.

Thank you for your attention and cooperation with the above conditions. If you have any questions or concerns, please do not hesitate to contact me at (302)323-4542.

Sincerely,

Thomas I. Lilly

Thomas I. Lilly, P.E.
Engineer
Engineering & Compliance Branch

JLF:TIL
F:\EngAndCompliance\TIL\til13104.doc

pc: Edward Wm. Jackson
Joanna L. French, P.E.
Karen A. Mattio, P.E.
David Bacher
NRG Energy
James Sadowski
NRG Energy (Indian River Operations, Inc.)
Dover File

TEST PROTOCOL
Compliance Testing
NRG Energy, Inc.
Indian River Power Plant
Combustion Turbine Unit 10
Dagsboro, Delaware

Date test plan written or revised:	May 30, 2013
Revision:	1.0
Scheduled test date(s):	To Be Determined (prior to 3/6/14)

PART I. GENERAL INFORMATION

1. Name and address of emission facility:

NRG Energy, Inc.
Indian River Generating Station
29416 Power Plant Road
Dagsboro, Delaware 19939

2. Name, Telephone and Email of contact person at emission facility:

Mr. Paul Straub
Phone: 302-934-3683
paul.straub@nrgenergy.com

3. Reason for Testing:

Title V Permit Required NOx compliance test requirement.
(Title V Permit ID: AOM-005/00001-Renewal 2)

4. Physical description and location of emission unit to be tested:

The Indian River Generating Station is located in Dagsboro, Delaware. Combustion Turbine 10 is a simple cycle Pratt and Whitney FT4A-9 Turbo Jet Power Pak, firing #2 Fuel Oil only and utilizes water injection for NOx reduction purposes.

5. Name of Testing Company, contact person, telephone and facsimile number:

Shaun Stenlake
NRG Energy Services, Air Resources Test Team
(570) 897-2140
(570) 897-2110 Fax
shaun.stenlake@nrgenergy.com

PART II. TESTING REQUIREMENTS

1. Testing Description

Triplicate one hour test runs for NOx emissions at dry conditions will be conducted at the stack outlet while firing at 90% capacity or greater based on the ambient temperature for the test day. The unit will be operated in automatic water injection mode.

2. **The following table is a description of the Pollutants to be tested, the applicable emission limits, and the applicable regulations for each pollutant:**

Test Location	Number of Runs and Duration	Pollutant Tested/ Specific Method	Applicable Emission Limit	Applicable Regulation
Combustion Turbine 10 EU05, exhaust outlet	(3) 1-hour test runs	NOx ppmvd RM 7E RM 3A (O2 Only)	NOx Limit 88 ppmvd	Permit AOM-005/00001 Condition 3, Table 1 Section (d.3.i.A.)

3. **The following is a detailed description of the procedure for fuel sampling and analysis to be followed for the applicable emission limit.**

Fuel samples are not required for this compliance testing program, no fuel samples will be taken.

PART III. OPERATING CONDITIONS

1. **The following table contains a description of the emission unit(s) to be tested: Detailed descriptions of operating parameters listed that will determine production, operating capacity, and/or operating conditions during testing are also included:**

Process Description			
Emission Unit	**Plant Equipment Description**	**Process Rates/ Operating Conditions**	**Control Equipment Description**
Combustion Turbine 10 (EU05)	Pratt and Whitney FT4A-9, Turbo Jet Power Pak	Base Load, #2 Fuel Oil firing $\geq$ 90% of maximum capacity based on ambient temperatures	Water Injection

The following operation data will be collected during each test run

Gross MW Load, Water Injection Rate, Ambient Temperature, Exhaust Temperature, Fuel Flow

PART IV. TEST METHODS

1. The following is a description of the methods, number of test runs, length of test runs, and sampling volume of each pollutant:

A: Determination of Sample Points
Code of Federal Regulations, Title 40, Part 60, Appendix A, 3A, 7E

Stratification Test

NOx and O2 will be measured at sample points determined by RM 7E, section 8.2.1, while the unit is operating at base load conditions. Run 1 will consist of the stratification test, consisting of 3 points located in the middle test port at 16.7%, 50.0% and 83.3% of the measurement line. The average concentration will be calculated for each traverse point and compared to the average concentration of the three point stratification test. The conditions specified in RM 7E, section 8.1.2 will be applied to the results and Test Runs 2 and 3 will be sampled accordingly.

Stack Sampling Locations For Combustion Turbine #10:

The following dimensions will be field verified prior to the test event:

Length = 133.3 inches
Width/Depth = 126 inches

Test Points Run #1 = 3
Test Points Run #2 and #3 = to be determined from results of Run #1

Run #1 - Stratification Traverse Points Per Port (not including port depth)

1 – 21.0 inches
2 – 63.0 inches
3 – 105.0 inches

B: Continuous Emission Monitoring By Instrumentation
Code of Federal Regulations, Title 40, Part 60, App A, 3A, 7E

Sampling System

The stack sample is pulled from an unheated stainless steel probe to a heated Teflon line and into the combination condenser/ pump. The temperature of the sample is maintained above the dew point until the inlet of the condenser. The sample flowrate is controlled by a valve in the pump. Upon exiting the pump, the sample dew point is reduced to 40^{o} F. The sample is transported through a clean Teflon sample line to the flow controller in the test trailer. The flow controller, upon automated command from the data logger, directs a constant flow dry exhaust gas sample or calibration standards to the instrumentation for analysis. The measured concentrations are scanned once every second, digitally recorded and reduced to one minute averages by an ESC 8816 data logger. Data from the logger is electronically downloaded into the test summary computer program where the run averages and relative accuracy are calculated.

NO2 to NO Converter Efficiency Check (Pre Test)

Prior to the field test a NO2 to NO conversion efficiency test will be conducted in accordance with RM 7E, Section 8.2.4.

Calibration Procedure

Calibration of the system is accomplished by flowing reference gases either directly into the analyzers or through an automatic valve at the end of the sampling probe. All calibration gases used are EPA Protocol 1 gases. Multi-component gas mixtures are selected, when possible, to streamline the calibration procedure. Calibration gas is sampled in the same manner as the stack gas and the system response is recorded automatically without any adjustment to the measurement system.

Prior to conducting the RM test runs, a system response time check is conducted. Calibration durations and system recovery events are timed to allow at least two times the longest parameter response time to ensure adequate system transition equilibration.

The calibration sequence is initiated with a three (3) point linearity check injected directly into the analyzers by the flow controller. The level of each gas used conforms to the specific requirement of the respective RM. The system must pass the linearity check requirements of less than 2% of span deviation from expected for each parameter. Following the linearity check, a system bias test is conducted with low level gas and an upscale gas by flowing the gas through the entire gas sampling and conditioning system. The upscale gas is selected to most closely match the stack concentrations from the linearity check mid and high gases. The results must be within 5% of span from the linearity check results. Following each test run, the bias test is repeated. The difference in the pre to post-run bias check calibrations must be verified to be less than the allowable 3% of span per run drift limitation.

The average of each test run is corrected according to the results of the bias test calibrations immediately prior to and following each run. All measurements made by the system are on a dry basis. Measurements of stack gas moisture, when necessary, are accomplished using an independent modified RM 4 sampling train run at the sampling location. The bias and moisture corrected run averages are compared to the appropriate CEM averages in the calculation of relative accuracy.

Calculations

$$C_{gas} = \left(C - C_o \right) \frac{C_{ma}}{C_m - C_o}$$

C_{gas} = *Effluent gas concentration, dry basis, ppm*
C = *Average gas concentration indicated by gas analyzer, dry basis, ppm*
C_o = *Average initial & final system cal. bias check response for zero gas, ppm*
C_{ma} = *Actual concentration of upscale calibration gas, ppm*
C_m = *Average initial & final system cal bias check responses for upscale cal gas, ppm*

$$C_b = \frac{\left(C_s - C_l \right)}{S} * 100$$

C_b = *System calibration bias check, % of span*
C_s = *System analyzer calibration response, ppm*
C_l = *Local analyzer calibration response, ppm*
S = *Analyzer span range*

$$C_e = \frac{(C_l - C_a)}{S} * 100$$

C_e = *Analyzer calibration error check, % of span*
C_l = *Local analyzer calibration response, ppm*
C_a = *Actual concentration of calibration gas cylinder, ppm*

$$D = \frac{(C_{sf} - C_{si})}{S} * 100$$

D = *Analyzer drift, % of span*
C_{sf} = *Final system analyzer calibration response, ppm*
C_{si} = *Initial system analyzer calibration response, ppm*
S = *Analyzer span range*

PART V. TEST SCHEDULE

The NOx compliance test schedule is to be determined. The exact test dates and times will be determined based on dispatch of the Unit. In accordance with the Title V permit, the testing must be completed prior to 3/6/14.

PART VI. REPORT SUBMITTAL

Hardcopies of the results will be submitted within 60 days of testing is completed. Electronic copies are also available and can be provided in addition to the hard copies or in lieu of hard copies.

----END OF REPORT----

Information Request Letter from The Delaware Division of Air Quality to NRG – Indian River
October 18, 2021

From:	Held, Renae (DNREC)
To:	Bacher, David
Subject:	Regional Haze Info Request - NRG response. Clarification questions about Unit 5/10
Date:	Monday, October 18, 2021 12:12:06 PM
Attachments:	image001.png NRG -- Indian River--1st RH response.doc NRG -- Indian River --2nd RH response.pdf
Importance:	High

David,

I have a few clarification questions on NRG's two responses for the Regional Haze Information Request for Indian River.

Annual Water Injection

- Regarding cost estimates for the *annual* operation of Water Injection Indian River, for Unit 5/10. How specifically did NRG calculate/estimate the cost for conversion to year-round water injection (new building, tanks, heat tracing, etc.)?
    - NRG says on page 2 of the attached letter "NRG – Indian River—1st RH response" (excerpt below), that it's "not based on actual contracts or bidder solicitation". Please provide more detailed information about how you arrived at the cost estimate of $205,200 – what is this estimate based on?

-

1st NRG Response

"Analysis

1. Cost of Compliance

Indian River conducted an evaluation to modify the current system for annual operation, specifically to utilize water injection. The initial cost is based on converting the water system for winter operation which required constructing a stand alone building for water injection system, new water tanks, transformers and electrical system modifications, heat tracing, heating systems, piping, foundation work, and control system modifications. The current estimate for this conversion is $205,200 however not based on actual contracts or bidder solicitation. Using this value and a high CF value such as 2018 at 61hours and a 25% reduction from the 4.28 tons emitted in 2018 (based on 50/50 summer winter operations and a 50% emissions reduction in winter), this equates to $192,000 per ton. However, a more realistic evaluation would be based on our average at 28 hours, this equates to $418 per ton. Data from 2016 and 2017 equates to about $2M per ton note the annual emissions would be around .5 tons or less and the reduction only 0.12 tons)."

-

April and Oct Water Injection

- Regarding the evaluation of extending water injection into *April and October*, for Unit 5/10. NRG said on page 2 of the attached letter "NRG – Indian River—2nd RH response", that the cost to extend into these seasons would be $10,000.

- Is this a flat rental cost, water usage costs, or a combination of the two?
- What is the basis for the cost estimation of $10,000 – existing rental/water usage costs, bid solicitation?
- Is this amount for both April and October or per month? What would the total estimate cost be per year to add April and October?

2nd NRG Response

"3. Technical Feasibility and Cost for extending use to include April and October – In regard to capital expenditures there would be no additional costs associated with expanding water injection operations to include April and October. However, because the demineralized water is required and the water source is rented, adding operations in April and October would result in an added expense in the range of $10,000."

Please let me know if you have any questions or would like to discuss.

Thanks,
Renae

Renae Held
Program Manager II
Airshed Planning & Inventory Program
Delaware Department of Natural Resources and Environmental Control
Division of Air Quality
100 W. Water Street, Suite 6A Dover, DE 19904
Phone: (302) 739-9402
Email: renae.held@delaware.gov

Information Request Response for NRG – Indian River

November 1, 2021

David Bacher
Indian River Power LLC
29416 Power Plant Road
Dagsboro, Delaware 19939

An NRG Energy Company

November 1, 2021

Renae Held
Environmental Scientist
Airshed Planning & Inventory Program
Delaware Division of Air Quality
100 Water Street
Dover, Delaware 19904

RE: Regional Haze Inquiry

Ms. Held,

I am writing in response to your inquiry of October 18, 2021 regarding our submittal of June 19, 2019 and July 21, 2021 in regard to Delaware's Regional Haze State Implementation Plan and pending amendments, in association with the Indian River Generating Station, Emission Unit 5, Indian River Unit 10 (IR10). We appreciate Delaware's commitment to Regional Haze and it partnership with the Mid Atlantic North East Visibility Union (MANE-VU) to collectively develop regional emission control strategies to address visibility impairment in Class 1 areas.

The restate the MANE-VU goals, the initiative is based on achieving reasonable progress goals by 2028 and participating states are asked to evaluate potential from qualified emission sources for reductions that can be quantified within a SIP revision. The initiative targets units 25MW or greater seeking operation near 25ppm at 15% O2 for natural gas and 42ppm at 15% O2 for distillate fuel and a request that each state adopt an ultra low sulfur in fuel content standard. Further states are requested to complete a four factor analysis to evaluate reduction potential, specifically for units 15 MW or more that operate equivalent to a 20% or less capacity factor or 1752 hours per year during 2014 to 2016. The analysis was submitted in our June 19, 2021 submittal, which at your request was a five factor analysis.

Unit 10 Combustion Turbine
Indian River Unit 10 (Regulation 30 Unit 5) is a 366 MMBTU/hr Turbo-Jet Pratt & Whitney FT4-9LF combustion turbine installed in 1967 that operates on distillate fuel (the -9 refers to the internal cooling of the engine turbine nozzle vanes, LF refers to a liquid fueled engine) equipped with a fuel manifold and Delavan Fuel nozzles for Water Injection. The unit has a summer rating of 17MW and a winter rating of 21MW. The unit was designed for black start capability and to serve as a critical resource and peaking unit available to the facility and the Independent System Operator (ISO) for reliability reasons, however over the past 10 years the unit has operated for an average of 28 hours per year which is comparable to a capacity factor of 0.32% annually. In 2009 the unit was equipped with water injection to comply with an 88ppm NOx

emission limit during the Ozone Season and achieved an average of 52.8ppm, verified by stack testing. In addition, the facility has taken action to further reduce NOx emissions including cleaning and tuning of other components of the fuel system and improving the control logic for water injection. As a result, our emission profile has improved based on stack testing with a reduction from 2009 at 52.8 ppm and 2013 at 56.8 ppm to 22.8 ppm in 2018, better than a 50% reduction in performance and most important**, our previous emission test in 2018 yielded an average of 22.77ppm which is 45% less than the maximum MANE-VU target of 42 ppm.**.

In addition, as a facility, Indian River has already supported this initiative with the retirement of three coal fired units (91MW, 91MW, and 165MW) and our AQCS project to significantly reduce SO_2, NOx, Hg, and PM emissions, an investment of almost $400M in Delaware and in our air quality.

October 18, 2021 DNREC Inquiry

Inquiry 1 – Please provide more information on how we arrived at a cost estimate of $205,000.

Reply – In our Five Factor Analysis, w provided the following statement.

> ***Cost of Compliance -*** *Indian River conducted an evaluation to modify the current system for annual operation, specifically to utilize water injection. The initial cost is based on converting the water system for winter operation which required constructing a stand alone building for water injection system, new water tanks, transformers and electrical system modifications, heat tracing, heating systems, piping, foundation work, and control system modifications.* ***The current estimate for this conversion is $205,200 however not based on actual contracts or bidder solicitation.***

The cost estimate was based on a project costs developed by a regional engineer who was evaluating a similar project in another region. As noted, we did not develop a specific scope of work or solicit bids which would be a was of time and cost for the facility and unfair to bidders in the most probable event the project would not go forward. The engineer took the list of items required and applied institutional knowledge (from other projects) to develop the cost estimate and provided me the cost estimate to use for this evaluation and to use to develop a capital project if required. I do not have the record of the cost evaluation and unfortunately the engineer has left the company. Please note, even if the project costs were half of the estimated value or even less, the project would not be justified based on the limited use of the unit or its contribution to reducing regional haze.

Inquiry 2 – Clarifying information on extending operations to April and October.

Reply – The cost estimate of $10,000 is based on previous rentals for demineralized water trailers used at the facility during the ozone season and represents a cost for the two additional months, meaning up to $5,000 per month. However, the facility does not anticipate the Unit to be called for system reliability in these months and would not schedule a required stack test at this time as well, meaning these costs are not justified. Further as previously noted, without the assurance of freeze protection, we believe it would put the unit at risk from the possibility of freezing weather which can occur in April and October.

After your review, please feel free to contact me on (302) 540-0327 or by E-Mail on david.bacher@nrgenergy.com.

Respectfully submitted,

David Bacher
Regional Manager, NRG Environmental Business

CC:	D. Fees	(DNREC)
	A. Carter	(Indian River)
	D. Burton	(Indian River)

Information Request Letter from The Delaware Division of Air Quality to City of Dover – VanSant

April 30, 2019

STATE OF DELAWARE
DEPARTMENT OF NATURAL RESOURCES
& ENVIRONMENTAL CONTROL
DIVISION OF AIR QUALITY
100 W. Water Street
DOVER, DELAWARE 19904

Telephone: (302) 739 - 9402
Fax No.: (302) 739 - 3106

April 30, 2019

Donna Mitchell
City Manager
City of Dover
P.O. Box 475 Delaware 19903-0475

Certified Mail # 7018 2290 0002 1278 0342
RETURN RECEIPT REQUIRED

Subject: Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule

Dear Ms. Mitchell:

The federal Clean Air Act (CAA) and Regional Haze Rule (40 CFR 51.308 (f)(2)(i) through (iv)) requires States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment. Under the Regional Haze Rule, States are required to develop a series of state implementation plans (SIP) to address visibility impairment in Class I areas and progress made toward achieving natural visibility conditions.

As part of its Regional Haze SIP, Delaware must consider emission reductions measures identified by Class I states as being necessary to make reasonable progress in any Class I area. Delaware is part of the Mid-Atlantic Northeast Visibility Union (MANE-VU), a regional planning organization in which member states work collaboratively to develop emission control strategies to address visibility impairment in Class I areas.

MANE-VU proposed six (6) emission management strategies (Asks) in order to meet the 2028 reasonable progress goal for regional haze (Attachment 1). While many of the strategies are directed at states to adopt, there are some strategies that required input from the City of Dover. Therefore, the Delaware Department of Natural Resources and Environmental Control (DNREC) is requesting information regarding an emission unit that meets the applicability criteria for one of the MANE-VU Asks: Ask # 5 – NOx Emission Limits for Peaking Combustion Turbines[1].

[1] For the purposes of the MANE-VU Ask, a peaking combustion turbine is defined as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016.

DNREC requests that City of Dover submit the following information for the VanSant Generating Station (VanSant) by June 14, 2019:

Unit 1

VanSant operates a combustion gas turbine (Unit 1) which uses a Water Injection system as a NOx control device. Unit 1 combusts natural gas as a primary fuel and distillate fuel oil as a secondary fuel. This Unit has been identified as a peaking combustion turbine that does not have stringent enough NOx limits, as compared to the year-round limits set forth in MANE-VU's Ask # 5 (Attachment 1). Therefore, DNREC requests that the City of Dover perform a Four-Factor Analysis for reasonable installation or upgrade to year-round NOx emission controls for the Unit[2]. A Four-Factor Analysis takes into consideration:

1) Cost of compliance[3];
2) Time necessary for compliance;
3) Energy and non-air quality environmental impacts of compliance; and
4) Remaining useful life of any potentially affected sources. (40 CFR 51.308(f)(2)(i))

Thank you in advance for your cooperation. If you have any questions or wish to further discuss this request, please contact Renae Held of the Division of Air Quality at (302) 739-9402 or renae.held@delaware.gov.

Sincerely,

David Fees

David F. Fees, P.E.
Director
Division of Air Quality

Cc: James S. Robinson, Electric Director, City of Dover

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[2] DNREC requests that City of Dover perform a four-factor analysis for installation or upgrade to year-round NOx controls necessary to meet both of the proposed emission limits listed in Ask #5: 42ppm at 15% O_2 for fuel oil and 25 ppm at 15% O_2 for natural gas.

[3] EPA's Control Cost Manual is a potential resource for determining the cost of compliance, it provides guidance for the development of accurate and consistent costs for air pollution control devices. https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. Fish and Wildlife Service
U.S. Forest Service

MANE-VU Class I Areas
ACADIA NATIONAL PARK ME
BRIGANTINE WILDERNESS NJ
GREAT GULF WILDERNESS NH
LYE BROOK WILDERNESS VT
MOOSEHORN WILDERNESS ME
PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH
ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

Mid-Atlantic/Northeast Visibility Union

MANE-VU

Reducing Regional Haze for Improved Visibility and Health

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION WITHIN MANE-VU TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP. This Ask by the MANE-VU Class I states, was developed through a collaborative process with all of the MANE-VU states. It is designed to identify reasonable emission reduction strategies which must be addressed by the states and tribal nations of MANE-VU through their regional haze SIP updates. This Ask has been developed and presented at this time so that SIPs may be developed and submitted between July of 2018 and July of 2021.

In addressing the emission reduction strategies in the Ask, the MANE-VU states will need to harmonize any activity on the strategies in the Ask with other federal or state

requirements that affect the sources and pollutants covered by the Ask. These federal and state requirements include, but are not limited to:

- The 2010 SO_2 standard,
- The Regional Greenhouse Gas Initiative (RGGI), if applicable,
- The Mercury and Air Toxics Standards (MATS), and
- The new 2015 ozone standard.

Because of this need for cross-program harmonization and because of the formal public process required by the federal CAA and state rulemaking processes, it is expected that there will be opportunities for stakeholders and the public to comment on how states intend to address the measures in the Ask.

Many of the MANE-VU states are also members of RGGI. RGGI is a market based cap-and-invest program designed to cost effectively reduce greenhouse gas emissions from the energy sector while returning value to rate-payers. One of the co-benefits of RGGI is that it will also significantly reduce SO_2 and NOx emissions, the two most important haze precursors. Because of this, the RGGI states, regionally, will likely achieve greater emission reductions than those envisioned in this Ask.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

Therefore, the course of action for pursuing the adoption and implementation of measures necessary to meet the 2028 reasonable progress goal for regional haze include the following "emission management" strategies:

1. Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or SO_2 controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;
2. Emission sources modeled by MANE-VU that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution

analyses (see attached listing) - perform a four-factor analysis for reasonable installation or upgrade to emission controls;

3. Each MANE-VU State that has not yet fully adopted an ultra-low sulfur fuel oil standard as requested by MANE-VU in 2007 - pursue this standard as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:
    a. distillate oil to 0.0015% sulfur by weight (15 ppm),
    b. #4 residual oil within a range of 0.25 to 0.5% sulfur by weight,
    c. #6 residual oil within a range of 0.3 to 0.5% sulfur by weight.
4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels – pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;
5. Where emission rules have not been adopted, control NOx emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:
    a. Striving to meet NOx emissions standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NOx emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or
    b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or
    c. Obtaining equivalent alternative emission reductions on high electric demand days.

High electric demand days are days when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet. Peaking combustion turbine is defined for the purposes of this "Ask" as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016;

(Note: SO_2 emissions for fuel oil units are addressed with Ask item 3.a. above)

6. Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 control measures.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

Listing of emission units that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area using actual 2015 emissions for EGUs and 2011 for other emission sources). The complete contribution analyses report is available at http://www.otcair.org/manevu.

State	Facility Name	Facility/ ORIS ID	Unit IDs	Max Extinction
MA	Brayton Point	1619	4	4.3
MA	Canal Station	1599	1	3.0
MD	Herbert A Wagner	1554	3	3.8
MD	Luke Paper Company	7763811	001-0011-3-0018	6.0
MD	Luke Paper Company	7763811	001-0011-3-0019	5.9
ME	The Jackson Laboratory	7945211	7945211	10.2
ME	William F Wyman	1507	4	5.6
ME	Woodland Pulp LLC	5974211		7.5
NH	Merrimack	2364	2	3.3
NJ	B L England	2378	2,3	5.6
NY	Finch Paper LLC	8325211	12	5.9
NY	Lafarge Building Materials Inc	8105211	43101	8.1
PA	Brunner Island	3140	1,2	4.0
PA	Brunner Island	3140	3	3.8
PA	Homer City	3122	1	9.3
PA	Homer City	3122	2	8.1
PA	Homer City	3122	3	3.3
PA	Keystone	3136	1	3.2
PA	Keystone	3136	2	3.1
PA	Montour	3149	1	4.4
PA	Montour	3149	2	4.1
PA	Shawville	3131	3,4	3.6

Information Request Response for City of Dover – VanSant

June 14, 2019

City of Dover

June 14, 2019

Mr. David F. Fees, PE
Director – Division of Air Quality
Delaware Department of Natural Resources & Environmental Control
100 West Water Street
Dover, DE 19904

Re: Response to Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule
City of Dover, Delaware

Dear Mr. Fees,

Per Delaware Department of Natural Resources & Environmental Control (DNREC) request for information letter dated April 30, 2019, please find attached an analysis completed by ALL4, LLC (ALL4). As requested, this report provides a Four-Factor Analysis for reasonable installations or upgrades to year-round nitrogen oxides (NOx) emission controls at the City of Dover's simple-cycle combustion turbine (Unit 11, referred to as Unit 1 in DNREC letter) located at the VanSant Generating Station.

If you have any questions regarding this submittal, please to contact me at (302) 736-7088.

Sincerely,

James S. Robinson
City of Dover Electric Director
jrobinson@dover.de.us
(302) 736-7088

June 14, 2019

ALL4

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James Robinson
Electric Director
City of Dover
P.O. Box 475
Dover, DE 19903-0475

RE: Response to Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule City of Dover, Delaware

Dear Mr. Robinson:

ALL4 LLC (ALL4), on behalf of City of Dover, hereby submits this letter in response to the Delaware Department of Natural Resources & Environmental Control (DNREC) Request for Information letter dated April 30, 2019 (Attachment A). The DNREC letter requested a Four-Factor Analysis for reasonable installation or upgrade to year-round nitrogen oxides (NO_X) emissions controls be conducted on the City of Dover's simple-cycle combustion turbine (Unit 11, referred to as Unit 1 in the letter from DNREC) located at the VanSant Generating Station, that examines the following:

1. Cost of compliance
2. Time necessary for compliance
3. Energy and non-air quality environmental impacts of compliance
4. Remaining useful life of any potentially affected sources

Unit 11 is a simple-cycle combustion turbine (CT) with a peak capacity of 44 megawatt (MW), and a current projected lifespan through 2041. Currently the CT utilizes water-injection to control NO_X emissions. Additionally, the unit can utilize inlet fogging to increase performance and power output. This modification, along with the associated air permit modification, was completed in 2017. An analysis is provided below that considered technically feasible additional or upgraded NO_X emissions control technologies. It was concluded that the cost of additional NO_X controls on the CT are not economically feasible to reduce the emissions of NO_X to meet the Mid-Atlantic Northeast Visibility Union (MANE-VU) Emissions Management Strategy goals [i.e., 25 parts per million (ppm) NO_X at 15% oxygen (O_2) when firing natural gas and 42 ppm NO_X at 15% O_2 while firing fuel oil]. The CT is already achieving the minimum MANE-VU emissions standards of 42 ppm NO_X at 15% O_2 when firing natural gas and 96 ppm NO_X at 15% O_2 while firing fuel oil.

Unit 11 is a peaking unit, meaning the unit generally operates only when there is a high demand for electricity. Over the past 10 years, the maximum annual operation time for the unit was 233 hours, resulting in less than 10 tons per year (tpy) of actual NO_X emissions.

Therefore, the potential for significant reductions of NO_X emissions from this unit is limited.

Technically Infeasible Technologies

There are several NO_X reduction technologies that are technically infeasible and were not considered as part of this Four-Factor Analysis including XONON™ Catalytic Combustor, regenerative selective catalytic reduction (RSCR), and EMx™ Catalytic Absorption/Oxidation. These technically infeasible control technologies and the basis for infeasibility are described below.

XONON™ Catalytic Combustor

Although developments to the XONON™ control technology are underway for natural gas CTs, such that it may become effective in gas CTs in the 1-1.4 MW range, this technology has not yet become available for application to larger CTs. In addition, fitting the CT with this technology would likely require a complete redesign of the burner system and combustion chamber. Based upon a review of the Reasonable Available Control Technology (RACT), Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) search results, existing permits for similar simple-cycle CT projects, CT vendor information and technical literature, XONON™ control technology has not been applied over the last 10 years for NO_X control. The current XONON™ catalytic combustor system has not been used on larger (i.e., greater than 1.4 MW) simple-cycle CT and therefore, it is not considered technically feasible.

Regenerative Selective Catalytic Reduction

RSCR is a technology developed by Babcock Power Inc. RSCR combines a selective catalytic reduction (SCR) system with regenerative thermal oxidizer (RTO) technology. Operation of an RSCR system involves high thermal efficiency heat recovery technology. The flue gas in an RCSR system must be in the temperature range between 350 degrees Fahrenheit (°F) and 650°F in order to be optimum for the chemical reaction to take place. Because the CT exhaust gas temperature is higher than the optimum temperature range at about 1,000°F, a cooling system would need to be installed as well. Based upon a review of the RBLC search results RSCR control technology has not been applied over the last 10 years for NO_X control on CTs. For these reasons, this technology is not feasible.

EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)

While EMx™ catalyst technology may have the potential to reduce NO_X emissions below the proposed limit, it is not feasible to install on the CT. According to the Utah Division of Air Quality, EMx™ systems have been demonstrated commercially in five applications, none of which have been simple cycle CTs[1]. Additionally, the optimal operating

[1] Utah Division of Air Quality, *$PM_{2.5}$ SIP Evaluation Report: Utah Municipal Power Association – West Valley Power Plant*. July 1, 2018. https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2018-006862.pdf

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temperature range of the EMx^{TM} technology is 300°F to 700°F, which is much lower than the pre-control temperature range of the CT's exhaust and the use of hydrogen for regeneration poses a serious safety concern due to the risk of explosion. Because of these reasons in addition to Unit 11 being a simple cycle CT, this technology for NO_X control is not considered technically feasible.

Technically Feasible Control Technologies

The technically feasible NO_X control options considered in this analysis are described below using the Four-Factor Analysis. The estimated time of compliance for equipping the CT with any of the control technologies would be approximately 16 to18 months.

Water or Steam Injection

Water or steam injection is a front-end NO_X control technology. The addition of an inert diluent, such as water or steam, into the high temperature region of the CT flame controls NO_X formation by quenching peak flame temperatures. Increasing the water-to-fuel ratio employed with this technique increases the control of NO_X emissions. However, flame instability occurs when the water-to-fuel ratio becomes too high and emissions of carbon monoxide (CO) and volatile organic compounds (VOC) increase due to incomplete combustion.

Economic Impacts

The CT is currently equipped with a water injection system, along with an inlet fogging system. The inlet fogging system injects de-ionized (DI) treated water into the incoming combustion air to cool the combustion air. With the addition of the water, the air becomes denser, which permits additional air input, and thus improves the performance and power being generated by the CT. The water injection for fogging adds additional loading onto the facility's DI water treatment system. The facility installed and made necessary permit changes for the fogging system back in 2017. The existing combustion water injection system has the capability to inject additional water (injection pumps rated for 70 gallons/minute) to further reduce NO_X emissions. Based on preliminary information from General Electric (GE), the maximum water injection rate that the CT could handle would be required to obtain additional NO_X reduction. It is unknown if this additional water injection will result in sufficient NO_X reduction to meet the MAINE-VU emissions standards. However, a control cost evaluation was performed and demonstrates that even if additional water injection provided enough NO_X reduction to meet the MAINE-VU emissions, the added cost is economically infeasible. Based on DI treated water being used for fogging, along with the current usage for water injection, the facility would have to upgrade the DI water treatment system, including additional tank installation, to meet the additional water usage demand. The total capital investment for this upgrade, including additional tanks, is approximately $1,355,000. A control cost analysis for increasing the water injection rate and an upgrade to the DI system was developed in accordance with Section 4, Chapter 3 of the Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual. The results of the control cost analysis demonstrate that

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at \$334,897 per ton of NO_X removed, it is not cost effective to increase the water injection rate to the Unit 11 CT. The control cost analysis is included in Attachment B.

Energy and Environmental Impacts
An upgrade to the water injection system would require the use of approximately 170,000 gallons of additional DI water per year. This additional water consumption is a mitigating environmental impact for the consideration of a larger water injection system. Also, indirect emissions would result from the electricity required to supply the DI system.

Dry Low-NO_X Combustion

Dry low-NO_X (DLN) combustion is a front-end NO_X control technology. DLN systems limit peak flame temperature and excess O_2 with lean, pre-mix flames that achieve NO_X control equal to or better than water or steam injection. Some vendors offer this control technology on advanced heavy-duty industrial CT units.

Economic Impacts
The total capital investment of retrofitting the CT with DLN combustion would be \$3,473,000. A control cost analysis for the retrofit of a DLN system on the CT was developed in accordance with Section 1, Chapter 2 of the OAQPS Air Pollution Control Cost Manual. The results of the control cost analysis demonstrate that at \$161,920 per ton of NO_X removed, it is not cost effective to retrofit the Unit 11 CT with DLN combustion technology. The control cost analysis is included in Attachment B.

Energy and Environmental Impacts
There is no expected energy or environmental impacts associated with the use of this technology.

Selective Catalytic Reduction

SCR is a "back end" control technology used to convert NO_X into diatomic nitrogen (N_2) and water using a catalyst. The reduction reactions used by SCR require oxygen (O_2), thus it is most effective at exhaust O_2 levels above 2-3%. The optimum temperature range for SCR is between 480°F and 800°F, which is lower than the CT's exhaust gas temperature. Base metals such as vanadium or titanium as well as zeolites are often used for the catalyst due to their effectiveness as a control technology for NO_X and cost-effectiveness for use with natural gas combustion. In addition, a gaseous reductant such as anhydrous ammonia or aqueous ammonia [$NH_{3(aq)}$] is added to the exhaust gas and absorbed onto the catalyst.

Economic Impacts
The total capital investment of retrofitting the CT with SCR is approximately \$5,875,572. A control cost analysis for the retrofit of an SCR system was developed in accordance with Section 4.2, Chapter 2 of the OAQPS Air Pollution Control Cost Manual. The results of the control cost analysis demonstrate that at \$155,431 per ton of NO_X removed, it is not cost effective to retrofit Unit 11 CT with SCR control technology. The control cost analysis is included in Attachment B.

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Energy and Environmental Impacts
The energy and environmental impacts associated with SCR include the transport, handling, and use of aqueous ammonia, a corrosive hazardous material. In addition, the use of SCR results in ammonia emissions through what is known as "ammonia slip". Ammonia poses a potential exposure health and safety risk. The spent catalyst from the SCR would be required to be periodically replaced and disposed of, creating residual waste that would need to be landfilled.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is a post-combustion control technology for NO_X emissions that uses a reduction-oxidation reaction to convert NO_X into N_2, water (H_2O), and carbon dioxide (CO_2). Like SCR, SNCR involves injecting ammonia (or urea) into the exhaust gas stream, which must be between approximately 1,400 and 2,000°F for the chemical reaction to occur. SNCR is more economically desirable because a catalyst is not required and, in theory, SNCR can control NO_X emissions with an efficiency similar to that of SCR (i.e., 90%). However, operating constraints on temperature, reaction time, and mixing often lead to less effective results when using SNCR in practice.

Because SNCR requires a temperature window that must be between approximately 1,400°F and 2,000°F, which is higher than the exhaust temperatures from natural gas-fired CT, the flue gas would need to be heated to be within that range. The supplemental heating system would rely on additional natural gas combustion thereby increasing emissions of products of combustion (POC) from the system.

Economic Impacts
The cost heating the flue gas from the CT to the proper range for SNCR would be $340,857 annually. A control cost analysis was conducted for only the heating of the flue gas, thus additional costs would result from fitting the CT with a SNCR system. The results of the control cost analysis demonstrate that the annual costs for the heating the flue gas are $100,784 per ton of NO_X removed from Unit 11. While the use of SNCR is technically feasible, this cost control analysis has demonstrated that it is not economically feasible for the CT. The control cost analysis is included in Attachment B.

Energy and Environmental Impacts
The environmental and energy impacts associated with SNCR include the transport, handling, and use of aqueous ammonia, a corrosive hazardous material. In addition, the use of SNCR results in ammonia emissions through what is known as "ammonia slip". Ammonia poses a potential exposure health and safety risk. Also, the increased use of natural gas for heating would result in additional POC emissions.

Conclusion

In consideration of the technical and economic feasibility of the various control technologies evaluated herein, City of Dover proposes to continue to use the existing water

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injection system and to continue to use good operating practices to minimize NO_X emissions below the minimum MANE-VU emissions standards of 42 ppm at 15% O_2 when firing natural gas and 96 ppm at 15% O_2 while firing fuel oil.

If you have any questions or concerns, please contact Stacy Johnson at 302-672-6304.

Sincerely,
ALL4 LLC

Robert Kuklentz
Directing Consultant

cc: Amanda Essner – ALL4 LLC
Robert Rowe – NAES
Stacy Johnson – NAES
Donna Mitchell – City of Dover

Attachments:
Attachment A – DNREC Request for Information Letter
Attachment B – Control Cost Tables

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ATTACHMENT A –
DNREC REQUEST FOR INFORMATION LETTER

STATE OF DELAWARE
DEPARTMENT OF NATURAL RESOURCES
& ENVIRONMENTAL CONTROL
DIVISION OF AIR QUALITY
100 W. Water Street
DOVER, DELAWARE 19904

Telephone: (302) 739 - 9402
Fax No.: (302) 739 - 3106

April 30, 2019

Donna Mitchell
City Manager
City of Dover
P.O. Box 475 Delaware 19903-0475

Certified Mail # 7018 2290 0002 1278 0342
RETURN RECEIPT REQUIRED

Subject: Request for Information – MANE-VU Emission Management Strategies Associated with Regional Haze Rule

Dear Ms. Mitchell:

The federal Clean Air Act (CAA) and Regional Haze Rule (40 CFR 51.308 (f)(2)(i) through (iv)) requires States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment. Under the Regional Haze Rule, States are required to develop a series of state implementation plans (SIP) to address visibility impairment in Class I areas and progress made toward achieving natural visibility conditions.

As part of its Regional Haze SIP, Delaware must consider emission reductions measures identified by Class I states as being necessary to make reasonable progress in any Class I area. Delaware is part of the Mid-Atlantic Northeast Visibility Union (MANE-VU), a regional planning organization in which member states work collaboratively to develop emission control strategies to address visibility impairment in Class I areas.

MANE-VU proposed six (6) emission management strategies (Asks) in order to meet the 2028 reasonable progress goal for regional haze (Attachment 1). While many of the strategies are directed at states to adopt, there are some strategies that required input from the City of Dover. Therefore, the Delaware Department of Natural Resources and Environmental Control (DNREC) is requesting information regarding an emission unit that meets the applicability criteria for one of the MANE-VU Asks: Ask # 5 – NOx Emission Limits for Peaking Combustion Turbines[1].

[1] For the purposes of the MANE-VU Ask, a peaking combustion turbine is defined as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016.

Delaware's good nature depends on you!

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DNREC requests that City of Dover submit the following information for the VanSant Generating Station (VanSant) by June 14, 2019:

Unit 1

VanSant operates a combustion gas turbine (Unit 1) which uses a Water Injection system as a NOx control device. Unit 1 combusts natural gas as a primary fuel and distillate fuel oil as a secondary fuel. This Unit has been identified as a peaking combustion turbine that does not have stringent enough NOx limits, as compared to the year-round limits set forth in MANE-VU's Ask # 5 (Attachment 1). Therefore, DNREC requests that the City of Dover perform a Four-Factor Analysis for reasonable installation or upgrade to year-round NOx emission controls for the Unit[2]. A Four-Factor Analysis takes into consideration:

1) Cost of compliance[3];
2) Time necessary for compliance;
3) Energy and non-air quality environmental impacts of compliance; and
4) Remaining useful life of any potentially affected sources. (40 CFR 51.308(f)(2)(i))

Thank you in advance for your cooperation. If you have any questions or wish to further discuss this request, please contact Renae Held of the Division of Air Quality at (302) 739-9402 or renae.held@delaware.gov.

Sincerely,

David Fees

David F. Fees, P.E.
Director
Division of Air Quality

Cc: James S. Robinson, Electric Director, City of Dover

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[2] DNREC requests that City of Dover perform a four-factor analysis for installation or upgrade to year-round NOx controls necessary to meet both of the proposed emission limits listed in Ask #5: 42ppm at 15% O_2 for fuel oil and 25 ppm at 15% O_2 for natural gas.

[3] EPA's Control Cost Manual is a potential resource for determining the cost of compliance, it provides guidance for the development of accurate and consistent costs for air pollution control devices. https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Members
Connecticut
Delaware
District of Columbia
Maine
Maryland
Massachusetts
New Hampshire
New Jersey
New York
Pennsylvania
Penobscot Indian Nation
Rhode Island
St. Regis Mohawk Tribe
Vermont

Nonvoting Members
U.S. Environmental Protection Agency
National Park Service
U.S. Fish and Wildlife Service
U.S. Forest Service

MANE-VU Class I Areas
ACADIA NATIONAL PARK ME
BRIGANTINE WILDERNESS NJ
GREAT GULF WILDERNESS NH
LYE BROOK WILDERNESS VT
MOOSEHORN WILDERNESS ME
PRESIDENTIAL RANGE DRY RIVER WILDERNESS NH
ROOSEVELT CAMPOBELLO INTERNATIONAL PARK ME/NB, CANADA

STATEMENT OF THE MID-ATLANTIC/NORTHEAST VISIBILITY UNION (MANE-VU) STATES CONCERNING A COURSE OF ACTION WITHIN MANE-VU TOWARD ASSURING REASONABLE PROGRESS FOR THE SECOND REGIONAL HAZE IMPLEMENTATION PERIOD (2018-2028)

The federal Clean Air Act (CAA) and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas. Most pollutants that affect visibility also contribute to ozone, fine particulate and sulfur dioxide (SO_2) air pollution. In order to assure protection of public health and the environment, any additional air pollutant emission reduction measures necessary to meet the 2028 reasonable progress goal for regional haze should be implemented as soon as practicable but no later than 2028.

According to the federal Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Asks," the State must describe the actions taken to resolve the disagreement in their Regional Haze SIP. This Ask by the MANE-VU Class I states, was developed through a collaborative process with all of the MANE-VU states. It is designed to identify reasonable emission reduction strategies which must be addressed by the states and tribal nations of MANE-VU through their regional haze SIP updates. This Ask has been developed and presented at this time so that SIPs may be developed and submitted between July of 2018 and July of 2021.

In addressing the emission reduction strategies in the Ask, the MANE-VU states will need to harmonize any activity on the strategies in the Ask with other federal or state

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requirements that affect the sources and pollutants covered by the Ask. These federal and state requirements include, but are not limited to:

- The 2010 SO_2 standard,
- The Regional Greenhouse Gas Initiative (RGGI), if applicable,
- The Mercury and Air Toxics Standards (MATS), and
- The new 2015 ozone standard.

Because of this need for cross-program harmonization and because of the formal public process required by the federal CAA and state rulemaking processes, it is expected that there will be opportunities for stakeholders and the public to comment on how states intend to address the measures in the Ask.

Many of the MANE-VU states are also members of RGGI. RGGI is a market based cap-and-invest program designed to cost effectively reduce greenhouse gas emissions from the energy sector while returning value to rate-payers. One of the co-benefits of RGGI is that it will also significantly reduce SO_2 and NOx emissions, the two most important haze precursors. Because of this, the RGGI states, regionally, will likely achieve greater emission reductions than those envisioned in this Ask.

To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast States will pursue a coordinated course of action designed to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measures may provide for the protection of public health and the environment. Per the Regional Haze rule, being on or below the uniform rate of progress for a given Class I area is not a factor in deciding if a State needs to undertake reasonable measures.

Therefore, the course of action for pursuing the adoption and implementation of measures necessary to meet the 2028 reasonable progress goal for regional haze include the following "emission management" strategies:

1. Electric Generating Units (EGUs) with a nameplate capacity larger than or equal to 25MW with already installed NOx and/or SO_2 controls - ensure the most effective use of control technologies on a year-round basis to consistently minimize emissions of haze precursors, or obtain equivalent alternative emission reductions;
2. Emission sources modeled by MANE-VU that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area, as identified by MANE-VU contribution

analyses (see attached listing) - perform a four-factor analysis for reasonable installation or upgrade to emission controls;

3. Each MANE-VU State that has not yet fully adopted an ultra-low sulfur fuel oil standard as requested by MANE-VU in 2007 - pursue this standard as expeditiously as possible and before 2028, depending on supply availability, where the standards are as follows:
   a. distillate oil to 0.0015% sulfur by weight (15 ppm),
   b. #4 residual oil within a range of 0.25 to 0.5% sulfur by weight,
   c. #6 residual oil within a range of 0.3 to 0.5% sulfur by weight.
4. EGUs and other large point emission sources larger than 250 MMBTU per hour heat input that have switched operations to lower emitting fuels – pursue updating permits, enforceable agreements, and/or rules to lock-in lower emission rates for SO_2, NOx and PM. The permit, enforcement agreement, and/or rule can allow for suspension of the lower emission rate during natural gas curtailment;
5. Where emission rules have not been adopted, control NOx emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:
   a. Striving to meet NOx emissions standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NOx emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or
   b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or
   c. Obtaining equivalent alternative emission reductions on high electric demand days.

   High electric demand days are days when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet. Peaking combustion turbine is defined for the purposes of this "Ask" as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, is used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale and that operated less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016;

   (Note: SO_2 emissions for fuel oil units are addressed with Ask item 3.a. above)

6. Each State should consider and report in their SIP measures or programs to: a) decrease energy demand through the use of energy efficiency, and b) increase the use within their state of Combined Heat and Power (CHP) and other clean Distributed Generation technologies including fuel cells, wind, and solar.

This long-term strategy to reduce and prevent regional haze will allow each state up to 10 years to pursue adoption and implementation of reasonable and cost-effective NOx and SO_2 control measures.

Signed on behalf of the MANE-VU states and tribal nations:

David Foerter, Executive Director
MANE-VU/OTC

August 25, 2017

Listing of emission units that have the potential for 3.0 Mm^{-1} or greater visibility impacts at any MANE-VU Class I area using actual 2015 emissions for EGUs and 2011 for other emission sources). The complete contribution analyses report is available at http://www.otcair.org/manevu.

State	Facility Name	Facility/ ORIS ID	Unit IDs	Max Extinction
MA	Brayton Point	1619	4	4.3
MA	Canal Station	1599	1	3.0
MD	Herbert A Wagner	1554	3	3.8
MD	Luke Paper Company	7763811	001-0011-3-0018	6.0
MD	Luke Paper Company	7763811	001-0011-3-0019	5.9
ME	The Jackson Laboratory	7945211	7945211	10.2
ME	William F Wyman	1507	4	5.6
ME	Woodland Pulp LLC	5974211		7.5
NH	Merrimack	2364	2	3.3
NJ	B L England	2378	2,3	5.6
NY	Finch Paper LLC	8325211	12	5.9
NY	Lafarge Building Materials Inc	8105211	43101	8.1
PA	Brunner Island	3140	1,2	4.0
PA	Brunner Island	3140	3	3.8
PA	Homer City	3122	1	9.3
PA	Homer City	3122	2	8.1
PA	Homer City	3122	3	3.3
PA	Keystone	3136	1	3.2
PA	Keystone	3136	2	3.1
PA	Montour	3149	1	4.4
PA	Montour	3149	2	4.1
PA	Shawville	3131	3,4	3.6

ATTACHMENT B – CONTROL COST TABLES

Table B-1
City of Dover - VanSant Generating Station
Current and Desired Combustion Turbine NO_X Emissions Information

Parameter	Heat Input (MMBtu/hr)	Load (MW)	NO_X Emissions Factor (ppm @ 15% O_2)	NO_X Emissions Factor (lb/hr)	NO_X Emissions [e] (tpy)
Base Load Case Firing Natural Gas [a]	465.90	36	26.60	48.19	-
Base Load Case Firing Fuel Oil [b]	400.17	33	67.33	104.77	-
Desired Base Load Case Firing Natural Gas [c]	465.90	36	25.00	45.29	4.28
Desired Base Load Case Firing Fuel Oil [c]	400.17	33	42.00	65.35	1.44
Actual 2018 Emissions [d]	453.50	--	--	--	9.10
Total Desired Base Load Case Emissions	453.50	--	--	--	5.72
			Percent Reduction Required	**37.17%**	

[a] Emissions data obtained from an Air Tox June 2018 stack test for natural gas using the average of 11 runs at the base load.

[b] Emissions data obtained from a Catalyst Air Management Inc. June 2015 stack test for fuel oil using the average of three runs at the base load.

[c] Desired emission rates represent the Mid-Atlantic Northeast Visibility Union (MANE-VU) Emissions Management Strategy goals.

[d] Actual emissions represent maximum emissions reported in 2018, which conservatively includes substituted data pursuant to 40 CFR Part 75.

[e] Operating hours information provided by the City of Dover. The maximum total operation from 2008 - 2018 was used as the representative annual operating hours with the year 2018 being the maximum. Representative percentages for fuel oil and natural gas usage were determined by taking the average fuel split from the same time frame (2008 - 2018).

Maximum Annual Operating Time (hours):	233.03
% Natural Gas Usage:	81.14%
% Fuel Oil Usage:	18.86%

Table B-2
City of Dover - VanSant Generating Station
Capital and Annualized Costs for an Upgrade to the Water Injection System

CAPITAL COST			
COST ITEM	**FACTOR**		**COST ($)**
Purchased Equipment Costs			
(a) Water Injection System		*A*	*$0*
(a) Additional Storage Tank System		*A*	*$300,000*
(a) Upgraded Ion Exchange System (including demolition and installation)		*A*	*$500,000*
(b) Instrumentation	0.10 × A		*$80,000*
(b) Freight	0.05 × A		*$40,000*
	Total Purchased Equipment Cost	*B*	*$920,000*
Direct Installation Costs for New Tank			
(c) Handling/Erection			*$17,000*
(c) Electrical/Controls			*$15,000*
(c) Piping/Valves			*$40,000*
(c) Site Preparation			*$41,000*
	Total Direct Installation Costs		*$113,000*
	Total Direct Capital Cost:	***TDC***	***$1,033,000***
Indirect Capital Costs			
(d) Engineering and Office Fees	0.10 × B		*$92,000*
(d) Contingencies	0.20 × B		*$184,000*
(d) General Facilities	0.05 × B		*$46,000*
	Total Indirect Capital Cost:	***TIC***	***$322,000***
	Total Capital Investment:	***TCI***	***$1,355,000***

ANNUALIZED COSTS				
COST ITEM	**COST FACTOR**	**UNIT COST**		**COST ($)**
Operating and Maintenance Costs				
(e) Maintenance Labor and Materials	1.5% of TCI			*$20,325*
Utilities				
(f) Water Production	720.0 gallon/hour	$0.15 per gallon of water		*$946,080*
		Total Direct Annual Costs:	***DAC***	***$966,405***
Indirect Annual Costs				
(b) Overhead	60% of sum of operating & maintenance costs			*$12,195*
(b) Administrative Charges	2% of TCI			*$27,100*
(b) Insurance	1% of TCI			*$13,550*
		Total Indirect Annual Costs:	***IDAC***	***$52,845***
		Total Annual Costs:	***TAC***	***$1,019,250***
Capital Recovery Costs				
(g) Expected lifetime of equipment, years	20			
(h) Interest rate, %/yr	5.5%			
(b) Capital recovery factor	0.084			
(b) Total Capital Investment Cost	$1,355,000			
	Annualized Capital Investment Cost:			***$113,385***
		Total Annualized Cost:		***$1,132,635***
Cost Effectiveness				
(i) Control Efficiency	37%			
Pre-retrofit NO_X Emissions	9.10 tons NO_X/yr			
Post-retrofit NO_X Emissions	5.72 tons NO_X/yr			
Potential Removed/Destroyed NO_X Emissions	3.38 tons NO_X/yr			
		Annual Cost/Ton Removed:		***$334,897***

(a) Cost information based on a representative vendor quote for an additional 132,000 gallon storage tank system and an upgraded ion exchange system. The quote for the upgraded ion exchange system includes demolition and installation. There is no capital cost associated with increasing usage of the water injection system.

(b) Costs were estimated following guidelines in the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, Sixth Edition (January 2002).

(c) Direct installation costs based on a vendor quote for a 132,000 gallon storage tank system.

(d) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(e) Maintenance costs were estimated based on engineering estimate.

(f) Price of additional water production includes labor, electricity, and chemical costs.

(g) Expected lifetime based on engineering estimate.

(h) Interest rate is equal to the U.S. bank prime rate, as of December 20, 2018.

(i) Control device efficiency based on the reduction of NO_X emissions from the current NO_X emissions rate to meet the Mid-Atlantic Northeast Visibility Union (MANE-VU) Emissions Management Strategy goals [i.e., 25 parts per million (ppm) NO_X at 15% oxygen (O_2) when firing natural gas and 42 ppm NO_X at 15% O_2 while firing fuel oil]

Table B-3
City of Dover - VanSant Generating Station
Capital and Annualized Costs for Dry Low-NO_X Combustor System

CAPITAL COSTS		
COST ITEM	**FACTOR**	**COST ($)**
Purchased Equipment Costs		
(a) Dry Low-NO_X Burner System (including demolition/installation/commissioning)	*A*	*$2,000,000*
(b) Instrumentation	0.10 × A	*$200,000*
(b) Freight	0.05 × A	*$100,000*
	Total Purchased Equipment Cost *B*	*$2,300,000*
Direct Installation Costs		
(c) Handling/Erection	0.10 × B	*$230,000*
(d) Electrical/Controls	0.04 × B	*$92,000.00*
(e) Piping	0.02 × B	*$46,000.00*
		$368,000
	Total Direct Capital Cost: TDC	***$2,668,000***
Indirect Capital Costs		
(f) Engineering and Office Fees	0.10 × B	*$230,000*
(f) Contingencies	0.20 × B	*$460,000*
(f) General Facilities	0.05 × B	*$115,000*
	Total Indirect Capital Cost: TIC	***$805,000***
	Total Capital Investment: TCI	***$3,473,000***

ANNUALIZED COSTS			
COST ITEM	**COST FACTOR**	**UNIT COST**	**COST ($)**
Operating and Maintenance Costs			
(g) Maintenance Costs	2.75% of TCI		*$95,508*
		Total Direct Annual Costs: DAC	***$95,508***
Indirect Annual Costs			
(b) Overhead	60% of sum of operating & maintenance costs		*$57,304.50*
(b) Administrative Charges	2% of TCI		*$69,460.00*
(b) Insurance	1% of TCI		*$34,730.00*
		Total Indirect Annual Costs: IDAC	***$161,495***
		Total Annual Costs: TAC	***$257,002***
Capital Recovery Costs			
(h) Expected lifetime of equipment, years	20		
(i) Interest rate, %/yr	5.5%		
(b) Capital recovery factor	0.084		
(b) Total Capital Investment Cost	$3,473,000		
		Annualized Capital Investment Cost:	***$290,618***
		Total Annualized Cost:	***$547,620***
Cost Effectiveness			
(j) Control Efficiency	37%		
Pre-retrofit NO_X Emissions	9.10 tons NO_X/yr		
Post-retrofit NO_X Emissions	5.72 tons NO_X/yr		
Potential Removed/Destroyed NO_X Emissions	3.38 tons NO_X/yr		
		Annual Cost/Ton Removed:	***$161,920***

(a) Cost information obtained from a General Electric (GE) quote.

(b) Costs were estimated following guidelines in the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, Sixth Edition (January 2002).

(c) Direct installation factors based on engineering judgement.

(d) Assume electrical is similar to RTO based on engineering judgement (e.g., controls, etc.).

(e) Assume piping is similar RTO based on engineering judgement (e.g., gas piping).

(f) Indirect capital cost factors (i.e., engineering and office fees, contingencies, and general facilities) based on guidance from "Methods for Evaluating the Costs of Utility NO_X Control Technologies," Loan K. Tran and H. Christopher Frey, June 1996.

(g) Maintenance costs were estimated based on the U.S. EPA OAQPS Alternative Control Techniques Document - NO_X Emissions from Process Heaters (Revised), Document No. EPA-453/R-93-034 (September 1993).

(h) Expected lifetime based on engineering estimate.

(i) Interest rate is equal to the U.S. bank prime rate, as of December 20, 2018.

(j) Control device efficiency based on the reduction of NO_X emissions from the current NO_X emissions rate to meet the Mid-Atlantic Northeast Visibility Union (MANE-VU) Emissions Management Strategy goals [i.e., 25 parts per million (ppm) NO_X at 15% oxygen (O_2) when firing natural gas and 42 ppm NO_X at 15% O_2 while firing fuel oil].

Table B-4
City of Dover - VanSant Generating Station
Capital and Annualized Costs for a Selective Catalytic Reduction System

CAPITAL COSTS			
	COST ITEM	**FACTOR**	**COST ($)**
Purchased Equipment Costs			
(a)	Selective Catalytic Reduction System	*A*	*$2,171,413*
(b)	Instrumentation	0.10 × A	*$217,141*
(b)	Freight	0.05 × A	*$108,571*
		Total Purchased Equipment Cost ***B***	*$2,497,125*
Direct Installation Costs			
(c)	Foundations and Supports	0.12 × B	*$299,655*
(d)	Handling and Erection	0.40 × B	*$998,850*
(e)	Electrical	0.01 × B	*$24,971*
(f)	Piping	0.05 × B	*$124,856*
(g)	Insulation for Ductwork	0.07 × B	*$174,799*
(h)	Painting	0.02 × B	*$49,943*
		Total Direct Installation Costs	*$1,673,074*
		Total Direct Capital Cost: TDC	***$4,170,199***
Indirect Capital Costs			
(b)	General Facilities	0.05 × TDC	*$208,510*
(b)	Engineering and Home Office Fees	0.10 × TDC	*$417,020*
(b)	Process Contingency	0.05 × TDC	*$208,510*
		Total Indirect Capital Cost: TIC	***$834,040***
(b)	Project Contingency	0.15 (TDC+TIC)	*$750,636*
(b)	Total Plant Cost	TDC+TIC+ Proj. Cont.	*$5,754,874*
(b)	Preproduction Cost	0.02 (Total Plant Cost)	*$115,097*
(b)(i)	Inventory Capital	$Vol_{reagent}$ * $Cost_{reagent}$	*$5,600*
		Total Capital Investment: TCI	***$5,875,572***

ANNUALIZED COSTS				
	COST ITEM	**COST FACTOR**	**UNIT COST**	**COST ($)**
Operating and Maintenance Costs				
(b)	Maintenance Labor and Materials	0.5% of TCI		*$29,378*
(i)	Aqueous Ammonia Reagent	1,393 gallons/yr	$0.56 per gallon	*$780*
(b)(j)	Catalyst Replacement			*$149*
Utilities				
(b)(k)	Electricity	139 kW	$0.114 per kWh	*$3,704*
			Total Direct Annual Costs: DAC	***$34,011***
Capital Recovery Costs				
(b)	Expected lifetime of equipment, years	20		
(l)	Interest rate, %/yr	5.5%		
(b)	Capital recovery factor	0.084		
(b)	Total Capital Investment Cost	$5,875,572		
			Annualized Capital Investment Cost:	***$491,664***
			Total Annualized Cost:	***$525,675***
Cost Effectiveness				
(m)	Control Efficiency	37%		
	Pre-retrofit NO_X Emissions	9.10 tons NO_X/yr		
	Post-retrofit NO_X Emissions	5.72 tons NO_X/yr		
	Potential Removed/Destroyed Emissions	3.38 tons NO_X/yr		
			Annual Cost/Ton Removed:	***$155,431***

(a) Cost information obtained from vendor quotation for a similar unit

(b) Cost information estimated based on the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, Seventh Edition (May 2016)

(c) Foundations and supports for ammonia tank, NH_3 AFCU skid, catalyst reactor housing, duct work, and connection to reactor support points assumed similar to absorber system based on engineering judgment

(d) Handling and erection includes installation of NH_3 AFCU skid, ammonia tank, catalyst reactor, ductwork, and catalyst loading assumed similar to absorber system based on engineering judgment

(e) Minimum factor provided in U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, Seventh Edition (May 2016) for add-on controls

(f) Piping and supports for piping between NH_3 storage tank, NH_3 AFCU and AIG riser pipes, assumed similar to venturi scrubber based on engineering judgment

(g) Vendor cost excludes insulation needed to keep surface temperature < 50 deg. C on reactor and transition pieces

(h) Painting of monolithic structure assumed similar to ESP based on engineering judgement

(i) Inventory capital is based on the reagent storage tank capacity, calculated based on equations 2.32 through 2.35 in Section 4.2, Chapter 2, Section 2.3 of the U.S. EPA OAQPS Control Cost Manual, and the reagent price for a 19% aqueous ammonia solution, based on a quote from Tanner Industries, Inc.

(j) Catalyst cost is from the U.S. EPA Air Pollution Control Technology Fact Sheet for Selective Catalytic Reduction, Document No. EPA-452/F-03-032, July 2003. The catalyst volume was sized using guidance from Section 4.2, Chapter 2, Section 2.3 of the U.S. EPA OAQPS Control Cost Manual

(k) Price of electricity from Electricity Local for Dover, DE, using the industrial electricity rates, see https://www.electricitylocal.com/states/delaware/dover/

(l) Interest rate is equal to the U.S. bank prime rate, as of December 20, 2018

(m) Control device efficiency based on the reduction of NO_X emissions from the current NO_X emissions rate to meet the Mid-Atlantic Northeast Visibility Union (MANE-VU) Emissions Management Strategy goals [i.e., 25 parts per million (ppm) NO_X at 15% oxygen (O_2) when firing natural gas and 42 ppm NO_X at 15% O_2 while firing fuel oil]

Table B-5
City of Dover - VanSant Generating Station
Annualized Costs for Heating of Flue Gas for a Selective Non-Catalytic Reduction System

Volumetric Flow Rate	Required Temperature Change[a] (ΔT)	Specific Heat[b] (c)	Density[c] (ρ)	Required Heat Input[d]	Amount of Natural Gas Required[e]	Annualized Cost for Air Reheat[f]	Potential Controlled Emissions[g]	Annual Cost/Ton of NO_x Removed
(acfm)	(°F)	(Btu/lb-°F)	lb/ft^3	(Btu/yr)	(scf/yr)	(dollars/yr)	(tons NO_x/yr)	
196,109	397	2.089	0.017	3.92E+10	3.84E+07	$340,857	3.38	**$100,784**

[a] Required temperature change based on the combustion turbine's exhaust gas outlet temperature, and the minimum temperature required for SNCR operation. It is assumed that the SNCR must be installed after the existing air pollution control train due to the potential for dust/particulate in the exhaust gas stream to ruin the SNCR catalyst.

Exhaust Temperature ($T_{initial}$):	1,003	°F
Minimum Temperature for SNCR Operation (T_{final}):	1,400	°F

[b] Specific heat is calculated using the following equation:

$$c = c_{dry\ air} + (c_{water\ vapor} \times x)$$ *(Equation 1)*

Where:

Specific Heat of Dry Air @ 1,003°F ($c_{dry\ air}$):	0.264	Btu/lb-°F
Specific Heat of Water Vapor @ 1,003°F ($c_{water\ vapor}$):	0.515	Btu/lb-°F

$$x = Humidity\ Ratio\ By\ Mass = \frac{m_{water\ vapor}}{m_{dry\ air}} = \frac{\rho_{water\ vapor} \times Moisture\ Content}{\rho_{dry\ air} \times (1 - Moisture\ Content)}$$ *(Equation 2)*

Humidity Ratio by Mass (x):	3.544	lb water vapor/lb dry air
Moisture Content:	7%	by volume
Density of Dry Air @ 1,003°F ($\rho_{dry\ air}$):	0.025	lb/ft^3
Density of Water Vapor @ 1,003°F ($\rho_{water\ vapor}$):	1.196	lb/ft^3

[c] Density is calculated using the following equation:

$$\rho = \frac{\rho_{dry\ air}(1 + x)}{\left[1 + \left(x \times {R_w}/{R_a}\right)\right]}$$ *(Equation 3)*

Where:

Individual Gas Constant of Air (R_a):	286.9	J/kg-K
Individual Gas Constant of Water Vapor (R_w):	461.5	J/kg-K

[d] The required annual heat input for reheating the air for SNCR operation is calculated using the following equation:

$$Required\ Heat\ Input = c \times \Delta T \times Flow\ \times \rho$$ *(Equation 4)*

[e] The annual amount of natural gas required for reheating the air for SNCR operation is calculated using the following:

Heating Value of Natural Gas:	1,020	Btu/scf

[f] Natural gas price (industrial) is March 2019 data for Delaware: https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SDE_m.htm

Price of Natural Gas:	$8.87	per Mcf

[g] Potential controlled emissions based on the uncontrolled emissions rate, based on engineering estimate, and the required SNCR control efficiency:

Uncontrolled Emissions:	9.10	tons/yr
Maximum SNCR Control Efficiency:	37.17%	--

The above calculations utilized the following conversion factors:

Conversion Factor 1:	60	min/hr
Conversion Factor 2:	233	hr/yr
Conversion Factor 3:	1,000	cf/Mcf