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Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

CPS Comments

1 message

Barb Adams <barb5100@comcast.net> Wed, Mar 20, 2019 at 5:17 PM
Reply-To: Barb Adams <barb5100@comcast.net>
To: alison.sinclair@deq.virginia.gov

Dear Ms Sinclair,

Thank you for receipt of my comments (attached) and the opportunity to share my concerns with the DEQ.

Barbara Adams

Ms Barbara Adams CPS Comments.docx
15K

Ms Barbara Adams
5100 Montebello Circle
Richmond, VA 23231
804-484-2773

Dear Ms. Sinclair,

I would like to register my concern about the Chickahominy Power Station and request that this project by reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610

FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

At 1.650 watts, the Chickahominy Power Station, to be being developed by Chickahominy Power, LLC, a subsidiary of Balico, LLC, would be the largest proposed fracked gas plant in the country, bigger than the existing Chesterfield Power Station. While on the surface and without much to compare it to in the state, this project is being passed on as a boon to county economy, with little downsides. But a greater understanding of fracked gas that will be burned in the plant would quickly dispel the seeming benefits of such a plant.

• At a time when the global climate change crisis is being driven by drastic increases in greenhouse gases, of which methane is a significant contributor pollutant (having 25 times the global warming potential than carbon dioxide), Virginia should be looking at greatly reducing its introduction of methane in the atmosphere, and boosting the state's commit to conversion to conservation and renewable energy sources.

• The fracked gas that would supply the plant would carry with it over 100 toxic chemicals that would be burned along with methane. The potential for increasing air pollution would very likely have a significant deleterious effect on an area with already higher than average incidence than normal of both COPD and asthma in the county. (VDH shows that relative to other areas of Virginia, Charles City County and the surrounding region show higher incidences of asthma.)

• Documents from DEQ show that of 10 proposed emission constituents, seven are above the threshold set by the department to classify a facility as a major stationary source of the pollutant. These include three types of particulate matter, nitrogen oxide, carbon monoxide, volatile organic compounds and carbon dioxide equivalents.

• With a continued trend of lowered demand for gas and electricity, it is unlikely that this plant will be in demand and state-of-the-energy-art in the quickly transforming energy landscape of the future.

Charles City County has a rich history and beautiful rural natural landscape and resources to protect. Projects such as these carry with them the potential for quick and damaging consequences that would not be worth the trade-off of creating wealth for this company.

I ask that DEQ reject this permit, at least until all residents are made aware of the true potential damage to water, air and health and have the opportunity to give educated feedback to county officials and the DEQ.

Thank you for your kind attention to my request.

Barbara Adams

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Comments on 52610 Chickahominy, LLC Draft PSD Permit

1 message

Peter Anderson <peter@appvoices.org> Wed, Mar 20, 2019 at 7:37 PM
To: Alison.Sinclair@deq.virginia.gov

Good evening Ms. Sinclair:

On behalf of the eight environmental organizations who have signed the document, please find attached comments on Balico/Chickahominy, LLC's draft PSD permit (No. 52610).

Thank you for your time and consideration.

Sincerely,

Peter Anderson

--
Peter Anderson
Virginia Program Manager
Appalachian Voices
812 E. High Street
Charlottesville, VA 22902
(434) 293-6373 office
(434) 249-6446 cell

Envtl Groups Comments - Chickahominy Power Station PSD Permit 52610.pdf
158K

March 20, 2019

Alison Sinclair
Department of Environmental Quality
Piedmont Regional Office
4949 Cox Road, Suite A
Glen Allen, VA 23060

via email to: Alison.Sinclair@DEQ.virginia.gov

Comments on Draft Prevention of Significant Deterioration Permit for the Construction and Operation of an Electric Power Generation Facility in Charles City, VA by Balico LLC/Chickahominy Power, Registration No. 52610

Dear Ms. Sinclair:

Balico LLC/Chickahominy Power has applied for a Prevention of Significant Deterioration Permit ("Permit") to construct and operate a new 1,650 MW capacity gas-fired electric generating facility in Charles City County. The Department of Environmental Quality (DEQ) has classified this proposed facility as a major source of air pollution. If permitted to operate, the proposed Chickahominy power facility threatens to impose significant adverse impacts on Virginia citizens and natural resources. We respectfully ask that this draft Permit be submitted to the Air Pollution Control Board (the Board) for public comment and hearing.

<u>Statement of Interest</u>

The undersigned environmental organizations represent thousands of members from across the Commonwealth who all share a direct interest in a healthy environment, a reduction in the risk of catastrophic climate change impacts, and a commitment to the principles of environmental justice. These principles dictate that no group of people—particularly historically disadvantaged groups such as minorities and lower-income populations—bear a disproportionate share of environmental degradation and pollution.

The operation of a new 1,650 MW gas-fired electric generating facility in Virginia is adverse to the interests of all Virginians as the Commonwealth seeks to meet its obligations to the U.S. Climate Alliance and to future generations—who will suffer the impacts of climate change more acutely than the present one. Moreover, many present-day Virginians are likely to suffer health consequences resulting from a significant new source of emissions of PM, NO_x, CO, SO_2, VOC, H_2SO_4, acrolein, formaldehyde, beryllium, cadmium, chromium, lead, mercury, and nickel.

<u>Environmental Justice Review Must be Supplemented with Local Information and Submitted to the Air Pollution Control Board for Further Analysis</u>

First, we are concerned that final approval of the Permit may allow the emission of pollutants in a manner that disproportionately impacts environmental justice communities in Charles City County.

The U.S. Environmental Protection Agency (EPA) defines *environmental justice* as “the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies.”[1] The EPA further specifies that “[f]air treatment means no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies.”[2]

Identifying environmental justice populations can be a challenging task, due both to situations where an affected population is tightly clustered and situations where an affected population is spread widely across the geographic unit studied. The Federal Interagency Working Group on Environmental Justice advises that “[t]o sufficiently identify small concentrations (i.e., pockets) of minority populations, agencies may wish to supplement Census data with local demographic data. Local demographic data and information (including data provided by the community and Tribes) can improve an agency’s decision-making process.”[3]

DEQ has run an EJSCREEN analysis at 1, 2, and 5 mile radii around the proposed Chickahominy Power site, estimating minority population percentages of 42, 45, and 34, respectively.[4] These numbers are above state averages, falling in the 61st, 65th, and 52nd percentiles for Virginia.

An initial review of U.S. Census information reveals that Charles City County is majority-minority, with the white (non-Hispanic) population of the county comprising 42.1% of the population, while minorities comprise the remaining 57.9% of the county.[5] Persons identifying as black or African-American comprise a plurality of the population, at 45.9%. In addition, persons identifying as American Indian or Alaska Native comprise a significant 6.9% of the county.

These numbers indicate that further environmental justice analysis is necessary. EPA cautions that Census block data alone can miss minority hotspots,[6] and the agency warns “EJSCREEN is a pre-decisional screening tool, and … should not be used to identify or label an area as an ‘EJ Community.’”[7] Accordingly, DEQ and the Board should follow federal guidance and seek local demographic data provided by the community and Tribes.

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[1] *Learn About Environmental Justice*, U.S. ENVTL. PROT. AGENCY, https://www.epa.gov/environmentaljustice/learn-about-environmental-justice (last updated Nov. 7, 2018).
[2] *Id.*
[3] FED. INTERAGENCY WORKING GRP. ON ENVTL. JUSTICE & NEPA COMM., PROMISING PRACTICES FOR EJ METHODOLOGIES IN NEPA REVIEWS 21 (2016), *available at* https://www.epa.gov/sites/production/files/2016-08/documents/nepa_promising_practices_document_2016.pdf.
[4] DEP’T OF ENVTL. QUALITY, ENGINEERING ANALYSIS, PERMIT NO. 52610-001, APPENDIX C – ENVIRONMENTAL JUSTICE REPORTS (Jan. 30, 2019), *available at* https://www.deq.virginia.gov/Programs/Air/PublicNotices/AirPermits.aspx.
[5] U.S. CENSUS BUREAU, *Quick Facts: Charles City County, Virginia*, https://www.census.gov/quickfacts/charlescitycountyvirginia (last visited Mar. 18, 2019).
[6] U.S. ENVTL. PROT. AGENCY, EJSCREEN TECHNICAL DOCUMENTATION 8, 9 (2017), *available at* https://www.epa.gov/sites/production/files/2017-09/documents/2017_ejscreen_technical_document.pdf.
[7] *Id.*

It should be noted that DEQ approved a new source PSD permit for another large (1,060 MW) gas-fired electric generating facility in 2018—the C4GT facility. The proposed Chickahominy and C4GT facilities would be sited within one mile of each other, creating further potential for a localized pollution hotspot.

DEQ notes in its Chickahominy engineering analysis that the combined estimated ozone impacts from NOx and VOC emissions of the Chickahominy facility and the C4GT facility would not place Virginia at risk of violating the 8-hour ozone NAAQS of 70 ppb.[8] However, this analysis does not discuss the impact of the combined emissions within smaller geographic units or within the 1, 2, and 5 mile radii analyzed in the EJSCREEN. Moreover, this analysis relies upon ozone data collected at the DEQ Shirley Plantation monitoring station, which lies approximately 10 miles southwest of the proposed electric generating facilities. It is unclear from this analysis whether ozone levels in directly impacted communities closer to the proposed facilities would comply with the 8-hour ozone NAAQS if both facilities were in operation. No other analysis of the combined air pollution from the C4GT and Chickahominy facilities has been provided.

Under the Commonwealth Energy Policy found in Virginia Code § 67-102 (A)(11), the Board must act to "[e]nsure that development of new, or expansion of existing, energy resources or facilities does not have a disproportionate adverse impact on economically disadvantaged or minority communities." In addition, the Board must consider the potential for disproportionate adverse impacts on environmental justice communities by analyzing "[t]he suitability of the activity to the area in which it is located."[9]

Because an environmental justice analysis is not complete and the Board is obligated by statute to act to prevent disproportionate adverse impacts on environmental justice communities, the draft Permit should be submitted to the Board for further analysis, public comment, and hearing.

The Board Must Analyze the Reasonableness of the Facility's Greenhouse Gas Emissions

We are also concerned that permitting a major new source of greenhouse gas emissions is adverse to the climate policies currently under development in the Commonwealth and counter to recommendations in the most recent report of the Intergovernmental Panel on Climate Change. This report finds that human-caused emissions of CO2, like electric generating facilities, "would need to fall by about 45 percent from 2010 levels by 2030, reaching 'net zero' around 2050" to avoid the most catastrophic impacts from global warming.[10]

The proposed Chickahominy facility would emit 5,779,348 or 6,479,692 tons of CO2e per year, depending on which turbines are chosen.[11] The facility's expected lifetime is "36 years or

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[8] DEP'T OF ENVTL. QUALITY, ENGINEERING ANALYSIS, PERMIT NO. 52610-001, APPENDIX B (Jan. 30, 2019), *available at* https://www.deq.virginia.gov/Programs/Air/PublicNotices/AirPermits.aspx.
[9] VA CODE ANN. § 10.1-1307 (E).
[10] INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, SUMMARY FOR POLICYMAKERS OF IPCC SPECIAL REPORT ON GLOBAL WARMING OF 1.5°C APPROVED BY GOVERNMENTS (Oct. 8, 2018), *available at* https://www.ipcc.ch/2018/10/08/summary-for-policymakers-of-ipcc-special-report-on-global-warming-of-1-5c-approved-by-governments/.
[11] DEP'T OF ENVTL. QUALITY, ENGINEERING ANALYSIS, PERMIT NO. 52610-001 at 5 (Jan. 30, 2019), *available at* https://www.deq.virginia.gov/Programs/Air/PublicNotices/AirPermits.aspx.

more."[12] If the facility is permitted and operates for its expected lifetime, it is difficult to imagine that Virginia will reach net zero CO2 emissions by 2050, unless those six million tons are completely offset (all other carbon-emitting sources in Virginia notwithstanding).

Moreover, the Board is currently finalizing a carbon budget trading program that would cap CO2 emissions from virtually all Virginia fossil fuel-fired electric generating facilities.[13] As a fossil fuel-fired unit with a generating capacity greater than 25 MWe, the Chickahominy facility would be regulated under this program.[14] The 2020 base budget for total emissions of all regulated units is 28 million tons per year.[15]

The Board must consider new greenhouse gas emissions when it considers the reasonableness of permitting new fossil fuel-fired power stations under Virginia Code § 10.1-1307. With specific regard to the proposed Chickahominy facility, the Board should consider whether it is reasonable to permit a single electric generating station whose emissions would represent approximately 23% of the entire 2020 base budget and approximately 33% of the 2030 base budget (19.6 million tons).

Permitting the operation of a new 1,650 MW fossil fuel-fired electric generating facility may also undermine the purpose and intent of Executive Directive 11, which is to respond to the climate crisis by reducing Virginia's use of fossil fuels and to encourage development of Virginia's clean energy sector.[16]

In addition, finalizing the Permit may prevent the Commonwealth from meeting its obligations under the U.S. Climate Alliance. Governor Northam has continued former Governor McAuliffe's commitment to greenhouse gas reductions and compliance with the terms of the Paris Accord.[17] Under this agreement, Virginia has committed to:

- Implement policies that advance the goals of the Paris Agreement, aiming to reduce greenhouse gas emissions by at least 26-28 percent below 2005 levels by 2025
- Track and report progress to the global community in appropriate settings, including when the world convenes to take stock of the Paris Agreement, and
- Accelerate new and existing policies to reduce carbon pollution and promote clean energy deployment at the state and federal level.[18]

These additional policy considerations are not required under the Clean Air Act, but they should be analyzed during the Board's required reasonableness analysis under Virginia Code

[12] *Id.* at 22.
[13] CO_2 Budget Trading Program, 35 Va. Reg. Regs. 1409 (proposed Feb. 4, 2019) (to be codified at 9 Va. Admin. Code §5-140-6010 *et seq.*).
[14] *Id.* at 1416.
[15] *Id.* at 1422.
[16] *See* Gov. Terence McAuliffe, Executive Directive 11 (May 16, 2017), *available at* http://jlarc.virginia.gov/pdfs/fiscal_analysis/FIR/2017_ED11.pdf.
[17] *See Governors*, U.S. CLIMATE ALLIANCE, https://www.usclimatealliance.org/governors-1 (last visited Mar. 19, 2019).
[18] *Alliance Principles*, U.S. CLIMATE ALLIANCE, https://www.usclimatealliance.org/alliance-principles (last visited Mar. 19, 2019).

§ 10.1-1307. At minimum, DEQ and the Board should analyze and notify the public what—if any—existing, more carbon-intensive electric generating facilities the C4GT and Chickahominy facilities are likely to displace and explain how the new facilities' emissions will be offset in order to reach net zero CO_2 emissions by 2050.

As the Air Board's near-final carbon regulation brings the Commonwealth closer to becoming the first Southern state to regulate greenhouse gas pollution from the power sector, these complex policy questions must be answered. Because the Board is obligated under statute to analyze whether the activities to be permitted are reasonable, the draft Permit should be submitted to the Board for further analysis, public comment, and hearing.

Thank you for the opportunity to comment on this important matter.

Respectfully,

Peter Anderson, Virginia Program Manager
Appalachian Voices
812 East High Street
Charlottesville, VA 22902
(434) 293-6373

Kate Addleson, Director
Sierra Club Virginia Chapter
100 West Franklin Street, Mezzanine
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John Bagwell, Consultant
Virginia Clinicians for Climate Action
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Richmond, VA 23227
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Marcia Geyer
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Charlottesville, VA 22902
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Mary Rafferty, Executive Director
Virginia Conservation Network
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Queen Zakia Shabazz

Coordinator, Virginia Environmental Justice Collaborative
Founder, United Parents Against Lead
4809 Old Warwick Road
P.O. Box 24773
Richmond, VA 23224
(804) 308-1518

Michael Town, Executive Director
Virginia League of Conservation Voters
100 West Franklin Street, Suite 102
Richmond, VA 23220
(804) 225-1902

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Please review the air permit for the Chickahominy Power Station - Fracked Gas is the wrong choice

1 message

Heidi Dhivya Berthoud <campaigns@good.do> Wed, Mar 20, 2019 at 9:05 AM
Reply-To: Heidi Dhivya Berthoud <heidi1008@gmail.com>
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair

I would like to register my concern about the Chickahominy Power Station and request that this project be reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed. This is the time to move forward, away from fossil fuels, towards renewables. The hour is beyond late.

Thank you for your time and attention.
NAME: Heidi Dhivya Berthoud
ADDRESS: 366 Wyland Rd Buckingham VA 23921
PHONE NUMBER: 434 979 9732

Yours sincerely,
Heidi Dhivya Berthoud
Buckingham, Virginia, 23921, United States

____

This email was sent by Heidi Dhivya Berthoud via Do Gooder, a website that allows people to contact you regarding issues they consider important. In accordance with web protocol FC 3834 we have set the FROM field of this email to our generic no-reply address at campaigns@good.do, however Heidi Dhivya provided an email address (heidi1008@gmail.com) which we included in the REPLY-TO field.

Please reply to Heidi Dhivya Berthoud at heidi1008@gmail.com.

To learn more about Do Gooder visit www.dogooder.co
To learn more about web protocol FC 3834 visit: www.rfc-base.org/rfc-3834.html

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

FW: Balico LLC; Registration No. 52610

1 message

bredl@skybest.com <bredl@skybest.com> Wed, Mar 27, 2019 at 2:19 PM
To: alison.sinclair@deq.virginia.gov

TO: Alison Sinclair

FROM: Lou Zeller, BREDL

RE: Balico Chickahominy permit

I apologize for the email error. My comments are attached.

Thank you for all you do,

Lou

Louis A. Zeller, Executive Director

Blue Ridge Environmental Defense League, Inc.

Main Office: PO Box 88 Glendale Springs, NC 28629

Phone: 1-336-982-2691

Mobile: 1-336-977-0852

Email: BREDL@skybest.com

Website: www.BREDL.org

Founded in 1984, we have projects and chapters in Alabama, Georgia, Tennessee, South Carolina, North Carolina and Virginia

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From: bredl@skybest.com <bredl@skybest.com>
Sent: Wednesday, March 20, 2019 5:03 PM
To: 'alison.sinclari@deq.virginia.gov' <alison.sinclari@deq.virginia.gov>
Cc: Sharon Ponton <ponton913@msn.com>; Mark E. Barker <mebarker@cox.net>
Subject: Balico LLC; Registration No. 52610

March 20, 2019

Alison Sinclair

Virginia Dept. of Environmental Quality

P.O. Box 1105

Richmond, VA 23218

alison.sinclair@deq.virginia.gov

RE: Balico LLC; Registration No. 52610

Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Comments Attached

190320_BREDL comments_Chickahominy Power Station.pdf
169K

Blue Ridge Environmental Defense League

www.BREDL.org 8260 Thomas Nelson Highway, Lovingston, Virginia 22949 BREDL@skybest.com(434) 420-1874

March 20, 2019

Alison Sinclair
Virginia Dept. of Environmental Quality
P.O. Box 1105
Richmond, VA 23218
alison.sinclair@deq.virginia.gov

RE: Balico LLC; Registration No. 52610
Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Dear Ms. Sinclair:

On behalf of the Blue Ridge Environmental Defense League and our members in the Commonwealth of Virginia, I write to provide comments on the permit for the proposed Chickahominy Power facility in Charles City County. For the reasons detailed below, we oppose the permitting of this facility.

Background

According to Balico LLC's application, the Chickahominy Power plant ("CPLLC"), if permitted, would be constructed as a 1650 Megawatt combined-cycle electric generation facility utilizing three combustion turbines fueled with natural gas. The plant would use supplementally-fired heat recovery steam generators and steam turbines. Air pollution control would include dry low nitrogen oxides burner technology, oxidation catalysts, and evaporative-inlet air cooling.[1]

Comments

Air Pollution

Combustion turbines are remarkable for their lack of efficiency in converting chemical energy to mechanical energy. Part of the output is lost the in compressor where intake air is compressed up to 30 atmospheres of pressure, before the fuel is burned. Accordingly, "More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive an external load."[2] Combined cycle units that utilize heat recovery steam generators have an efficiency of 38 to 60 percent. This means that from 40 to 62

[1] CPLLC's August 24, 2017 Application amends CPLLC's April 5, 2017 Application, which replaced CPLLC's initial March 13, 2017 Application. The August 24, 2017 filing also amends Exhibit I, Responses to 20 VAC 5-302-20. On April 13, 2017, CPLLC filed supplemental Exhibit 4 to its Application, a map identifying the location of the proposed facility for notice purposes. On August 16, 2017, CPLLC filed supplemental Exhibit 5, a July 2017 Environmental Assessment of the Project Site. CPLLC identifies 1,650 MW as the net nominal generating capacity of the proposed Facility at 95 degrees Fahrenheit ambient temperature.

[2] US EPA Air Pollution Emission Factors, AP-42, Stationary Gas Turbines, Section 3.1.2 Process Description

percent of the fuel burned produces no electric power. But air pollution and global warming gases are created by combustion whether power is produced or not.

Moreover, how the turbines are operated affects air pollution emissions and efficiency. This may result in underestimated levels of toxic air pollution. According to the US Environmental Protection Agency:

> Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion.[3]

The products of incomplete production—carbon monoxide and PM-10—increase with reduced operating loads. Before issuing this permit, the DEQ must assess the impacts of operating factors. Best available control technology for criteria pollutants and maximum achievable control technology for hazardous air pollutants are the standards which must be required for the Chickahominy Power plant.

Climate Change

The use of natural gas as a fuel is not an acceptable alternative to coal-fired power. The gas at the proposed Chickahominy plant would largely be supplied by hydrofracking. According to the Union of Concerned Scientists:

> The drilling and extraction of natural gas from wells and its transportation in pipelines results in the leakage of methane, primary component of natural gas that is 34 times stronger than CO2 at trapping heat over a 100-year period and 86 times stronger over 20 years. Preliminary studies and field measurements show that these so-called "fugitive" methane emissions range from 1 to 9 percent of total life cycle emissions. Whether natural gas has lower life cycle greenhouse gas emissions than coal and oil depends on the assumed leakage rate, the global warming potential of methane over different time frames, the energy conversion efficiency, and other factors. One recent study found that methane losses must be kept below 3.2 percent for natural gas power plants to have lower life cycle emissions than new coal plants over short time frames of 20 years or fewer. And if burning natural gas in vehicles is to deliver even marginal benefits, methane losses must be kept below 1 percent and 1.6 percent compared with diesel fuel

[3] *Id.* Page 3.1-3

> and gasoline, respectively. Technologies are available to reduce much of the leaking methane.[4]

Natural gas is not a "bridge fuel" because it does not reduce the emissions of greenhouse gases.

Environmental Justice

The most recent available census data reveals that Charles City County with a total population of just over 7,000. The county's population is 43.3% white, 45.9% African American and 6.9% Native American.[5]

Many studies have shown that hazardous and solid waste facilities, industrial plants, and power stations of many types have traditionally been sited disproportionately in communities of color and low-income neighborhoods. In addition to being aesthetically unappealing, power plants emit toxic air pollution which has a negative effect on the health and well-being of plant neighbors. Low-income communities often lack the economic or political clout to fight these facilities. A review of environmental justice and equity law by the American Bar Association and the Hastings College of Law revealed the following:

> Poor communities of color breathe some of the least healthy air in the nation. For example, the nation's worst air quality is in the South Coast Air Basin in Southern California, where studies have shown that Latinos are twice as likely as Whites to live within one mile of an EPA Toxic Release Inventory listed facility, and Latinos, African Americans, and Asian populations in the region face 50% higher cancer risks than Anglo-Americans in the region. Advocates nationwide argue that because poor people of color bear a disproportionate burden of air pollution, their communities should receive a disproportionate share of money and technology to reduce toxic emissions, and that laws like the Clean Air Act should close loopholes that allow older, polluting facilities to escape pollution control upgrades.[6]

Walter Fauntroy, District of Columbia Congressional Delegate to Congress, prompted the General Accounting Office to investigate environmental justice issues. The GAO released its findings that three-quarters of the hazardous waste landfill sites in eight southeastern states were located in primarily poor, African American and Latino communities. United Church of Christ's Commission for Racial Justice published *Toxic Wastes and Race in the United States*, which revealed that race was the single most important factor in determining where toxic facilities were located, and that it was the intentional result of local, state and federal land-use policies. Dr.

[4] Environmental Impacts of Natural Gas, http://www.ucsusa.org/clean-energy/coal-and-other-fossil-fuels/environmental-impacts-of-natural-gas#bf-toc-1
[5] https://www.census.gov/quickfacts/fact/table/charlescitycountyvirginia/PST045217
[6] Environmental Justice for All: A Fifty State Survey of Legislation, Policies and Cases (fourth ed.), Steven Bonorris, Editor , Copyright © 2010 American Bar Association and Hastings College of the Law. With citation, any portion of this document may be copied and distributed for non-commercial purposes without prior permission. All other rights are reserved. http://www.abanet.org/environ/resources.html or www.uchastings.edu/cslgl

Robert Bullard published *Dumping in Dixie: Race, Class, and Environmental Quality*, in which he showed the importance of race as a factor in the siting of polluting industrial facilities.[7]

Virginia Law Requires Equitable Development

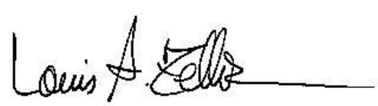
The Hastings study also focused on individual state law and found that Virginia statutes governing energy development articulate support for environmental justice. One of the stated objectives is "developing energy resources and facilities in a manner that does not impose a disproportionate adverse impact on economically disadvantaged or minority communities."[8]

The Virginia statutes direct various state agencies to work together to create a comprehensive 10-year energy plan that reinforces the EJ and other objectives.[9] The state's 10-Year Plan, among other things, must include the following information: an analysis of siting of energy facilities to identify any disproportionate adverse impact of such activities on economically disadvantaged or minority communities. In considering which parcels of land are suitable for energy facility development, the agencies must consider, in addition to technical matters, "potential impacts to natural and historic resources and to economically disadvantaged or minority communities and compatibility with the local land use plan."[10] State law is clear in this matter. Todate, the county the Planning Commission and the State Corporation Commission have failed with respect to its statutory obligation to ensure that the Chickahominy Power plant does not have a disproportionate impact on Charles City County's African American community. Unless and until state law in complied with, DEQ cannot approve this permit.

Conclusion

The Virginia Department of Environmental Quality lacks adequate regulatory basis for this facility and cannot issue a permit for the Chickahominy Power plant until the applicant demonstrates it has met all statutory requirements.

Respectfully submitted



Louis A. Zeller
Executive Director

[7] Natural Resources Defense Council, https://www.nrdc.org/stories/environmental-justice-movement
[8] VA. CODE ANN. § 67-101 (2009); *see also Id*. at § 67-102, stating that to achieve the objectives of § 67-101, it shall be the policy of the Commonwealth to "ensure that development of new, or expansion of existing, energy resources or facilities does not have a disproportionate adverse impact on economically disadvantaged or minority communities."
[9] *Id*. at § 67-201
[10] *Id*. at § 67-201(d)

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

RE: FW: Balico LLC; Registration No. 52610

1 message

bredl@skybest.com <bredl@skybest.com> Wed, Apr 3, 2019 at 6:27 PM
To: "Sinclair, Alison" <alison.sinclair@deq.virginia.gov>

Ms. Sinclair,

I write to confirm the comments I submitted on both March 20 and March 27 were identical. The first was filed with an incorrect email for you, which was an oversight on my part.

Below, I have copied the March 20 email with the typo in your last name in the email address highlighted in yellow.

Thank you for your attention to this matter.

Louis A. Zeller, Executive Director

Blue Ridge Environmental Defense League, Inc.

Main Office: PO Box 88 Glendale Springs, NC 28629

Phone: 1-336-982-2691

Mobile: 1-336-977-0852

Email: BREDL@skybest.com

Website: www.BREDL.org

Founded in 1984, we have projects and chapters in Alabama, Georgia, Tennessee, South Carolina, North Carolina and Virginia

From: bredl@skybest.com <bredl@skybest.com>
Sent: Wednesday, March 20, 2019 5:03 PM
To: 'alison.sinclari@deq.virginia.gov' <alison.sinclari@deq.virginia.gov>
Cc: Sharon Ponton <ponton913@msn.com>; Mark E. Barker <mebarker@cox.net>
Subject: Balico LLC; Registration No. 52610

March 20, 2019

Alison Sinclair

Virginia Dept. of Environmental Quality

P.O. Box 1105

Richmond, VA 23218

alison.sinclair@deq.virginia.gov

RE: Balico LLC; Registration No. 52610

Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Comments Attached

From: Sinclair, Alison <alison.sinclair@deq.virginia.gov>
Sent: Wednesday, April 3, 2019 9:30 AM
To: bredl@skybest.com
Subject: Re: FW: Balico LLC; Registration No. 52610

Mr. Zeller,

I am compiling the comments for the PSD permit for Chickahominy Power and need your help. Since we received your comments a week later than the deadline for the Public Comments for the Chickahominy Air Permit we want to make sure that the comments are not excluded as part of the record by someone not familiar with the circumstances. The DEQ is requesting that you verify that the comments that were attached to the email that you sent on March 27th were not modified or revised in any way from the comments that you attempted to send us on the 20th. **Could you reply with a statement that confirms what happened between March 20th and March 27th, and if the comments you sent on the 27th were the same as what was attached to the March 20th email that bounced?**

I will then include your statement in the file as part of the record explaining what happened. Thank you very much for your attention to this matter.

On Wed, Mar 27, 2019 at 2:28 PM Sinclair, Alison <alison.sinclair@deq.virginia.gov> wrote:

> Hey, we got it! I'm in the middle of compiling the comments so it will be counted. Thank you.
>
> On Wed, Mar 27, 2019 at 2:19 PM <bredl@skybest.com> wrote:
>
>> TO: Alison Sinclair
>>
>> FROM: Lou Zeller, BREDL
>>
>> RE: Balico Chickahominy permit
>>
>> I apologize for the email error. My comments are attached.
>>
>> Thank you for all you do,
>>
>> Lou
>>
>> Louis A. Zeller, Executive Director
>>
>> Blue Ridge Environmental Defense League, Inc.
>>
>> Main Office: PO Box 88 Glendale Springs, NC 28629
>>
>> Phone: 1-336-982-2691
>>
>> Mobile: 1-336-977-0852
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>> Email: BREDL@skybest.com
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>> Website: www.BREDL.org
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>> Founded in 1984, we have projects and chapters in Alabama, Georgia, Tennessee, South Carolina, North Carolina and Virginia
>>
>> ---
>>
>> **From:** bredl@skybest.com <bredl@skybest.com>
>> **Sent:** Wednesday, March 20, 2019 5:03 PM
>> **To:** 'alison.sinclari@deq.virginia.gov' <alison.sinclari@deq.virginia.gov>
>> **Cc:** Sharon Ponton <ponton913@msn.com>; Mark E. Barker <mebarker@cox.net>
>> **Subject:** Balico LLC; Registration No. 52610
>>
>> March 20, 2019
>>
>> Alison Sinclair
>>
>> Virginia Dept. of Environmental Quality
>>
>> P.O. Box 1105
>>
>> Richmond, VA 23218
>>
>> alison.sinclair@deq.virginia.gov
>>
>> **RE: Balico LLC; Registration No. 52610**
>>
>> **Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171**
>>
>> Comments Attached
>
> --
>
> Alison Sinclair
>
> Air Permit Writer Sr II
>
> DEQ Piedmont Regional Office
>
> 4949 Cox Road
>
> Glen Allen, VA 23060
>
> (804) 527-5155

--

Alison Sinclair

Air Permit Writer Sr II

DEQ Piedmont Regional Office

4949 Cox Road

Glen Allen, VA 23060

(804) 527-5155

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

No natural gas plant in Charles City: Transition to sustainable energy

1 message

whati <whatican@hotmail.com> Wed, Mar 20, 2019 at 11:55 PM
To: "Alison.Sinclair@DEQ.virginia.gov" <Alison.Sinclair@deq.virginia.gov>

from Gretchen Boise
224 Academy Street
Salem, VA 24153

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Chickahominy Power Station

1 message

Tiziana Bottino <tiziana.bottino@gmail.com> Wed, Mar 20, 2019 at 11:59 PM
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair,
I would like to address my concern about the Chickahominy Power Station and request that this project by reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.
Thank you for your time and attention.

Best,
Tiziana

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Concerns for Chickahominy Power Station

1 message

Frank Cain <frankjcain1988@gmail.com> Wed, Mar 20, 2019 at 8:34 AM
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair,
I would like to register my concern about the Chickahominy Power Station and request that this project by reviewed by the Air Pollution Control Board.
APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171
Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed. Thank you for your time and attention.

Frank Justin Cain
500 Hull Street, Apt 117 Richmond VA 23224

● The closest monitoring station, at Shirley Plantation, sits in the opposite direction from prevailing winds relative to the Chickahominy Power Station.
○ Violations will be difficult to detect.
○ With two proposed fracked gas plants and one landfill on site, it will be difficult to determine which site is in violation.
○ How will DEQ ensure that violations are being captured and appropriately charged?

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Please review the air permit for the Chickahominy Power Station - Fracked Gas is the wrong choice
1 message

Gregory Caplan <campaigns@good.do> Wed, Mar 20, 2019 at 1:29 PM
Reply-To: Gregory Caplan <glcaplan@earthlink.net>
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair

I would like to register my concern about the Chickahominy Power Station and request that this project be reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.

No more Fracked gas projects should be built ! This fossil industrial process is an abomination against nature and a threat to humanity and all living things.
Stop it now !

Thank you for your time and attention.
NAME:
ADDRESS:
PHONE NUMBER:

Yours sincerely,
Gregory Caplan

____
This email was sent by Gregory Caplan via Do Gooder, a website that allows people to contact you regarding issues they consider important. In accordance with web protocol FC 3834 we have set the FROM field of this email to our generic no-reply address at campaigns@good.do, however Gregory provided an email address (glcaplan@earthlink.net) which we included in the REPLY-TO field.

Please reply to Gregory Caplan at glcaplan@earthlink.net.

To learn more about Do Gooder visit www.dogooder.co
To learn more about web protocol FC 3834 visit: www.rfc-base.org/rfc-3834.html

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Permit for Charles City New Natural Gas Plant
1 message

Freeda Cathcart <contactfreeda@gmail.com> Wed, Mar 20, 2019 at 2:55 PM
To: Alison.Sinclair@deq.virginia.gov

Please deny the request and permit for a new natural gas plant in Charles City. Energy efficiency and renewables have eliminated the need to build new natural gas plants. It would be irresponsible to harm the environment while holding Virginia's economy with outdated fossil fuel energy production.

My family still lives on Shirley plantation and it would be unfair for them and others in the surrounding area to be subjected to more air pollution for no good reason.

Thank you,
Freeda Cathcart
Roanoke, Virginia
--
540-598-7231

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Project Review Request - Chickahominy Power Station

1 message

Nicole Falceto <nfalceto@gmail.com> Wed, Mar 20, 2019 at 6:30 AM
To: alison.sinclair@deq.virginia.gov

I would like to register my concern about the Chickahominy Power Station and request that this project by reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.

This permit should be rejected because we are looking to limit our greenhouse gas emissions from our fossil-fuel sector. DEQ monitors carbon not methane. Although methane emissions are lower than carbon dioxide emissions, it is a major greenhouse gas because each methane molecule has 86 times the global warming potential of a carbon dioxide molecule.

As an independent power producer, Chickahominy would sell its power directly to the **PJM Interconnection wholesale market. This is a major polluter that will soil our air quality for profit to markets far, far away. With limited economic benefit to Virginians, why should we shoulder the pollution burden?

This is the LARGEST proposed fracked gas plant in the country. At 1,650 Megawatts, it is bigger than nearby Chesterfield Power Station. In a time of declining fracked gas need, rising energy efficiencies, and more accessible renewable options - do we really need to commit to this large scale plant that would be in operation for the next 40 years?

There is already a higher incidence than normal of both chronic obstructive pulmonary disease and asthma in this county, and any additions to polluting this atmosphere is of great concern. Virginia Department of Health maps show that relative to other areas of Virginia, Charles City County and the surrounding region show higher incidences of asthma.

Thank you for your time and attention.

Nicole Falceto
41314 Cochran Mill RD
Leesburg, VA 20175
703 830 3590

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Chickahominy Power Station, Balico LLC; 52610

1 message

Lakshmi Fjord <lakshmi.fjord@gmail.com> Wed, Mar 20, 2019 at 10:02 AM
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair,

I write to strongly oppose the permit for the Chickahominy Power Station applied for by Balico LLC; registration number, 52610.

There are too many unanswered questions and issues related to environmental justice and geometrically increasing the cumulative impacts of already existing sources of toxic emissions that impact the health of nearby residents most, but also would contribute to climate change. At this time when the price of renewables is decreasing at the fastest rate in history, when corporations like Walmart seek to change over completely to renewables, why are our state and our counties not looking at energy production and distribution that will do no harm? Gas is now proven to be far more harmful to climate change and health than once industry-driven only science claimed. Those claims are no longer accepted by credentialed scientists who are independent and peer-review the scientific evidence through actual site testing, gas contents testing, air monitoring, and leak testing. Do you in Charles County know enough about these studies to ensure that your neighbors and your children and grandchildren are actually protected? Most of us do not, and there is no shame in that lack of information, because gas transmission and production corporations have been able to shield themselves from even physicians asking about the contents of emissions after patients nearby to the fracked gas well drilling sites, compressor stations, and gas plants turn up with devastating symptoms of toxic exposure. Corporations have been able to claim this vital preventive and emergency health information is considered proprietary. Therefore at this time, shielding corporations from purported "competition" overrides the need county and state governments need to make informed decisions.

Without that information, granting a permit to this gas plant is a far worse gamble with your health and well-being that most are being allowed to know and realize. All across the county, independent scientists who are not paid by the industry are finding that even small amounts of the chemicals to which you would allow residents to be exposed is causing premature mortality. In fact, toxic pollution now accounts for over 25% of U.S. mortality. Why aid corporations who only object is profit to target your community for so much toxic pollution? Is it located in the suburbs of the CEOs? Of course not. The environmental injustice of fracked gas infrastructure is that all of the worst pollution, the well sites, the compressor stations, the power plants are all located in low-income places, in places that have long faced discrimination by being primarily rural, or a majority are minorities, or Appalachians.

We can no longer afford to spend one more cent on building gas infrastructure for which there is no need at all. The State Corporate Commission did not accept Dominion Power's energy plan because it was replete with misinformation about the need for any further gas infrastructure. They are paying themselves the money required to be spent for energy efficiency to profit themselves but also to ensure that no energy efficiency measures will lesson need for gas. It is not possible to trust the projections of the gas industry because they must convince places like Charles County that there is a need. All across the Eastern U.S., the factual information about no-need is reaching local communities, agencies, and national leaders. As former VP Al Gore just said in Union Hill, Buckingham, Virginia, gas producers and transmission companies receive their money through *building* the infrastructure and then passing the costs along to utlity rate payers for generations. Do you want Charles County and its residents to be entirely indebted and committed to an energy source that *no one wants who is forward thinking?*

The gas explosions in Massachusetts that were responsible for over 75 homes being destroyed, have now been closely studied. Those occurred when the high pressure fracked gas whose contents contain all of the more than 80 forms of toxic chemicals that are used in the fracking process were distributed into smaller pipelines and then the fracked gas entered homes and kitchens and blew up. Studies of the contents of those pipelines found every form of toxic chemical used in fracking were entering into our kitchen and homes through our stoves, through leaks in the gas pipes. And, there is no agency in our state or nation that is holding those pipeline transmission companies accountable for keeping this information from the agencies and the public.

Therefore, the only wise approach is to say no to the pressure by industry to quickly permit this power station. It is not needed. The market will end this rush to build. But, if built, the cost will be passed on to you and every other utility rate payer in Virginia --- one of the few states that allows this form of self-dealing by parent companies of utility providers.

Please take the cautious course and deny this permit. The promised tax revenues are proven to completely over-inflated. Please look to other places that already have this infrastructure in place to see how the companies keep what they pay those who carry the greatest burdens of their toxic pollution as low as possible.

Wish you all the best in making the decision that you can live with for generations to come, and not the fast and pressured decisions forced upon you by those who have no interest in the well-being of the people most impacted.

Sincerely,
Lakshmi Fjord, Ph.D.
Friends of Buckingham County Virginia
Visiting Scholar, Dept. of Anthropology, University of Virgnia
420 Altamont St., Charlottesville, VA 22902
cell: 510-684-1403

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Natural Gas Plant in Charles City, VA

1 message

Matthew Fleenor <matthewcfleenor@gmail.com> Wed, Mar 20, 2019 at 9:42 PM
To: Alison.Sinclair@deq.virginia.gov

Hello Alison.
Let's don't seek out new reasons to justify a pipeline after the fact. We know that the ACP and MVP are bad for Virginia, and Virginians have spoken out about prostituting our natural lands in order for folks in PA and WV to get rich (and their shareholders). If we are now trying to find reasons to justify the pipeline ex post facto, that is not good business, nor is it good representation. We do not need a natural gas plant in Charles City, VA. Or, do we?

Please send me some literature and/or electronic websites from (mostly) unbiased sites that reveal a deficit that could be met by natural gas. It is well-documented that the Eastern seaboard is saturated with natural gas pipelines, so it seems odd to me that we would wholesale agree to allow more to be built (and then find a reason to justify private investors to make money from it). I am a natural learner and I want to try and keep an open mind.

Peace, and best. I'm sure your job is not an easy one.
Matthew C Fleenor, PhD, citizen of Salem, VA

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Comment for DEQ in regard to Power Station in Charles City County

1 message

Charles Brown <chbrown@greenpeace.org>
To: Alison.Sinclair@deq.virginia.gov

Wed, Mar 20, 2019 at 1:13 PM

Dear Department of Environmental Quality.

My name is Charles Brown and I work for Greenpeace. I'm also a resident of Virginia and therefore have an interest in how my state generates energy.

At a time when we as a species should be scaling back our use of dirty energy, the proposed natural gas Chickahominy Power Station to be constructed in Charles City County will lead our species further in the wrong direction. According to the Intergovernmental Panel on Climate Change it necessary and even vital to maintain the global temperature increase below 1.5°C versus higher levels in order to prevent the catastrophic effects of climate change within the next 15 years.

In addition to be unmindful of environmental impacts to the area, this project is also fiscally irresponsible for one main reason: data centers are being used as one of the main justifications for the construction of power plants like the Chickahominy Power Station, yet many data companies including Facebook, Microsoft, Amazon Web Services and more, representing more than 3GW energy capacity in Virginia, have already committed to use 100% renewable energy and are actively pursuing non-fossil fuel energy sources in Virginia, which further questions the need for new gas infrastructure.

We need dramatic investment in more clean energy projects in the state, such as the proposed construction of a 340-megawatt solar farm in Charles City County, VA.

We can and must power our grid with clean, renewable energy that doesn't contribute to greenhouse gas emissions, toxic air quality from fumes or polluted land and water from waste run off.

For these reasons, I urge you to reject permit to construct the Chickahominy Power Station being proposed to Charles City County by Chickahominy Power, LLC, a subsidiary of Balico, LLC.

Thank you for your time

Charles Brown
He/Him
Greenpeace USA Pipeline Organizer
Direct Phone: 757-842-3000
Skype: live:526dbd56c23682cb

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Air Quality Permit for the Chickahominy Power Plant

1 message

Thomas Hadwin <tzhad13@gmail.com>
To: Alison.Sinclair@deq.virginia.gov

Wed, Mar 20, 2019 at 4:41 PM

Prevention of Significant Deterioration Permit

Air Pollution Control Board

Applicant: Balico LLC 52610

Chickahominy Power Station

Alison.Sinclair@DEQ.virginia.gov

Dear Ms. Sinclair,

I wish to express my concern to the Air Pollution Control Board about the permit being considered for the Chickahominy Power Station being developed by Ballico LLC in Charles City County, Virginia.

Demand for electricity is not growing in Virginia, as shown by the actual weather normalized peak demand in Virginia for the past nine years, compared to Dominion's over-estimated forecasts, as shown below:

https://i0.wp.com/www.baconsrebellion.com/app/uploads/2018/09/Dom-Weather-Normalized.jpg?resize=500%2C370&ssl=1

PJM, our regional independent system operator, has reported that it has a surplus in capacity beyond what it needs to meet its reserve requirements. New gas-fired power plants are under construction around the gas fields in Pennsylvania and Ohio that will add to this surplus.

As a merchant generator, Ballico is developing this project at its own financial risk. However, such a development will have an impact on the citizens of Virginia.

The DEQ and the Air Quality Board are considering the implementation of carbon dioxide emission controls in Virginia that will link to the RGGI auction. A cap of 28 million tons of CO_2 has been established for Virginia in 2020. That cap will be shared by all electricity generators over 25 MW. The 1,650 MW Chickahominy plant will be the largest fossil-fired unit in Virginia. As such, it will use a significant portion of Virginia's CO_2 budget, which is intended to decline by 3% each year.

With a portion of the budget occupied by the Chickahominy plant, there will be greater pressure for investor-owned utilities in Virginia to retire some of their older coal, oil- and gas-fired units earlier than planned. Because these units are in the rate base, even if they are no longer operating, ratepayers will be obligated to continue paying for them until they reach the end of their financial life. Ratepayers also could be exposed to earlier payments for replacement capacity for these units.

Higher energy costs to families and businesses ripple through our economy. If built by a generator that supplies energy to those customers, the higher costs can be offset to some degree. However, as a merchant generator, the Chickahominy plant will be using up the carbon cap at the expense of Virginians, while providing energy to customers elsewhere in PJM.

In addition, we have been told to think of gas-fired power plants as a "clean" alternative to coal. From a total greenhouse gas perspective, this is not the case. Along with the CO_2 released from a new gas-fired generator, the methane releases along the supply chain and from the power plant are the source of greenhouse gas effects equal to the greenhouse gas effects of the CO_2 emissions. Methane is released in much lower quantities but it is 86 times more potent as a greenhouse gas compared to CO_2 20 years after its release and 34 times more potent after 100 years.[1], [2]

By authorizing this new facility, the Air Quality Board would have approved the release of greenhouse gases that have the greenhouse gas impact equivalent to the releases from a 1,650 MW coal plant. No benefit would accrue to Virginia because the power will be consumed by others outside the state. We will be left with poorer air quality, and higher costs.

Please take these factors into consideration when reviewing the request for the air quality permit.

Respectfully submitted,

Thomas Hadwin

Former electric & gas utility executive

328 Walnut Ave.
Waynesboro, VA 22980
540 256-7474

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[1] *Assessment of methane emissions from the U.S. oil and gas supply chain,* Ramon A. Alvarez, et al., Science, July 13, 2018, Vol. 361, Issue 6398, pp. 186 -188

[2] *Assessing the Methane Emissions from Natural Gas-Fired Power Plants and Oil Refineries,* Tegan N. Lavoie, et al., Environmental Science & Technology, February 21, 2017, 51 (6), pp 3373-3381, https://pubs.acs.org/doi/full/10.1021/acs.est.6b05531

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Please review the air permit for the Chickahominy Power Station - Fracked Gas is the wrong choice

1 message

Kenda Hanuman <campaigns@good.do> Wed, Mar 20, 2019 at 9:45 AM
Reply-To: Kenda Hanuman <kendahanuman@gmail.com>
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair

I would like to register my concern about the Chickahominy Power Station and request that this project be reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.

Thank you for your time and attention.
Kenda Hanuman
247 Ramaa Lane
Buckingham, VA 23921

Yours sincerely,
Kenda Hanuman

This email was sent by Kenda Hanuman via Do Gooder, a website that allows people to contact you regarding issues they consider important. In accordance with web protocol FC 3834 we have set the FROM field of this email to our generic no-reply address at campaigns@good.do, however Kenda provided an email address (kendahanuman@gmail.com) which we included in the REPLY-TO field.

Please reply to Kenda Hanuman at kendahanuman@gmail.com.

To learn more about Do Gooder visit www.dogooder.co
To learn more about web protocol FC 3834 visit: www.rfc-base.org/rfc-3834.html

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

permits for the Chickahominy Power Station

1 message

Pamela Hill <pamatrlpc@gmail.com> Wed, Mar 20, 2019 at 12:50 AM
To: alison.sinclair@deq.virginia.gov

.Dear Ms. Sinclair,

My name is Pamela Hill and I both live and work in Chesterfield County, as do many members of my family. My address is 8112 Hillcreek Drive, Midlothian, 23112. My phone number is 804-739-2768.

I would like to register my concern about the Chickahominy Power Station and request that this project by reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171
Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.
○ The Air Pollution Control Board (board) primarily considers the adoption, amendment or repeal of regulations at meetings and may consider the issuance or amendment of certain permits. The regulations concern the control and reduction of air pollution throughout the Commonwealth or in affected areas. The Department of Environmental Quality administers the day-to-day operation of Virginia's air pollution programs, issues permits, and enforces permits and regulations as delegated by Virginia law. Please let the Air Pollution Board review the cumulative impacts of this fracked gas plant before it is rubber stamped by DEQ.

● As an independent power producer, Chickahominy would sell its power directly to the **PJM Interconnection wholesale market. This is a major polluter that will soil our air quality for profit to markets far, far away. With limited economic benefit to Virginians, why should we shoulder the pollution burden?
○ **PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.
○ PJM is expecting capacity to significantly outstrip demand in the near future, according to data from the organization. Dominion has said it has no plans to build new combined-cycle natural gas facilities.
● This permit should be rejected because we are looking to limit our greenhouse gas emissions from our fossil-fuel sector. DEQ monitors carbon not methane. Although methane emissions are lower than carbon dioxide emissions, it is a major greenhouse gas because each methane molecule has 86 times the global warming potential of a carbon dioxide molecule.
○ In a time of increasing threats from climate change, Virginia needs to be driving down our greenhouse gas emissions not increasing them.
● There is already a higher incidence than normal of both chronic obstructive pulmonary disease and asthma in this county, and any additions to polluting this atmosphere is of great concern. Virginia Department of Health maps show that relative to other areas of Virginia, Charles City County and the surrounding region show higher incidences of asthma.
● This is the LARGEST proposed fracked gas plant in the country. At 1,650 Megawatts, it is bigger than nearby Chesterfield Power Station.
○ In a time of declining fracked gas need, rising energy efficiencies, and more accessible renewable options - do we really need to commit to this large scale plant that would be in operation for the next 40 years?
● The closest monitoring station, at Shirley Plantation, sits in the opposite direction from prevailing winds relative to the Chickahominy Power Station.

○ Violations will be difficult to detect.

○ With two proposed fracked gas plants and one landfill on site, it will be difficult to determine which site is in violation.
○ How will DEQ ensure that violations are being captured and appropriately charged?

I did not write the above questions, but in reading each one I find they raise serious concerns about the safety of these power plants.

thank you for your time and please note the actions on this will affect the health of many people.

Sincerely,

Pamela Hill

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Virginia's best energy choices

1 message

Cindy Honeycutt <hrahdoc@yahoo.com> Wed, Mar 20, 2019 at 8:42 PM
To: alison.sinclair@deq.virginia.gov

To all at Virginia DEQ,
Considering that we need to work toward less air and water pollution and have many more excellent environmentally and health conscious energy options for Virginia, a natural gas plant in Charles City, Virginia would not be a wise direction for Virginia. It is also not appropriate to place this plant in a marginalized community whose voices are often ignored. I hope you will make wise decisions for Virginia.

Warm Regards,
Cinthia Honeycutt

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Chickahominy Power Station requires stronger consideration

1 message

Morgan Johns <morgan.avery.johns@gmail.com>
To: alison.sinclair@deq.virginia.gov

Wed, Mar 20, 2019 at 11:09 AM

Good morning, Ms. Sinclair,

My name is Morgan Johns and I live at 728 W Marshall St, Richmond, VA 23220. I am 19 years old and will one day be left to deal with the consequences of such projects as the Chickahominy Power Station. I encourage that it be thoroughly considered by the Air Pollution Control Board.

According to its mission statement, the Virginia Department of Environmental Quality “protects and enhances Virginia’s environment, and promotes the health and well being of the citizens of the Commonwealth.” Nowhere in these self-imposed guidelines does it state that corporations take precedence over human health. Evidence against fossil fuel usage is not only ample, but so urgently relevant that global policy actively directs towards its immediate reduction. A localized project cannot assume that it is separate from the world. Air and water know no passports, epidemics and oblivion stretch far beyond their country’s limits. The more that is developed, the further problems we have. We must be subtracting, not adding.

Supporters propose vague reassurance that is meant to subdue the masses. For example, Charles City Supervisor Bill Coada stated, “if you compare it to a coal-fired unit, you’ll find these are much cleaner.” In this planet’s state of emissions emergency, we cannot afford to permit further dangerous activities on the grounds that they are not the worst offenders. They are still offenders. As a Virginia resident, I denounce the fact that such passive statements could put the DEQ’s priority - my health - at risk.

For further information on the dangers that such work imposes, I strongly recommend David Wallace-Wells new book, “The Uninhabitable Earth.” Having been born in 1999, my primary goal in life has always been to live until 2100. That way, I will have experienced three centuries. This book is proving to me that my goal will rely more heavily on environmental policy than exercise and a healthy diet, seeing as humanity itself is threatened by the end of the century.

To conclude, I reinforce that I strongly urge for the weaknesses of the Chickahominy Power Station to be addressed and heavily considered by the Air Pollution Control Board.

Thank you for your attention to this matter,

Morgan Johns

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Chickahominy Power Station

1 message

Stephanie Malady <stephaniemalady@hotmail.com> Wed, Mar 20, 2019 at 7:47 AM
To: "alison.sinclair@deq.virginia.gov" <alison.sinclair@deq.virginia.gov>

Dear Ms. Sinclair,

I would like to register my concern about the Chickahominy Power Station and request that this project by reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610

FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.

Thank you for your time and attention.

Stephanie Malady
3248 W Hundred Rd
Chester, VA 23831
804.513.3979

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

gas-fired power plant in Charles City County

1 message

Charlotte McConnell <charlottepsnnova@gmail.com> Wed, Mar 20, 2019 at 1:36 PM
To: Alison.Sinclair@deq.virginia.gov

We do not need a new natural gas-fired power plant in Charles City County. We need to be investing in clean energy and not outdated technology.

Pronouns she/her/hers
Charlotte McConnell
about.me/charlottemcconnell

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

No need for a natural gas plant in Charles City

1 message

Cynthia Munley <cmunley@live.com> Wed, Mar 20, 2019 at 4:52 PM
To: "Alison.Sinclair@DEQ.virginia.gov" <Alison.Sinclair@deq.virginia.gov>

There is no need for a natural gas plant in Charles City, Virginia. It would afflict a marginalized community and is the wrong direction for VA. We do not need more air and water pollution.

Cynthia Munley
Salem, VA

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

No need for a natural gas plant in Charles City

1 message

Frank Munley <fjmunley@gmail.com>
To: "Alison.Sinclair@deq.virginia.gov" <Alison.Sinclair@deq.virginia.gov>

Wed, Mar 20, 2019 at 4:58 PM

Dear Ms. Sinclair:

There is no need for a natural gas plant in Charles City, Virginia. It would afflict a marginalized community and is the wrong direction for VA. We do not need more air and water pollution. There is a superglut of gas already, in large part because natural gas plants are on the way out. That's one reason why the GE plant in Salem is downsizing. Generate electricity with gas? That's so gone!

Frank Munley
Salem, VA

http://munley.weebly.com
fjmunley@gmail.com

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Please review the air permit for the Chickahominy Power Station - Fracked Gas is the wrong choice

1 message

David Partington <campaigns@good.do> Wed, Mar 20, 2019 at 1:40 PM
Reply-To: David Partington <sagecarpentry@yahoo.com>
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair

I would like to register my concern about the Chickahominy Power Station and request that this project be reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.

Thank you for your time and attention.
NAME: David Partington
ADDRESS: 1691 White Rock Rd. N.W., Floyd, Va.24091
PHONE NUMBER:

Yours sincerely,
David Partington

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This email was sent by David Partington via Do Gooder, a website that allows people to contact you regarding issues they consider important. In accordance with web protocol FC 3834 we have set the FROM field of this email to our generic no-reply address at campaigns@good.do, however David provided an email address (sagecarpentry@yahoo.com) which we included in the REPLY-TO field.

Please reply to David Partington at sagecarpentry@yahoo.com.

To learn more about Do Gooder visit www.dogooder.co
To learn more about web protocol FC 3834 visit: www.rfc-base.org/rfc-3834.html

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

comment on the construction of a new natural gas plant in Charles City, Virginia

1 message

Theresia Riesenhuber (WORTgewalt) <redaktion@wortgewalt.com> Wed, Mar 20, 2019 at 4:23 PM
To: "Alison.Sinclair@DEQ.virginia.gov" <Alison.Sinclair@deq.virginia.gov>

Dear Mrs. Sinclair,

Carbon pollution from burning fossil fuels like coal, oil, and yes, natural gas is warming our planet and driving climate change. It's throwing natural systems out of balance – to often devastating effect. That means, events like torrential rains, floods, heatwaves, hurricanes, the "polar vortex," and drought are becoming more frequent and/or intense.

Natural gas is not a zero-emissions fuel. When burned, it produces approximately half the carbon emissions of coal per unit of electricity generated, but the drilling, extraction, and pipeline transportation of natural gas frequently results in methane leakage. These leaks can sometimes be substantial.

Shifting the U.S. from a coal- to a natural gas-dominated electricity system would still generate substantial global warming emissions — and fail to effectively address the growing dangers of climate change. Natural gas does have a role to play in the U.S. power supply, but an overreliance on natural gas over the long-term will not achieve the emissions reductions needed to address global warming.

Instead the U.S. must invest in achieving a low-carbon electricity future by generating more electricity from renewable energy sources and improving energy efficiency.

I urge you to reconsider your support for the construction of a new natural gas plant in Charles City. A long-term solution is relying on sustainable energy sources – as solar, wind and water.

Thanks and with kind regards,

Theresia Riesenhuber

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Please think again....
1 message

Brent Riley <BrentRiley2005@msn.com>
To: "Alison.Sinclair@DEQ.virginia.gov" <Alison.Sinclair@deq.virginia.gov>
Wed, Mar 20, 2019 at 9:19 PM

...on the propriety of more natural gas plants. Moisture records are being broken all over the world, threatening indigenous cultures, endangered species, and a livable planet. Virginia's beauty is more valuable than profits for enterprising propositions based on monetary gain.

We must take a longer view and respect the future.

Thanks for your consideration,
Brent Riley
Roanoke, VA

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Please review the air permit for the Chickahominy Power Station - Fracked Gas is the wrong choice

1 message

Donna Shaunesey <campaigns@good.do> Wed, Mar 20, 2019 at 7:25 PM
Reply-To: Donna Shaunesey <shaunesey@hotmail.com>
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair

The Chickahominy is one of my favorite paddling destinations. Clean water and clean air are my favorite things, along with slowing down climate change. I would like to register my concern about the Chickahominy Power Station and request that this project be reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.

Thank you for your time and attention.
NAME:
ADDRESS:
PHONE NUMBER:

Yours sincerely,
Donna Shaunesey
Charlottesville, Virginia, 22903, United States

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This email was sent by Donna Shaunesey via Do Gooder, a website that allows people to contact you regarding issues they consider important. In accordance with web protocol FC 3834 we have set the FROM field of this email to our generic no-reply address at campaigns@good.do, however Donna provided an email address (shaunesey@hotmail.com) which we included in the REPLY-TO field.

Please reply to Donna Shaunesey at shaunesey@hotmail.com.

To learn more about Do Gooder visit www.dogooder.co
To learn more about web protocol FC 3834 visit: www.rfc-base.org/rfc-3834.html

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Natural Gas Power Plant in Charles City

1 message

Shelley Sheehe <shelleysheehe@lizmoore.com> Wed, Mar 20, 2019 at 10:32 PM
To: "Alison.Sinclair@DEQ.virginia.gov" <Alison.Sinclair@deq.virginia.gov>

To whom it may concern,

As a resident of Charles City, Va. I am most concerned with the health and environmental impacts of such a facility.

Green house emissions of this level are no longer acceptable in our environment.

There could be significant health issues associated living near such a plant.

The project should be sent for review by the State Air Quality Control Board.

Thank you,

Shelley Sheehe, Realtor
Liz Moore & Associates
5350 Discovery Park Blvd
Williamsburg, Va 23188
757-870-4640

Licensed in Va

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Sierra Club's Comments on Chickahominy PSD permit

1 message

Tess Fields <tess.fields@sierraclub.org> Wed, Mar 20, 2019 at 3:57 PM
To: Alison.Sinclair@deq.virginia.gov
Cc: Dori Jaffe <dori.jaffe@sierraclub.org>

Good afternoon,

Attached please find Sierra Club's Comments on the Draft Prevention of Significant Deterioration Permit for the Proposed Chickahominy Power Combined Cycle Power Plant (Registration No. 52610) and relevant exhibits.

Regards,
Tess Fields

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Tess Fields
Legal Assistant
Environmental Law Program
50 F Street NW, Eighth Floor
Washington, DC 20001
Phone: 202-548-4593
E-mail: tess.fields@sierraclub.org

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Proudly represented by Progressive Workers Union (PWU)

3 attachments

Sierra Club Comments on Chickahominy PSD Permit with exhibits.pdf
16061K

Ex 7_Shirley Plantation NO2 Monitor Summary Values 2014 to 2018.xlsx
14K

Ex 8_Chickahominy_Inventory.xlsx
87K

March 20, 2019

Ms. Alison Sinclair
Virginia Division of Air Environmental Quality
Piedmont Regional Office
4949 Cox Road
Glen Allen, Virginia 23060
Via e-mail to Alison.Sinclair@DEQ.virginia.gov

Re: **Sierra Club Comments on the Draft Prevention of Significant Deterioration Permit for the Proposed Chickahominy Power Combined Cycle Power Plant (Registration No. 52610)**

Dear Ms. Sinclair:

On behalf of its more than 20,000 Virginia members, Sierra Club respectfully submits these comments and requests for Board consideration on the Virginia Department of Environmental Quality's ("VDEQ") draft prevention of significant deterioration ("PSD") permit and stationary source permit to construct and operate the proposed Chickahominy combined cycle power plant project to be located Charles City County, Virginia (Registration Number 52610).[1] This plant is proposed by be constructed by Balico LLC/Chickahominy Power (hereinafter referred to as "Chickahominy Power").

REGULATORY FRAMEWORK

The Clean Air Act aims to "protect and enhance the quality of the Nation's air resources."[2] To this end, the Act employs a variety of programs—including the Prevention of Significant Deterioration (PSD) program, which governs air pollution in areas where the air quality meets or is cleaner than the national ambient air quality standards.[3] The PSD program establishes maximum allowable

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1 These comments were prepared with the assistance of Victoria Stamper, Boise, ID. Ms. Stamper is an independent air quality consultant and engineer with extensive experience in the Clean Air Act and new source review permitting. Ms. Stamper's Curriculum Vitae is included as Ex. 1.

2 42 U.S.C. § 7401.

3 42 U.S.C. § 7470.

increases of pollutants over baseline concentrations and establishes preconstruction requirements.[4] The preconstruction requirements described in the Clean Air Act state that no new major stationary source or major modification to an existing major source may commence until a permit is issued that establishes that the new source or the modification to the existing source will meet a number of conditions required by the Clean Air Act.[5] For a new major source such as the Chickahominy Power Plant, those requirements include that a source must install best available control technology ("BACT") for all pollutants that it would emit in significant amounts.[6] A new major source that triggers PSD review for a traditional PSD pollutant also triggers a PSD review for Greenhouse Gas ("GHG") emissions if the source would emit or have the potential to emit 75,000 tons per year of GHGs on a CO_2 equivalents (CO_2-e) basis.[7] BACT is defined, in part, under Virginia and federal PSD rules as

> an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated New Source Review ("NSR") pollutant that would be emitted from any proposed major stationary source or major modification that the board, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.[8]

In addition, an owner of a proposed source must demonstrate that

> allowable emissions increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to a violation of: 1. Any ambient air quality control standard in any air quality region; or 2. Any applicable maximum allowable increase over the baseline concentration in any area.[9]

Importantly, if a proposed new or major stationary source could cause or contribute to a violation of any ambient air quality standard (including the National Ambient Air Quality Standards (NAAQS)) or the maximum allowable increases over baseline concentration (i.e., PSD increments), the Virginia Air Quality Board must deny the proposed construction unless the source obtains sufficient emission reductions to, at a minimum, compensate for its adverse ambient impact.[10]

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[4] 42 U.S.C. § 7473; 42 U.S.C. § 7475.

[5] 40 C.F.R. § 52.21(a)(2); 9 Virginia Administrative Code § 5-80-1625.A–B.

[6] 9 Virginia Administrative Code § 5-80-1705.B.

[7] 40 C.F.R. § 52.21(b)(49)(iv)

[8] 9 Virginia Administrative Code § 5-80-1615.C. *See also* 40 C.F.R. § 52.21(b)(12).

[9] 9 Virginia Administrative Code § 5-80-1715.A.

[10] 9 Virginia Administrative Code § 5-80-1715.B.2.

Virginia administers the PSD program through an approved state implementation plan (SIP). Like its federal counterpart, Virginia's PSD program requires would-be permittees to analyze all potential impacts of its proposal on visibility, soils, and vegetation.[11] It also adopts the five-step "top down" BACT analysis propounded by the EPA, further developed by its Environmental Appeals Board,[12] and upheld by the federal courts.[13] The Air Pollution Control Board's *Air Permitting Guidelines* expressly incorporate the top-down BACT approach[14] and direct permit writers to the EPA's *New Source Review Workshop Manual*[15] for additional guidance.[16] Failing to conduct a complete BACT analysis, including failure to consider all potentially applicable control alternatives, is an abuse of the permitting authority's discretion.[17]

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[11] 9 Virginia Administrative Code § 5-80-1755.

[12] The EPA's Environmental Appeals Board adjudicates appeals from federally-issued PSD permits (as well as state permits issued under federal delegation) and has developed a body of case law on BACT requirements. Because state PSD programs must "implement standards and limitations as stringent as those set by the EPA" and must be interpreted "with an eye to furthering the goals of the [federal] PSD program," state courts and agencies turn to the Board's rulings in applying their respective state PSD programs. *Utah Chapter of the Sierra Club v. Air Quality Board*, 226 P.3d 719, 727, 733 (Utah 2009). *Accord Sierra Club v. Wisconsin Department of Natural Resources*, 787 N.W.2d 855, 862 (Wis. Ct. App. 2010), *rev. denied*, 797 N.W.2d 523 (2011); *Cities of Annandale and Maple Lake NPDES/SDS Permit*, 731 N.W.2d 502, 520 (Minn. 2007). In fact, some states have indicated that the Board's decisions establish a regulatory "floor" for state PSD program: while its decisions are not always binding on a state permitting authority, *Utah Chapter of the Sierra Club*, 226 P.3d at 733, this is largely a function of the fact that state programs may "in certain respects [be] stricter than the federal program." *See Snyder v. Pennsylvania Department of Environmental Protection*, Docket No. 2015-027-L, 2015 WL 9590755, *7 (Pa. Env. Hrg. Bd. 2015). In short, a permitting authority is required to follow the EPA's analytical framework unless it has clearly articulated (and provided a statutory foundation for) its own alternative. *Creek Generation LLC*, Petition No. IV-2008-1, 9 (E.P.A. December 15, 2009), available at http://1.usa.gov/1q45FX9 (*Cash Creek I*).

[13] *See generally Sierra Club v. Environmental Protection Agency*, 499 F.3d 653 (7th Cir. 2007).

[14] *See* Virginia Air Pollution Control Board, *Air Permitting Guidelines – New and Modified PSD Sources*, Doc. ID APG-309, 4-1 (November 2, 2015), available at http://1.usa.gov/1SgbYjt (enclosed as Attachment 1).

[15] *See* Environmental Protection Agency, *New Source Review Workshop Manual* (1990), available at http://1.usa.gov/1UWvgOp (enclosed as Attachment 2).

[16] Virginia Air Pollution Control Board, *Air Permitting Guidelines* at 4-1.

[17] *See Louisville Gas & Electric Co.,* 2009 WL 7698409, 13 (E.P.A. 2009) (enclosed as Attachment 98) (citing *Prairie State Generation*, 13 E.A.D. ___, PSD Appeal No. 05-05, slip op. at 19 (E.A.B. 2006); *Knauf Fiber Glass,* 8 E.A.D. 121, 142 (E.A.B. 1999); *Masonite Corp.* 5 E.A.D. 551, 568-569 (E.A.B. 1994)).

PROPOSED PROJECT

The Chickahominy Power Plant ("Chickahominy") is a proposed natural gas-fired combined cycle power plant located near Roxbury, in St. Charles County, Virginia. Chickahominy would have a generating capacity of 1,650 nominal net megawatts (MW), and consist of either (1) three General Electric (GE) 7HA.02 combustion turbine generators, each with heat recovery steam generators, or (2) three Mitsubishi Hitachi Power Systems (MHPS) M501JAC combustion turbine generators with heat recovery steam generators.[18] VDEQ proposed in the draft permit that this source is subject to PSD permitting requirements for nitrogen oxides (NO_X), carbon monoxide (CO), particulate matter (PM), PM less than 10 microns (PM_{10}), PM less than 2.5 microns ($PM_{2.5}$), greenhouse gases (GHG or CO_2-e), volatile organic compounds (VOCs), sulfuric acid mist (H_2SO_4), and sulfur dioxide (SO_2) under the federal and state PSD regulations.[19]

COMMENTS

Sierra Club provides the following comments on the draft permit for Chickahominy and its compliance with the PSD permitting requirements.

I. COMMENTS ON VDEQ'S PROPOSED EMISSION LIMITS FOR TUNING AND WATER WASHING

VDEQ proposed short term limits to meet BACT on either a pollutant-mass-per-fuel-heat-input basis or as a limit on concentration of the pollutant in the gas stream. These short-term averaging times and limits, including the NO_X limit of 2.0 parts per million dry volume (ppmvd) at 15% oxygen (O_2) which applies on a one-hour averaging time basis,[20] are generally in line with what has been required to meet BACT at other combined cycle power plants. However, VDEQ's draft permit would exempt periods of tuning and water washing from the short term average NO_X, CO, VOC, and $PM/PM_{10}/PM_{2.5}$ BACT limits and instead impose a pound per calendar limit (for NO_X and CO) or time limits on tuning or water washing (for VOCs and PM) when those events occur.[21] VDEQ failed to justify the relaxed emission limits for tuning and on-line water washing events as satisfying BACT.

Comment No. 1: There is No Adequate Justification in the Permit Record for the Alternative BACT Emission Limits for Tuning and On-Line Water Washing Events.

A review of other permits for similar sources with the same turbine type found that air permits generally do not have exemptions for tuning or on-line water washing events. For example, a 2015 air permit issued for the CPV Towantic combined cycle power plant in Connecticut, an 805-MW

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18 Permit Application at 1-1.

19 As discussed in VDEQ's January 30, 2019 Engineering Analysis for the Chickahominy Plant at 2.

20 Draft Permit at 12 (Condition 33).

21 *Id.*

power plant equipped with two GE 7HA.01 combustion turbines with dry low NO_X combustors, selective catalytic reduction (SCR), and oxidation catalyst has hourly emission limits similar to those proposed for Chickahominy, but the permit has no exemptions or alternative emission limits for tuning, maintenance, or on-line water washing.[22] Similarly, a 2018 air permit for the Harrison County combined cycle power plant—a West Virginia plant using one GE 7HA.02 combined cycle turbine and equipped with the same pollution controls[23]—has hourly emission limits but the permit has no exemptions or alternative emission limits for tuning (or maintenance) or on-line water washing.[24] Further, a 2018 air permit issued for the proposed NTE Connecticut combined cycle power plant—a Killingly, Connecticut plant using one MHPS M501JAC combustion turbine equipped with the same pollution controls—has hourly emission limits but no exemptions/alternative emission limit for tuning or water washing.[25] Given that there are other permits for the same types of combustion turbines with short-term average BACT limits (including one-hour average limits for NO_X) without any alternative limits for tuning and water washing, VDEQ must justify the need for alternative and less-stringent emission limits (pound/calendar day limits rather than limiting the concentration of a pollutant in the gas stream over each hour of operation) for tuning and water washing at Chickahominy. VDEQ must explain why circumstances at the Chickahominy units are different than the circumstances at these similar plants with identical combustion turbine technology and why alternative limits for tuning and water washing events are justified in light of the fact that similar source permits do not have such alternative limits.

In addition, Chickahominy did not even request an alternative BACT limit for tuning and water washing for particulates,[26] and yet VDEQ inexplicably allowed for such exemptions, on its own, in the draft permit.[27] There is absolutely no justification in the permit record for alternative PM BACT limits for tuning and water washing events.

Comment No. 2: If VDEQ Can Justify Alternative Emission Limits for Tuning and Water Washing, VDEQ Must Impose Limits on the Duration and Frequency of Such Events to Ensure These Exemptions from Concentration-Based BACT Limits are Limited to the Maximum Extent Possible.

In the event VDEQ can put forth adequate justification for alternative emission limits for tuning and water washing at Chickahominy, VDEQ must ensure that the frequency and duration of any

[22] November 30, 2015 Permit Number 144-0023 for CPV Towantic, LLC, at 2, 4-5, and 7 (attached as Ex. 2).

[23] As discussed in the permit application for the Harrison County power plant, available at http://dep.wv.gov/daq/Documents/December%202016%20Applications/033-00264_APPL_R14-0036.pdf.

[24] March 27, 2018 Permit No. R14-0036 for Harrison County Facility, at 3, 13 (attached as Ex. 3).

[25] December 10, 2018 Permit Number 089-0107 for NTE Connecticut LLC, at 2, 5-6, and 7 (attached as Ex. 4).

[26] *Id.* at 5-31.

[27] Draft Permit at 12-13 (Condition 33) and at 14-15 (Condition 34).

alternative emission limits are minimized to the greatest extent possible.[28] While VDEQ may argue that the pound-per-calendar-day emission limits are reflective of BACT because they reflect the BACT concentration limits at maximum operating capacity over an entire day,[29] BACT emissions limits are required to reflect the maximum degree of emission reduction achievable,[30] imposed over averaging times that are protective of the NAAQS.[31] For NO_X and CO emissions, that means BACT should be imposed over an hourly averaging time to protect the 1-hour average NAAQS for these pollutants. The alternative emission limits for NO_X and CO that apply on a pound-per-calendar-day basis are not protective of the short-term average NAAQS. Further, although the alternative limits for tuning and water washing reflect the pounds of pollutants that would be allowed at the maximum steady-state capacity under the BACT limits over a calendar day,[32] these limits do not ensure the maximum degree of emission reduction is achieved and thus they are generally not consistent with BACT. This is particularly true because, based on the information provided by Chickahominy Power in the permit application, there is no need for a 24-hour exemption from the short-term average, concentration-based BACT limits for tuning and water washing events that generally will not last anywhere near 24 hours. Thus, assuming VDEQ can adequately justify the need for alternative BACT limits, it must ensure that those alternative emission limits are minimized in quantity and duration. Chickahominy Power provided information in its permit application to justify such restrictions, but, without explanation, VDEQ did not impose such restrictions in the draft permit.

The Chickahominy permit application indicates that there are three levels of tuning:

(1) combustion inspections,
(2) hot gas path inspections, and
(3) major overhauls.[33]

The permit application states that tuning may take "**up to** 18 hours in a calendar day."[34] It is not likely that all three of these types of tuning would occur for a full 18 hours a day, and yet VDEQ's draft permit does not differentiate between the different types of tuning and allows a tuning event

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28 This is stated as EPA's policy for startup and shutdown exemptions, but the same policy would hold true for any BACT exemptions. *See State Implementation Plans: Response to Petition for Rulemaking: Restatement and Update of EPA's SSM Policy Applicable to SIPS; Findings of Substantial Inadequacy; and SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction*, 80 Fed. Reg. 33,840 at 33,914 (June 12, 2015).

29 *See* Permit Application at 5-31.

30 *See* 40 C.F.R. §52.21(b)(12).

31 *See* November 24, 1986 EPA Memorandum with Subject "Need for a Short-term Best Available Control Technology (BACT) Analysis for the Proposed William A. Zimmer Power Plant," attached as Ex. 5.

32 As discussed in the Permit Application at 5-31.

33 Permit Application at 5-20.

34 *Id.* at 5-35 (Emphasis added).

to be exempt from hourly BACT limits for an entire calendar day. Further, the permit application indicates that on-line water washing events would take no longer than 60 minutes per turbine.[35] Yet VDEQ proposed an alternative calendar day emissions cap rather than the units having a 1-hour average alternative BACT limit.[36] While VDEQ did impose limits on the duration of tuning and water washing events as alternative limits for VOCs, PM, PM_{10}, and $PM_{2.5}$,[37] it did not impose any such duration limits on the alternative limits for NO_X and CO—if a tuning event or washing event occurs, the unit is allowed a pound-per-calendar-day limit in lieu of short term average BACT. Further, with respect to VDEQ's limits on duration of events for VOCs and PM limits, the draft permit allows tuning events to occur up to 18 consecutive hours, when that is likely a longer duration than warranted for all three types of tuning events for which Chickahominy Power has requested a separate emission limit. Indeed, the permit application implies that some tuning events would last only 8 hours or less.[38] Thus, VDEQ must request more information on the duration as well as frequency of the tuning events expected at Chickahominy and, assuming alternative emission limits can be justified for such periods, impose different emission limits for those time periods and activities. This is similar to how VDEQ addressed startup and shutdown activities, where VDEQ proposed to limit the duration of startup and shutdowns <u>and</u> imposed limits on pounds-per-duration of startup or shutdown.[39]

Further, to limit the frequency of the exemptions from BACT limits for tunings and water washes, the draft permit must impose limits on the frequency of such events. The permit application indicates that the maximum time per year that burner tuning would need to occur at each combustion turbine is 96 hours.[40] Yet, VDEQ did not impose any limit on the total number of hours of burner tuning that would be allowed per year at each combustion turbine.

For water washing, the Chickahominy permit application indicates that the maximum amount of time needed to conduct water washes in a year is 52 hours.[41] This is, on average, once per week. VDEQ is essentially proposing alternative emission limits for water washing that allow Chickahominy to be exempt from the hourly average BACT limits one day a week on average for water washing events that, according to the permit application, only last 60 minutes per turbine. If any exemption from BACT limits for water washing is justified (which is questionable given the other similar source permits do not have such BACT exemptions/alternatives), it must be limited to no longer than 60 minutes (similar to the startup and shutdown alternative emission limits of the draft permit) and the total number of hours conducting water washing must be limited as well to no more than the 52 hours per year—the time the company has claimed is the maximum amount of time that water washing will occur at Chickahominy.

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[35] *Id.* at 5-30.

[36] Draft Permit at 13 (Condition 33.b) and 14 (Condition 34.b).

[37] Draft Permit at 13 (Condition 33.b) and 14 (Condition 34.b) and at 6 (Condition 10).

[38] Permit Application at 5-35.

[39] Draft Permit at 5-6 (Condition 9), 13 (Condition 33.d) and 14 (Condition 34.d).

[40] Permit Application at 5-30.

[41] *Id.* at 5-37.

Comment No. 3: The Draft Permit Fails to Require Advance Notification to VDEQ of Tuning and Water Washing Events and Fails to Require Adequate Recordkeeping and Reporting for these Events.

VDEQ's draft permit also fails to include reporting and recordkeeping requirements pertaining to the tuning or water washing events time periods. The Chickahominy permit application states that the company would notify VDEQ at least 24 hours in advance of a planned tuning event,[42] and yet the permit application requires no such advance notification or even recordkeeping of these events. Advance notification of tuning events, as well as recordkeeping and reporting, is imperative to ensure that the owner/operator cannot justify an exemption from hourly BACT limits simply by claiming a period of higher emissions was due to a tuning or water washing event. Further, advance notification, recordkeeping, and reporting is also extremely important to the enforceability of the permit terms—so it is clear to the source owner/operator, VDEQ, and the public which emission limits apply to each hour of operation. Thus, to the extent that VDEQ can justify including alternative emission limits for tuning and on-line water washing as BACT, advance notification to VDEQ and recordkeeping and reporting requirements for those events must be required in the permit.

VDEQ must also require recordkeeping of the events that led to the decision to conduct a tuning event to ensure such exemptions from short term BACT limits are justified. The Chickahominy permit application states that the company will conduct tuning "only when necessary to maintain compliance with short term emission limits."[43] The draft permit should therefore require recordkeeping and reporting of short-term average emission rates before and after tuning events to verify that such tuning events were justified and, in fact, effective.

Summary: Alternative Emission Limits for Tuning and On-Line Water Washing Must Be Properly Justified and If Allowed, Limited in Duration and Quantity.

VDEQ failed to justify imposing different and less stringent emission limits for NO_X, CO, VOCs, and $PM/PM_{10}/PM_{2.5}$ during episodes of tuning or on-line water washing. Similar sources with hourly BACT limits and identical model combustion turbines did not have alternative emission limits for tuning and water washing allowed in air permits. The NO_X and CO pound-per-calendar-day emission limits of the draft permit for tuning and water washing events are less stringent than even requested in the Chickahominy permit application, and the company did not request alternative emission limits for particulate matter. Thus, the permit record does not support the alternative emission limits for tuning and water washing as proposed in the draft permit. If VDEQ can justify such limits, it must impose requirements to limit the duration and frequency of such events, and it must also impose adequate reporting and recordkeeping as discussed above.

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42 *Id.* at 5-35.

43 *Id.* at 5-36.

II. COMMENTS ON VDEQ'S PROPOSED EMISSION LIMITS FOR STARTUPS AND SHUTDOWNS

Comment No. 4: The Draft Permit Fails to Adequately Justify the Numeric Pound-Per-Event Limit.

VDEQ's draft permit would exempt periods of startup and shutdown from the short term average NO_X, CO, VOC, and $PM/PM_{10}/PM_{2.5}$ BACT limits.[44] The draft permit includes time limits on the various types of startups (e.g., cold startup, warm startup, hot startup) that are 66 minutes or less in duration and on shutdowns, which are only allowed to occur for 15 minutes.[45] During these periods, the units would be exempt from the short-term average concentration-based BACT limits and would instead be subject to limits on pounds of a pollutant per startup/shutdown event.[46] However, the permit record does not adequately justify the numeric pound-per-event limits of the draft permit. The permit application indicates that NO_X, CO and VOC emissions are based on "Gemma data,"[47] however, that data and its assumptions do not appear to be in the permit record.[48]

Comment No. 5: The Draft Permit Fails to Include Limits on the Number of Allowed Startups and Shutdowns Per Year.

Further, the draft permit does not include any limits on the number of allowed startups and shutdowns per year. As discussed above, EPA's policy on alternative emission limits for startup and shutdowns requires that such events be limited in duration and frequency to the maximum extent possible.[49] The permit application includes information on the number of expected startups and shutdowns per year,[50] and VDEQ should impose such limits as permit terms to ensure that excess emissions during startup and shutdown are minimized.

Comment No. 6: The Draft Permit Fails to Require Reporting of Startup and Shutdown Events.

While the draft permit requires recordkeeping of startup and shutdown events, it fails to require reporting of such events to VDEQ.[51] Such reporting is extremely important to the enforceability of the permit terms—so it is clear to the source owner/operator, VDEQ, and the public, which emission limits apply to each hour of operation. It is also important to ensure that that the

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44 Draft Permit at 12-14 (Conditions 33 and 34).

45 *Id.* at 5-6 (Condition 9).

46 *Id.* at 12-14.

47 Permit Application, Appendix B at B-4 (Table B-1.3) and B-14 (Table B-2.3).

48 *See U.S. Steel Corp.*, Petition No. V-2009-03, 2011 WL 3533368, *14–28 (EPA January 31, 2011) (vacating air permit where state agency did not disclose the origin of emission factors it relied upon and failed to explain why it believed those factors to be representative).

49 *See* 80 Fed. Reg. 33,840 at 33,914 (June 12, 2015).

50 Permit Application, Appendix B at B-4 (Table B-1.3) and B-14 (Table B-2.3).

51 Draft Permit at 6 (Condition 9).

owner/operator has taken all possible steps to minimize emissions during startup and shutdown, as required by EPA for alternative emission limits.[52] Thus, VDEQ must require timely reporting of all periods of startup and shutdown of Chickahominy as well as information about the operation of pollution controls during such periods to VDEQ.

III. COMMENTS ON VDEQ'S PROPOSED EMISSION LIMITS FOR GREENHOUSE GAS EMISSIONS

Comment No. 7: VDEQ Failed to Adequately Justify its Proposed BACT Limits for Greenhouse Gases.

VDEQ addressed BACT for greenhouse gases (GHG) by proposing a limit on CO_2-e emissions in terms of pounds-per-net-megawatt-hour (lb/MWh net) that ranges over years of operation of the plant from 824 lb/MWh net to 884 lb/MWh net and by proposing heat rate requirements in terms of British-Thermal-Units-per-net-kilowatt-hour (Btu/kWh net) that range over the years of operation of the plant from 6,550 to 7,172 Btu/kWh net.[53] Unlike BACT for other pollutants, VDEQ did not propose different CO_2-e BACT limits for the two types of combustion turbines that could be constructed under this permit. The data collected by VDEQ on emission limits and the actual emissions for other similar combustion turbines demonstrate that the BACT limits proposed by VDEQ do not reflect the maximum degree of reduction in emissions that can be achieved at Chickahominy.

First, it must be noted that the Chickahominy units will not have duct burners to increase generating capacity, which is a very important factor in setting CO_2-e BACT limits for the combustion turbine generators. It seems to be more common to design combined cycle plants with duct firing to increase the generating capacity of the units. However, combined cycle units with duct firing have higher heat rates in terms of Btu/kWh and have higher lb CO_2-e/MWh rates due to more fuel burned per unit of electricity produced. Specifically, one analysis showed that duct burners increase the heat rate by about 4.7% compared to no duct firing.[54] In Draft Permit Condition 8, where VDEQ describes the GHG control strategies, VDEQ should also indicate that the absence of duct burners at the Chickahominy combine cycle units is inherently part of the CO_2-e BACT determination. Stating this clearly in the permit is necessary to make sure that, if Chickahominy Power ever decides to add duct firing to the combined cycle units, it is treated as a revision to the BACT determination, which would necessitate a PSD permit revision regardless of whether adding such duct firing would result in a significant emission increase of any NSR regulated pollutant.

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52 *See* 80 Fed. Reg. 33,840 at 33,914 (June 12, 2015).

53 Draft Permit at 5 (Condition 8) and 15 (Condition 35).

54 *See*, e.g., 2/2/2006 Power Engineering article, To Cool or Not to Cool, available at https://www.power-eng.com/articles/print/volume-110/issue-2/features/to-cool-or-not-to-cool.html. Specifically, Table 2 shows that the heat rate for Case 3 with duct-firing (6668 Btu/kWh) is about 4.7% higher than the heat rate for Case 1 with no duct-firing (6371 Btu/kWh).

Second, it is not clear why VDEQ did not propose two different CO_2-e BACT determinations depending on the combustion turbines installed at this facility (i.e., GE 7HA.02 combustion turbine generators or MHPS M501JAC combustion turbine generators). Notably, in its evaluation of similar source BACT heat rate requirements, VDEQ evaluated data for sources with GE turbines separately from sources with MHPS turbines.[55] And the data presented by VDEQ shows varying heat rates and/or lb/MWh limits that, in part, seem to pertain to the specific combustion turbine. Thus, it makes sense for VDEQ to establish different CO_2-e BACT determinations for the two turbine types that could be constructed under this permit, as VDEQ did for BACT for other pollutants.

Third, VDEQ should also impose a limit on pounds of CO_2-e per gross MWh in lieu of, or in addition to, lb/per net MWh. The mass of CO_2-e per gross electricity production is what matters in terms of the climate impacts from CO_2-e emissions, as it reflects the total amount of emissions due to the operation of the power plant, not just total CO_2-e emissions due to the amount of electricity sent to the grid for sale. An appropriately stringent limit on pounds of CO_2-e per gross MWh would encourage Chickahominy Power to limit the parasitic load and would promote overall improvements in efficiency.

A review of the existing BACT limits and emission rates for combined cycle units with the MHPS M501JAC combustion turbine generators shows that the lowest BACT heat rate limit for greenhouse gases is that imposed by VDEQ for the Dominion Greensville Power Station, which are initially set at 6,457 Btu/kWh.[56] This is more stringent than the initial heat rate required in the Chickahominy BACT determination, which is 6,550 Btu/kWh net.[57] Yet, VDEQ dismissed this lower rate, which VDEQ itself imposed as BACT for a similar source, because they did not yet have data that the limit was being achieved at the Dominion Greensville plant. VDEQ's reasoning is flawed because that lack of data did not prevent VDEQ from imposing the limit on the Greensville plant in the first place. Moreover, testing was recently performed at the Greensville plant and VDEQ (as the permitting and enforcement authority for the Greensville plant) could have easily requested that data from Dominion.

Not only is the initial test Btu/kWh net limit for the Greensville plant more stringent than the initial heat rate for Chickahominy, but the Year 6, Year 12, Year 18, and Year 24 Btu/kWh net limits for the Greensville plant are all lower than the VDEQ's proposed heat rate limits for those same operational years at the Chickahominy units.[58] This information from the Greensville permit is extremely relevant to the BACT determination for Chickahominy. VDEQ must ensure that the CO_2-e BACT limits it imposes on the Chickahominy combustion turbine generators are at least as

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55 VDEQ Engineering Analysis at 17-18.

56 *Id.* at 22. Importantly, this heat rate is required to be met without duct burning and so it for a similar unit to the Chickahominy units.

57 *Id. See also* Draft Permit at 5 (Condition 8).

58 *See* June 17, 2016 Air Permit Registration No. 52525 for the Greensville Power Station at 5 (Condition 8), attached as Ex. 6, and compare to the net heat rates identified in the greenhouse BACT analysis for the Chickahominy power station (in the VDEQ Engineering Analysis at 22). *See also* Draft Permit at 5 (Condition 8).

stringent as the most stringent emission limit required for all similar sources. If VDEQ determines such a limit, as it imposed on the similar Greensville plant, is not justified as BACT for the Chickahominy units, it must document in the permit record why such limits would not be achievable.[59]

In addition to the Greensville heat rate limits being more stringent than what VDEQ proposed as BACT for the Chickahominy units, the lb CO_2-e/MWh net limits for the Greensville Power Station are also more stringent than the lb CO_2-e/MWh net limits imposed in the Draft Permit for Chickahominy for Years 1-24.[60] Specifically, the Greensville BACT limits range from 812-859 lb CO_2-e/MWh net for Years 1-24, while VDEQ's proposed BACT limits for Chickahominy Power are higher, ranging from 824-868 lb CO_2-e/MWh for Years 1-24.[61] Further, based on the data presented by VDEQ in its Engineering Analysis, there are other similar plants with lower CO_2-e BACT limits as well, including the CPV Towantic combustion turbine (a GE 7HA.01 combustion turbine), which began operating in mid-2018 and has an initial CO_2-e BACT limit of 809 lb/MWh net (compared to the 824 lb/MWh net limit proposed by VDEQ for the Chickahominy units).[62]

More stringent CO_2-e BACT limits have been imposed for sources very similar to the Chickahominy units, and VDEQ cannot ignore those lower emission limits in its GHG BACT determination without providing "clear justification" that the lower emission limits imposed on similar sources to meet BACT are not appropriate for the Chickahominy units.[63] VDEQ has not put forth any such clear justification to ignore the more stringent CO_2-e BACT limits required for similar sources, and thus VDEQ's CO_2-e BACT analysis and limits are significantly flawed.

Last, it also must be stated that the ton per year CO_2-e limits in Draft Permit Condition 36 cannot be considered as reflective of BACT, because these CO_2-e emission limits of 1,901,202 tons per year for the GE turbines and of 2,123,519 for the MHPS turbines simply reflect the worst-case hourly emission rate multiplied by 8,760 hours in a year with the expected startup and shutdown CO_2-e emissions added in.[64] If VDEQ does not impose a limit on lb CO_2-e per MWh gross, then it should impose a ton per year limit but one that is reflective of BACT, not a limit based on worst-case CO_2-e emissions.

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59 *See* U.S. EPA, October 1990, New Source Review Workshop Manual at B.26-B.29.

60 *See* June 17, 2016 Air Permit Registration No. 52525 for the Greensville Power Station at 15 (Condition 40), attached as Ex. 6, and see Draft Permit for the Chickahominy plant at 15 (Condition 35).

61 *Id.*

62 VDEQ Engineering Analysis at 23.

63 U.S. EPA, October 1990, New Source Review Workshop Manual at B26-B29.

64 Permit Application, Appendix B at b-3 to B-5 and at B.12-B.15.

IV. COMMENTS ON MODELING DEFICIENCIES AND FAILURE TO ENSURE CHICKAHNOMINY WILL NOT CAUSE OR CONTRIBUTE TO NAAQS VIOLATIONS

The modeling analysis for the Chickahominy permit is deficient for several reasons, including that Chickahominy Power failed to model worst-case emissions allowed under the tuning and water washing alternative emission limits and because the company failed to model worst-case startup NO_X emissions. Further, the cumulative NAAQS analysis is deficient because Chickahominy Power failed to adequately model the nearby planned C4GT/Novi Energy combined cycle power plant. Because of these deficiencies, VDEQ must require revised modeling before it can determine whether Chickahominy will cause or contribute to a violation of the NAAQS.

Comment No. 8: Chickahominy Power Failed to Model Worst Case Emissions Allowed under the Alternative Emission Limits for Tuning and Water Washes.

Despite requesting alternative emission limits to BACT for tuning and on-line water washing, Chickahominy Power did not conduct any NO_X or CO modeling for the alternative emission limits applicable during these events. The modeling section of the Chickahominy permit application does not explain why, but we surmise that Chickahominy Power may have assumed the base-load modeling of BACT limits addressed tuning and water washing emissions because the company claimed the pound-per-calendar-day limits that apply to those events were equivalent to BACT limits at maximum capacity.[65] While that may be the basis for those limits, the fact that the limits had to be imposed over a 24-hour calendar day rather than over the 1 hour (for NO_X) or 3 hour (for CO) averaging time of the BACT limits reflects how much higher than BACT emission levels the company expects NO_X and CO emissions could be during tuning events.

For both the tuning events and water washing events, the permit application states that the "dry low-NO_X combustors may not be as effective during tuning and water washing."[66] Dry low-NO_X combustors, when operating correctly, significantly reduce NO_X emissions—typically to 9 parts per million (ppm).[67] If the dry low-NO_X combustors are not working as well during tuning or water washing, NO_X emissions from the combustion turbines could reach 25 ppm or higher. The SCR, assuming it is operated during such events, would only be designed to achieve about 78% NO_X control[68] and thus emissions could be significantly higher than the 2 ppm BACT limit if the dry low-NO_X combustors were not working as effectively during tuning or water washing events. For tuning events, the Chickahominy permit application indicates that the unit will be operated at low,

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65 Permit Application at 5-37.

66 *Id.* at 5-35.

67 *See*, e.g., EPA's Catalog of CHP Technologies, Section 3. Technology Characterization – Combustion Turbines, at 3-16, available at https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf.

68 This percent control was based on the 9 ppm NO_X rate from the low-NO_X combustors and the 2 ppm BACT limit.

mid, and high loads.[69] Thus, the varying levels of fuel input—and, consequently, mass emissions of NO_X and CO—over those events would mean that the pound-per-calendar-day limit, which is based on emissions at maximum fuel input while meeting BACT limits, would enable a unit to emit at very high hourly NO_X and CO rates for some part of the day because total calendar day emissions will likely be balanced out by lower NO_X and CO rates at low or mid load during other parts of the day. Similarly, Chickahominy Power has indicated water washing events would last 60 minutes, and yet VDEQ proposed to allow compliance with a pound-per-calendar-day limit when these events occur. Clearly in these situations, emissions could be much higher over the water washing hour and balanced out with lower emissions over the rest of the day. VDEQ must require a determination and modeling of the worst-case hourly emissions that would be allowed under the alternative emission limits for these events.

Further, as discussed above, nothing in the draft permit would limit the frequency of the tuning and water washing events. The Chickahominy permit application indicates water washing events could occur 52 times per year,[70] meaning on average, a combustion turbine could be allowed to comply with a pound-per-day limit rather than a short term average ppm limit once a week. However, the permit does not limit water washes or tuning events. These events and exemptions from short term NO_X and CO limits are allowed to occur quite frequently, thus mandating that peak hourly emissions during such events be modeled for compliance with the NAAQS.

Moreover, under the terms of the draft permit, if a startup and/or shutdown occurs during a calendar day with a tuning or water washing event, those startup and shutdown emissions are allocated separate emission limits and those emissions do not count against the tuning/on-line water washing emission limits.[71] Thus, if a startup and shutdown occurred with a tuning or water washing event, emissions from those timeframes would not count towards compliance with the pound-per-calendar-day limits, which allows the combustion turbine to emit even higher rates in a calendar day than the alternative tuning and water washing limits would normally allow.

For all of these reasons, it is imperative that VDEQ require modeling of worst-case emissions allowed under the alternative pound-per-calendar-day limits for NO_X and CO for tuning and water washing events. Such modeling must be done for the 1-hour NO_2 NAAQS, the 1-hour and 8-hour CO NAAQS, and, given the frequency of these events allowed under the permit, the annual NO_2 NAAQS. VDEQ cannot determine whether Chickahominy will cause or contribute to a violation of the NAAQS under the emissions allowed under its draft permit until such modeling has been conducted.

Comment No. 9: The Modeling of Emissions Allowed During Startup is Flawed.

Chickahominy Power failed to properly model worst-case hourly NO_X or CO emissions allowed under the terms of the draft permit for cold starts of the GE 7HA.02 combustion turbine generators. According to the Permit Application, Chickahominy Power modeled startup emissions for

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69 Permit Application at 5-36.

70 *Id.* at 5-37.

71 Draft Permit at 13 (Condition 33.b) and at 14 (Condition 34.b).

averaging times for which the duration of the startup is shorter than the averaging period, and the remaining time in the averaging period was assumed to be associated with 100% load (and presumably BACT emission limits).[72] However, for cold startups of the GE 7HA.02 combustion turbine generators (which reflect the worst-case emissions for startups), Chickahominy Power limited the modeled NO_X and CO emissions by assuming the allowable emissions for cold startups could not be emitted in an hour because the Draft Permit allows cold startups to last up to 66 minutes. Chickahominy Power's modeling of cold startups does not reflect worst-case impacts from cold starts of the GE 7HA.02 combustion turbine generators.

Of all of the separate limits for startups and shutdowns, the draft permit allows the highest NO_X and CO emissions for cold starts from GE 7HA02 combustion turbine generators. Specifically, the draft permit allows 312 lbs of NO_X per cold start event per turbine and it allows 924 lbs of CO per cold start event per GE 7HA.02 turbine.[73] The draft permit states that cold startups shall not exceed 66 minutes per occurrence.[74] The permit application indicates that a cold start can take 66 minutes,[75] but nothing in the permit application indicates that NO_X or CO emissions occur at the same rate over a cold startup time period or that cold startups will always last a full 66 minutes. Indeed, in a permit recently issued for the nearby C4GT combined cycle power plant—which has proposed, as one option, to install the same GE 7HA.02 combustion turbine generators—only allows up to 60 minutes for a cold startup of the GE turbines.[76] Further, it does not make sense to assume the 1-hour average NO_X limit or the 3-hour average CO limit will be complied with immediately after the 66 minute mark after a cold startup, because compliance with a 1-hour or 3-hour average BACT limits under the permit is for discrete periods between the beginning of an hour and the end of that hour.[77] The short-term limits do not apply on a rolling 60-minute or 180-minute basis. In other words, if a cold startup occurs from 9:15 A.M. for 66 minutes until 10:21 A.M., neither the hour starting at 10 A.M. nor the hour starting at 11 A.M. would be counted for compliance with the 1-hour NO_X limit or the 3-hour CO limit. Compliance with those short term BACT limits would not be required under the terms of the permit until 11:00 A.M.

Yet, in the company's modeling of cold startups for the GE 7HA.02 combustion turbine generators, the allowable NO_X and CO emissions were reduced by the ratio of 60 minutes/66 minutes.[78] This modeling is not a realistic worst-case assessment of the maximum emissions that could be allowed

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72 Permit Application at 6-6.

73 Draft Permit at 13 (Condition 33.d).

74 *Id.* at 5 (Condition 9.a.ii).

75 Permit Application at 3-2.

76 *See* Draft PSD Permit Registration No. 52588 for the C4GT plant at 2 (under Equipment List) and at 5 (Condition 9.a.ii), attached as Ex. 9. Sierra Club has been unable to locate the final version of this permit on VDEQ's website.

77 Draft Permit at 19 (Condition 45).

78 Permit Application at 6-7. (60/66)*the allowable 312 lbs of NO_X per cold startup event per GE 7HA.02 turbine = 283.64 lb/hr, which was modeled for each turbine to reflect the cold startup impacts.

in an hour with cold startups of the GE 7HA.02 combustion turbine generators. Instead, the company must be required to model the entire allowable 312 lbs of NO_X and 924 lbs of CO as being emitted at each turbine over an hour. Such emissions would clearly be allowed to occur in one hour under the draft permit. That is the only reasonable approach for evaluating whether the maximum allowable hourly emissions for cold startups under the terms of the draft permit will cause or contribute to a NAAQS violation.

Comment No. 10: The Background 1-Hour NO_2 Concentrations Used in the 1-Hour NO_2 NAAQS Modeling Have Not Been Justified.

Chickahominy Power did not accurately reflect background NO_2 concentrations in its 1-hour NO_2 modeling assessments. Specifically, although Chickahominy Power identified the background 1-hour average NO_2 concentration as 42 parts per billion (ppb) based on the Shirley Plantation monitor, the company did not use that 1-hour NO_2 background concentration in the modeling of startup emissions. Instead, Chickahominy Power used NO_2 background concentrations that varied by hour of day and by seasons.[79] None of those NO_2 concentrations over season and hour of the day, which are listed in Table 6-16 of the permit application, even approached the 42 ppb background concentration for the Shirley Plantation monitor listed in Table 6-15 of the permit application. The highest of the NO_2 concentrations developed by the company for season and hour of day was 27.4 ppb, which is only 65% of the 2016 background concentration that would be used to assess compliance with the 1-hour NAAQS of 42 ppb.[80] Even using the most recent three years of data for the Shirley Plantation NO_2 monitor of 2016-2018, the background concentration would be 35.7 ppb based on the three-year average of the 98th-percentile daily maximum hourly concentrations.[81] The background concentrations used by Chickahominy Power as varying by hour of day and season are not reflective of the current background concentration that would be used to assess the area's compliance with the 1-hour NO_2 NAAQS.

Chickahominy Power stated the Shirley Plantation monitor is in the same county as the proposed Chickahominy plant, within 14 kilometers of the proposed plant, and generally downwind of the proposed Chickahominy plant and upwind of the industrialized site in the city of Hopewell.[82] Thus, the company found that the NO_2 concentration measured at the Shirley Plantation monitor "should be very representative of background air quality data" for the proposed project.[83] Chickahominy Power has not provided any justification for not using the very representative background concentration in the form that is used to assess compliance with the NAAQS, nor has the company justified its use of background 1-hour NO_2 concentrations varying by hour and by season. Further,

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79 Permit Application at 6-25.

80 Compliance with the 1-hour NO_2 NAAQS is based on the three-year average of the 98th percentile daily maximum monitored hourly NO_2 concentration. *See* 40 C.F.R. §51.11(f).

81 *See* spreadsheet with Shirley Plantation NO_2 monitor summary data attached as Ex. 7 downloaded from EPA's Outdoor Air Quality Data Website at https://www.epa.gov/outdoor-air-quality-data/download-daily-data.

82 Permit Application at 6-24.

83 *Id.*

the record does not contain the hourly and seasonal concentration data that underlie the seasonal and time of day background concentrations that the company used in the modeling in Table 6-16, nor does it explain how those monitor values were derived.

The use of a proper background 1-hour NO_2 concentration is extremely important given how close the modeling of the Chickahominy plant when equipped with GE 7HA.02 turbines is to the 1-hour NO_2 NAAQS. Chickahominy Power reported a modeled concentration of 1-hour NO_2 of the plant with GE 7HGA.02 turbines of 180.23 µg/m3, which is almost 96% of the 1-hour NO_2 NAAQS of 188 µg/m3.[84] But this modeling result was based on use of NO_2 background concentrations that vary by season and by hour of the day and that do not reflect the actual background concentration data that would be used to assess compliance with the 1-hour NO_2 NAAQS. VDEQ must require Chickahominy Power to assess whether the Chickahominy plant will cause or contribute to a 1-hour NO_2 NAAQS violation based on a proper background concentration representative of the data that is used to assess compliance with the 1-hour NO_2 NAAQS.

Comment No. 11: The Cumulative NO_2 Modeling is Flawed Because Chickahominy Power Failed to Model Allowable NO_x Emissions from the Proposed C4GT Charles City Combined Cycle Power Plant.

VDEQ recently proposed a permit for another gas-fired combined cycle power plant, the C4GT Charles City Combined Cycle Power Plant, which is planned to be located within a mile of Chickahominy. Given the proximity of these sources, it is imperative that the Charles City Power Plant's emissions be included in the cumulative modeling done for Chickahominy. Based on the background source inventory for Chickahominy that we obtained from VDEQ, it appears that the cumulative modeling for Chickahominy did include the C4GT power plant. However, a careful review of the emissions listed as modeled for the C4GT plant in comparison to the permit limits shows that the cumulative modeling for Chickahominy understated allowable NO_X emissions from the C4GT power plant.

Specifically, according to the background source inventory for Chickahominy, the C4GT combustion turbine generators were modeled at NO_X rates of 3.67786 grams per second for the annual NO_2 and 1-hour average NO_2 NAAQS modeling,[85] equating to 24.13998 pounds per hour. The short-term average NO_X BACT limit for the two C4GT combustion turbine generators is 2.0 ppmvd at 15% oxygen,[86] equating to about 0.00739 pounds per million British Thermal Units heat input (lb/MMBtu). The maximum heat input capacity allowed at the C4GT combustion turbine generators is 3,957 MMBtu/hr if Option 1 is selected and GE 7HA.02 combustion turbine generators are installed and is 4,107 MMBtu/hr if Option 2 is selected and Siemens SGT6-8000H

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84 Permit Application at 8-2.

85 *See* Background Source Inventory spreadsheet, obtained by Sierra Club from VDEQ, at tabs labeled "Annual_NO2" and "1hr_NO2," at cells I4 and I5. A copy of the Background Source Inventory is attached as Ex. 8.

86 *See* Draft PSD Permit Registration No. 52588 at 3 (Condition 1), attached as Ex. 9. Sierra Club has been unable to locate the final version of this permit on VDEQ's website.

combustion turbine generators are installed.[87] Thus, for normal source operation, the two C4GT combustion turbine generators should have been modeled at 29.24223 lb/hr (for the GE 7HA.02 units) or at 30.35073 lb/hr (for the Siemens SGT6-8000H units). Clearly, the cumulative modeling for Chickahominy understated emissions from the C4GT combustion turbine generators and thus the cumulative NO_2 analysis is significantly flawed, especially given how close these plants will be to each other. Further, as stated above, the 1-hour NO_2 modeling for Chickahominy already shows 1-hour NO_2 concentrations that are almost 96% of the 1-hour NO_2 NAAQS of 188 µg/m3.[88] That modeling is based on background 1-hour NO_2 concentrations that are significantly lower than what is currently considered the background concentration for the area and that fails to reflect worst-case hourly startup NO_X emissions from the Chickahominy plant.

Further, given the proximity of the C4GT plant to Chickahominy, the fact that both plants will presumably be using the same transmission lines and possibly the same substation, VDEQ needs to take into account the likelihood that both plants could come off line concurrently and that cold startup emission rates could occur at both plants at the same time. The C4GT plant draft permit allows 273 pounds of NO_X per cold startup event per turbine for the GE 7HA.02 units,[89] and it appears that the C4GT plant will be equipped with those turbines.[90] VDEQ must require the modeling of a scenario of cold startups occurring at both plants.

Moreover, the C4GT plant permit appears to have similar exemptions from short term average NO_X BACT limits for tuning and water washing, allowing up to 683 pounds of NO_X per turbine per calendar day for those events, with no limit on the number or total hours of such events at the plant.[91] Given how frequently these events could occur at both the Chickahominy and G4CT power plants, VDEQ must require a cumulative modeling analysis of the worst-case allowable hourly emissions from these events to ensure protection of the 1-hour NO_2 NAAQS.

For all of these reasons, the cumulative NO_2 NAAQS analysis is significantly flawed due to the failure to adequately model allowable short-term average NO_X emissions from the nearby C4GT plant and the failure to model concurrent worst case NO_X emissions from both the C4GT plant and Chickahominy.

Summary of Flaws in Modeling for the Chickahominy Permit

In summary, for the various reasons discussed above, VDEQ cannot find that Chickahominy will not cause or contribute to a violation of the NO_2 NAAQS without new modeling that addresses (1)

87 *Id.* at 2, under Equipment List. The total hourly heat input includes the heat input of the duct burners, as the 2.0 ppmvd NO_X limits apply with or without duct burning.

88 Permit Application at 8-2.

89 *See* Draft PSD Permit Registration No. 52588 at 12 (Condition 34.d).

90 *See* March 7, 2019 GE Press Release, NOVI Energy Selects GE's HA Gas Turbine for Charles City Combined Cycle Plant in Virginia, at https://www.genewsroom.com/press-releases/novi-energy-selects-ge%E2%80%99s-ha-gas-turbine-charles-city-combined-cycle-plant-virginia.

91 *See* Draft PSD Permit Registration No. 52588 at 7 (Condition 10) and at 12 (Condition 34.b).

worst case emissions from tuning and water washing, (2) worst case hourly emission rates allowed under the terms of the permit for cold startups (with worst case being allowed for the GE 7HA.02 combustion turbine generators), (3) proper background NO_2 concentration data from the Shirley Plantation monitoring site, and (4) the short-term NO_X emissions allowed by the permit for the C4GT power plant, and the worst- case NO_X emissions allowed for this nearby plant together with the worst-case NO_X emissions allowed for the Chickahominy power plant.

REQUEST FOR DIRECT CONSIDERATION BY THE AIR POLLUTION CONTROL BOARD

The substantial legal and factual issues set forth in the comments above warrant direct consideration by the State Air Pollution Control Board under 9 Virginia Administrative Code § 5-80-25. In support of this request for Board consideration, the Sierra Club states:

1. The undersigned's mailing address and telephone number are:

   Dori E. Jaffe
   Sierra Club
   50 F St NW, Eighth Floor
   Washington, D.C. 20001
   (202) 675-6275

2. The undersigned is acting as a representative of the Sierra Club, whose mailing address and telephone number is:

   Virginia Chapter—Sierra Club
   442 East Franklin Street, Suite 302
   Richmond, Virginia 23219
   (804) 225-9113

3. The Sierra Club is a nonprofit conservation organization with more than 600,000 dues-paying members nationwide and 20,000 members in Virginia. The Sierra Club is dedicated to exploring, enjoying, and protecting the wild places of the Earth; to practicing and promoting responsible use of the Earth's resources and ecosystems; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and using all lawful means to carry out those objectives. Through its Clean Power Solutions campaign, the Sierra Club's Virginia Chapter encourages investments in the Commonwealth's substantial renewable energy potential. The Sierra Club's members reside within proximity of the proposed plant, and they live within the airsheds and other areas potentially affected by its operations. As such, the Sierra Club and its members have immediate, pecuniary, and substantial interests in the outcome of this permitting proceeding and would be adversely affected by the construction and operation of the facility.

4. All substantive comments set forth above are incorporated by reference. We maintain that these comments must be addressed in order to bring the proposed permit into conformance

with the Clean Air Act, the Virginia Air Pollution Control Law, and Virginia's State Implementation Plan. These comments raise substantial (and presumably disputed) issues relevant to the issuance of the permit in question. Furthermore, the actions requested in the above comments are not inconsistent with the Virginia Air Pollution Control Law or any other federal law or regulation promulgated thereunder; the actions requested are in fact *necessary* in order to satisfy the requirements of the law.

5. Due to the substantial nature of the legal and factual issues raised in the comments above, the Director should submit the proposed permit action to the Board under either 9 Virginia Administrative Code § 5-80-25(C) or 9 Virginia Administrative Code § 5-80-25(F), as appropriate, and the Board should grant consideration of this permitting action—either at the suggestion of the director under 9 Virginia Administrative Code § 5-80-25(C) or 9 Virginia Administrative Code § 5-80-25(F), or acting independently under 9 Virginia Administrative Code § 5-80-25(D).

To the extent an evidentiary or other public hearing to contest this permit action is permitted under 9 Virginia Administrative Code § 5-80-35 or any other provision of Virginia law, the Sierra Club requests such a hearing to facilitate the presentation of additional evidence and legal argument concerning the proposed action. In support of this request, Paragraphs 1–5 above are incorporated by reference.

Sierra Club appreciates the opportunity to comment on this draft permit.

Sincerely,

____

Dori E. Jaffe
Senior Attorney
Sierra Club
50 F St. NW, 8th Floor
Washington, DC 20001
(202) 675-6275 (direct)
Dori.Jaffe@sierraclub.org

Counsel for the Virginia Chapter of the Sierra Club

Exhibit 1

Curriculum Vitae

Victoria R. Stamper
P.O. Box 9571
Boise, Idaho 83707
stamper.vr@gmail.com

Areas of Expertise

Comprehensive knowledge of the Clean Air Act - accomplished in the requirements for new source review (NSR) and prevention of significant deterioration (PSD) construction permits, Title V operating permits, Maximum Achievable Control Technology (MACT) Approvals, Class I area protection including regional haze plans and best available retrofit technology (BART) determinations, and state implementation plans for compliance with the national ambient air quality standards.

Extensive experience with new source review permitting – have evaluated numerous PSD and synthetic minor permit applications, draft permits, associated air modeling analyses, and determinations of best available control technology.

Professional Experience

Air Quality Consultant — April 2003 to Present
Boise, ID 83707

I provide consulting services on numerous air quality issues such as:

- Reviewing and commenting on EPA state implementation plan (SIP) actions.
- Reviewing/preparing comments on all aspects of air quality construction and operating permit applications and permits for industrial sources including coal-fired power plants.
- Providing technical expertise for the appeal of air quality permits that do not comply with federal or state clean air requirements.
- Investigating facility compliance with federal and state air quality regulations.
- Analyzing proposed or available mercury and other hazardous air pollutant controls for coal-fired power plants.
- Reviewing and commenting on Class I regional haze and visibility protection plans.
- Evaluating proposed best available retrofit technology determinations.
- Critiquing prevention of significant deterioration increment analyses.
- Evaluating and commenting on air quality analyses and environmental impact statements for proposed oil and gas development in the West.

<u>Environmental Engineer/Legal Assistant</u> May 2001 to April 2003
Reed Zars, Attorney at Law
Laramie, WY82070

Responsibilities included:

- Investigating industrial facilities' compliance with Clean Air Act requirements through review of public documents.
- Researching pollution reduction measures and effectiveness.
- Reviewing and preparing comments on proposed air quality construction and operating permits.
- Reviewing and preparing written comments on proposed EPA state implementation plan approvals regarding topics such as opacity regulations, emission limit exemptions, Class I area visibility plans and permitting regulations.

<u>New Source Review Program Manager</u> December 1990 to April 2001
Air and Radiation Program
U.S. Environmental Protection Agency, Region VIII
Denver, Colorado 80202

Responsibilities included:

- Serving as the Region VIII lead for state rules regarding the new source review and prevention of significant deterioration programs, and industrial source control measures.
- Reviewing all aspects of prevention of significant deterioration increment analyses.
- Reviewing state implementation plans for consistency with requirements of Clean Air Act.
- Preparing documents to justify EPA approval or disapproval of state submittals.
- Educating and assisting tribes in developing regulations for tribal implementation plans.
- Participating in workgroups to ensure national consistency and provide input on rulemakings.
- Reviewing state operating permit programs under Title V of the Clean Air Act.
- Researching and compiling the EPA-approved state implementation plans.
- Developing and reviewing state implementation plans for particulate matter nonattainment areas, as well as assisting in the preparation of requests to redesignate to attainment.
- Reviewing environmental impact statements for consistency with Clean Air Act.
- Serving as primary contact for air quality issues in the state of Wyoming.

<u>Environmental Engineer</u> August 1989- July 1990
Envirometrics, Inc.
Seattle, Washington 98103

Responsibilities included:

- Designing components of research projects pertaining to pollution control systems.
- Developing testing criteria and measuring the effectiveness of these control systems.
- Preparing air pollution permit applications and related documentation for industrial sources.
- Compiling input data for modeling of ambient air quality impacts on Class I areas.
- Developing emission inventories.

Selected Reports and Papers

- Stamper, V., Technical Support Document to Comments of Conservation Organizations; EPA's Proposed Regional Haze FIP for Texas, May 3, 2017.

- Stamper, V., Technical Support Document to Comments of Conservation Organizations; Proposed Utah Regional Haze SIP Approval and FIP, March 14, 2016.

- Stamper, V., Technical Support Document to Comments of Conservation Organizations; Proposed Regional Haze FIP for Arkansas, August 5, 2016.

- Stamper, V., Technical Support Document to Comments of Conservation Organizations; EPA's Proposed Reasonable Progress Measures for Texas and Oklahoma, April 27, 2015.

- Stamper, V., Technical Support Document to Comments of Conservation Organizations; Proposed Wyoming Regional Haze Partial SIP Approval and Partial FIP, August 1, 2012.

- Stamper, V., C. Copeland, M. Williams, and T. Spencer (contributing editor), Poisoning the Great Lakes: Mercury Emissions from Coal-Fired Power Plants in the Great Lakes Region, Natural Resources Defense Council Publication, June 2012.

- Fox, Phyllis and V. Stamper, Technical Support Document to Comments of Conservation Organizations: Proposed Montana Regional Haze FIP, June 15, 2012.

- Technical Support Attachment to Comments of Conservation Organizations; Minnesota Regional Haze SIP Proposed Approval – February 21, 2012.

- Stamper, V., Review of EPA's Proposed Best Available Control Technology (BART) Requirements for the Four Corners Power Plant on Navajo Nation Land, April 28, 2011.

- Stamper, V. and C. Copeland, *Stop the Rollbacks, Cleaner, Healthier Air for Colorado*, Environmental Defense publication, 2005.

- Banerjee, S. and V. Stamper, *Mercury Air Pollution The Case for Rigorous MACT Standards For Subbituminous Coal*, prepared for Rocky Mountain Office of Environmental Defense and the Land and Water Fund of the Rockies, May 2003.

Education

Bachelor of Science Degree
Civil Engineering, Michigan State University
East Lansing, Michigan

Exhibit 2

Connecticut Department of
ENERGY &
ENVIRONMENTAL
PROTECTION

79 Elm Street • Hartford, CT 06106-5127 www.ct.gov/deep Affirmative Action/Equal Opportunity Employer

NOV 30 2015

Mr. Andrew Bazinet
Director of Development
CPV Towantic, LLC
50 Braintree Hill Office Park Suite 300
Braintree, MA 02184

Dear Mr. Bazinet:

Enclosed are copies of your new permits to construct and operate a 805 MW Combined Cycle Power Plant consisting of two GE 7HA.01 combustion turbines with duct firing, one auxiliary boiler and two emergency diesel fired engines at 16 Woodruff Hill Road, Oxford, CT.

This letter does not relieve you of the responsibility to comply with the requirements of other appropriate Federal, State, and municipal agencies. These permits are not transferable from one permittee to another (without prior written approval), from one location to another, or from one piece of equipment to another. The permits must be made available at the site of operation throughout the period that such permit is in effect.

Permit renewal applications must be filed at least one hundred twenty (120) days prior to the permit expiration date, if applicable. Pursuant to Section 22a-174-3a of the Regulations of Connecticut State Agencies, CPV Towantic, LLC must apply for a permit modification/revision in writing if it plans any physical change, change in method of operation, or addition to this source which constitutes a modification or revision pursuant to Section 22a-174-1 and 22a-174-2a, respectively. Any such changes should first be discussed with Mr. James Grillo of the Bureau of Air Management, by calling (860) 424-4152. Such changes shall not commence prior to the issuance of a permit modification.

Sincerely,

Gary S. Rose

Gary S. Rose
Director
Engineering & Enforcement Division
Bureau of Air Management

GSR:JAG:jad
Enclosure

Connecticut Department of

ENERGY &
ENVIRONMENTAL
PROTECTION

BUREAU OF AIR MANAGEMENT
NEW SOURCE REVIEW PERMIT
TO CONSTRUCT AND OPERATE A STATIONARY SOURCE

Issued pursuant to Title 22a of the Connecticut General Statutes (CGS) and Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA).

Owner/Operator	CPV Towantic, LLC
Address	50 Braintree Hill Office Park, Suite 300 Braintree, MA 02184
Equipment Location	16 Woodruff Hill Road, Oxford, CT
Equipment Description	General Electric 7HA.01Gas Turbine with DLN combustors, Duct Burners and Heat Recovery Steam Generator (Unit 1)
Collateral Conditions	Part VII of this permit contains collateral conditions with other NSR permits affecting the Greenhouse Gas requirements and the certified NOx emissions reduction offsets for the entire facility.
Town-Permit Numbers	144-0023
Premises Number	14
Stack Number	7
Permit Issue Date	NOV 30 2015
Expiration Date	None

Michael Sullivan
Michael Sullivan
Deputy Commissioner

November 30, 2015
Date

This permit specifies necessary terms and conditions for the operation of this equipment to comply with state and federal air quality standards. The Permittee shall at all times comply with the terms and conditions stated herein.

PART I. DESIGN SPECIFICATIONS

A. General Description

CPV Towantic, LLC operates a power generation facility consisting of two (2) General Electric 7HA.01 combustion turbines with DLN combustors and a combined nominal gross electrical output of 805 MW in Oxford, CT. The turbines are dual fuel fired combined cycle units, each with a separate heat recovery steam generator (HRSG) that includes natural gas supplementary firing (duct burners) to power a single steam turbine generator. Oil firing for the turbines is limited to ultra-low sulfur distillate (ULSD) No. 2 fuel oil during periods of natural gas curtailment or as allowed in Part VII of this permit. Pollution control equipment will include selective catalytic reduction (SCR), oxidation catalyst, and water injection (ULSD firing only) to control NOx, CO and VOC emissions. The turbine, duct burner and HRSG are designated as Unit 1 for this permit.

B. Equipment Design Specifications

1. Turbine
   The design gross heat input to the turbine is 2,544 MMBtu/hr while firing natural gas and 2,511 MMBtu/hr while firing ULSD oil. These heat inputs are based on an ambient temperature of 59^{0}F and result in firing rates of 2,435,742 scf of natural gas (HHV 996 Btu/scf) and 17,326 gallons of ULSD (HHV 138,000 Btu/gal) per hour. Heat input will vary by approximately $\pm$5% over the typical range of temperatures expected, with higher heat input occurring at lower ambient temperatures.

2. Duct Burner
   The design gross heat input to the duct burner is 962 MMBtu/hr while firing natural gas. The heat input is based on an assumed HHV of 996 Btu/scf and results in a firing rate of 965,863 scfh.

C. Stack Parameters

1. Minimum Stack Height (ft): 150 (above base elevation)

2. Minimum Exhaust Gas Flow Rate at minimum operating load, turbine only (acfm): 663,327 (gas); 860,408 (ULSD)

3. Minimum Stack Exit Temperature at 100% load (°F): 170

4. Minimum Distance from Stack to Property Line (ft): 188

D. Definitions

1. "Steady-state" operation shall be defined as all periods other than transient operation.

2. "Transient" operation shall be all modes of operation at loads less than 30%, including periods of startup, shutdown, fuel switching and equipment cleaning. "Load" shall be defined as the net electrical output of the turbine. No period of transient operation shall exceed 60 consecutive minutes.

3. "Shakedown" shall be defined as turbine operations including, but not limited to, the first firing of the turbine, proof of interlocks, steam blowing, chemical cleaning and initial turbine roll. The shakedown period shall not extend to or beyond the required date for the initial performance tests specified in Part V.B of this permit.

PART II. OPERATIONAL CONDITIONS and REQUIREMENTS

A. Equipment

1. Turbine
   a. Allowable Fuel Types: Natural Gas; Ultra-Low Sulfur Distillate (ULSD)
   b. Maximum Heat Input over any Consecutive 12 Month Period: 2.12×10^7 MMBtu (gas); 1.72×10^6 MMBtu (ULSD)
   c. Maximum Distillate Fuel Oil Sulfur Content (% by weight, dry basis): 0.0015
   d. Natural gas shall be the primary fuel combusted in this unit. Firing of ULSD is allowed only in the following scenarios:
      i. ISO-NE declares an Energy Emergency as defined in ISO New England's Operating Procedure No. 21 and requests the firing of ULSD.
      ii. The natural gas supply is curtailed by an entity through which gas supply and/or transportation is contracted,
      iii. There exists a physical blockage or breakage in the natural gas pipeline,
      iv. During all periods of commissioning of the plant including performance testing,
      v. During routine maintenance and readiness testing.
      vi. In order to maintain an appropriate turnover of the on-site fuel inventory, to prevent wastage of oil, the owner/operator can fire ULSD when the last delivery of oil was more than six months ago.
   e. The Permittee shall not operate the duct burner while firing ULSD in the turbine.

2. Duct Burner
   a. Allowable Fuel: Natural Gas
   b. Maximum Heat Input over any Consecutive 12 Month Period: 4.09×10^6 MMBtu

B. The Permittee shall operate this equipment, including the SCR, oxidation catalyst, and water injection in a manner to comply with the emissions limits in Part III of this permit.

C. The Permittee shall operate and maintain this equipment, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup and shutdown.

D. The Permittee shall operate and maintain this equipment in accordance with the manufacturer's specifications and written recommendations.

E. The Permittee shall minimize emissions during periods of startup and shutdown and shall start the ammonia injection as soon as the SCR vendor's recommended minimum catalyst temperature is reached.

F. The Permittee shall not operate the auxiliary boiler, Permit No. 144-0025, simultaneously with the combustion turbines for more than 500 hours in any calendar year.

G. The Permittee shall not exceed a maximum allowable heat rate at full operating load while firing natural gas, without duct firing, of 7,220 Btu/kW-hr (HHV, net plant), on a12-month rolling average for Units 1 and 2 combined.

H. The Permittee shall immediately institute shutdown of the turbine in the event where emissions are in excess of a limit in Part III of this permit that cannot be corrected within three hours of when the emissions exceedance was identified.

I. The Permittee shall not exceed 250 startup events per calendar year for this unit.

PART III. ALLOWABLE EMISSION LIMITS

A. Steady State

Except during the initial shakedown period, the Permittee shall not cause or allow this equipment to exceed the emission limits stated herein at any time during steady state operation.

1. Turbine Operating on Natural Gas without Duct Firing

Pollutant	lb/hr	ppmvd @ 15% O_2	lb/MMBtu
PM	9.73		6.5E-3
$PM_{10/2.5}$	9.73		6.5E-3
SO_2	4.49		1.5E-3
NOx	19.4	2.0	
VOC	3.37	1.0	
CO	5.31	0.9	
Lead	1.3E-03		
H_2SO_4	2.11		
Ammonia		2.0	

2. Turbine Operating on Natural Gas with Duct Firing

Pollutant	lb/hr	ppmvd @ 15% O_2	lb/MMBtu
PM	20.4		8.1E-3
$PM_{10/2.5}$	20.4		8.1E-3
SO_2	6.2		1.5E-3
NOx	26.8	2.0	
VOC	8.82	2.0	
CO	13.8	1.7	
Lead	1.7E-03		
H_2SO_4	2.7		
Ammonia		2.0	

3. Turbine Operating on ULSD

Pollutant	lb/hr	ppmvd @ 15% O_2	lb/MMBtu
PM	42.6		3.19E-2
$PM_{10/2.5}$	42.6		3.19E-2
SO_2	4.92		1.53E-3
NOx	52.0	5.0	
VOC	6.2	2.0	
CO	12.7	2.0	
Lead	3.7E-02		
H_2SO_4	2.31		
Ammonia		5.0	

B. Transient Emissions

1. Except during the initial shakedown period, the Permittee shall not cause or allow this equipment to exceed these limits during startup and shutdown events. No startup or shutdown event shall last longer than 1 hour in duration.

	Type of Event			
	Startup		Shutdown	
	Natural Gas	ULSD	Natural Gas	ULSD
NO_x (lb/hr)	93	104	19	34
VOC (lb/hr)	37	90	60	23
CO (lb/hr)	242	231	121	18

2. Ammonia (NH_3) emissions shall not exceed 5 ppmvd @ 15% O_2 (both fuels) during transient operation.

C. Total Allowable Annual Emission Limits (per unit)

The Permittee shall not cause or allow this equipment to exceed the emission limits stated herein at any time.

1. Pollutants

Pollutant	tons per 12 consecutive months
PM	76.7
$PM_{10/2.5}$	76.7
SO_2	19.7
NOx	94.7
VOC	24.5
CO	64.5
Pb	1.9E-02
H_2SO_4	9.1
NH_3	35

D. Greenhouse Gas Emissions

1. The Permittee shall not exceed a combined annual CO_2e emissions limit of 2,675,185 tons/yr for this unit in combination with the units operating under permit numbers 144-0024, 144-0025, 144-0026, and 144-0027. Compliance with this limitation shall be determined on a consecutive 12-month rolling basis. The Permittee shall make and keep monthly records of CO_2e emissions with the following methodologies:
   a. CO_2 emissions from the combustion turbines, operating under permit numbers 144-0023 and 144-0024, shall be determined by the methodology found in 40 CFR Part 75, Appendix G, Equation G-4.
   b. CO_2 emissions from the boiler and two diesel engines, operating under permit numbers 144-0025, 144-0026, and 144-0027, shall be determined using the default emissions factors found in 40 CFR Part 98, Subpart C, Table C-1.
   c. Methane (CH_4) and nitrous oxide (N_2O) for all combustion sources shall be determined using the default emissions factors found in 40 CFR Part 98, Subpart C, Table C-2.
   d. Estimated fugitive emissions of sulfur hexafluoride (SF_6) from the electrical circuit breakers shall be determined using mass balance.
   e. Estimated fugitive emissions of CH_4 from the natural gas pipeline and associated components shall be determined using default emissions factors found in 40 CFR Part 98, Subpart W, Table W-7.

E. Hazardous Air Pollutants (HAP)

This equipment shall not cause an exceedance of the Maximum Allowable Stack Concentration (MASC) for any hazardous air pollutant (HAP) emitted and listed in RCSA Section 22a-174-29. [STATE ONLY REQUIREMENT]

F. Opacity

This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR 60, Appendix A, Reference Method 9.

G. Demonstration of compliance with the above emission limits may be met by calculating emissions based on emission factors from the following sources:

- *PM/PM10/PM2.5, VOC, H_2SO_4: Stack test data*
- *SO_2: Sulfur content in fuel*
- *NOx & CO (steady state): CEM data*
- NOx, VOC, & CO (transient): Manufacturer's recommended uncontrolled emission factors
- HAP: AP-42, Fifth Edition, Volume I Chapter 3.1, April 2000 except for those HAP with required stack test found in Part V of this permit.

H. The Permittee is not required to demonstrate compliance with the short-term emission limits stated herein prior to the completion of the Shakedown period. Emissions prior to the completion of the Shakedown period shall be counted towards the annual emission limits stated herein.

I. The commissioner may require other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall comply with the CEM requirements as set forth in RCSA Section 22a-174-4, RCSA §22a-174-22, 40 CFR 60 Subpart *KKKK and* 40 CFR Parts 72-78, as applicable. Continuous Emissions Monitoring (CEM) is required for the following pollutants and enforced on the following basis:

Pollutant	Averaging Times	Emission Limit (ppmvd @15% O_2)
Opacity (ULSD only)	six minute block	10%
NOx	1 hour block	See Part III.A
CO	1 hour block	See Part III.A
NH_3	1 hour block	See Part III.A

2. The Permittee shall continuously monitor the following parameters:

Operational Parameter	Averaging Times
O_2	1 hour block
Fuel Flow	1 hour block
Net Electrical Output	Continuous

3. At least sixty (60) days prior to the initial stack test, the Permittee shall submit a CEM monitoring plan to the Commissioner in accordance with RCSA 22a-174-4(c)(3).

4. The Permittee shall use fuel flow meters, certified in accordance with 40 CFR Part 75 Appendix D to measure and record the flow rate of fuels to the turbine and duct burner.

5. The Permittee shall perform inspections and maintenance of the SCR and oxidation catalysts as recommended by the manufacturer.

6. Prior to operation, the Permittee shall develop a written plan for the operation, inspection, maintenance, preventive and corrective measures for minimizing GHG emissions (CH_4 emissions from the natural gas pipeline components and SF_6 emissions from the insulated electrical equipment). At a minimum the plan shall provide for:

   i. Implementation daily auditory/visual/olfactory inspections of the natural gas piping components supplying natural gas to the combustion turbine/duct burner;

   ii. An installed leak detection system to include audible alarms to identify SF_6 leakage from the circuit breakers;

   iii. Inspection for SF_6 emissions from the insulated electrical equipment on at least a monthly basis.

B. Record Keeping

1. For the turbine, the Permittee shall keep records of monthly and consecutive 12 month fuel consumption (for each fuel). The consecutive 12 month fuel consumption shall be determined by adding (for each fuel) the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

2. For the duct burner, the Permittee shall keep records of monthly and consecutive 12 month natural gas consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

3. The Permittee shall keep records of the monthly and consecutive 12 month heat input to the turbine for both natural gas and ULSD firing. The records shall include sample calculations.

4. The Permittee shall keep records of the monthly and consecutive 12 month heat input to the duct burner. The records shall include sample calculations.

5. The Permittee shall keep records of the fuel certification for each delivery of fuel oil from a bulk petroleum provider or a copy of the current contract with the fuel supplier supplying the fuel used by the equipment that includes the applicable sulfur content of the fuel as a condition of each shipment. The shipping receipt or contract shall include the date of delivery, the name of the fuel supplier, type of fuel delivered, the percentage of sulfur in such fuel, by weight, dry basis, and the method used to determine the sulfur content of such fuel.

6. The Permittee shall calculate and record the monthly and consecutive 12 month PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO, H_2SO_4, NH_3, and CO_2e emissions in units of tons for all fuels combusted.

   The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.

   Emissions during startup and shutdown shall be included in the monthly and consecutive 12 month calculations.

7. The Permittee shall keep records of the number of startup events for each calendar year.

8. The Permittee shall keep records of the emissions of this turbine and duct burner during the initial shakedown period. Emissions during shakedown shall be calculated using good engineering judgment and the best data and methodology available for estimating such emissions. Emissions during shakedown shall be counted towards the annual emission limitation in Part III.C of this permit.

9. The Permittee shall keep records of the occurrence and duration of all transient operation of the unit; any malfunction of the air pollution control equipment that causes an exceedance of any emission limitation found in Part III of this permit; or any periods during which a continuous monitoring system or monitoring device is inoperative.

   Such records shall contain the following information:
   a. type of event and percent load;
   b. equipment affected;
   c. date of event;
   d. duration of event (minutes);
   e. fuel being used during event; and
   f. total NO_x, CO and VOC emissions emitted (lb) during the event.

10. The Permittee shall keep records of each delivery of aqueous ammonia/urea. The records shall include:
    a. the date of delivery;
    b. the name of the supplier;
    c. the quantity of aqueous ammonia delivered; and
    d. the percentage of ammonia in solution, by weight.

11. The Permittee shall keep records of the inspection and maintenance of the SCR and oxidation catalysts. The records shall include:
    a. the name of the person conducting the inspection/maintenance;
    b. the date of the inspection/maintenance;
    c. the results or actions taken; and
    d. the date the catalyst is replaced.

12. The Permittee shall keep records of all repairs/replacement of parts and other maintenance activities for the equipment.

13. The Permittee shall keep records of the electrical output of the plant (net) and the heat rate for the turbines while firing natural gas (HHV, net plant) without duct firing, on a 12-month rolling average for the plant.

14. The Permittee shall keep records of the inspection, maintenance, preventive and corrective measures for minimizing GHG emissions from the natural gas pipeline components and the insulated electrical equipment. The records shall include:
    a. the name of the person conducting the inspection/maintenance;
    b. the date the inspection/maintenance;
    c. the results or actions taken;
    d. the leak detection methods used; and
    e. the amount of SF_6 added (if any) to the electrical equipment

15. The Permittee shall keep monthly records of the audible alarms from the SF_6 leak detection system and inspections for the insulated electrical equipment. The records shall include:
    a. the name of the person conducting the inspection/maintenance;
    b. the date the inspection/maintenance;
    c. the results or actions taken.

16. The Permittee shall make and keep records of each hour of co-firing of this unit with the auxiliary boiler for each month and consecutive 12 months.

17. The Permittee shall make and keep records of all occurrences of firing ULSD in the turbine. At a minimum these records shall contain the following information:
    a. the duration of ULSD firing,
    b. the reason for ULSD firing, and
    c. the heat input to the turbine.

18. The Permittee shall keep a certified copy of this permit on the premises at all times, and shall make this copy available upon request of the Commissioner for the duration of this permit. This copy shall also be available for public inspection during regular business hours.

19. The Permittee shall keep records of the manufacturer written recommendations for operation and maintenance of the equipment found in this permit.

20. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

C. Reporting

1. The Permittee shall notify the commissioner in writing of all exceedances of an emissions limitation, and shall identify the cause or likely cause of such exceedance, all corrective actions and preventive measures taken with respect thereto, and the dates of such actions and measures as follows:
   a. For any hazardous air pollutant, no later than 24 hours after such exceedance was identified; and
   b. For any other regulated air pollutant, no later than ten days after such exceedance commenced.

2. The Permittee shall notify the commissioner, in writing, of the dates of commencement of construction, completion of construction, and initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART V. STACK EMISSION TEST REQUIREMENTS

A. Stack emission testing shall be performed in accordance with the RCSA 22a-174-5 and the Emission Test Guidelines available on the DEEP website.

B. Initial stack emission testing is required for the following pollutant(s):

☒ PM/$PM_{10/2.5}$ ☒ SO_2 ☒ NOx ☒ CO ☒ CO_2
☒ VOC ☒ Opacity
☒ Other (HAPs): Sulfuric Acid, Formaldehyde, arsenic

1. Stack emissions testing firing natural gas, without duct firing, for CO_2 shall only be required during the initial performance test to show compliance with an emissions limit of 809 lbs/MW-hr (net plant), corrected to ISO conditions, as defined in the approved stack test protocol.

2. For the purposes of determining maximum heat input of the turbine during performance testing, the following equations may be used:

$$\mathbf{MHI_T = Q_1 - [(T - T_1)/(T_2 - T_1)] \times (Q_1 - Q_2)}$$

Where,

MHI_T = Turbine maximum heat input at ambient temperature (^{0}F)
T = Ambient Temperature
T_1 = Temperature Value from Table 1 that is below the ambient temperature
T_2 = Temperature Value from Table 1 that is above the ambient temperature
Q_1 = Heat Input at corresponding T_1
Q_2 = Heat Input at corresponding T_2

Table 1

Natural Gas Firing			ULSD Firing	
Temperature (T) ^0F	Heat Input (Q)		Temperature (T) ^0F	Heat Input (Q)
-14.2	2649		-14.2	2652
20	2672		20	2613
50	2590		50	2559
59	2544		59	2511
90	2416		90	2390
100	2409		100	2331

3. The Duct Burner shall be required to meet a minimum heat input value of 770 MMBtu/hr for all ambient temperatures during initial and recurring performance testing.

4. The Permittee shall perform one set of tests on this turbine when burning natural gas with the duct burner and one set without duct firing. The Permittee shall perform one set of tests with the turbine burning ULSD.

C. The Permittee shall conduct initial stack emission testing within 60 days of achieving the maximum production rate, but not later than 180 days after initial startup. The Permittee shall submit test results within 60 days after completion of testing.

D. Recurrent stack testing of all pollutants listed in Part V.B of this permit, except for VOC and CO_2, shall be performed within five years from the date of the previous stack test. Testing shall be as described in Part V.B of this permit with the following exceptions:

1. After the initial performance test, stack testing may not be required for pollutants requiring CEM. The commissioner retains the right to require stack testing of any pollutant at any time to demonstrate compliance.

2. More frequent testing of VOC is required to verify the correlation between VOC and the CO CEM data. Performance testing for VOC shall be performed within 18-months from the date of the previous stack test.

E. Fuel oil analysis of the arsenic in the distillate oil may be substituted for stack testing while firing distillate oil. Arsenic testing is not required for natural gas firing.

F. Stack Emission test results shall be reported as follows: all pollutants in units of lb/hr; NOx, CO, VOC, formaldehyde, and ammonia in units of ppmvd at 15% O_2;

PART VI. SPECIAL REQUIREMENTS

A. The Permittee shall possess, at least, 235 tons of external emissions reductions to offset the quantity of NO_x emitted from the sources covered under following Permit Numbers. to comply with RCSA 22a-174-3a(l):

- 144-0023 [General Electric 7HA.01 combustion turbine/duct Burner]
- 144-0024 [General Electric 7HA.01 combustion turbine/duct burner]
- 144-0025 [92.4 MMBtu/hr natural gas fired auxiliary boiler]
- 144-0026 [1,500 kW ULSD fired emergency generator]
- 144-0027 [350 bhp ULSD fired emergency fire pump]

Such a quantity is sufficient to offset the emissions from the sources listed above at a ratio of 1.2 to

1 tons of reduction for every ton of NOx emissions allowed under the permits listed. Specifically, the reductions are real, quantifiable, surplus, permanent, and enforceable as defined in RCSA 22a-174-3a(l)(5). The Permittee shall maintain sole ownership and possession of these emissions reductions for the duration of this permit and any subsequent changes to the permit.

Such offsets have been obtained from the following sources:

- 106 tons from Consolidated Edison Company of New York: NY-NY-DEC-2-6301-00006-106
- 110 tons from Akeida Capital Management LLC: CT4NOX00-015-0045-7888-110
- 19 tons from Sikorsky Aircraft Corporation: CTNOX1011-178-0039-19

The Permittee may be required to obtain additional NOx offsets and complete additional ambient air quality analysis to show that the NAAQS and PSD increments have not been violated, if observed steady state or transient emissions exceed a limit specified in Parts III.A, III.B or III.C of this permit.

B. Total annual VOC emissions from all VOC emitting sources located at the premises shall not exceed 49.9 tons/year.

Demonstration of compliance with the annual VOC premises wide limit shall be based on each consecutive 12 month time period and shall be determined by adding the current month's VOC premises wide emissions to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

Monthly premises wide VOC emissions shall be calculated using the following equations:

$$VOC_{premises} = \Sigma VOC_{turbines} + \Sigma VOC_{engines} + VOC_{aux\ boiler} + \Sigma VOC_{storage\ tanks} + \Sigma VOC_{add}$$

where,

$\Sigma VOC_{turbines}$ = The sum of VOC emissions from the two turbine trains covered by permits 144-0023 and 144-0024 determined by correlating the VOC emissions to the CO emissions using the results of a diagnostic stack test and tracked using the CO CEMS. VOC emissions from the turbine train shall be recorded on the CEMS data acquisition system.

$\Sigma VOC_{engines}$ = The sum of emissions from the emergency engines covered by permit numbers 144-0026 and 144-0027. VOC emissions shall be calculated using the following equation:

VOC (ton/month)= [X (VOC lbs/hr) * Y (hrs/month)] * 1 ton/2000 lbs

$VOC_{aux\ boiler}$ = The emissions from the auxiliary boiler covered by permit 144-0025. VOC emissions shall be calculated using the following equation:

VOC (ton/month)= [X (VOC lbs/hr) * Y (hrs/month)] * 1 ton/2000 lbs

$\Sigma VOC_{storage\ tanks}$ = The emissions from any storage tanks located on the premises shall be determined using the latest version of the EPA TANKS model or other equivalent method.

ΣVOC_{add} = The VOC emissions from any additional VOC emitting equipment that is added to the premises after the issuance of this permit. The VOC emissions from such equipment shall be calculated using good engineering practices.

The Commissioner may require other methods for determining VOC emissions from these sources as allowed by state or federal statute, law or regulation.

C. Upon completion of construction of the turbines and control equipment regulated under Permit No. 144-0023 and 144-0024, the Permittee shall prepare and submit a written standby plan in accordance with the RCSA 22a-174-6(d)(2) through (d)(5).

D. The Permittee shall comply with all applicable sections of the following New Source Performance Standard(s) at all times.

Title 40 CFR Part 60, Subpart: KKKK and A

Copies of the Code of Federal Regulations (CFR) are available online at the U.S. Government Printing Office website.

E. The Permittee shall operate this facility at all times in a manner so as not to violate or contribute significantly to the violation of any applicable state noise control regulations, as set forth in RCSA Sections 22a-69-1 through 22a-69-7.4. [STATE ONLY REQUIREMENT]

F. Unless directed otherwise by the Commissioner, if construction does not commence within eighteen (18) months from the date of issuance of this permit, the Permittee shall submit a written updated review of all prior BACT determinations for this unit. The Permittee shall submit this review to the Commissioner within 30 days of the end of such 18 month period.

PART VII. ADDITIONAL TERMS AND CONDITIONS

A. This permit does not relieve the Permittee of the responsibility to conduct, maintain and operate the regulated activity in compliance with all applicable requirements of any federal, municipal or other state agency. Nothing in this permit shall relieve the Permittee of other obligations under applicable federal, state and local law.

B. Any representative of the DEEP may enter the Permittee's site in accordance with constitutional limitations at all reasonable times without prior notice, for the purposes of inspecting, monitoring and enforcing the terms and conditions of this permit and applicable state law.

C. This permit may be revoked, suspended, modified or transferred in accordance with applicable law.

D. This permit is subject to and in no way derogates from any present or future property rights or other rights or powers of the State of Connecticut and conveys no property rights in real estate or material, nor any exclusive privileges, and is further subject to any and all public and private rights and to any federal, state or local laws or regulations pertinent to the facility or regulated activity affected thereby. This permit shall neither create nor affect any rights of persons or municipalities who are not parties to this permit.

E. Any document, including any notice, which is required to be submitted to the commissioner under this permit shall be signed by a duly authorized representative of the Permittee and by the person who is responsible for actually preparing such document, each of whom shall certify in writing as follows: "I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any applicable statute."

F. Nothing in this permit shall affect the commissioner's authority to institute any proceeding or take any other action to prevent or abate violations of law, prevent or abate pollution, recover costs and natural resource damages, and to impose penalties for violations of law, including but not limited to violations of this or any other permit issued to the Permittee by the commissioner.

G. Within 15 days of the date the Permittee becomes aware of a change in any information submitted to the commissioner under this permit, or that any such information was inaccurate or misleading or that any relevant information was omitted, the Permittee shall submit the correct or omitted information to the commissioner.

H. The date of submission to the commissioner of any document required by this permit shall be the date such document is received by the commissioner. The date of any notice by the commissioner under this permit, including but not limited to notice of approval or disapproval of any document or other action, shall be the date such notice is personally delivered or the date three days after it is mailed by the commissioner, whichever is earlier. Except as otherwise specified in this permit, the word "day" means calendar day. Any document or action which is required by this permit to be submitted or performed by a date which falls on a Saturday, Sunday or legal holiday shall be submitted or performed by the next business day thereafter.

I. Any document required to be submitted to the commissioner under this permit shall, unless otherwise specified in writing by the commissioner, be directed to: Office of Director; Engineering & Enforcement Division; Bureau of Air Management; Department of Energy and Environmental Protection; 79 Elm Street, 5th Floor; Hartford, Connecticut 06106-5127.

Connecticut Department of

ENERGY & ENVIRONMENTAL PROTECTION

BUREAU OF AIR MANAGEMENT
NEW SOURCE REVIEW PERMIT
TO CONSTRUCT AND OPERATE A STATIONARY SOURCE

Issued pursuant to Title 22a of the Connecticut General Statutes (CGS) and Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA).

Owner/Operator	CPV Towantic, LLC
Address	50 Braintree Hill Office Park, Suite 300 Braintree, MA 02184
Equipment Location	16 Woodruff Hill Road, Oxford, CT
Equipment Description	General Electric 7HA.01Gas Turbine with DLN combustors, Duct Burners and Heat Recovery Steam Generator (Unit 2)
Collateral Conditions	Part VII of this permit contains collateral conditions with other NSR permits affecting the Greenhouse Gas requirements and the certified NOx emissions reduction offsets for the entire facility.
Town-Permit Numbers	144-0024
Premises Number	14
Stack Number	8
Permit Issue Date	NOV 30 2015
Expiration Date	None

Michael Sullivan

Michael Sullivan
Deputy Commissioner

November 30, 2015
Date

This permit specifies necessary terms and conditions for the operation of this equipment to comply with state and federal air quality standards. The Permittee shall at all times comply with the terms and conditions stated herein.

PART I. DESIGN SPECIFICATIONS

A. General Description

CPV Towantic, LLC operates a power generation facility consisting of two (2) General Electric 7HA.01 combustion turbines with DLN combustors and a combined nominal gross electrical output of 805 MW in Oxford, CT. The turbines are dual fuel fired combined cycle units, each with a separate heat recovery steam generator (HRSG) that includes natural gas supplementary firing (duct burners) to power a single steam turbine generator. Oil firing for the turbines is limited to ultra-low sulfur distillate (ULSD) No. 2 fuel oil during periods of natural gas curtailment or as allowed in Part VII of this permit. Pollution control equipment will include selective catalytic reduction (SCR), oxidation catalyst, and water injection (ULSD firing only) to control NOx, CO and VOC emissions. The turbine, duct burner and HRSG are designated as Unit 1 for this permit.

B. Equipment Design Specifications

1. Turbine
   The design gross heat input to the turbine is 2,544 MMBtu/hr while firing natural gas and 2,511 MMBtu/hr while firing ULSD oil. These heat inputs are based on an ambient temperature of 59^{0}F and result in firing rates of 2,435,742 scf of natural gas (HHV 996 Btu/scf) and 17,326 gallons of ULSD (HHV 138,000 Btu/gal) per hour. Heat input will vary by approximately $\pm$5% over the typical range of temperatures expected, with higher heat input occurring at lower ambient temperatures.

2. Duct Burner
   The design gross heat input to the duct burner is 962 MMBtu/hr while firing natural gas. The heat input is based on an assumed HHV of 996 Btu/scf and results in a firing rate of 965,863 scfh.

C. Stack Parameters

1. Minimum Stack Height (ft): 150 (above base elevation)

2. Minimum Exhaust Gas Flow Rate at minimum operating load, turbine only (acfm): 663,327 (gas); 860,408 (ULSD)

3. Minimum Stack Exit Temperature at 100% load (°F): 170

4. Minimum Distance from Stack to Property Line (ft): 188

D. Definitions

1. "Steady-state" operation shall be defined as all periods other than transient operation.

2. "Transient" operation shall be all modes of operation at loads less than 30%, including periods of startup, shutdown, fuel switching and equipment cleaning. "Load" shall be defined as the net electrical output of the turbine. No period of transient operation shall exceed 60 consecutive minutes.

3. "Shakedown" shall be defined as turbine operations including, but not limited to, the first firing of the turbine, proof of interlocks, steam blowing, chemical cleaning and initial turbine roll. The shakedown period shall not extend to or beyond the required date for the initial performance tests specified in Part V.B of this permit.

PART II. OPERATIONAL CONDITIONS and REQUIREMENTS

A. Equipment

1. Turbine
   a. Allowable Fuel Types: Natural Gas; Ultra-Low Sulfur Distillate (ULSD)
   b. Maximum Heat Input over any Consecutive 12 Month Period: 2.12×10^7 MMBtu (gas); 1.72×10^6 MMBtu (ULSD)
   c. Maximum Distillate Fuel Oil Sulfur Content (% by weight, dry basis): 0.0015
   d. Natural gas shall be the primary fuel combusted in this unit. Firing of ULSD is allowed only in the following scenarios:
      i. ISO-NE declares an Energy Emergency as defined in ISO New England's Operating Procedure No. 21 and requests the firing of ULSD.
      ii. The natural gas supply is curtailed by an entity through which gas supply and/or transportation is contracted,
      iii. There exists a physical blockage or breakage in the natural gas pipeline,
      iv. During all periods of commissioning of the plant including performance testing,
      v. During routine maintenance and readiness testing.
      vi. In order to maintain an appropriate turnover of the on-site fuel inventory, to prevent wastage of oil, the owner/operator can fire ULSD when the last delivery of oil was more than six months ago.
   e. The Permittee shall not operate the duct burner while firing ULSD in the turbine.

2. Duct Burner
   a. Allowable Fuel: Natural Gas
   b. Maximum Heat Input over any Consecutive 12 Month Period: 4.09×10^6 MMBtu

B. The Permittee shall operate this equipment, including the SCR, oxidation catalyst, and water injection in a manner to comply with the emissions limits in Part III of this permit.

C. The Permittee shall operate and maintain this equipment, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup and shutdown.

D. The Permittee shall operate and maintain this equipment in accordance with the manufacturer's specifications and written recommendations.

E. The Permittee shall minimize emissions during periods of startup and shutdown and shall start the ammonia injection as soon as the SCR vendor's recommended minimum catalyst temperature is reached.

F. The Permittee shall not operate the auxiliary boiler, Permit No. 144-0025, simultaneously with the combustion turbines for more than 500 hours in any calendar year.

G. The Permittee shall not exceed a maximum allowable heat rate at full operating load while firing natural gas, without duct firing, of 7,220 Btu/kW-hr (HHV, net plant), on a12-month rolling average for the Units 1 and 2 combined.

H. The Permittee shall immediately institute shutdown of the turbine in the event where emissions are in excess of a limit in Part III of this permit that cannot be corrected within three hours of when the emissions exceedance was identified.

I. The Permittee shall not exceed 250 startup events per calendar year for this unit.

PART III. ALLOWABLE EMISSION LIMITS

A. Steady State

Except during the initial shakedown period, the Permittee shall not cause or allow this equipment to exceed the emission limits stated herein at any time during steady state operation.

1. Turbine Operating on Natural Gas without Duct Firing

Pollutant	lb/hr	ppmvd @ 15% O_2	lb/MMBtu
PM	9.73		6.5E-3
$PM_{10/2.5}$	9.73		6.5E-3
SO_2	4.49		1.5E-3
NOx	19.4	2.0	
VOC	3.37	1.0	
CO	5.31	0.9	
Lead	1.3E-03		
H_2SO_4	2.11		
Ammonia		2.0	

2. Turbine Operating on Natural Gas with Duct Firing

Pollutant	lb/hr	ppmvd @ 15% O_2	lb/MMBtu
PM	20.4		8.1E-3
$PM_{10/2.5}$	20.4		8.1E-3
SO_2	6.2		1.5E-3
NOx	26.8	2.0	
VOC	8.82	2.0	
CO	13.8	1.7	
Lead	1.7E-03		
H_2SO_4	2.7		
Ammonia		2.0	

3. Turbine Operating on ULSD

Pollutant	lb/hr	ppmvd @ 15% O_2	lb/MMBtu
PM	42.6		3.19E-2
$PM_{10/2.5}$	42.6		3.19E-2
SO_2	4.92		1.53E-3
NOx	52.0	5.0	
VOC	6.2	2.0	
CO	12.7	2.0	
Lead	3.7E-02		
H_2SO_4	2.31		
Ammonia		5.0	

B. Transient Emissions

1. Except during the initial shakedown period, the Permittee shall not cause or allow this equipment to exceed these limits during startup and shutdown events. . No startup or shutdown event shall last longer than 1 hour in duration.

	Type of Event			
	Startup		Shutdown	
	Natural Gas	ULSD	Natural Gas	ULSD
NO_x (lb/hr)	93	104	19	34
VOC (lb/hr)	37	90	60	23
CO (lb/hr)	242	231	121	18

2. Ammonia (NH_3) emissions shall not exceed 5 ppmvd @ 15% O_2 (both fuels) during transient operation.

C. Total Allowable Annual Emission Limits (per unit)

The Permittee shall not cause or allow this equipment to exceed the emission limits stated herein at any time.

1. Pollutants

Pollutant	tons per 12 consecutive months
PM	76.7
$PM_{10/2.5}$	76.7
SO_2	19.7
NOx	94.7
VOC	24.5
CO	64.5
Pb	1.9E-02
H_2SO_4	9.1
NH_3	35

D. Greenhouse Gas Emissions

1. The Permittee shall not exceed a combined annual CO_2e emissions limit of 2,675,185 tons/yr for this unit in combination with the units operating under permit numbers 144-0023, 144-0025, 144-0026, and 144-0027. Compliance with this limitation shall be determined on a consecutive 12-month rolling basis. The Permittee shall make and keep monthly records of CO_2e emissions with the following methodologies:
   a. CO_2 emissions from the combustion turbines, operating under permit numbers 144-0023 and 144-0024, shall be determined by the methodology found in 40 CFR Part 75, Appendix G, Equation G-4.
   b. CO_2 emissions from the boiler and two diesel engines, operating under permit numbers 144-0025, 144-0026, and 144-0027, shall be determined using the default emissions factors found in 40 CFR Part 98, Subpart C, Table C-1.
   c. Methane (CH_4) and nitrous oxide (N_2O) for all combustion sources shall be determined using the default emissions factors found in 40 CFR Part 98, Subpart C, Table C-2.
   d. Estimated fugitive emissions of sulfur hexafluoride (SF_6) from the electrical circuit breakers shall be determined using mass balance.
   e. Estimated fugitive emissions of CH_4 from the natural gas pipeline and associated components shall be determined using default emissions factors found in 40 CFR Part 98, Subpart W, Table W-7.

E. Hazardous Air Pollutants (HAP)

This equipment shall not cause an exceedance of the Maximum Allowable Stack Concentration (MASC) for any hazardous air pollutant (HAP) emitted and listed in RCSA Section 22a-174-29. [STATE ONLY REQUIREMENT]

F. Opacity

This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR 60, Appendix A, Reference Method 9.

G. Demonstration of compliance with the above emission limits may be met by calculating emissions based on emission factors from the following sources:

- *PM/PM10/PM2.5, VOC, H_2SO_4: Stack test data*
- *SO_2: Sulfur content in fuel*
- *NOx & CO (steady state): CEM data*
- NOx, VOC, & CO (transient): Manufacturer's recommended uncontrolled emission factors
- HAP: AP-42, Fifth Edition, Volume I Chapter 3.1, April 2000 except for those HAP with required stack test found in Part V of this permit.

H. The Permittee is not required to demonstrate compliance with the short-term emission limits stated herein prior to the completion of the Shakedown period. Emissions prior to the completion of the Shakedown period shall be counted towards the annual emission limits stated herein.

I. The commissioner may require other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall comply with the CEM requirements as set forth in RCSA Section 22a-174-4, RCSA §22a-174-22, 40 CFR 60 Subpart *KKKK and* 40 CFR Parts 72-78, as applicable. Continuous Emissions Monitoring (CEM) is required for the following pollutants and enforced on the following basis:

Pollutant	Averaging Times	Emission Limit (ppmvd @15% O_2)
Opacity (ULSD only)	six minute block	10%
NOx	1 hour block	See Part III.A
CO	1 hour block	See Part III.A
NH_3	1 hour block	See Part III.A

2. The Permittee shall continuously monitor the following parameters:

Operational Parameter	Averaging Times
O_2	1 hour block
Fuel Flow	1 hour block
Net Electrical Output	Continuous

3. At least sixty (60) days prior to the initial stack test, the Permittee shall submit a CEM monitoring plan to the Commissioner in accordance with RCSA 22a-174-4(c)(3).

4. The Permittee shall use fuel flow meters, certified in accordance with 40 CFR Part 75 Appendix D to measure and record the flow rate of fuels to the turbine and duct burner.

5. The Permittee shall perform inspections and maintenance of the SCR and oxidation catalysts as recommended by the manufacturer.

6. Prior to operation, the Permittee shall develop a written plan for the operation, inspection, maintenance, preventive and corrective measures for minimizing GHG emissions (CH_4 emissions from the natural gas pipeline components and SF_6 emissions from the insulated electrical equipment). At a minimum the plan shall provide for:

   i. Implementation daily auditory/visual/olfactory inspections of the natural gas piping components supplying natural gas to the combustion turbine/duct burner;

   ii. An installed leak detection system to include audible alarms to identify SF_6 leakage from the circuit breakers;

   iii. Inspection for SF_6 emissions from the insulated electrical equipment on at least a monthly basis.

B. Record Keeping

1. For the turbine, the Permittee shall keep records of monthly and consecutive 12 month fuel consumption (for each fuel). The consecutive 12 month fuel consumption shall be determined by adding (for each fuel) the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

2. For the duct burner, the Permittee shall keep records of monthly and consecutive 12 month natural gas consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

3. The Permittee shall keep records of the monthly and consecutive 12 month heat input to the turbine for both natural gas and ULSD firing. The records shall include sample calculations.

4. The Permittee shall keep records of the monthly and consecutive 12 month heat input to the duct burner. The records shall include sample calculations.

5. The Permittee shall keep records of the fuel certification for each delivery of fuel oil from a bulk petroleum provider or a copy of the current contract with the fuel supplier supplying the fuel used by the equipment that includes the applicable sulfur content of the fuel as a condition of each shipment. The shipping receipt or contract shall include the date of delivery, the name of the fuel supplier, type of fuel delivered, the percentage of sulfur in such fuel, by weight, dry basis, and the method used to determine the sulfur content of such fuel.

6. The Permittee shall calculate and record the monthly and consecutive 12 month PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO, H_2SO_4, NH_3, and CO_2e emissions in units of tons for all fuels combusted.

   The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.

   Emissions during startup and shutdown shall be included in the monthly and consecutive 12 month calculations.

7. The Permittee shall keep records of the number of startup events for each calendar year.

8. The Permittee shall keep records of the emissions of this turbine and duct burner during the initial shakedown period. Emissions during shakedown shall be calculated using good engineering judgment and the best data and methodology available for estimating such emissions. Emissions during shakedown shall be counted towards the annual emission limitation in Part III.C of this permit.

9. The Permittee shall keep records of the occurrence and duration of all transient operations of the unit; any malfunction of the air pollution control equipment that causes an exceedance of any emission limitation found in Part III of this permit; or any periods during which a continuous monitoring system or monitoring device is inoperative.

   Such records shall contain the following information:
   a. type of event and percent load;
   b. equipment affected;
   c. date of event;
   d. duration of event (minutes);
   e. fuel being used during event; and
   f. total NO_x, CO and VOC emissions emitted (lb) during the event.

10. The Permittee shall keep records of each delivery of aqueous ammonia/urea. The records shall include:
    a. the date of delivery;
    b. the name of the supplier;
    c. the quantity of aqueous ammonia delivered; and
    d. the percentage of ammonia in solution, by weight.

11. The Permittee shall keep records of the inspection and maintenance of the SCR and oxidation catalysts. The records shall include:
    a. the name of the person conducting the inspection/maintenance;
    b. the date of the inspection/maintenance;
    c. the results or actions taken; and
    d. the date the catalyst is replaced.

12. The Permittee shall keep records of all repairs/replacement of parts and other maintenance activities for the equipment.

13. The Permittee shall keep records of the electrical output of the plant (net) and the heat rate for the turbines while firing natural gas (HHV, net plant) without duct firing, on a 12-month rolling average for the plant.

14. The Permittee shall keep records of the inspection, maintenance, preventive and corrective measures for minimizing GHG emissions from the natural gas pipeline components and the insulated electrical equipment. The records shall include:
    a. the name of the person conducting the inspection/maintenance;
    b. the date the inspection/maintenance;
    c. the results or actions taken;
    d. the leak detection methods used; and
    e. the amount of SF_6 added (if any) to the electrical equipment

15. The Permittee shall keep monthly records of the audible alarms from the SF_6 leak detection system and inspections for the insulated electrical equipment. The records shall include:
    a. the name of the person conducting the inspection/maintenance;
    b. the date the inspection/maintenance;
    c. the results or actions taken.

16. The Permittee shall make and keep records of each hour of co-firing of this unit with the auxiliary boiler for each month and consecutive 12 months.

17. The Permittee shall make and keep records of all occurrences of firing ULSD in the turbine. At a minimum these records shall contain the following information:
    a. the duration of ULSD firing,
    b. the reason for ULSD firing, and
    c. the heat input to the turbine.

18. The Permittee shall keep a certified copy of this permit on the premises at all times, and shall make this copy available upon request of the Commissioner for the duration of this permit. This copy shall also be available for public inspection during regular business hours.

19. The Permittee shall keep records of the manufacturer written recommendations for operation and maintenance of the equipment found in this permit.

20. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

C. Reporting

1. The Permittee shall notify the commissioner in writing of all exceedances of an emissions limitation, and shall identify the cause or likely cause of such exceedance, all corrective actions and preventive measures taken with respect thereto, and the dates of such actions and measures as follows:
   a. For any hazardous air pollutant, no later than 24 hours after such exceedance was identified; and
   b. For any other regulated air pollutant, no later than ten days after such exceedance commenced.

2. The Permittee shall notify the commissioner, in writing, of the dates of commencement of construction, completion of construction, and initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART V. STACK EMISSION TEST REQUIREMENTS

A. Stack emission testing shall be performed in accordance with the RCSA 22a-174-5 and the Emission Test Guidelines available on the DEEP website.

B. Initial stack emission testing is required for the following pollutant(s):

☒ PM/$PM_{10/2.5}$ ☒ SO_2 ☒ NOx ☒ CO ☒ CO_2
☒ VOC ☒ Opacity
☒ Other (HAPs): Sulfuric Acid, Formaldehyde, arsenic

1. Stack emissions testing firing natural gas, without duct firing, for CO_2 shall only be required during the initial performance test to show compliance with an emissions limit of 809 lbs/MW-hr net plant), corrected to ISO conditions, as defined in the approved stack test protocol.

2. For the purposes of determining maximum heat input of the turbine during performance testing, the following equations may be used:

$$\mathbf{MHI_T = Q_1 - [(T - T_1)/(T_2 - T_1)] \times (Q_1 - Q_2)}$$

Where,

MHI_T = Turbine maximum heat input at ambient temperature (^{0}F)
T = Ambient Temperature
T_1 = Temperature Value from Table 1 that is below the ambient temperature
T_2 = Temperature Value from Table 1 that is above the ambient temperature
Q_1 = Heat Input at corresponding T_1
Q_2 = Heat Input at corresponding T_2

Table 1

Natural Gas Firing			ULSD Firing	
Temperature (T) ^{0}F	Heat Input (Q)		Temperature (T) ^{0}F	Heat Input (Q)
-14.2	2649		-14.2	2652
20	2672		20	2613
50	2590		50	2559
59	2544		59	2511
90	2416		90	2390
100	2409		100	2331

3. The Duct Burner shall be required to meet a minimum heat input value of 770 MMBtu/hr for all ambient temperatures during initial and recurring performance testing.

4. The Permittee shall perform one set of tests on this turbine when burning natural gas with the duct burner and one set without duct firing. The Permittee shall perform one set of tests with the turbine burning ULSD.

C. The Permittee shall conduct initial stack emission testing within 60 days of achieving the maximum production rate, but not later than 180 days after initial startup. The Permittee shall submit test results within 60 days after completion of testing.

D. Recurrent stack testing of all pollutants listed in Part V.B of this permit, except for VOC and CO_2, shall be performed within five years from the date of the previous stack test. Testing shall be as described in Part V.B of this permit with the following exceptions:

1. After the initial performance test, stack testing may not be required for pollutants requiring CEM. The commissioner retains the right to require stack testing of any pollutant at any time to demonstrate compliance.

2. More frequent testing of VOC is required to verify the correlation between VOC and the CO CEM data. Performance testing for VOC shall be performed within 18-months from the date of the previous stack test.

E. Fuel oil analysis of the arsenic in the distillate oil may be substituted for stack testing while firing distillate oil. Arsenic testing is not required for natural gas firing.

F. Stack Emission test results shall be reported as follows: all pollutants in units of lb/hr; NOx, CO, VOC, formaldehyde, and ammonia in units of ppmvd at 15% O_2;

PART VI. SPECIAL REQUIREMENTS

A. The Permittee shall possess, at least, 235 tons of external emissions reductions to offset the quantity of NO_x emitted from the sources covered under following Permit Numbers. to comply with RCSA 22a-174-3a(l):

- 144-0023 [General Electric 7HA.01 combustion turbine/duct Burner]
- 144-0024 [General Electric 7HA.01 combustion turbine/duct burner]
- 144-0025 [92.4 MMBtu/hr natural gas fired auxiliary boiler]
- 144-0026 [1,500 kW ULSD fired emergency generator]
- 144-0027 [350 bhp ULSD fired emergency fire pump]

Such a quantity is sufficient to offset the emissions from the sources listed above at a ratio of 1.2 to

1 tons of reduction for every ton of NOx emissions allowed under the permits listed. Specifically, the reductions are real, quantifiable, surplus, permanent, and enforceable as defined in RCSA 22a-174-3a(l)(5). The Permittee shall maintain sole ownership and possession of these emissions reductions for the duration of this permit and any subsequent changes to the permit.

Such offsets have been obtained from the following sources:

- 106 tons from Consolidated Edison Company of New York: NY-NY-DEC-2-6301-00006-106
- 110 tons from Akeida Capital Management LLC: CT4NOX00-015-0045-7888-110
- 19 tons from Sikorsky Aircraft Corporation: CTNOX1011-178-0039-19

The Permittee may be required to obtain additional NOx offsets and complete additional ambient air quality analysis to show that the NAAQS and PSD increments have not been violated, if observed steady state or transient emissions exceed a limit specified in Parts III.A, III.B or III.C of this permit.

B. Total annual VOC emissions from all VOC emitting sources located at the premises shall not exceed 49.9 tons/year.

Demonstration of compliance with the annual VOC premises wide limit shall be based on each consecutive 12 month time period and shall be determined by adding the current month's VOC premises wide emissions to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

Monthly premises wide VOC emissions shall be calculated using the following equations:

$$VOC_{premises} = \Sigma VOC_{turbines} + \Sigma VOC_{engines} + VOC_{aux\ boiler} + \Sigma VOC_{storage\ tanks} + \Sigma VOC_{add}$$

where,

$\Sigma VOC_{turbines}$ = The sum of VOC emissions from the two turbine trains covered by permits 144-0023 and 144-0024 determined by correlating the VOC emissions to the CO emissions using the results of a diagnostic stack test and tracked using the CO CEMS. VOC emissions from the turbine train shall be recorded on the CEMS data acquisition system.

$\Sigma VOC_{engines}$ = The sum of emissions from the emergency engines covered by permit numbers 144-0026 and 144-0027. VOC emissions shall be calculated using the following equation:

VOC (ton/month)= [X (VOC lbs/hr) * Y (hrs/month)] * 1 ton/2000 lbs

$VOC_{aux\ boiler}$ = The emissions from the auxiliary boiler covered by permit 144-0025. VOC emissions shall be calculated using the following equation:

VOC (ton/month)= [X (VOC lbs/hr) * Y (hrs/month)] * 1 ton/2000 lbs

$\Sigma VOC_{storage\ tanks}$ = The emissions from any storage tanks located on the premises shall be determined using the latest version of the EPA TANKS model or other equivalent method.

ΣVOC_{add} = The VOC emissions from any additional VOC emitting equipment that is added to the premises after the issuance of this permit. The VOC emissions from such equipment shall be calculated using good engineering practices.

The Commissioner may require other methods for determining VOC emissions from these sources as allowed by state or federal statute, law or regulation.

C. Upon completion of construction of the turbines and control equipment regulated under Permit No. 144-0023 and 144-0024, the Permittee shall prepare and submit a written standby plan in accordance with the RCSA 22a-174-6(d)(2) through (d)(5).

D. The Permittee shall comply with all applicable sections of the following New Source Performance Standard(s) at all times.

Title 40 CFR Part 60, Subpart: KKKK and A

Copies of the Code of Federal Regulations (CFR) are available online at the U.S. Government Printing Office website.

E. The Permittee shall operate this facility at all times in a manner so as not to violate or contribute significantly to the violation of any applicable state noise control regulations, as set forth in RCSA Sections 22a-69-1 through 22a-69-7.4. [STATE ONLY REQUIREMENT]

F. Unless directed otherwise by the Commissioner, if construction does not commence within eighteen (18) months from the date of issuance of this permit, the Permittee shall submit a written updated review of all prior BACT determinations for this unit. The Permittee shall submit this review to the Commissioner within 30 days of the end of such 18 month period.

PART VII. ADDITIONAL TERMS AND CONDITIONS

A. This permit does not relieve the Permittee of the responsibility to conduct, maintain and operate the regulated activity in compliance with all applicable requirements of any federal, municipal or other state agency. Nothing in this permit shall relieve the Permittee of other obligations under applicable federal, state and local law.

B. Any representative of the DEEP may enter the Permittee's site in accordance with constitutional limitations at all reasonable times without prior notice, for the purposes of inspecting, monitoring and enforcing the terms and conditions of this permit and applicable state law.

C. This permit may be revoked, suspended, modified or transferred in accordance with applicable law.

D. This permit is subject to and in no way derogates from any present or future property rights or other rights or powers of the State of Connecticut and conveys no property rights in real estate or material, nor any exclusive privileges, and is further subject to any and all public and private rights and to any federal, state or local laws or regulations pertinent to the facility or regulated activity affected thereby. This permit shall neither create nor affect any rights of persons or municipalities who are not parties to this permit.

E. Any document, including any notice, which is required to be submitted to the commissioner under this permit shall be signed by a duly authorized representative of the Permittee and by the person who is responsible for actually preparing such document, each of whom shall certify in writing as follows: "I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any applicable statute."

F. Nothing in this permit shall affect the commissioner's authority to institute any proceeding or take any other action to prevent or abate violations of law, prevent or abate pollution, recover costs and natural resource damages, and to impose penalties for violations of law, including but not limited to violations of this or any other permit issued to the Permittee by the commissioner.

G. Within 15 days of the date the Permittee becomes aware of a change in any information submitted to the commissioner under this permit, or that any such information was inaccurate or misleading or that any relevant information was omitted, the Permittee shall submit the correct or omitted information to the commissioner.

H. The date of submission to the commissioner of any document required by this permit shall be the date such document is received by the commissioner. The date of any notice by the commissioner under this permit, including but not limited to notice of approval or disapproval of any document or other action, shall be the date such notice is personally delivered or the date three days after it is mailed by the commissioner, whichever is earlier. Except as otherwise specified in this permit, the word "day" means calendar day. Any document or action which is required by this permit to be submitted or performed by a date which falls on a Saturday, Sunday or legal holiday shall be submitted or performed by the next business day thereafter.

I. Any document required to be submitted to the commissioner under this permit shall, unless otherwise specified in writing by the commissioner, be directed to: Office of Director; Engineering & Enforcement Division; Bureau of Air Management; Department of Energy and Environmental Protection; 79 Elm Street, 5th Floor; Hartford, Connecticut 06106-5127.

Connecticut Department of

ENERGY &
ENVIRONMENTAL
PROTECTION

BUREAU OF AIR MANAGEMENT
NEW SOURCE REVIEW PERMIT
TO CONSTRUCT AND OPERATE A STATIONARY SOURCE

Issued pursuant to Title 22a of the Connecticut General Statutes (CGS) and Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA).

Owner/Operator	CPV Towantic, LLC
Address	50 Braintree Hill Office Park, Suite 300 Braintree, MA 02184
Equipment Location	16 Woodruff Hill Road Oxford, CT
Equipment Description	92.4 MMBtu/hr Natural Gas Fired CB Nebraska Boiler Model Number NB-300D-70
Town-Permit Numbers	144-0025
Premises Number	14
Stack Number	9
Permit Issue Date	NOV 3 0 2015
Expiration Date	None

Michael Sullivan
Michael Sullivan
Deputy Commissioner

November 30, 2015
Date

This permit specifies necessary terms and conditions for the operation of this equipment to comply with state and federal air quality standards. The Permittee shall at all times comply with the terms and conditions stated herein.

PART I. DESIGN SPECIFICATIONS

A. General Description

CB-Nebraska NB-300D-70, 92.4 MMBtu/hr is a natural gas fired auxiliary boiler. The boiler will provide steam to warm up the steam turbine to minimize the duration of plant start-ups.

B. Equipment Design Specifications

1. Fuel Type(s): Natural Gas

2. Maximum Fuel Firing Rate(s) (CF/hr): 89,900

3. Maximum Gross Heat Input (MMBTU/hr): 92.4

4. Maximum Steam Flow (lbs/hr) @ 387^{0}F and 200 psig: 77,000

C. Control Equipment Design Specifications

1. Ultra-Low NOx Burner/Flue Gas Recirculation
   a. Make: CB-Nebraska

D. Stack Parameters

1. Minimum Stack Height (ft): 62

2. Minimum Exhaust Gas Flow Rate at maximum firing rate (acfm): 4,910

3. Minimum Stack Exit Temperature at maximum firing rate (°F): 241 (at economizer exit)

4. Minimum Distance from Stack to Property Line (ft): 136

PART II. OPERATIONAL CONDITIONS

A. Equipment

1. This unit shall only fire natural gas.

2. Maximum Fuel Consumption over any Consecutive 12 Month Period: 359.6 MMft^3

3. The Permittee shall not operate this unit with either of the combustion turbines, permit numbers 144-0023 and 144-0024, for 500 hrs or more in any calendar year.

4. The Permittee shall operate and maintain this equipment in accordance with the manufacturer's specifications and written recommendations.

5. The Permittee shall properly operate the flue gas recirculation (FGR) system at all times that this equipment is in operation and emitting air pollutants.

PART III. ALLOWABLE EMISSION LIMITS

The Permittee shall not cause or allow this equipment to exceed the emission limits stated herein at any time.

A. Pollutants

Pollutant	lb/hr		tpy
PM_{10}	0.65		1.29
$PM_{2.5}$	0.65		1.29
SO_2	0.14		0.28
NOx	0.79	7 ppmvd @3% O_2	1.6
VOC	0.38		0.75
CO	3.42	50 ppmvd @3% O_2	6.83
Pb	4.5E-05		9.1E-05
H_2SO_4	0.011		0.02
CO_2e		117 lbs/MMBtu	21,627

B. Hazardous Air Pollutants

This equipment shall not cause an exceedance of the Maximum Allowable Stack Concentration (MASC) for any hazardous air pollutant (HAP) emitted and listed in RCSA Section 22a-174-29. [STATE ONLY REQUIREMENT]

C. Opacity

This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR 60, Appendix A, Reference Method 9.

D. Demonstration of compliance with the above emission limits may be met by calculating emissions based on emission factors from the following sources:

- *NOx, CO, VOC: Stack test data*
- *PM_{10}: Guaranteed Vendor Emissions Factor*
- *Opacity: Stack Test Data*
- *SO_2, H_2SO_4: Calculated from fuel sulfur content not exceeding 0.5 grains of Sulfur/100 dscf*
- *Pb: AP-42, Table 1.4-2*
- *CO_2e: 40 CFR part 98, Tables A-1, C-1, and C-2*

The commissioner may require other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall continuously monitor this unit's fuel consumption using a non-resettable totalizing fuel meter.

2. The Permittee shall perform inspections of the burners and flue gas recirculation (FGR) system as recommended by the manufacturer.

3. The Permittee shall monitor all hours of simultaneous operations of this unit with either of the combustion turbines.

B. Record Keeping

1. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

2. The Permittee shall calculate and record the monthly and consecutive 12 month PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO, and CO_2e emissions in units of tons. The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.

3. The Permittee shall make and keep records of all maintenance and tune-up activities for this unit.

4. The Permittee shall make and keep records of all inspections of the burners and FGR system.

5. The Permittee shall make and keep records of all hours of simultaneous operation of this unit with either of the combustion turbines. The Permittee shall total these hours for each month and for the calendar year. The Permittee shall make these calculations within 30 days of the end of the previous month.

6. The Permittee shall make and keep records of manufacturer written specifications and recommendations for operation and maintenance.

7. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

C. Reporting

1. The Permittee shall comply with the applicable reporting requirements of Section 22a-174-22(l).

2. The Permittee shall comply with the record keeping and reporting requirements in 40 CFR 60.49b

3. The Permittee shall notify the commissioner, in writing, of the date of commencement of construction and the date of initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART V. STACK EMISSION TEST REQUIREMENTS

Stack emission testing shall be performed in accordance with the Emission Test Guidelines available on the DEEP website.

Initial stack testing shall be required for the following pollutant(s):

☐ PM ☐ PM_{10} ☐ $PM_{2.5}$ ☐ SO_2 ☒ NOx ☒ CO
☒ VOC ☒ Opacity ☐ Other (HAPs):

The Permittee shall conduct initial stack testing within 60 days of achieving the maximum production rate, but not later than 180 days after initial startup. The Permittee shall submit test results within 30 days after completion of testing.

Recurrent stack testing for the above pollutants shall be conducted within 5 years from the date of the previous stack test.

Stack test results shall be reported as follows: all pollutants in units of lb/hr and ppmvd at 3% O_2.

PART VII. SPECIAL REQUIREMENTS

A. The Permittee shall comply with all applicable sections of the following New Source Performance Standard(s) at all times.

Title 40 CFR Part 60, Subparts Dc and A

Copies of the Code of Federal Regulations (CFR) are available online at the U.S. Government Printing Office website.

B. The Permittee shall not cause or permit the emission of any substance or combination of substances which creates or contributes to an odor beyond the property boundary of the premises that constitutes a nuisance as set forth in RCSA Section 22a-174-23. [STATE ONLY REQUIREMENT]

PART VIII. ADDITIONAL TERMS AND CONDITIONS

A. This permit does not relieve the Permittee of the responsibility to conduct, maintain and operate the regulated activity in compliance with all applicable requirements of any federal, municipal or other state agency. Nothing in this permit shall relieve the Permittee of other obligations under applicable federal, state and local law.

B. Any representative of DEEP may enter the Permittee's site in accordance with constitutional limitations at all reasonable times without prior notice, for the purposes of inspecting, monitoring and enforcing the terms and conditions of this permit and applicable state law.

C. This permit may be revoked, suspended, modified or transferred in accordance with applicable law.

D. This permit is subject to and in no way derogates from any present or future property rights or other rights or powers of the State of Connecticut and conveys no property rights in real estate or material, nor any exclusive privileges, and is further subject to any and all public and private rights and to any federal, state or local laws or regulations pertinent to the facility or regulated activity affected thereby. This permit shall neither create nor affect any rights of persons or municipalities who are not parties to this permit.

E. Any document, including any notice, which is required to be submitted to the commissioner under this permit shall be signed by a duly authorized representative of the Permittee and by the person who is responsible for actually preparing such document, each of whom shall certify in writing as follows: "I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any applicable statute."

F. Nothing in this permit shall affect the commissioner's authority to institute any proceeding or take any other action to prevent or abate violations of law, prevent or abate pollution, recover costs and natural resource damages, and to impose penalties for violations of law, including but not limited to violations of this or any other permit issued to the Permittee by the commissioner.

G. Within 15 days of the date the Permittee becomes aware of a change in any information submitted to the commissioner under this permit, or that any such information was inaccurate or misleading or that any relevant information was omitted, the Permittee shall submit the correct or omitted information to the commissioner.

H. The date of submission to the commissioner of any document required by this permit shall be the date such document is received by the commissioner. The date of any notice by the commissioner under this permit, including but not limited to notice of approval or disapproval of any document or other action, shall be the date such notice is personally delivered or the date three days after it is mailed by the commissioner, whichever is earlier. Except as otherwise specified in this permit, the word "day" means calendar day. Any document or action which is required by this permit to be submitted or performed by a date which falls on a Saturday, Sunday or legal holiday shall be submitted or performed by the next business day thereafter.

I. Any document required to be submitted to the commissioner under this permit shall, unless otherwise specified in writing by the commissioner, be directed to: Office of Director; Engineering & Enforcement Division; Bureau of Air Management; Department of Energy and Environmental Protection; 79 Elm Street, 5th Floor; Hartford, Connecticut 06106-5127.

Connecticut Department of

ENERGY &
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BUREAU OF AIR MANAGEMENT
NEW SOURCE REVIEW PERMIT
TO CONSTRUCT AND OPERATE A STATIONARY SOURCE

Issued pursuant to Title 22a of the Connecticut General Statutes (CGS) and Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA).

Owner/Operator	CPV Towantic, LLC
Address	50 Braintree Hill Office Park, Suite 300 Braintree, MA 02184
Equipment Location	16 Woodruff Hill Road Oxford, CT
Equipment Description	1500 kW Diesel Fired Emergency Engine
Town-Permit Numbers	144-0026
Premises Number	14
Stack Number	10
Permit Issue Date	NOV 30 2015
Expiration Date	None

Michael Sullivan

Michael Sullivan
Deputy Commissioner

November 30, 2015
Date

This permit specifies necessary terms and conditions for the operation of this equipment to comply with state and federal air quality standards. The Permittee shall at all times comply with the terms and conditions stated herein.

PART I. DESIGN SPECIFICATIONS

A. General Description

CPV Towantic LLC operates a Caterpillar 3512C 4-Stroke Lean Burn 1500 kW diesel fired emergency engine to provide emergency back-up power to the facility. The generator is not connected to the electrical grid and is only utilized as an emergency engine pursuant to RCSA 22a-174-22. The unit is also subject to 40 CFR Part 60 Subpart IIII.

B. Equipment Design Specifications

1. Allowable Fuel Type: Ultra Low Sulfur Distillate (ULSD)

2. Maximum Fuel Firing Rate (gal/hr): 104.6

3. Maximum Gross Heat Input (MMBTU/hr): 14.4

C. Stack Parameters

1. Minimum Stack Height (ft): 14.5

2. Minimum Exhaust Gas Flow Rate at maximum firing rate (acfm): 10,909

3. Minimum Stack Exit Temperature at maximum firing rate (°F): 1,145

4. Minimum Distance from Stack to Property Line (ft): 295

PART II. OPERATIONAL CONDITIONS

A. Equipment

1. This equipment shall fire only Ultra Low Sulfur Diesel (ULSD)

2. Maximum Fuel Consumption over any Consecutive 12 Month Period: 31,380 gallons

3. Maximum Fuel Sulfur Content: 0.0015% by weight

4. The Permittee may operate this source for up to 300 hours per calendar year. Total engine hours of operation from this unit and the fire pump, permit number 144-0027, shall not exceed 500 hours per calendar year.

5. The Permittee shall operate and maintain this equipment in accordance with the manufacturer's specifications and written recommendations.

6. The Permittee shall operate and maintain this equipment and any monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

B. For Emergency Use

1. This emission unit shall only operate in accordance with the definition of emergency engine as defined in RCSA Section 22a-174-22.

2. The Permittee shall not operate the subject engine for routine scheduled testing or maintenance during days when ambient ozone is forecasted by the commissioner to be "moderate unhealthy for sensitive groups" to "very unhealthy" anywhere in Connecticut.
   a. Forecast Information

      Official ambient ozone information can be obtained by calling:
      i. (860) 424-4167 Department's Bureau of Air Management Monitoring Section (Recorded Message Updated daily at 3:00 p.m.)
      ii. (860) 424-3027 Department's Bureau of Air Management Monitoring Section (For additional air quality information)

PART III. ALLOWABLE EMISSION LIMITS

The Permittee shall not cause or allow this equipment to exceed the emission limits stated herein at any time.

A. Short Term Emission Limits

1. Criteria Pollutants

Pollutant	lb/hr	(lbs/MMBtu)
PM	0.15	
$PM_{10/2.5}$	0.15	
SO_2	0.02	
NOx	19.84	
VOC	0.53	
CO	2.14	
Pb	1.1E-05	
H_2SO_4	1.66E-03	
CO_2		163.6

C. Annual Emission Limits

Pollutant	tons per 12 consecutive months
PM	0.02
$PM_{10/2.5}$	0.02
SO_2	0.003
NOx	2.98
VOC	0.08
CO	0.32
Pb	1.7E-06
H_2SO_4	2E-04
CO_2e	354

D. Hazardous Air Pollutants

This equipment shall not cause an exceedance of the Maximum Allowable Stack Concentration (MASC) for any hazardous air pollutant (HAP) emitted and listed in RCSA Section 22a-174-29. [STATE ONLY REQUIREMENT]

E. Opacity

Opacity resulting from operation of this engine shall not exceed 10% during any six-minute block average or 40% reduced to a one-minute block average; as measured by 40 CFR 60, Appendix A, Reference Method 9.

F. Demonstration of compliance with the above emission limits may be met by calculating emissions based on emission factors from the following sources:

- *SO_2, H_2SO_4: Calculated from fuel sulfur content*
- *NOx, $PM_{10/2.5}$, VOC, CO: EPA Certified Vendor Emissions Factor*
- *Pb: AP-42 Sec. 3.1*
- *CO_2: 40 CFR 98 Subpart C, Table C-1*
- *CO_2e: 40 CFR 98, Subpart C, Table C-2*

The commissioner may require other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall continuously monitor fuel consumption by this unit using a non-resettable totalizing fuel meter.

2. The Permittee shall monitor all hours that this unit is in operation.

B. Record Keeping

1. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

2. The Permittee shall keep records of the fuel certification for each delivery of fuel oil from a bulk petroleum provider or a copy of the current contract with the fuel supplier supplying the fuel used by the equipment that includes the applicable sulfur content of the fuel as a condition of each shipment. The shipping receipt or contract shall include the date of delivery, the name of the fuel supplier, type of fuel delivered, the percentage of sulfur in such fuel, by weight, dry basis, and the method used to determine the sulfur content of such fuel.

3. The Permittee shall calculate and record the monthly and consecutive 12 month PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO H_2SO_4, and CO_2e emissions in units of tons. The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.

4. The Permittee shall keep monthly and calendar year records of all hours of operation and fuel use for this unit.

   Such records shall contain the following information:
   a. reason for operating;
   b. date of event;
   c. duration of event (minutes);
   d. gallons of fuel combusted;
   e. ozone level as forecasted for the day;
   f. total engine hours of operation and total combined engine hours of operation with the fire pump, permit number 144-0027.

5. The Permittee shall keep records of the inspection and maintenance for this engine. The records shall include:
   a. the name of the person conducting the inspection or maintenance;
   b. the date of the inspection or maintenance;
   c. the results or actions taken.

6. The Permittee shall comply with the applicable record keeping requirements of Section 22a-174-22(l).

7. The Permittee shall keep records of the manufacturer's specifications and written recommendations.

8. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

C. Reporting

1. The Permittee shall comply with the applicable reporting requirements of Section 22a-174-22(l).

2. The Permittee shall comply with the reporting requirements in 40 CFR 60.4214

3. The Permittee shall notify the commissioner, in writing, of the date of commencement of construction and the date of initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART V. SPECIAL REQUIREMENTS

A. The Permittee shall comply with all applicable sections of the following New Source Performance Standard(s) at all times.

Title 40 CFR Part 60, Subparts: IIII and A

Copies of the Code of Federal Regulations (CFR) are available online at the U.S. Government Printing Office website.

B. The Permittee shall not cause or permit the emission of any substance or combination of substances which creates or contributes to an odor beyond the property boundary of the premises that constitutes a nuisance as set forth in RCSA Section 22a-174-23. [STATE ONLY REQUIREMENT]

PART VI. ADDITIONAL TERMS AND CONDITIONS

A. This permit does not relieve the Permittee of the responsibility to conduct, maintain and operate the regulated activity in compliance with all applicable requirements of any federal, municipal or other state agency. Nothing in this permit shall relieve the Permittee of other obligations under applicable federal, state and local law.

B. Any representative of the DEEP may enter the Permittee's site in accordance with constitutional limitations at all reasonable times without prior notice, for the purposes of inspecting, monitoring and enforcing the terms and conditions of this permit and applicable state law.

C. This permit may be revoked, suspended, modified or transferred in accordance with applicable law.

D. This permit is subject to and in no way derogates from any present or future property rights or other rights or powers of the State of Connecticut and conveys no property rights in real estate or material, nor any exclusive privileges, and is further subject to any and all public and private rights and to any federal, state or local laws or regulations pertinent to the facility or regulated activity affected thereby. This permit shall neither create nor affect any rights of persons or municipalities who are not parties to this permit.

E. Any document, including any notice, which is required to be submitted to the commissioner under this permit shall be signed by a duly authorized representative of the Permittee and by the person who is responsible for actually preparing such document, each of whom shall certify in writing as follows: "I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any applicable statute."

F. Nothing in this permit shall affect the commissioner's authority to institute any proceeding or take any other action to prevent or abate violations of law, prevent or abate pollution, recover costs and natural resource damages, and to impose penalties for violations of law, including but not limited to violations of this or any other permit issued to the Permittee by the commissioner.

G. Within 15 days of the date the Permittee becomes aware of a change in any information submitted to the commissioner under this permit, or that any such information was inaccurate or misleading or that any relevant information was omitted, the Permittee shall submit the correct or omitted information to the commissioner.

H. The date of submission to the commissioner of any document required by this permit shall be the date such document is received by the commissioner. The date of any notice by the commissioner under this permit, including but not limited to notice of approval or disapproval of any document or other action, shall be the date such notice is personally delivered or the date three days after it is mailed by the commissioner, whichever is earlier. Except as otherwise specified in this permit, the word "day" means calendar day. Any document or action which is required by this permit to be submitted or performed by a date which falls on a Saturday, Sunday or legal holiday shall be submitted or performed by the next business day thereafter.

I. Any document required to be submitted to the commissioner under this permit shall, unless otherwise specified in writing by the commissioner, be directed to: Office of Director; Engineering & Enforcement Division; Bureau of Air Management; Department of Energy and Environmental Protection; 79 Elm Street, 5th Floor; Hartford, Connecticut 06106-5127.

Connecticut Department of

ENERGY & ENVIRONMENTAL PROTECTION

BUREAU OF AIR MANAGEMENT
NEW SOURCE REVIEW PERMIT
TO CONSTRUCT AND OPERATE A STATIONARY SOURCE

Issued pursuant to Title 22a of the Connecticut General Statutes (CGS) and Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA).

Owner/Operator	CPV Towantic, LLC
Address	50 Braintree Hill Office Park, Suite 300 Braintree, MA 02184
Equipment Location	16 Woodruff Hill Road Oxford, CT
Equipment Description	350 bhp Diesel Fire Pump
Town-Permit Numbers	144-0027
Premises Number	14
Stack Number	11
Permit Issue Date	NOV 30 2015
Expiration Date	None

Michael Sullivan
Deputy Commissioner

November 30, 2015
Date

This permit specifies necessary terms and conditions for the operation of this equipment to comply with state and federal air quality standards. The Permittee shall at all times comply with the terms and conditions stated herein.

PART I. DESIGN SPECIFICATIONS

A. General Description

CPV Towantic LLC operates a 350 bhp 4-stroke lean-burn John Deere fire pump to provide emergency fire protection to the facility. The generator is not connected to the electrical grid and is only utilized as a fire pump pursuant to RCSA 22a-174-22. The unit is also subject to 40 CFR Part 60 Subpart IIII.

B. Equipment Design Specifications

1. Allowable Fuel Type: Ultra Low Sulfur Distillate (ULSD)
2. Maximum Fuel Firing Rate (gal/hr): 17.8
3. Maximum Gross Heat Input (MMBTU/hr): 2.45

C. Stack Parameters

1. Minimum Stack Height (ft): 17.5
2. Minimum Exhaust Gas Flow Rate at maximum firing rate (acfm): 1,877
3. Minimum Stack Exit Temperature at maximum firing rate (°F): 961
4. Minimum Distance from Stack to Property Line (ft): 275

PART II. OPERATIONAL CONDITIONS

A. Equipment

1. This equipment shall only fire Ultra Low Sulfur Diesel (ULSD)
2. Maximum Fuel Consumption over any Consecutive 12 Month Period: 5,330 gallons
3. Maximum Fuel Sulfur Content: 0.0015% by weight
4. The Permittee may operate this source for up to 300 hours per calendar year. Total engine hours of operation from this unit and the emergency engine, permit number 144-0026, shall not exceed 500 hours per calendar year.
5. The Permittee shall operate and maintain this equipment in accordance with the manufacturer's specifications and written recommendations.
6. The Permittee shall operate and maintain this equipment and any monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction.

B. For Emergency Use

1. This emission unit shall only operate in accordance with the definition of emergency engine as defined in RCSA Section 22a-174-22.

2. The Permittee shall not operate the subject engine for routine scheduled testing or maintenance during days when ambient ozone is forecasted by the commissioner to be "moderate unhealthy for sensitive groups" to "very unhealthy" anywhere in Connecticut.

   a. Forecast Information

   Official ambient ozone information can be obtained by calling:

   i. (860) 424-4167 Department's Bureau of Air Management Monitoring Section (Recorded Message Updated daily at 3:00 p.m.)

   ii. (860) 424-3027 Department's Bureau of Air Management Monitoring Section (For additional air quality information)

PART III. ALLOWABLE EMISSION LIMITS

The Permittee shall not cause or allow this equipment to exceed the emission limits stated herein at any time.

A. Short Term Emission Limits

1. Criteria Pollutants

Pollutant	lbs/hr	lb/MMBtu
PM	0.1	
$PM_{10/2.5}$	0.1	
SO_2	0.0037	
NOx	2.65	
VOC	0.07	
CO	0.64	
Pb	1.9E-06	
H_2SO_4	2.8E-04	
CO_2		163.6

C. Annual Emission Limits

Pollutant	tons per 12 consecutive months
PM	0.014
$PM_{10/2.5}$	0.014
SO_2	6E-04
NOx	0.4
VOC	0.01
CO	0.09
Pb	2.8E-07
H_2SO_4	4E-05
CO_2e	60

D. Hazardous Air Pollutants

This equipment shall not cause an exceedance of the Maximum Allowable Stack Concentration (MASC) for any hazardous air pollutant (HAP) emitted and listed in RCSA Section 22a-174-29. [STATE ONLY REQUIREMENT]

E. Opacity

Opacity resulting from operation of this engine shall not exceed 10% during any six-minute block average or 40% reduced to a one-minute block average; as measured by 40 CFR 60, Appendix A, Reference Method 9.

F. Demonstration of compliance with the above emission limits may be met by calculating emissions based on emission factors from the following sources:

- *SO_2, H_2SO_4: Calculated from fuel sulfur content*
- *NOx: EPA Certified Vendor emission factor.*
- *NOx, $PM_{10/2.5}$, VOC, CO: EPA Certified Vendor Emissions Factor*
- *Pb: AP-42 Sec. 3.1*
- *CO_2: 40 CFR 98 Subpart C, Table C-1*
- *CO_2e: 40 CFR 98, Subpart C, Table C-2*

The commissioner may require other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall continuously monitor fuel consumption by this unit using a non-resettable totalizing fuel meter.

2. The Permittee shall monitor all hours that this unit is in operation.

B. Record Keeping

1. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

2. The Permittee shall keep records of the fuel certification for each delivery of fuel oil from a bulk petroleum provider or a copy of the current contract with the fuel supplier supplying the fuel used by the equipment that includes the applicable sulfur content of the fuel as a condition of each shipment. The shipping receipt or contract shall include the date of delivery, the name of the fuel supplier, type of fuel delivered, the percentage of sulfur in such fuel, by weight, dry basis, and the method used to determine the sulfur content of such fuel.

3. The Permittee shall calculate and record the monthly and consecutive 12 month PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO, and CO_2e emissions in units of tons. The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.

4. The Permittee shall keep monthly and calendar year records of all hours of operation and fuel use for this unit.

   Such records shall contain the following information:
   a. reason for operating;
   b. date of event;
   c. duration of event (minutes);
   d. gallons of fuel combusted;
   e. ozone level as forecasted for the day;
   f. total engine hours of operation and total combined engine hours of operation with the emergency generator, permit number 144-0026.

5. The Permittee shall keep records of the inspection and maintenance for this engine. The records shall include:
   a. the name of the person conducting the inspection or maintenance;
   b. the date of the inspection or maintenance;
   c. the results or actions taken.

6. The Permittee shall comply with the applicable record keeping requirements of Section 22a-174-22(l).

7. The Permittee shall keep records of the manufacturer's specifications and written recommendations.

8. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

C. Reporting

1. The Permittee shall comply with the applicable reporting requirements of Section 22a-174-22(l).

2. The Permittee shall comply with the reporting requirements in 40 CFR 60.4214

3. The Permittee shall notify the commissioner, in writing, of the date of commencement of construction and the date of initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART V. SPECIAL REQUIREMENTS

A. The Permittee shall comply with all applicable sections of the following New Source Performance Standard(s) at all times.

Title 40 CFR Part 60, Subparts: IIII and A

Copies of the Code of Federal Regulations (CFR) are available online at the U.S. Government Printing Office website.

B. The Permittee shall not cause or permit the emission of any substance or combination of substances which creates or contributes to an odor beyond the property boundary of the premises that constitutes a nuisance as set forth in RCSA Section 22a-174-23. [STATE ONLY REQUIREMENT]

PART VI. ADDITIONAL TERMS AND CONDITIONS

A. This permit does not relieve the Permittee of the responsibility to conduct, maintain and operate the regulated activity in compliance with all applicable requirements of any federal, municipal or other state agency. Nothing in this permit shall relieve the Permittee of other obligations under applicable federal, state and local law.

B. Any representative of the DEEP may enter the Permittee's site in accordance with constitutional limitations at all reasonable times without prior notice, for the purposes of inspecting, monitoring and enforcing the terms and conditions of this permit and applicable state law.

C. This permit may be revoked, suspended, modified or transferred in accordance with applicable law.

D. This permit is subject to and in no way derogates from any present or future property rights or other rights or powers of the State of Connecticut and conveys no property rights in real estate or material, nor any exclusive privileges, and is further subject to any and all public and private rights and to any federal, state or local laws or regulations pertinent to the facility or regulated activity affected thereby. This permit shall neither create nor affect any rights of persons or municipalities who are not parties to this permit.

E. Any document, including any notice, which is required to be submitted to the commissioner under this permit shall be signed by a duly authorized representative of the Permittee and by the person who is responsible for actually preparing such document, each of whom shall certify in writing as follows: "I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any applicable statute."

F. Nothing in this permit shall affect the commissioner's authority to institute any proceeding or take any other action to prevent or abate violations of law, prevent or abate pollution, recover costs and natural resource damages, and to impose penalties for violations of law, including but not limited to violations of this or any other permit issued to the Permittee by the commissioner.

G. Within 15 days of the date the Permittee becomes aware of a change in any information submitted to the commissioner under this permit, or that any such information was inaccurate or misleading or that any relevant information was omitted, the Permittee shall submit the correct or omitted information to the commissioner.

H. The date of submission to the commissioner of any document required by this permit shall be the date such document is received by the commissioner. The date of any notice by the commissioner under this permit, including but not limited to notice of approval or disapproval of any document or other action, shall be the date such notice is personally delivered or the date three days after it is mailed by the commissioner, whichever is earlier. Except as otherwise specified in this permit, the word "day" means calendar day. Any document or action which is required by this permit to be submitted or performed by a date which falls on a Saturday, Sunday or legal holiday shall be submitted or performed by the next business day thereafter.

I. Any document required to be submitted to the commissioner under this permit shall, unless otherwise specified in writing by the commissioner, be directed to: Office of Director; Engineering & Enforcement Division; Bureau of Air Management; Department of Energy and Environmental Protection; 79 Elm Street, 5th Floor; Hartford, Connecticut 06106-5127.

Exhibit 3

west virginia department of environmental protection

Division of Air Quality
601 57th Street, SE
Charleston, WV 25304
Phone: (304) 926-0475

Austin Caperton, Cabinet Secretary
dep.wv.gov

March 27, 2018

Andrew Dorn
ESC Harrison County Power, LLC
360 Delaware Ave., Suite 406
Buffalo, NY 14202

Re: ESC Harrison County Power, LLC
Harrison County Facility
Permit No. R14-0036
Plant ID No. 033-00264

Dear Mr. Dorn:

Your application for a permit as required by Section 3 of 45CSR14 - "Permits For Construction and Major Modification of Major Stationary Sources for the Prevention of Significant Deterioration of Air Quality" has been approved. The enclosed permit R14-0036 is hereby issued pursuant to Subsection 3.3 of 45CSR14. Please be aware of the notification requirements in the permit which pertain to commencement of construction, modification, or relocation activities; startup of operations; and suspension of operations.

In accordance with 45CSR30- Operating Permit Program, the permittee shall submit a certified emissions statement and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §§22-5-14.

Should you have any questions or comments, please contact me at (304) 926-0499, extension 1218.

Sincerely,

Steven R. Pursley, PE
Engineer

Enclosures
c: Toby Hanna, ERM
NCRO

West Virginia Department of Environmental Protection

Austin Caperton

Cabinet Secretary

Permit to Construct

R14-0036

This permit is issued in accordance with the West Virginia Air Pollution Control Act (West Virginia Code §§ 22-5-1 et seq.) and 45 C.S.R. 13 — Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation, and 45 C.S.R. 14 - Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration. The permittee identified at the facility listed below is authorized to construct the stationary sources of air pollutants identified herein in accordance with all terms and conditions of this permit.

Issued to:

ESC Harrison County Power, LLC

Harrison County Combined Cycle Power Plant

033-00264

William F. Durham

Director

Issued: March 27, 2018

Facility Location:	Near Clarksburg, Harrison County, West Virginia
Mailing Address:	360 Delaware Avenue, Suite 406 Buffalo, NY 14202
Facility Description:	Nominal 640 Megawatt, natural gas fired, combined cycle power plant
NAICS Codes:	221112
UTM Coordinates:	558.35 km Easting • 4,349.17 km Northing • Zone 17
Permit Type:	PSD Major Construction
Description of Source:	Construction of a 640 MW natural gas fired, combined cycle power plant.

Any person whose interest may be affected, including, but not necessarily limited to, the applicant and any person who participated in the public comment process, by a permit issued, modified or denied by the Secretary may appeal such action of the Secretary to the Air Quality Board pursuant to article one [§§ 22B-1-1 et seq.], Chapter 22B of the Code of West Virginia. West Virginia Code §22-5-14.

The source is a major source subject to 45CSR30. The Title V (45CSR30) application will be due within twelve (12) months after the date of the commencement of the operation or activity (activities) authorized by this permit.

Table of Contents

1.0 Emission Units

Table 1.0

Emission Unit ID	Emission Point ID	Emission Unit Description	Year Installed	Design Capacity	Control Device[1]
HCCT-1	HCCT-1	Combustion Turbine	2020	3,496 MMBTU/hr	DLNB, SCR & OC
HRSG-1	HCCT-1	HRSG w/ Duct Burner	2020	1,001 MMBTU/hr	SCR & OC
FGH-1	FGH-1	Fuel Gas Heater	2020	5.5 MMBTU/hr	LNB
AB-1	AB-1	Auxiliary Boiler	2020	77.8 MMBTU/hr	LNB
FP-1	FP-1	Fire Water Pump	2020	315 hp	N
EG-1	EG-1	Emergency Generator	2020	2,000 kW	N
ST-1	ST-1	FP-1Tank (ULSD)	2020	500 gallons	N
ST-2	ST-2	EG-1 Tank (ULSD)	2020	3,000 gallons	N

[1] SCR = Selective Catalytic Reduction; DLNB = Dry Low NOx Burners; OC = Oxidation Catalyst; LNB = Low NO_x Burner; N = None; USLD = Ultra Low Sulfur Diesel

2.0. General Conditions

2.1. Definitions

2.1.1. All references to the "West Virginia Air Pollution Control Act" or the "Air Pollution Control Act" mean those provisions contained in W.Va. Code §§ 22-5-1 to 22-5-18.

2.1.2. The "Clean Air Act" means those provisions contained in 42 U.S.C. §§ 7401 to 7671q, and regulations promulgated thereunder.

2.1.3. "Secretary" means the Secretary of the Department of Environmental Protection or such other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§ 22-1-6 or 22-1-8 (45 CSR § 30-2.12.). The Director of the Division of Air Quality is the Secretary's designated representative for the purposes of this permit.

2.2. Acronyms

CAAA	Clean Air Act Amendments
CBI	Confidential Business Information
CEM	Continuous Emission Monitor
CES	Certified Emission Statement
C.F.R. *or* **CFR**	Code of Federal Regulations
CO	Carbon Monoxide
C.S.R. *or* **CSR**	Codes of State Rules
DAQ	Division of Air Quality
DEP	Department of Environmental Protection
dscm	Dry Standard Cubic Meter
FOIA	Freedom of Information Act
HAP	Hazardous Air Pollutant
HON	Hazardous Organic NESHAP
HP	Horsepower
lbs/hr	Pounds per Hour
LDAR	Leak Detection and Repair
M	Thousand
MACT	Maximum Achievable Control Technology
MDHI	Maximum Design Heat Input
MM	Million
MMBtu/hr *or* **mmbtu/hr**	Million British Thermal Units per Hour
MMCF/hr *or* **mmcf/hr**	Million Cubic Feet per Hour
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter less than 2.5µm in diameter
PM_{10}	Particulate Matter less than 10µm in diameter
Ppb	Pounds per Batch
pph	Pounds per Hour
ppm	Parts per Million
Ppmv or ppmv	Parts per million by volume
PSD	Prevention of Significant Deterioration
psi	Pounds per Square Inch
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TAP	Toxic Air Pollutant
TPY	Tons per Year
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate
USEPA	United States Environmental Protection Agency
UTM	Universal Transverse Mercator
VEE	Visual Emissions Evaluation
VOC	Volatile Organic Compounds
VOL	Volatile Organic Liquids

2.3. Authority

This permit is issued in accordance with West Virginia Air Pollution Control Law W.Va. Code §§22-5-1 et seq. and the following Legislative Rules promulgated thereunder:

2.3.1. 45CSR13 – *Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Temporary Permits, General Permits and Procedures for Evaluation;*

2.3.2. 45CSR14 – *Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration;*

2.4. Term and Renewal

2.4.1. This permit shall remain valid, continuous and in effect unless it is revised, suspended, revoked or otherwise changed under an applicable provision of 45CSR13 or any applicable legislative rule.

2.5. Duty to Comply

2.5.1. The permitted facility shall be constructed and operated in accordance with the plans and specifications filed in Permit Application R14-0036 and any modifications, administrative updates, or amendments thereto. The Secretary may suspend or revoke a permit if the plans and specifications upon which the approval was based are not adhered to;
[45CSR§§13-5.11 and 13-10.3]

2.5.2. The permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the West Virginia Code and the Clean Air Act and is grounds for enforcement action by the Secretary or USEPA;

2.5.3. Violations of any of the conditions contained in this permit, or incorporated herein by reference, may subject the permittee to civil and/or criminal penalties for each violation and further action or remedies as provided by West Virginia Code 22-5-6 and 22-5-7;

2.5.4. Approval of this permit does not relieve the permittee herein of the responsibility to apply for and obtain all other permits, licenses and/or approvals from other agencies; i.e., local, state and federal, which may have jurisdiction over the construction and/or operation of the source(s) and/or facility herein permitted.

2.6. Duty to Provide Information

The permittee shall furnish to the Secretary within a reasonable time any information the Secretary may request in writing to determine whether cause exists for administratively updating, modifying, revoking or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Secretary copies of records to be kept by the permittee. For information claimed to be confidential, the permittee shall furnish such records to the Secretary along with a claim of confidentiality in accordance with 45CSR31. If confidential information is to be sent to USEPA, the permittee shall directly provide such information to USEPA along with a claim of confidentiality in accordance with 40 C.F.R. Part 2.

2.7. Duty to Supplement and Correct Information

Upon becoming aware of a failure to submit any relevant facts or a submittal of incorrect information in any permit application, the permittee shall promptly submit to the Secretary such supplemental facts or corrected information.

2.8. Administrative Update

The permittee may request an administrative update to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-4]

2.9. Permit Modification

The permittee may request a minor modification to this permit as defined in and according to the procedures specified in 45CSR13.
[45CSR§13-5.4.]

2.10. Major Permit Modification

The permittee may request a major modification as defined in and according to the procedures specified in 45CSR14 or 45CSR19, as appropriate.
[45CSR§13-5.1]

2.11. Inspection and Entry

The permittee shall allow any authorized representative of the Secretary, upon the presentation of credentials and other documents as may be required by law, to perform the following:

a. At all reasonable times (including all times in which the facility is in operation) enter upon the permittee's premises where a source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

c. Inspect at reasonable times (including all times in which the facility is in operation) any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

d. Sample or monitor at reasonable times substances or parameters to determine compliance with the permit or applicable requirements or ascertain the amounts and types of air pollutants discharged.

2.12. Emergency

2.12.1. An "emergency" means any situation arising from sudden and reasonable unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

2.12.2. Effect of any emergency. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of Section 2.12.3 are met.

2.12.3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. The permitted facility was at the time being properly operated;

c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and,

d. The permittee submitted notice of the emergency to the Secretary within one (1) working day of the time when emission limitations were exceeded due to the emergency and made a request for variance, and as applicable rules provide. This notice must contain a detailed description of the emergency, any steps taken to mitigate emission, and corrective actions taken.

2.12.4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

2.12.5. The provisions of this section are in addition to any emergency or upset provision contained in any applicable requirement.

2.13. Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it should have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in determining penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continued operations.

2.14. Suspension of Activities

In the event the permittee should deem it necessary to suspend, for a period in excess of sixty (60) consecutive calendar days, the operations authorized by this permit, the permittee shall notify the Secretary, in writing, within two (2) calendar weeks of the passing of the sixtieth (60) day of the suspension period.

2.15. Property Rights

This permit does not convey any property rights of any sort or any exclusive privilege.

2.16. Severability

The provisions of this permit are severable and should any provision(s) be declared by a court of competent jurisdiction to be invalid or unenforceable, all other provisions shall remain in full force and effect.

2.17. Transferability

This permit is transferable in accordance with the requirements outlined in Section 10.1 of 45CSR13.
[45CSR§13-10.1]

2.18. Notification Requirements

The permittee shall notify the Secretary, in writing, no later than thirty (30) calendar days after the actual startup of the operations authorized under this permit.

2.19. Credible Evidence

Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defense otherwise available to the permittee including, but not limited to, any challenge to the credible evidence rule in the context of any future proceeding.

3.0. Facility-Wide Requirements

3.1. Limitations and Standards

3.1.1. **Open burning.** The open burning of refuse by any person, firm, corporation, association or public agency is prohibited except as noted in 45CSR§6-3.1.
[45CSR§6-3.1.]

3.1.2. **Open burning exemptions.** The exemptions listed in 45CSR§6-3.1 are subject to the following stipulation: Upon notification by the Secretary, no person shall cause, suffer, allow or permit any form of open burning during existing or predicted periods of atmospheric stagnation. Notification shall be made by such means as the Secretary may deem necessary and feasible.
[45CSR§6-3.2.]

3.1.3. **Asbestos.** The permittee is responsible for thoroughly inspecting the facility, or part of the facility, prior to commencement of demolition or renovation for the presence of asbestos and complying with 40 C.F.R. § 61.145, 40 C.F.R. § 61.148, and 40 C.F.R. § 61.150. The permittee, owner, or operator must notify the Secretary at least ten (10) working days prior to the commencement of any asbestos removal on the forms prescribed by the Secretary if the permittee is subject to the notification requirements of 40 C.F.R. § 61.145(b)(3)(i). The USEPA, the Division of Waste Management and the Bureau for Public Health - Environmental Health require a copy of this notice to be sent to them.
[40CFR§61.145(b) and 45CSR§34]

3.1.4. **Odor.** No person shall cause, suffer, allow or permit the discharge of air pollutants which cause or contribute to an objectionable odor at any location occupied by the public.
[45CSR§4-3.1 State-Enforceable only.]

3.1.5. **Permanent shutdown.** A source which has not operated at least 500 hours in one 12-month period within the previous five (5) year time period may be considered permanently shutdown, unless such source can provide to the Secretary, with reasonable specificity, information to the contrary. All permits may be modified or revoked and/or reapplication or application for new permits may be required for any source determined to be permanently shutdown.
[45CSR§13-10.5.]

3.1.6. **Standby plan for reducing emissions.** When requested by the Secretary, the permittee shall prepare standby plans for reducing the emissions of air pollutants in accordance with the objectives set forth in Tables I, II, and III of 45 C.S.R. 11.
[45CSR§11-5.2.]

3.2. Monitoring Requirements

3.2.1 Emission Limit Averaging Time. Unless otherwise specified, compliance with all annual limits shall be based on a rolling twelve month total. A rolling twelve month total shall be the sum of the measured parameter of the previous twelve calendar months. Compliance with all hourly emission limits, unless specified in this permit, shall be based on the applicable NAAQS averaging times or, where applicable, as given in any approved performance test method.

3.3. Testing Requirements

3.3.1. **Stack testing.** As per provisions set forth in this permit or as otherwise required by the Secretary, in accordance with the West Virginia Code, underlying regulations, permits and orders, the permittee shall conduct test(s) to determine compliance with the emission limitations set forth in this permit and/or established or set forth in underlying documents. The Secretary, or his duly authorized representative, may at his option witness or conduct such test(s). Should the Secretary exercise his option to conduct such test(s), the operator shall provide all necessary sampling connections and sampling ports to be located in such manner as the Secretary may require, power for test equipment and the required safety equipment, such as scaffolding, railings and ladders, to comply with generally accepted good safety practices. Such tests shall be conducted in accordance with the methods and procedures set forth in this permit or as otherwise approved or specified by the Secretary in accordance with the following:

a. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with 40 C.F.R. Parts 60, 61, and 63 in accordance with the Secretary's delegated authority and any established equivalency determination methods which are applicable. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4 or 45CSR§13-5.4 as applicable.

b. The Secretary may on a source-specific basis approve or specify additional testing or alternative testing to the test methods specified in the permit for demonstrating compliance with applicable requirements which do not involve federal delegation. In specifying or approving such alternative testing to the test methods, the Secretary, to the extent possible, shall utilize the same equivalency criteria as would be used in approving such changes under Section 3.3.1.a. of this permit. If a testing method is specified or approved which effectively replaces a test method specified in the permit, the permit may be revised in accordance with 45CSR§13-4 or 45CSR§13-5.4 as applicable.

c. All periodic tests to determine mass emission limits from or air pollutant concentrations in discharge stacks and such other tests as specified in this permit shall be conducted in accordance with an approved test protocol. Unless previously approved, such protocols shall be submitted to the Secretary in writing at least thirty (30) days prior to any testing and shall contain the information set forth by the Secretary. In addition, the permittee shall notify the Secretary at least fifteen (15) days prior to any testing so the Secretary may have the opportunity to observe such tests. This notification shall include the actual date and time during which the test will be conducted and, if appropriate, verification that the tests will fully conform to a referenced protocol previously approved by the Secretary.

d. The permittee shall submit a report of the results of the stack test within sixty (60) days of completion of the test. The test report shall provide the information necessary to document the objectives of the test and to determine whether proper procedures were used to accomplish these objectives. The report shall include the following: the certification described in paragraph 3.5.1.; a statement of compliance status, also signed by a responsible official; and, a summary of conditions which form the basis for the compliance status evaluation. The summary of conditions shall include the following:

1. The permit or rule evaluated, with the citation number and language;
2. The result of the test for each permit or rule condition; and,
3. A statement of compliance or noncompliance with each permit or rule condition.

[WV Code § 22-5-4(a)(14-15) and 45CSR13]

3.4. Recordkeeping Requirements

3.4.1. **Retention of records.** The permittee shall maintain records of all information (including monitoring data, support information, reports and notifications) required by this permit recorded in a form suitable and readily available for expeditious inspection and review. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation. The files shall be maintained for at least five (5) years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent two (2) years of data shall be maintained on site. The remaining three (3) years of data may be maintained off site, but must remain accessible within a reasonable time. Where appropriate, the permittee may maintain records electronically (on a computer, on computer floppy disks, CDs, DVDs, or magnetic tape disks), on microfilm, or on microfiche.

3.4.2. **Odors.** For the purposes of 45CSR4, the permittee shall maintain a record of all odor complaints received, any investigation performed in response to such a complaint, and any responsive action(s) taken.
[45CSR§4. *State-Enforceable only.*]

3.5. Reporting Requirements

3.5.1. **Responsible official.** Any application form, report, or compliance certification required by this permit to be submitted to the DAQ and/or USEPA shall contain a certification by the responsible official that states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

3.5.2. **Confidential information.** A permittee may request confidential treatment for the submission of reporting required by this permit pursuant to the limitations and procedures of W.Va. Code § 22-5-10 and 45CSR31.

3.5.3. **Correspondence.** All notices, requests, demands, submissions and other communications required or permitted to be made to the Secretary of DEP and/or USEPA shall be made in writing and shall be deemed to have been duly given when delivered by hand, or mailed first class with postage prepaid to the address(es) set forth below or to such other person or address as the Secretary of the Department of Environmental Protection may designate:

If to the DAQ:	**If to the USEPA:**
Director WVDEP Division of Air Quality 601 57th Street, SE Charleston, WV 25304-2345 **DAQ Compliance and Enforcement[1]:** DEPAirQualityReports@wv.gov	Associate Director Office of Air Enforcement and Compliance Assistance (3AP20) U. S. Environmental Protection Agency Region III 1650 Arch Street Philadelphia, PA 19103-2029

[1]For All self-monitoring reports (MACT, GACT, NSPS, etc.), stack tests and protocols, Notice of Compliance Status Reports, Initial Notifications, etc.

3.5.4. **Operating Fee.**

3.5.4.1. In accordance with 45CSR30 – Operating Permit Program, the permittee shall submit a Certified Emissions Statement (CES) and pay fees on an annual basis in accordance with the submittal requirements of the Division of Air Quality. A receipt for the appropriate fee shall be maintained on the premises for which the receipt has been issued, and shall be made immediately available for inspection by the Secretary or his/her duly authorized representative.

3.5.4.2. In accordance with 45CSR30 – Operating Permit Program, enclosed with this permit is a Certified Emissions Statement (CES) Invoice, from the date of initial startup through the following June 30. Said invoice and the appropriate fee shall be submitted to this office no later than 30 days prior to the date of initial startup. For any startup date other than July 1, the permittee shall pay a fee or prorated fee in accordance with the Section 4.5 of 45CSR22. A copy of this schedule may be found attached to the Certified Emissions Statement (CES) Invoice. .

3.5.5. **Emission inventory.** At such time(s) as the Secretary may designate, the permittee herein shall prepare and submit an emission inventory for the previous year, addressing the emissions from the facility and/or process(es) authorized herein, in accordance with the emission inventory submittal requirements of the Division of Air Quality. After the initial submittal, the Secretary may, based upon the type and quantity of the pollutants emitted, establish a frequency other than on an annual basis.

4.0. Source-Specific Requirements

4.1. Limitations and Standards

4.1.1. The ESC Harrison County Power, LLC Harrison County Combined Cycle Power Plant shall consist of only the pollutant-emitting equipment and processes identified under Section 1.0 of this permit and any other processes/units defined as De Minimis per 45CSR13. In accordance with the information filed in Permit Application R14-0036, the equipment shall be installed, maintained, and operated so as to minimize any fugitive escape of pollutants and the equipment/processes shall use the specified control devices.

4.1.2 Hourly emissions from the combustion turbine/HRSG unit shall not exceed the following (except in cases of startup and shutdown):

Pollutant	Emission Rate (lb/hr)
CO	20 (based on a 1 hour average)
NO_x	32.9 (based on a 1 hour average)
PM(1)	22.6
PM_{10}(1)	22.6
$PM_{2.5}$(1)	22.6
SO_2	6.0
VOCs	11.4
Pb	0.002
GHGs (CO_2e)	528,543
H_2SO_4	3.8
HAPs	1.34

[1] Includes both filterable and condensable particulate matter

4.1.3 Pursuant to the BACT provisions under 45CSR14, the combustion turbine/HRSG unit shall not exceed the following emission rates and annual emissions for startups and shutdowns:

Pollutant[1]	Type of Event[2]	Emission Factor (lb/event)	Annual Emissions (lb/yr)
NO_x	Hot Start	67	24,200
	Warm Start	130	
	Cold Start	264	
	Shutdown	7	
CO	Hot Start	120	72,900
	Warm Start	155	
	Cold Start	790	
	Shutdown	124	

PM[3]	Hot Start	4.6	2,180
	Warm Start	9.1	
	Cold Start	13	
	Shutdown	2.7	
PM_{10}[3]	Hot Start	4.6	2,180
	Warm Start	9.1	
	Cold Start	13	
	Shutdown	2.7	
$PM_{2.5}$[3]	Hot Start	4.6	2,180
	Warm Start	9.1	
	Cold Start	13	
	Shutdown	2.7	
VOCs[4]	Hot Start	9	9,700
	Warm Start	10	
	Cold Start	55	
	Shutdown	26	

1 Pollutants not listed in this table are limited to the rates in condition 4.1.2 at all times including startup and shutdown.
2 A hot start is defined as a start following 8 hours of shutdown or less. A warm start is defined as a start following at least 8 hours of shutdown but not more than 72 hours of shutdown. A cold start is defined as a start following 72 hours of shutdown or more.
3 Includes both filterable and condensable particulate matter.
4 As Methane

4.1.4 Total annual emissions from the turbine/HRSG unit shall not exceed the following.

Pollutant	tons/year
CO	124.00
NO_x	156.20
$PM/PM_{10}/PM_{2.5}$[(1)]	100.10
SO_2	26.10
VOCs	54.80
H_2SO_4	16.70
Lead	0.01
GHGs (CO_2e)	2,315,020.00
Total HAPs	5.86

1 Includes both filterable and condensable particulate matter

Compliance with the annual emission limits shall be determined using CEMs for CO and NO_x. For all other pollutants, it shall be determined by multiplying the hourly steady state emissions in condition 4.1.2 by the number of hours of steady state operation and adding the appropriate start up and shut down emissions from condition 4.1.3.

4.1.5 Pursuant to the BACT provisions under 45CSR14, the permittee shall not exceed the follwing emission limits and meet the technology requirements for the combustion turbine/HRSG unit:

Pollutant	Limit	Technology[(1)]
CO	2.0 ppmvd	OC, CP
NO_x	2.0 ppmvd	DLNB, SCR, CP
$PM_{2.5}$ / PM_{10} / PM[(2)]	18.2 lb/hr	AF, NG, CP
VOCs[(3)]	1 ppmvd 2 ppmvd	OC, CP
H_2SO_4	0.0009 lb/mmbtu	NG
GHGs	826 lb/MW-hr[(4)]	NG, GE7HA

1 CP=Good Combustion Practices; SCR = Selective Catalytic Reduction; DLNB = Dry Low NOx Burners; OC = Oxidation Catalyst; AF = inlet air filtration; NG = Use of Natural Gas as a fuel; GE7HA = use of GE Frame 7HA.02 turbine (or equivalent).
2 PM emission rates are given in total particulate (filterable + condensable) matter
3 1ppm limit applies when duct firing is not occurring. 2 ppm limit applies when duct firing is occurring. Ppm values are by volume, dry basis, corrected to 15% oxygen.
4 Compliance shall be based on initial manufacturer design for combined cycle gross MW output, at 32°F ambient temperature, with duct firing, evaporative cooling off and operating at base load.

4.1.5.1 Pursuant to the BACT provisions under 45CSR14, during startup and shut down the applicant shall minimize the emissions by:

1. Operating and maintaining the turbine/HRSG unit and associated air pollution control equipment in accordance with good combustion and air pollution control practices, safe operating practices, and protection of the facility. Good combustion and air pollution control practices shall mean proper operation and maintenance of combustion control systems and air pollution control equipment in accordance with manufacturer specifications. Additionally, it shall mean such practices that promote sufficient residence time of the fuel in the combustion zone, thorough mixing of air and fuel and proper combustion temperatures.

2. Implementing operations and maintenance practices comprised of maintaining a high level of operation time, and minimizing (as much as practicable) the frequency of startup and shutdown events.

3. Operate continuous emission monitoring system (CEMS), and other continuous monitoring systems and devices required by this permit.

4.1.6 The combustion turbine/HRSG unit shall burn only pipeline quality natural gas with a maximum sulfur content of 0.4 grains per 100 dscf.

4.1.7 The combustion turbine/HRSG unit shall use the emission control devices specified under Table 1.0 at all times when in operation except during periods of startup and shutdown when operating temperatures do not allow for proper use of the emission control devices.

4.1.8 In order to minimize NO_x emissions, within 180 days of startup, the permittee shall determine the optimal injection rate of aqueous ammonia into the SCR. The permittee shall then operate the SCR at the determined injection rate.

4.1.9 Ammonia slip from the SCR shall not exceed 5 ppmvd at 15% O_2 except during periods of startup and shutdown.

4.1.10 Emissions of NO_x from the combustion turbine/HRSG unit shall not exceed one of the following:

4.1.10.1 15 ppmvd at 15% oxygen or;

4.1.10.2 0.43 lb/MW-hr gross energy output.
[40 CFR §60.4320]

4.1.11 The combustion turbine/HRSG unit shall meet one of the following requirements:

4.1.11.1 The permittee must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or

4.1.11.2 The permittee must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.
[40 CFR §60.4330(a)]

4.1.12 Visible emissions from the combustion turbine/HRSG unit shall not exceed 10 percent opacity based on a six minute block average.
[45CSR§2-3.1.]

4.1.13 Emissions from the turbine shall not exceed 1,000 pounds of CO_2 per megawatt-hour on a gross energy output basis.
[40 CFR §60.5520]

4.1.14 Emissions from the auxiliary boiler shall not exceed the following:

Pollutant	lb/hr	tpy
CO	2.88	6.58
NO_x	0.86	1.96
$PM/PM_{10}/PM_{2.5}$	0.60	1.38
SO_2	0.09	0.20
VOCs	0.62	1.42
GHGs (CO_2e basis)	9,107	20,837
H_2SO_4	0.0132	0.03
HAPs	0.15	0.33

4.1.15 The auxiliary boiler shall be fitted with Low NO_x burners.

4.1.16 The auxiliary boiler shall burn only pipeline quality natural gas with an overall maximum sulfur content of 0.4 grains per 100 dscf as fuel.

4.1.17 The auxiliary boiler shall not consume more than 75,509 scf of fuel per hour nor more than 346,000 mscf of fuel per year.

4.1.18 *[Reserved]*

4.1.19 Visible emissions from the auxiliary boiler shall not exceed 10 percent opacity based on a six minute block average.
[45CSR§2-3.1.]

4.1.20 Pursuant to the BACT provisions under 45CSR14, the permittee shall meet the following requirements for the auxiliary boiler:

Pollutant	Limit	Technology(1)
CO	0.037 lb/mmbtu	CP
NO_x	0.011 lb/mmbtu	LNB, CP
$PM_{2.5}$ / PM_{10} / PM(2)	0.008 lb/mmbtu	NG, CP
VOCs	0.008 lb/mmbtu	CP, NG
H_2SO_4	0.00017 lb/mmbtu	NG
GHGs	9,107 lb/hr	NG

1 CP=Good Combustion Practices; LNB = Low NOx Burners; NG = Use of Natural Gas as a fuel;
2 PM emission rates are given in total particulate (filterable + condensable) matter

4.1.21 Non emergency emissions from the emergency generator shall not exceed the following:

Pollutant	**lb/hr**	**tpy**
CO	1.77	0.09
NO_x	32.22	1.61
$PM/PM_{10}/PM_{2.5}$	0.15	0.01
SO_2	0.03	0.01
VOCs	0.65	0.03
GHGs (CO_2e basis)	3,161	158
HAPs	0.04	0.01

4.1.22 The emergency generator shall fire only ultra low sulfur diesel fuel with a sulfur content of no greater than 0.0015% by weight.

4.1.23 The emergency generator shall not consume more than 138 gallons of fuel oil per hour based on vendor documentation.

4.1.24 The emergency generator shall not operate more than 100 hours per year nor more than 1 hour in any 24 consecutive hours for non emergency purposes (e.g. maintenance and testing).

4.1.25 Emissions from the emergency generator shall not exceed the following (all limits in g/hp-hr):

$NMHC + NO_x$	CO	PM
4.8	2.6	0.15

[40 CFR §60.4205]

4.1.25.1 Compliance with the above limits shall be determined by purchasing an engine certified to meet the emission standards in §60.4204(b) or §60.4205(b) or (c) as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturers emission related specifications, except as permitted in paragraph (g) of this section.
[40 CFR §60.4211(c)]

4.1.26 The emergency generator shall fire only nonroad diesel fuel that meets the requirements of 40 CFR 80.510(b).
[40 CFR §60.4207(b)]

4.1.27 The emergency generator must meet all applicable requirements of 40 CFR 60 Subpart IIII.
[40 CFR §63.6590(c)(1)]

4.1.28 Non emergency emissions from the fire water pump engine shall not exceed the following:

Pollutant	**lb/hr**	**tpy**
CO	0.31	0.02
NO_x	1.87	0.09
$PM/PM_{10}/PM_{2.5}$	0.05	0.01
SO_2	0.01	0.01
VOCs	0.06	0.01
GHGs (CO_2e basis)	344	17
HAPs	0.01	0.01

4.1.29 The fire water pump engine shall fire only ultra low sulfur diesel fuel with a sulfur content of no greater than 0.0015% by weight.

4.1.30 The fire water pump engine shall not consume more than 15 gallons of fuel oil per hour based on vendor documentation.

4.1.31 The fire water pump engine shall not operate more than 100 hours per year nor more than 1 hour in any 24 consecutive hours for non emergency purposes (e.g. maintenance and testing).

4.1.32 Emissions from the fire water pump engine shall not exceed the following (all limits in g/hp-hr):

$NMHC + NO_x$	CO	PM
3	2.6	0.15

[40 CFR §60.4205]

4.1.32.1 Compliance with the above limits shall be determined by purchasing an engine certified to meet the emission standards in §60.4204(b) or §60.4205(b) or (c) as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturers emission related specifications, except as permitted in paragraph (g) of this section.
[40 CFR §60.4211(c)]

4.1.33 The fire water pump engine shall fire only nonroad diesel fuel that meets the requirements of 40 CFR 80.510(b).
[40 CFR §60.4207(b)]

4.1.34 The fire water pump engine must meet all applicable requirements of 40 CFR 60 Subpart IIII.
[40 CFR §63.6590(c)(1)]

4.1.35 The fuel gas heater shall burn only pipeline quality natural gas with a maximum sulfur content of 0.4 grains per 100 dscf.

4.1.36 Emissions from the fuel gas heater shall not exceed the following:

Pollutant	**lb/hr**	**tpy**
CO	0.21	0.93
NO_x	0.20	0.86
$PM/PM_{10}/PM_{2.5}$	0.04	0.19
SO_2	0.01	0.03
VOCs	0.04	0.17
GHGs (CO_2e basis)	641	2,806
H_2SO_4	0.0010	0.0041
HAPs	0.01	0.05

4.1.37. **Operation and Maintenance of Air Pollution Control Equipment.** The permittee shall, to the extent practicable, install, maintain, and operate all pollution control equipment listed in Section 1.0 and associated monitoring equipment in a manner consistent with safety and good air pollution control practices for minimizing emissions, or comply with any more stringent limits set forth in this permit or as set forth by any State rule, Federal regulation, or alternative control plan approved by the Secretary.
[45CSR§13-5.11.]

4.2. Monitoring Requirements

4.2.1. In order to determine compliance with the CO and NO_x limits of condition 4.1.2, 4.1.3, 4.1.4, 4.1.5 and 4.1.10 of this permit, the permittee shall install a continuous emissions monitoring system (CEMS). Said CEMS shall be designed, installed, operated and maintained in accordance with performance specification 4 of 40 CFR 60 and §60.4345 as applicable.

4.2.2 In order to determine compliance with the requirements of 4.1.3, the permittee shall monitor the type and number of each event and the duration of each shutdown.

4.2.3 In order to determine compliance with the requirements of 4.1.6 of this permit, the permittee shall monitor the amount of natural gas used by the combustion turbine / HRSG unit in scf/hour. The fuel flow meters used to measure the natural gas shall meet the requirements of 40 CFR Part 75, Appendix D, Section 2.1.

4.2.4 In order to determine compliance with the requirements 4.1.7 of this permit, the permittee shall monitor the operating times for the SCR and oxidation catalyst.

4.2.5 In order to determine compliance with the requirements of 4.1.8 of this permit, the permittee shall monitor the ammonia injection rate into the SCR on at least an hourly basis.

4.2.6 In order to determine compliance with the requirements of 4.1.9 of this permit, the permittee shall monitor ammonia slip from the SCR on at least an hourly basis.

4.2.7 In order to determine compliance with the requirements of 4.1.11 of this permit, the permittee shall either demonstrate compliance with 4.1.11.2 of this permit per 40 CFR §60.4365 or demonstrate compliance with 4.1.11.1 of this permit by monitoring fuel sulfur content per 40 CFR §60.4370.

4.2.8 In order to determine compliance with the emission limitations of 4.1.14 of this permit and the requirements of 4.1.16 and 4.1.17 of this permit, the permittee shall monitor the amount of fuel consumed by the auxiliary boiler on at least a monthly basis.

4.2.9 In order to determine compliance with the SO_2 emission limitations of 4.1.14 of this permit and the fuel sulfur content limit of 4.1.16 of this permit, the permittee shall monitor fuel sulfur content of the fuel combusted by the auxiliary boiler. In lieu of this monitoring, the permittee may maintain onsite a valid purchase contract guaranteeing that the maximum sulfur content of the fuel is not greater than 0.4 grains per 100 dscf.

4.2.10 Compliance with 4.1.13 of this permit shall be determined using the applicable procedures of 40 CFR §60.5525 and 40 CFR §60.5535 .

4.2.11 In order to determine compliance with the emission limitations of 4.1.21 of this permit, and the operating limits of 4.1.23 of this permit, the permittee shall monitor the amount of fuel used by the emergency generator on at least a daily basis (whenever the generator is operated).

4.2.12 In order to determine compliance with the fuel sulfur limits of 4.1.22 of this permit the permittee shall monitor fuel sulfur content of the fuel oil combusted by the emergency generator. In lieu of this monitoring, the permittee may maintain onsite a valid purchase contract, tariff sheet or transportation contract guaranteeing that the maximum sulfur content of the fuel is not greater than 0.0015% by weight.

4.2.13 In order to determine compliance with the operating limits of 4.1.24 of this permit, the permittee shall monitor the emergency generator operating time.

4.2.14 In order to determine compliance with the emission limitations of 4.1.25 of this permit, the permittee shall only use an emergency generator certified by the manufacturer to meet those emission limitations.

4.2.15 In order to determine compliance with the emission limitations of 4.1.28 of this permit, and the operating limits of 4.1.30 of this permit, the permittee shall monitor the amount of fuel used by the fire water pump engine on at least a daily basis (whenever the engine is operated).

4.2.16 In order to determine compliance with the fuel sulfur limits of 4.1.29 of this permit the permittee shall monitor fuel sulfur content of the fuel oil combusted by the fire water pump engine. In lieu of this monitoring, the permittee may maintain onsite a valid purchase contract, tariff sheet or transportation contract guaranteeing that the maximum sulfur content of the fuel is not greater than 0.0015% by weight.

4.2.17 In order to determine compliance with the operating limits of 4.1.31 of this permit, the permittee shall monitor the fire water pump engine operating time.

4.2.18 In order to determine compliance with the emission limitations of 4.1.32 of this permit, the permittee shall only use a fire water pump engine certified by the manufacturer to meet those emission limitations.

4.2.19 In order to determine compliance with the SO_2 emission limitations of 4.1.36 of this permit and the fuel sulfur content limit of 4.1.35 of this permit, the permittee shall monitor fuel sulfur content of the fuel combusted by the fuel gas heater. In lieu of this monitoring, the permittee may maintain onsite a valid purchase contract guaranteeing that the maximum sulfur content of the fuel is not greater than 0.4 grains per 100 dscf.

4.3. Testing Requirements

4.3.1. In order to determine compliance with the emission limitations of 4.1.2, 4.1.4 and 4.1.5 of this permit, the permittee shall perform EPA approved stacktesting on the combustion turbine / HRSG unit within 180 days of startup. Said testing shall utilize the following methods unless otherwise approved by the Director.

Pollutant	Test Method(1)
CO(2)	Method 10B
PM	Method 202
PM (filterable only)	Method 5
$PM_{10}/PM_{2.5}$	Method 202
$PM_{10}/PM_{2.5}$ (filterable)	Method 201A
VOCs	Method 18
H_2SO_4	Method 8
GHGS	Method 3A or 3B for CO_2. Emission calculations for non CO_2 GHGs.

(1) All test methods refer to those given under 40 CFR 60, Appendix A
(2) Data obtained during required RATA testing of the CO CEMs may be used in lieu of the required testing.

4.3.2 The testing required under 4.3.1 of this permit shall be repeated at least once every 5 years.

4.3.3 In order to determine compliance with the opacity limits of 4.1.12 and 4.1.19 of this permit, the permittee shall conduct visible emission checks and / or opacity monitoring and recordkeeping for the combustion turbine / HRSG stack and the auxiliary boiler stack.

a. The visible emission check shall determine the presence or absence of visible emissions. At a minimum, the observer must be trained and knowledgeable regarding the effects of background contrast, ambient lighting, observer position relative to lighting, wind, and the presence of uncombined water (condensing water vapor) on the visibility of emissions. This training may be obtained from written materials found in the References 1 and 2 from 40CFR Part 60, Appendix A, Method 22 or from the lecture portion of the 40CFR Part 60, Appendix A, Method 9 certification course.

b. Visible emission checks shall be conducted at least once per calendar month with a maximum of forty-five (45) days between consecutive readings. These checks shall be performed for a sufficient time interval, but no less than one (1) minute, to determine if any visible emissions are present. Each observation must be recorded as either visible emissions observed or no visible emissions observed. Visible emission checks shall be performed during periods of normal facility operation and appropriate weather conditions.

c. If visible emissions are present at a source(s) the permittee shall perform Method 9 readings to confirm that visible emissions are within the limits of 4.1.12 or 4.1.19 (as applicable) of this permit. Said Method 9 readings shall be taken as soon as practicable, but within seventy-two (72) operating hours of the Method 22 emission check.

4.3.4 The permittee shall perform any applicable, required testing under 40 CFR 60 Subpart KKKK including but not limited to the following:

4.3.4.1 The permittee shall conduct an initial and subsequent annual performance tests to determine compliance with NO_x emission limits using either EPA Method 7E or EPA Method 20.
[40 CFR §60.4400(a)]

4.3.4.2 Since NOx-diluent CEMS are required in this permit, the initial performance test required by 4.3.4.1 may be alternatively performed by the methods prescribed by 40 CFR §60.4405.
[40 CFR §60.4405]

4.3.4.3 The permittee shall conduct an initial and subsequent annual performance tests to determine compliance with SO_2 emission limits using one of the three methods described in 40 CFR §60.4415(a).
[40 CFR §60.4415(a)]

4.4. Recordkeeping Requirements

4.4.1. **Record of Monitoring.** The permittee shall keep records of monitoring information that include the following:

a. The date, place as defined in this permit and time of sampling or measurements;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of the analyses; and

f. The operating conditions existing at the time of sampling or measurement.

4.4.2. **Record of Maintenance of Air Pollution Control Equipment.** For all pollution control equipment listed in Section 1.0, the permittee shall maintain accurate records of all required pollution control equipment inspection and/or preventative maintenance procedures.

4.4.3. **Record of Malfunctions of Air Pollution Control Equipment.** For all air pollution control equipment listed in Section 1.0, the permittee shall maintain records of the occurrence and duration of any malfunction or operational shutdown of the air pollution control equipment during which excess emissions occur. For each such case, the following information shall be recorded:

a. The equipment involved.

b. Steps taken to minimize emissions during the event.

c. The duration of the event.

d. The estimated increase in emissions during the event.

For each such case associated with an equipment malfunction, the additional information shall also be recorded:

e. The cause of the malfunction.

f. Steps taken to correct the malfunction.

g. Any changes or modifications to equipment or procedures that would help prevent future recurrences of the malfunction.

4.4.4. In order to determine compliance with 4.2.2 of this permit, the permittee shall record the type and number of each event and the duration of each shutdown as limited by 4.1.3.

4.4.5 The permittee shall record the amount of fuel used by the combustion turbine / HRSG unit on an hourly basis as limited by 4.1.6.

4.4.6 The permittee shall record the operating times for the SCR and oxidation catalyst as required by 4.1.7.

4.4.7 The permittee shall record the ammonia injection rate into the SCR as required by 4.1.8.

4.4.8 The permittee shall record the ammonia slip from the SCR as limited by 4.1.9.

4.4.9 The permittee shall either maintain records of compliance with 4.1.11.2 of this permit per 40 CFR §60.4365 or maintain records of compliance with 4.1.11.1 of this permit by recordkeeping fuel sulfur content per 40 CFR §60.4370.

4.4.10 The permittee shall record the amount of fuel consumed by the auxiliary boiler as limited by 4.1.17.

4.4.11 The permittee shall record fuel sulfur content of the natural gas combusted by the auxiliary boiler as limited by 4.1.16. In lieu of this recordkeeping, the permittee may maintain onsite a valid purchase contract guaranteeing that the maximum sulfur content of the fuel is not greater than 0.4 grains per 100 mscf.

4.4.12 [Reserved]

4.4.13 The permittee shall record the amount of fuel used by the emergency generator as limited by 4.1.23.

4.4.14 The permittee shall record the sulfur content of the fuel oil combusted by the emergency generators limited by 4.1.22. In lieu of this recordkeeping, the permittee may maintain onsite a valid purchase contract, tariff sheet or transportation contract guaranteeing that the maximum sulfur content of the fuel is not greater than 0.0015% by weight.

4.4.15 The permittee shall record the emergency generators operating times as limited by 4.1.24.

4.4.16 The permittee shall record the amount of fuel used by the fire water pump engine as limited by 4.1.30.

4.4.17 The permittee shall record fuel sulfur content of the fuel oil combusted by the fire water pump engine as limited by 4.1.29. In lieu of this recordkeeping, the permittee may maintain onsite a valid purchase contract, tariff sheet or transportation contract guaranteeing that the maximum sulfur content of the fuel is not greater than 0.0015% by weight.

4.4.18 The permittee shall record the fire water pump engine operating times as limited by 4.1.31.

4.4.19 The permittee shall record fuel sulfur content of the natural gas combusted by the fuel gas heater as limited by 4.1.35. In lieu of this recordkeeping, the permittee may maintain onsite a valid purchase contract guaranteeing that the maximum sulfur content of the fuel is not greater than 0.4 grains per 100 mscf.

4.4.20 The permittee shall record the CEMS readings required by 4.2.1. Said records shall be used to determine compliance with the annual emission limits of 4.1.3 and 4.1.4.

4.5. Reporting Requirements

4.5.1. The permittee shall submit any and all applicable notifications and reports required under 40 CFR 60 Subpart IIII.

4.5.2 For the combustion turbine / HRSG unit you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.
[40 CFR §60.4375(a)]

4.5.3 For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.
[40 CFR §60.4375(b)]

4.5.4 The permittee shall submit any and all applicable notifications and reports required under 40 CFR 60 Subpart Dc.
[40 CFR §60.48c]

CERTIFICATION OF DATA ACCURACY

I, the undersigned, hereby certify that, based on information and belief formed after reasonable inquiry, all information contained in the attached ____________________________, representing the period beginning ____________________ and ending ____________________, and any supporting documents appended hereto, is true, accurate, and complete.

Signature[1] (please use blue ink) ____________________________ Responsible Official or Authorized Representative ________________ Date

Name and Title (please print or type) ____________________________ Name ________________ Title

Telephone No. ____________________ Fax No. ____________________

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1 This form shall be signed by a "Responsible Official." "Responsible Official" means one of the following:

a. For a corporation: The president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

   (I) the facilities employ more than 250 persons or have a gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or

   (ii) the delegation of authority to such representative is approved in advance by the Director;

b. For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

c. For a municipality, State, Federal, or other public entity: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of USEPA); or

d. The designated representative delegated with such authority and approved in advance by the Director.

Exhibit 4

Connecticut Department of
ENERGY & ENVIRONMENTAL PROTECTION

79 Elm Street • Hartford, CT 06106-5127 www.ct.gov/deep Affirmative Action/Equal Opportunity Employer

DEC 10 2018

Mr. Tim Eves
Vice President
NTE Connecticut, LLC
24 Cathedral Place Suite 300
Saint Augustine, FL 32084

Dear Mr. Eves:

Enclosed is a copy of your modified permit to construct and operate 647 MW combined cycle power plant consisting of a Mitsubishi M501JAC combustion turbine and duct burner at 180/189 Lake Road, Killingly, CT.

This letter does not relieve you of the responsibility to comply with the requirements of other appropriate Federal, State, and municipal agencies. This permit is not transferable from one permittee to another without prior written approval, from one location to another, or from one piece of equipment to another. The permit must be made available at the site of operation throughout the period that such permit is in effect.

Pursuant to Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA), NTE Connecticut, LLC must apply for a permit modification/revision in writing if it plans any physical change, change in method of operation, or addition to this source which constitutes a modification or revision pursuant to RCSA sections 22a-174-1 and 22a-174-2a, respectively. Any such changes should first be discussed with Mr. James Grillo of the Bureau of Air Management, by calling (860) 424-4152. Such changes shall not commence prior to the issuance of a permit modification.

Sincerely,

Jaimeson Sinclair
Assistant Director, Engineering
Bureau of Air Management

JS:JAG:jad
cc (via electronic mail): Keith Hill, Air Enforcement
S. Babcock, Tetra Tech, Inc.

Enclosure

Connecticut Department of

ENERGY &
ENVIRONMENTAL
PROTECTION

BUREAU OF AIR MANAGEMENT
NEW SOURCE REVIEW PERMIT
TO CONSTRUCT AND OPERATE A STATIONARY SOURCE

Issued pursuant to Title 22a of the Connecticut General Statutes (CGS) and Section 22a-174-3a of the Regulations of Connecticut State Agencies (RCSA).

Owner/Operator	NTE Connecticut, LLC
Address	24 Cathedral Place, Suite 300, Saint Augustine, FL 32084
Equipment Location	180/189 Lake Road, Killingly, CT 06241
Equipment Description	Mitsubishi M501JAC Combustion Turbine with DLN combustors, Duct Burners and Heat Recovery Steam Generator
Collateral Conditions	This permit contains collateral conditions for one 84 MMBtu/hr natural gas fired boiler, one 305 bhp emergency fire pump engine, one 7 MMBtu/hr natural gas heater, and one 1,380 kW emergency generator engine (Permit No. 089-0108)
Town-Permit Numbers	089-0107
Premises Number	101
Stack Number	1
Modification Issue Date	DEC 10 2018
Prior Permit Issue Dates	March 16, 2018 (Minor Modification) June 30, 2017 (Initial Permit)
Expiration Date	None

for [signature]
Robert E. Kaliszewski
Deputy Commissioner

12/10/18
Date

ORIGINAL

This permit specifies necessary terms and conditions for the operation of this equipment to comply with state and federal air quality standards. The Permittee shall at all times comply with the terms and conditions stated herein.

PART I. DESIGN SPECIFICATIONS

A. General Description

NTE Connecticut, LLC operates a power generation facility consisting of one Mitsubishi M501JAC combustion turbine with dry low-NOx (DLN) combustors with a nominal gross electrical output of 647 MW in Killingly, CT. The turbine is a dual fuel fired combined cycle unit, with a separate heat recovery steam generator (HRSG) that includes natural gas supplementary firing (duct burners) to power a single steam turbine generator. Oil firing for the turbine is limited to ultra-low sulfur distillate (ULSD) No. 2 fuel oil as allowed in Part II.A.1.d of this permit. Pollution control equipment will include selective catalytic reduction (SCR), oxidation catalyst, and water injection (ULSD firing only) to control NOx, CO and VOC emissions. The turbine, duct burner, and HRSG are considered the combustion turbine generator (CTG) and designated as Emissions Unit 1 (EU-1) for this permit.

There is one 1,380 kW ULSD fired emergency generator engine that operates under permit number 089-0108.

The ancillary equipment that do not require permits includes: one 84 MMBtu/hr natural gas fired auxiliary boiler with flue-gas-recirculation (FGR) to control NOx emissions; one 305 bhp emergency ULSD fired fire pump engine, and one 7 MMBtu/hr natural gas heater. The boiler and gas heater will be able to operate for approximately 4,600 and 4,000, hours respectively, per year at maximum rated capacity with the allowable fuel limits. The emergency generator engine and emergency fire pump engine can only fire ULSD and are each limited to 300 hr/yr and not more than 500 hr/yr combined. Collateral conditions for this equipment are included in Part VI of this permit.

The CTG will also be fed by a ULSD oil tank with a capacity of one million gallons. The emergency engines will have self-contained oil tanks. There will be a 12,000 gallon storage tank for the 19% aqueous ammonia (NH_3) used in the NOx control system.

B. Equipment Design Specifications

1. Turbine
   The design gross heat input is 3,863 MMBtu/hr while firing natural gas and 3,256 MMBtu/hr while firing ULSD. These heat inputs are based on an ambient temperature of 59^{0}F and result in firing rates of 3,757,455 scf of natural gas (HHV 1028 Btu/scf) and 23,594 gallons of ULSD (HHV 138,000 Btu/gal) per hour. Heat input will vary by approximately $\pm$10% over the typical range of expected ambient temperatures, with higher heat input occurring at lower ambient temperatures.

2. Duct Burner
   The design gross heat input to the duct burner is 1,106 MMBtu/hr while firing natural gas. The heat input is based on an assumed HHV of 1028 Btu/scf and results in a firing rate of 1,075,875 scf/hr.

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C. Stack Parameters

1. Minimum Stack Height (ft): 150 (above base elevation)

2. Minimum Exhaust Gas Flow Rate at maximum operating load, CTG only (acfm): 1,721,122 (gas); 1,772,183 (ULSD)

3. Minimum Stack Exit Temperature at 100% load (°F): 175

4. Minimum Distance from Stack to Property Line (ft): 425

D. Definitions

1. "Steady-State" operation shall be defined as all periods other than transient operation.

2. "Transient" operation shall be all modes of operation at Loads less than 50%, including periods of startup, shutdown, fuel switching and equipment cleaning.

3. "Load" shall be defined as the net electrical output of the CTG.

4. "Shakedown" shall be defined as CTG operations including, but not limited to, the first firing of the unit, proof of interlocks, steam blowing, chemical cleaning, initial turbine roll and ending after the equipment vendor service representative conducts operational and contractual testing and tuning of the turbine to meet warranted emission rates on site. The Shakedown period shall not extend beyond the required date for the initial performance test.

5. "Btu" shall be defined as British Thermal Units and "MMBtu" as one million Btu, both on a higher heating value (HHV) basis.

PART II. OPERATIONAL CONDITIONS and REQUIREMENTS

A. Equipment

1. CTG
   a. Allowable Fuel Types: Natural Gas (primary); Ultra-Low Sulfur Distillate (ULSD)
   b. Maximum Heat Input over any Consecutive 12 Month Period: 3.38×10^7 MMBtu (gas); 2.34×10^6 MMBtu (ULSD)
   c. Maximum ULSD Sulfur Content (% by weight, dry basis): 0.0015
   d. Firing of ULSD is allowed only in the following scenarios:
      i. ISO-NE declares an Energy Emergency as defined in ISO New England's Operating Procedure No. 21 and requests the firing of ULSD;
      ii. ISO-NE required audits of capacity;
      iii. The natural gas supply is curtailed by an entity through which gas supply and/or transportation is contracted;
      iv. Any equipment (whether on- or off-site) required to allow the CTG to operate on natural gas has failed, including a physical blockage of the supply pipeline. In the event of failure of onsite equipment, the Permittee shall document that this equipment has been maintained in accordance with manufacturer's recommendations and that the failed equipment was repaired or replaced and the CTG was returned to natural gas firing as soon as practicable;
      v. During the Shakedown period when the CTG is required to operate on ULSD pursuant to the manufacturer's written instructions;

vi. For emission testing purposes, as specified in the Part V of this permit or as required by DEEP, USEPA or other regulatory order requiring emissions testing during ULSD firing; or

vii. During routine maintenance and readiness testing, if any equipment requires ULSD operation.

e. The Permittee shall not operate the duct burner while firing ULSD in the CTG.

f. No period of Transient operation shall exceed 60 consecutive minutes.

2. Duct Burner

a. Allowable Fuel: Natural Gas

b. Maximum Heat Input over any Consecutive 12 Month Period: 2.85×10^6 MMBtu

3. The Permittee shall comply with all applicable sections of the following New Source Performance Standards at all times.

Title 40 CFR Part 60 Subparts KKKK, TTTT and A

Copies of the Code of Federal Regulations (CFR) are available online at the U.S. Government Printing Office website.

B. The Permittee shall operate this equipment, including the SCR, oxidation catalyst, and water injection in a manner to comply with the emissions limits in Part III of this permit.

C. The Permittee shall operate and maintain this equipment, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup and shutdown.

D. The Permittee shall operate and maintain this equipment in accordance with the manufacturer's specifications and written recommendations.

E. The Permittee shall minimize emissions during periods of startup and shutdown to the extent practicable, and during startup shall start the ammonia injection as soon as the SCR vendor's recommended minimum catalyst temperature is reached. The Permittee shall incorporate the SCR vendor's recommended minimum catalyst temperature into this permit by modification pursuant to RCSA Section 22a-174-2a, and shall submit an application for such modification prior to or concurrently with submittal of the Permittee's application for an operating permit pursuant to RCSA Section 22a-174-33.

F. The Permittee shall not operate the auxiliary boiler (EU-2) simultaneously with the CTG for more than 500 hours in any calendar year.

G. The Permittee shall not exceed a maximum allowable heat rate at full operating load while firing natural gas, without duct firing, of 7,273 Btu/kW-hr, 12 month rolling average (HHV, net plant).

H. The Permittee shall immediately institute shutdown of the CTG in the event where emissions are in excess of a limit in Part III.A of this permit that cannot be corrected within three hours of when the emissions exceedance was identified.

I. The Permittee shall not operate CTG during startup and shutdown events for more than 500 hours per calendar year.

PART III. CTG ALLOWABLE EMISSION LIMITS

A. Steady State

Except during the Shakedown period, the Permittee shall not cause or allow this equipment to exceed these emission limits stated herein at any time during Steady-State operation.

1. CTG Operating on Natural Gas without Duct Firing

Pollutant	lb/hr	ppmvd @ 15% O_2	lb/MMBtu
PM	7.9		0.0022
$PM_{10/2.5}$	7.9		0.0022
SO_2	6.0		0.0015
NOx	29.6	2.0	
VOC	3.6	0.7	
CO	8.1	0.9	
Lead	1.9E-03		4.9E-07
H_2SO_4	2.1		0.00053
Ammonia		2.0	

2. CTG Operating on Natural Gas with Duct Firing

Pollutant	lb/hr	ppmvd @ 15% O_2	lb/MMBtu
PM	21.9		0.0046
$PM_{10/2.5}$	21.9		0.0046
SO_2	7.6		0.0015
NOx	37.2	2.0	
VOC	10.4	1.6	
CO	19.2	1.7	
Lead	2.3E-03		4.9E-07
H_2SO_4	2.7		0.00052
Ammonia		2.0	

3. CTG Operating on ULSD

Pollutant	lb/hr	ppmvd @ 15% O_2	lb/MMBtu
PM	26.7		0.0083
$PM_{10/2.5}$	26.7		0.0083
SO_2	4.9		0.0015
NOx	50.6	4.0	
VOC	8.9	2.0	
CO	14.1	1.8	
Lead	3.2E-03		1.05E-06
H_2SO_4	1.8		0.00054
Ammonia		5.0	

B. Transient Emissions

1. Except during the Shakedown period, the Permittee shall not cause or allow this equipment to exceed these emission limits during startup and shutdown events on a 1-hour block hour average beginning with the first minute of each clock hour consistent with the CEMS monitoring in Part IV.A.1 of this permit. No startup or shutdown event shall last longer than 60 consecutive minutes.

	Type of Event			
	Startup		Shutdown	
	Natural Gas	ULSD	Natural Gas	ULSD
NO_x (lb/hr)	59	178	77	148
VOC (lb/hr)	92	622	115	167
CO (lb/hr)	385	1,004	139	171

2. Ammonia (NH_3) emissions shall not exceed 5.0ppmvd @ 15% O_2 (both fuels) during Transient operation.

C. Total Allowable Annual Emission Limits

The Permittee shall not cause or allow this equipment to exceed these emission limits stated herein at any time.

Pollutant	tons per 12 consecutive months
PM	54.9
$PM_{10/2.5}$	54.9
SO_2	25.1
NOx	130.1
VOC	45.5
CO	77.8
Pb	0.009
H_2SO_4	9.62
CO_2e	2,207,451
NH_3	54.6

D. Greenhouse Gas Emissions

The Permittee shall not exceed an annual CO_2e emissions limit of 2,232,604 tons/yr for combustion sources identified as EU-1, EU-2, EU-4, and EU-5 in this permit, along with permit number 089-0108, including SF_6 containing insulated electrical equipment. Compliance with this limitation shall be determined on a consecutive 12 month rolling basis.

E. Hazardous Air Pollutants (HAP)

This equipment shall not cause an exceedance of the Maximum Allowable Stack Concentration (MASC) for any hazardous air pollutant (HAP) emitted and listed in RCSA Section 22a-174-29. [STATE ONLY REQUIREMENT]

F. Opacity

This equipment shall not exceed 10% opacity during any six minute block average as measured by

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40 CFR Part 60, Appendix A, Reference Method 9.

G. Demonstration of compliance with the above emission limits may be met by calculating emissions based on emission factors from the following sources:

1. $PM/PM_{10}/PM_{2.5}$, VOC, Formaldehyde, H_2SO_4: Most recent Stack test data.

2. SO_2: Sulfur content in fuel.

3. NOx & CO (Steady-State): CEM data.

4. NOx, VOC, & CO (Transient): Manufacturer's uncontrolled emission factors.

5. HAP: AP-42, Fifth Edition, Volume I Chapter 3.1, April 2000, except for those HAP with required stack test found in Part V of this permit.

6. GHG (CO_2e) Emissions:
   a. CO_2 emissions from the combustion CTG shall be determined by the methodology found in 40 CFR Part 75, Appendix G, Equation G-4.
   b. CO_2 emissions from the auxiliary boiler (EU-2), the emergency fire pump engine (EU-4), and the natural gas heater (EU-5) shall be determined using the default emissions factors found in 40 CFR Part 98, Subpart C, Table C-1.
   c. Methane (CH_4) and nitrous oxide (N_2O) for all combustion sources shall be determined using the default emissions factors found in 40 CFR Part 98 Subpart C, Table C-2.
   d. Estimated fugitive emissions of sulfur hexafluoride (SF_6) from the electrical circuit breakers shall be determined using mass balance.
   e. Estimated fugitive emissions of CH_4 from the natural gas pipeline and associated components shall be determined using default emissions factors found in 40 CFR Part 98 Subpart W, Table W-7.

H. Emissions prior to the completion of the Shakedown period shall be counted towards the annual emission limits stated herein.

I. The commissioner may require other means (e.g. stack testing) to demonstrate compliance with the above emission limits, as allowed by state or federal statute, law or regulation.

PART IV. MONITORING, RECORD KEEPING AND REPORTING REQUIREMENTS

A. Monitoring

1. The Permittee shall comply with the CEM requirements as set forth in RCSA Section 22a-174-4, the applicable sections of RCSA Sections 22a-174-22, 22a-174-22e and 22a-174-31; 40 CFR Part 60 Subparts KKKK and TTTT, *and* 40 CFR Parts 72-78, as applicable. Continuous Emissions Monitoring (CEM) is required for the following and enforced on the following basis:

Pollutant	Averaging Times	Emission Limit (ppmvd @15% O_2)
Opacity (ULSD only)	six minute block	10%
NOx	1 hour block	See Part III.A
CO	1 hour block	See Part III.A
NH_3	1 hour block	See Part III.A

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2. The Permittee shall continuously monitor the following parameters:

Operational Parameter	Averaging Times
O_2	1 hour block
Fuel Flow	1 hour block
Net Electrical Output	Continuous

3. At least 60 days prior to the initial stack test specified in Part V.B, the Permittee shall submit a CEM monitoring plan to the commissioner in accordance with RCSA Section 22a-174-4(c)(3).

4. The Permittee shall use fuel flow meters, certified in accordance with 40 CFR Part 75, Appendix D to measure and record the flow rate of fuels to the CTG.

5. The Permittee shall perform inspections and maintenance of the SCR and oxidation catalysts as recommended by the manufacturer.

6. Prior to operation, the Permittee shall develop a written plan for the operation, inspection, maintenance, preventive and corrective measures for minimizing fugitive GHG emissions (CH_4 emissions from the natural gas pipeline components and SF_6 emissions from the insulated electrical equipment). At a minimum the plan shall provide for:
   a. Implementation of daily auditory/visual/olfactory inspections of the natural gas piping components supplying natural gas to the CTG;
   b. An installed leak detection system to include audible alarms to identify SF_6 leakage from the circuit breakers; and
   c. Inspection for SF_6 emissions from the insulated electrical equipment on at least a monthly basis.

B. Record Keeping

1. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption for the CTG (for each fuel). The consecutive 12 month fuel consumption shall be determined by adding (for each fuel) the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.

2. The Permittee shall keep records of the monthly and consecutive 12 month heat input for the CTG (for each fuel). The consecutive 12 month heat input shall be determined by adding (for each fuel) the current month's heat input to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month. The records shall include sample calculations.

3. The Permittee shall keep records of the fuel certification for each delivery of ULSD from a bulk petroleum provider or a copy of the current contract with the fuel supplier supplying the ULSD used by the equipment that includes the applicable sulfur content of the ULSD as a condition of each shipment. The shipping receipt or contract shall include the date of delivery, the name of the ULSD supplier, type of fuel delivered, the percentage of sulfur in the ULSD, by weight, dry basis, and the method used to determine the sulfur content of such fuel.

4. The Permittee shall calculate and record the monthly and consecutive 12 month PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO,H_2SO_4, NH_3, and CO_2e emissions in units of tons for the CTG.

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The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.

Emissions during startup and shutdown shall be included in the monthly and consecutive 12 month calculations.

5. The Permittee shall keep records of the emissions of this CTG during the Shakedown period. Emissions during Shakedown shall be calculated using good engineering judgment and the best data and methodology available for estimating such emissions. Emissions during Shakedown shall be counted towards the annual emission limitation in Part III.C of this permit.

6. The Permittee shall keep records of the occurrence and duration of all Transient operation of the unit; any malfunction of the air pollution control equipment that causes an exceedance of any emission limitation found in Part III of this permit; or any periods during which a continuous monitoring system or monitoring device is inoperative.

   Such records shall contain the following information:
   a. type of event and percent Load;
   b. equipment affected;
   c. date of event;
   d. duration of event (minutes);
   e. fuel being used during event; and
   f. total NO_x, CO and VOC emissions emitted (lb) during the event.

7. The Permittee shall keep records of each delivery of aqueous ammonia. The records shall include:
   a. the date of delivery;
   b. the name of the supplier;
   c. the quantity of aqueous ammonia delivered; and
   d. the percentage of ammonia in solution, by weight.

8. The Permittee shall keep records of the inspection and maintenance of the SCR and oxidation catalysts. The records shall include:
   a. the name of the person conducting the inspection/maintenance;
   b. the date of the inspection/maintenance;
   c. the results or actions taken; and
   d. the date the catalyst is replaced.

9. The Permittee shall keep records of all repairs/replacement of parts and other maintenance activities for the equipment.

10. The Permittee shall keep records of the electrical output to the ISO-NE transmissions system and the heat rate for the turbine while firing natural gas (HHV, net) without duct firing, on a 12month rolling average for the plant.

11. The Permittee shall keep records of the inspection, maintenance, preventive and corrective measures for minimizing GHG emissions from the natural gas pipeline components and the SF_6containing insulated electrical equipment. The records shall include:
    a. the name of the person conducting the inspection/maintenance;
    b. the date the inspection/maintenance;
    c. the results or actions taken;
    d. the leak detection methods used;

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e. the amount of SF_6 added (if any) to the electrical equipment;
f. the monthly records of the audible alarms from the SF_6 leak detection system; and
g. All monitoring, record keeping and reporting pursuant to the relevant provisions of 40 CFR Part 98 Subpart DD, as applicable.

12. The Permittee shall make and keep records of all occurrences of firing ULSD in the CTG. At a minimum these records shall contain the following information:
    a. the duration of ULSD firing,
    b. the reason for ULSD firing, and
    c. the heat input to the CTG while firing ULSD.

13. The Permittee shall keep a signed copy of this permit on the premises at all times, and shall make this copy available upon request of the commissioner for the duration of this permit. This copy shall also be available for public inspection during regular business hours.

14. The Permittee shall keep a copy of all notifications submitted as required by Part IV.C of this permit.

15. The Permittee shall keep records of the manufacturer written recommendations for operation and maintenance of the equipment found in this permit.

16. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

C. Reporting

1. The Permittee shall notify the commissioner in writing of all exceedances of an emissions limitation, and shall identify the cause or likely cause of such exceedance, all corrective actions and preventive measures taken with respect thereto, and the dates of such actions and measures as follows:
    a. For any hazardous air pollutant, no later than 24 hours after such exceedance was identified; and
    b. For any other regulated air pollutant, no later than ten days after such exceedance commenced.

2. The Permittee shall notify the commissioner, in writing, of the dates of commencement of construction, completion of construction, and initial startup, and the date of completion of initial shakedown period of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART V. STACK EMISSION TEST REQUIREMENTS

A. Stack emission testing shall be performed in accordance with the RCSA Section 22a-174-5 and the Emission Test Guidelines available on the DEEP website.

B. For the purposes of determining maximum heat input of the turbine during stack testing, the following equation may be used to determine the MHI between temperatures provided in Table 1

$$\mathbf{MHI_T = Q_1 - [[(T - T_1)/(T_2 - T_1)] \times (Q_1 - Q_2)]}$$

Where,

MHI_T = Turbine maximum heat input at ambient temperature (^0F)
T = Ambient Temperature

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T_1 = Temperature Value from Table 1 that is immediately below the ambient temperature
T_2 = Temperature Value from Table 1 that is immediately above the ambient temperature
Q_1 = Heat Input at corresponding T_1 for corresponding fuel type
Q_2 = Heat Input at corresponding T_2 for corresponding fuel type

Table 1

Ambient Temperature (T)^{0}F	Gas Firing Heat Input (Q)	ULSD Heat Input (Q)
-10	3,617	3,256
0	3,862	3,256
20	4,016	3,256
30	3,961	3,256
50	3,885	3,256
59	3,863	3,256
65	3,878	3,236
90	3,828	3,106
100	3,794	3,022

C. The duct burner shall be required to meet a minimum heat input value of 885 MMBtu/hr for all ambient temperatures during initial and recurring stack testing.

D. The Permittee shall perform one set of tests on this CTG when burning natural gas with the duct burner and one set without duct firing. The Permittee shall perform one set of tests with the CTG burning ULSD.

E. Initial Performance Testing

1. Initial stack emission testing for the CTG is required for the following pollutant(s):

   ☒ $PM_{10/2.5}$(includes filterable and condensable) ☒ SO_2 ☒ NOx ☒ CO
   ☒ CO_2 ☒ VOC ☒ Opacity
   ☒ Other (HAPs): Sulfuric Acid, Formaldehyde (gas firing only)

2. Compliance with the VOC emission limits shall be determined by correlating the VOC emissions with a monitored parameter or pollutant during the initial stack testing for this unit. The Permittee shall submit a modification to this permit within 60 days of such testing to incorporate the monitoring methodology to be used for VOC emission compliance.

3. Stack emissions testing for the CTG firing natural gas, without duct firing, for CO_2 shall be required to show compliance with an emissions limit of 816 lb/MW-hr (net), corrected to ISO conditions, as defined in the approved stack test protocol.

4. Performance testing shall be required to show compliance with the heat rate found in Part II.G of this permit.

5. Initial stack testing for the auxiliary boiler in Part VI.A of this permit is required for the following pollutants:

   ☒ NOx ☒ CO ☒ VOC

6. The Permittee shall conduct initial stack testing no later than 180 days after initial startup. The Permittee shall submit test results within 60 days after completion of testing.

F. Recurrent Performance Testing

1. Recurrent stack testing for the CTG shall be performed within five years from the date of the previous stack test for the following pollutants:

   ☒ $PM_{10/2.5}$(includes filterable and condensable) ☒SO_2 ☒ NOx ☒ CO
   ☒ VOC ☒ Opacity ☒ Other (HAPs): Sulfuric Acid, Formaldehyde (gas firing only)

   After the initial stack test, stack testing may not be required for pollutants using CEM. The commissioner retains the right to require stack testing of any pollutant at any time.

2. Recurrent performance testing shall be required within five years from the date of the previous test to show compliance with the heat rate found in Part II.G of this permit.

3. Recurrent stack testing for the auxiliary boiler in Part VI.A of this permit shall be performed within five years from the date of the previous stack test for the following pollutants:

   ☒ NOx ☒ CO ☒ VOC

4. Recurrent testing shall be required at least once every five years from the date of the last test, unless otherwise noted, but no less than 9 calendar months or no more than 15 calendar months from the required test date.

G. Stack emission test results shall be reported in the applicable units for each pollutant found in Part III.A of this permit.

PART VI. COLLATERAL CONDITIONS FOR AUXILIARY COMBUSTION SOURCES (EU-2 through EU-5)

A. EU-2: 84 MMBtu/hr Natural Gas Fired Boiler with FGR

1. Operational Conditions
   a. Make and Model: TBD
   b. Allowable Fuel: Natural Gas
   c. Minimum Stack Height (ft): 90
   d. Maximum Allowable Fuel Use over any consecutive 12 month period: 375,875,500 ft^3
   e. This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR Part 60, Appendix A, Reference Method 9.
   f. The Permittee shall comply with all applicable sections of the following New Source Performance Standards.

      Title 40 CFR Part 60 Subparts Dc and A;

      Copies of the Code of Federal Regulations (CFR) are available online at the U.S. Government Printing Office website.

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2. Allowable Emissions

Pollutant	lb/MMBtu	ppmvd @ 3% O_2	tons per 12 consecutive months
$PM_{2.5}$	0.005		0.97
PM_{10}	0.005		0.97
NOx	0.0085	7.0	1.64
SO_2	0.0015		0.29
VOC	0.0041		0.78
CO	0.037	50	7.14
Lead	4.9E-07		9.5E-05
H_2SO_4	1.1E-04		0.02
CO_2e	116.98		22,610

Demonstration of compliance with the above emission limits may be met by using emission factors from the following sources:

- SO_2 and H_2SO_4: Calculated from fuel sulfur content
- NOx, VOC, CO, Opacity: Most Recent Stack Test Data
- $PM_{10/2.5}$: Vendor Emissions Guarantee
- CO_2e: 40 CFR Part 98Subpart C, Tables C-1 and C-2
- Lead: AP-42, Fifth Edition, Volume I Chapter 1.4, July 1998

3. Monitoring
   a. The Permittee shall continuously monitor fuel consumption by this unit using a non-resettable totalizing fuel meter or a billing meter.
   b. The Permittee shall perform inspections of the burners and flue gas recirculation (FGR) system as recommended by the manufacturer.

4. Record Keeping
   a. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.
   b. The Permittee shall calculate and record the monthly and consecutive 12 month PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO, and CO_2e emissions in units of tons. The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.
   c. The Permittee shall make and keep records of all maintenance and tune-up activities for this unit.
   d. The Permittee shall make and keep records of all inspections of the burners and FGR system.
   e. The Permittee shall make and keep records of all hours of simultaneous operation of this unit with the CTG. The Permittee shall total these hours for each month and for the calendar year. The Permittee shall make these calculations within 30 days of the end of the previous month.
   f. The Permittee shall make and keep records of manufacturer written specifications and recommendations for operation and maintenance.
   g. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

5. Reporting
   a. The Permittee shall comply with the record keeping and reporting requirements in 40 CFR §60.49b.
   b. The Permittee shall notify the commissioner, in writing, of the date of commencement of construction and the date of initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

6. Stack emission test requirements
   Stack emission testing shall be conducted as required in Part V of this perm

B. EU-4: 305 bhp Emergency Fire Pump

1. Operational Conditions
   a. Make and Model: Clarke JU6H-UFADX8
   b. Allowable Fuel: ULSD
   c. Minimum Stack Height (ft): 20
   d. Maximum ULSD Sulfur Content (% by weight, dry basis): 0.0015
   e. Maximum Allowable Fuel Use over any consecutive 12 month period: 4,380 gallons
   f. This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR Part 60, Appendix A, Reference Method 9.
   g. The Permittee shall not operate this emergency engine and the emergency engine operating under permit number 089-0108 individually for more than 300 hours per calendar year or more than 500 hours per calendar year in combination per calendar year.
   h. The Permittee shall comply with all applicable sections of the following New Source Performance Standards at all times.

      Title 40 CFR Part 60 Subparts: IIII and A

      Copies of the Code of Federal Regulations (CFR) are available online at the U.S. Government Printing Office website.

2. Allowable Emissions

Pollutant	lb/MMBtu	g/bhp-hr	Tons per 12 consecutive months
$PM_{2.5}$	0.05	0.15	0.015
PM_{10}	0.05	0.15	0.015
NOx		3.0	0.30
SO_2	0.0015		5E-04
VOC		0.15	0.02
CO		2.6	0.26
H_2SO_4	1.1E-04		3.0E-05
CO_2e	163.1		49

Demonstration of compliance with the above emission limits may be met by calculating the using emission factors from the following sources:

- SO_2 and H_2SO_4: Calculated from fuel sulfur content
- NOx, $PM_{10/2.5}$, VOC, CO: Vendor Emissions Guarantee
- CO_2e: 40 CFR Part 98 Subpart C, Tables C-1 and C-2

3. Monitoring
   a. The Permittee shall continuously monitor fuel consumption by this unit using a non-resettable totalizing fuel meter.
   b. The Permittee shall monitor all hours that this unit is in operation.

4. Record Keeping
   a. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.
   b. The Permittee shall keep records of the fuel certification for each delivery of fuel oil from a bulk petroleum provider or a copy of the current contract with the fuel supplier supplying the fuel used by the equipment that includes the applicable sulfur content of the fuel as a condition of each shipment. The shipping receipt or contract shall include the date of delivery, the name of the fuel supplier, type of fuel delivered, the percentage of sulfur in such fuel, by weight, dry basis, and the method used to determine the sulfur content of such fuel.
   c. The Permittee shall calculate and record the monthly and consecutive 12 month PM_{10},$PM_{2.5}$, SO_2, NOx, VOC, CO H_2SO_4, and CO_2e emissions in units of tons. The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.
   d. The Permittee shall keep records of the monthly and calendar year hours of operation for this unit.

      Such records shall contain the following information:
      i. reason for operating;
      ii. date of event;
      iii. duration of event (minutes);
      iv. gallons of fuel combusted;
      v. for any testing or scheduled maintenance operation, the ozone level as forecasted for the day;
      vi. total engine hours of operation and total combined engine hours of operation with the emergency generator engine (EU-3, Permit Number 089-0108).
   e. The Permittee shall keep records of the inspection and maintenance for this engine. The records shall include:
      i. the name of the person conducting the inspection or maintenance;
      ii. the date of the inspection or maintenance;
      iii. the results or actions taken.
   f. The Permittee shall keep records of the manufacturer's specifications and written recommendations.
   g. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

5. Reporting
   a. The Permittee shall comply with the reporting requirements in 40 CFR §60.4214.
   b. The Permittee shall notify the commissioner, in writing, of the date of commencement of construction and the date of initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

C. EU-5: 7 MMBtu/hr Natural Gas Heater

1. Operational Conditions
   a. Make and Model: TERi or equivalent
   b. Allowable Fuel: Natural Gas
   c. Minimum Stack Height (ft): 20
   d. Maximum Allowable Fuel Use over any consecutive 12 month period: 24,237,354 ft^3
   e. This equipment shall not exceed 10% opacity during any six minute block average as measured by 40 CFR Part 60, Appendix A, Reference Method 9.

2. Allowable Emissions

Pollutant	lb/MMBtu	Tons/yr
$PM_{2.5}$	0.005	0.07
PM_{10}	0.005	0.07
NOx	0.012	0.17
SO_2	0.0015	0.021
VOC	0.0034	0.05
CO	0.037	0.52
H_2SO_4	1.1E-04	0.002
CO_2	116.9	1,637

Demonstration of compliance with the above emission limits may be met by using emission factors from the following sources:

- SO_2 and H_2SO_4: Calculated from fuel sulfur content
- NOx, $PM_{10/2.5}$, VOC, CO: Vendor Emissions Guarantee
- CO_2e: 40 CFR Part 98 Subpart C, Tables C-1 and C-2

3. Monitoring
   The Permittee shall continuously monitor fuel consumption by this unit using a non-resettable totalizing fuel meter.

4. Record Keeping
   a. The Permittee shall keep records of monthly and consecutive 12 month fuel consumption. The consecutive 12 month fuel consumption shall be determined by adding the current month's fuel consumption to that of the previous 11 months. The Permittee shall make these calculations within 30 days of the end of the previous month.
   b. The Permittee shall calculate and record the monthly and consecutive 12 month PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO, and CO_2e emissions in units of tons. The consecutive 12 month emissions shall be determined by adding (for each pollutant) the current month's emissions to that of the previous 11 months. Such records shall include a sample calculation for each pollutant. The Permittee shall make these calculations within 30 days of the end of the previous month.
   c. The Permittee shall make and keep records of all maintenance and tune-up activities for this unit.
   d. The Permittee shall make and keep records of all inspections of the burner system.
   e. The Permittee shall make and keep records of manufacturer written specifications and recommendations for operation and maintenance.
   f. The Permittee shall keep all records required by this permit for a period of no less than five years and shall submit such records to the commissioner upon request.

5. Reporting
The Permittee shall notify the commissioner, in writing, of the date of commencement of construction and the date of initial startup of this equipment. Such written notifications shall be submitted no later than 30 days after the subject event.

PART VII. SPECIAL REQUIREMENTS

A. The Permittee shall possess, at least, 163 tons of external emissions reductions to offset the quantity of NO_x emitted from the following sources to comply with RCSA Section 22a-174-3a(l):

- EU-1: Mitsubishi M501JAC Combustion Turbine, Permit Number 089-0107
- EU-2: 84 MMBtu/hr natural gas fired auxiliary boiler, Permit Number 089-0107
- EU-3: 1,380 kW emergency generator engine, Permit Number 089-0108
- EU-4: 305 bhp emergency fire pump engine, Permit Number 089-0107
- EU-5: 7 MMBtu/hr natural gas fired heater, Permit Number 089-107

Such a quantity is sufficient to offset the emissions from the sources listed above at a ratio of 1.2 to 1 for every ton of NOx emissions allowed under this permit. Specifically, the reductions are real, quantifiable, surplus, permanent, and enforceable as defined in RCSA Section 22a-174-3a(l)(5). The Permittee shall maintain sole ownership and possession of these emissions reductions for the duration of this permit and any subsequent changes to the permit.

Such offsets have been obtained from the following sources:

- 112.64 tons from Glenwood Combustion Turbine Facility: (NY-DEC-1-2822-00481-112.64)
- 50.36 tons from National Grid Far Rockaway Power Station: (NY-DEC-2-6308-00040-50.36)

The offsets were approved by the Department on June 14, 2017. The Permittee shall maintain sole ownership and possession of these emissions reductions for the duration of this permit and any subsequent changes to the permit.

The Permittee may be required to obtain additional NOx offsets and complete additional ambient air quality analysis to show that the NAAQS and PSD increments have not been violated, if observed Steady-State or Transient emissions exceed limits specified in Parts III.A, III.B or III.C of this permit.

The commissioner may require other methods for determining NOx emissions from these sources as allowed by state or federal statute, law or regulation.

B. Upon completion of construction of the CTG and control equipment, the Permittee shall prepare and submit a written standby plan in accordance with the RCSA Sections 22a-174-6(d)(2) through (d)(5).

C. The Permittee shall operate this facility at all times in a manner so as not to violate or contribute significantly to the violation of any applicable state noise control regulations, as set forth in RCSA Sections 22a-69-1 through 22a-69-7.4. [STATE ONLY REQUIREMENT]

D. The Permittee shall resubmit for review and approval a Best Available Control Technology (BACT) analysis if such construction or phased construction has not commenced within the 18 months following the commissioner's approval of the current BACT determination (i.e., the issue date of this permit) for such construction or phase of construction. [RCSA Section 22a-174-3a(j)(4)]

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PART VIII. ADDITIONAL TERMS AND CONDITIONS

A. This permit does not relieve the Permittee of the responsibility to conduct, maintain and operate the regulated activity in compliance with all applicable requirements of any federal, municipal or other state agency. Nothing in this permit shall relieve the Permittee of other obligations under applicable federal, state and local law.

B. Any representative of the DEEP may enter the Permittee's site in accordance with constitutional limitations at all reasonable times without prior notice, for the purposes of inspecting, monitoring and enforcing the terms and conditions of this permit and applicable state law.

C. This permit may be revoked, suspended, modified or transferred in accordance with applicable law.

D. This permit is subject to and in no way derogates from any present or future property rights or other rights or powers of the State of Connecticut and conveys no property rights in real estate or material, nor any exclusive privileges, and is further subject to any and all public and private rights and to any federal, state or local laws or regulations pertinent to the facility or regulated activity affected thereby. This permit shall neither create nor affect any rights of persons or municipalities who are not parties to this permit.

E. Any document, including any notice, which is required to be submitted to the commissioner under this permit shall be signed by a duly authorized representative of the Permittee and by the person who is responsible for actually preparing such document, each of whom shall certify in writing as follows: "I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of those individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief. I understand that any false statement made in the submitted information may be punishable as a criminal offense under section 22a-175 of the Connecticut General Statutes, under section 53a-157b of the Connecticut General Statutes, and in accordance with any applicable statute."

F. Nothing in this permit shall affect the commissioner's authority to institute any proceeding or take any other action to prevent or abate violations of law, prevent or abate pollution, recover costs and natural resource damages, and to impose penalties for violations of law, including but not limited to violations of this or any other permit issued to the Permittee by the commissioner.

G. Within 15 days of the date the Permittee becomes aware of a change in any information submitted to the commissioner under this permit, or that any such information was inaccurate or misleading or that any relevant information was omitted, the Permittee shall submit the correct or omitted information to the commissioner.

H. The date of submission to the commissioner of any document required by this permit shall be the date such document is received by the commissioner. The date of any notice by the commissioner under this permit, including but not limited to notice of approval or disapproval of any document or other action, shall be the date such notice is personally delivered or the date three days after it is mailed by the commissioner, whichever is earlier. Except as otherwise specified in this permit, the word "day" means calendar day. Any document or action which is required by this permit to be submitted or performed by a date which falls on a Saturday, Sunday or legal holiday shall be submitted or performed by the next business day thereafter.

I. Any document required to be submitted to the commissioner under this permit shall, unless otherwise specified in writing by the commissioner, be directed to: Office of Director; Engineering & Enforcement Division; Bureau of Air Management; Department of Energy and Environmental Protection; 79 Elm Street, 5th Floor; Hartford, Connecticut 06106-5127.

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Exhibit 5

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

MEMORANDUM

DATE: November 24, 1986

SUBJECT: Need for a Short-term Best Available Control Technology (BACT) Analysis for the Proposed William A. Zimmer Power Plant

FROM: Gerald A. Emison, Director
Office of Air Quality Planning and Standards (MD-10)

TO: David Kee, Director
Air Management Division, Region V (5AR-26)

This is in response to your November 17, 1986, memorandum, in which you requested comment on Region V's belief that prevention of significant deterioration (PSD) permits must contain short-term emission limits to ensure protection of the applicable national ambient air quality standards (NAAQS) and PSD increments. I concur with your position and emphasize to you that this position reflects our current national policy. Consequently, I recommend that you continue to identify this apparent deficiency to the Ohio Environmental Protection Agency and seek correction of the draft permit for the William A. Zimmer Power Plant.

The PSD regulations clearly require that the application of BACT conform with any applicable standard of performance under 40 CFR Part 60 at a minimum. However, this should not be taken to supercede any additional limitations as needed to enable the source to demonstrate compliance with the NAAQS and PSD increments. In the case of sulfur dioxide (SO2), source compliance with the 30-day rolling average emission limit under subpart D(a) does not adequately demonstrate compliance with the short-term NAAQS and PSD increments. Consequently, enforceable limits pertaining to the performance of the flue gas desulfurization system on a short-term basis must also be established. Note, however, that the short-term limits can result from either BACT analyses or the need to protect air quality. Therefore, the short-term limit could be more stringent than the BACT limit.

I recognize that the sulfur variability issue tends to complicate the setting of short-term SO2 emission limits, but such limits must be defined nevertheless. Continuous emission monitoring data from comparable sources can be used in order to estimate worst-case short-term SO2 emissions that could occur at the plant. The modeling techniques used to determine compliance with the short-term NAAQS and increments should employ the enforceable short-term SO2 emission limits which the permitting agency establishes.

CPDD:SIB:NSRS:D.deroech:m.Whitt629-5591:rtp MD15:11/19/86 deRoeck 5-29-3

From David Kee	Control No CPDD-427
Subject and Date Request for Guidance on Short Term BACT Analysis	Date Rec'd 11-18-86
	Due Date 11-21-86

Referred (1) McCutchen	(2) DeRoeck	(3)	(4)
Date 11-18-86	11-18-86		

Reply Sent To	Date Released
Remarks Easy response -- Agree with Region 5; if disagree, see Darryl. Prepare reply for Gerald A. Emison's signature.	Acknowledged-Date ☐
	No Answer Needed ☐ (Explain in emarks)

MAIL CONTROL SCHEDULE

To: G.EMISON (EPA6200)

FROM: ARB/REG.V (EPA9553) (Posted) Mon 17-Nov-86 10:44 EST Sys 63 (39)

SUBJECT: Request for Guidance on Short-Term BACT Analysis
Request for Guidance on Short-Term BACT Analysis

David Kee, Director
Air Management Division (5AR-26)

Gerald A. Emison, Director
Office of Air Quality Planning & Standards

Region V has recently completed an evaluation of Ohio EPA's draft permit for the William A. Zimmer Power Station Plant. Compliance with all pertinent Clean Air Act requirements, including Best Available Control Technology (BACT) requirements, was evaluated. During the course of these evaluations, a potentially significant problem arose in dealing with this fossil-fueled power plant employing flue gas desulfurization (FGD). Ohio's SO2 BACT analyses and emissions limits appear to have been based solely on a 30-day rolling average, an approach consistent with Subpart D(a) provisions for fossil fuel fired steam electric generating units. Region V is concerned that no emission limits based on 3-hr or 24-hr averaging periods have been included in Ohio's draft permit. The Region believes that short-term limits are necessary to ensure protection of the NAAQS and to adequately assess and protect increment consumption.

Accordingly, Region V has expressed its concerns to Ohio about the potential need for the SO2 BACT analysis to consider the performance of FGD systems on a short-term basis (i.e., 3-hr and/or 24-hr). Region V has also indicated that such short-term limits are necessary to protect the NAAQS and PSD increments. Region V would appreciate your guidance, concurrence or comments on the BACT analysis issue. Since Region V and Ohio will be discussing the need for a short-term BACT analysis and emission limits within ten (10) days, a prompt response is important. If you have any questions regarding this matter, please contact Joseph Paisie of my staff at 886-5777.

Exhibit 6

COMMONWEALTH of VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY
PIEDMONT REGIONAL OFFICE
4949A Cox Road, Glen Allen, Virginia 23060
(804) 527-5020 Fax (804) 527-5106
www.deq.virginia.gov

Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Michael P. Murphy
Regional Director

June 17, 2016

Mr. Mark D. Mitchell
Vice President
Virginia Electric and Power Company
5000 Dominion Blvd.
Glen Allen, VA 23060

Location: Greensville County
Registration No.: 52525

Dear Mr. Mitchell:

Attached is a permit to construct and operate an electric power generation facility in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Environmental Quality (DEQ) deemed the application complete on February 10, 2016 and solicited written public comments by placing newspaper advertisements in the Emporia Independent Messenger on February 14, 2016. A public hearing was held on March 16, 2016. The required comment period, provided by 9 VAC 5-80-1775 F expired on March 31, 2016.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and/or civil charges. Please read all permit conditions carefully.

This permit approval to construct and operate shall not relieve Virginia Electric and Power Company of the responsibility to comply with all other local, state, and federal permit regulations. Please note that the combustion turbines are affected facilities under 40 CFR 60, New Source Performance Standard (NSPS), Subpart TTTT. Also, your proposed diesel emergency generator (EG-1) and diesel emergency fire water pump (FWP-1) may be affected facilities under 40 CFR 60, New Source Performance Standard (NSPS), Subpart IIII and the propane emergency generators (EG-2 and EG-3) may be affected facilities under NSPS, Subpart JJJJ. Therefore, these units may be subject to owner/operator requirements of the NSPS and 40 CFR 63, Maximum Achievable Control Technology (MACT), Subpart ZZZZ. In summary, the units could be required to comply with certain federal emission standards and operating limitations over their useful life. The DEQ advises you to review the attached NSPS and MACT to ensure compliance with applicable emission and operational limitations. As the owner/operator you are also responsible for monitoring, notification, reporting and recordkeeping requirements of the NSPS and MACT. Notifications shall be sent to both EPA, Region III and Virginia DEQ.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit, please contact the regional office at (804) 527-5020.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

KIW/AMS/52525_001_16_PSD.docx

Attachments: Permit
Source Testing Report Format

The following federal regulations can be found at **http://www.gpo.gov/fdsys/search/showcitation.action**
Code of Federal Regulations Title 40
Part 60, NSPS, Subparts Db, Dc, IIII, JJJJ, KKKK, and TTTT
Part 63, MACT, Subpart ZZZZ

cc: Chief, Office of Air Enforcement and Compliance Assistance, U.S. EPA, Region III (electronic file submission)
Inspector, Air Compliance

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

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Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

Michael P. Murphy
Regional Director

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE

This permit includes designated equipment subject to New Source Performance Standards (NSPS).

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060
Registration No.: 52525
County-Plant ID: 081-00061

is authorized to construct and operate

an electric power generation facility

located at

2500 Rogers Rd., Emporia, VA

in accordance with the Conditions of this permit.

Approved on June 17, 2016.

Deputy Regional Director
Department of Environmental Quality

Permit consists of 34 pages.
Permit Conditions 1 to 86.

INTRODUCTION

This permit approval is based on the permit application dated November 24, 2014; including amendment information dated August 27, 2015, December 9, 2015, and February 10, 2016. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

Equipment List - Equipment at this facility consists of:

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
Three on one power block with three natural gas-fired combustion turbine generators, each with a duct-fired heat recovery steam generator (HRSG) , providing steam to a common steam turbine generator			
CT-1	MHPS M501J combustion turbine generator with duct burner (natural gas-fired)	3,227 MMBtu/hr CT 500 MMBtu/hr DB	NSPS, Subpart KKKK
CT-2	MHPS M501J combustion turbine generator with duct burner (natural gas-fired)	3,227 MMBtu/hr CT 500 MMBtu/hr DB	NSPS, Subpart KKKK
CT-3	MHPS M501J combustion turbine generator with duct burner (natural gas-fired)	3,227 MMBtu/hr CT 500 MMBtu/hr DB	NSPS, Subpart KKKK
Ancillary Equipment			
B-1	Auxiliary Boiler (natural gas-fired)	185 MMBtu/hr	NSPS Subpart Db
FGH-1,2,3	Three Fuel Gas Heaters (natural gas-fired)	16.1 MMBtu/hr each	NSPS Subpart Dc

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
FGH-4,5,6	Three Fuel Gas Heaters (natural gas-fired)	7.8 MMBtu/hr each	None
EG-1	Emergency Generator (S15 ULSD)	3000 kW	NSPS IIII, MACT ZZZZ
EG-2 & 3	Two Emergency Generators (propane)	150 kW (230 hp) each	NSPS JJJJ, MACT ZZZZ
FWP-1	Fire Water Pump (S15 ULSD)	376 bhp	NSPS IIII, MACT ZZZZ
DC-1	Delugeable Auxiliary Equipment Cooler	180,000 gallons of water/hr	None
IC-1 through 4	Four Turbine Inlet Air Chillers (mechanical draft cooling towers)	581,400 gallons of water/hr each	None
CB-1 through CB-11	Eleven Electrical Circuit Breakers	1,645 lbs SF_6 per breaker	None
CB-12 through CB-14	Three Generator Breakers	110 lbs SF_6 per breaker	None
FUG-1	Fugitive equipment leaks from natural gas piping components	-	None
T-1	ULSD storage tank	6,000 gallons	None

Specifications included in the above table are for informational purposes only and do not form enforceable terms or conditions of the permit.

PROCESS REQUIREMENTS

Combined-cycle gas turbine generators and duct-fired HRSG (CT-1, CT-2, CT-3)

1. **Emission Controls: Turbine Generators -** Nitrogen oxide (NO_x) emissions from each of the combined cycle gas turbine generators and associated duct-fired heat recovery steam generators (HRSG) (CT-1, CT-2, CT-3) shall be controlled by dry, low NO_x burners and selective catalytic reduction (SCR) with a NO_x performance of 2.0 ppmvd at 15% O_2. The low NO_x burners shall be installed and operated in accordance with manufacturer's specifications. The SCR shall be provided with adequate access for inspection and shall be in operation when the combined cycle gas turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 9).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

2. **Monitoring Devices: Turbine Generators - SCR -** Each SCR system shall be equipped with devices to continuously measure, or allow calculation of, and record ammonia feed rate and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating. To ensure good performance of the SCR, the devices used to continuously measure the ammonia feed rate and catalyst bed inlet temperature on the SCR shall be monitored by the permittee.
(9 VAC 5-50-20 C, 9 VAC 5-50-50H and 9 VAC 5-80-1705 B)

3. **Emission Controls: Turbine Generators** – Carbon monoxide (CO) emissions from each of the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) shall be controlled by an oxidation catalyst and good combustion practices (eg., controlled fuel/air mixing, adequate temperature, and gas residence time). The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combined cycle gas turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 9).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

4. **Emission Controls: Turbine Generators** – Volatile organic compound (VOC) emissions from each of the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) shall be controlled by an oxidation catalyst and good combustion practices (eg., controlled fuel/air mixing, adequate temperature, and gas residence time). The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combined cycle gas turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 9).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

5. **Monitoring Devices: Oxidation Catalyst** - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating. To ensure good performance of the oxidation catalyst system, the device used to continuously measure and record the catalyst bed inlet and outlet gas temperature on the oxidation catalyst shall be monitored by the permittee.
(9 VAC 5-50-20 C, 9 VAC 5-50-50 H and 9 VAC 5-80-1705 B)

6. **Emission Controls: Turbine Generators** – Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions from each of the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average. Compliance will be based on fuel monitoring results as required by Condition 27.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

7. **Emission Controls: Turbine Generators** – Particulate Matter (PM_{10}, $PM_{2.5}$) emissions from each of the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) shall be controlled by good combustion practices (eg., controlled fuel/air mixing, adequate temperature, and gas residence time) and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

8. **Emission Controls:** Turbine Generators – Greenhouse gas emissions (carbon dioxide, methane, and nitrous oxide), as CO_2e from the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) shall be controlled by the use of low carbon fuel (natural gas) and high efficiency design and operation of the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3 and steam turbine generator). The efficiency of the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3 and steam turbine generator) at full load without duct burning, corrected to ISO conditions, and providing for incremental degradation of the units, shall not exceed the following:

	Btu/kWh net (HHV) output
Initial Test	6,457
Year 6	6,583
Year 12	6,709
Year 18	6,835
Year 24	6,961
Year 30	7,087
Year 31 and later	7,212

Compliance shall be demonstrated as contained in Conditions 67 and 70. The Year is defined in Condition 40.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

9. **Startup/Shutdown: Turbine Generators** –The permittee shall comply with the requirements of this permit at all times except where noted by a specific condition. For the purpose of this permit, this condition defines startup and shutdown operating scenarios for the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3).
   a. Startup periods are defined as follows:
      i. For the purpose of this permit, startup is defined as the period of time beginning the first fuel feed after a shutdown event and ending at the earlier of the unit (CT-1, CT-2, or CT-3) reaching 50 percent load or the following time:
      ii. For Cold Startup defined as restarts made 72 hours or more after shutdown, startup periods shall not exceed 436 minutes per occurrence.
      iii. For Warm Startup defined as restarts made more than 8 but less than 72 hours after shutdown, startup periods shall not exceed 166 minutes per occurrence.
      iv. For Hot Startup restarts made 8 hours or less after shutdown, startup periods shall not exceed 84 minutes per occurrence.

v. If the SCR was not engaged during startup of a particular combustion turbine (including ammonia injection), the subsequent startup of that turbine shall be a cold start.

b. For the purpose of this permit, shutdown is defined as the period of time beginning when the unit (CT-1, CT-2, or CT-3) falls and remains below 50 percent load until the cessation of fuel feeding, not to exceed 30 minutes; or the 30 minutes of operation directly preceding the cessation of fuel feeding, whichever is shorter.

c. The permittee shall operate the CEMS during periods of startup and shutdown.

d. The permittee shall record the time, date and duration of each startup and shutdown event. The records must include calculations of NO_x and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

e. During startup and shutdown, the combustion turbine SCR system, including ammonia injection, and oxidation catalyst shall be operated in a manner to minimize emissions, as technologically feasible, and following the SCR manufacturer's written protocol or best engineering practices for minimizing emissions. Where best practices are used, the permittee shall maintain written documentation explaining the sufficiency of such practices. If such practices are used in lieu of the manufacturer's protocol, the documentation shall justify why the practices are at least equivalent to manufacturer's protocols with respect to minimizing emissions.

f. The permittee shall operate the facility so as to minimize the frequency and duration of startup and shutdown events.

(9 VAC 5-50-280 and 9 VAC 5-80-1705)

10. **Alternate Operating Scenario: Turbine Generators - Tuning** – The permitee shall comply with the requirements of this permit at all times except where noted by a specific condition. For the purpose of this permit, this condition defines the tuning operating scenario for the combined cycle gas turbine generators and associated HRSG (CT-1, CT-2, CT-3).

a. For the purpose of this permit, tuning is defined as the manipulation of the units and the associated emission controls by a qualified professional to ensure optimized operation and minimized emissions.

b. No tuning event shall last more than 18 consecutive hours.

c. Annual tuning events shall be limited to 96 hours per CT per 12-month rolling period.

d. The permittee shall notify the Piedmont Regional Air Compliance Manager at the address below, or by email, 24 hours prior to each declared CT tuning event unless approval for a shorter notice is given by DEQ. The notification shall include, but is not limited to, the following information:

i. Identification of the specific CT to be tuned.

ii. Reason for the declared tuning event

iii. Measures that will be taken to minimize the length of the declared tuning event.

iv. Justification why the person performing the tuning is qualified.

DEQ Regional Air Compliance Manager
Piedmont Regional Office
4949-A Cox Rd.
Glen Allen, VA 23060

e. The permittee shall furnish a written report to the Regional Air Compliance Manager at the address above, including all pertinent facts concerning any declared tuning event, as soon as practicable but not less than 14 business days after the retuning event. The notification shall include, but is not limited to, the following information:

i. Identification of the CT that was tuned.

ii. The date and time of commencement and completion of the declared tuning events.

iii. NO_x and CO emissions during the declared tuning events.

f. NO_x and CO emissions during CT tuning events shall be recorded and included in the associated quarterly excess emission report if the applicable emission limits are exceeded. Emissions during tuning shall be included in the facility-wide total.

(9 VAC 5-20-180J and 9 VAC 5-50-20E)

11. **Alternate Operating Scenario: Turbine Generators – On-line Water Wash** –The permittee shall comply with the requirements of this permit at all times except where noted by a specific condition. For the purpose of this permit, this condition defines the on-line water wash operating scenario for the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3)

a. On-line water washing is defined as spraying water through the turbine while a unit (CT-1, CT-2, CT-3) is operating

b. No on-line water wash event shall last for more than 60 minutes in a calendar day.

c. Annual on-line water wash events shall not exceed 52 hours per CT per 12-month rolling period.

d. The permittee shall notify the Piedmont Regional Air Compliance Manager at the address below, or by email, 24 hours prior to each declared on-line CT water wash event unless approval for a shorter notice is given by DEQ. The notification shall include, but is not limited to, the following information:

i. Identification of the specific CT to be washed.

ii. Reason for the declared washing event

DEQ Regional Air Compliance Manager
Piedmont Regional Office
4949-A Cox Rd.

Glen Allen, VA 23060

e. The permittee shall furnish a written report to the Regional Air Compliance Manager at the address above, including all pertinent facts concerning the declared on-line water wash event, as soon as practicable but not less than 14 business days after the declared on-line water wash event. The notification shall include, but is not limited to, the following information:

   i. Identification of the CT that was washed.

   ii. The date and time of commencement and completion of the declared on-line water wash event.

   iii. NO_x and CO emissions during the declared on-line water wash event.

f. NO_x and CO emissions during each declared CT on-line water wash event shall be recorded and included in the associated quarterly excess emission report if the applicable emission limits are exceeded. Emissions during on-line water wash events shall be included in the facility-wide total.

(9 VAC 5-20-180J and 9 VAC 5-50-20E)

Auxiliary boiler (B-1) and fuel gas heaters (FGH-1 through FGH-6)

12. **Emission Controls: Fuel Gas Heaters and Auxiliary Boiler** – NO_x emissions from the auxiliary boiler (B-1) and six fuel gas heaters (FGH-1 through FGH-6) shall be controlled by ultra low-NO_x burners with a NO_x performance of 0.011 lbs/MMBtu (equivalent to 9 ppmvd at 3% O_2). The low NO_x burners shall be installed and operated in accordance with manufacturer's specifications.
(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

13. **Emission Controls: Fuel Gas Heaters and Auxiliary Boiler** – CO and VOC emissions from the auxiliary boiler (B-1) and six fuel gas heaters (FGH-1 through FGH-6) shall be controlled by good combustion practices, operator training, and proper emissions unit design, construction and maintenance to achieve a maximum CO emission rate of 0.035 lb/MMBtu (B-1) and 0.037 lb/MMBtu (FGH-1 through FGH-6) (equivalent to 50 ppmvd at 3% O_2) and a maximum VOC emission rate of 0.005 lb/MMBtu. Boiler and heater operators shall be trained in the proper operation of all such equipment. Training shall consist of a review and familiarization of the manufacturer's operating instructions, at a minimum. The permittee shall maintain records of the required training including a statement of time, place and nature of training provided. The permittee shall have available good written operating procedures and a maintenance schedule for the boiler and heater. These procedures shall be based on the manufacturer's recommendations and/or best engineering practices, at a minimum. All records required by this condition shall be kept on site and made available for inspection by the DEQ.
(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

14. **Emission Controls: Fuel Gas Heaters and Auxiliary Boiler** – SO_2 and H_2SO_4 emissions from auxiliary boiler (B-1) and six fuel gas heaters (FGH-1 through FGH-6) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average. Compliance will be based on fuel monitoring results as required by Condition 27.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

15. **Emission Controls: Fuel Gas Heaters and Auxiliary Boiler** – PM_{10} and $PM_{2.5}$ emissions from the auxiliary boiler (B-1) and six fuel gas heaters (FGH-1 through FGH-6) shall be controlled by good combustion practices and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

16. **Emission Controls: Fuel Gas Heaters and Auxiliary Boiler** – CO_2e from the auxiliary boiler (B-1) and six fuel gas heaters (FGH-1 through FGH-6) shall be controlled by the use of natural gas fuel and high efficiency design and operation.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emergency Units (EG-1, EG-2, EG-3 and FWP-1)

17. **Emission Controls: EG-1, FWP-1** - PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, VOC, and H_2SO_4 emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by good combustion practices and the use of ultra low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

18. **Emission Controls: EG-2 and EG-3** - PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, VOC, and H_2SO_4 emissions from the propane emergency units (EG-2 and EG-3) shall be controlled by good combustion practices and demonstrated compliance with NSPS Subpart JJJJ.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

19. **Emission Controls: EG-1, FWP-1** – CO_2e emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by the use of S15 ULSD and high efficiency design and operation.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

20. **Monitoring Devices: EG-1, EG-2, EG-3** – The permittee must install a non-resettable hour meter on the emergency generators (EG-1, EG-2, and EG3) and the emergency fire water pump (FWP-1) prior to the startup of each unit. The hour meters shall be provided with adequate access for inspection.
(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

Miscellaneous Processes

21. **Emission Controls: Inlet Chillers** – Particulate matter emissions from the four, 9,690-gallon/minute inlet chillers (CH-1 through CH-4) shall be controlled to a drift rate of 0.0005

percent of the circulating water flow and a total dissolved solids content of the cooling water of no more than 1500 mg/l. The permittee shall keep a log of weekly testing for total dissolved solids content of the cooling water. Weekly testing for dissolved solids shall be done when the Chiller Package is in service for more than eight consecutive hours during a calendar week.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

22. **Emission Controls: Delugeable Auxiliary Equipment Cooler** – Particulate matter emissions from the 3,000 gallon/minute delugeable auxiliary equipment cooler (AEC-1) shall be controlled to a drift rate of 0.010 percent of the circulating water flow and a total dissolved solids content of the cooling water of no more than 300 mg/l. The permittee shall keep a log of weekly testing for total dissolved solids content of the cooling water. Weekly testing for total dissolved solids shall be done when the Deluge System is in service for more than two consecutive hours during a calendar week.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

23. **Emission Controls: Equipment Leaks** – Fugitive emissions from natural gas piping components (valves and flanges) located on the power plant property (FUG-1) shall be minimized by using best management practices to prevent, detect and repair leaks of natural gas from the piping components. The permittee shall implement a daily auditory/ visual/olfactory (AVO) inspection program for detecting leaking in natural gas piping components. The first attempt to repair any component found to be leaking during an AVO inspection shall be made within 5 days. The leaking component shall be repaired within 15 days of discovery. The permittee shall maintain a list of difficult to repair components, which when leaking, the repair requires facility shutdown or cannot otherwise be completed within 15 days of discovery. Documentation justifying the inclusion of a component on the list shall be included. Records of the daily AVO inspection results, repair attempts, and the list of long-term leaking components and reason for each delay shall be maintained on site. The AVO plan shall be submitted for review no later than 60 prior to start-up of the facility.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

24. **Emission Controls: Electrical Breakers** – Greenhouse gas emissions (including SF_6) from the fourteen electrical circuit breakers and generator breakers (CB-1 through CB-14) shall be controlled by an enclosed-pressure circuit breaker, with a maximum annual leakage rate of 0.5 percent, and a low pressure detection system (with alarm). The low pressure detection system shall be in operation when the circuit breakers are in use.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

OPERATING LIMITATIONS

25. **Fuel: Gas turbines, Fuel Gas Heaters, and Auxiliary boiler** - The approved fuel for the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3), fuel gas heaters (FGH-1 through FGH-6) and the auxiliary boiler (B-1) is pipeline quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average basis. A change in the fuel may require a permit to modify and operate.

(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

26. **Fuel Throughput: Turbine Generators** -The three combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) combined shall consume no more than a total of 97,948.2 x 10^6 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

27. **Fuel Monitoring: Turbine Generators**– The permittee shall conduct tests for the total sulfur content of the natural gas being fired at the electric power generation facility to verify that the sulfur content of the natural gas is less than or equal to 0.4 grains of total sulfur per 100 scf on a 12-month rolling average in order to demonstrate that potential sulfur dioxide and sulfuric acid mist emissions shall not exceed the limits specified in Condition 39.a for the combustions turbines (CT-1, CT-2, CT-3). The permittee shall demonstrate compliance with the sulfur content limit in Condition 25 using one of the following:

    a. Determine and record the total sulfur content of the natural gas each month. A monthly sample is not required for months when the turbines operated for 48 hours or less, or

    b. Develop custom schedules for determination of the sulfur content of the natural gas based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval.

    (9 VAC 5-50-410, 9 VAC 5-50-280, 40 CFR 60.4365(a), 40 CFR 60.4370(b), and 40 CFR 60.4370(c))

28. **Fuel Throughput: Auxiliary Boiler** -The auxiliary boiler (B-1) shall consume no more than 158.9 x 10^6 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

29. **Fuel: EG-1 and FWP-1** - The approved fuel for the emergency diesel fire water pump (FWP-1) and emergency diesel generator (EG-1) is ultra low sulfur diesel (S15 ULSD). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

30. **Fuel: EG-2 and EG-3** - The approved fuel for the emergency propane generators (EG-2 and EG-3) is liquid petroleum gas (LPG)(as propane). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

31. **Fuel: EG-1, EG-2, EG-3, and FWP-1**- The fuels for the fire pump (FWP-1) and generators (EG-1, EG-2, and EG3) shall meet the specifications below:

ULTRA LOW SULFUR DIESEL FUEL (S15 ULSD) which meets the ASTM D975-10b specification for S15 fuel oil:
Maximum sulfur content per shipment: 0.0015%

LPG, including butane and propane, which meets ASTM specification D1835.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

32. **Operating Hours: EG-1, EG-2, EG-3, and FWP-1** - The emergency generators (EG-1, EG-2, and EG-3) and emergency fire water pump (FWP-1) shall not operate more than 500 hours each per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

33. **Emergency Operation: EG-1, EG-2, EG-3, and FWP-1** – The operation of the emergency generators (EG-1, EG-2, and EG-3) and emergency fire water pump (FWP-1) is limited to emergency situations. Emergency situations include a) emergency generator use to produce power for critical networks or equipment (including power supplied to portions of the facility) when electric power from the local utility (or the normal source, if the facility runs on its own power production) is interrupted and b) emergency engine use to pump water in the case of fire or flood, etc. The emergency generators (EG-1, EG-2, and EG-3) and emergency fire water pump (FWP-1) may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per calendar year for each unit.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

34. **Fuel Certification: EG-1 and FWP-1** - The permittee shall obtain a certification from the fuel supplier with each shipment of S15 ULSD oil. Each fuel supplier certification shall include the following:

    a. The name of the fuel supplier;

    b. The date on which the S15 ULSD oil was received;

    c. The quantity of S15 ULSD oil delivered in the shipment;

    d. A statement from the supplier that the fuel oil is S15 ULSD oil;

    Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 31. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.
    (9 VAC 5-50-280)

35. **Maintenance and Operation: EG-1, EG-2, EG-3, and FWP-1** – The permittee must maintain and operate the emergency fire pump (FWP-1) and emergency generators (EG-1, EG-2, and EG-3) according to the manufacturer's recommendations and/or procedures developed by the permittee using best engineering practices, over the entire life of the engine. (9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

36. **Fuel Throughput: Fuel Gas Heaters** -The three 16.1 MMBtu/hr fuel gas heaters (FGH-1 through FGH-3) combined shall consume no more than a total of 415 x 10^6 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-50-280)

37. **Fuel Throughput: Fuel Gas Heaters** -The three 7.8 MMBtu/hr fuel gas heaters (FGH-4 through FGH-6) combined shall consume no more than a total of 201 x 10^6 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-50-280)

38. **Requirements by Reference: NSPS** - Except where this permit is more restrictive than the applicable requirement, the NSPS equipment as described in the equipment table in the Introduction on page 2 of this permit shall be operated in compliance with the requirements of 40 CFR 60, Subparts Db, Dc and KKKK.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

<u>EMISSION LIMITS</u>

39. **Short-Term Emission Limits: Turbine Generators** -Emissions from the operation of each combined-cycle gas turbine generator and associated HRSG duct burner (CT-1, CT-2, CT-3), shall not exceed the limits specified below:
    a. Normal operation – Unless otherwise specified, the limits in this paragraph apply during all operation except for periods considered startup and shutdown as defined in Condition 9 of this permit, and alternate operating scenarios as defined in Conditions 10 and 11.

Pollutant	Short term emission limits
PM_{10} (including condensable PM)	0.0030 lb/MMBtu and 9.2 lb/hr as an average of three test runs without duct burner firing 0.0039 lb/MMBtu and 14.1 lb/hr as an average of three test runs with duct burner firing.
$PM_{2.5}$ (including condensable PM)	0.0030 lb/MMBtu and 9.2 lb/hr as an average of three test runs without duct burner firing 0.0039 lb/MMBtu and 14.1 lb/hr as an average of three test runs with duct burner firing.
Sulfur dioxide	0.00114 lb/MMBtu (this limit applies at all times)
Nitrogen Oxides (as NO_2)	2.0 ppmvd @ 15% O_2 as a one-hour average with or without duct burning
Carbon monoxide	1.0 ppmvd @ 15% O_2 as a three-hour rolling average without duct burning 1.6 ppmvd @ 15% O_2 as a three-hour rolling average with duct burning
Volatile organic compounds	0.7 ppmvd @ 15% O_2 without duct burner firing 1.4 ppmvd @ 15% O_2 with duct burner firing
Sulfuric acid mist	0.00053 lb/MMBtu without duct burner firing 0.00060 lb/MMBtu with duct burner firing (These limits apply at all times)

Where:

ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short-term emission limits represent averages for a three-hour sampling period for CO, VOC, SO_2 and H_2SO_4. Nitrogen oxides shall be calculated as a one-hour average. PM_{10} and $PM_{2.5}$ limits represent the average of three test runs.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 1, 3, 4, 25, 48, 52, 61, and 62.

b. During each CT (CT-1, CT-2 and CT-3) tuning event or on-line water wash event, emissions shall not exceed the following limits. Operating periods considered tuning are defined in Condition 10. Operating periods considered on-line water washes are defined in Condition 11.

Pollutant	Limitations for Maintenance Activities (Tuning/Water Washing)
NO_x	Tuning or water washing: 648 lb/turbine/calendar day
CO	Tuning or water washing: 436 lb/turbine/calendar day

The emissions limits for tuning and on-line water wash events do not include emissions from startup and/or shutdown that may occur on the same calendar day.

c. NO_x emission concentrations shall not exceed the NO_x standards of the NSPS Subpart KKKK of 15 ppm at loads > 75% or 96 ppm at loads ≤ 75% corrected to 15% O_2 (on a rolling 30-day average basis).

d. During each startup or shutdown event, emissions shall not exceed the following:

Pollutant	Startup/Shutdown Limitations
NO_x	cold start event - 1,231 lb/turbine warm start event - 395 lb/turbine hot start event - 148 lb/turbine shutdown event - 65 lb/turbine
CO	cold start event - 6,944 lb/turbine warm start event - 3,316 lb/turbine hot start event - 1,771 lb/turbine shutdown event - 1,004 lb/turbine

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 9 and 52.

(9 VAC 5-50-280, 9 VAC 5-80-1705, 9 VAC 5-80-1715)

40. **Emission Limits: Turbine Generators** – CO_2e emissions from the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) and the steam turbine, providing for incremental degradation of the units, shall not exceed the following:

Degradation Period	Applicable limit in lb CO_{2e}/MWh net output
Years 1-6	812
Years 7-12	828
Years 13-18	843
Years 19-24	859
Years 25-30	875
Years 31 and later	890

For the purposes of determining which limit is applicable, Year 1 begins upon commencement of commercial operation and ends on December 31 of the first full calendar year after that date. Each limit increments on January 1 of the respective year. For example, if the facility commences commercial operation on April 15, 2019, Year 1 begins on April 15, 2019 and ends on December 31, 2020. Year 7 begins, and the increased limit becomes effective, on January 1, 2026.

Compliance with the applicable limit shall be calculated monthly on a 12- month rolling basis. The applicable limit applies at all times. Compliance shall be determined each month by summing the calculated CO_2e emissions from the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) during the previous 12 months and dividing that value by the sum of the plant net electrical energy output over that same period. (9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

41. **Annual Process Emission Limits: Turbine Generators** – Emissions from the operation of <u>each</u> of the three combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) shall not exceed the limits specified below:

PM_{10}	61.5	tons/yr (on a 12-month, rolling total)
$PM_{2.5}$	61.5	tons/yr (on a 12-month, rolling total)
Sulfur Dioxide	18.7	tons/yr (on a 12-month, rolling total)
Nitrogen Oxides (as NO_2)	118.3	tons/yr (on a 12-month, rolling total)
Carbon Monoxide	286.0	tons/yr (on a 12-month, rolling total)
Volatile Organic Compounds	214.8	tons/yr (on a 12-month, rolling total)
Sulfuric Acid Mist	9.9	tons/yr (on a 12-month, rolling total)
CO_2e	1,911,596	tons/yr (on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 1, 3, 4, 6, 7, 26, 27, 50, 52 and 55. (9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

42. **Process Emission Limits: Auxiliary Boiler** – Emissions from the operation of the auxiliary boiler (B-1) shall not exceed the limits specified below:

PM_{10}	1.4	lbs/hr	0.6	tons/yr (on a 12-month, rolling total)
$PM_{2.5}$	1.4	lbs/hr	0.6	tons/yr (on a 12-month, rolling total)
Nitrogen Oxides (as NO_2)	2.1	lbs/hr	0.9	tons/yr (on a 12-month, rolling total)
Carbon Monoxide	6.6	lbs/hr	2.9	tons/yr (on a 12-month, rolling total)
Volatile Organic Compounds	0.005	lbs/MMBtu	0.5	tons/yr (on a 12-month, rolling total)
CO_2e			9,489	tons/yr (on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be

considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 12, 13, 25 and 28.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

43. **Process Emission Limits: Electrical Breakers** - Emissions from the operation of the electrical circuit breakers and generator breakers (CB-1 through CB-14) shall not exceed the limits specified below:

Circuit Breakers CB1-CB11 combined	1032 tons of CO_2e/year (12 month rolling average)
Circuit Breakers CB12-CB14 combined	19 tons of CO_2e/year (12-month rolling average)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Condition 24.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

44. **Process Emission Limits: FWP-1** - Emissions from the operation of the fire water pump (FWP-1) shall not exceed the limits specified below:

PM (filterable only)	0.15	g/hp-hr
PM_{10}	0.30	g/hp-hr
$PM_{2.5}$	0.30	g/hp-hr
Nitrogen Oxides (as NO_2) + Non-methane hydrocarbons	3.0	g/hp-hr
Carbon Monoxide	2.6	g/hp-hr
Sulfur Dioxide	0.00154	lb/MMBtu
Sulfuric Acid Mist	0.00012	lb/MMBtu
CO_2e	104	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 29, 31, 32, 33, 35 and 50.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

45. **Process Emission Limits: EG-1** - Emissions from the operation of the diesel emergency generator (EG-1) shall not exceed the limits specified below:

PM (filterable only)	0.2	g/kW-hr

PM_{10}	0.4	g/kW-hr	0.7	tons/yr (on a 12-month rolling total)
$PM_{2.5}$	0.4	g/kW-hr	0.7	tons/yr (on a 12-month rolling total)
Sulfur Dioxide	0.00154	lb/MMBtu		
Nitrogen Oxides (as NO_2) + Non-methane hydrocarbons	6.4	g/kW-hr	10.6	tons/yr (on a 12-month rolling total)
Carbon Monoxide	3.5	g/kW-hr	5.8	tons/yr (on a 12-month rolling total)
Sulfuric Acid Mist	0.00012	lb/MMBtu		
CO_2e			1178	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 29, 31, 33, 35, and 50.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

46. **Process Emission Limits: EG-2, EG-3** - Emissions from the operation of the propane emergency generators (EG-2 and EG-3) combined shall not exceed the limits specified below:

PM_{10} (including condensable)	0.019	g/hp-hr		
$PM_{2.5}$ (including condensable)	0.019	g/hp-hr		
Sulfur Dioxide	0.00059	lb/MMBtu		
Nitrogen Oxides (as NO_2)	2.0	g/hp-hr	0.5	tons/yr (on a 12-month rolling total)
Carbon Monoxide	4.0	g/hp-hr	1.0	tons/yr (on a 12-month rolling total)
Volatile Organic Compounds	1.0	g/hp-hr		
Sulfuric Acid Mist	0.00005	lb/MMBtu		
CO_2e			121	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 29, 31, 33, 35, and 51.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

47. **Process Emission Limits: Fuel Gas Heaters** – Emissions from the operation of each of the fuel gas heaters (FGH-1 through FGH-6) shall not exceed the limits specified below:

	PM_{10}	$PM_{2.5}$	Nitrogen Oxides (as NO_2)	Carbon Monoxide	Volatile Organic Compounds	CO_2e
FGH-1 through FGH-3	0.007 lb/MMBtu	0.007 lb/MMBtu	0.011 lb/MMBtu	0.037 lb/MMBtu	0.005 lb/MMBtu	-
	0.6 tons/yr	0.6 tons/yr	0.8 tons/yr	2.6 tons/yr	0.4 tons/yr	8,258 tons/yr
FGH-4 through FGH-6	0.007 lb/MMBtu	0.007 lb/MMBtu	0.011 lb/MMBtu	0.037 lb/MMBtu	0.005 lb/MMBtu	-
	0.3 tons/yr	0.3 tons/yr	0.4 tons/yr	1.3 tons/yr	0.2 tons/yr	4,001 tons/yr

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 12, 13, 14, 15, 16, 25, 36, 37 and 49.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

48. **Visible Emission Limit: Turbine Generators** - Visible emissions from the combined cycle gas turbine generators and associated duct-fired HRSG (CT-1, CT-2, CT-3) shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

49. **Visible Emission Limit: Fuel Gas Heaters** - Visible emissions from the fuel gas heaters (FGH-1 through FGH-3 and FGH-4 through FGH-6) and auxiliary boiler (B-1) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

50. **Visible Emission Limit: EG-1 and FWP-1** - Visible emissions from the emergency fire water pump (FWP-1) and diesel emergency generator (EG-1) shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

51. **Visible Emission Limit: EG-2 and EG-3**- Visible emissions from the propane-fired emergency generators (EG-2 and EG-3) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

<u>CEMS</u>

52. **CEMS: Turbine Generators** - Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO_x (measured as NO_2), CO_2, and CO from each combined cycle combustion turbine and associated duct-fired HRSG (CT-1, CT-2, CT-

3) in ppmvd, corrected to 15 percent O_2. CEMS for NO_x shall meet the design specifications of 40 CFR Part 75 whereas CEMS for CO shall be installed, evaluated, and operated according to the monitoring requirements in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_x and CO emissions are monitored and measure heat input and power output. A CEMS or alternative method as allowed by 40 CFR 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR 75 (acid rain program monitoring). For compliance with the emission limits contained in Condition 39.a, CO_2 and NO_x data shall be reduced to 1-hour block averages. CO data shall be reduced to 3-hour rolling averages.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

53. **CEMS Performance Evaluations -** Performance evaluations of the NO_x and, if applicable, SO_2 CEMS shall be conducted in accordance with 40 CFR Part 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. Two copies of the performance evaluations report shall be submitted to the Piedmont Region within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30 day notification, prior to the demonstration of continuous monitoring system's performance, and subsequent notifications shall be submitted to the Piedmont Region.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

54. **CEMS Quality Control Program -** A CEMS quality control program which is equivalent to the requirements of 40 CFR 75 Appendix B shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

55. **CEMS Emissions Data** – For the purposes of this permit and DEQ's emissions inventory, CEMS data shall be used to report annual emissions of NO_x, CO, and CO_2 from the stack of each combined cycle combustion turbine and associated duct-fired HRSG (CT-1, CT-2, CT-3) in tons/yr.
(9 VAC 5-50-50)

56. **CEMS: Excess Emissions and Monitor Downtime for NO_x -** For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 58 are defined as follows:

   a. An excess emission period is a normal unit operating period (does not apply to startup, shutdown, malfunction, or alternative operating scenarios) in which the average one-hour NO_x emission rate exceeds the applicable emission limit in Condition 39.a; and

   b. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_x concentration, O_2 concentration,

fuel flow rate, steam pressure, or megawatts. The steam flow rate is only required if the permittee uses this information for compliance purposes.
(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4380)

57. **CEMS: Excess Emissions and Monitor Downtime for SO_2** - Continuous Monitoring Systems Excess emissions and monitoring downtime are defined, for the purpose of this permit, as follows:

    a. For samples of gaseous fuel obtained using daily sampling or for proportional sampling, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit; and

    b. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4385)

58. **CEMS: Reports** - The permittee shall furnish written reports to the Piedmont Region of excess emissions from any process monitored by a continuous monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

    b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

    c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

    d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

    e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.

    (9 VAC 5-50-50)

59. **CEMS: Excess Emissions** – For purposes of identifying excess emissions:

    a. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h);

b. For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm, using the appropriate equation in 40 CFR Part 60, Appendix A, Method 19. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations; and

c. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4350)

INITIAL COMPLIANCE DETERMINATION

60. **Emissions Testing: Facility** - The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from excessive cyclonic flow as defined in 40 CFR 60 Appendix A. Sampling ports shall be provided at the appropriate locations (in accordance with the applicable performance specification in 40 CFR Part 60, Appendix B) and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30 F and 9 VAC 5-80-1675)

61. **Initial Performance Test: Turbine Generators** - Initial performance tests shall be conducted for CO, PM_{10} (including condensable PM), $PM_{2.5}$ (including condensable PM), and total VOC from each combustion turbine and associated duct burner (CT-1, CT-2, and CT-3) to determine compliance with the emission limits contained in Condition 39.a. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. Tests shall be conducted for two different operating scenarios: natural gas firing at full load with the duct burners off; and natural gas firing at full load with the duct burners on. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 45 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1675, and 9 VAC 5-50-410)

62. **Initial Performance Test: Turbine Generators** – Initial performance tests shall be conducted on each combustion turbine and associated duct burner (CT-1, CT-2, and CT-3)

for NO_x (as NO_2) to determine compliance with the limits contained in Condition 39.a as follows:

a. 40 CFR 60, Appendix A, Methods 7E or 20 shall be used to measure the NO_x concentration (in ppm). Sampling traverse points for NO_x and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

b. Notwithstanding Condition 62.a above, the permittee may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met: The permittee may perform a stratification test for NO_x and diluent pursuant to the procedures specified in 40 CFR 75, Appendix A, Section 6.5.6.1(a) through (e). Once the stratification sampling is completed, the permittee may use the following alternative sample point selection criteria for the performance test:

   i. If each of the individual traverse point NO_x concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent O_2 from the mean for all traverse points, three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall) may be used. The three points must be located along the measurement line that exhibited the highest average NO_x concentration during the stratification test; or

   ii. The permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_x concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent O_2 from the mean for all traverse points.

c. The performance test must be done at any load condition as required by 40 CFR 60.4400(b). Testing maybe performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. Three separate test runs for each performance test must be conducted. The minimum time per run is 20 minutes.

d. The permittee must measure the total NO_x emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

e. Compliance with the applicable NO_x emission limit in Condition 39.a must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_x emission rate at each tested level meets the applicable emission limit in Condition 39.a.

f. The performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit.

g. The ambient temperature must be greater than 0°F during the performance test.

h. The permittee may use the following as alternatives to the reference methods and procedures specified in this condition:

   i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, as required by 40 CFR 60.4400(b). The ambient temperature must be greater than 0°F during the RATA runs.

   ii. Compliance with the applicable emission limit in Condition 39.a is achieved if the arithmetic average of all of the NO_x emission rates for the RATA runs, expressed in units of ppm at 15% O_2, does not exceed the emission limit.

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 45 days after test completion but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-50-410, and 9 VAC 5-80-1675)

63. **Initial Performance Test: Turbine Generators** – Initial performance tests shall be conducted on each combustion turbine and associated duct burner (CT-1, CT-2, and CT-3) for SO_2 to determine compliance with the limits contained in Condition 39.a. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

   a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manually sampling using Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D5504, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

   b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and

Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit. If fuel sampling is used, as described in 63.a above, no test protocol or test report is required.
(9 VAC 5-50-30, 9 VAC 5-50-410 and 9 VAC 5-80-1675)

64. **Initial Performance Test: Auxiliary Boiler and Fuel Gas Heater -** Initial performance tests shall be conducted for NO_x and CO from the auxiliary boiler (B-1) and each of the six fuel gas heaters (FGH-1 through FGH-6) to determine compliance with the emission limits contained in Conditions 42 or 47, as applicable. The tests shall be performed, reported and demonstrate compliance within 60 days after the boiler or fuel gas heater, as applicable, reach the maximum load level at which the unit will be operated but in no event later than 180 days after its initial start-up. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 45 days of test completion but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1985 E, and 9 VAC 5-50-410)

65. **Visible Emissions Evaluation: Turbine Generators -** Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combustion turbine and associated duct burner (CT-1, CT-2, and CT-3). Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. At least one VEE shall be conducted for each of the operating conditions and loads for which emissions tests are required for the stack tests contained in Condition 61. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate

compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit.

Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Piedmont Regional Office within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

66. **Visible Emissions Evaluation: Auxiliary Boiler and Fuel Gas Heaters** - Concurrently with the initial performance tests in Condition 64, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on the auxiliary boiler (B-1) and fuel gas heaters (FGH-1 through FGH-6). Each test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the boiler will be operated but in no event later than 180 days after start-up of the boiler.

Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Piedmont Regional Office within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

67. **Testing: Power Block Heat Rate** - Initial compliance testing, using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996) or equivalent method approved by the Piedmont Regional Office, shall be conducted for the heat rate of the power blocks (i.e., a combination of CT-1, CT-2, and CT-3 and the steam turbine generator) to show compliance with the initial limit contained in Condition 8. The testing shall be performed, reported and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after commencement of commercial operation of the permitted facility. Testing shall be conducted when combusting natural gas without duct burning. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 45 days of test completion and shall conform to the test report format

enclosed with this permit. An initial exceedance of the applicable heat rate in Condition 8 triggers a requirement for the permittee to submit a maintenance plan to DEQ within 15 days that specifies the actions the permittee will to take in order to achieve the heat rate limit. The details of this plan are to be arranged with the Piedmont Regional Office. A re-test shall be completed within 60 days. One copy of the re-test results shall be submitted to the Piedmont Regional Office within 45 days of test completion and shall conform to the test report format enclosed with this permit. A second exceedance of the applicable heat rate in Condition 8 shall be considered a violation.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

CONTINUING COMPLIANCE DETERMINATION

68. **Continuing Compliance: Combustion Turbines** – The permittee shall conduct additional performance tests for VOC, PM_{10} and $PM_{2.5}$ from the Combustion Turbines (CT-1, CT-2, CT-3) to demonstrate compliance with the emission limits contained in this permit. The tests shall occur no less than 54 months and no more than 66 months after the previous test. The details of the tests shall be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

69. **Annual Performance Test: Turbine Generators** – Annual performance tests shall be conducted on each combustion turbine and associated duct burner (CT-1, CT-2, and CT-3) for SO_2 to determine compliance with the limits contained in Condition 39.a. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

    a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manual sampling using the Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D5504, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

    b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

    c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 45 days after test completion and shall conform to the test report format enclosed with this permit. If fuel sampling is used, as described in 69.a above, no test protocol or test report is required.
(9 VAC 5-50-30, 9 VAC 5-50-410)

70. **Periodic Testing: Power Block Heat Rate**–The permittee shall conduct subsequent heat rate testing of the power blocks in accordance with Condition 67 to show compliance with the applicable heat rate contained in Condition 8 in Years 6, 12, 18, 24 and 30. After Year 30, additional tests shall be conducted between 60 and 73 months after the previous test. The details of the evaluation are to be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

71. **Stack Tests: Continuing Compliance** – Upon request by DEQ, the permittee shall conduct additional performance tests to determine compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 G)

<u>RECORDS</u>

72. **On Site Records: Facility** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Region. These records shall include, but are not limited to:

    a. Annual hours of operation of the emergency fire water pump (FWP-1) and emergency generators (EG-1, EG-2, and EG-3) for emergency purposes and for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

    b. All fuel supplier certifications for the S15 ULSD fuel used in the diesel emergency units (EG-1 and FWP-1);

    c. Monthly and annual throughput of natural gas to the three combustion turbines and associated duct burners (CT-1, CT-2, and CT-3), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

d. Monthly emissions calculations for PM_{10}, $PM_{2.5}$ and VOC from the combined cycle combustion turbines and associated duct burners (CT-1, CT-2, CT-3) using calculation methods approved by the Piedmont Regional Office to verify compliance with the ton/yr emissions limitations in Condition 41;

e. Monthly and annual records of plant net electrical energy output used in the demonstrations of compliance required in Condition 40;

f. Monthly and annual emissions of CO_2 and CO_2e, calculated monthly as the sum of each consecutive 12-month period;

g. Monthly and annual calculations of CO_2e emission rates (lb/MWh net) to demonstrate compliance with the requirements of Condition 40. Compliance for the consecutive 12-month period shall be demonstrated monthly as required in Condition 40;

h. Monthly and annual throughput of natural gas to the auxiliary boiler (B-1) and the fuel gas heaters (FGH-1 through FGH-6), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

i. Fuel quality records for natural gas combusted in the combustion turbine and associated duct burner (CT-1, CT-2, and CT-3), auxiliary boiler (B-1), and fuel gas heaters (FGH-1 through FGH-6);

j. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions;

k. Operation and control device monitoring records for each SCR system and oxidation catalyst as required in Conditions 2 and 5;

l. Records of alternative operating scenarios as required by Conditions 10 and 11;

m. The occurrence and duration of any startup, shutdown, or malfunction of the affected facility, any malfunction of the air pollution control equipment, or any periods during which a continuous emission monitoring system is inoperative;

n. Weekly logs of dissolved solids content of cooling water to the four inlet coolers (IC-1 through IC-4) and the auxiliary equipment chiller (AEC-1).

o. Scheduled and unscheduled maintenance, and operator training.

p. Results of all stack tests, power block heat rate tests, visible emission evaluations, and performance evaluations.

q. Manufacturer's instructions for proper operation of equipment.

r. Results of daily AVO inspections for fugitive natural gas leak detection, dates and results of first and final repair attempt, any repairs performed to the piping components (valves and flanges), and the list of difficult to repair leaking components and reason for each delay.

s. Records showing the circuit breakers are operating in accordance with the manufacturer's specifications (see Condition 24).

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50 and 9 VAC 5-50-410)

73. **Emissions Testing: Facility** - The electric generating facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from excessive cyclonic flow as defined in 40 CFR 60 Appendix A. Sampling ports shall be provided when requested at the appropriate locations and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30 F and 9 VAC 5-80-1180)

NOTIFICATIONS

74. **Initial Notifications** - The permittee shall furnish written notification to the Piedmont Regional Office of:

a. The actual date on which construction of the electric power generation facility commenced within 30 days after such date.

b. The anticipated start-up date of the electric power generation facility postmarked not more than 60 days nor less than 30 days prior to such date.

c. The actual start-up date of the electric power generation facility within 15 days after such date.

d. The anticipated date of continuous monitoring system performance evaluations postmarked not less than 30 days prior to such date.

e. The anticipated date of performance tests of the combustion turbines (CT-1, CT-2, and CT-3), auxiliary boiler (B-1), and six fuel gas heaters (FGH-1 through FGH-6), postmarked at least 30 days prior to such date.

f. The actual date the electric power generation facility commenced commercial operation within 15 days after such date.

Copies of the written notification referenced in items a through e above are to be sent to:

Associate Director
Office of Air Enforcement and Compliance Assistance (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-50-50 and 9 VAC 5-50-410)

GENERAL CONDITIONS

75. **Permit Invalidation** –This permit to construct the electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

    a. A program of continuous construction or modification is not commenced within 18 months from the date of this permit.

    b. A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of the phased construction of a new stationary source or project.

    (9 VAC 5-80-1985)

76. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

    a. Knowingly makes material misstatements in the permit application or any amendments to it;

    b. Fails to comply with the conditions of this permit;

    c. Fails to comply with any emission standards applicable to a permitted emissions unit;

    d. Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or

    e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

    (9 VAC 5-80-1985 F)

77. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

    a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

    b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

    c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

    d. To sample or test at reasonable times.

    For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
    (9 VAC 5-170-130 and 9 VAC 5-80-1180)

78. **Maintenance/Operating Procedures** – At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the

affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment and process equipment which affect such emissions:

a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9 VAC 5-50-20 E)

79. **Record of Malfunctions** – The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9VAC 5-20-180 J)

80. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Piedmont Regional Office of malfunctions of the affected facility or, related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone, email, or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Piedmont Regional Office.
(9 VAC 5-20-180 C)

81. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I)

82. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Piedmont Regional Office of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1985 E)

83. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1985 E)

STATE-ONLY ENFORCEABLE REQUIREMENTS

The following terms and conditions are included in this permit to implement the requirements of 9 VAC 5-40-130 et seq., 9 VAC 5-50-130 et seq., 9 VAC 5-60-200 et seq. and/or 9 VAC 5-60-300 et seq. and are enforceable only by the Virginia Air Pollution Control Board. Neither their inclusion in this permit nor any resulting public comment period make these terms federally enforceable.

84. **(SOE) Emission Limits: Toxic Air Pollutants** – Emissions from the electric power generation facility shall not exceed the limits specified below:

Pollutant	CAS#	Lb/hr	Tons/yr
Acrolein	107-02-8	0.050 lb/hr	0.18 tons/yr
Beryllium	7440-41-7	0.00014 lb/hr	0.00058 tons/yr
Cadmium*	7440-43-9	--	0.053 tons/yr
Chromium	7440-47-3	0.016 lb/hr	0.068 tons/yr
Formaldehyde	50-00-0	1.6 lb/hr	6.5 tons/yr
Lead*	7439-92-1	--	0.024 tons/yr
Mercury*	7439-97-6	--	0.013 tons/yr
Nickel	7440-02-0	0.024 lb/hr	0.11 tons/yr

*Hourly emissions of these pollutants are exempt

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 4, 7, 9, and 26.
(9 VAC 5-60-320 and 9 VAC 5-80-1625G)

85. **(SOE) Stack Test: Toxic Air Pollutants** – An initial performance test shall be conducted for formaldehyde from each combustion turbine and associated duct burner (CT-1, CT-2, and CT-3) to determine compliance with the emission limits contained in Condition 84. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as

set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. Tests shall be conducted for two different operating scenarios: natural gas firing at full load with the duct burners off; and natural gas firing at full load with the duct burners on. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 45 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

86. **(SOE) On Site Records: Toxic Air Pollutants** – The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Regional Office. These records shall include, but are not limited to the average hourly (in pounds), monthly (in tons), and annual emissions (in tons) of each toxic compound listed in Condition 84. Hourly emissions shall be calculated monthly. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These records shall be available for inspection by DEQ and current for at least the most recent five years.
(9 VAC 5-50-50 and 9 VAC 5-80-1625G)

SOURCE TESTING REPORT FORMAT

Report Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Test Dates.
4. Tester; name, address and report date

Certification
1. Signed by team leader/certified observer (include certification date)
2. Signed by responsible company official
3. *Signed by reviewer

Copy of approved test protocol

Summary
1. Reason for testing
2. Test dates
3. Identification of unit tested & the maximum rated capacity
4. *For each emission unit, a table showing:
   a. Operating rate
   b. Test Methods
   c. Pollutants tested
   d. Test results for each run and the run average
   e. Pollutant standard or limit
5. Summarized process and control equipment data for each run and the average, as required by the test protocol
6. A statement that test was conducted in accordance with the test protocol or identification & discussion of deviations, including the likely impact on results
7. Any other important information

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Sampling port location and dimensioned cross section Attached protocol includes: sketch of stack (elevation view) showing sampling port locations, upstream and downstream flow disturbances and their distances from ports; and a sketch of stack (plan view) showing sampling ports, ducts entering the stack and stack diameter or dimensions

Test Results
1. Detailed test results for each run
2. *Sample calculations
3. *Description of collected samples, to include audits when applicable

Appendix
1. *Raw production data
2. *Raw field data
3. *Laboratory reports
4. *Chain of custody records for lab samples
5. *Calibration procedures and results
6. Project participants and titles
7. Observers' names (industry and agency)
8. Related correspondence
9. Standard procedures

* Not applicable to visible emission evaluations

Exhibit 7

Exhibit 7 is an Excel file and is therefore attached in its native form as "Ex 7_Shirley Plantation NO2 Monitor Summary Values 2014 to 2018."

Exhibit 8

Exhibit 8 is an Excel file and is therefore attached in its native form as "Ex 7_Chickahominy_Inventory."

Exhibit 9

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

PIEDMONT REGIONAL OFFICE
4949A Cox Road, Glen Allen, Virginia 23060
(804) 527-5020 Fax (804) 527-5106
www.deq.virginia.gov

Matthew J. Strickler
Secretary of Natural Resources

David K. Paylor
Director

Jeffery Steers
Regional Director

DRAFT

Mr. Anand Gangadharan
President/CEO NOVI Energy for
C4GT, LLC
23955 Novi Rd
Novi, MI 48375

Location: Charles City County
Registration No.: 52588

Dear Mr. Gangadharan:

Attached is a permit to construct and operate an electric power generation facility in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Environmental Quality (DEQ) deemed the application complete on November 15, 2017 and solicited written public comments by placing newspaper advertisements in the Charles City/New Kent Chronicle and Richmond Times-Dispatch on March 7, 2018. A public hearing was held on April 9, 2018. The required comment period, provided by 9 VAC 5-80-1775 F expired on April 24, 2018. [No comments were received.]

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and/or civil charges. Please read all permit conditions carefully.

This permit approval to construct and operate shall not relieve C4GT, LLC of the responsibility to comply with all other local, state, and federal permit regulations.

Please note that the combustion turbines are affected facilities under 40 CFR 60, New Source Performance Standard (NSPS), Subpart TTTT. The proposed diesel emergency generator (EG-1) and diesel emergency fire water pump (FWP-1) may be subject to 40 CFR 60, New Source Performance Standard (NSPS), Subpart IIII and 40 CFR 63, Maximum Achievable Control Technology (MACT), Subpart ZZZZ. In summary, the units may be required to comply with certain federal emission standards and operating limitations. The DEQ advises you to review the referenced NSPS and MACT to ensure compliance with applicable emission and operational limitations. As the owner/operator you are also responsible for monitoring, notification, reporting and recordkeeping requirements of the NSPS and MACT. Notifications shall be sent to both EPA Region III and Virginia DEQ.

To review any federal rules referenced in the above paragraph or in the attached permit, the US Government Publishing Office maintains the text of these rules at **www.ecfr.gov**, Title 40, Parts 60 and 63.

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit, please contact the regional office at (804) 527-5020.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

KIW/AMS/52588_001_18_PSD.docx

Attachments: Permit
Source Testing Report Format

cc: Chief, Office of Air Enforcement and Compliance Assistance, U.S. EPA, Region III (electronic file submission)
Inspector, Air Compliance

COMMONWEALTH of VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY
PIEDMONT REGIONAL OFFICE
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Matthew J. Strickler
Secretary of Natural Resources

David K. Paylor
Director

Jeffery Steers
Regional Director

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to
New Source Performance Standards (NSPS).

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

C4GT, LLC
c/o NOVI Energy
23955 Novi Rd.
Novi, MI 48375
Registration No.: 52588

is authorized to construct and operate

an electric power generation facility

located at

3001 Roxbury Rd, Charles City VA

in accordance with the Conditions of this permit.

Approved on DRAFT.

____
Deputy Regional Director
Department of Environmental Quality

Permit consists of 32 pages.
Permit Conditions 1 to 84.

INTRODUCTION

This permit approval is based on the permit applications dated June 21, 2016; February 7, 2017; April 21, 2017; and November 15, 2017; and including amendment information dated August 3, 2017. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

Equipment List - Equipment at this facility consists of:

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
Two on one power block with two natural gas-fired combustion turbine generators, each with a duct-fired heat recovery steam generator (HRSG) , providing steam to a common steam turbine generator			
CT-1	**Option 1**: GE 7HA.02 combustion turbine generator with duct burner (natural gas-fired)	3,482 MMBtu/hr CT (HHV) 475 MMBtu/hr DB (HHV)	NSPS, Subpart KKKK
	Option 2: Siemens SGT6-8000H combustion turbine generator with duct burner (natural gas-fired)	3,116 MMBtu/hr CT (HHV) 991 MMBtu/hr DB (HHV)	NSPS, Subpart KKKK
CT-2	**Option 1:** GE 7HA.02 combustion turbine generator with duct burner (natural gas-fired)	3,482 MMBtu/hr CT (HHV) 475 MMBtu/hr DB (HHV)	NSPS, Subpart KKKK
	Option 2: Siemens SGT6-8000H combustion turbine generator with duct burner (natural gas-fired)	3,116 MMBtu/hr CT (HHV) 991 MMBtu/hr DB (HHV)	NSPS, Subpart KKKK
STG (no emissions)	**Option 1:** GE steam turbine generator	356 MW at ISO with DB	None
	Option 2: Siemens steam turbine generator	473 MW at ISO with DB	None

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
Ancillary Equipment			
B-1	Auxiliary Boiler (natural gas-fired)	105 MMBtu/hr (HHV)	NSPS, Subpart Db
DPH-1	Dew Point Heater (natural gas-fired)	16 MMBtu/hr (HHV)	NSPS, Subpart Dc
EG-1	Emergency Generator (S15 ULSD)	2500 kW	NSPS IIII, MACT ZZZZ
FWP-1	Fire Water Pump (S15 ULSD)	315 bhp	NSPS IIII, MACT ZZZZ
CWT-1	Mechanical draft cooling tower (18 cell)	348,500 gallons of water/min	None
CB-1 thru CB-4	Four Electrical Circuit Breakers	1,900 lbs SF_6 per breaker	None
CB-5 and CB-6	Two Generator Breakers	30 lbs SF_6 per breaker	None
T-1	ULSD storage tank	3,000 gallons	None
T-2	ULSD storage tank	400 gallons	None
FUG-1	Fugitive equipment leaks	--	None

Specifications included in the above table are for informational purposes only and do not form enforceable terms or conditions of the permit.

PROCESS REQUIREMENTS

Combustion turbine generators and duct-fired HRSG (CT-1, CT-2)

1. **Emission Controls: Turbine Generators -** Nitrogen oxide (NO_x) emissions from each of the combustion turbine generators and associated duct-fired heat recovery steam generators (HRSG) (CT-1, CT-2) shall be controlled by dry, low NO_x burners and selective catalytic reduction (SCR) with a NO_x performance of 2.0 ppmvd at 15% O_2. The low NO_x burners shall be installed and operated in accordance with manufacturer's specifications. The SCR shall be provided with adequate access for inspection and shall be in operation when the combustion turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 9).
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

2. **Monitoring Devices: Turbine Generators - SCR** - Each SCR system shall be equipped with devices to continuously measure, or allow calculation of, and record ammonia feed rate and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating. To ensure good performance of the SCR, the devices used to continuously measure the ammonia feed rate and catalyst bed inlet temperature on the SCR shall be monitored daily by the permittee when the SCR is in operation.
(9 VAC 5-50-20 C, 9 VAC 5-50-50H and 9 VAC 5-80-1705B)

3. **Emission Controls: Turbine Generators –** Carbon monoxide (CO) emissions from each of the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2) shall be controlled by an oxidation catalyst and good combustion practices (e.g., controlled fuel/air

mixing, adequate temperature, and gas residence time). The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combustion turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 9).
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

4. **Emission Controls: Turbine Generators –** Volatile organic compound (VOC) emissions from each of the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2) shall be controlled by an oxidation catalyst and good combustion practices (e.g., controlled fuel/air mixing, adequate temperature, and gas residence time). The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combustion turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 9).
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

5. **Monitoring Devices: Oxidation Catalyst** - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating. To ensure good performance of the oxidation catalyst system, the device used to continuously measure and record the catalyst bed inlet and outlet gas temperature on the oxidation catalyst shall be monitored by the permittee.
(9 VAC 5-50-20 C, 9 VAC 5-50-50H and 9 VAC 5-80-1705B)

6. **Emission Controls: Turbine Generators –** Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions from each of the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average. Compliance will be based on fuel monitoring results as required by Condition 24.
(9 VAC 5-80-1705B, 9 VAC 5-50-280, 9 VAC 5-80-1180, and 9 VAC 5-50-260)

7. **Emission Controls: Turbine Generators –** Particulate Matter (PM, PM_{10}, $PM_{2.5}$) emissions from each of the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2) shall be controlled by good combustion practices (e.g., controlled fuel/air mixing, adequate temperature, and gas residence time) and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

8. **Emission Controls: Greenhouse Gases –** Greenhouse gas emissions (including carbon dioxide, methane, and nitrous oxide), as CO_2e from the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2) shall be controlled by the use of low carbon fuel

(natural gas) and high efficiency design and operation of the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2, and steam turbine generator). **Option 1:** the initial heat rate of the GE combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2, and steam turbine generator) at full load without duct burning, corrected to ISO conditions, shall not exceed 6,745 Btu/kWh net HHV output. Compliance with this limit shall be demonstrated as contained in Condition 68. **Option 2:** the initial heat rate of the Siemens combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2 and steam turbine generator) at full load without duct burning, corrected to ISO conditions, shall not exceed 6,625 Btu/kWh net HHV output. Compliance with this limit shall be demonstrated as contained in Condition 68.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

9. **Startup/Shutdown: Turbine Generators –**The permittee shall comply with the requirements of this permit at all times except where noted by a specific condition. For the purpose of this permit, this condition defines startup and shutdown operating scenarios for the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2).

   a. Startup periods are defined as follows:

      i. For the purpose of this permit, startup is defined as the time from gas turbine ignition to the HRSG stack NO_x and CO steady state emission compliance (see Condition 34.a for the GE turbines and Condition 35.a for the Siemens turbines) or the duration of the applicable exclusion periods indicated in items ii through iv below, whichever is shorter:

      ii. Cold Startup: **Option 1:** For the GE turbines, cold startup is defined as restarts made 48 hours or more after shutdown. Exclusion from the short-term numerical emissions limits for cold startup periods for the GE turbines shall not exceed 60 minutes per occurrence; **Option 2:** For the Siemens turbines, cold startup is defined as restarts made 64 hours or more after shutdown. Exclusion from the short-term numerical emissions limits for cold startup periods for the Siemens turbines shall not exceed 55 minutes per occurrence.

      iii. Warm Startup: **Option 1:** For the GE turbines, warm startup is defined as restarts made more than 8 but less than 48 hours after shutdown. Exclusion from the short-term numerical emissions limits for warm startup periods for the GE turbines shall not exceed 50 minutes per occurrence; **Option 2:** For the Siemens turbines, warm startup is defined as restarts made more than 16 but less than 64 hours after shutdown. Exclusion from the short-term numerical emissions limits for warm startup periods for the Siemens turbines shall not exceed 55 minutes per occurrence.

      iv. Hot Startup: **Option 1:** For the GE turbines, hot startup is defined as restarts made 8 hours or less after shutdown. Exclusion from the short-term numerical emissions limits for hot startup for the GE turbines shall not exceed 30 minutes per occurrence; **Option 2:** For the Siemens turbines, hot startup is defined as restarts made 16 hours or less after shutdown. Exclusion from the short-term numerical emissions limits for hot startup for the Siemens turbines shall not exceed 50 minutes per occurrence.

v. If the SCR was not engaged during startup of a particular combustion turbine (including ammonia injection), the subsequent startup of that turbine shall be a cold start.

b. For the purpose of this permit, shutdown is defined as the point that either the HRSG stack NO_x or CO emissions exceed steady state compliance (see Condition 34.a for the GE turbines and Condition 35.a for the Siemens turbines) following a normal stop signal to the termination of fuel flow to the gas turbine. **Option 1:** exclusion from the short-term emissions limits for shutdown shall not exceed 30 minutes per occurrence for the GE turbines. **Option 2:** exclusion from the short-term emissions limits for shutdown shall not exceed 38 minutes per occurrence for the Siemens turbines.

c. The permittee shall operate the Continuous Emission Monitoring System (CEMS) during periods of startup and shutdown.

d. The permittee shall record the time, date and duration of each startup and shutdown event. The records must include calculations of NO_x and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

e. During startup and shutdown, the combustion turbine SCR system, including ammonia injection and oxidation catalyst shall be operated in a manner to minimize emissions, as technologically feasible, and following the SCR manufacturer's written protocol or best engineering practices for minimizing emissions. Where best practices are used, the permittee shall maintain written documentation explaining the sufficiency of such practices. If such practices are used in lieu of the manufacturer's protocol, the documentation shall justify why the practices are at least equivalent to manufacturer's protocols with respect to minimizing emissions.

(9 VAC 5-50-280 and 9 VAC 5-80-1705)

10. **Alternate Operating Scenarios: Turbine Generators – Tuning and On-line Water Washing Events –** As part of the regularly scheduled procedures conducted on the CTs to maintain the high-efficiency operation of those units, the permittee shall perform periodic burner tuning and on-line water washing of the turbine blades. The following conditions apply to these alternative operating scenarios:

a. No tuning event shall last more than 18 consecutive hours.

b. No on-line water wash event shall last for more than 60 minutes in a calendar day.

c. NO_x and CO emissions during these events shall be recorded and included in the associated quarterly excess emission report if the applicable emission limits in **Option 1**, Condition 34.b or **Option 2**, Condition 35.b are exceeded. Emissions associated with these events shall be included in the annual facility-wide total.

(9 VAC 5-20-180J and 9 VAC 5-50-20E)

Auxiliary boiler (B-1) and dew point heater (DPH-1)

11. **Emission Controls: Dew point heater and Auxiliary Boiler –** NO_x emissions from the auxiliary boiler (B-1) and dew point heater (DPH-1) shall be controlled by low-NO_x burners with a NO_x performance of 0.011 lbs/MMBtu (corrected to 3 percent O_2). The low NO_x burners shall be installed and operated in accordance with manufacturer's specifications.
(9 VAC 5-50-280 and 9 VAC 5-80-1705B)

12. **Emission Controls: Dew point heater and Auxiliary Boiler –** CO and VOC emissions from the auxiliary boiler (B-1) and dew point heater (DPH-1) shall be controlled by good combustion practices, operator training, and proper emissions unit design, construction and maintenance to achieve a maximum CO emission rate of 0.037 lb/MMBtu and a maximum VOC emission rate of 0.005 lb/MMBtu. Boiler and heater operators shall be trained in the proper operation of all such equipment. Training shall consist of a review and familiarization of the manufacturer's operating instructions, at a minimum. The permittee shall maintain records of the required training including a statement of time, place and nature of training provided. The permittee shall have available good written operating procedures and a maintenance schedule for the boiler and heater. These procedures shall be based on the manufacturer's recommendations and/or best engineering practices, at a minimum. All records required by this condition shall be kept on site and made available for inspection by the DEQ.
(9 VAC 5-50-280 and 9 VAC 5-80-1705B)

13. **Emission Controls: Dew point heater and Auxiliary Boiler –** SO_2 and H_2SO_4 emissions from the auxiliary boiler (B-1) and dew point heater (DPH-1) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average. Compliance will be based on fuel monitoring results required by Condition 24 for the combustion turbines.
(9 VAC 5-80-1705B, 9 VAC 5-50-280, 9 VAC 5-80-1180, and 9 VAC 5-50-260)

14. **Emission Controls: Dew point heater and Auxiliary Boiler –** PM, PM_{10} and $PM_{2.5}$ emissions from the auxiliary boiler (B-1) and dew point heater (DPH-1) shall be controlled by good combustion practices and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 scf, on a 12-month rolling average.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

15. **Emission Controls: Dew point heater and Auxiliary Boiler –** CO_2e emissions from the auxiliary boiler (B-1) and dew point heater (DPH-1) shall be controlled by the use of natural gas fuel and high efficiency design and operation.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

Emergency Units (EG-1 and FWP-1)

16. **Emission Controls: EG-1, FWP-1 –** PM, PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, VOC, and H_2SO_4 emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by good

combustion practices and the use of ultra-low sulfur diesel (S15 ULSD) fuel oil with a maximum sulfur content of 15 ppmw.
(9 VAC 5-80-1705B, 9 VAC 5-50-280, 9 VAC 5-80-1180 and 9 VAC 5-50-260)

17. **Emission Controls: EG-1, FWP-1 –** CO_2e emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by the use of S15 ULSD and high efficiency design and operation.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

18. **Monitoring Devices: EG-1, FWP-1 –** The permittee must install a non-resettable hour meter on the emergency generator (EG-1) and the emergency fire water pump (FWP-1) prior to the startup of each unit. The hour meters shall be provided with adequate access for inspection.
(9 VAC 5-50-280 and 9 VAC 5-80-1705B)

Miscellaneous Processes

19. **Emission Controls: Cooling Tower –** Particulate matter emissions from the cooling tower (CWT-1) shall be controlled to a drift rate of 0.00050 percent of the circulating water flow with mist eliminators and a total dissolved solids content of the cooling water effluent shall not exceed 6250 mg/l. The permittee shall keep a log of monthly testing for total dissolved solids content of the cooling water effluent. Monthly testing for total dissolved solids shall be done when the cooling tower is in service for 48 hours or more during a calendar month.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

20. **Emission Controls: Equipment Leaks** - Fugitive emissions from gas piping components (valves and flanges) located on the power plant property (FUG-1) shall be minimized by using best management practices. The permittee shall implement a daily auditory/visual/ olfactory (AVO) inspection program for detecting leaking in natural gas piping components. Records of AVO inspection results, repair attempts, and repair results shall be maintained on site. The AVO plan shall be submitted for review no later than 60 days prior to commercial startup of the facility.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

21. **Emission Controls: Electrical breakers –** Greenhouse gas emissions (including SF_6) from the six circuit breakers (CB-1 through CB-6) shall be controlled by an enclosed-pressure circuit breaker, with a maximum annual leakage rate of 0.5 percent, and a low pressure detection system (with alarm). The low pressure detection system shall be in operation when the circuit breakers are in use. The permittee shall develop a maintenance plan for the circuit breakers that includes procedures for minimizing emissions and corrective action to be taken in the event of a low pressure alarm. The permittee shall keep records of the total quantity of SF_6 gas added to the circuit breakers in a calendar year.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

OPERATING LIMITATIONS

22. **Fuel: Gas turbines, Dew Point Heater, and Auxiliary boiler** - The approved fuel for the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2), dew point heater (DPH-1), and the auxiliary boiler (B-1) is pipeline quality natural gas. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1705B, 9 VAC 5-50-280, 9 VAC 5-80-1180, and 9 VAC 5-50-260)

23. **Fuel Throughput: Turbine Generators – Option 1:** each GE combustion turbine generator and associated duct-fired HRSG (CT-1, CT-2) shall consume no more than a total of 3.4×10^{10} scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. **Option 2:** each Siemens combustion turbine generator and associated duct-fired HRSG (CT-1, CT-2) shall consume no more than a total of 3.5×10^{10} scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

24. **Fuel Monitoring: Turbine Generators –** The permittee shall conduct tests for the total sulfur content of the natural gas being fired at the electric power generation facility to verify that the sulfur content of the natural gas is 0.4 grains of total sulfur per 100 scf or less on a 12-month rolling average in order to demonstrate that potential sulfuric acid mist emissions shall not exceed the limits specified in **Option 1**, Condition 34.a or **Option 2**, Condition 35.a, and that potential sulfur dioxide emissions shall not exceed the limits specified in **Option 1,** Condition 36 or **Option 2,** Condition 38. The permittee shall demonstrate compliance with the sulfur content limit in Condition 6 using one of the following:

    a. Determine and record the total sulfur content of the natural gas each month. A monthly sample is not required for months when the turbines operated for 48 hours or less, or

    b. Develop custom schedules for determination of the sulfur content of the natural gas based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval.

    (9 VAC 5-50-410, 9 VAC 5-50-260, 9 VAC 5-50-280, 40 CFR 60.4365(a), 40 CFR 60.4370(b), and 40 CFR 60.4370(c))

25. **Fuel Throughput: Auxiliary Boiler** -The auxiliary boiler (B-1) shall consume no more than 9.02×10^{8} scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

26. **Fuel: EG-1 and FWP-1** - The approved fuel for the emergency diesel fire water pump (FWP-1) and emergency diesel generator (EG-1) is ultra-low sulfur diesel (S15 ULSD). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1705B, 9 VAC 5-50-280, 9 VAC 5-80-1180, and 9 VAC 5-50-260)

27. **Fuel: EG-1 and FWP-1**- The fuels for the fire pump (FWP-1) and generator (EG-1) shall meet the specifications below:

    ULTRA-LOW SULFUR DIESEL FUEL (S15 ULSD) which meets the ASTM D975-10b specification for S15 fuel oil: Maximum sulfur content per shipment: 0.0015%

    (9 VAC 5-80-1705B, 9 VAC 5-50-280, 9 VAC 5-80-1180, and 9 VAC 5-50-260)

28. **Operating Hours: EG-1 and FWP-1** - The emergency generator (EG-1) and emergency fire water pump (FWP-1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705B and 9 VAC 5-50-280)

29. **Emergency Operation: EG-1 and FWP-1 –** The operation of the emergency generator (EG-1) and emergency fire water pump (FWP-1) is limited to emergency situations. Emergency situations include a) emergency generator use to produce power for critical networks or equipment (including power supplied to portions of the facility) when electric power from the local utility (or the normal source, if the facility runs on its own power production) is interrupted and b) emergency engine use to pump water in the case of fire or flood, etc. The emergency generator (EG-1) and emergency fire water pump (FWP-1) may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per calendar year for each unit.
(9 VAC 5-80-1705B)

30. **Fuel Certification: EG-1 and FWP-1** - The permittee shall obtain a certification from the fuel supplier with each shipment of S15 ULSD oil. Each fuel supplier certification shall include the following:

    a. The name of the fuel supplier;

    b. The date on which the S15 ULSD oil was received;

    c. The quantity of S15 ULSD oil delivered in the shipment;

    d. A statement from the supplier that the fuel oil is S15 ULSD oil;

    Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel

specifications stipulated in Condition 27. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-80-1180)

31. **Maintenance and Operation: EG-1 and FWP-1 –** The permittee must maintain and operate the emergency fire pump (FWP-1) and emergency generator (EG-1) according to the manufacturer's recommendations and/or procedures developed by the permittee using best engineering practices, over the entire life of the engine.
(9 VAC 5-50-280 and 9 VAC 5-80-1705B)

32. **Fuel Throughput: Dew point heater**-The dew point heater (DPH-1) shall consume no more than a total of 1.4×10^8 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-50-280)

33. **Requirements by Reference: NSPS** - Except where this permit is more restrictive than the applicable requirement, the NSPS equipment as described in the equipment table in the Introduction on page 2 of this permit shall be operated in compliance with the requirements of 40 CFR 60, Subparts Db, Dc and KKKK.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

EMISSION LIMITS

34. **Short-Term Emission Limits: Option 1, GE Turbine Generators -**Emissions from the operation of each of the two GE combustion turbine generators and associated HRSG duct burners (CT-1, CT-2), shall not exceed the limits specified below:

    a. Normal operation – Unless otherwise specified, the limits in this paragraph apply during all operation except for periods considered startup and shutdown as defined in Condition 9 of this permit, and alternate operating scenarios as defined in Condition 10.

Pollutant	Short term emission limits
Particulate Matter (filterable only)	0.0046 lb/MMBtu without duct burner firing 0.0038 lb/MMBtu with duct burner firing. (These limits apply at all times)
PM_{10}	0.0069 lb/MMBtu; 12.2 lb/hr without duct burner firing 0.0049 lb/MMBtu; 17.3 lb/hr with duct burner firing. (These limits apply at all times)
$PM_{2.5}$	0.0069 lb/MMBtu; 12.2 lb/hr without duct burner firing 0.0049 lb/MMBtu; 17.3 lb/hr with duct burner firing. (These limits apply at all times)
Nitrogen Oxides (as NO_2)	2.0 ppmvd @ 15% O_2 as a one-hour average with or without duct firing

Pollutant	Short term emission limits
Carbon monoxide	1.0 ppmvd @ 15% O_2 without duct firing 1.6 ppmvd @ 15% O_2 with duct burning
Volatile organic compounds (as CH_4)	0.7 ppmvd @ 15% O_2 without duct burner firing 1.4 ppmvd @ 15% O_2 with duct burner firing
Sulfuric acid mist	2.5 lb/hr without duct burner firing 2.7 lb/hr with duct burner firing (These limits apply at all times)

Where:

ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short-term emission limits represent averages for a three-hour sampling period except for nitrogen oxides, which shall be calculated as a one-hour average.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 1, 3, 4, 6, 7, 22, 46, 49, 61, and 62.

b. During each CT tuning event or on-line water wash event, as described in Condition 10, emissions shall not exceed the following limits.

Pollutant	Limitations for Maintenance Activities (Tuning/On-line Water Washing)
Nitrogen Oxides (as NO_2)	Tuning or on-line water washing: 638 lb/turbine/calendar day
Carbon monoxide	Tuning or on-line water washing: 194 lb/turbine/calendar day

c. NO_x emission concentrations shall not exceed the NO_x standards of the NSPS Subpart KKKK of 15 ppm at loads > 75% or 96 ppm at loads $\leq$ 75% corrected to 15% O_2 (on a rolling 30-day average basis).

d. During each startup or shutdown event, emissions shall not exceed the following:

Pollutant	Startup/Shutdown Limitations
Nitrogen Oxides (as NO_2)	cold start event - 273 lb/turbine warm start event - 163 lb/turbine hot start event - 105 lb/turbine shutdown event - 18 lb/turbine
Carbon monoxide	cold start event - 840 lb/turbine warm start event - 188 lb/turbine hot start event - 180 lb/turbine shutdown event - 100 lb/turbine

Pollutant	Startup/Shutdown Limitations
Volatile organic compounds (as CH_4)	cold start event - 60 lb/turbine warm start event - 13 lb/turbine hot start event - 14 lb/turbine shutdown event - 65 lb/turbine

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these NO_x and CO limits may be determined as stated in Conditions 9 and 49. Compliance with the VOC limits may be determined by demonstrating correlation of VOC emissions to CO emissions, using CO and VOC stack testing and CO CEM data.

(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

35. **Short-Term Emission Limits: Option 2, Siemens Turbine Generators -** Emissions from the operation of each of the two Siemens combustion turbine generators and associated HRSG duct burners (CT-1, CT-2), shall not exceed the limits specified below:

a. Normal operation – Unless otherwise specified, the limits in this paragraph apply during all operation except for periods considered startup and shutdown as defined in Condition 9 of this permit, and alternate operating scenarios as defined in Condition 10.

Pollutant	Short term emission limits
Particulate Matter (filterable only)	0.0049 lb/MMBtu without duct burner firing 0.0056 lb/MMBtu with duct burner firing. (These limits apply at all times)
PM_{10}	0.0065 lb/MMBtu; 13.7 lb/hr without duct burner firing 0.0065 lb/MMBtu; 24.2 lb/hr with duct burner firing. (These limits apply at all times)
$PM_{2.5}$	0.0065 lb/MMBtu; 13.7 lb/hr without duct burner firing 0.0065 lb/MMBtu; 24.2 lb/hr with duct burner firing. (These limits apply at all times)
Nitrogen Oxides (as NO_2)	2.0 ppmvd @ 15% O_2 as a one-hour average with or without duct burning
Carbon monoxide	1.8 ppmvd @ 15% O_2 with or without duct burning
Volatile organic compounds (as CH_4)	1.0 ppmvd @ 15% O_2 without duct burner firing 2.0 ppmvd @ 15% O_2 with duct burner firing
Sulfuric acid mist	2.2 lb/hr without duct burner firing 2.7 lb/hr with duct burner firing (These limits apply at all times)

Where:

ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short-term emission limits represent averages for a three-hour sampling period except for nitrogen oxides, which shall be calculated as a one-hour average.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 1, 3, 4, 6, 7, 22, 46, 49, 61, and 62.

b. During each CT tuning event or on-line water wash event, as described in Condition 10, emissions shall not exceed the following limits:

Pollutant	Limitations for Maintenance Activities (Tuning/Water Washing)
Nitrogen Oxides (as NO_2)	Tuning or water washing: 564 lb/turbine/calendar day
Carbon monoxide	Tuning or water washing: 309 lb/turbine/calendar day

c. NO_x emission concentrations shall not exceed the NO_x standards of the NSPS Subpart KKKK of 15 ppm at loads > 75% or 96 ppm at loads $\leq$ 75% corrected to 15% O_2 (on a rolling 30-day average basis).

d. During each startup or shutdown event, emissions shall not exceed the following:

Pollutant	Startup/Shutdown Limitations
Nitrogen Oxides (as NO_2)	cold start event - 95 lb/turbine warm start event - 117 lb/turbine hot start event - 98 lb/turbine shutdown event - 51 lb/turbine
Carbon monoxide	cold start event - 434 lb/turbine warm start event - 397 lb/turbine hot start event - 336 lb/turbine shutdown event - 184 lb/turbine
Volatile organic compounds (as CH_4)	cold start event - 37 lb/turbine warm start event - 34 lb/turbine hot start event - 34 lb/turbine shutdown event - 56 lb/turbine

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these NO_x and CO limits may be determined as stated in Conditions 9 and 49. Compliance with these VOC limits may be determined by showing correlation of VOC emissions to CO emissions, using CO and VOC stack testing and CO CEM data.

(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

36. **Process Emission Limits: Option 1, GE Turbine Generators** - Emissions from the operation of each of the two GE combustion turbine generators and associated HRSG duct burners (CT-1, CT-2), shall not exceed the limits specified below:

Sulfur Dioxide	0.00114 lb/MMBtu	19.1 tons/yr	(on a 12-month, rolling total)

Compliance with these limits may be determined as stated in Conditions 6 and 23.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

37. **Annual Process Emission Limits: Option 1, GE Turbine Generators –** Emissions from the operation of each of the two GE combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2) shall not exceed the limits specified below:

PM (filterable only)	70.2	tons/yr (on a 12-month, rolling total)
PM_{10}	75.9	tons/yr (on a 12-month, rolling total)
$PM_{2.5}$	75.9	tons/yr (on a 12-month, rolling total)
Nitrogen Oxides (as NO_2)	141.3	tons/yr (on a 12-month, rolling total)
Carbon Monoxide	98.7	tons/yr (on a 12-month, rolling total)
Volatile Organic Compounds	40.3	tons/yr (on a 12-month, rolling total)
Sulfuric Acid Mist	11.8	tons/yr (on a 12-month, rolling total)
CO_2e	2,029,949	tons/yr (on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 1, 3, 4, 6, 7, 8, 23, 24, 48, 49, 50 and 55.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

38. **Process Emission Limits: Option 2, Siemens Turbine Generators** - Emissions from the operation of each of the two Siemens combustion turbine generators and associated HRSG duct burners (CT-1, CT-2), shall not exceed the limits specified below:

Sulfur Dioxide	0.00114 lb/MMBtu	19.3 tons/yr	(on a 12-month, rolling total)

Compliance with these limits may be determined as stated in Conditions 6 and 23.
(9 VAC 5-80-1180 and 9 VAC 5-50-260)

39. **Annual Process Emission Limits: Option 2, Siemens Turbine Generators –** Emissions from the operation of <u>each</u> of the two Siemens combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2), including emissions from startups and shutdowns, shall not exceed the limits specified below:

PM (filterable only)	94.5	tons/yr (on a 12-month, rolling total)

PM_{10}	105.8	tons/yr (on a 12-month, rolling total)
$PM_{2.5}$	105.8	tons/yr (on a 12-month, rolling total)
Nitrogen Oxides (as NO_2)	141.4	tons/yr (on a 12-month, rolling total)
Carbon Monoxide	134.1	tons/yr (on a 12-month, rolling total)
Volatile Organic Compounds	54.1	tons/yr (on a 12-month, rolling total)
Sulfuric Acid Mist	11.9	tons/yr (on a 12-month, rolling total)
CO_2e	2,106,802	tons/yr (on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 1, 3, 4, 6, 7, 8, 23, 24, 48, 49, 50 and 55.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

40. **Emission Limits: Turbine Generators –** The following limit includes all operating conditions over the lifetime of the units: CO_2e emissions from the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2) shall not exceed 883 lbs/MWh net calculated monthly on a 12-month rolling basis. This limit applies at all times. Compliance may be determined each month by summing the CO_2e emissions for all hours in which power is being generated to the grid during the previous 12 months (Condition 50) and dividing that value by the sum of the electrical energy output over that same period (Condition 51).
(9 VAC 5-50-280, 9 VAC 5-80-1705)

41. **Emission Limits: Turbine Generators –** In the event that conditions make it impossible for the permittee to comply with the Condition 40 emission limit, the permittee may request that DEQ adjust the Condition 40 CO_2e emission limit to a level not to exceed 915 lbs/MWh net (calculated monthly on a 12-month rolling basis). In order for DEQ to consider and approve such a request, the permittee shall provide at least 12 months of representative CO_2e emission and operating (load) data demonstrating that it is unable to comply with the Condition 40 emission limit and a demonstration that the proposed revised emission limit is representative of the BACT measures specified in Condition 8. The demonstration shall include a description of the ongoing operational and maintenance measures employed by the permittee to minimize CO_2e emissions. If DEQ approves the request, the revision of the Condition 40 CO_2e emission limit shall be accomplished administratively. During the period of time beginning on the date that the permittee submits the information required by this condition for DEQ to evaluate the request and ending on the date that DEQ acts on the request, failure to meet the Condition 40 emission limit shall not be a violation of this permit

so long as the CO_2e emission rate does not exceed 915 lbs/MWh net (calculated monthly on a 12-month rolling basis).
(9 VAC 5-50-280, 9 VAC 5-80-1705)

42. **Process Emission Limits: Auxiliary Boiler –** Emissions from the operation of the auxiliary boiler (B-1) shall not exceed the limits specified below:

PM (filterable only)	0.8	lbs/hr	3.3	tons/yr (on a 12-month, rolling total)
PM_{10}	0.8	lbs/hr	3.3	tons/yr (on a 12-month, rolling total)
$PM_{2.5}$	0.8	lbs/hr	3.3	tons/yr (on a 12-month, rolling total)
Sulfur Dioxide	0.00118	lb/MMBtu	0.6	tons/yr (on a 12-month rolling total)
Nitrogen Oxides (as NO_2)	1.2	lb/hr	5.1	tons/yr (on a 12-month, rolling total)
Carbon Monoxide	3.9	lbs/hr	17.1	tons/yr (on a 12-month, rolling total)
Volatile Organic Compounds	0.005	lbs/MMBtu	2.3	tons/yr (on a 12-month, rolling total)
CO_2e			53,863	tons/yr (on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 11, 12, 13, 22, and 25.
(9 VAC 5-80-1705, 9 VAC 5-50-280, 9 VAC 5-80-1180 and 9 VAC 5-50-260)

43. **Process Emission Limits: FWP-1** - Emissions from the operation of the fire water pump (FWP-1) shall not exceed the limits specified below:

PM (filterable only)	0.15	g/hp-hr
PM_{10}	0.15	g/hp-hr
$PM_{2.5}$	0.15	g/hp-hr
Nitrogen Oxides (as NO_2) + Non-methane hydrocarbons	3.0	g/hp-hr
Carbon Monoxide	2.6	g/hp-hr
Sulfuric Acid Mist	0.00016	lb/hp-hr
CO_2e	90	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the

exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 26, 27, 28, 29, 31 and 48.
(9 VAC 5-50-280, 9 VAC 5-80-1705)

44. **Process Emission Limits: EG-1** - Emissions from the operation of the diesel emergency generator (EG-1) shall not exceed the limits specified below:

PM (filterable only)	0.15	g/hp-hr		
PM_{10}	0.15	g/hp-hr		
$PM_{2.5}$	0.15	g/hp-hr		
Nitrogen Oxides (as NO_2) + Non-methane hydrocarbons	4.8	g/hp-hr	9.6	tons/yr (on a 12-month rolling total)
Carbon Monoxide	2.6	g/hp-hr	5.2	tons/yr (on a 12-month rolling total)
CO_2e			1040	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 26, 27, 29, 31, and 48.
(9 VAC 5-50-280 and 9 VAC 5-80-1705)

45. **Process Emission Limits: Dew point heater**– Emissions from the operation of the dew point heater (DPH-1) shall not exceed the limits specified below:

PM (filterable only)	0.5	tons/yr (on a 12-month rolling total)
PM_{10}	0.5	tons/yr (on a 12-month rolling total)
$PM_{2.5}$	0.5	tons/yr (on a 12-month rolling total)
Nitrogen Oxides (as NO_2)	0.8	tons/yr (on a 12-month rolling total)
Carbon Monoxide	2.6	tons/yr (on a 12-month rolling total)
CO_2e	8,208	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 11, 12, 13, 14, 15, 22, 32, and 47.
(9 VAC 5-50-280 and 9 VAC 5-80-1705)

46. **Visible Emission Limit: Turbine Generators** - Visible emissions from the combustion turbine generators and associated duct-fired HRSG (CT-1, CT-2) shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall

not exceed 20 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

47. **Visible Emission Limit: Dew point heater and Auxiliary boiler**- Visible emissions from the dew point heater (DPH-1) and auxiliary boiler (B-1) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

48. **Visible Emission Limit: EG-1 and FWP-1** - Visible emissions from the emergency fire water pump (FWP-1) and emergency generator (EG-1) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

CONTINUOUS MONITORING SYSTEMS

49. **CEMS: Turbine Generators -** Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO_x (measured as NO_2) and CO from each combustion turbine generator and associated duct-fired HRSG (CT-1, CT-2) in ppmvd, corrected to 15 percent O_2. CEMS for NO_x shall meet the design specifications of 40 CFR Part 75, whereas CEMS for CO shall be installed, evaluated, and operated according to the monitoring requirements in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_x and CO emissions are monitored and measure heat input and power output. A CEMS or alternative method as allowed by 40 CFR 75.11 (d) and (e) shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR 75 (acid rain program monitoring). For compliance with the emission limits contained in **Option 1,** Condition 34.a or **Option 2,** Condition 35.a, NO_x data shall be reduced to 1-hour block averages using procedures approved by the Piedmont Regional Office.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

50. **Continuous Monitoring: Turbine Generators – Greenhouse gases –** CO_2 emissions from each combustion turbine generator and associated duct-fired HRSG (CT-1, CT-2) shall be monitored using one of the methods in 40 CFR Part 75.13. The permittee shall notify the Piedmont Regional Office as to which method was used to determine the emissions of CO_2 from the turbines and associated duct-fired HRSGs. The methods in Appendix G to 40 CFR Part 75, shall be used to report annual CO_2 emissions. CH_4 and N_2O emissions shall be calculated using fuel heat value data and the emission factors found in 40 CFR Part 98, Subpart C, Table C-2. Annual CO_2e emissions shall be calculated using the global warming potential factors found in 40 CFR Part 98, Subpart A, Table A-1 for CO_2, CH_4 and N_2O.
(9 VAC 5-50-50)

51. **Continuous Metering: Net Power Output and Fuel Flow –** The permittee shall continuously monitor the net electrical output of the combustion turbine generator and

associated steam turbine (CT-1, CT-2) and the fuel flow to the turbines and duct burners to show compliance with the emission factor in Condition 40 or Condition 41, as applicable, on a 12-month rolling basis.
(9 VAC 5-50-40F)

52. **CEMS: Auxiliary Boiler –** Compliance with the Auxiliary Boiler (B-1) NO_x emission limits in Condition 42 shall be determined by one of the following methods:

    a. CEMS shall be installed to measure and record the emissions of NO_x (measured as NO_2) from the auxiliary boiler (B-1) in lb/MMBtu as described in 40 CFR 60.48b(b). The CEMS shall also measure and record the oxygen content (or CO_2 emissions) of the flue gas. The CEMS shall be installed, calibrated, maintained, audited and operated in accordance with the requirements of 40 CFR 60.13.

    b. If Virginia DEQ approves an operational monitoring plan for the Auxiliary Boiler (B-1), as provided by 40 CFR 60.48b (g) (2) and 60.49b (c), rather than using a continuous emissions monitoring system for NO_x, the permittee shall conduct performance tests for NO_x and monitor the operating conditions during testing to develop a plan to predict NOx emissions from the boiler.

    For compliance with the emission limit contained in Condition 42, NO_x data shall be reduced to a 30-day rolling average basis using procedures approved by the Piedmont Regional Office.
    (9 VAC 5-50-350 and 9 VAC 5-50-410)

53. **CEMS Performance Evaluations -** Performance evaluations of the NO_x and, if applicable, SO_2 CEMS shall be conducted in accordance with 40 CFR Part 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. Two copies of the performance evaluations report shall be submitted to the Piedmont Region within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30 day notification, prior to the demonstration of continuous monitoring system's performance, and subsequent notifications shall be submitted to the Piedmont Region.
    (9 VAC 5-50-350 and 9 VAC 5-50-40)

54. **CEMS Quality Control Program -** A CEMS quality control program which is equivalent to the requirements of 40 CFR 75 Appendix B shall be implemented for all continuous monitoring systems.
    (9 VAC 5-50-350 and 9 VAC 5-50-40)

55. **CEMS Emissions Data –** CEMS data shall be used to report annual emissions of NO_x and CO from the stack of each combustion turbine generator and associated duct-fired HRSG (CT-1, CT-2) in tons/yr for the purpose of emission inventory.
    (9 VAC 5-50-50)

56. **CEMS: Excess Emissions and Monitor Downtime for NO_x -** For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 58 are defined as follows:

   a. An excess emission period is a normal unit operating period (does not apply to startup, shutdown, malfunction, or alternative operating scenarios) in which the average one-hour NO_x emission rate exceeds the applicable emission limit in **Option 1,** Condition 34.a or **Option 2**, Condition 35.a; and

   b. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_x concentration, O_2 concentration, fuel flow rate, steam pressure, or megawatts. The steam flow rate is only required if the permittee uses this information for compliance purposes.

   (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4380)

57. **Excess Emissions and Monitoring Downtime for SO_2 -** Excess emissions and monitoring downtime are defined, for the purpose of this permit, as follows:

   a. Excess emissions of SO_2 from the combustion turbine generators occurs when the 12-month rolling average sulfur content of the fuel being fired in the combustion turbine generators and associated duct burners (CT-,1 CT-2) exceeds the applicable limit in Condition 6 based on monthly fuel testing in Condition 24. The excess emission period ends on the date that 12-month rolling average sulfur content of the fuel demonstrates compliance with the sulfur limit; and

   b. A period of monitoring downtime begins when a required sample is not taken by its due date. A period of monitoring downtime also begins on the date of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date of the next valid sample.

   (9 VAC 5-50-50, 9 VAC 5-50-260)

58. **Continuous Monitoring Excess Emissions Reports -** The permittee shall furnish written reports to the Piedmont Region of excess emissions from any process monitored by a continuous monitoring system on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

   a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

   b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.

(9 VAC 5-50-50)

59. **CEMS: Excess Emissions –** For purposes of identifying excess emissions:

a. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h);

b. For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm, using the appropriate equation in 40 CFR Part 60, Appendix A, Method 19. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations; and

c. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Appendix D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4350)

INITIAL COMPLIANCE DETERMINATION

60. **Emissions Testing: Facility** - The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from excessive cyclonic flow as defined in 40 CFR 60 Appendix A. Sampling ports shall be provided at the appropriate locations (in accordance with the applicable performance specification in 40 CFR Part 60, Appendix B) and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30F and 9 VAC 5-80-1675)

61. **Stack Test: Turbine Generators -** Initial performance tests shall be conducted for CO, PM (filterable), PM_{10}, $PM_{2.5}$, and total VOC from each combustion turbine generator and associated duct burner (CT-1, CT-2) to determine compliance with the emission limits contained in **Option 1**, Condition 34.a or **Option 2,** Condition 35.a. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as

set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. Tests shall be conducted for the following operating scenarios: natural gas firing at full load with the duct burners off; and natural gas firing at full load with the duct burners on. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1675, and 9 VAC 5-50-410)

62. **Stack Test: Turbine Generators -** Initial performance tests shall be conducted for CO and total VOC from each combustion turbine generator (CT-1, CT-2) for startup and shutdown periods as defined in Condition 9 to determine compliance with the emission limits contained in **Option 1**, Condition 34.d or **Option 2**, Condition 35.d. The tests shall be performed and demonstrate compliance within the first 12 months of turbine operation. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The protocol shall include procedures for development of the required CO and VOC correlation for the combustion turbine generators and associated duct burners (CT-1, CT-2). One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1675)

63. **Initial Performance Test: Turbine Generators –** Initial performance tests shall be conducted on each combustion turbine generator and associated duct burner (CT-1, CT-2) for NO_x (as NO_2) to determine compliance with the limits contained in **Option 1**, Condition 34.a or **Option 2**, Condition 35.a using 40 CFR 60, Appendix A, Methods 7E or 20 to measure the NO_x concentration (in ppm) and following the performance test specifications found in 40 CFR 60.4400.

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-50-410, and 9 VAC 5-80-1675)

64. **Initial Performance Test: Turbine Generators –** Initial performance tests shall be conducted on each combustion turbine generator and associated duct burner (CT-1, CT-2) for SO_2 to determine compliance with the limits contained in **Option 1**, Condition 36 or **Option 2**, Condition 38. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

    a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manually sampling using Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

    b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

    c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

    The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 60 days after test completion and shall conform to the test report format enclosed with this permit. If fuel sampling is used, as described in 64.a above, no test protocol or test report is required, however, the permittee shall notify the Piedmont Regional Office as to which method was used to determine the total sulfur content of the fuel sample.
    (9 VAC 5-50-30, 9 VAC 5-50-410 and 9 VAC 5-80-1675)

65. **Stack Test: Auxiliary Boiler and Dew Point Heater -** Initial performance tests shall be conducted for NO_x and CO from the auxiliary boiler (B-1) and the dew point heater (DPH-1) to determine compliance with the emission limits contained in Conditions 42 and 45, as applicable. The tests shall be performed, reported and demonstrate compliance within 60 days after the boiler or dew point heater, as applicable, reach the maximum load level at

which the unit will be operated but in no event later than 180 days after its initial start-up. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1985E, and 9 VAC 5-50-410)

66. **Visible Emissions Evaluation: Turbine Generators -** Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combustion turbine generator and associated duct burner (CT-1, CT-2). Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. At least one VEE shall be conducted for each of the operating conditions and loads for which emissions tests are required for the stack tests contained in Condition 61. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit.

    Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Piedmont Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
    (9 VAC 5-50-30 and 9 VAC 5-80-1675)

67. **Visible Emissions Evaluation: Auxiliary Boiler and Dew point heater -** Concurrently with the initial performance tests in Condition 65, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on the auxiliary boiler (B-1) and dew point heater (DPH-1). Each test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the boiler will be operated but in no event later than 180 days after start-up of the boiler.

    Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be

submitted to the Piedmont Regional Office within 60 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

68. **Initial Performance Testing: Power Block Heat Rate Limit -** Initial compliance testing, using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996) or equivalent method approved by the Piedmont Regional Office, shall be conducted for the heat rate limit of the power blocks (i.e., a combination of CT-1 and CT-2 and the steam turbine generator) to show compliance with the heat rate limit contained in Condition 8. The testing shall be performed, reported and demonstrate compliance within 90 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after commencement of commercial operation of the permitted facility. Testing shall be conducted when combusting natural gas. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

<u>CONTINUING COMPLIANCE DETERMINATION</u>

69. **Annual Performance Test: Turbine Generators –** Annual performance tests shall be conducted on each combustion turbine generator and associated duct burner (CT-1, CT-2) for SO_2 to determine compliance with the limits contained in **Option 1**, Condition 36 or **Option 2**, Condition 38. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

   a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manual sampling using the Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D5504, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

   b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

   c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 60 days after test completion and shall conform to the test report format enclosed with this permit. If fuel sampling is used, as described in 69.a above, no test protocol or test report is required, however the permittee shall notify the Piedmont Regional Office as to which method was used to determine the total sulfur content of the fuel sample.
(9 VAC 5-50-30, 9 VAC 5-50-410)

70. **Compliance with NSPS CO_2 Standard –** The permittee shall demonstrate compliance with the applicable CO_2 emission standard by following the procedures in 40 CFR 60.5520(d)(1) for maintaining fuel purchase records.
(9 VAC 5-80-1675 and 9 VAC 5-50-20)

71. **Stack Tests: Continuing Compliance –** Upon request by DEQ, the permittee shall conduct additional performance tests to determine compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30G)

RECORDS

72. **On Site Records: Facility** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Region. These records shall include, but are not limited to:

    a. Annual hours of operation of the emergency fire water pump (FWP-1) and emergency generator (EG-1) for emergency purposes and for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

    b. All fuel supplier certifications for the S15 ULSD fuel used in the diesel emergency units (EG-1 and FWP-1);

    c. Monthly and annual throughput of natural gas to the two combustion turbine generators and associated duct burners (CT-1, CT-2), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

d. Monthly and annual throughput of natural gas to the auxiliary boiler (B-1) and the dew point heater (DPH-1), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

e. Fuel sulfur monitoring records for the natural gas combusted in the combustion turbine generators and associated duct burners (CT-1, CT-2), auxiliary boiler (B-1), and dew point heater (DPH-1);

f. Net power output of the combined cycle combustion turbine generators and associated steam turbine (CT-1, CT-2).

g. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions;

h. Operation and control device monitoring records for each SCR system and oxidation catalyst as required in Conditions 2 and 5;

i. Records of alternative operating scenarios as required by Condition 10;

j. The occurrence and duration of any startup, shutdown, or malfunction of the affected facility, any malfunction of the air pollution control equipment, or any periods during which a continuous emission monitoring system is inoperative;

k. Monthly log of dissolved solids content of cooling water to the cooling tower (CWT-1).

l. Results of daily AVO inspections of piping and components.

m. Scheduled and unscheduled maintenance and operator training.

n. Results of all stack tests, visible emission evaluations, performance evaluations, and initial power block heat rate test.

o. Manufacturer’s instructions for proper operation of equipment.

p. Records showing the circuit breakers are operating in accordance with the manufacturer’s specifications (see Condition 21).

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50 and 9 VAC 5-50-410)

NOTIFICATIONS

73. **Initial Notifications** - The permittee shall furnish written notification to the Piedmont Regional Office of:

a. The actual date on which construction of the electric power generation facility commenced within 30 days after such date.

b. The anticipated start-up date of the electric power generation facility postmarked not more than 60 days nor less than 30 days prior to such date.

c. The actual start-up date of the electric power generation facility within 15 days after such date.

d. The anticipated date of continuous monitoring system performance evaluations postmarked not less than 30 days prior to such date.

e. The anticipated date of performance tests of the combustion turbine generators (CT-1, CT-2), auxiliary boiler (B-1), and dew point heater (DPH-1), postmarked at least 30 days prior to such date.

Copies of the written notification referenced in items a through e above are to be sent to:

Associate Director
Office of Air Enforcement and Compliance Assistance (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-50-50 and 9 VAC 5-50-410)

GENERAL CONDITIONS

74. **Permit Invalidation –**This permit to construct the electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

a. A program of continuous construction or modification is not commenced within 18 months from the date of this permit.

b. A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of the phased construction of a new stationary source or project.

(9 VAC 5-80-1985)

75. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

a. Knowingly makes material misstatements in the permit application or any amendments to it;

b. Fails to comply with the conditions of this permit;

c. Fails to comply with any emission standards applicable to a permitted emissions unit;

d. Causes emissions from the stationary source which result in violations of, or interfere with the attainment and maintenance of, any ambient air quality standard; or

e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

(9 VAC 5-80-1985F)

76. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

    a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

    b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

    c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

    d. To sample or test at reasonable times.

    For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
    (9 VAC 5-170-130 and 9 VAC 5-80-1180)

77. **Maintenance/Operating Procedures –** At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

    The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment and process equipment which affect such emissions:

    a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

    b. Maintain an inventory of spare parts.

    c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

    d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

    Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
    (9 VAC 5-50-20E)

78. **Record of Malfunctions –** The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records

shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9 VAC 5-20-180J)

79. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Piedmont Regional Office of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone, email, or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Piedmont Regional Office.
(9 VAC 5-20-180C)

80. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180I)

81. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Piedmont Regional Office of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1985E)

82. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1985E)

STATE-ONLY ENFORCEABLE REQUIREMENTS

The following terms and conditions are included in this permit to implement the requirements of 9 VAC 5-40-130 et seq., 9 VAC 5-50-130 et seq., 9 VAC 5-60-200 et seq. and/or 9 VAC 5-60-300 et seq. and are enforceable only by the Virginia Air Pollution Control Board. Neither their inclusion in this permit nor any resulting public comment period make these terms federally enforceable.

83. **(SOE) Emission Limits: Toxic Air Pollutants –** Emissions from the electric power generation facility shall not exceed the limits specified below:

		Option 1 GE turbines		**Option 2** Siemens turbines	
Pollutant	CAS#	Lb/hr	Tons/yr	Lb/hr	Tons/yr
Acrolein	107-02-8	0.045	0.20	0.040	0.18

		Option 1 GE turbines		**Option 2** Siemens turbines	
Pollutant	CAS#	Lb/hr	Tons/yr	Lb/hr	Tons/yr
Formaldehyde	50-00-0	1.7	7.1	1.7	7.3
Cadmium	7440-43-9	exempt	exempt	exempt	0.010
Chromium	7440-47-3	exempt	exempt	exempt	0.013
Nickel	7440-02-0	exempt	exempt	exempt	0.019

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 4, 7, 9, and 23.
(9 VAC 5-60-320 and 9 VAC 5-80-1625G)

84. **(SOE) Stack Test: Toxic Air Pollutants –** An initial performance test shall be conducted for formaldehyde from each combustion turbine generator and associated duct burner (CT-1, CT-2) to determine compliance with the emission limits contained in Condition 83. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test shall be conducted in accordance with applicable EPA reference test methods that must be approved through the test protocol review process. Tests shall be conducted at full load with the duct burners on. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 60 days of test completion.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

85. **(SOE) On Site Records: Toxic Air Pollutants –** The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Regional Office. These records shall include, but are not limited to the average hourly (in pounds), monthly (in tons), and annual emissions (in tons) of each toxic compound listed in Condition 83. Hourly emissions shall be calculated as a monthly average. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These records shall be available for inspection by DEQ and current for at least the most recent five years.
(9 VAC 5-50-50, and 9 VAC 5-80-1625G)

SOURCE TESTING REPORT FORMAT

Report Cover

1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Test Dates.
4. Tester; name, address and report date

Certification

1. Signed by team leader/certified observer (include certification date)
2. Signed by responsible company official
3. *Signed by reviewer

Copy of approved test protocol

Summary

1. Reason for testing
2. Test dates
3. Identification of unit tested & the maximum rated capacity
4. *For each emission unit, a table showing:
    a. Operating rate
    b. Test Methods
    c. Pollutants tested
    d. Test results for each run and the run average
    e. Pollutant standard or limit
5. Summarized process and control equipment data for each run and the average, as required by the test protocol
6. A statement that test was conducted in accordance with the test protocol or identification & discussion of deviations, including the likely impact on results
7. Any other important information

Source Operation

1. Description of process and control devices
2. Process and control equipment flow diagram
3. Sampling port location and dimensioned cross section Attached protocol includes: sketch of stack (elevation view) showing sampling port locations, upstream and downstream flow disturbances and their distances from ports; and a sketch of stack (plan view) showing sampling ports, ducts entering the stack and stack diameter or dimensions

Test Results

1. Detailed test results for each run
2. *Sample calculations
3. *Description of collected samples, to include audits when applicable

Appendix

1. *Raw production data
2. *Raw field data
3. *Laboratory reports
4. *Chain of custody records for lab samples
5. *Calibration procedures and results
6. Project participants and titles
7. Observers' names (industry and agency)
8. Related correspondence
9. Standard procedures

* Not applicable to visible emission evaluations

Year	EPA Region	State	County	City	CBSA	Address	Site ID	POC	Exc Events	Obs	98th Percentile	first_max_1 hr	second_max _1hr	annual_mea nC
2014	3	VA	Charles	Not in a City	Richmond, VA	Shirley Plantation, Route 5	510360002	1	None	8133	44	56	52	4.61
2015	3	VA	Charles	Not in a City	Richmond, VA	Shirley Plantation, Route 5	510360002	1	None	8216	38	49	45	4.05
2016	3	VA	Charles	Not in a City	Richmond, VA	Shirley Plantation, Route 5	510360002	1	None	8155	44	48	47	3.38
2017	3	VA	Charles	Not in a City	Richmond, VA	Shirley Plantation, Route 5	510360002	1	None	8317	32	44	41	3.83
2018	3	VA	Charles	Not in a City	Richmond, VA	Shirley Plantation, Route 5	510360002	1	None	8229	31	40	35	4.98
										2014-2016 avg	42			
										2016-2018 avg	35.67			
1_hour NO2 Ambient Air Data downloaded from EPA's Outdoor Air Quality Data Website at https://www.epa.gov/outdoor-air-quality-data/download-daily-data.														

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 2.5 Microns (PM-2.5) Emissions (PM-2.5 Annual)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	Annual PM25 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Charles City	C4GT	1	CT1	C4GTCT1	308449.79	4146576.16	39.78	3.04159	57.91	339.36	17.25	6.71
Charles City	C4GT	2	CT2	C4GTCT2	308414.46	4146605.18	39.78	3.04159	57.91	339.36	17.25	6.71
Charles City	C4GT	3	AUXILIARY BOILER	C4GTAUX	308366.52	4146636.85	39.78	0.09324	45.72	422.04	8.96	1.14
Charles City	C4GT	4	DEW POINT HEATER	C4GTDPH	308378.45	4146744.40	39.78	0.01386	12.19	483.15	40.60	0.30
Charles City	C4GT	5	EMERGENCY GENERATOR	C4GTEG	308522.68	4146710.06	39.78	0.00630	15.24	763.71	45.28	0.30
Charles City	C4GT	6	FIRE WATER PUMP	C4GTFWP	308311.94	4146551.18	39.78	0.00054	3.66	789.26	36.22	0.15
Charles City	C4GT	7	COOLING TOWER 1	CT1	308320.52	4146711.38	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	8	COOLING TOWER 2	CT2	308335.66	4146704.44	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	9	COOLING TOWER 3	CT3	308313.66	4146696.42	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	10	COOLING TOWER 4	CT4	308328.80	4146689.47	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	11	COOLING TOWER 5	CT5	308306.80	4146681.45	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	12	COOLING TOWER 6	CT6	308321.95	4146674.51	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	13	COOLING TOWER 7	CT7	308299.94	4146666.49	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	14	COOLING TOWER 8	CT8	308315.09	4146659.55	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	15	COOLING TOWER 9	CT9	308293.08	4146651.53	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	16	COOLING TOWER 10	CT10	308308.23	4146644.58	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	17	COOLING TOWER 11	CT11	308286.22	4146636.56	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	18	COOLING TOWER 12	CT12	308301.37	4146629.62	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	19	COOLING TOWER 13	CT13	308279.36	4146621.60	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	20	COOLING TOWER 14	CT14	308294.51	4146614.65	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	21	COOLING TOWER 15	CT15	308272.50	4146606.63	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	22	COOLING TOWER 16	CT16	308287.65	4146599.69	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	23	COOLING TOWER 17	CT17	308265.64	4146591.67	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	24	COOLING TOWER 18	CT18	308280.79	4146584.73	39.78	8.39E-06	16.02	293.15	7.81	10.00
Hopewell City	Chemtrade Solutions LLC - Hopewell	1	DIGESTER	VP252588	297928.95	4129723.66	12.19	0.71776	10.00	363.71	0.001	0.0001
Hopewell City	Chemtrade Solutions LLC - Hopewell	3	Dust Collector (Emissions from Lime Slurry Manufacturing)	VP252590	297928.95	4129723.66	12.19	0.00044	3.35	294.26	12.29	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	102	Boiler FU-17	VP252929	298585.86	4130666.56	12.19	0.05531	46.02	533.15	5.18	2.13
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	102	Boiler FU-17	VP252932	298585.86	4130666.56	12.19	0.03798	46.02	533.15	5.18	2.13
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	103	KELLOGG PRIME RFMR VENT	VP252934	298585.86	4130666.56	12.19	1.10924	32.00	387.59	13.68	3.44
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	106	GIRDLER RFMR VENT STACK	VP252935	298585.86	4130666.56	12.19	0.09784	15.24	433.15	6.60	1.52
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	108	SULFURIC ACID PLANT	VP252936	298585.86	4130666.56	12.19	0.62768	56.39	310.93	16.82	1.52
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	112	Area 11 RD3 Dryer Stack	VP252937	298585.86	4130666.56	12.19	0.01901	12.80	326.48	13.30	0.76
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	113	AREA 11 RD4 VENT	VP252938	298585.86	4130666.56	12.19	0.03137	10.67	366.48	12.03	1.10
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	114	AREA 11 RD6 VENT	VP252939	298585.86	4130666.56	12.19	0.01901	12.80	321.48	29.00	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	115	AREA 11 RD7 VENT	VP252940	298585.86	4130666.56	12.19	0.02567	12.80	327.59	32.85	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP252941	298585.86	4130666.56	12.19	0.00029	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP252943	298585.86	4130666.56	12.19	0.08055	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP252944	298585.86	4130666.56	12.19	0.05926	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	121	Kellogg Cooling Tower	VP252945	298585.86	4130666.56	12.19	0.07408	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	122	Miscellaneous Cooling Towers	VP252946	298585.86	4130666.56	6.10	0.12600	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	405	A14 FU14 INCENERATOR VENT	VP252958	298585.86	4130666.56	12.19	0.00748	45.72	358.15	12.42	0.76
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	406	Honeywell Specialty Products Cooling Tower TW-77	VP252959	298585.86	4130666.56	12.19	0.12082	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	707	AREA 7 FUME SCRUBBER FS-1	VP252960	298585.86	4130666.56	12.19	0.06961	20.73	310.93	15.03	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	708	AREA 7 FUME SCRUBBER FS-2	VP252961	298585.86	4130666.56	12.19	0.06961	20.73	310.93	15.03	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	710	CAPROLACTAM REMELT	VP252962	298585.86	4130666.56	12.19	0.00058	9.14	305.37	25.88	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	711	HE-221 STEAM SUPERHEATER	VP252963	298585.86	4130666.56	12.19	0.00633	9.75	688.71	4.20	0.53
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	712	HE-305 STEAM SUPERHEATER	VP252964	298585.86	4130666.56	12.19	0.00633	9.75	688.71	4.20	0.53
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	713	Area 8 Flaker #2	VP252965	298585.86	4130666.56	12.19	0.00173	9.14	305.37	25.88	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	719	BELT FILTER VACUUM PUMP	VP252967	298585.86	4130666.56	12.19	0.06961	21.64	316.48	24.38	0.20
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	720	Area 7 Cooling Tower TW-71	VP252968	298585.86	4130666.56	12.19	0.01062	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	725	Area 7 Caprolactam Recovery Unit (CRU) Fume Scrubber SE-149 Stack	VP252969	298585.86	4130666.56	12.19	0.01007	17.37	322.04	8.41	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	726	Area 7 Caprolactam Recovery Unit (CRU) Hot Oil Heater Stack	VP252970	298585.86	4130666.56	12.19	0.00273	17.37	322.04	8.41	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	804	AREA 16 THERMOX	VP252971	298585.86	4130666.56	12.19	0.00219	7.62	1033.15	4.48	1.68
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	900	AMMONIUM NITRITE "A" TRAN	VP252972	298585.86	4130666.56	12.19	0.05725	33.53	278.15	43.88	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	901	AMMONIUM NITRITE "B" TRAN	VP252973	298585.86	4130666.56	12.19	0.17087	33.53	278.15	43.88	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	902	AMMONIUM NITRITE "C" TRAN	VP252974	298585.86	4130666.56	12.19	0.11909	38.10	278.15	34.74	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	903	AMMONIUM NITRITE "D" TRAN	VP252975	298585.86	4130666.56	12.19	0.00604	38.10	278.15	34.74	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	904	AMMONIUM NITRITE "E" TRAN	VP252976	298585.86	4130666.56	12.19	0.00690	35.05	278.15	0.003	0.61

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 2.5 Microns (PM-2.5) Emissions (PM-2.5 Annual)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	Annual PM25 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	905	HYDROXLAMIN DISLF "A" TRN	VP252977	298585.86	4130666.56	12.19	0.02531	40.23	290.37	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	906	HYDRXLAMIN DISULF "B" TRN	VP252978	298585.86	4130666.56	12.19	0.14182	34.14	288.15	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	907	HYDRXLAMIN DISULF "C" TRN	VP252979	298585.86	4130666.56	12.19	0.04315	40.23	288.15	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	908	HYDRXLAMIN DISULF "D" TRN	VP252980	298585.86	4130666.56	12.19	0.04401	40.23	290.37	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	909	HYDRXLAMIN DISULF "E" TRN	VP252981	298585.86	4130666.56	12.19	0.03538	34.14	290.37	23.45	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	910	Area 9 Cooling Tower TW-37	VP252982	298585.86	4130666.56	12.19	0.04082	10.00	ambient	0.001	0.0001
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	1	Boiler	VP252984	297872.53	4134755.12	7.62	0.02403	6.10	547.04	11.38	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	1	Boiler	VP252986	297872.53	4134755.12	7.62	0.03277	6.10	547.04	11.38	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	1	Boiler	VP252988	297872.53	4134755.12	7.62	0.04032	6.10	547.04	11.38	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	2	Boiler	VP252990	297872.53	4134755.12	7.62	0.00046	6.10	533.15	10.36	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	3	HE-66 Process Furnace	VP252992	297872.53	4134755.12	7.62	0.00030	7.62	638.71	1.07	1.07
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	4	HE-260 Process Furnace	VP252994	297872.53	4134755.12	7.62	0.00944	13.72	533.15	6.78	0.46
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	5	HE-259 Process Furnace	VP252996	297872.53	4134755.12	7.62	0.00872	13.72	533.15	6.37	0.61
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	71	Stack 5-2 for HE-1	VP253006	297872.53	4134755.12	7.62	0.00125	13.72	533.15	11.32	0.61
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	80	E-Train Polymerization Line (5E-1 and 5E-2)	VP253009	297872.53	4134755.12	7.62	0.00428	25.30	317.59	4.33	0.20
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	96	A-Train (DC-11, DC-20)	VP253010	297872.53	4134755.12	7.62	0.01577	25.30	317.59	4.32	0.20
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	97	B-Train (DC-8, DC-10)	VP253011	297872.53	4134755.12	7.62	0.01103	25.30	317.59	4.32	0.20
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	99	D-Train (DC-14, DC-15, DC-63, DC-64) (VP-74, VP-75, VP-76)	VP253012	297872.53	4134755.12	7.62	0.02682	25.30	317.59	4.32	0.20
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	99	D-Train (DC-14, DC-15, DC-63, DC-64) (VP-74, VP-75, VP-76)	VP253013	297872.53	4134755.12	7.62	0.00915	25.30	317.59	4.32	0.20
Hopewell City	Hercules LLC	8	Natrosol Production Area - Particulate Emissions	VP253147	298324.15	4129237.95	12.19	0.15160	15.24	298.15	25.39	0.34
Hopewell City	Hercules LLC	11	Klucel Production Area - Particulate Emissions	VP253148	298324.15	4129237.95	12.19	0.02301	8.23	338.71	0.54	0.21
Hopewell City	Hercules LLC	13	CMC Production Area - Particulate Emissions	VP253149	298324.15	4129237.95	12.19	0.11161	15.24	298.15	9.31	0.30
Hopewell City	Hercules LLC	35	EC Production Area - Particulate Emissions	VP253150	298324.15	4129237.95	12.19	0.02129	20.12	283.15	0.03	0.91
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VP253151	299276.01	4130497.44	12.19	2.59173	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VP253152	299276.01	4130497.44	12.19	0.00114	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VP253154	299276.01	4130497.44	12.19	0.02540	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VP253155	299276.01	4130497.44	12.19	0.84040	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VP253156	299276.01	4130497.44	12.19	0.81882	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VP253157	299276.01	4130497.44	12.19	0.14737	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	3	SMELT TANK STACK	VP253160	299276.01	4130497.44	12.19	0.63353	88.39	338.71	9.14	1.52
Hopewell City	WestRock CP LLC - Hopewell	4	LIME KILN STACK	VP253161	299276.01	4130497.44	12.19	0.17803	28.65	349.82	8.53	1.92
Hopewell City	WestRock CP LLC - Hopewell	5	SLAKER MIX TANKS	VP253162	299276.01	4130497.44	12.19	0.07324	19.81	343.15	26.84	0.30
Hopewell City	WestRock CP LLC - Hopewell	10	RECAUSTICIZING AREA FUG EMISSIONS	VP253163	299276.01	4130497.44	12.19	0.00178	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	24	Fugitive TSP/PM10/PM2.5 from woodyard	VP253164	299276.01	4130497.44	12.19	0.03826	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	25	Fugitive emissions from roads not in wood yard	VP253165	299276.01	4130497.44	12.19	0.01256	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	25	Fugitive emissions from roads not in wood yard	VP253166	299276.01	4130497.44	12.19	0.03596	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	26	SALT CAKE UNLOADING SYSTEM	VP253167	299276.01	4130497.44	12.19	0.01090	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	27	COAL STORAGE & HANDLING	VP253168	299276.01	4130497.44	12.19	0.00001	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	27	COAL STORAGE & HANDLING	VP253169	299276.01	4130497.44	12.19	0.00003	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	27	COAL STORAGE & HANDLING	VP253170	299276.01	4130497.44	12.19	0.00001	10.00	ambient	0.001	0.0001
Chesterfield County	DuPont Teijin Films	1	Boilers	VP253413	297115.10	4136147.55	6.10	0.00000	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VP253414	297115.10	4136147.55	6.10	0.00411	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VP253415	297115.10	4136147.55	6.10	0.00000	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VP253416	297115.10	4136147.55	6.10	0.00379	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	2	Boilers	VP253418	297115.10	4136147.55	6.10	0.00118	25.91	422.04	6.71	0.91
Chesterfield County	DuPont Teijin Films	2	Boilers	VP253420	297115.10	4136147.55	6.10	0.00118	25.91	422.04	6.71	0.91
Chesterfield County	DuPont Teijin Films	3	Boilers	VP253421	297115.10	4136147.55	6.10	0.00000	18.29	430.37	3.05	1.01
Chesterfield County	DuPont Teijin Films	3	Boilers	VP253422	297115.10	4136147.55	6.10	0.00352	18.29	430.37	3.05	1.01
Chesterfield County	DuPont Teijin Films	8	Poly Chip Transfer	VP253423	297115.10	4136147.55	6.10	0.00229	15.24	533.15	65.87	0.15
Chesterfield County	DuPont Teijin Films	8	Poly Chip Transfer	VP253424	297115.10	4136147.55	6.10	0.00059	15.24	533.15	65.87	0.15
Chesterfield County	DuPont Teijin Films	11	Film Line 42	VP253427	297115.10	4136147.55	6.10	0.02053	9.14	449.82	9.71	0.30
Chesterfield County	DuPont Teijin Films	12	Film Line 43	VP253428	297115.10	4136147.55	6.10	0.06878	9.14	449.82	0.01	0.30
Chesterfield County	DuPont Teijin Films	12	Film Line 43	VP253430	297115.10	4136147.55	6.10	0.00437	9.14	449.82	0.01	0.30
Chesterfield County	DuPont Teijin Films	12	Film Line 43	VP253431	297115.10	4136147.55	6.10	0.00344	9.14	449.82	0.01	0.30
Chesterfield County	DuPont Teijin Films	13	Film Line 44	VP253432	297115.10	4136147.55	6.10	0.01769	21.34	449.82	20.71	0.15
Chesterfield County	DuPont Teijin Films	13	Film Line 44	VP253433	297115.10	4136147.55	6.10	0.00941	21.34	449.82	20.71	0.15
Chesterfield County	DuPont Teijin Films	13	Film Line 44	VP253434	297115.10	4136147.55	6.10	0.00898	21.34	449.82	20.71	0.15
Chesterfield County	DuPont Teijin Films	14	Film Line 45	VP253435	297115.10	4136147.55	6.10	0.01696	30.48	298.15	2.46	0.52

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City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	Annual PM25 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Chesterfield County	DuPont Teijin Films	14	Film Line 45	VP253436	297115.10	4136147.55	6.10	0.00902	30.48	298.15	2.46	0.52
Chesterfield County	DuPont Teijin Films	14	Film Line 45	VP253437	297115.10	4136147.55	6.10	0.00155	30.48	298.15	2.46	0.52
Chesterfield County	DuPont Teijin Films	15	Film Line 46	VP253438	297115.10	4136147.55	6.10	0.03049	17.07	422.04	21.57	0.09
Chesterfield County	DuPont Teijin Films	15	Film Line 46	VP253440	297115.10	4136147.55	6.10	0.01622	17.07	422.04	21.57	0.09
Chesterfield County	DuPont Teijin Films	15	Film Line 46	VP253441	297115.10	4136147.55	6.10	0.00319	17.07	422.04	21.57	0.09
Chesterfield County	DuPont Teijin Films	16	Film Line 47	VP253442	297115.10	4136147.55	6.10	0.01527	9.45	380.37	19.41	0.12
Chesterfield County	DuPont Teijin Films	16	Film Line 47	VP253443	297115.10	4136147.55	6.10	0.00812	9.45	380.37	19.41	0.12
Chesterfield County	DuPont Teijin Films	16	Film Line 47	VP253444	297115.10	4136147.55	6.10	0.00285	9.45	380.37	19.41	0.12
Chesterfield County	DuPont Teijin Films	17	Storage	VP253445	297115.10	4136147.55	6.10	0.00253	22.86	310.93	20.38	0.21
Chesterfield County	DuPont Teijin Films	18	Bunkers	VP253446	297115.10	4136147.55	6.10	0.05115	15.85	298.15	54.34	0.21
Chesterfield County	DuPont Teijin Films	19	Bunker/Dryer	VP253447	297115.10	4136147.55	6.10	0.09349	25.30	298.15	4.28	0.39
Chesterfield County	DuPont Teijin Films	20	Storage	VP253448	297115.10	4136147.55	6.10	0.00154	16.46	294.26	6.57	0.24
Chesterfield County	DuPont Teijin Films	21	Material Unload	VP253449	297115.10	4136147.55	6.10	0.00002	2.44	298.15	19.02	0.21
Chesterfield County	Philip Morris USA Inc - Park 500	1	Pulping (pneumatic transfer) [L1CY0101, L1CY0102, L2CY0101, & L2CY0102]	VP253717	297878.33	4135042.65	7.62	0.00022	19.20	349.26	26.82	0.25
Chesterfield County	Philip Morris USA Inc - Park 500	11	PACKER ROOM BH EXH (L1&2)	VP253724	297878.33	4135042.65	7.62	0.00242	28.35	303.15	5.39	1.29
Chesterfield County	Philip Morris USA Inc - Park 500	19	TANKS (L2)	VP253726	297878.33	4135042.65	7.62	0.00178	6.10	310.93	12.98	0.28
Chesterfield County	Philip Morris USA Inc - Park 500	20	TANKS (L2)	VP253727	297878.33	4135042.65	7.62	0.00151	28.96	310.93	12.92	0.30
Chesterfield County	Philip Morris USA Inc - Park 500	21	PREP&SERVICE TKS L2	VP253728	297878.33	4135042.65	7.62	0.00789	28.96	299.82	10.91	0.75
Chesterfield County	Philip Morris USA Inc - Park 500	22	DRYER (L2) DD	VP253729	297878.33	4135042.65	7.62	0.00094	28.96	374.26	18.68	0.71
Chesterfield County	Philip Morris USA Inc - Park 500	23	DRYER (L2) DT	VP253730	297878.33	4135042.65	7.62	0.01316	28.96	327.59	14.05	1.12
Chesterfield County	Philip Morris USA Inc - Park 500	24	VACUUM PUMP SEAL PIT (L2)	VP253731	297878.33	4135042.65	7.62	0.00625	29.87	324.82	6.61	0.61
Chesterfield County	Philip Morris USA Inc - Park 500	26	DRYER (L2) DR	VP253732	297878.33	4135042.65	7.62	0.01019	28.96	302.59	17.25	0.46
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VP253733	297878.33	4135042.65	60.96	0.00414	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VP253734	297878.33	4135042.65	60.96	0.00414	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VP253735	297878.33	4135042.65	60.96	0.01031	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VP253736	297878.33	4135042.65	60.96	0.01031	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	61	AB Dry Processes (BL Process)	VP253737	297878.33	4135042.65	60.96	0.07051	15.24	299.82	10.78	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	64	AB Cooling and Packing - AB Pkg (BL Process)	VP253738	297878.33	4135042.65	60.96	0.00675	15.24	299.82	10.78	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	77	R & B BH0501 BH0601 (L1 & 2) DC0301-06, DC0401-07, BW0301-07, BW0401-07, HM0201-04, BC0301, SP0101, SP0201	VP253739	297878.33	4135042.65	7.62	0.00344	22.56	299.26	11.22	1.68
Chesterfield County	Philip Morris USA Inc - Park 500	77	R & B BH0501 BH0601 (L1 & 2) DC0301-06, DC0401-07, BW0301-07, BW0401-07, HM0201-04, BC0301, SP0101, SP0201	VP253740	297878.33	4135042.65	7.62	0.00305	22.56	299.26	11.22	1.68
Chesterfield County	Philip Morris USA Inc - Park 500	104	3 DIESEL GENS (fire pump, wastewater treatment plant)	VP253742	297878.33	4135042.65	7.62	0.00128	3.66	310.93	3.23	0.30
Chesterfield County	Philip Morris USA Inc - Park 500	104	3 DIESEL GENS (fire pump, wastewater treatment plant)	VP253743	297878.33	4135042.65	7.62	0.00005	3.66	310.93	3.23	0.30
Chesterfield County	Philip Morris USA Inc - Park 500	1000	BOILER 1 (BO0501)	VP253744	297878.33	4135042.65	7.62	0.00000	42.67	505.37	14.72	1.52
Chesterfield County	Philip Morris USA Inc - Park 500	1000	BOILER 1 (BO0501)	VP253745	297878.33	4135042.65	7.62	0.00354	42.67	505.37	14.72	1.52
Chesterfield County	Philip Morris USA Inc - Park 500	1004	BOILER BO0302	VP253748	297878.33	4135042.65	7.62	0.07170	80.47	463.71	19.29	1.46
Chesterfield County	Philip Morris USA Inc - Park 500	1005	BOILER BO0701	VP253749	297878.33	4135042.65	7.62	0.00000	80.47	463.71	19.29	1.46
Chesterfield County	Philip Morris USA Inc - Park 500	1005	BOILER BO0701	VP253750	297878.33	4135042.65	7.62	0.00748	80.47	463.71	19.29	1.46
Hopewell City	City Point Energy Center, LLC	1	Coal Boilers	VP253999	298812.35	4129886.04	12.19	0.32794	60.35	430.37	17.99	2.65
Hopewell City	City Point Energy Center, LLC	2	Coal Boilers	VP254000	298812.35	4129886.04	12.19	0.17867	60.35	430.37	17.99	2.65
Hopewell City	City Point Energy Center, LLC	4	6 COAL BUNKERS	VP254002	298812.35	4129886.04	12.19	0.00014	26.21	293.15	17.29	0.20
Hopewell City	City Point Energy Center, LLC	10	Cooling Towers	VP254003	298812.35	4129886.04	12.19	0.00004	10.00	ambient	0.001	0.0001
Hopewell City	City Point Energy Center, LLC	20	Diesel Emergency Fire Pump	VP254004	298812.35	4129886.04	15.24	0.00029	0.91	422.04	12.94	0.30
Hopewell City	City Point Energy Center, LLC	40	Paved Roads Particulate Emissions	VP254005	298812.35	4129886.04	15.24	0.00717	10.00	ambient	0.001	0.0001
Hopewell City	City Point Energy Center, LLC	50	Lime Storage Silo	VP254006	298812.35	4129886.04	15.24	0.00000	10.00	ambient	0.001	0.0001
Hopewell City	Hopewell Cogeneration Ltd Partnership	1	Brown-Boveri 11N Turbine	VP254023	297732.89	4129638.24	12.19	0.00049	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	1	Brown-Boveri 11N Turbine	VP254024	297732.89	4129638.24	12.19	0.07474	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	2	Brown-Boveri 11N Turbine	VP254025	297732.89	4129638.24	12.19	0.00018	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	2	Brown-Boveri 11N Turbine	VP254026	297732.89	4129638.24	12.19	0.09128	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	3	Brown-Boveri 11N Turbine	VP254027	297732.89	4129638.24	12.19	0.00029	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	3	Brown-Boveri 11N Turbine	VP254028	297732.89	4129638.24	12.19	0.08804	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	4	#1 B&W Aux Boiler	VP254029	297732.89	4129638.24	12.19	0.00000	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	4	#1 B&W Aux Boiler	VP254030	297732.89	4129638.24	12.19	0.00308	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	5	#2 B&W Aux Boiler	VP254032	297732.89	4129638.24	12.19	0.00545	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	7	Emergency Generators	VP254033	297732.89	4129638.24	12.19	0.00005	3.96	477.59	8.28	0.30
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP254153	297435.30	4130292.05	12.19	0.00007	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP254154	297435.30	4130292.05	12.19	0.28409	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP254155	297435.30	4130292.05	12.19	0.00007	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP254156	297435.30	4130292.05	12.19	0.20943	67.06	341.48	23.62	2.44

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 2.5 Microns (PM-2.5) Emissions (PM-2.5 Annual)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	Annual PM25 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Hopewell City	Dominion - Hopewell Power Station	4	Coal/biomass handling system	VP254157	297435.30	4130292.05	12.19	0.00130	35.97	298.15	0.29	0.91
Hopewell City	Dominion - Hopewell Power Station	7	Diesel water pump	VP254158	297435.30	4130292.05	12.19	0.00001	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	9	1.63 MMBTU/HR FIRE PUMP	VP254160	297435.30	4130292.05	12.19	0.00007	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	10	Recycle ash handling	VP254161	297435.30	4130292.05	12.19	0.02848	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	13	FLY/BOTTOM ASH SILO	VP254162	297435.30	4130292.05	12.19	0.00833	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	14	TRUCK LOADING	VP254165	297435.30	4130292.05	12.19	0.00001	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	16	Ash storage silo	VP254167	297435.30	4130292.05	12.19	0.00316	3.66	283.15	0.02	0.20
Hopewell City	Dominion - Hopewell Power Station	17	CEMENT SILO BAGHOUSE	VP254168	297435.30	4130292.05	12.19	0.00004	24.38	288.15	0.01	0.33
Charles City County	HDI Manufacturing	1	BAGHOUSE STACK	VP254297	309496.98	4147804.60	36.58	0.07440	7.32	294.26	13.74	0.61
Charles City County	Charles City County Landfill	1	CANDLE STICK FLARE 3600 scfm	VP254438	311668.02	4145592.36	48.77	0.01151	9.75	1033.15	23.28	0.30
Charles City County	Charles City County Landfill	2	CANDLE STICK FLARE 2500 scfm	VP254439	311668.02	4145592.36	48.77	0.00704	9.75	1033.15	16.17	0.30
Charles City County	Charles City County Landfill	21	Fugitives Road Dust Emissions	VP254444	311668.02	4145592.36	48.77	0.06588	10.00	ambient	0.001	0.0001
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VP254582	311729.50	4145688.56	51.82	0.02650	10.06	672.04	65.82	0.41
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VP254583	311729.50	4145688.56	51.82	0.36580	10.06	672.04	65.82	0.41
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254759	297071.03	4130563.89	13.72	0.00201	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254760	297071.03	4130563.89	13.72	0.12456	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254761	297071.03	4130563.89	13.72	0.00069	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254762	297071.03	4130563.89	13.72	0.00010	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254763	297071.03	4130563.89	13.72	0.00010	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	3	RTO	VP254765	297214.23	4130305.51	13.72	0.64725	30.48	432.04	3.88	1.52
Hopewell City	Green Plains Hopewell Limited Liability Company	4	Grain Receiving	VP254766	297071.03	4130563.89	14.63	0.13463	14.63	297.04	41.39	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	6	Hammer Mill #1	VP254767	297071.03	4130563.89	14.63	0.03337	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	7	Hammer Mill #2	VP254768	297071.03	4130563.89	14.63	0.03337	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	9	Hammer Mill #4	VP254770	297071.03	4130563.89	14.63	0.01352	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	10	DDGS Handling	VP254771	297071.03	4130563.89	14.63	0.01151	14.63	297.04	8.62	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	11	DDGS Loadout	VP254772	297071.03	4130563.89	14.63	0.06070	14.63	297.04	8.62	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	12	Loadout Flare	VP254773	297071.03	4130563.89	14.63	0.00001	6.10	533.15	0.86	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	14	Emergency Fire Pump #1 (EU-59)	VP254774	297071.03	4130563.89	14.63	0.00016	2.44	699.82	92.04	0.23
Hopewell City	Green Plains Hopewell Limited Liability Company	15	Boilers	VP254775	297071.03	4130563.89	13.72	0.15065	30.48	432.04	3.88	1.52
Hopewell City	Green Plains Hopewell Limited Liability Company	16	Hammer Mill #5	VP254776	297071.03	4130563.89	14.63	0.00320	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	21	Emergency Fire Pump #2 (EU-74)	VP254777	297071.03	4130563.89	14.63	0.00007	2.44	699.82	92.04	0.23

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 2.5 Microns (PM-2.5) Emissions (PM-2.5 24-hour)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	24hr PM25 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Charles City	C4GT	1	CT1	C4GTCT1	308449.79	4146576.16	39.78	3.04159	57.91	339.36	17.25	6.71
Charles City	C4GT	2	CT2	C4GTCT2	308414.46	4146605.18	39.78	3.04159	57.91	339.36	17.25	6.71
Charles City	C4GT	3	AUXILIARY BOILER	C4GTAUX	308366.52	4146636.85	39.78	0.09324	45.72	422.04	8.96	1.14
Charles City	C4GT	4	DEW POINT HEATER	C4GTDPH	308378.45	4146744.40	39.78	0.01386	12.19	483.15	40.60	0.30
Charles City	C4GT	5	EMERGENCY GENERATOR	C4GTEG	308522.68	4146710.06	39.78	0.00630	15.24	763.71	45.28	0.30
Charles City	C4GT	6	FIRE WATER PUMP	C4GTFWP	308311.94	4146551.18	39.78	0.00054	3.66	789.26	36.22	0.15
Charles City	C4GT	7	COOLING TOWER 1	CT1	308320.52	4146711.38	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	8	COOLING TOWER 2	CT2	308335.66	4146704.44	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	9	COOLING TOWER 3	CT3	308313.66	4146696.42	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	10	COOLING TOWER 4	CT4	308328.80	4146689.47	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	11	COOLING TOWER 5	CT5	308306.80	4146681.45	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	12	COOLING TOWER 6	CT6	308321.95	4146674.51	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	13	COOLING TOWER 7	CT7	308299.94	4146666.49	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	14	COOLING TOWER 8	CT8	308315.09	4146659.55	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	15	COOLING TOWER 9	CT9	308293.08	4146651.53	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	16	COOLING TOWER 10	CT10	308308.23	4146644.58	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	17	COOLING TOWER 11	CT11	308286.22	4146636.56	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	18	COOLING TOWER 12	CT12	308301.37	4146629.62	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	19	COOLING TOWER 13	CT13	308279.36	4146621.60	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	20	COOLING TOWER 14	CT14	308294.51	4146614.65	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	21	COOLING TOWER 15	CT15	308272.50	4146606.63	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	22	COOLING TOWER 16	CT16	308287.65	4146599.69	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	23	COOLING TOWER 17	CT17	308265.64	4146591.67	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	24	COOLING TOWER 18	CT18	308280.79	4146584.73	39.78	8.39E-06	16.02	293.15	7.81	10.00
Hopewell City	Chemtrade Solutions LLC - Hopewell	1	DIGESTER	VP252588	297928.95	4129723.66	12.19	0.98321	10.00	363.71	0.001	0.0001
Hopewell City	Chemtrade Solutions LLC - Hopewell	3	Dust Collector (Emissions from Lime Slurry Manufacturing)	VP252590	297928.95	4129723.66	12.19	0.06955	3.35	294.26	12.29	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	102	Boiler FU-17	VP252929	298585.86	4130666.56	12.19	0.05531	46.02	533.15	5.18	2.13
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	102	Boiler FU-17	VP252932	298585.86	4130666.56	12.19	0.03798	46.02	533.15	5.18	2.13
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	103	KELLOGG PRIME RFMR VENT	VP252934	298585.86	4130666.56	12.19	1.10924	32.00	387.59	13.68	3.44
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	106	GIRDLER RFMR VENT STACK	VP252935	298585.86	4130666.56	12.19	0.09784	15.24	433.15	6.60	1.52
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	108	SULFURIC ACID PLANT	VP252936	298585.86	4130666.56	12.19	0.62768	56.39	310.93	16.82	1.52
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	112	Area 11 RD3 Dryer Stack	VP252937	298585.86	4130666.56	12.19	0.01901	12.80	326.48	13.30	0.76
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	113	AREA 11 RD4 VENT	VP252938	298585.86	4130666.56	12.19	0.03137	10.67	366.48	12.03	1.10
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	114	AREA 11 RD6 VENT	VP252939	298585.86	4130666.56	12.19	0.01901	12.80	321.48	29.00	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	115	AREA 11 RD7 VENT	VP252940	298585.86	4130666.56	12.19	0.02567	12.80	327.59	32.85	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP252941	298585.86	4130666.56	12.19	0.00029	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP252943	298585.86	4130666.56	12.19	0.08055	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP252944	298585.86	4130666.56	12.19	0.05926	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	121	Kellogg Cooling Tower	VP252945	298585.86	4130666.56	12.19	0.07408	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	122	Miscellaneous Cooling Towers	VP252946	298585.86	4130666.56	6.10	0.12600	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	405	A14 FU14 INCENERATOR VENT	VP252958	298585.86	4130666.56	12.19	0.00748	45.72	358.15	12.42	0.76
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	406	Honeywell Specialty Products Cooling Tower TW-77	VP252959	298585.86	4130666.56	12.19	0.12082	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	707	AREA 7 FUME SCRUBBER FS-1	VP252960	298585.86	4130666.56	12.19	0.06961	20.73	310.93	15.03	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	708	AREA 7 FUME SCRUBBER FS-2	VP252961	298585.86	4130666.56	12.19	0.06961	20.73	310.93	15.03	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	710	CAPROLACTAM REMELT	VP252962	298585.86	4130666.56	12.19	0.00058	9.14	305.37	25.88	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	711	HE-221 STEAM SUPERHEATER	VP252963	298585.86	4130666.56	12.19	0.00633	9.75	688.71	4.20	0.53
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	712	HE-305 STEAM SUPERHEATER	VP252964	298585.86	4130666.56	12.19	0.00633	9.75	688.71	4.20	0.53
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	713	Area 8 Flaker #2	VP252965	298585.86	4130666.56	12.19	0.00173	9.14	305.37	25.88	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	719	BELT FILTER VACUUM PUMP	VP252967	298585.86	4130666.56	12.19	0.06961	21.64	316.48	24.38	0.20
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	720	Area 7 Cooling Tower TW-71	VP252968	298585.86	4130666.56	12.19	0.01062	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	725	Area 7 Caprolactam Recovery Unit (CRU) Fume Scrubber SE-149 Stack	VP252969	298585.86	4130666.56	12.19	0.01007	17.37	322.04	8.41	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	726	Area 7 Caprolactam Recovery Unit (CRU) Hot Oil Heater Stack	VP252970	298585.86	4130666.56	12.19	0.00273	17.37	322.04	8.41	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	804	AREA 16 THERMOX	VP252971	298585.86	4130666.56	12.19	0.00219	7.62	1033.15	4.48	1.68
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	900	AMMONIUM NITRITE "A" TRAN	VP252972	298585.86	4130666.56	12.19	0.05725	33.53	278.15	43.88	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	901	AMMONIUM NITRITE "B" TRAN	VP252973	298585.86	4130666.56	12.19	0.17087	33.53	278.15	43.88	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	902	AMMONIUM NITRITE "C" TRAN	VP252974	298585.86	4130666.56	12.19	0.11909	38.10	278.15	34.74	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	903	AMMONIUM NITRITE "D" TRAN	VP252975	298585.86	4130666.56	12.19	0.00604	38.10	278.15	34.74	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	904	AMMONIUM NITRITE "E" TRAN	VP252976	298585.86	4130666.56	12.19	0.00690	35.05	278.15	0.003	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	905	HYDROXLAMIN DISLF "A" TRN	VP252977	298585.86	4130666.56	12.19	0.02531	40.23	290.37	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	906	HYDRXLAMIN DISULF "B" TRN	VP252978	298585.86	4130666.56	12.19	0.14182	34.14	288.15	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	907	HYDRXLAMIN DISULF "C" TRN	VP252979	298585.86	4130666.56	12.19	0.04315	40.23	288.15	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	908	HYDRXLAMIN DISULF "D" TRN	VP252980	298585.86	4130666.56	12.19	0.04401	40.23	290.37	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	909	HYDRXLAMIN DISULF "E" TRN	VP252981	298585.86	4130666.56	12.19	0.03538	34.14	290.37	23.45	0.61

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 2.5 Microns (PM-2.5) Emissions (PM-2.5 24-hour)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	24hr PM25 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	910	Area 9 Cooling Tower TW-37	VP252982	298585.86	4130666.56	12.19	0.04082	10.00	ambient	0.001	0.0001
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	1	Boiler	VP252984	297872.53	4134755.12	7.62	0.02403	6.10	547.04	11.38	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	1	Boiler	VP252986	297872.53	4134755.12	7.62	0.03277	6.10	547.04	11.38	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	1	Boiler	VP252988	297872.53	4134755.12	7.62	0.04032	6.10	547.04	11.38	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	2	Boiler	VP252990	297872.53	4134755.12	7.62	0.00046	6.10	533.15	10.36	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	3	HE-66 Process Furnace	VP252992	297872.53	4134755.12	7.62	0.00030	7.62	638.71	1.07	1.07
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	4	HE-260 Process Furnace	VP252994	297872.53	4134755.12	7.62	0.00944	13.72	533.15	6.78	0.46
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	5	HE-259 Process Furnace	VP252996	297872.53	4134755.12	7.62	0.10605	13.72	533.15	6.37	0.61
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	71	Stack 5-2 for HE-1	VP253006	297872.53	4134755.12	7.62	0.00125	13.72	533.15	11.32	0.61
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	80	E-Train Polymerization Line (5E-1 and 5E-2)	VP253009	297872.53	4134755.12	7.62	0.00428	25.30	317.59	4.33	0.20
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	96	A-Train (DC-11, DC-20)	VP253010	297872.53	4134755.12	7.62	0.01577	25.30	317.59	4.32	0.20
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	97	B-Train (DC-8, DC-10)	VP253011	297872.53	4134755.12	7.62	0.01103	25.30	317.59	4.32	0.20
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	99	D-Train (DC-14, DC-15, DC-63, DC-64) (VP-74, VP-75, VP-76)	VP253012	297872.53	4134755.12	7.62	0.02682	25.30	317.59	4.32	0.20
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	99	D-Train (DC-14, DC-15, DC-63, DC-64) (VP-74, VP-75, VP-76)	VP253013	297872.53	4134755.12	7.62	0.00915	25.30	317.59	4.32	0.20
Hopewell City	Hercules LLC	8	Natrosol Production Area - Particulate Emissions	VP253147	298324.15	4129237.95	12.19	0.17092	15.24	298.15	25.39	0.34
Hopewell City	Hercules LLC	11	Klucel Production Area - Particulate Emissions	VP253148	298324.15	4129237.95	12.19	0.02350	8.23	338.71	0.54	0.21
Hopewell City	Hercules LLC	13	CMC Production Area - Particulate Emissions	VP253149	298324.15	4129237.95	12.19	0.11673	15.24	298.15	9.31	0.30
Hopewell City	Hercules LLC	35	EC Production Area - Particulate Emissions	VP253150	298324.15	4129237.95	12.19	0.02362	20.12	283.15	0.03	0.91
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VP253151	299276.01	4130497.44	12.19	2.59173	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VP253152	299276.01	4130497.44	12.19	0.00114	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VP253154	299276.01	4130497.44	12.19	0.02540	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VP253155	299276.01	4130497.44	12.19	0.84040	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VP253156	299276.01	4130497.44	12.19	0.81882	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VP253157	299276.01	4130497.44	12.19	0.14737	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	3	SMELT TANK STACK	VP253160	299276.01	4130497.44	12.19	0.63353	88.39	338.71	9.14	1.52
Hopewell City	WestRock CP LLC - Hopewell	4	LIME KILN STACK	VP253161	299276.01	4130497.44	12.19	0.17803	28.65	349.82	8.53	1.92
Hopewell City	WestRock CP LLC - Hopewell	5	SLAKER MIX TANKS	VP253162	299276.01	4130497.44	12.19	0.07324	19.81	343.15	26.84	0.30
Hopewell City	WestRock CP LLC - Hopewell	10	RECAUSTICIZING AREA FUG EMISSIONS	VP253163	299276.01	4130497.44	12.19	0.00178	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	24	Fugitive TSP/PM10/PM2.5 from woodyard	VP253164	299276.01	4130497.44	12.19	0.03826	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	25	Fugitive emissions from roads not in wood yard	VP253165	299276.01	4130497.44	12.19	0.01256	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	25	Fugitive emissions from roads not in wood yard	VP253166	299276.01	4130497.44	12.19	0.03596	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	26	SALT CAKE UNLOADING SYSTEM	VP253167	299276.01	4130497.44	12.19	0.01090	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	27	COAL STORAGE & HANDLING	VP253168	299276.01	4130497.44	12.19	0.00004	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	27	COAL STORAGE & HANDLING	VP253169	299276.01	4130497.44	12.19	0.00011	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	27	COAL STORAGE & HANDLING	VP253170	299276.01	4130497.44	12.19	0.00005	10.00	ambient	0.001	0.0001
Chesterfield County	DuPont Teijin Films	1	Boilers	VP253413	297115.10	4136147.55	6.10	0.00000	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VP253414	297115.10	4136147.55	6.10	0.00568	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VP253415	297115.10	4136147.55	6.10	0.00000	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VP253416	297115.10	4136147.55	6.10	0.00432	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	2	Boilers	VP253418	297115.10	4136147.55	6.10	0.00123	25.91	422.04	6.71	0.91
Chesterfield County	DuPont Teijin Films	2	Boilers	VP253420	297115.10	4136147.55	6.10	0.00120	25.91	422.04	6.71	0.91
Chesterfield County	DuPont Teijin Films	3	Boilers	VP253421	297115.10	4136147.55	6.10	0.00000	18.29	430.37	3.05	1.01
Chesterfield County	DuPont Teijin Films	3	Boilers	VP253422	297115.10	4136147.55	6.10	0.00489	18.29	430.37	3.05	1.01
Chesterfield County	DuPont Teijin Films	8	Poly Chip Transfer	VP253423	297115.10	4136147.55	6.10	0.00232	15.24	533.15	65.87	0.15
Chesterfield County	DuPont Teijin Films	8	Poly Chip Transfer	VP253424	297115.10	4136147.55	6.10	0.00059	15.24	533.15	65.87	0.15
Chesterfield County	DuPont Teijin Films	11	Film Line 42	VP253427	297115.10	4136147.55	6.10	0.02204	9.14	449.82	9.71	0.30
Chesterfield County	DuPont Teijin Films	12	Film Line 43	VP253428	297115.10	4136147.55	6.10	0.07677	9.14	449.82	0.01	0.30
Chesterfield County	DuPont Teijin Films	12	Film Line 43	VP253430	297115.10	4136147.55	6.10	0.00488	9.14	449.82	0.01	0.30
Chesterfield County	DuPont Teijin Films	12	Film Line 43	VP253431	297115.10	4136147.55	6.10	0.00384	9.14	449.82	0.01	0.30
Chesterfield County	DuPont Teijin Films	13	Film Line 44	VP253432	297115.10	4136147.55	6.10	0.08172	21.34	449.82	20.71	0.15
Chesterfield County	DuPont Teijin Films	13	Film Line 44	VP253433	297115.10	4136147.55	6.10	0.04347	21.34	449.82	20.71	0.15
Chesterfield County	DuPont Teijin Films	13	Film Line 44	VP253434	297115.10	4136147.55	6.10	0.04147	21.34	449.82	20.71	0.15
Chesterfield County	DuPont Teijin Films	14	Film Line 45	VP253435	297115.10	4136147.55	6.10	0.01859	30.48	298.15	2.46	0.52
Chesterfield County	DuPont Teijin Films	14	Film Line 45	VP253436	297115.10	4136147.55	6.10	0.00989	30.48	298.15	2.46	0.52
Chesterfield County	DuPont Teijin Films	14	Film Line 45	VP253437	297115.10	4136147.55	6.10	0.00170	30.48	298.15	2.46	0.52
Chesterfield County	DuPont Teijin Films	15	Film Line 46	VP253438	297115.10	4136147.55	6.10	0.03383	17.07	422.04	21.57	0.09
Chesterfield County	DuPont Teijin Films	15	Film Line 46	VP253440	297115.10	4136147.55	6.10	0.01799	17.07	422.04	21.57	0.09
Chesterfield County	DuPont Teijin Films	15	Film Line 46	VP253441	297115.10	4136147.55	6.10	0.00354	17.07	422.04	21.57	0.09
Chesterfield County	DuPont Teijin Films	16	Film Line 47	VP253442	297115.10	4136147.55	6.10	0.01679	9.45	380.37	19.41	0.12
Chesterfield County	DuPont Teijin Films	16	Film Line 47	VP253443	297115.10	4136147.55	6.10	0.00893	9.45	380.37	19.41	0.12
Chesterfield County	DuPont Teijin Films	16	Film Line 47	VP253444	297115.10	4136147.55	6.10	0.00313	9.45	380.37	19.41	0.12
Chesterfield County	DuPont Teijin Films	17	Storage	VP253445	297115.10	4136147.55	6.10	0.00262	22.86	310.93	20.38	0.21
Chesterfield County	DuPont Teijin Films	18	Bunkers	VP253446	297115.10	4136147.55	6.10	0.05303	15.85	298.15	54.34	0.21

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 2.5 Microns (PM-2.5) Emissions (PM-2.5 24-hour)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	24hr PM25 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Chesterfield County	DuPont Teijin Films	19	Bunker/Dryer	VP253447	297115.10	4136147.55	6.10	0.09695	25.30	298.15	4.28	0.39
Chesterfield County	DuPont Teijin Films	20	Storage	VP253448	297115.10	4136147.55	6.10	0.00160	16.46	294.26	6.57	0.24
Chesterfield County	DuPont Teijin Films	21	Material Unload	VP253449	297115.10	4136147.55	6.10	0.00037	2.44	298.15	19.02	0.21
Henrico County	Mondelez Global LLC - Richmond Bakery	1	Boilers	VP253663	292138.53	4152770.01	45.72	0.00316	6.71	422.04	7.92	0.52
Henrico County	Mondelez Global LLC - Richmond Bakery	2	Heaters	VP253664	292138.53	4152770.01	45.72	0.00032	6.71	366.48	10.35	0.08
Henrico County	Mondelez Global LLC - Richmond Bakery	3	Emergency Fire Pumps	VP253665	292138.53	4152770.01	45.72	0.07812	1.83	366.48	10.35	0.08
Henrico County	Mondelez Global LLC - Richmond Bakery	4	Ovens	VP253666	292138.53	4152770.01	45.72	0.02813	15.24	422.04	1.15	0.30
Henrico County	Mondelez Global LLC - Richmond Bakery	7	Storage Bins/Transfer Systems	VP253667	292138.53	4152770.01	45.72	0.00605	29.26	293.15	10.78	0.18
Henrico County	Mondelez Global LLC - Richmond Bakery	7	Storage Bins/Transfer Systems	VP253668	292138.53	4152770.01	45.72	0.00149	29.26	293.15	10.78	0.18
Henrico County	Mondelez Global LLC - Richmond Bakery	7	Storage Bins/Transfer Systems	VP253669	292138.53	4152770.01	45.72	0.00143	29.26	293.15	10.78	0.18
Henrico County	Mondelez Global LLC - Richmond Bakery	8	Seasoning Process on Line #7	VP253670	292138.53	4152770.01	45.72	0.00000	15.24	293.15	10.35	0.08
Chesterfield County	Philip Morris USA Inc - Park 500	1	Pulping (pneumatic transfer) [L1CY0101, L1CY0102, L2CY0101, & L2CY0102]	VP253717	297878.33	4135042.65	7.62	0.00022	19.20	349.26	26.82	0.25
Chesterfield County	Philip Morris USA Inc - Park 500	11	PACKER ROOM BH EXH (L1&2)	VP253724	297878.33	4135042.65	7.62	0.00242	28.35	303.15	5.39	1.29
Chesterfield County	Philip Morris USA Inc - Park 500	19	TANKS (L2)	VP253726	297878.33	4135042.65	7.62	0.00178	6.10	310.93	12.98	0.28
Chesterfield County	Philip Morris USA Inc - Park 500	20	TANKS (L2)	VP253727	297878.33	4135042.65	7.62	0.00151	28.96	310.93	12.92	0.30
Chesterfield County	Philip Morris USA Inc - Park 500	21	PREP&SERVICE TKS L2	VP253728	297878.33	4135042.65	7.62	0.00789	28.96	299.82	10.91	0.75
Chesterfield County	Philip Morris USA Inc - Park 500	22	DRYER (L2) DD	VP253729	297878.33	4135042.65	7.62	0.00094	28.96	374.26	18.68	0.71
Chesterfield County	Philip Morris USA Inc - Park 500	23	DRYER (L2) DT	VP253730	297878.33	4135042.65	7.62	0.01716	28.96	327.59	14.05	1.12
Chesterfield County	Philip Morris USA Inc - Park 500	24	VACUUM PUMP SEAL PIT (L2)	VP253731	297878.33	4135042.65	7.62	0.00625	29.87	324.82	6.61	0.61
Chesterfield County	Philip Morris USA Inc - Park 500	26	DRYER (L2) DR	VP253732	297878.33	4135042.65	7.62	0.01019	28.96	302.59	17.25	0.46
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VP253733	297878.33	4135042.65	60.96	0.00414	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VP253734	297878.33	4135042.65	60.96	0.00414	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VP253735	297878.33	4135042.65	60.96	0.01031	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VP253736	297878.33	4135042.65	60.96	0.01031	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	61	AB Dry Processes (BL Process)	VP253737	297878.33	4135042.65	60.96	0.07051	15.24	299.82	10.78	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	64	AB Cooling and Packing - AB Pkg (BL Process)	VP253738	297878.33	4135042.65	60.96	0.00675	15.24	299.82	10.78	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	77	R & B BH0501 BH0601 (L1 & 2) DC0301-06, DC0401-07, BW0301-07, BW0401-07, HM0201-04, BC0301, SP0101, SP0201	VP253739	297878.33	4135042.65	7.62	0.00344	22.56	299.26	11.22	1.68
Chesterfield County	Philip Morris USA Inc - Park 500	77	R & B BH0501 BH0601 (L1 & 2) DC0301-06, DC0401-07, BW0301-07, BW0401-07, HM0201-04, BC0301, SP0101, SP0201	VP253740	297878.33	4135042.65	7.62	0.00305	22.56	299.26	11.22	1.68
Chesterfield County	Philip Morris USA Inc - Park 500	104	3 DIESEL GENS (fire pump, wastewater treatment plant)	VP253742	297878.33	4135042.65	7.62	0.09334	3.66	310.93	3.23	0.30
Chesterfield County	Philip Morris USA Inc - Park 500	104	3 DIESEL GENS (fire pump, wastewater treatment plant)	VP253743	297878.33	4135042.65	7.62	0.00335	3.66	310.93	3.23	0.30
Chesterfield County	Philip Morris USA Inc - Park 500	1000	BOILER 1 (BO0501)	VP253744	297878.33	4135042.65	7.62	0.00000	42.67	505.37	14.72	1.52
Chesterfield County	Philip Morris USA Inc - Park 500	1000	BOILER 1 (BO0501)	VP253745	297878.33	4135042.65	7.62	0.00354	42.67	505.37	14.72	1.52
Chesterfield County	Philip Morris USA Inc - Park 500	1004	BOILER BO0302	VP253748	297878.33	4135042.65	7.62	0.07170	80.47	463.71	19.29	1.46
Chesterfield County	Philip Morris USA Inc - Park 500	1005	BOILER BO0701	VP253749	297878.33	4135042.65	7.62	0.00000	80.47	463.71	19.29	1.46
Chesterfield County	Philip Morris USA Inc - Park 500	1005	BOILER BO0701	VP253750	297878.33	4135042.65	7.62	0.00748	80.47	463.71	19.29	1.46
Hopewell City	City Point Energy Center, LLC	1	Coal Boilers	VP253999	298812.35	4129886.04	12.19	0.40027	60.35	430.37	17.99	2.65
Hopewell City	City Point Energy Center, LLC	2	Coal Boilers	VP254000	298812.35	4129886.04	12.19	0.33601	60.35	430.37	17.99	2.65
Hopewell City	City Point Energy Center, LLC	4	6 COAL BUNKERS	VP254002	298812.35	4129886.04	12.19	0.00018	26.21	293.15	17.29	0.20
Hopewell City	City Point Energy Center, LLC	10	Cooling Towers	VP254003	298812.35	4129886.04	12.19	0.00004	10.00	ambient	0.001	0.0001
Hopewell City	City Point Energy Center, LLC	20	Diesel Emergency Fire Pump	VP254004	298812.35	4129886.04	15.24	0.05070	0.91	422.04	12.94	0.30
Hopewell City	City Point Energy Center, LLC	40	Paved Roads Particulate Emissions	VP254005	298812.35	4129886.04	15.24	0.00717	10.00	ambient	0.001	0.0001
Hopewell City	City Point Energy Center, LLC	50	Lime Storage Silo	VP254006	298812.35	4129886.04	15.24	0.00000	10.00	ambient	0.001	0.0001
Hopewell City	Hopewell Cogeneration Ltd Partnership	1	Brown-Boveri 11N Turbine	VP254023	297732.89	4129638.24	12.19	0.01722	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	1	Brown-Boveri 11N Turbine	VP254024	297732.89	4129638.24	12.19	2.60851	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	2	Brown-Boveri 11N Turbine	VP254025	297732.89	4129638.24	12.19	0.02155	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	2	Brown-Boveri 11N Turbine	VP254026	297732.89	4129638.24	12.19	11.10618	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	3	Brown-Boveri 11N Turbine	VP254027	297732.89	4129638.24	12.19	0.01730	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	3	Brown-Boveri 11N Turbine	VP254028	297732.89	4129638.24	12.19	5.17584	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	4	#1 B&W Aux Boiler	VP254029	297732.89	4129638.24	12.19	0.00000	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	4	#1 B&W Aux Boiler	VP254030	297732.89	4129638.24	12.19	0.00560	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	5	#2 B&W Aux Boiler	VP254032	297732.89	4129638.24	12.19	0.02645	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	7	Emergency Generators	VP254033	297732.89	4129638.24	12.19	0.08449	3.96	477.59	8.28	0.30
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP254153	297435.30	4130292.05	12.19	0.00007	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP254154	297435.30	4130292.05	12.19	0.28409	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP254155	297435.30	4130292.05	12.19	0.00007	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP254156	297435.30	4130292.05	12.19	0.20943	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	4	Coal/biomass handling system	VP254157	297435.30	4130292.05	12.19	0.01062	35.97	298.15	0.29	0.91
Hopewell City	Dominion - Hopewell Power Station	7	Diesel water pump	VP254158	297435.30	4130292.05	12.19	0.02142	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	9	1.63 MMBTU/HR FIRE PUMP	VP254160	297435.30	4130292.05	12.19	0.01158	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	10	Recycle ash handling	VP254161	297435.30	4130292.05	12.19	0.10469	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	13	FLY/BOTTOM ASH SILO	VP254162	297435.30	4130292.05	12.19	0.37410	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	14	TRUCK LOADING	VP254165	297435.30	4130292.05	12.19	0.00005	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	16	Ash storage silo	VP254167	297435.30	4130292.05	12.19	0.01144	3.66	283.15	0.02	0.20

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 2.5 Microns (PM-2.5) Emissions (PM-2.5 24-hour)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	24hr PM25 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Hopewell City	Dominion - Hopewell Power Station	17	CEMENT SILO BAGHOUSE	VP254168	297435.30	4130292.05	12.19	0.00004	24.38	288.15	0.01	0.33
Charles City County	HDI Manufacturing	1	BAGHOUSE STACK	VP254297	309496.98	4147804.60	36.58	0.24502	7.32	294.26	13.74	0.61
Charles City County	Charles City County Landfill	1	CANDLE STICK FLARE 3600 scfm	VP254438	311668.02	4145592.36	48.77	0.01747	9.75	1033.15	23.28	0.30
Charles City County	Charles City County Landfill	2	CANDLE STICK FLARE 2500 scfm	VP254439	311668.02	4145592.36	48.77	0.00864	9.75	1033.15	16.17	0.30
Charles City County	Charles City County Landfill	21	Fugitives Road Dust Emissions	VP254444	311668.02	4145592.36	48.77	0.06588	10.00	ambient	0.001	0.0001
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VP254582	311729.50	4145688.56	51.82	0.03186	10.06	672.04	65.82	0.41
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VP254583	311729.50	4145688.56	51.82	0.43980	10.06	672.04	65.82	0.41
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254759	297071.03	4130563.89	13.72	0.00201	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254760	297071.03	4130563.89	13.72	0.12456	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254761	297071.03	4130563.89	13.72	0.00069	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254762	297071.03	4130563.89	13.72	0.00010	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP254763	297071.03	4130563.89	13.72	0.00010	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	3	RTO	VP254765	297214.23	4130305.51	13.72	0.64725	30.48	432.04	3.88	1.52
Hopewell City	Green Plains Hopewell Limited Liability Company	4	Grain Receiving	VP254766	297071.03	4130563.89	14.63	0.13463	14.63	297.04	41.39	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	6	Hammer Mill #1	VP254767	297071.03	4130563.89	14.63	0.03337	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	7	Hammer Mill #2	VP254768	297071.03	4130563.89	14.63	0.03337	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	9	Hammer Mill #4	VP254770	297071.03	4130563.89	14.63	0.01352	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	10	DDGS Handling	VP254771	297071.03	4130563.89	14.63	0.01151	14.63	297.04	8.62	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	11	DDGS Loadout	VP254772	297071.03	4130563.89	14.63	0.06070	14.63	297.04	8.62	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	12	Loadout Flare	VP254773	297071.03	4130563.89	14.63	0.00001	6.10	533.15	0.86	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	14	Emergency Fire Pump #1 (EU-59)	VP254774	297071.03	4130563.89	14.63	0.00288	2.44	699.82	92.04	0.23
Hopewell City	Green Plains Hopewell Limited Liability Company	15	Boilers	VP254775	297071.03	4130563.89	13.72	0.15065	30.48	432.04	3.88	1.52
Hopewell City	Green Plains Hopewell Limited Liability Company	16	Hammer Mill #5	VP254776	297071.03	4130563.89	14.63	0.00320	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	21	Emergency Fire Pump #2 (EU-74)	VP254777	297071.03	4130563.89	14.63	0.00120	2.44	699.82	92.04	0.23

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 10 Microns (PM-10) Emissions (PM-10 24-hour)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	24hr PM10 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Charles City	C4GT	1	CT1	C4GTCT1	308449.79	4146576.16	39.78	3.04159	57.91	339.36	17.25	6.71
Charles City	C4GT	2	CT2	C4GTCT2	308414.46	4146605.18	39.78	3.04159	57.91	339.36	17.25	6.71
Charles City	C4GT	3	AUXILIARY BOILER	C4GTAUX	308366.52	4146636.85	39.78	0.09324	45.72	422.04	8.96	1.14
Charles City	C4GT	4	DEW POINT HEATER	C4GTDPH	308378.45	4146744.40	39.78	0.01386	12.19	483.15	40.60	0.30
Charles City	C4GT	5	EMERGENCY GENERATOR	C4GTEG	308522.68	4146710.06	39.78	0.00630	15.24	763.71	45.28	0.30
Charles City	C4GT	6	FIRE WATER PUMP	C4GTFWP	308311.94	4146551.18	39.78	0.00054	3.66	789.26	36.22	0.15
Charles City	C4GT	7	COOLING TOWER 1	CT1	308320.52	4146711.38	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	8	COOLING TOWER 2	CT2	308335.66	4146704.44	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	9	COOLING TOWER 3	CT3	308313.66	4146696.42	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	10	COOLING TOWER 4	CT4	308328.80	4146689.47	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	11	COOLING TOWER 5	CT5	308306.80	4146681.45	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	12	COOLING TOWER 6	CT6	308321.95	4146674.51	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	13	COOLING TOWER 7	CT7	308299.94	4146666.49	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	14	COOLING TOWER 8	CT8	308315.09	4146659.55	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	15	COOLING TOWER 9	CT9	308293.08	4146651.53	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	16	COOLING TOWER 10	CT10	308308.23	4146644.58	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	17	COOLING TOWER 11	CT11	308286.22	4146636.56	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	18	COOLING TOWER 12	CT12	308301.37	4146629.62	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	19	COOLING TOWER 13	CT13	308279.36	4146621.60	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	20	COOLING TOWER 14	CT14	308294.51	4146614.65	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	21	COOLING TOWER 15	CT15	308272.50	4146606.63	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	22	COOLING TOWER 16	CT16	308287.65	4146599.69	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	23	COOLING TOWER 17	CT17	308265.64	4146591.67	39.78	8.39E-06	16.02	293.15	7.81	10.00
Charles City	C4GT	24	COOLING TOWER 18	CT18	308280.79	4146584.73	39.78	8.39E-06	16.02	293.15	7.81	10.00
Hopewell City	Chemtrade Solutions LLC - Hopewell	1	DIGESTER	VP104588	297928.95	4129723.66	12.19	0.98321	10.00	363.71	0.001	0.0001
Hopewell City	Chemtrade Solutions LLC - Hopewell	3	Dust Collector (Emissions from Lime Slurry Manufacturing)	VP104590	297928.95	4129723.66	12.19	0.06955	3.35	294.26	12.29	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	102	Boiler FU-17	VP104936	298585.86	4130666.56	12.19	0.05531	46.02	533.15	5.18	2.13
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	102	Boiler FU-17	VP104939	298585.86	4130666.56	12.19	0.03798	46.02	533.15	5.18	2.13
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	103	KELLOGG PRIME RFMR VENT	VP104941	298585.86	4130666.56	12.19	1.10924	32.00	387.59	13.68	3.44
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	106	GIRDLER RFMR VENT STACK	VP104942	298585.86	4130666.56	12.19	0.09784	15.24	433.15	6.60	1.52
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	108	SULFURIC ACID PLANT	VP104943	298585.86	4130666.56	12.19	0.62768	56.39	310.93	16.82	1.52
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	109	KELLOGG START-UP HEATER	VP104944	298585.86	4130666.56	12.19	0.00180	23.16	1149.82	60.87	1.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	112	Area 11 RD3 Dryer Stack	VP104946	298585.86	4130666.56	12.19	0.21403	12.80	326.48	13.30	0.76
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	113	AREA 11 RD4 VENT	VP104947	298585.86	4130666.56	12.19	0.35314	10.67	366.48	12.03	1.10
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	114	AREA 11 RD6 VENT	VP104948	298585.86	4130666.56	12.19	0.21403	12.80	321.48	29.00	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	115	AREA 11 RD7 VENT	VP104949	298585.86	4130666.56	12.19	0.28903	12.80	327.59	32.85	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP104950	298585.86	4130666.56	12.19	0.14959	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP104951	298585.86	4130666.56	12.19	0.09752	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP104952	298585.86	4130666.56	12.19	0.53707	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	118	SULFATE HANDLING FUGITIVE	VP104953	298585.86	4130666.56	12.19	0.35009	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	121	Kellogg Cooling Tower	VP104954	298585.86	4130666.56	12.19	0.07408	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	122	Miscellaneous Cooling Towers	VP104955	298585.86	4130666.56	6.10	0.12600	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	405	A14 FU14 INCENERATOR VENT	VP104968	298585.86	4130666.56	12.19	0.00748	45.72	358.15	12.42	0.76
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	406	Honeywell Specialty Products Cooling Tower TW-77	VP104969	298585.86	4130666.56	12.19	0.12082	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	707	AREA 7 FUME SCRUBBER FS-1	VP104970	298585.86	4130666.56	12.19	0.04344	20.73	310.93	15.03	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	708	AREA 7 FUME SCRUBBER FS-2	VP104971	298585.86	4130666.56	12.19	0.04344	20.73	310.93	15.03	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	710	CAPROLACTAM REMELT	VP104972	298585.86	4130666.56	12.19	0.00029	9.14	305.37	25.88	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	711	HE-221 STEAM SUPERHEATER	VP104973	298585.86	4130666.56	12.19	0.00633	9.75	688.71	4.20	0.53
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	712	HE-305 STEAM SUPERHEATER	VP104974	298585.86	4130666.56	12.19	0.00633	9.75	688.71	4.20	0.53
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	713	Area 8 Flaker #2	VP104975	298585.86	4130666.56	12.19	0.00173	9.14	305.37	25.88	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	719	BELT FILTER VACUUM PUMP	VP104977	298585.86	4130666.56	12.19	0.06961	21.64	316.48	24.38	0.20
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	720	Area 7 Cooling Tower TW-71	VP104988	298585.86	4130666.56	12.19	0.01062	10.00	ambient	0.001	0.0001
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	725	Area 7 Caprolactam Recovery Unit (CRU) Fume Scrubber SE-149 Stack	VP104989	298585.86	4130666.56	12.19	0.01007	17.37	322.04	8.41	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	726	Area 7 Caprolactam Recovery Unit (CRU) Hot Oil Heater Stack	VP104990	298585.86	4130666.56	12.19	0.00273	17.37	322.04	8.41	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	804	AREA 16 THERMOX	VP104991	298585.86	4130666.56	12.19	0.00219	7.62	1033.15	4.48	1.68
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	900	AMMONIUM NITRITE "A" TRAN	VP104992	298585.86	4130666.56	12.19	0.11449	33.53	278.15	43.88	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	901	AMMONIUM NITRITE "B" TRAN	VP104993	298585.86	4130666.56	12.19	0.22438	33.53	278.15	43.88	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	902	AMMONIUM NITRITE "C" TRAN	VP104994	298585.86	4130666.56	12.19	0.12283	38.10	278.15	34.74	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	903	AMMONIUM NITRITE "D" TRAN	VP104995	298585.86	4130666.56	12.19	0.01237	38.10	278.15	34.74	0.41

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 10 Microns (PM-10) Emissions (PM-10 24-hour)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	24hr PM10 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	904	AMMONIUM NITRITE "E" TRAN	VP104996	298585.86	4130666.56	12.19	0.01381	35.05	278.15	0.003	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	905	HYDROXLAMIN DISLF "A" TRN	VP104997	298585.86	4130666.56	12.19	0.05092	40.23	290.37	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	906	HYDRXLAMIN DISULF "B" TRN	VP104998	298585.86	4130666.56	12.19	0.17835	34.14	288.15	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	907	HYDRXLAMIN DISULF "C" TRN	VP104999	298585.86	4130666.56	12.19	0.08630	40.23	288.15	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	908	HYDRXLAMIN DISULF "D" TRN	VP105000	298585.86	4130666.56	12.19	0.08803	40.23	290.37	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	909	HYDRXLAMIN DISULF "E" TRN	VP105001	298585.86	4130666.56	12.19	0.07077	34.14	290.37	23.45	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	910	Area 9 Cooling Tower TW-37	VP105002	298585.86	4130666.56	12.19	0.04082	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VP105191	299276.01	4130497.44	12.19	3.54203	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VP105192	299276.01	4130497.44	12.19	0.00116	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VP105194	299276.01	4130497.44	12.19	0.02540	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VP105195	299276.01	4130497.44	12.19	1.36909	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VP105196	299276.01	4130497.44	12.19	0.81882	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VP105197	299276.01	4130497.44	12.19	0.14737	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	3	SMELT TANK STACK	VP105200	299276.01	4130497.44	12.19	0.76600	88.39	338.71	9.14	1.52
Hopewell City	WestRock CP LLC - Hopewell	4	LIME KILN STACK	VP105201	299276.01	4130497.44	12.19	0.21973	28.65	349.82	8.53	1.92
Hopewell City	WestRock CP LLC - Hopewell	5	SLAKER MIX TANKS	VP105202	299276.01	4130497.44	12.19	0.07503	19.81	343.15	26.84	0.30
Hopewell City	WestRock CP LLC - Hopewell	10	RECAUSTICIZING AREA FUG EMISSIONS	VP105203	299276.01	4130497.44	12.19	0.00220	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	24	Fugitive TSP/PM10/PM2.5 from woodyard	VP105204	299276.01	4130497.44	12.19	0.15620	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	25	Fugitive emissions from roads not in wood yard	VP105205	299276.01	4130497.44	12.19	0.05863	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	25	Fugitive emissions from roads not in wood yard	VP105206	299276.01	4130497.44	12.19	0.35744	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	26	SALT CAKE UNLOADING SYSTEM	VP105207	299276.01	4130497.44	12.19	0.02180	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	27	COAL STORAGE & HANDLING	VP105208	299276.01	4130497.44	12.19	0.00016	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	27	COAL STORAGE & HANDLING	VP105209	299276.01	4130497.44	12.19	0.00053	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	27	COAL STORAGE & HANDLING	VP105210	299276.01	4130497.44	12.19	0.00021	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	28	Power plant cooling tower #1	VP105211	299276.01	4130497.44	12.19	0.19502	10.00	ambient	0.001	0.0001
Hopewell City	WestRock CP LLC - Hopewell	33	Evaporator cooling tower #2	VP105212	299276.01	4130497.44	12.19	0.16356	10.00	ambient	0.001	0.0001
Chesterfield County	DuPont Teijin Films	1	Boilers	VP105459	297115.10	4136147.55	6.10	0.00000	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VP105460	297115.10	4136147.55	6.10	0.00568	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VP105461	297115.10	4136147.55	6.10	0.00001	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VP105462	297115.10	4136147.55	6.10	0.00432	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	2	Boilers	VP105464	297115.10	4136147.55	6.10	0.00123	25.91	422.04	6.71	0.91
Chesterfield County	DuPont Teijin Films	2	Boilers	VP105466	297115.10	4136147.55	6.10	0.00120	25.91	422.04	6.71	0.91
Chesterfield County	DuPont Teijin Films	3	Boilers	VP105467	297115.10	4136147.55	6.10	0.00000	18.29	430.37	3.05	1.01
Chesterfield County	DuPont Teijin Films	3	Boilers	VP105468	297115.10	4136147.55	6.10	0.00489	18.29	430.37	3.05	1.01
Chesterfield County	DuPont Teijin Films	8	Poly Chip Transfer	VP105472	297115.10	4136147.55	6.10	0.00232	15.24	533.15	65.87	0.15
Chesterfield County	DuPont Teijin Films	8	Poly Chip Transfer	VP105473	297115.10	4136147.55	6.10	0.00059	15.24	533.15	65.87	0.15
Chesterfield County	DuPont Teijin Films	11	Film Line 42	VP105476	297115.10	4136147.55	6.10	0.02204	9.14	449.82	9.71	0.30
Chesterfield County	DuPont Teijin Films	12	Film Line 43	VP105477	297115.10	4136147.55	6.10	0.07677	9.14	449.82	0.01	0.30
Chesterfield County	DuPont Teijin Films	12	Film Line 43	VP105479	297115.10	4136147.55	6.10	0.00488	9.14	449.82	0.01	0.30
Chesterfield County	DuPont Teijin Films	12	Film Line 43	VP105480	297115.10	4136147.55	6.10	0.00384	9.14	449.82	0.01	0.30
Chesterfield County	DuPont Teijin Films	13	Film Line 44	VP105481	297115.10	4136147.55	6.10	0.08172	21.34	449.82	20.71	0.15
Chesterfield County	DuPont Teijin Films	13	Film Line 44	VP105482	297115.10	4136147.55	6.10	0.04347	21.34	449.82	20.71	0.15
Chesterfield County	DuPont Teijin Films	13	Film Line 44	VP105483	297115.10	4136147.55	6.10	0.04147	21.34	449.82	20.71	0.15
Chesterfield County	DuPont Teijin Films	14	Film Line 45	VP105484	297115.10	4136147.55	6.10	0.01859	30.48	298.15	2.46	0.52
Chesterfield County	DuPont Teijin Films	14	Film Line 45	VP105485	297115.10	4136147.55	6.10	0.00989	30.48	298.15	2.46	0.52
Chesterfield County	DuPont Teijin Films	14	Film Line 45	VP105486	297115.10	4136147.55	6.10	0.00170	30.48	298.15	2.46	0.52
Chesterfield County	DuPont Teijin Films	15	Film Line 46	VP105487	297115.10	4136147.55	6.10	0.03383	17.07	422.04	21.57	0.09
Chesterfield County	DuPont Teijin Films	15	Film Line 46	VP105489	297115.10	4136147.55	6.10	0.01799	17.07	422.04	21.57	0.09
Chesterfield County	DuPont Teijin Films	15	Film Line 46	VP105490	297115.10	4136147.55	6.10	0.00354	17.07	422.04	21.57	0.09
Chesterfield County	DuPont Teijin Films	16	Film Line 47	VP105491	297115.10	4136147.55	6.10	0.01679	9.45	380.37	19.41	0.12
Chesterfield County	DuPont Teijin Films	16	Film Line 47	VP105492	297115.10	4136147.55	6.10	0.00893	9.45	380.37	19.41	0.12
Chesterfield County	DuPont Teijin Films	16	Film Line 47	VP105493	297115.10	4136147.55	6.10	0.00313	9.45	380.37	19.41	0.12
Chesterfield County	DuPont Teijin Films	17	Storage	VP105494	297115.10	4136147.55	6.10	0.00262	22.86	310.93	20.38	0.21
Chesterfield County	DuPont Teijin Films	18	Bunkers	VP105495	297115.10	4136147.55	6.10	0.05303	15.85	298.15	54.34	0.21
Chesterfield County	DuPont Teijin Films	19	Bunker/Dryer	VP105496	297115.10	4136147.55	6.10	0.09695	25.30	298.15	4.28	0.39
Chesterfield County	DuPont Teijin Films	20	Storage	VP105497	297115.10	4136147.55	6.10	0.00160	16.46	294.26	6.57	0.24
Chesterfield County	DuPont Teijin Films	21	Material Unload	VP105498	297115.10	4136147.55	6.10	0.00037	2.44	298.15	19.02	0.21
Hopewell City	City Point Energy Center, LLC	1	Coal Boilers	VP106107	298812.35	4129886.04	12.19	0.79317	60.35	430.37	17.99	2.65
Hopewell City	City Point Energy Center, LLC	2	Coal Boilers	VP106108	298812.35	4129886.04	12.19	0.67961	60.35	430.37	17.99	2.65

Virginia Source Inventory for Particulate Matter with an Aerodynamic Diameter Less Than or Equal to 10 Microns (PM-10) Emissions (PM-10 24-hour)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	24hr PM10 Emission Rate (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Hopewell City	City Point Energy Center, LLC	4	6 COAL BUNKERS	VP106109	298812.35	4129886.04	12.19	0.00105	26.21	293.15	17.29	0.20
Hopewell City	City Point Energy Center, LLC	4	6 COAL BUNKERS	VP106110	298812.35	4129886.04	12.19	0.00105	26.21	293.15	17.29	0.20
Hopewell City	City Point Energy Center, LLC	10	Cooling Towers	VP106111	298812.35	4129886.04	12.19	0.00661	10.00	ambient	0.001	0.0001
Hopewell City	City Point Energy Center, LLC	20	Diesel Emergency Fire Pump	VP106112	298812.35	4129886.04	15.24	0.05070	0.91	422.04	12.94	0.30
Hopewell City	City Point Energy Center, LLC	40	Paved Roads Particulate Emissions	VP106113	298812.35	4129886.04	15.24	0.02914	10.00	ambient	0.001	0.0001
Hopewell City	City Point Energy Center, LLC	50	Lime Storage Silo	VP106114	298812.35	4129886.04	15.24	0.00001	10.00	ambient	0.001	0.0001
Hopewell City	Hopewell Cogeneration Ltd Partnership	1	Brown-Boveri 11N Turbine	VP106134	297732.89	4129638.24	12.19	0.02873	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	1	Brown-Boveri 11N Turbine	VP106135	297732.89	4129638.24	12.19	3.66383	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	2	Brown-Boveri 11N Turbine	VP106136	297732.89	4129638.24	12.19	0.03595	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	2	Brown-Boveri 11N Turbine	VP106137	297732.89	4129638.24	12.19	15.58762	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	3	Brown-Boveri 11N Turbine	VP106138	297732.89	4129638.24	12.19	0.02887	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	3	Brown-Boveri 11N Turbine	VP106139	297732.89	4129638.24	12.19	7.26131	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	4	#1 B&W Aux Boiler	VP106140	297732.89	4129638.24	12.19	0.00000	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	4	#1 B&W Aux Boiler	VP106141	297732.89	4129638.24	12.19	0.00747	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	5	#2 B&W Aux Boiler	VP106143	297732.89	4129638.24	12.19	0.03527	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	7	Emergency Generators	VP106144	297732.89	4129638.24	12.19	0.10105	3.96	477.59	8.28	0.30
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP106273	297435.30	4130292.05	12.19	0.00007	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP106274	297435.30	4130292.05	12.19	0.30120	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP106275	297435.30	4130292.05	12.19	0.00007	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VP106276	297435.30	4130292.05	12.19	0.21940	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	4	Coal/biomass handling system	VP106277	297435.30	4130292.05	12.19	0.05923	35.97	298.15	0.29	0.91
Hopewell City	Dominion - Hopewell Power Station	7	Diesel water pump	VP106278	297435.30	4130292.05	12.19	0.02142	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	9	1.63 MMBTU/HR FIRE PUMP	VP106280	297435.30	4130292.05	12.19	0.01158	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	10	Recycle ash handling	VP106281	297435.30	4130292.05	12.19	0.10469	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	13	FLY/BOTTOM ASH SILO	VP106282	297435.30	4130292.05	12.19	0.37410	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	14	TRUCK LOADING	VP106285	297435.30	4130292.05	12.19	0.00005	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	16	Ash storage silo	VP106287	297435.30	4130292.05	12.19	0.01144	3.66	283.15	0.02	0.20
Hopewell City	Dominion - Hopewell Power Station	17	CEMENT SILO BAGHOUSE	VP106288	297435.30	4130292.05	12.19	0.00004	24.38	288.15	0.01	0.33
Charles City County	HDI Manufacturing	1	BAGHOUSE STACK	VP106444	309496.98	4147804.60	36.58	0.24502	7.32	294.26	13.74	0.61
Charles City County	Charles City County Landfill	1	CANDLE STICK FLARE 3600 scfm	VP106609	311668.02	4145592.36	48.77	0.01747	9.75	1033.15	23.28	0.30
Charles City County	Charles City County Landfill	2	CANDLE STICK FLARE 2500 scfm	VP106610	311668.02	4145592.36	48.77	0.00864	9.75	1033.15	16.17	0.30
Charles City County	Charles City County Landfill	21	Fugitives Road Dust Emissions	VP106615	311668.02	4145592.36	48.77	0.04430	10.00	ambient	0.001	0.0001
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VP106779	311729.50	4145688.56	51.82	0.03186	10.06	672.04	65.82	0.41
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VP106780	311729.50	4145688.56	51.82	0.43980	10.06	672.04	65.82	0.41
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP107023	297071.03	4130563.89	13.72	0.00805	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP107024	297071.03	4130563.89	13.72	0.12456	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP107025	297071.03	4130563.89	13.72	0.00414	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP107026	297071.03	4130563.89	13.72	0.00010	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	1	Fugitive Emissions	VP107027	297071.03	4130563.89	13.72	0.00010	10.00	ambient	0.001	0.0001
Hopewell City	Green Plains Hopewell Limited Liability Company	3	RTO	VP107029	297214.23	4130305.51	13.72	0.64725	30.48	432.04	3.88	1.52
Hopewell City	Green Plains Hopewell Limited Liability Company	4	Grain Receiving	VP107030	297071.03	4130563.89	14.63	0.13463	14.63	297.04	41.39	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	6	Hammer Mill #1	VP107031	297071.03	4130563.89	14.63	0.03337	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	7	Hammer Mill #2	VP107032	297071.03	4130563.89	14.63	0.03337	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	9	Hammer Mill #4	VP107034	297071.03	4130563.89	14.63	0.01352	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	10	DDGS Handling	VP107035	297071.03	4130563.89	14.63	0.01151	14.63	297.04	8.62	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	11	DDGS Loadout	VP107036	297071.03	4130563.89	14.63	0.06070	14.63	297.04	8.62	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	12	Loadout Flare	VP107037	297071.03	4130563.89	14.63	0.00001	6.10	533.15	0.86	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	14	Emergency Fire Pump #1 (EU-59)	VP107038	297071.03	4130563.89	14.63	0.00288	2.44	699.82	92.04	0.23
Hopewell City	Green Plains Hopewell Limited Liability Company	15	Boilers	VP107039	297071.03	4130563.89	13.72	0.15065	30.48	432.04	3.88	1.52
Hopewell City	Green Plains Hopewell Limited Liability Company	16	Hammer Mill #5	VP107040	297071.03	4130563.89	14.63	0.00320	14.63	297.04	7.25	0.76
Hopewell City	Green Plains Hopewell Limited Liability Company	21	Emergency Fire Pump #2 (EU-74)	VP107041	297071.03	4130563.89	14.63	0.00120	2.44	699.82	92.04	0.23
Henrico County	Premier Store Fixtures Inc	1	Paint Booth B1 Combined Stack	VP107150	292924.78	4156066.48	48.77	0.07346	9.14	294.26	17.25	0.91
Henrico County	Premier Store Fixtures Inc	2	Paint Booth B2 Stack	VP107151	292924.78	4156066.48	48.77	0.38836	9.14	294.26	17.25	0.91
Henrico County	Premier Store Fixtures Inc	3	Paint Booth B3 Stack	VP107152	292924.78	4156066.48	48.77	0.66632	9.14	294.26	17.25	0.91

Virginia Source Inventory for Nitrogen Oxides (as NO2) Emissions (Annual NO2)

City/County	Site Name	Release Point Number	Release Point Description	Model ID	UTM	UTM	Base Elevation (m)	Annual NO2 Emissions (g/s)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Charles City	C4GT	1	CT1	C4GTCT1	308449.79	4146576.16	39.78	3.67786	57.91	339.36	17.25	6.71
Charles City	C4GT	2	CT2	C4GTCT2	308414.46	4146605.18	39.78	3.67786	57.91	339.36	17.25	6.71
Charles City	C4GT	3	AUXILIARY BOILER	C4GTAUX	308366.52	4146636.85	39.78	0.14616	45.72	422.04	8.96	1.14
Charles City	C4GT	4	DEW POINT HEATER	C4GTDPH	308378.45	4146744.40	39.78	0.02268	12.19	483.15	40.60	0.30
Charles City	C4GT	5	EMERGENCY GENERATOR	C4GTEG	308522.68	4146710.06	39.78	0.19360	15.24	763.71	45.28	0.30
Charles City	C4GT	6	FIRE WATER PUMP	C4GTFWP	308311.94	4146551.18	39.78	0.01050	3.66	789.26	36.22	0.15
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	102	Boiler FU-17	VNO22806	298585.86	4130666.56	12.19	0.31295	46.02	533.15	5.18	2.13
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	102	Boiler FU-17	VNO22809	298585.86	4130666.56	12.19	0.18155	46.02	533.15	5.18	2.13
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	103	KELLOGG PRIME RFMR VENT	VNO22810	298585.86	4130666.56	12.19	14.64214	32.00	387.59	13.68	3.44
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	106	GIRDLER RFMR VENT STACK	VNO22811	298585.86	4130666.56	12.19	1.76116	15.24	433.15	6.60	1.52
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	109	KELLOGG START-UP HEATER	VNO22812	298585.86	4130666.56	12.19	0.03323	23.16	1149.82	60.87	1.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	112	Area 11 RD3 Dryer Stack	VNO22813	298585.86	4130666.56	12.19	0.03308	12.80	326.48	13.30	0.76
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	113	AREA 11 RD4 VENT	VNO22814	298585.86	4130666.56	12.19	0.10931	10.67	366.48	12.03	1.10
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	114	AREA 11 RD6 VENT	VNO22815	298585.86	4130666.56	12.19	0.03308	12.80	321.48	29.00	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	115	AREA 11 RD7 VENT	VNO22816	298585.86	4130666.56	12.19	0.07767	12.80	327.59	32.85	0.49
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	117	ONAN EMERGENCY GENERATOR	VNO22817	298585.86	4130666.56	12.19	0.01019	4.57	786.48	0.01	0.21
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	405	A14 FU14 INCENERATOR VENT	VNO22821	298585.86	4130666.56	12.19	0.51492	45.72	358.15	12.42	0.76
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	622	AREA 6 FLARE	VNO22823	298585.86	4130666.56	12.19	0.09205	24.38	922.04	10.06	0.15
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	711	HE-221 STEAM SUPERHEATER	VNO22824	298585.86	4130666.56	12.19	0.05178	9.75	688.71	4.20	0.53
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	712	HE-305 STEAM SUPERHEATER	VNO22825	298585.86	4130666.56	12.19	0.03107	9.75	688.71	4.20	0.53
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	726	Area 7 Caprolactam Recovery Unit (CRU) Hot Oil Heater Stack	VNO22826	298585.86	4130666.56	12.19	0.03596	17.37	322.04	8.41	0.30
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	804	AREA 16 THERMOX	VNO22827	298585.86	4130666.56	12.19	0.02877	7.62	1033.15	4.48	1.68
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	900	AMMONIUM NITRITE "A" TRAN	VNO22828	298585.86	4130666.56	12.19	27.35405	33.53	278.15	43.88	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	901	AMMONIUM NITRITE "B" TRAN	VNO22829	298585.86	4130666.56	12.19	0.64437	33.53	278.15	43.88	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	902	AMMONIUM NITRITE "C" TRAN	VNO22830	298585.86	4130666.56	12.19	0.68752	38.10	278.15	34.74	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	903	AMMONIUM NITRITE "D" TRAN	VNO22831	298585.86	4130666.56	12.19	10.51415	38.10	278.15	34.74	0.41
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	904	AMMONIUM NITRITE "E" TRAN	VNO22832	298585.86	4130666.56	12.19	13.66696	35.05	278.15	0.003	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	905	HYDROXLAMIN DISLF "A" TRN	VNO22833	298585.86	4130666.56	12.19	25.48136	40.23	290.37	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	906	HYDRXLAMIN DISULF "B" TRN	VNO22834	298585.86	4130666.56	12.19	0.31643	34.14	288.15	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	907	HYDRXLAMIN DISULF "C" TRN	VNO22835	298585.86	4130666.56	12.19	0.42287	40.23	288.15	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	908	HYDRXLAMIN DISULF "D" TRN	VNO22836	298585.86	4130666.56	12.19	14.59899	40.23	290.37	18.27	0.61
Hopewell City	AdvanSix Resins and Chemicals LLC - Hopewell Plant	909	HYDRXLAMIN DISULF "E" TRN	VNO22837	298585.86	4130666.56	12.19	15.51089	34.14	290.37	23.45	0.61
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	1	Boiler	VNO22840	297872.53	4134755.12	7.62	0.31616	6.10	547.04	11.38	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	1	Boiler	VNO22842	297872.53	4134755.12	7.62	0.43118	6.10	547.04	11.38	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	1	Boiler	VNO22844	297872.53	4134755.12	7.62	0.53055	6.10	547.04	11.38	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	2	Boiler	VNO22846	297872.53	4134755.12	7.62	0.00611	6.10	533.15	10.36	1.52
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	3	HE-66 Process Furnace	VNO22848	297872.53	4134755.12	7.62	0.00400	7.62	638.71	1.07	1.07
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	4	HE-260 Process Furnace	VNO22850	297872.53	4134755.12	7.62	0.12427	13.72	533.15	6.78	0.46
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	5	HE-259 Process Furnace	VNO22852	297872.53	4134755.12	7.62	0.11469	13.72	533.15	6.37	0.61
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	71	Stack 5-2 for HE-1	VNO22857	297872.53	4134755.12	7.62	0.01611	13.72	533.15	11.32	0.61
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	85	Emer.Gen. (Ref. no. MG-184, S. of Bldg. 41)	VNO22859	297872.53	4134755.12	7.62	0.00001	7.62	638.71	1.07	1.07
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	86	Emer.Gen. (Ref. no. MG-1046, Bldg. 12)	VNO22860	297872.53	4134755.12	7.62	0.00003	7.62	638.71	1.07	1.07
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	88	Emer.Gen. (Ref. no. EG-3, Bl. 1 East)	VNO22861	297872.53	4134755.12	7.62	0.00001	7.62	638.71	1.07	1.07
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	89	Emer.Gen. (Ref. no. EG-4, Bl. 1 Medical)	VNO22862	297872.53	4134755.12	7.62	0.00000	7.62	638.71	1.07	1.07
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	90	Emer.Gen. (Ref. no. MG-717, Bldg. 75)	VNO22863	297872.53	4134755.12	7.62	0.00313	7.62	638.71	1.07	1.07
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	91	Emer.Gen. (Ref. no. EG-1, Bldg. 73 fire pump)	VNO22864	297872.53	4134755.12	7.62	0.00421	7.62	638.71	1.07	1.07
Chesterfield County	AdvanSix Resins and Chemicals LLC - Chesterfield	92	Emer.Gen. (Ref. no. EG-2, Bldg. 7 fire pump)	VNO22865	297872.53	4134755.12	7.62	0.00113	7.62	638.71	1.07	1.07
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VNO22938	299276.01	4130497.44	12.19	14.85924	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VNO22939	299276.01	4130497.44	12.19	0.03503	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	1	RECOVERY FURNACE (2 STACKs from PRECIPITATOR)	VNO22941	299276.01	4130497.44	12.19	0.33422	88.39	477.59	12.74	2.68
Hopewell City	WestRock CP LLC - Hopewell	2	COMBINATION BOILER STACK	VNO22942	299276.01	4130497.44	12.19	11.63892	88.39	449.82	9.45	4.11
Hopewell City	WestRock CP LLC - Hopewell	3	SMELT TANK STACK	VNO22943	299276.01	4130497.44	12.19	0.12095	88.39	338.71	9.14	1.52
Hopewell City	WestRock CP LLC - Hopewell	4	LIME KILN STACK	VNO22944	299276.01	4130497.44	12.19	0.65760	28.65	349.82	8.53	1.92
Hopewell City	WestRock CP LLC - Hopewell	10	RECAUSTICIZING AREA FUG EMISSIONS	VNO22945	299276.01	4130497.44	12.19	0.01059	10.00	ambient	0.001	0.0001
Chesterfield County	DuPont Teijin Films	1	Boilers	VNO22988	297115.10	4136147.55	6.10	0.00005	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VNO22989	297115.10	4136147.55	6.10	0.21628	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VNO22990	297115.10	4136147.55	6.10	0.00014	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	1	Boilers	VNO22991	297115.10	4136147.55	6.10	0.19927	18.29	422.04	6.04	1.46
Chesterfield County	DuPont Teijin Films	2	Boilers	VNO22993	297115.10	4136147.55	6.10	0.06216	25.91	422.04	6.71	0.91
Chesterfield County	DuPont Teijin Films	2	Boilers	VNO22995	297115.10	4136147.55	6.10	0.06216	25.91	422.04	6.71	0.91
Chesterfield County	DuPont Teijin Films	3	Boilers	VNO22996	297115.10	4136147.55	6.10	0.00004	18.29	430.37	3.05	1.01

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Chesterfield County	DuPont Teijin Films	3	Boilers	VNO22997	297115.10	4136147.55	6.10	0.18536	18.29	430.37	3.05	1.01
Chesterfield County	Philip Morris USA Inc - Park 500	26	DRYER (L2) DR	VNO23078	297878.33	4135042.65	7.62	0.01971	28.96	302.59	17.25	0.46
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VNO23079	297878.33	4135042.65	60.96	0.05445	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	60	Combined Stacks for L4D1, L4D2, L5D1 and L5D2 (BL Process)	VNO23080	297878.33	4135042.65	60.96	0.05445	15.24	433.15	21.56	0.91
Chesterfield County	Philip Morris USA Inc - Park 500	104	3 DIESEL GENS (fire pump, wastewater treatment plant)	VNO23081	297878.33	4135042.65	7.62	0.04033	3.66	310.93	3.23	0.30
Chesterfield County	Philip Morris USA Inc - Park 500	104	3 DIESEL GENS (fire pump, wastewater treatment plant)	VNO23082	297878.33	4135042.65	7.62	0.00133	3.66	310.93	3.23	0.30
Chesterfield County	Philip Morris USA Inc - Park 500	1000	BOILER 1 (BO0501)	VNO23083	297878.33	4135042.65	7.62	0.00003	42.67	505.37	14.72	1.52
Chesterfield County	Philip Morris USA Inc - Park 500	1000	BOILER 1 (BO0501)	VNO23084	297878.33	4135042.65	7.62	0.05940	42.67	505.37	14.72	1.52
Chesterfield County	Philip Morris USA Inc - Park 500	1004	BOILER BO0302	VNO23087	297878.33	4135042.65	7.62	1.79240	80.47	463.71	19.29	1.46
Chesterfield County	Philip Morris USA Inc - Park 500	1005	BOILER BO0701	VNO23088	297878.33	4135042.65	7.62	0.00002	80.47	463.71	19.29	1.46
Chesterfield County	Philip Morris USA Inc - Park 500	1005	BOILER BO0701	VNO23089	297878.33	4135042.65	7.62	0.18692	80.47	463.71	19.29	1.46
Hopewell City	Hopewell Water Renewal	3	Sludge Incinerator	VNO23091	299894.96	4129941.71	12.50	0.51910	23.16	348.71	18.40	0.91
Hopewell City	Hopewell Water Renewal	3	Sludge Incinerator	VNO23092	299894.96	4129941.71	12.50	0.04229	23.16	348.71	18.40	0.91
Hopewell City	City Point Energy Center, LLC	1	Coal Boilers	VNO23260	298812.35	4129886.04	12.19	19.21314	60.35	430.37	17.99	2.65
Hopewell City	City Point Energy Center, LLC	2	Coal Boilers	VNO23262	298812.35	4129886.04	12.19	8.26461	60.35	430.37	17.99	2.65
Hopewell City	City Point Energy Center, LLC	20	Diesel Emergency Fire Pump	VNO23264	298812.35	4129886.04	15.24	0.00259	0.91	422.04	12.94	0.30
Hopewell City	Hopewell Cogeneration Ltd Partnership	1	Brown-Boveri 11N Turbine	VNO23271	297732.89	4129638.24	12.19	4.44557	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	2	Brown-Boveri 11N Turbine	VNO23272	297732.89	4129638.24	12.19	0.07451	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	2	Brown-Boveri 11N Turbine	VNO23273	297732.89	4129638.24	12.19	6.58666	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	3	Brown-Boveri 11N Turbine	VNO23274	297732.89	4129638.24	12.19	0.01611	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	3	Brown-Boveri 11N Turbine	VNO23275	297732.89	4129638.24	12.19	5.05111	60.96	399.82	22.81	4.63
Hopewell City	Hopewell Cogeneration Ltd Partnership	4	#1 B&W Aux Boiler	VNO23277	297732.89	4129638.24	12.19	0.13664	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	5	#2 B&W Aux Boiler	VNO23279	297732.89	4129638.24	12.19	0.27069	60.96	449.82	17.94	1.49
Hopewell City	Hopewell Cogeneration Ltd Partnership	7	Emergency Generators	VNO23280	297732.89	4129638.24	12.19	0.00002	3.96	477.59	8.28	0.30
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VNO23377	297435.30	4130292.05	12.19	3.24774	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	1	Spreader Stoker Boiler	VNO23379	297435.30	4130292.05	12.19	3.14705	67.06	341.48	23.62	2.44
Hopewell City	Dominion - Hopewell Power Station	7	Diesel water pump	VNO23380	297435.30	4130292.05	12.19	0.00017	10.00	ambient	0.001	0.0001
Hopewell City	Dominion - Hopewell Power Station	9	1.63 MMBTU/HR FIRE PUMP	VNO23382	297435.30	4130292.05	12.19	0.00086	10.00	ambient	0.001	0.0001
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VNO23677	311729.50	4145688.56	51.82	0.36361	10.06	672.04	65.82	0.41
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VNO23678	311729.50	4145688.56	51.82	5.06999	10.06	672.04	65.82	0.41
Hopewell City	Green Plains Hopewell Limited Liability Company	3	RTO	VNO23797	297214.23	4130305.51	13.72	1.13915	30.48	432.04	3.88	1.52
Hopewell City	Green Plains Hopewell Limited Liability Company	12	Loadout Flare	VNO23798	297071.03	4130563.89	14.63	0.01668	6.10	533.15	0.86	0.46
Hopewell City	Green Plains Hopewell Limited Liability Company	14	Emergency Fire Pump #1 (EU-59)	VNO23799	297071.03	4130563.89	14.63	0.00319	2.44	699.82	92.04	0.23
Hopewell City	Green Plains Hopewell Limited Liability Company	15	Boilers	VNO23800	297071.03	4130563.89	13.72	0.62078	30.48	432.04	3.88	1.52
Hopewell City	Green Plains Hopewell Limited Liability Company	21	Emergency Fire Pump #2 (EU-74)	VNO23801	297071.03	4130563.89	14.63	0.00132	2.44	699.82	92.04	0.23

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Charles City	C4GT	1	CT1	C4GTCT1	308449.79	4146576.16	39.78	3.67786	57.91	339.36	17.25	6.71
Charles City	C4GT	2	CT2	C4GTCT2	308414.46	4146605.18	39.78	3.67786	57.91	339.36	17.25	6.71
Charles City	C4GT	3	AUXILIARY BOILER	C4GTAUX	308366.52	4146636.85	39.78	0.14616	45.72	422.04	8.96	1.14
Charles City	C4GT	4	DEW POINT HEATER	C4GTDPH	308378.45	4146744.40	39.78	0.02268	12.19	483.15	40.60	0.30
Henrico County	QTS Richmond Data Center	1	E-CR-01	VNO23587	301108.96	4151609.10	45.72	0.00456	16.76	422.04	20.32	0.61
Henrico County	QTS Richmond Data Center	3	E-CR-03	VNO23589	301108.96	4151609.10	45.72	0.00456	16.76	422.04	20.32	0.61
Henrico County	QTS Richmond Data Center	5	EG01-17	VNO23590	301108.96	4151609.10	45.72	1.37092	15.24	744.26	30.48	0.38
Henrico County	QTS Richmond Data Center	5	EG01-17	VNO23591	301108.96	4151609.10	45.72	0.25101	15.24	744.26	30.48	0.38
Henrico County	QTS Richmond Data Center	5	EG01-17	VNO23592	301108.96	4151609.10	45.72	3.68953	15.24	744.26	30.48	0.38
Charles City County	Charles City County Landfill	1	CANDLE STICK FLARE 3600 scfm	VNO23617	311668.02	4145592.36	48.77	0.07248	9.75	1033.15	23.28	0.30
Charles City County	Charles City County Landfill	2	CANDLE STICK FLARE 2500 scfm	VNO23618	311668.02	4145592.36	48.77	0.00004	9.75	1033.15	16.17	0.30
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VNO23677	311729.50	4145688.56	51.82	0.43717	10.06	672.04	65.82	0.41
Charles City County	INGENCO - Charles City	1	48 Electric Generators	VNO23678	311729.50	4145688.56	51.82	6.09568	10.06	672.04	65.82	0.41

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Chickahominy Power Station

1 message

Katie Skiff <katie.skiff@gmail.com> Wed, Mar 20, 2019 at 4:39 PM
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair,
I would like to register my concern about the Chickahominy Power Station and request that this project by reviewed by the Air Pollution Control Board.
APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171
Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.

As an independent power producer, Chickahominy would sell its power directly to the **PJM Interconnection wholesale market. This is a major polluter that will soil our air quality for profit to markets far, far away. With limited economic benefit to Virginians, why should we shoulder the pollution burden?

● This permit should be rejected because we are looking to limit our greenhouse gas emissions from our fossil-fuel sector. DEQ monitors carbon not methane. Although methane emissions are lower than carbon dioxide emissions, it is a major greenhouse gas because each methane molecule has 86 times the global warming potential of a carbon dioxide molecule.
○ In a time of increasing threats from climate change, Virginia needs to be driving down our greenhouse gas emissions not increasing them.
● There is already a higher incidence than normal of both chronic obstructive pulmonary disease and asthma in this county, and any additions to polluting this atmosphere is of great concern. Virginia Department of Health maps show that relative to other areas of Virginia, Charles City County and the surrounding region show higher incidences of asthma.

Thank you for your time and attention.

Katherine Skiff
4101 Hanover Ave
Richmond, VA 23221

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Concerns re Chickahominy Power Station

1 message

Christopher Thomas <chris@nihilitia.com> Wed, Mar 20, 2019 at 2:06 PM
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair,
I would like to register my concern about the Chickahominy Power Station and request that this project by reviewed by the Air Pollution Control Board.
APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171
Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.
Thank you for your time and attention.

Chris Thomas

4101 Hanover Ave., Richmond, VA 213221

703.785.0119

● This permit should be rejected because we are looking to limit our greenhouse gas emissions from our fossil-fuel sector. DEQ monitors carbon not methane. Although methane emissions are lower than carbon dioxide emissions, it is a major greenhouse gas because each methane molecule has 86 times the global warming potential of a carbon dioxide molecule.
○ In a time of increasing threats from climate change, Virginia needs to be driving down our greenhouse gas emissions not increasing them.
● There is already a higher incidence than normal of both chronic obstructive pulmonary disease and asthma in this county, and any additions to polluting this atmosphere is of great concern. Virginia Department of Health maps show that relative to other areas of Virginia, Charles City County and the surrounding region show higher incidences of asthma.
● This is the LARGEST proposed fracked gas plant in the country. At 1,650 Megawatts, it is bigger than nearby Chesterfield Power Station.
○ In a time of declining fracked gas need, rising energy efficiencies, and more accessible renewable options - do we really need to commit to this large scale plant that would be in operation for the next 40 years?
● The closest monitoring station, at Shirley Plantation, sits in the opposite direction from prevailing winds relative to the Chickahominy Power Station.
○ Violations will be difficult to detect.
○ With two proposed fracked gas plants and one landfill on site, it will be difficult to determine which site is in violation.
○ How will DEQ ensure that violations are being captured and appropriately charged?

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Comment - proposed Chickahominy Power plant

1 message

jtwitmyer@aol.com <jtwitmyer@aol.com> Wed, Mar 20, 2019 at 9:05 PM

To: Alison.Sinclair@deq.virginia.gov

Thank you for the opportunity to comment
Attacked please find my submission comments ...

Jane M Twitmyer
RR# 1 PO Box 741
Roseland, VA
22967-9213
703-376-7475

March 20.docx
20K

March 20, 2019

Department of Environmental Quality
RE: Public Comment
Balico LLC, 52610 Chickahominy Power proposed natural gas fired Electricity plant

Attention: Alison.Sinclair@DEQ.virginia.gov

There are 3 very good reasons not to approve this plant: the Court challenge to the EPA to reinstate Good Neighbor air quality requirements; questions about the viability of the shale industry itself; and the nature of the projected increase in demand as well as the cost effectiveness of alternative electricity generation sources. Examination of these issues should lead you to refuse to grant permission to build additional long-term fossil fuel infrastructure, which at their basis increases our vulnerability to all the effects of climate change.

This 'Good Neighbor' air policy began in 2003 when the Court required Dominion to spend an additional $1.2 billion on 8 coal-burning plants they had recently upgraded without pollution controls. Surveys had shown damage from acidification and mercury in the waters, forests and soils of the Adirondack Mountains. Native fish struggled to survive and mountain top trees died from the continued airborne pollution discharged from upwind states.

In June 2018 a federal district court in Manhattan found that the EPA had violated statutory deadlines to issue plans to reduce interstate air pollution from five upwind states that was causing unhealthy smog in the downwind states. A second ruling that same week cited the EPA for their non-action in enforcing the Clean Air Act and failing to hold upwind states accountable for clean air standards. Virginia is one of the five upwind states. However, the EPA under Pruitt ignored the issue and then reversed the policy, saying no enforcement was necessary.

In response, The Petition for Review was filed in the United States Court of Appeals for the District of Columbia Circuit. If successful, or with a new administration, the EPA will have to reexamine its rule and potentially impose stricter air quality controls on upwind states. Approving this plant will make the eventual necessary compliance more difficult for Virginia. DEQ's own documents show that 7 of the 10 new proposed emission components

will classify this proposed new plant a facility as a major stationary source of the pollutants. Virginia is not a 'good neighbor'.

The second issue ... ten years ago natural gas was expected to be the bridge fuel to a 100% clean energy economy. Apparently large-scale gas reserves were being mined in the nearby shale rock of West Virginia, PA and Ohio using a horizontal drilling technique called fracking. With the development of fracking, and the ability to lift the restriction on exporting natural gas that had kept the US price of natural gas well below the international price, natural gas was an investors dream. In addition, burning natural gas doesn't emit many of the air pollutants emitted by burning coal, and gas creates CO2 emissions at a rate 50% lower than coal when it is burned to make electricity.

A decade later new information has shown that ...

- **the fracking industry has been a money losing proposition for the past decade.**
- **maximum production of a shale wells is reached in three years, questioning the size of the estimated gas reserves**
- **methane's contribution to climate change while the gas is in our atmosphere is 85 times more destructive for the climate than CO2 emissions.**

Today some on Wall Street are even calling shale a 'Ponzi scheme'. Since 2016 the equity and bond deals in the shale market are down 50%. Wall Street financed unprofitable drilling for years holding on to the promise that rapid production growth would eventually pay off. However, that hasn't happened and the price competitiveness of wind, solar, and soon even storage, are winning electricity generation contracts. "Wind and solar are set to surge to almost '50 by 50' – 50% of world generation by 2050." – (BNEF annual outlook 2018)

The steep decline in new gas industry debt and equity issuance is a sign that major investors are no longer rushing to finance unprofitable shale drilling. The plant you are considering will sell gas-fired generation directly into the PJM market where demand for electricity has been flat. "In the Mid-Atlantic and Northeast regions, ... reserve margins appear to be more than adequate." A chart shows that PJM's margin is 10% above their reference level.

Finally, by replacing coal, natural gas has increased its source as a generator of electricity from 35 to 53% of total generation in 2018. But despite this growing capacity, more and more gas-fired facilities are "either dedicated 'peakers' or run at lower capacity factors, helping to balance variable renewables, rather than ... around-the-clock." Since additional

gas generated electricity will not be needed in PJM, the expanding gas market is an export market, a fact that will drive up the price of natural gas here at home as export is no longer restricted. Projected to decline dramatically in Europe, gas use it will grow in China and pick up materially in India beyond 2040.

One final comment about the demand for electricity and corporate economic expansion, especially as it relates to the IT industry. The business community is the primary cause of any increase in demand in the future, but they are driving demand for renewable sourced energy, not continued fossil use. “Retailers, major technology firms, and even an oil major, contracted record volumes of renewable power through direct contracts.” (BNEF 2019)

This corporate commitment can be seen in the letter sent to the SCC last year from a group of data center providers and customers with facilities throughout Virginia. “The letter from companies including Adobe, eBay, Equinix, and Salesforce encouraged Dominion and the SCC to think a lot harder about the utilities’ renewables mix, especially considering that data centers are responsible for much of the growth in demand predicted by Dominion at a time when improvements in energy efficiency are keeping load growth generally flat.”

“The companies noted that renewable energy is the most cost-effective resource, meaning more renewable energy will help data centers control energy costs, and that investors are more vocal about wanting data centers and cloud service facilities to be operated in ways that reduce their carbon footprint as much as possible.”

“They also warned of over-investing in new dirty-energy infrastructure, which could burden ratepayers with unnecessary and expensive assets, noting that a “clean grid is the grid of the future” and offering to help accelerate the transition to such a clean grid.”
(https://www.southernenvironment.org/news-and-press/news-feed/data-centers-driving-power-demand-in-virginia-want-renewable-energy)

To recap the reasons not to permit this proposed new gas plant … demand in Virginia and much of PJM is flat or declining except for the tech industry, an industry that is committed to keeping both cost and emissions as low as possible. Virginia has extensive rural solar and offshore wind resources that can readily supply their needs with renewable sourced electricity. … The shale industry has lost favor with investors and may actually not be as abundant as originally presumed. … Finally, fossil based

infrastructure produces smog and other health and environmental damage, including accelerating Climate Change. As the Governor of CT said, "the EPA's recent failure to hold upwind states accountable is not acceptable." Virginia has other choices and can become a Good Neighbor regardless of the EPA's current irresponsible posture.

Thank you for the opportunity to comment.

Jane M Twitmyer
RR# 1 PO Box 741
Roseland, VA 22967-9213
703-376-7475
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Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Public Comment For Balico LLC 52160 Chickahominy Power Station

1 message

VTForestryMom <vtforestrymomvt@gmail.com> Wed, Mar 20, 2019 at 1:16 PM
To: Alison.Sinclair@deq.virginia.gov

To:
Alison Sinclair, Piedmont Regional Office, 4949 Cox Rd., Ste. A, Glen Allen, VA 23060;
Phone: (804) 527-5155; E-mail: Alison.Sinclair@DEQ.virginia.gov; Fax: (804) 527-5106

From:
Amy C Walker, 3640 Milton Mews Ct, Quinton, VA 23141

RE: Balico LLC Active Air Permit, Public Comment, Chickahominy Power Station, Reg No 52160

Dear Mrs. Sinclair,

I would like the following comments documented regarding the Chickahominy Power Station. I am strongly opposed to the construction of the power station in the proposed location. I find it a disservice to the citizenry of New Kent County that the the study circumference was not expanded to at least 5-7 miles as the population numbers would have exponentially increased due to the large subdivisions on the New Kent side of Rt 60. The number of children would have increased exponentially as well, as these are all densely populated suburban single family subdivisions. This lack of acknowledgement of population centers is disturbing, particularly those so densely populated with children (Patriot's Landing, Five Lakes, Woodhaven Shores)

I am a current resident of New Kent County, and would be located within approximately 7 miles of the proposed power station. While I have been a resident of New Kent County for nearly a decade, we have recently built a brand new home in Quinton. **I am a severe asthmatic and would never have built a home within such proximity of a power station**. I note the allowable discharges in the permit, but also the long list of exceptions, the averages these discharges can be based on, and calendar 12-month totals for some pollutants. The long list of allowable discharge components and limits, exceptions, and testing regimes; do not eliminate the fact that various compounds would be released into the air that I will be breathing into my already compromised lungs. As can be seen in the 1 mile vs 2 mile radius information provided, settling of of the components away from the stacks can be noted. Before this permit is approved, I would request a study circumference of 5-7 miles be provided publicly so that myself and residents of the single family subdivisions may understand what would be airborne and/or settling on them and provide comment as they feel appropriate.

The noted compliance information and monitoring regime provides no assurance to me that this power station will be required to meet safety standards at all times. More assurance of monitoring and stricter guidelines for discharges at all times needs to be instituted versus a 12-month total or averages. Averages and year long totals allow for extreme high values for short periods of time that may exceed safety standards. There is a permitted air discharge facility in a neighboring county that has exceeded permitted discharge levels time and again; noting again facility discharge levels are not always within permitted requirements, and even if caught, the discharges continue until eventual action is taken. These high level discharges, even short sporadic ones, could severely affect individuals such as myself with already compromised breathing.

I will refer once more that my residence is approximately within 7 miles of the proposed power station. The potential negative impact on our home price has not been identified in these studies, but is a very real factor; as the 'plumes' will be potentially visible from our home. A study of the impact on home prices within the 5-7 mile radius of the power station should also be conducted in order to truly reflect the economic impact of the station. (The actual need for the station within Charles City County should be further examined as part of the economic impact by the Commonwealth as discussed by previous commenters.)

Respectfully Submitted,
Amy Walker

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Please review the air permit for the Chickahominy Power Station - Fracked Gas is the wrong choice

1 message

Kimberly Williams <campaigns@good.do> Wed, Mar 20, 2019 at 4:36 PM
Reply-To: Kimberly Williams <krwilliams65@gmail.com>
To: alison.sinclair@deq.virginia.gov

Dear Ms. Sinclair

I would like to register my concern about the Chickahominy Power Station and request that this project be reviewed by the Air Pollution Control Board.

APPLICANT NAME AND REGISTRATION NUMBER: Balico LLC; 52610
FACILITY NAME AND ADDRESS: Balico LLC/Chickahominy Power, 1380 Coppermine Rd. Ste.115, Herndon, VA 20171

Issues around environmental justice, increased carbon emissions, and the health and welfare of the most vulnerable citizens in the area are all issues that need to be addressed.

Also, we live in a time of increasing threats from climate change. Virginia needs to be driving down our greenhouse gas emissions not increasing them.

Thank you for your time and attention.
NAME: Kimberly Williams
ADDRESS: 2616 Bowdens Ferry Rd., Norfolk, VA 23508
PHONE NUMBER:757-472-5388

Yours sincerely,
Kimberly Williams
Norfolk, Virginia, 23508, United States

____

This email was sent by Kimberly Williams via Do Gooder, a website that allows people to contact you regarding issues they consider important. In accordance with web protocol FC 3834 we have set the FROM field of this email to our generic no-reply address at campaigns@good.do, however Kimberly provided an email address (krwilliams65@gmail.com) which we included in the REPLY-TO field.

Please reply to Kimberly Williams at krwilliams65@gmail.com.

To learn more about Do Gooder visit www.dogooder.co
To learn more about web protocol FC 3834 visit: www.rfc-base.org/rfc-3834.html

Commonwealth of Virginia

Sinclair, Alison <alison.sinclair@deq.virginia.gov>

Please deny the permit for the Chickahominy Power Station

1 message

Nathan Soules <nsoules@gmail.com> Wed, Mar 20, 2019 at 9:45 PM
To: Alison.Sinclair@deq.virginia.gov

Hi Alison,

My name is Nathan Soules and I'm with Zero Carbon Virginia. I urge you to consider denying the permit to build the Chickahominy Power Station. This power plant would have a negative impact on air quality, contribute to climate change, and lock ratepayers into a bad long-term investment.

Charles City County and its surrounding region have high rates of hospitalizations from asthma, according to a report from the Virginia Department of Health. The American Lung Association gives Charles City a "C" grade on ground-level ozone, which is a known contributor to respiratory ailments. According to your department, the Chickahominy Power Station would emit 407 tons of Nitrogen Oxides (NOx) and 211 tons of Volatile Organic Compounds (VOCs) annually. These pollutants lead to an increase in ground-level ozone.

DEQ also claims that the plant would emit 6,479,692 tons of CO2E every year. As we know from the UN IPCC report on climate change, the planet has a limited amount of time to reduce carbon output before causing severe, irreversible consequences. Building this plant would be a step in the wrong direction - Virginia should be shutting down fossil fuel plants, not opening new ones.

One of the rationales for building the plant - that it could be used to power data centers in Northern Virginia - is dubious. Many companies with large data centers have commitments to using renewable energy. They do not want to rely on fossil fuels. Virginia should support their efforts and build renewable energy. It would help Virginia maintain its position atop the data center market.

Natural gas plants typically have a life about 36 years. Consider for example, the Greensville County Power Station, which is also a combined-cycle gas plant of a similar capacity. In twenty years or less, however, it is expected that it will be cheaper to build new renewable energy sources than to run a natural gas plant. The Chickahominy Power Station would then become a "stranded asset", leaving ratepayers on the hook.

Thank you for taking the time to listen. I hope you will do what is right for the future of the Commonwealth of Virginia.

Respectfully,

Nathan Soules
Zero Carbon Virginia

19402 Coppermine Sq.
Leesburg, VA, 20176
703-732-6040