625 Liberty Avenue, Suite 1700 | Pittsburgh, PA 15222
844-MVP-TALK | mail@mountainvalleypipeline.info
www.mountainvalleypipeline.info

Ms. Anita Walthall
Air Permit Writer
Virginia DEQ – Blue Ridge Regional Office
901 Russel Drive
Salem, VA 24153

June 30, 2020

Re: MVP Southgate Project – Lambert Compressor Station Minor New Source Article 6 Permit Application – Revised Application

Dear Ms. Walthall:

Mountain Valley Pipeline, LLC ("Mountain Valley") filed an initial minor new source review Article 6 permit application for the proposed Lambert Compressor Station on November 8, 2018. Mountain Valley submitted a revised permit application on April 25, 2019 and provided additional modeling information on January 31, 2020. Mountain Valley is submitting a revised application with revised modeling that includes the changes to the application to date. Mountain Valley is preparing an analysis and report on Environmental Justice related issues consistent with VA Code 10.1-1307.E and legislation enacted by the 2020 Session of The Virginia General Assembly. Work on this analysis has been delayed due to the COVID 19 pandemic and the protests and other activities resulting from the death of George Floyd. We anticipate Mountain Valley will submit this report to the DEQ by August of 2020.

We look forward to continuing working with you and your staff on this project. If you have any questions or comments regarding this revised application or any other information provided in support of the proposed air permit application, please contact me at 561-691-7065 or christina.akly@nee.com.

Sincerely,

Christina Akly

cc: Paul Jenkins, VADEQ – Blue Ridge Regional Office
Mike Kiss, VADEQ – Central Office
Tamera Thompson, VADEQ – Central Office
Michael Dowd, VADEQ – Central Office
Stanley Faggert, VADEQ – Central Office

Article 6 Air Permit Application
for the
Lambert Compressor Station
MVP Southgate Project

Mountain Valley Pipeline, LLC

November 2018
Revision 1 – April 2019
Revision 2 – June 2020

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1.0 INTRODUCTION

1.1 Project Overview

Mountain Valley Pipeline, LLC ("Mountain Valley") has been issued a Certificate of Public Convenience and Necessity ("Certificate") from the Federal Energy Regulatory Commission ("FERC") pursuant to Section 7(c) of the Natural Gas Act to construct and operate the MVP Southgate Project ("Project") (FERC, 2020). The pipeline project will be located in Pittsylvania County, Virginia and Rockingham and Alamance counties, North Carolina. Mountain Valley proposes to construct approximately a 0.5-mile-long 24-inch-diameter pipeline (H-605) and 74.6 miles of 24- and 16-inch-diameter natural gas pipeline (H-650) to provide timely, cost-effective access to new natural gas supplies to meet the growing needs of natural gas users in the southeastern United States ("U.S."), including for the project's anchor shipper, a local distribution company serving customers in North Carolina. The pipeline's proposed route passes through a portion of the Southern Virginia Mega Site at Berry Hill, which is one of the largest business parks on the East Coast. As an open-access pipeline, the Project may also provide additional access to other new and existing end users in proximity to the route.

The proposed pipeline will interconnect with and receive gas from the Mountain Valley Pipeline near Chatham, Virginia, and receive gas from the East Tennessee Natural Gas, LLC mainline near Eden, North Carolina, and will deliver gas to connections with customers' existing facilities in Eden and Graham, North Carolina. The MVP Southgate Project is a stand-alone project from the Mountain Valley Pipeline and has an expected in-service date of 2021.

The MVP Southgate Project will require one new compressor station, the Lambert Compressor Station, to move gas from the beginning of the H-650 pipeline at milepost 0.0 in Pittsylvania County, Virginia, to the downstream delivery points along the pipeline, as shown in Figure 1-1. The Project anticipates the supply pressure at the Lambert Interconnect to be approximately 780 psig while the delivery pressure at the T-21 Haw River Interconnect (MP 73.2) is expected to be approximately 650 psig. The gas flow will drop in pressure due to frictional losses and elevation changes as it travels southward within the pipeline. To compensate for these losses, as well as to meet the pressure requirements at the Dominion Energy North Carolina (DENC) delivery interconnects, the pressure will be boosted by the proposed compressor station. Natural gas fired turbine engines will power the compressors for the MVP Southgate Project. The natural gas to power the compressors will be provided by the Project's shippers, providing gas for compression whenever needed. The Station will receive gas from the Mountain Valley Pipeline system via the H-605 pipeline for delivery to downstream interconnects on the H-650 pipeline. The MVP

Southgate Project is proposing to construct and operate two gas-driven turbines, one Solar Taurus 70 compressor turbine (11,146 hp) and one Solar Mars 100 compressor turbine (16,610 hp) at the Lambert Compressor Station ("Station"), which combined will provide 27,756 nominal hp of compression.

The Lambert Compressor Station will be a new natural gas transmission facility covered by Standard Industrial Classification (SIC) 4922. Ancillary project emission sources include five (5) Capstone microturbines rated at 200 kW each, one (1) 0.77 MMBtu/hr natural gas fired heater, two (2) 10,000 gallon produced fluids tanks, gas filter/separators, gas coolers, inlet air filters, exhaust silencers, and blowdown silencers. The Station is expected to include a compressor building, electrical control building, utility building, storage, and air compressor building. A chain linked security fence will surround the perimeter of the station site upon completion of construction. The Station will also contain launching and receiving facilities to accommodate in-line inspection tools (smart pigs) for periodic internal inspections of the pipeline during operations.

In May 2018, Mountain Valley requested – and received – permission to enter the FERC's pre-filing process. Through the next six months, the Project team engaged stakeholders, participated in extensive outreach efforts, performed important fieldwork, and conducted detailed engineering and construction analyses.

On Nov. 6, 2018, Mountain Valley filed a formal application with the FERC for approval to construct, own, and operate the MVP Southgate Project. The application requesting the FERC Certificate of Public Convenience and Necessity was received and the MVP Southgate Project was issued Docket Number CP19-14. Since November 2018, the FERC and the Project team have collaborated on the project route and scope, and diligently worked to minimize environmental impacts across the project footprint. On February 14, 2020 the FERC issued its Final Environmental Impact Statement (FEIS). Among other items, the FEIS concluded that the project would result in limited adverse environmental impacts, and that most would be temporary and reduced to less-than-significant levels through the measures outlined by the FERC.

1.2 Application Summary

The Lambert Compressor Station is a proposed minor stationary source, as defined under Article 6 of the State Air Pollution Control Board's regulations regarding Permits for New and Modified Stationary Sources. As demonstrated in Section 4 of this application, the proposed project is not subject to major source New Source Review (NSR) or Title V air permitting requirements.

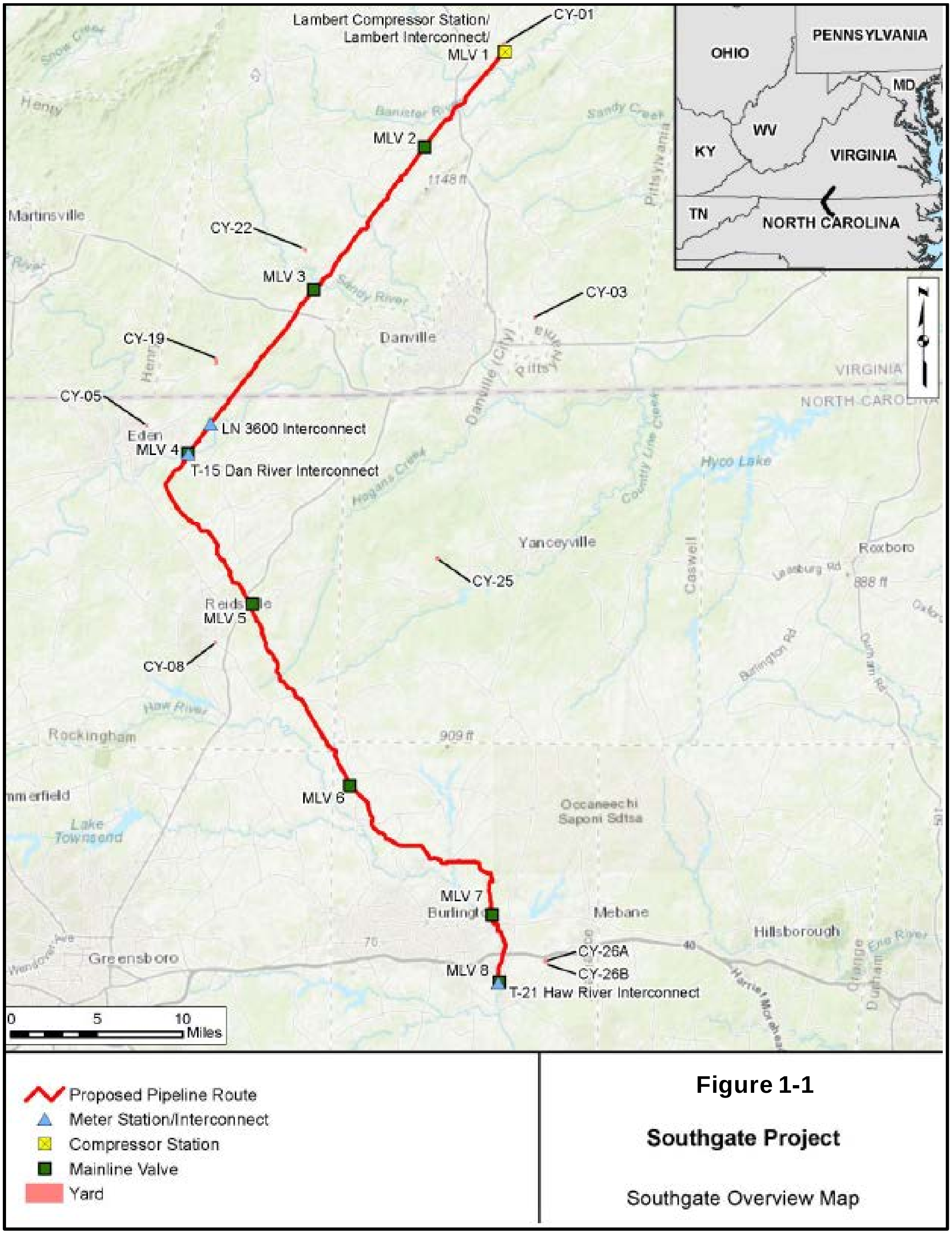
The Station will be located near the town of Chatham, Pittsylvania County, Virginia, which is part of the Central Virginia Interstate Air Quality Control Region (AQCR) in Virginia. Pittsylvania County is considered attainment or unclassifiable for all criteria pollutants.

This Article 6 Air Permit Application package per 9 VAC 5-80-1100 is designed to address the air regulatory requirements of Virginia Department of Environmental Quality (VADEQ). As such, Mountain Valley is submitting an initial minor source State Facility air permit application for the new Lambert Compressor Station. The new Solar Taurus 70 and Mars 100 combustion turbines will be subject to 40 CFR 60 Subpart KKKK, New Source Performance Standards for Stationary Gas Turbines as well as the applicable state regulations as outlined in Section 4 of this application.

This application contains the following appendices:

Appendix A: VADEQ Application Forms
Appendix B: Detailed Emission Calculations and Vendor Data
Appendix C: RLBC Database Search Results
Appendix D: Legal Analysis of Electric Compression in BACT Determination
Appendix E: Supplemental Information on Electric vs. Gas Compression Analysis
Appendix F: EPA's NAAQS: Protection of Public Health & Welfare
Appendix G: Air Dispersion Modeling Report
Appendix H: Specific Safety Measures
Appendix I: 2018 Air Emissions Inventory for Pittsylvania County
Appendix J: Real Estate Appraiser Letter
Appendix K: MVP Southgate Project Support Letters
Appendix L: Economic Benefits of the MVP Southgate Project in Virginia and North Carolina
Appendix M: FERC Resource Report 10 – Summary of Alternatives
Appendix N: Environmental Justice Report
Appendix O: Environmental Justice Information Submitted to FERC
Appendix P: Tribal Outreach

Figure 1-1: Southgate Project Overview Map



(Source: FERC Final Environmental Impact Statement, Figure 2-1.1)

2.0 PROJECT DESCRIPTION

2.1 Site Location and Surroundings

The proposed Lambert Compressor Station will be located on an undeveloped parcel of land in a rural area near the Town of Chatham, Virginia. The Lambert Compressor Station will be constructed at the beginning of the pipeline at milepost 0.0 in Pittsylvania County, Virginia on a parcel of land owned by Mountain Valley near a couple of existing compressor stations (Stations 165 and 166) owned by Transcontinental Pipeline Company (Transco) as shown in Figure 2-1. The approximate Universal Transverse Mercator (UTM) coordinates of the facility are: 647,900 meters east and 4,076,900 meters north in Zone 17 (North American Datum of 1983 (NAD83)).

2.2 Facility Overview

As a part of the Southgate Project, Mountain Valley is proposing to install the following equipment at the Lambert Compressor Station:

- One Solar Mars 100 natural gas turbine compressor unit rated at 16,610 hp;
- One Solar Taurus 70 natural gas turbine compressor unit, rated at 11,146 hp;
- Five (5) Capstone Microturbines each rated at 200 kW;
- One 0.77 MMBtu/hr fuel gas heater; and
- Two 10,000 gallon produced fluids storage tanks.

Pipeline quality natural gas will enter the facility from the Mountain Valley Pipeline system via the H-605 24-inch pipeline. The gas will pass through a series of filter separators to remove any liquids or solids. The gas will then enter the Solar Taurus 70 and Solar Mars 100 compressor units and will be compressed to the desired pressure. The compressed gas will exit the compressor station and will be discharged for delivery to downstream interconnects on the H-650 pipeline. All condensate and produced fluids collected by the various filters throughout the facility will be transferred to the produced fluids storage tanks. The facility includes 5 microturbines to provide primary electrical power to the facility to operate ancillary equipment such as fans as well as to maintain building functions. The site will use utility power as backup emergency power for ancillary equipment and buildings. A detailed plot plan of the proposed facility is shown in Figure 2-2.

Figure 2-1: Site Location Map

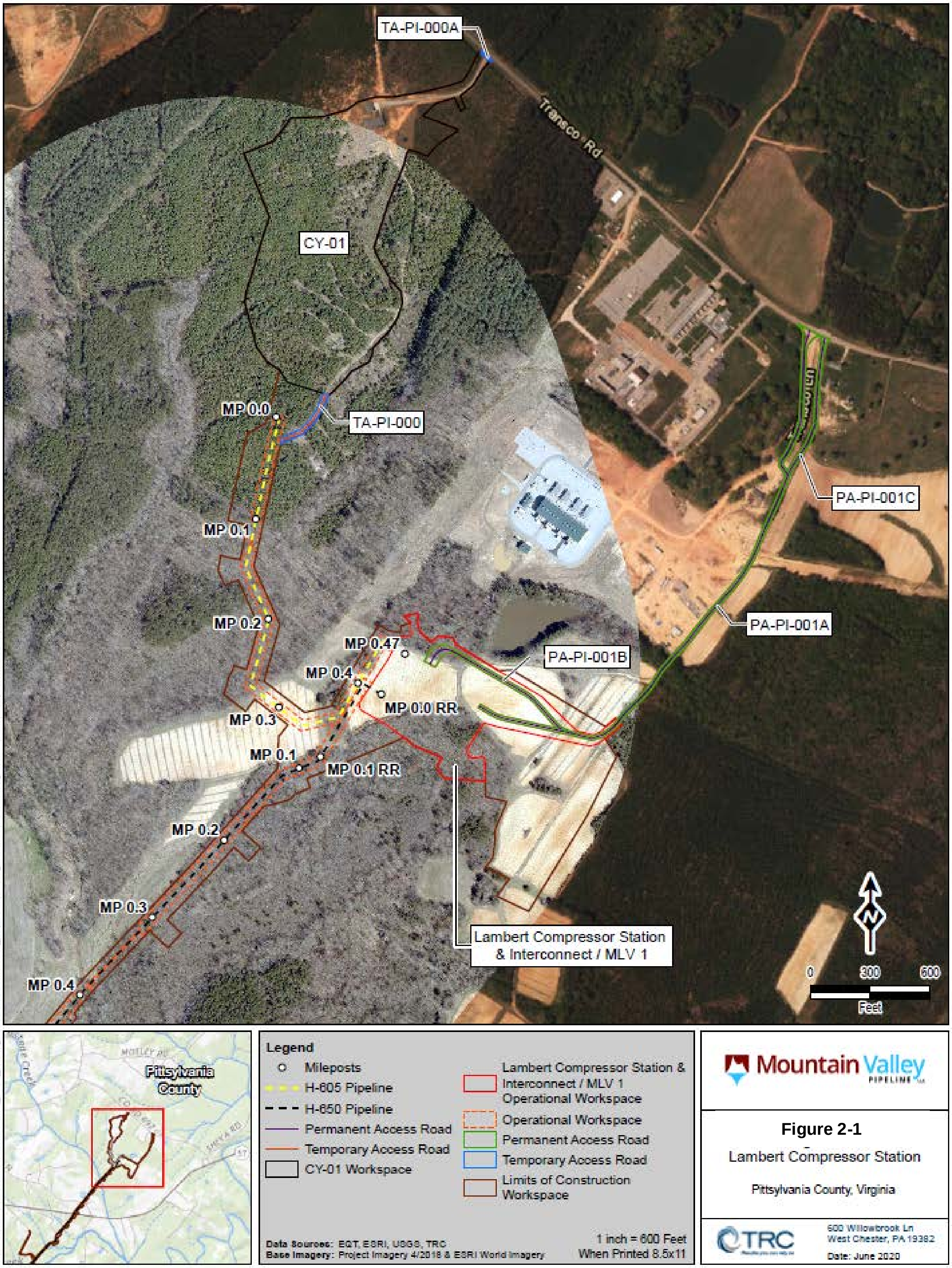
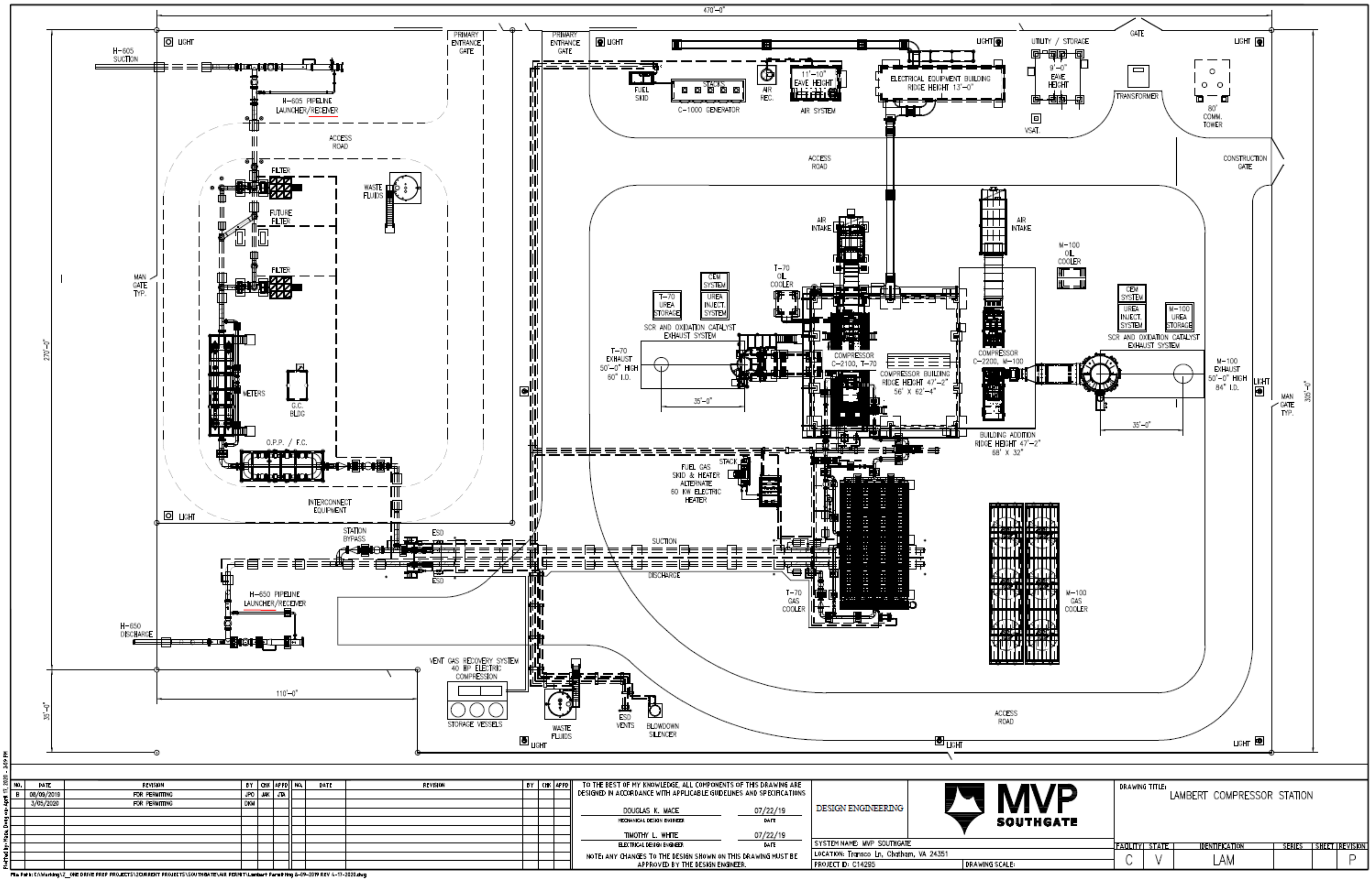


Figure 2-2: Facility Plot Plan


H-605 SUCTION
H-605 PIPELINE LAUNCHER/RECEIVER
PRIMARY ENTRANCE GATE
ACCESS ROAD
FILTER
FUTURE FILTER
WASTE FLUIDS
MAN GATE TYP.
METERS
G.C. BLDG
O.P.P. / F.C.
INTERCONNECT EQUIPMENT
STATION BYPASS
ESD
H-650 PIPELINE LAUNCHER/RECEIVER
H-650 DISCHARGE
110'-0"
270'-0"
35'-0"
470'-0"
LIGHT
FUEL SKID
STACKS
C-1000 GENERATOR
AIR REC.
11'-10" EAVE HEIGHT
AIR SYSTEM
ELECTRICAL EQUIPMENT BUILDING RIDGE HEIGHT 13'-0"
UTILITY / STORAGE
9'-0" EAVE HEIGHT
VSAT.
GATE
TRANSFORMER
80' COMM. TOWER
CONSTRUCTION GATE
AIR INTAKE
T-70 OIL COOLER
M-100 OIL COOLER
CEM SYSTEM
UREA INJECT. SYSTEM
T-70 UREA STORAGE
M-100 UREA STORAGE
SCR AND OXIDATION CATALYST EXHAUST SYSTEM
T-70 EXHAUST 50'-0" HIGH 60" I.D.
M-100 EXHAUST 50'-0" HIGH 84" I.D.
COMPRESSOR C-2100, T-70
COMPRESSOR C-2200, M-100
COMPRESSOR BUILDING RIDGE HEIGHT 47'-2" 56' X 62'-4"
BUILDING ADDITION RIDGE HEIGHT 47'-2" 68' X 32"
FUEL GAS SKID & HEATER ALTERNATE 60 KW ELECTRIC HEATER
STACK
SUCTION
DISCHARGE
T-70 GAS COOLER
M-100 GAS COOLER
VENT GAS RECOVERY SYSTEM 40 HP ELECTRIC COMPRESSION
STORAGE VESSELS
WASTE FLUIDS
ESD VENTS
BLOWDOWN SILENCER
305'-0"
NO. DATE REVISION BY CHK APPD
B 08/09/2019 FOR PERMITTING JPO JAK JTA
3/05/2020 FOR PERMITTING DKM
TO THE BEST OF MY KNOWLEDGE, ALL COMPONENTS OF THIS DRAWING ARE DESIGNED IN ACCORDANCE WITH APPLICABLE GUIDELINES AND SPECIFICATIONS
DOUGLAS K. MACE 07/22/19
MECHANICAL DESIGN ENGINEER DATE
TIMOTHY L. WHITE 07/22/19
ELECTRICAL DESIGN ENGINEER DATE
NOTE: ANY CHANGES TO THE DESIGN SHOWN ON THIS DRAWING MUST BE APPROVED BY THE DESIGN ENGINEER.
DESIGN ENGINEERING
MVP SOUTHGATE
SYSTEM NAME: MVP SOUTHGATE
LOCATION: Transco Ln, Chatham, VA 24351
PROJECT ID: C14295
DRAWING SCALE:
DRAWING TITLE: LAMBERT COMPRESSOR STATION
FACILITY STATE IDENTIFICATION SERIES SHEET REVISION
C V LAM P

3.0 PROJECT EMISSIONS

As discussed earlier, the Lambert Compressor Station will include the following air emissions sources. Note that the number provided in parenthesis next to the emission source is the emission unit identification (EU ID) used throughout the calculations to identify these emissions sources.

- One Solar Mars 100 natural gas turbine compressor unit rated at 16,610 hp (CT-01)
- One Solar Taurus 70 natural gas turbine compressor unit, rated at 11,146 hp (CT-02)
- Five (5) Capstone Microturbines each rated at 200 kW (MT-01 to MT-05)
- One 0.77 MMBtu/hr fuel gas heater (HT-01)
- Two 10,000 gallon produced fluids storage tanks (TK-01 and TK-02)

The turbines' horsepower (hp) rating is based on 100% load, 0^oF, 60% relative humidity and 660 ft elevation. In addition to the point sources identified above, intermittent and non-point sources of air pollution at the facility will include:

- Natural gas venting/blowdowns (BDE)
- Fugitive components such as pumps, flanges, valves, etc. associated with the proposed compressor station (FUG)

The Station will utilize pipeline natural gas as the sole fuel for all proposed equipment. The natural gas is assumed to have a higher heating value (HHV) of approximately 1,098 Btu/standard cubic foot (SCF) and is expected to contain no more than 2.0 grains of sulfur per 100 SCF of gas on an annual average basis.

Equipment controls, operational assumptions and emission factors used to determine the maximum potential emissions at the facility are discussed in the following sections. Potential emissions were calculated for nitrous oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM) with aerodynamic diameter less than 10 (PM_{10}), PM with aerodynamic diameter less than 2.5 ($PM_{2.5}$), sulfur dioxide (SO_2), hazardous air pollutants (HAPs) and greenhouse gases (GHGs) including carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).

3.1 Compressor Turbines

The proposed Solar Taurus 70 and Mars 100 natural gas-fired turbines to be installed at the Lambert Compressor Station will be equipped with dry low NOx burners, which are part of the combustion turbines SoLoNOx technology. These burners are integral to the units and are required for the operation of the compressors.

Potential emissions for the Solar turbines conservatively assume that the units will operate up to 8,760 hours per year and up to 100% rated output. The vendor provided uncontrolled emission rates for normal operating conditions are as follows (all emissions rates are in terms of parts per million dry volume (ppmvd) @ 15% O_2):

Solar Mars 100 (Uncontrolled)

- 9 ppmvd NOx;
- 25 ppmvd CO;
- 25 ppmvd unburned hydrocarbons (UHC);
- 5 ppmvd VOC;

Solar Taurus 70 (Uncontrolled)

- 9 ppmvd NOx;
- 25 ppmvd CO;
- 25 ppmvd unburned hydrocarbons (UHC); and
- 5 ppmvd VOC.

Although no additional emissions controls are required for these units as per 9 VAC 5-80, the turbines will be equipped with the following post combustion controls in order to provide the most emission control available:

- Selective Catalytic Reduction (SCR) for additional NOx control
- Oxidation Catalyst for the control of CO and VOCs

The SCR is expected to achieve a 70% control efficiency for NOx while the oxidation catalyst will achieve efficiencies as high as 92% for CO and 90% for VOCs, including formaldehyde. Ammonia for the SCR system will be provided in the form of 19% aqueous ammonia using an ammonia injection system that also includes an ammonia storage tank. In addition to post combustion controls, the turbines will be equipped with inlet air filters to reduce incoming PM in inlet air.

Depending upon demand, the turbines may operate at loads ranging from 50% to 100% of full capacity. Because different emission rates and exhaust characteristics occur at different loads and ambient temperatures, a matrix of operating modes is presented in this air permit application (See Appendix B). Emission parameters for three turbine loads (50%, 75%, and 100%) and six ambient temperatures (0°F, 20°F, 40°F, 60°F, 80°F, and 100°F) are accounted for in this air permit application to cover the range of steady-state turbine operations.

At very low load and cold temperature extremes, the turbine system must be controlled differently in order to assure stable operation. The required adjustments to the turbine controls at these conditions cause emissions of NOx, CO and VOC to increase while the emission rates of other pollutants remain unchanged. Low-load operation of the turbines is expected to occur only during periods of startup and shutdown and for maintenance or unforeseen emergency events. Solar has provided emissions estimates during start-up and shutdown and low load operation. This information is provided in the Solar Product Information Letter (PIL) 170 ("Emission Estimates at Start-up, Shutdown, and Commissioning for SoLoNOx Combustion Products") included as part of the vendor attachments in Appendix B.

Turbine emission rates during start-up and shutdown events increase for CO and VOC as compared to operating above 50% load. The start-up process for the Solar Mars 100 and Taurus 70 turbines takes approximately 10 minutes from the initiation of start-up to normal operation (equal to or greater than 50% load). Shutdown takes approximately 10 minutes. Mountain Valley has estimated there would be 52 start-up/shutdown events per year. Emissions per start-up and shutdown event for the turbine were estimated based on Table 2 of Solar PIL 170. Appendix B contains these per-event emission calculations for start-up and shutdown and the associated Solar PIL 170.

Similarly, Solar has provided emission estimates for low temperature operation (inlet combustion air temperature less than 0° F and greater than -20° F) in Table 1 of Solar PIL 167 ("SoLoNOx Products: Emissions in Non-SoLoNOx Modes"), which were used for low temperature operation cases included in the potential to emit calculations.

Mountain Valley reviewed historic meteorological data from the previous 5 years for the region to estimate the worst case number of hours per year under sub-zero (less than 0° F) conditions. Based on that review, the annual hours of operation during sub-zero conditions was assumed to be not more than 24 hours per year. Table 3-1 summarizes the emissions used for low temperature operation and startup and shutdown operations.

Table 3-1: Emission Factors for Low Temperature and Startup/Shutdown Operations

Turbine Type	Solar Taurus 70 Turbine					Solar Mars 100 Turbine				
Pollutant	**NOx**	**CO**	**UHC**	**VOC**	**CO_2**	**NOx**	**CO**	**UHC**	**VOC**	**CO_2**
Low Temperature Operation (ppm @ 15% O2) (1)	42	100	50	10	NA	42	100	50	10	NA
Startup Operations (lb/event) (2)	1	88	88	18	381	1	46	20	4	385
Shutdown Operations (lb/event) (2)	1	62	40	8	473	1	82	26	5	676

(1) Emission estimates from Solar Production Information Letter (PIL) 167, Table 1

(2) Emission estimates from Solar PIL 170, Table 2

3.2 Ancillary Equipment

Mountain Valley is proposing to install five (5) new natural gas fired Capstone C200 (200 kW) microturbines to provide primary electrical power to the Station. Maximum hourly and annual emission rates for the microturbines are provided in Appendix B. Emissions of NOx, CO, and VOC are based on vendor data included in Appendix B. Emission rates for SO_2, particulates, and hazardous air pollutants (HAPs) are based on USEPA AP-42 emission factors (Chapter 3.1, Table 3.1-2a). GHG emissions are based on 40 CFR Part 98 Tables A-1, C-1, and C-2. The emission rates are based on the microturbines operating at peak load.

Mountain Valley is also proposing to install one new 0.77 MMBtu/hr (heat input) fuel gas heater. Emission factors for the heater were obtained from AP-42 Chapter 1.4 for criteria pollutants and 40 CFR Part 98 for GHGs. Appendix B provides information on the emission factors used to calculate emissions from the heater.

Proposed produced fluid storage tanks at the Lambert Compressor Station may have associated emissions, such as the flashing losses that occur when the pressure of a liquid is decreased or the temperature is increased, as well as working and breathing emissions from storage. At the Station, these losses will occur at the 10,000 gallon produced fluids storage tanks and include VOCs and GHGs as provided in Appendix B.

3.3 Blowdown Emissions

Blowdown or vented emissions are defined as those emissions which pass through a stack, vent, or equivalent opening. A compressor may be vented for startup, shutdown, maintenance, or for protection of gas seals from contamination. An individual compressor or the entire station may be blown down (i.e., vented) for testing, or in the event of an emergency.

Potential blowdown emissions may result from two types of gas blowdown events that could occur at the Station: (1) a type of maintenance gas blowdown that could occur when a compressor is stopped and gas between the suction/discharge valves and compressors is vented to the atmosphere via a blowdown vent, and (2) an emergency full station shutdown (ESD) test that would only occur infrequently as required by U.S. Department of Transportation (DOT), or in an emergency situation.

The Lambert Compressor Station is proposing to install pressurized hold (PH) and a vent gas recovery system (VGRS) to reduce the amount of gas being vented from the station, including during unit shutdowns and startups. Pressurize hold uses control logic, system valves and a pneumatic booster pump, when necessary, to maintain differential pressure across the compressor seals. PH allows the compressor to maintain a shutdown condition with the compressor case at suction pressure. The VGRS is a pressure management system that uses an electric pressure management compressor to lower the pressure in the unit to reduce the amount of gas vented in the event the unit needs to be blowdown for maintenance purposes.

Utilization of PH and VGRS under normal operating scenarios provides the following benefits: (1) avoids blowing a compressor unit down when the compressor capacity is not needed (i.e. allows unit to be maintained in a pressurized standby mode), (2) avoids purging the unit during startup (as this is not needed if unit has been kept in pressurized standby mode), and (3) reduces unit case and piping pressures to a significantly lower pressure before being vented, therefore minimizing the amount of gas vented during maintenance events.

In accordance with DOT requirements, the compressor station is equipped with an emergency shutdown system that blocks natural gas out of the station and blows down the station piping and gas containing equipment and vessels. The compressor station is also equipped with pressure controls, redundant controls and relief devices (or other suitable protective devices) to ensure the maximum operating pressure is not exceeded. System blowdowns are directed to natural gas blowdown stacks. The shutdown system and pressure relief devices (or other suitable protective devices) are required to be inspected and tested on an annual basis. Under typical compressor station procedures, natural gas would be vented from the blowdown stacks during the required annual system test. However, the Station is proposing to conduct capped ESD tests using block valves that ensure no gas escapes during the required annual testing. Block valves will be permanently installed immediately downstream of the ESD blowdown valve. During the capped ESD test, these block valves are closed and the ESD test is initiated to ensure that the ESD blowdown valves have moved to the correct position. Once the test has been documented and the ESD blowdown valves demonstrated to have worked properly, the ESD blowdown valves are closed and the gas trapped between the ESD blowdown valves and the block valve is released through the vent valve by opening the vent valves. Therefore, the only gas released from the system during a capped ESD test is the gas trapped in the piping between the ESD blowdown valves and the block valve. The emissions vented from these ESD capped tests are considered negligible as the amount of gas released will be less than 5 scf.

The blowdown emission controls proposed for this facility are voluntary controls added with the purpose of minimizing the GHG emission impact of the site and to provide the maximum available HAP control from these blowdown and venting emissions events. The emissions resulting from these events are calculated using the released volume and the pipeline natural gas analysis, specifications and properties, as provided in Appendix B.

3.4 Fugitive emissions

Fugitive emissions are defined as those emissions which do not pass through a stack, vent, or other functionally equivalent opening, and include natural gas leaks from valves, flanges, pumps, compressors, seals, connections, etc.

Fugitive emissions at natural gas compressor stations include leaks from piping components (valves, flanges, connectors and open-ended lines). These were estimated using EPA emission factors and Interstate Natural Gas Association of America (INGAA) guidelines. Mountain Valley has provided fugitive emissions estimates for VOC and GHG emissions in Appendix B.

The facility will routinely be inspected for fugitive emissions with an optical gas imaging (OGI) camera, as discussed in Section 4.1.5. Additionally, inspections will be conducted by facility operators on any day that the site is manned; such inspections will detect leaks using audio, visual, and olfactory (AVO) methods. For both inspection types, all detected leaks will be repaired according to state and federal requirements.

3.5 Proposed Project Potential Emissions

Table 3-2 presents project uncontrolled potential emissions from the new units to be installed at the proposed Lambert Compressor Station. For new emission units, project potential emissions are equal to the potential to emit. Table 3-3 presents the Project's controlled potential emissions, which include the emissions after post-combustion control efficiencies resulting from the SCR and the oxidation catalyst and the blowdown emissions controlled by the VGRS and block valve for ESD testing. Detailed emission calculations and supporting vendor data are provided in Appendix B of this permit application.

Table 3-2: Proposed Facility Potential Uncontrolled Emissions in Tons Per Year (tpy)

Proposed Sources	Emission Unit ID	Criteria Pollutants					Greenhouse Gases (GHGs)				HAPs
		NOx	CO	VOC	SO_2	PM/PM_{10}/ $PM_{2.5}$	CO_2	CH_4	N_2O	CO_2e	Total HAPs
		(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Solar Mars 100(1)	CT-01	19.58	36.26	3.99	3.09	5.95	69,632	1.31	0.13	69,704	2.54
Solar Taurus 70(1)	CT-02	13.35	26.34	3.23	2.11	4.06	47,355	0.89	0.09	47,404	1.65
Capstone C200 Microturbines (5 Units)	MT-01 to MT-05	1.81	4.79	0.44	0.17	0.33	5,841	0.11	0.011	5,847	0.21
Fuel Gas Heater	HT-01	0.31	0.26	0.02	0.018	0.02	394.5	0.01	0.001	395	0.01
Produced Fluids Tanks	TK-01, TK-02	-	-	0.43	-	-	-	-	-	4.2	0.004
Blowdowns	BDE	-	-	0.54	-	-	0.26	50.13	-	1,254	0.05
Station Fugitives	FUG	-	-	0.75	-	-	0.36	69.59	-	1,740	0.07
Totals (tons/year)		**35.04**	**67.65**	**9.40**	**5.39**	**10.36**	**123,224**	**122.04**	**0.23**	**126,349**	**4.53**

Notes:

Emissions based on the following turbine specifications: 9 ppm NOx, 25 ppm CO, 5 ppm VOC

Table 3-3: Proposed Controlled Facility Potential Emissions in Tons Per Year (tpy)

Proposed Sources	Emission Unit ID	Criteria Pollutants					Greenhouse Gases (GHGs)				HAPs
		NOx	CO	VOC	SO_2	$PM/PM_{10}/PM_{2.5}$	CO_2	CH_4	N_2O	CO_2e	Total HAPs
		(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Solar Mars 100	CT-01	6.09	6.30	0.63	3.09	5.95	69,632	1.31	0.13	69,704	0.42
Solar Taurus 70	CT-02	4.16	5.93	0.94	2.11	4.06	47,355	0.89	0.09	47,404	0.36
Capstone C200 Microturbines (5 Units)	MT-01 to MT-05	1.81	4.79	0.44	0.17	0.33	5,841	0.11	0.011	5,847	0.21
Fuel Gas Heater	HT-01	0.31	0.26	0.02	0.02	0.02	395	0.01	0.001	395	0.01
Produced Fluids Tanks	TK-01, TK-02	-	-	0.43	-	-	-	-	-	4.2	0.004
Blowdowns	BDE	-	-	0.12	-	-	0.06	11.29	-	282.2	0.011
Station Fugitives	FUG	-	-	0.75	-	-	0.36	69.59	-	1,740	0.07
Totals (tons/year)		**12.37**	**17.28**	**3.33**	**5.39**	**10.36**	**123,224**	**83.20**	**0.23**	**125,377**	**1.09**

Based on the following turbine control efficiencies and the use of VGRS and block valve for capped ESD Testing:

Control Technology	Control Efficiency		
	NOx	CO	VOC
Selective Catalytic Reduction (SCR)	70%	-	-
Oxidation Catalyst	-	92%	90%

4.0 RULE APPLICABILITY ANALYSIS

This section contains an analysis of the applicability of federal and state air quality regulations to the proposed Project. The specific regulations included in this applicability review are the Federal New Source Performance Standards (NSPS), Prevention of Significant Deterioration (PSD) and New Source Review (NSR) requirements, Maximum Achievable Control Technology (MACT) requirements for HAPs, and VADEQ Regulations and Policy.

4.1 Federal New Source Performance Standards (NSPS)

The 40 CFR Part 60 NSPS are technology-based standards that apply to new, modified, and reconstructed stationary sources. The 40 CFR 60 NSPS requirements have been established for approximately 70 source categories. The proposed Project is subject to the following three subparts: General Provisions (40 CFR Part 60, Subpart A), Standards of Performance for Stationary Combustion Turbines (40 CFR Part 60, Subpart KKKK), and the Standards of Performance for Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources (40 CFR Part 60, Subpart OOOOa).

4.1.1 40 CFR Part 60, Subpart A – General Provisions

The new Solar Taurus 70 and Mars 100 turbines are subject to the general provisions for NSPS units in 40 CFR Part 60 Subpart A. These include the requirements for notification, record keeping, and performance testing contained in 40 CFR Parts 60.7 and 60.8.

4.1.2 40 CFR Part 60 Subpart Dc – Small Industrial-Commercial-Institutional Steam Generating Units

Subpart Dc applies to steam generating units for which construction, modification, or reconstruction is commenced after June 9, 1989 and that have a maximum design heat capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. The proposed heater to be located at the facility has a maximum heat input capacity of 0.77 MMBtu/hr. Therefore, this subpart will not apply.

4.1.3 40 CFR Part 60 Subpart Kb - Volatile Organic Liquid Storage Vessels

Subpart Kb potentially applies to storage vessels with a capacity greater than 75 cubic meters (m^3) (19,813 gallons) that will store volatile organic liquids. Tanks with a capacity greater than 75 m^3 are not proposed to be constructed, reconstructed, or modified at the Lambert Compressor Station.

Therefore, this subpart will not apply. The only 2 tanks that will be installed at this site have a 10,000-gallon capacity.

4.1.4 40 CFR Part 60, Subpart KKKK – Stationary Combustion Turbines

On July 6, 2006, the USEPA promulgated Subpart KKKK to establish emission standards and compliance schedules for the control of emissions from new stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005. Note that stationary combustion turbines regulated under Subpart KKKK are exempt from Subpart GG requirements, which are applicable to units constructed, modified, or reconstructed prior to February 18, 2005.

Pursuant to 40 CFR 60.4305(a), the new Solar Taurus 70 and Mars 100 gas turbines are subject to requirements of 40 CFR 60 Subpart KKKK, because the heat input at peak load will be greater than or equal to 10 MMBtu/hr (HHV) and Mountain Valley will have commenced the construction or modification of the turbines after February 18, 2005. Pursuant to 40 CFR 60.4320(a) and Table 1 to Subpart KKKK of Part 60 – Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines, the new gas turbines, which will have HHV heat inputs of between 50 and 850 MMBtu/hr, will comply with a NOx emission standard of 25 ppm at 15 percent O_2 or 1.2 lb/MWh useful output as indicated by the vendor guarantee of 9 ppm shown in Appendix B. Subpart KKKK also includes a NOx limit of 150 ppmvd at 15% O_2 or 8.7 lb/MWh for turbine operation at temperatures less than 0°F and turbine operation at loads less than 75% of peak load which the new turbine will meet as indicated by the vendor guarantee shown in Appendix B. The new turbines will not burn any fuel that has the potential to emit in excess of 0.060 lb/MMBtu SO_2 heat input, pursuant to 40 CFR 60.4330(a)(1) and (2), respectively.

Pursuant to 40 CFR 60.4305(a), the five microturbines do not have a heat input at peak load equal to or greater than 10 MMBtu/hr, and are therefore not subject to NSPS Subpart KKKK.

4.1.5 40 CFR 60, Subparts OOOO and OOOOa – Crude Oil and Natural Gas Production, Transmission and Distribution

Subpart OOOO currently applies to affected facilities that commenced construction, reconstruction, or modification after August 23, 2011 and on or before September 18, 2015. The equipment at the proposed Station will have a construction date after September 18, 2015, and therefore will not be subject to Subpart OOOO.

Oil and gas facilities constructed, modified or reconstructed after September 18, 2015, such as the proposed compressor station, are subject to the requirements under NSPS 60 Subpart OOOOa. Potential equipment at compressor stations regulated under Subpart OOOOa includes storage tanks, continuous bleed pneumatic controllers, pneumatic pumps, reciprocating and wet seal centrifugal compressors, and fugitive emission components. The Lambert compressor station will not include continuous bleed pneumatic controllers, pneumatic pumps or reciprocating or wet seal centrifugal compressors. The storage vessels that will be located at the facility have the potential for VOC emissions less than or equal to 6 tons per year, so they are not subject to this subpart. Fugitive emissions components at the facility will be subject to Subpart OOOOa. For equipment leaks, Subpart OOOOa requires quarterly surveys using optical gas imaging (OGI) technology and subsequent repair of any identified leaks. The project will comply with all applicable leak detection, repair and reporting provisions of Subpart OOOOa. Details of the Leak Detection and Repair (LDAR) program and AVO methods will be developed after the construction of the facility when specific locations of fugitive emissions equipment are available and will be in place prior to operation of the units.

4.1.6 40 CFR 60, Subparts IIII and JJJJ – Stationary Compression Ignition (IIII) and Spark Ignition (JJJJ) Internal Combustion Engines

NSPS Subpart IIII and JJJJ were promulgated in 2008 and these rules are applicable to new stationary compression ignition and spark ignition internal combustion engines, respectively. The Lambert CS will not install any compression ignition or spark ignition internal combustion engine on the site. These are generally used in backup generators, but since the facility will use centrifugal micro turbines for primary power and power from the grid for backup, no emergency engines will be installed in this site. Therefore, these subparts do not apply to the site.

4.2 Prevention of Significant Deterioration (PSD)

Preconstruction air permitting programs that regulate the construction of new stationary sources of air pollution and the modification of existing stationary sources are commonly referred to as New Source Review (NSR). NSR can be divided into major NSR and minor NSR. Major NSR is comprised of the PSD program. Major NSR requirements are established on a federal level but may be implemented by state or local permitting authorities under either a delegation agreement with USEPA or as a state implementation plan (SIP) program approved by USEPA.

The Lambert Compressor Station is not classified as one of the 28 named source categories listed in Section 169 of the Clean Air Act. Therefore, to be considered a "major stationary source" subject to PSD, the facility would need to have potential emissions of 250 tons per year or more of any regulated pollutant (except CO_2). The final PSD and Title V GHG Tailoring Rule was published in the Federal Register on June 3, 2010 (75 FR 31514) but was ultimately overturned on June 23, 2014 by the US Supreme Court. Under the formerly effective rule, GHGs could, as of July 1, 2011, become "subject to regulation" under the PSD program for construction projects that would result in potential GHG emissions of 100,000 tons per year (tpy) carbon dioxide equivalents (CO_2e) or more. However, the June 23, 2014 Supreme Court Decision clarified that construction projects cannot trigger major NSR for GHGs unless major NSR is otherwise triggered for any other criteria pollutants.

As shown in Table 4-1, the proposed Lambert Compressor Station is a minor stationary source with respect to NSR as all pollutants with the exception of CO_2e are below the PSD source thresholds. Therefore, the Project is not subject to PSD requirements.

Table 4-1: PSD/NNSR Applicability Assessment

Pollutant	PSD/NNSR Major Source Threshold (tpy)	Total Uncontrolled Facility Emissions (tpy)	Total Controlled Facility Emissions (tpy)	Emissions Exceed PSD/NNSR Major Source Threshold
Nitrogen Oxides (NOx)	250	35.04	12.37	No
Carbon Monoxide (CO)	250	67.65	17.28	No
Sulfur Dioxide (SO_2)	250	5.39	5.39	No
TSP	250	10.36	10.36	No
PM_{10}	250	10.36	10.36	No
$PM_{2.5}$	250	10.36	10.36	No
VOC	250	9.40	3.33	No
Greenhouse Gases (CO_2e)	100,000	126,349	125,377	No(1)
Total HAP	25	4.53	1.09	No
Individual HAP - Formaldehyde	10	3.50	0.82	No

(1) GHGs cannot trigger major NSR unless major NSR is otherwise triggered for any other criteria pollutants as per June 23, 2014 US Supreme Court decision. *UARG v EPA*, 573 U.S. 302 (2014)

4.3 Title V Operating Permits

The Title V permit program in 40 CFR Part 70 requires major sources of air pollutants to obtain federal operating permits. The major source thresholds under the Title V program, as defined in 40 CFR 70.2 and which are different from the federal NSR major source thresholds, are 100 tpy of any air pollutant, 10 tpy of any single hazardous air pollutant (HAP), or 25 tpy of total HAPs.

As shown in Table 4-2, potential emissions of all regulated pollutants are below the Title V major source thresholds of 100 tpy. As such, the facility is not subject to Title V permitting requirements.

Table 4-2: Title V Permit Applicability Assessment

Pollutant	Title V Source Threshold (tpy)	Total Uncontrolled Facility Emissions (tpy)	Total Controlled Facility Emissions (tpy)	Emissions Exceed Title V Source Threshold
Nitrogen Oxides (NOx)	100	35.04	12.37	No
Carbon Monoxide (CO)	100	67.65	17.28	No
Sulfur Dioxide (SO_2)	100	5.39	5.39	No
TSP	100	10.36	10.36	No
PM_{10}	100	10.36	10.36	No
$PM_{2.5}$	100	10.36	10.36	No
VOC	100	9.40	3.33	No
Total HAP	25	4.53	1.09	No
Individual HAP - Formaldehyde	10	3.50	0.82	No

4.4 National Emission Standards for Hazardous Air Pollutants

The USEPA has established National Emission Standards for Hazardous Air Pollutants (NESHAP) for specific pollutants and industries in 40 CFR Part 61. The Project does not include any of the specific sources for which NESHAP have been established in Part 61. Therefore, Part 61 NESHAP requirements will not apply to the proposed facility. The USEPA has also established NESHAP requirements in 40 CFR Part 63 for various source categories. The applicability to the

Project of several NESHAP rules is discussed below. The applicability analysis shows that Part 63 NESHAP requirements will not apply to the proposed facility.

4.4.1 40 CFR Part 63 Subpart HHH (NESHAP from Natural Gas Transmission and Storage Facilities)

Subpart HHH applies to natural gas transmission and storage facilities that are major sources of HAPs and that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company). The Lambert Station is an area (minor) source of HAPs. Therefore, this subpart will not apply because it only applies to major sources of HAPs.

4.4.2 40 CFR Part 63 Subpart YYYY (NESHAP for Stationary Combustion Turbines)

Emissions and operating limitations under Subpart YYYY apply to new and reconstructed stationary combustion turbines located at major sources of HAPs. The Lambert Station is an area source (i.e., not major source) of HAPs. Therefore, this subpart is not applicable to the turbines at this site.

4.4.3 40 CFR Part 63 Subpart DDDDD (NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters) and 40 CFR Part 63 Subpart JJJJJJ (NESHAP for Area Sources: Industrial, Commercial, and Institutional Boilers)

Subpart DDDDD applies to certain new and existing boilers and process heaters at major HAP sources. The Lambert Station is an area source of HAPs. Therefore, this subpart will not apply because it only applies to major sources of HAPs. The area source regulation for boilers, Subpart JJJJJJ, exempts all process heaters and also exempts boilers that are natural gas-fired. The proposed heater at the site will be only fired with natural gas, so it is therefore exempted from the area source NESHAP under subpart JJJJJJ.

4.4.4 40 CFR Part 63 Subpart ZZZZ (NESHAP for Stationary Reciprocating Internal Combustion Engines)

Subpart ZZZZ applies to reciprocating internal engines (RICE) at both major and minor sources. The proposed facility does not have any RICE units. Therefore, this subpart does not apply to the site.

4.5 Greenhouse Gas Reporting Rule

Per 40 CFR 98.2(a)(2), facilities that contain a source category listed in Table A-4 of the rule and emit 25,000 metric tons or more per year of carbon dioxide equivalent ("CO_2e") in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories in Tables A-3 and A-4 of the rule are subject to reporting under the Greenhouse Gas Mandatory Reporting Rule ("MRR"). Table A-4 of 40 CFR 98 Subpart A includes Petroleum and Natural Gas Systems. Greenhouse gas emissions from the compressor station are over 25,000 metric tpy on a potential basis. The actual emissions will be calculated annually following subpart W applicability and calculation methodology and compared with the 25,000 metric tpy of CO_2 to address the applicability of the rule. The Project will meet all requirements of the MRR for the new compressor station, as applicable. No other subparts under the MRR are applicable to the compressor station.

4.6 Virginia Regulations

The air quality regulations for the Commonwealth of Virginia are codified in Title 9 of the Virginia Administrative Code (9 VAC) Agency 5, State Air Pollution Control Board. Potentially applicable regulations are identified below:

- **9 VAC 5-20 "General Provisions."** The Air Pollution Control Board may require an owner of a stationary source to submit a control program, in a form and manner satisfactory to the board, showing how compliance is achieved. For cases of equipment maintenance or malfunctions, a facility record and notification of instances to the board are required and will be submitted if any malfunctions occur.
- **9 VAC 5-30 "Ambient Air Quality Standards"** are required to assure that ambient concentrations of air pollutants are consistent with established criteria and shall serve as the basis for effective and reasonable management of the air resources of the Commonwealth of Virginia. An air quality analysis utilizing dispersion modeling was conducted to demonstrate compliance with the NAAQS as discussed in Section 6.0.
- **9 VAC 5-60 "State Toxics Rule"** contains the emissions standards for toxic air pollutants from new and modified sources. Emissions of toxic air pollutants discharged into the atmosphere from any affected facility may not cause, or contribute to, the endangerment of human health. Facilities that have a potential to emit toxic air pollutants in quantities that endanger human health are required to employ BACT for the control of toxic air pollutants. The proposed new facility emissions of toxic air pollutants were compared to the exemption thresholds contained in 9VAC5-60-300C. The only toxic air pollutant that is potentially emitted above the exemption thresholds is formaldehyde. The ambient air quality modeling

analysis in Section 6.0 demonstrates that the proposed facility will not cause, or contribute to, any significant ambient air concentration that may cause, or contribute to, the endangerment of human health.

- **9 VAC-5-80-50 "Federal Operating Permits"** are required for any major source or an area source subject a standard, limitation, or other requirement under Sections 111-112 of the Clean Air Act, unless otherwise exempt. Because the site is below the Title V major source emissions thresholds and is not subject to a Title V by rule through a Federal standard, the Lambert CS is not subject to this rule.
- **9 VAC 5-80-800 "State Operating Permits."** Virginia's SOPs are most often used by stationary sources to establish federally enforceable limits on potential emissions to avoid major NSR permitting (PSD and Non-Attainment permits), Title V permitting, and/or major source Maximum Achievable Control Technology (MACT) applicability. When a source chooses to use a SOP to limit their emissions below major source permitting thresholds, it is commonly referred to as a "synthetic minor" source. SOPs can also be used to combine multiple permits from a stationary source into one permit or to implement emissions trading requirements. When a source chooses to use a SOP to limit their emissions below major source permitting thresholds, it is commonly referred to as a "synthetic minor" source. SOPs can also be used to combine multiple permits from a stationary source into one permit or to implement emissions trading requirements. The Lambert Compressor Station is a true minor source, so it does not need an SOP for establishing synthetic minor status, and therefore, is not subject to this regulation.
- **9 VAC 5-80-1100 "Construction Permits."** Article 6 regulations require a minor source preconstruction permit where the uncontrolled emissions of criteria or non-criteria pollutants from a proposed source will exceed applicable thresholds (9 VAC- 5-80-1100, 9 VAC 5-80-1105). The DEQ has established the following protocol for determining the applicability of the minor source permitting requirement.

  (i) Step 1: List all of the emission units at the new stationary source.

  (ii) Step 2: Delete from the list developed in Step 1, any emission units that are individually exempt under 9 VAC 5-80-1105B.

  (iii) Step 3: Calculate the annual uncontrolled emission rate (UER) for each regulated pollutant listed in 9 VAC 5-80-1105C for each of the affected emissions units. Include fugitive emissions unless all of the emissions at the new stationary source are fugitive.

  (iv) Step 4: Sum the annual UER from the affected emission units and compare the result with the exempt emission rates listed in 9 VAC 5-80-1105 C.1. An Article 6 permit will be required if any of the listed pollutants are emitted at rates equal to or exceeding the emission rates in 9 VAC 5-80-1105 C.1.

(v) Step 5: Regardless of the exemption status determined in Step 4, if the source emits toxic pollutants that are not exempt under 9 VAC 5-80-1105 E and F, then an Article 6 permit will be required.

The uncontrolled emission rates for the Lambert CS provided in Table 3-2 above and Table 4-3 below were calculated using the steps outlined above.

Step 1 – Emission Units

The proposed emission units at the LCS include the following:

- One Solar Mars 100, 16,610 hp natural gas turbine compressor unit (CT-01)
- One Solar Taurus 70, 11,146 hp natural gas turbine compressor unit (CT-02)
- Five (5) Capstone Microturbines each rated at 200 kW (MT-01 to MT-05)
- One 0.77 MMBtu/hr gas fuel heater (HT-01)
- Two 10,000 gallon produced fluids storage tanks (TK-01, TK-02)

Potential Project emissions also include trivial station blowdowns and fugitive emissions as detailed in Section 3.0 and Appendix B.

Step 2 – Individually Exempt Equipment

The emission units exempted under 9 VAC 5-80-1105 B are listed below:

- One 0.77 MMBtu/hr heater – exempt as a combustion source < 50 MMBtu/hr
- Two 10,000 gallon produced fluids storage tanks – exempt as storage tanks < 40,000 gallons.

Step 3 – Calculate the Annual UER for regulated pollutants

The Uncontrolled Emission Rate (UER) for each non-exempt new stationary source is summarized in Table 4-3.

Table 4-3: Uncontrolled Emission Rate (UER) for Non-Exempt Emission Sources at LCS

Proposed Sources	Unit Reference No.	NOx	CO	VOC	SO_2	$PM/PM_{10}/PM_{2.5}$
		(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Solar Mars 100	CT-01	19.58	36.26	3.99	3.09	5.95
Solar Taurus 70	CT-02	13.35	26.34	3.23	2.11	4.06
Capstone C200 Microturbines (5 Units)	MT-01 to MT-05	1.81	4.79	0.44	0.17	0.33
Blowdowns	BDE	-	-	0.54	-	-
Station Fugitives	FUG	-	-	0.75	-	-
Totals (tons/year)		**34.7**	**67.4**	**9.0**	**5.4**	**10.3**

Step 4 – UER vs. Exempt Emission Rates

As shown in Table 4-4 below, the only pollutant UER exceeding the VADEQ permit exemption thresholds applicable to the proposed facility is $PM_{2.5}$. Therefore, the proposed facility is required to obtain a State Article 6 Air Permit per 9 VAC 5-80-1100. Article 6 permitting must be completed before construction of a new source. The required Form 7 application forms (Appendix A) and attachments are included with this application to satisfy this requirement for the construction of sources at the Lambert Compressor Station.

Table 4-4: VA DEQ Minor NSR Permit Applicability Assessment

Pollutant	VADEQ Minor Source Permit Exemption Threshold as per 9 VAC 5-80-1105 C.1 (tpy)	Total Facility Uncontrolled Emission Rate (UER) (tpy)	Emissions Exceed VADEQ Minor Source Permit Exemption Threshold
Nitrogen Oxides (NOx)	40	34.7	No
Carbon Monoxide (CO)	100	67.4	No
Sulfur Dioxide (SO_2)	40	5.4	No
PM	25	10.3	No
PM_{10}	15	10.3	No
$PM_{2.5}$	**10**	**10.3**	**Yes**
VOC	25	9.0	No

Step 5: Toxic Pollutants Emissions

It was determined in Step 4 that a State Article 6 Air Permit is required because $PM_{2.5}$ UER is above the exemption threshold. Furthermore, the facility is also required to obtain a State Article 6 Air Permit because the toxic pollutant emissions provided in Appendix B indicate that formaldehyde cannot be exempted under 9 VAC 5-80-1105 E and F.

- **9 VAC 5-50-260 "Best Available Control Technology (BACT)"** is a requirement to reduce emissions through the use of available reduction techniques (i.e., control devices, adjustments to prevent pollution formation, work practices, etc.). This requirement considers whether or not the emission reduction is BACT using various factors including the technical feasibility and cost effectiveness of the control system. BACT review is relative to a specific pollutant and a specific type of operation. Generally, for BACT, minor sources in Virginia undergo a review to compare the relative level of control with other similar Virginia sources. BACT applicability is determined pollutant-by-pollutant, based on the corresponding permit applicability thresholds. For a new stationary source, BACT shall apply for each pollutant with an increase in the uncontrolled emission rate equal to or greater than the levels in 9VAC 5-80-1105C. Each affected emissions unit emitting a pollutant that is subject to permitting shall apply BACT for that pollutant. For the proposed Lambert CS, BACT is only applicable for $PM_{2.5,}$ as shown in Table 4-4. A BACT analysis is provided in Section 5.0.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

Consistent with Virginia's June 12, 2015 memo APG-354; Permitting and BACT Applicability under Chapter 80 Article 6 (VADEQ, 2015), Mountain Valley has reviewed the proposed sources to determine applicability of BACT review. Article 6 requires that minor sources meet applicable performance standards set out in 9 VAC 5-50 and 9 VAC 5-80-1180.A. One of those performance standards imposes emissions limitations representing best available control technology (BACT) for any pollutant exceeding the permitting threshold (VAC 5-50-260.A. and B).

If permitting applicability is triggered for a pollutant, then BACT applicability is also triggered for that same pollutant. Therefore, as shown in Table 4-4, since permitting is triggered for $PM_{2.5}$, BACT is also triggered for $PM_{2.5}$. Accordingly, Mountain Valley conducted a BACT analysis for the $PM_{2.5}$ emissions from the Solar Taurus 70 turbine, Solar Mars 100 turbine, and five Capstone microturbines, which are the non-exempt sources of $PM_{2.5}$ at the facility.

Applicable regulations require the owner of an affected facility to employ control strategies as may be directed by the board for the control of toxic pollutants (9 VAC 5-60-220.2). According to VA DEQ permitting guidelines (VADEQ, 2020), proposed projects subject to the State Air Toxics Regulation that exceed the corresponding exemption threshold level for a particular air toxic must apply BACT to minimize air toxic emissions. Only Formaldehyde emissions are above the air toxic exemption level, and thus control of formaldehyde is subject to BACT requirements. Accordingly, Mountain Valley conducted a BACT analysis for formaldehyde emissions at the facility.

5.1 Approach used in BACT Analysis

The BACT analysis for the proposed Project was conducted consistent with the USEPA's five step "top-down" BACT process as discussed in the USEPA's October 1990 draft New Source Review Workshop Manual. This methodology results in the selection of the most stringent control technology in consideration of the technical feasibility and the energy, environmental, and economic impacts. Control options are first identified for each pollutant subject to BACT and evaluated for their technical feasibility. Options found to be technically feasible are ranked in order of their effectiveness and then evaluated for their energy, economic, and environmental impacts. In the event that the most stringent control identified is selected, no further analysis of impacts is performed. If the most stringent control is ruled out based upon economic, energy, or environmental impacts, the next most stringent technology is similarly evaluated until BACT is determined.

The "top-down" procedure followed for each pollutant subject to BACT is outlined as follows:

Step 1: Identify available control options from review of agency permits for similar sources, literature review and contacts with air pollution control system vendors.

Step 2: Eliminate technically infeasible options - evaluation of each identified control to rule out those technologies that are not technically feasible (i.e., not available and applicable per USEPA guidance).

Step 3: Rank remaining control technologies - "Top-down" analysis, involving ranking of control technology effectiveness.

Step 4: Evaluate most effective controls and document results - Economic, energy, and environmental impact analyses are conducted if the "top" or most stringent control technology is not selected to determine if an option can be ruled out based on unreasonable economic, energy or environmental impacts.

Step 5: Select the BACT based upon the highest ranked option that cannot be eliminated, which includes development of an achievable emission limitation based on that technology.

Mountain Valley reviewed publicly available databases to identify potential control systems that are commercially available and have been successfully installed including:

- EPA's New Source Review website
- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database
- Various state air quality regulations and websites
- Vendors' information
- Technical books and articles
- State and federal guidance documents

5.2 BACT for Particulate Matter ($PM_{2.5}$)

The Solar Taurus 70, Solar Mars 100, and Capstone C200 combustion turbines are all sources of $PM_{2.5}$ emissions. The following provides the $PM_{2.5}$ BACT evaluation conducted for the Lambert Compressor Station.

Step 1 – Identify Potential Control Technologies

The main sources of $PM_{2.5}$ emissions from the gaseous fuel-fired combustion turbines are:

- The conversion of any fuel sulfur to sulfates and ammonium sulfates; and
- Unburned hydrocarbons that can lead to the formation of PM in the exhaust stack.

Pre-Combustion Control Technologies

Pre-combustion technologies that minimize the formation of $PM_{2.5}$ include:

- Use of clean-burning, low-sulfur gaseous fuels;
- Good combustion practices; and
- High efficiency inlet filters

The use of clean-burning, low-sulfur gaseous fuels will result in minimal formation of $PM_{2.5}$ during combustion. Good combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, which will minimize emissions of unburned hydrocarbons that can lead to the formation of $PM_{2.5}$ emissions. The use of high efficiency inlet filters will ensure high removal of particulate matter in the inlet air to the combustion turbine.

Post-Combustion Control Technologies

There are several post-combustion PM control systems potentially feasible to reduce $PM_{2.5}$ emissions from the combustion turbine including:

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

Cyclones/centrifugal collectors are generally used in industrial applications to control large diameter particles (>10 microns). Cyclones impart a centrifugal force on the gas stream, which directs entrained particles outward. Upon contact with an outer wall, the particles slide down the cyclone wall, and are collected at the bottom of the unit. The design of a centrifugal collector provides for a means of allowing the clean gas to exit through the top of the device. However, cyclones are inefficient at removing small particles, such as $PM_{2.5.}$ (Cooper & Alley, 2011)

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

ESPs are used on a wide variety of industrial sources, including certain boilers. ESPs use electrical forces to move particles out of a flowing gas stream onto collector plates. The particles are given an electric charge by forcing them to pass through a region of gaseous ion flow called a "corona." An electrical field generated by electrodes at the center of the gas stream forces the charged particles to ESP's collecting plates. Removal of the particles from the collecting plates is required to maintain sufficient surface area to clean the flowing gas stream. Removal must be performed in a manner to minimize re-entrainment of the collected particles. The particles are typically removed from the plates by "rapping" or knocking them loose, and collecting the fallen particles in a hopper below the plates.

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

Inherently Lower Emitting Processes/Practices

Although Mountain Valley does not consider electric compression to be an inherently lower emitting process/practice as discussed in Section 5.5, this technology was still analyzed as a potentially lower emitting alternative in each step of the BACT analysis. Electric compression failed at each step and the detailed analysis is provided in Sections 5.5 and 5.6.

Step 2 - Eliminate Technically Infeasible Options

Pre-Combustion Control Technologies

The pre-combustion control technologies identified above (i.e., clean-burning of low-sulfur fuels, good combustion practices and high efficiency inlet filters) are available and technically feasible for reducing $PM_{2.5}$ emissions from the combustion turbine exhaust streams.

Post-Combustion Control Technologies

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

Cyclones are not effective on particles with diameters of 10 microns or less (Cooper & Alley, 2011). The particles emitted from gaseous fuel-fired combustion turbines are typically less than 1 micron in diameter. <u>Therefore, a cyclone/centrifugal collection device is not a technically feasible alternative.</u>

Post combustion controls, such as baghouses, scrubbers and electrostatic precipitators are impractical due to the high pressure drops associated with these units, the large flue gas volumes, and the low concentrations of $PM_{2.5}$ present in the exhaust gas (Cooper & Alley, 2011). As shown in EPA's RBLC Database search results in Appendix C, baghouses, ESPs, and scrubbers have not been applied to commercial combustion turbines burning gaseous fuels. Baghouses, ESPs, and scrubbers are typically used on solid or liquid-fuel fired sources with high PM emission concentrations, and are not used in gaseous fuel-fired applications, which have inherently low PM emission concentrations. None of these control technologies are appropriate for use on gaseous fuel-fired combustion turbines because of their very low PM emissions levels, and the small aerodynamic diameter of PM from gaseous fuel combustion.

In deciding not to develop a new turbine NSPS for PM, EPA noted that (EPA, 2005):

> Particulate matter emissions from turbines result primarily from carryover of noncombustible trace constituents in the fuel. Particulate matter emissions are negligible with natural gas firing due to the low sulfur content of natural gas..... A review of the BACT and LAER determinations in the RBLC since January of 2003 showed that no add-on controls were required to limit PM for any of the turbines. Permit requirements included the use of clean fuel or good combustion practices. Emission limitations required by permits in the RBLC database with permit dates after January of 2003 ranged from 9 pounds per hour (lb/hr) to 27 lb/hr for PM for natural gas, and 27 to 44 lb/hr for PM for diesel-fired turbines. [70 FR 8321, February 18, 2005]

As discussed above, the post-combustion controls are not technically feasible and have not been demonstrated in practice for use with simple-cycle combustion turbines. <u>Therefore, the use of baghouses, ESPs, and scrubbers is not considered technically feasible.</u>

Inherently Lower Emitting Processes/Practices

Electric compression is incapable of providing reliable and timely service for the Project; therefore, it is not a technically feasible technology. The details of this evaluation are provided in Sections 5.5 and 5.6.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The ranking of technologies is:

1. clean-burning low sulfur fuels, good combustion practices and high efficiency inlet filters
2. In addition to being neither available nor feasible, electric compression is not inherently lower emitting for all pollutants as explained in Section 5.5 and Table 5-2. Thus, electric compression ranks below clean-burning low sulfur fuels, good combustion practices and high-efficiency inlet filters.

Step 4 - Evaluate Most Effective Controls and Document Results

The top ranked technology, clean-burning low sulfur fuels, good combustion practices and inlet filters are part of the compressor design for the project and present no environmental or additional economic costs to the proposed project.

There are no emissions reductions shown in Table 3-3 from the use of clean burning low sulfur fuels, good combustion practices and inlet filters compared to uncontrolled emissions in Table 3-2. This is because uncontrolled emissions already incorporate the use of very low sulfur burning fuels and the selection of a combustion turbine with high combustion efficiency. Use of fuels with higher sulfur content, however, would result in higher $PM_{2.5}$ emissions as shown by the higher $PM_{2.5}$ emission factors recommended by the manufacturer based on the fuel content (See PIL 171 in Appendix B).

While electric compression is not available, feasible or inherently lower emitting, for completeness, the energy, environmental and economic costs of using this technology were evaluated and found to be unacceptable. They include:

(i) energy impacts - electrical energy losses due to generation and transmission put electric compression at a disadvantage compared to the direct on-site combustion in highly efficient, well controlled natural gas compression;

(ii) environmental impacts: not only are overall emissions estimated to be similar or higher for electric compression, but also there would be a far greater impacts to lands and state waters due to the required construction of new electrical infrastructure; and

(iii) economic impact: the extraordinary cost of new electrical infrastructure and the projected miniscule reduction in onsite emissions (ignoring the increase in offsite emissions) gives a cost effectiveness of reducing on-site $PM_{2.5}$ emissions using electric compression of **$547,271** per ton removed, which is economically unfeasible.

The summary of the BACT analysis is provided in Table 5-1 and the details of this analysis are presented in Sections 5.6.1 and 5.6.2 and Appendix E.

Step 5 – Select BACT

After eliminating the infeasible post-combustion controls and electric compression, the use of clean-burning low sulfur fuels, good combustion practices and high efficiency inlet filters are considered BACT for $PM_{2.5}$. This is consistent with BACT at other similar sources as shown in Appendix C. Therefore, Mountain Valley's proposed BACT for $PM_{2.5}$ emissions from the combustion turbines is the use of clean-burning low sulfur fuel, good combustion practices and air inlet filters. The combustion turbines design will include high efficiency inlet air filtering to reduce the incoming particulate in the inlet air.

Gas turbines equipped with SoLoNOx™ technology and restricted to firing only natural gas are representative of BACT for the Lambert Compressor Station turbines. Lambert reviewed information from the RBLC for simple-cycle turbines. Based on this review, the lowest permitted emissions rate for $PM_{2.5}$ emissions on a heat-input basis was 0.0066 lb/MMBtu, which is the EPA AP-42 emission factor for PM_{Total} for combustion turbines (AP-42, Chapter 3.1, Table 3.1-2a). The PM_{Total} AP-42 factor is the sum of the PM filterable and PM condensable factor for turbines, which were developed based on 5 emission source tests conducted on a single turbine using water-steam injection for emissions control. Each test report had a data quality rating of "C" which means that the tests were based on an untested or new methodology or that they lacked a significant amount of background data. Furthermore, the emission factors determined for PM showed high variability as noted by the high relative standard deviation (RSD): 90.9% for PM condensable and 49.5% for PM filterable (EPA, 2000). Given that these factors were based on tests conducted in 1994 on a single turbine with a capacity of 86 MW used for power generation and the factors have high RSD, Mountain Valley does not consider the AP-42 factor to be representative of the compression turbines for this project.

The Lambert Compressor Station proposed $PM_{2.5}$ limit is 0.010 lb/MMBtu. This is the manufacturer guarantee emission rate for these turbines firing pipeline natural gas that contains less than 2 grains of sulfur per 100 scf (See letter from Solar in Appendix B). On a lb/hr basis, these limits are equivalent to 1.36 lb/hr for the Mars 100 turbine and 0.93 lb/hr for Taurus 70 turbine. The proposed limit is consistent with other BACT determinations for simple cycle turbines as provided in Appendix C and comparable to recent $PM_{2.5}$ BACT limits required for other natural gas compressor station turbines in Virginia.

Therefore, Mountain Valley is proposing a $PM_{2.5}$ BACT limit of 0.010 lb/MMBtu on a 3-hour block average basis for the proposed Mars 100 and Taurus 70 combustion turbines at the Lambert Compressor Station. The limit will be achieved with the use of clean-burning low sulfur fuel, good combustion practices and high efficiency inlet air filters.

5.3 BACT for Formaldehyde

As noted by VADEQ, because many of the air toxics are either VOC or particulate matter compounds, control measures that reduce these criteria pollutant emissions may be used to reduce air toxic emissions (VADEQ, 2020). Formaldehyde is a VOC and thus control technologies used for VOCs that also control for formaldehyde are included in this BACT evaluation.

Formaldehyde is formed during the incomplete combustion of fuel in the combustion process and released as a combustion byproduct. The two Solar combustion turbines are the only significant emissions of formaldehyde at the site. The microturbines and gas heater are also a source of formaldehyde; however, the formaldehyde emission levels from these units are only 0.03 tpy for each of the microturbines and 0.00025 tpy for the gas heater. The low emission rates and small capacity of these units make it difficult for control technologies to be technically feasible.

Step 1 – Identify Potential Technologies

Based upon a search of nationally permitted control technology options conducted using the RBLC Database, the following options are available control candidates for formaldehyde emissions from simple-cycle turbines combusting natural gas:

- Combustion controls
- CO Oxidation Catalysts

Combustion Control: Because formaldehyde is a by-product of incomplete or inefficient combustion, it is important that combustion control constitutes the primary mode of reduction of

CO emissions. As later discussed for the NOx BACT, the SoLoNOx dry low NOx combustors use lean combustion control technology to ensure uniform air/fuel mixture and to minimize formation of regulated pollutants while maintaining the same power and heat rate as equivalent models with conventional combustion technology. SoLoNOx combustor technology not only ensures significant NOx reductions but also achieves some reduction in CO emissions. The basic premise of the technology involves premixing the fuel and air prior to entering the combustion zone, which provides for a uniform fuel/air mixture and prevents local hotspots in the combustor, thereby reducing NOx emissions. However, the residence time of the combustion gases in these lean-premixed combustors must be increased to ensure complete combustion of the fuel to minimize VOC emissions.

Oxidation catalyst systems serve to remove CO and VOCs, including formaldehyde, from the turbine exhaust gas rather than limiting pollutant formation at the source. The technology does not require introduction of additional chemicals for the reaction to proceed. The oxidation of CO to CO_2 uses the excess air present in the turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. The flue gas exhaust from a turbine passes through a honeycomb catalyst which oxidizes the VOCs to form carbon dioxide.

Inherently Lower Emitting Processes/Practices

Although Mountain Valley does not consider electric compression to be an inherently lower emitting process/practice as discussed in Section 5.5, this technology was still analyzed as a potentially lower emitting alternative in each step of the BACT analysis. Electric compression failed at each step and the detailed analysis is provided in Sections 5.5 and 5.6

Step 2 - Eliminate Technically Infeasible Options

Both combustion controls and oxidation catalyst are technologies considered technically feasible.

Inherently Lower Emitting Processes/Practices

Electric compression is incapable of providing reliable and timely service for the Project; therefore, it is not a technically feasible technology. The details of this evaluation are provided in Sections 5.5 and 5.6.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The ranking of technologies, which have been demonstrated in commercial practice on turbines in decreasing order of control effectiveness, are:

1. Oxidation Catalyst
2. Combustion Controls
3. In addition to being neither available nor feasible, electric compression is not inherently lower emitting for all pollutants as explained in Section 5.5 and Table 5-2. Thus, electric compression ranks below oxidation catalyst and combustion controls.

Step 4 - Evaluate Most Effective Controls and Document Results

For the type and design of turbines proposed for the Lambert Compressor Station, oxidation catalysts systems are commonly disqualified as BACT based on economic infeasibility. However, for this project, Mountain Valley is proposing the install oxidation catalysts for the proposed Solar Taurus 70 and Solar Mars 100 combustion turbines. VOCs, including formaldehyde, will be reduced as part of the oxidation process.

The major source NESHAP for combustion turbines, Subpart YYYY, requires the use of oxidation catalyst to control formaldehyde. When oxidation catalysts are not used, the formaldehyde emissions need to meet the 91 ppbvd at 15% O_2 standard as demonstrated by annual stack test to show compliance with the NESHAP. In the recent National Emission Standards for Hazardous Air Pollutants: Stationary Combustion Turbines Residual Risk and Technology Review (RTR), effective on March 3, 2020, EPA identified no new cost-effective controls under the technology review that would achieve further emissions reductions from the stationary combustion turbine source category. Thus, the 91 ppb formaldehyde emission limit achieved by using good combustion practices and/or oxidation catalyst remain as the cost effective control technologies for formaldehyde. In the RTR preamble, EPA noted that "no cost-effective developments in practices, processes, or control technologies were identified in our technology review to warrant revisions to the standards." (EPA, 2020)

Because Mountain Valley will use the most effective control technologies, oxidation catalyst and combustion controls, for the Solar turbines, no further analysis regarding economic, environmental, or energy impacts for these technologies is required. However, a cost comparison was conducted to show the cost effectiveness of this technology compared to the others in the ranking. The summary of the BACT cost evaluation is provided in Table 5-1 and the details are provided in Appendix E. The only adverse environmental impact for oxidation catalyst is the replacement and disposal of the catalyst, which will depend on the quality of the flue gas, but can vary between 3 to 5 years (Cooper & Alley, 2011).

While electric compression is not available, feasible or inherently lower emitting, for completeness, the energy, environmental and economic costs of using this technology were estimated and they are unacceptable. They include:

(i) energy impacts - electrical energy losses due to generation and transmission put electric compression at a disadvantage compared to the direct combustion in highly efficient, well controlled natural gas compression;

(ii) environmental impacts: not only are emissions estimated to be similar or higher for electric compression, but also there is a far greater impact to lands and state waters due to the required construction of new electrical infrastructure; and

(iii) economic impact: the extraordinary cost of new electrical infrastructure and the projected miniscule reduction in onsite emissions (ignoring the increase in offsite emissions) gives a cost effectiveness of reducing on-site formaldehyde emissions using electric compression of **$1,639,713** per ton of formaldehyde removed, which is economically unfeasible.

The details of this analysis are presented in Sections 5.6.1 and 5.6.2.

<u>Step 5 – Select BACT</u>

Mountain Valley proposes to use Solar turbines with lean combustion control technology and implement oxidation catalysts to reduce formaldehyde emissions from the turbines during normal operation. Solar has indicated that the proposed Solar turbines are capable of achieving an uncontrolled hydrocarbon emission rate of 25 ppmvd, 20% of which is considered VOC, or approximately 5 ppmvd at 15% O_2.

The oxidation catalyst is expected to achieve approximately 90% control efficiency for VOCs, including formaldehyde. VOC emissions will be limited to 2.5 ppmvd @ 15% O_2 from the turbines, as measured on a 3-hour basis. The control efficiency is expected to be achieved at all times, except for periods of start-up and shutdown and periods when the ambient temperature is less than 0°F.

5.4 BACT for NOx

As noted in Section 3.1, the compression turbines for the Lambert Compressor Station are turbines built with SoLoNOx combustion technology which utilizes, among other things, dry low NOx (DLN) burners. SoLoNOx combustion technology differs from a conventional (non-SoLoNOx) combustion system in the following ways:

Conventional (Non-Solonox) Combustion System:

- Air and fuel are injected into the combustor separately
- Fuel burns at a high temperature and stoichiometric air-fuel ratio
- The combustion chamber requires a smaller liner and smaller cooling air ports
- The system does not monitor Dynamic Fuel Pressure

SoLoNOx Combustion System:

- Air, pilot and main fuel is premixed in the fuel injector
- Fuel burns at a lower temperature and at a lean air-fuel ratio
- The combustion chamber liner is much larger with larger and additional cooling air ports which allows improved "Augmented Backside Cooling" of the liner
- SoLoNOx combustion includes a Burner Acoustic Monitor (BAM) to measure Dynamic Fuel Pressure
- The SoLoNOx control system includes Pilot Active Control Logic and additional control system enhancements compared to conventional combustion

SoLoNOx combustion technology utilizes a very different combustion chamber, combustion cooling system, fuel delivery system and combustion parameter monitoring and controls than a conventional combustion system. These very different physical characteristics do not allow the addition or subtraction of SoLoNOx to an operating turbine. To change from conventional to SoLoNOx combustion requires a shop environment overhaul or complete replacement of the turbine.

For these reasons, SoLoNOx should not be considered an air pollution control equipment as defined by VADEQ under 9VAC5-80-1110 since the system and components are inherent and vital to the unit and it is not possible to bypass the technology. It is possible for the emission levels of the SoLoNOx system to vary during certain operational conditions, such as low load and low ambient temperature, as explained in other sections of this application. However, it is not possible for the SoLoNOx Combustion System to operate as a Conventional (Non- SoLoNOx) Combustion System as defined above.

Based on relevant portion of VADEQ's definition of "uncontrolled emission rate" in 9VAC5-80-1110 shown below, the emissions calculated in Table 3-2 represent the uncontrolled NOx emissions for the project because SoLoNOx combustion technology is inherent and "vital to" the units' design, construction and operation. Thus, based on the uncontrolled emissions calculated in Table 3-2, this Project does not trigger BACT for NOx.

> "Uncontrolled emission rate" means the emission rate from an emissions unit when operating at maximum capacity without air pollution control equipment. Air pollution control equipment includes control equipment that is not vital to its operation, except that its use enables the owner to conform to applicable air pollution control laws and regulations." (9VAC5-80-1110)

Although the Project believes that uncontrolled emissions are properly calculated for NOx and that SoLoNOx combustion technology should not be considered an air pollution control equipment in the uncontrolled emission rate calculation as per 9VAC5-80-1110, Mountain Valley has prepared a BACT analysis for NOx under the potential case that SoLoNOx would be considered air pollution control equipment and the assumption that turbines using conventional (Non-SoLoNOx) combustion burners or higher NOx emitting SoloNOx turbines could result in emission rates above the exemption emissions levels in Table 4-4.

The Solar Taurus 70, Solar Mars 100, and Capstone C200 combustion turbines are NOx emissions units. The following provides the NOx BACT evaluation conducted for the Lambert Compressor Station.

<u>Step 1 – Identify Potential Technologies</u>

NOx from combustion turbines is formed by either of two mechanisms: thermal NOx or fuel NOx. Thermal NOx is the NOx formed by reactions between nitrogen and oxygen in the air used for combustion. The rate of formation of thermal NOx is extremely temperature sensitive, and becomes rapid only at "flame" temperatures (3000-3600°F). Fuel NOx results from the combustion of fuels that contain organic nitrogen in the fuel (primarily coal or heavy oil) ((Cooper & Alley, 2011). Fuel NOx is not very predominant when combusting natural gas. NOx emissions are affected by combustion parameters including temperature, residence time and oxygen concentration in the flame zone. Thus, many techniques focus on preventing the formation of NOx during combustion. When NOx is formed during the combustion process, flue gas treatment techniques can be used to remove NOx from flue gases.

Combustion Techniques

Combustion equipment can be designed to limit the formation of NOx. These include:

- Dry Low NOx (DLN) Combustor Technology
- Wet Controls - Water and Steam Injection
- Catalytic Combustion – XononTM

DLN combustion techniques reduce NOx emissions without the use of water or steam injection, thus they are considered dry combustion techniques. Two DLN combustion designs are available: lean pre-mixed combustion and rich/quench/lean staged combustion. Historically, gas turbine combustors were designed for operation with a 1:1 stoichiometric ratio (equal ratio of fuel and air). However, with fuel lean combustion (sub-stoichiometric conditions), the additional excess air cools the flame and reduces the rate of thermal NOx formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors resulting in the combustion gases attaining a high temperature for a shorter time, thus reducing the rate of thermal NOx formation. Pilot flames are used to maintain combustion stability and fuel-lean conditions. Solar's SoLoNOx combustion technology uses lean combustion control technology to ensure uniform air/fuel mixture and to minimize formation of regulated pollutants while maintaining the same power and heat rate as equivalent models with conventional combustion technology.

Rich/Quench/Lean Combustion: RQL combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone, thereby reducing both thermal and fuel NOx. Incomplete combustion under fuel-rich conditions in the primary zone produces an atmosphere with a high concentration of CO and H_2, which replace some of the O_2 for NOx formation and act as reducing agents for NOx formed in the primary zone. Based on available test results, this control alternative is more effective for higher fuel-bound nitrogen fuels in retarding the rate of fuel NOx formation.

Wet technology: The injection of water or steam into the combustor is commonly termed wet technology for gas turbines. Steam or water injection reduces NOx emissions by decreasing the peak flame temperature. Water and steam injection directly into the flame area of the turbine combustor results in a lower flame temperature and reduces thermal NOx formation; however, fuel NOx formation is not reduced with this technique. It is essential that the water or steam be free of contaminants, so a water treatment system might be a necessary component of a wet system.

Catalytic Combustion – Xonon™: Xonon™ is a catalytic combustion technology in development that reduces the formation of NOx. In a catalytic combustor, the fuel and air are premixed into a fuel-lean mixture and then passed into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame front, thereby reducing peak combustion temperatures below 2,000ºF, which is the temperature at which significant amounts of thermal NOx begin to form.

Post Combustion Techniques

Post combustion controls or flue gas treatment techniques are used to remove NOx from flue gases after the NOx has been formed. Some post combustion controls include:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Catalytic Absorption (formally SCONOxTM)

Selective Catalytic Reduction (SCR): In the SCR process, ammonia (NH_3), usually diluted with air or steam, is injected through a grid system into the flue/exhaust gas stream upstream of a catalyst bed. The catalyst could be titanium dioxide, vanadium pentoxide or zeolite-based catalysts. On the catalyst surface, the NH_3 reacts with NOx to form molecular nitrogen (N_2) and water. The basic reactions are as follows:

$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$
$8NH_3 + 6NO_2 = 7N_2 + 12H_2O$

Depending on system design and the inlet NOx level, NOx removal can vary. The reaction of NH_3 and NOx is favored by the presence of excess O_2. Another variable affecting NOx reduction is exhaust gas temperature. The greatest NOx reduction occurs within a reaction window at catalyst bed temperatures between 400°F and 800°F for base metal catalyst types (i.e., conventional SCR applications with lower temperature range platinum catalysts and with higher temperature range 550°F – 800°F vanadium-titanium catalysts). The proposed simple cycle combustion turbines have exhaust temperatures of approximately 880°F to 1000°F (depending on inlet ambient air temperature and load rating) and would likely require higher temperature catalysts or would require the introduction of cooling air into the exhaust stream prior to reaching the SCR catalyst bed.

Selective Non-Catalytic Reduction (SNCR): SNCR technology involves using ammonia or urea injection similar to SCR technology but at a much higher temperature window of 1,600°- 2,200°F. The following chemical reaction occurs without the presence of a catalyst:

$NOx + NH_3 + O_2 + H_2O + (H_2) = N_2 + H_2O$

The operating temperature can be lowered from 1,600°F to 1,300°F by injecting readily oxidizable hydrogen with the ammonia. However, beyond the upper temperature limit, the ammonia is converted to NOx, resulting in increased NOx emissions.

Catalytic Absorption (formally SCONOX™): SCONOX™ is a post-combustion technology that removes NOx from the exhaust gas stream following NOx formation in combined-cycle combustion turbine applications. SCONOX™ employs an oxidation catalyst followed by a potassium carbonate bed located within a heat recovery steam generator to obtain the proper temperature window. The bed adsorbs NOx where it then reacts to form potassium nitrates. Periodically, a hydrogen gas stream is passed through individual sections of the catalyst, reacting with the potassium nitrates to reform potassium carbonate and to eject nitrogen gas and water. The advantage of SCONOX™ relative to SCR is that SCONOX™ does not require ammonia injection to achieve NOx emissions control.

Inherently Lower Emitting Processes/Practices

Although Mountain Valley does not consider electric compression to be an inherently lower emitting process/practice as discussed in Section 5.5, this technology was still analyzed as a potentially lower emitting alternative in each step of the BACT analysis. Electric compression failed at each step and the detailed analysis is provided in Sections 5.5 and 5.6

Step 2 - Eliminate Technically Infeasible Options

Combustion Techniques

Dry Low NOx (DLN) Combustors: The proposed simple-cycle turbines are Solar turbines equipped with SoLoNOx dry low NOx combustors. Accordingly, DLN combustion technology is considered technically feasible and considered further in this analysis.

Similarly, the proposed Capstone microturbines use lean premix combustion technology. Lean-premix operation requires operating at a high air to fuel ratio within the primary combustion zone. The large amount of air is thoroughly mixed with the fuel before combustion. This premixing of the air and fuel enables clean combustion to occur at a relatively low temperature, which minimizes NOx formation. Injectors control the air to fuel ratio and the air-fuel mixture in the primary zone to ensure that the optimal flame temperature is achieved for NOx minimization. Accordingly, DLN combustion technology is considered technically feasible and considered further in this analysis for the microturbines.

RQL Combustion is theoretically applicable to natural gas-fired turbines; however, based on information presented in the US EPA ACT (Alternative Control Techniques) document, RQL combustors are not commercially available for most turbine designs and there is no known application for natural gas-fired simple-cycle combustion turbines. Because it is not commercially demonstrated on simple-cycle combustion turbines, RQL combustion is considered technically infeasible and is eliminated from further consideration in this BACT analysis.

Wet Controls: The water or steam injection rate is typically described on a mass basis by a water-to fuel ratio (WFR) or steam-to-fuel ratio (SFR). Higher WFRs and SFRs translate to greater NOx reductions, but may also cause potential flameouts, increasing maintenance requirements and reducing turbine efficiency. During startup and shutdown events for the combustion turbines, introduction of water or steam injection into the DLN combustors would cause severe disruption to combustion dynamics and would likely result in damage to the combustion system and related components. Therefore, the use of water or steam injection will not be considered further in this BACT analysis for the turbines.

Catalytic Combustion – Xonon™ is a technology that has only been tested on small turbines (less than 10 megawatts [MW]) and it is still not commercially available for the proposed simple-cycle combustion turbines. Both GE and Solar Turbines have successfully operated on a 7.5 MW and a 10 MW engine using the XONON combustion system. Both engines demonstrated low NOx performance but neither has yet made them commercially available. In view of the above limitations in utilizing catalytic combustor control, this alternative control technology is eliminated from further consideration in this BACT analysis.

Post Combustion Techniques

Selective Catalytic Reduction (SCR): The proposed Solar turbines will be equipped with an SCR system. Accordingly, SCR is considered technically feasible and considered further in this analysis

The proposed Capstone microturbines are not equipped with an SCR, and based on a review of USEPA's RACT/BACT/LAER Clearinghouse (RBLC) database (Appendix C), SCR systems have not been installed on such small (200 kW) simple cycle combustion turbines and are therefore not considered technically feasible. The emissions from each microturbine are already very small at only 0.36 tons of NOx per year. At such low emission levels, even high removal efficiencies using a 70% efficient SCR would result in a decrease of NOx emissions to 0.11 tpy. Such low decrease in emissions coupled with an ammonia slip of typically 10 ppmv, make SCR applications unfeasible for such small units. The application of SCR systems on the Capstone microturbines is considered to be technically infeasible and thus, is removed from further consideration.

Selective Non-Catalytic Reduction (SNCR): The exhaust temperatures in gas turbines typically do not exceed 1,100°F. Therefore, the operative temperature window of this control alternative is not technically feasible for this application. Exhaust temperatures for the proposed Solar and Capstone gas turbines are approximately 900 °F and 500 °F, respectively. These operating temperatures are well below the range for SNCR applications. Further, a review of the RBLC database for recent BACT/LAER determinations for this particular source category do not indicate that SNCR systems have been successfully installed for NOx control for similar simple cycle turbines. In view of the above limitations in utilizing SNCR control, this control alternative is not considered technically feasible and will be precluded from further consideration in this BACT determination.

While catalytic absorption (SCONOX™) has been marketed for more than ten years in the US, it has been installed and tested on only a handful of installations. However, the benefit of not using ammonia has been replaced by other potential operational problems that impair the effectiveness of the technology. First, the technology has not been demonstrated for larger turbines and the vendor's contention is still being debated. Second, the technology is not readily adaptable to high-temperature applications outside the 300 ° F to 700 ° F range and is susceptible to potential thermal cycling. Lastly, the potassium carbonate coating on the catalyst surface is an active chemical reaction and reformulation site, which makes it particularly vulnerable to fouling. Based on the review of the US EPA's RBLC database and other permits issued in various states, this technology has not been applied on simple-cycle combustion turbines used for natural gas compression. Therefore, this technology is considered technically infeasible and is not considered further in this BACT analysis.

Inherently Lower Emitting Processes/Practices

Electric compression is incapable of providing reliable and timely service for the Project; therefore, it is not a technically feasible technology. The details of this evaluation are provided in Sections 5.5 and 5.6.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The ranking of technologies, which have been demonstrated in commercial practice on turbines, in decreasing order of control effectiveness, are:

1. Selective catalytic reduction (SCR)
2. Dry low NOx technology
3. In addition to being neither available nor feasible, electric compression is not inherently lower emitting for all pollutants as explained in Section 5.5 and Table 5-2. Thus, electric compression ranks below SCR and DLN technology.

<u>Step 4 - Evaluate Most Effective Controls and Document Results</u>

For the type and design of turbines proposed for the Lambert Compressor Station, SCR systems are commonly disqualified as BACT based on economic infeasibility. The cost effectiveness for the ranking of technologies in Step 3 is provided in Table 5-1. Although potentially not economically feasible, Mountain Valley is proposing the use of SCR, in addition to DLN combustion (SoLoNOx technology), as BACT for NOx for the proposed Solar Taurus 70 and Solar Mars 100 combustion turbines.

Since Mountain Valley is already proposing the most stringent control technologies, SCR and SoLoNOx, for the Solar turbines, no further analysis regarding economic, environmental, or energy impacts for these technologies is required. However, the economic analysis was conducted and is provided in Table 5-1. Furthermore, the adverse environmental impacts for this control technology are the potential ammonia emissions resulting from the use of SCR and the replacement and disposal of the catalyst, which will depend on the quality of the flue gas, but can vary between 3 to 5 years, with a few regeneration opportunities in between (Cooper & Alley, 2011).

Mountain Valley is proposing the use of DLN Combustor Technology for the Capstone microturbines and as noted in step 2, SCR is not considered technically feasible for these small turbines. Thus, the top ranked technology for this type of turbines is already being proposed. Therefore, further analysis regarding economic, environmental, or energy impacts for this technology were not evaluated.

While electric compression is not available, feasible or inherently lower emitting, for completeness, the energy, environmental and economic costs of using this technology were estimated and they are unacceptable. They include:

(i) <u>energy impacts</u> - electrical energy losses due to generation and transmission put electric compression at a disadvantage compared to the direct combustion in highly efficient, well controlled natural gas compression;

(ii) <u>environmental impacts</u>: not only are emissions estimated to be similar or higher for electric compression, but also there is a far greater impact to lands and state waters due to the required construction of new electrical infrastructure; and

(iii) <u>economic impact</u>: the extraordinary cost of new electrical infrastructure and the projected miniscule reduction in onsite emissions (ignoring the increase in offsite emissions) gives a cost effectiveness of reducing on-site NOx emissions using electric compression of **$103,551** per ton of NOx removed, which is economically unfeasible.

The details of this analysis are presented in Section 5.6.1 and 5.6.2.

Step 5 – Select BACT

The proposed Lambert Compressor Station Solar Taurus 70 and Mars 100 turbines include SoLoNOx technology and will be equipped with SCR. The SCR post combustion removal efficiency for these turbines will be 70%, which will result in NOx emission rates of 2.7 ppmv @ 15% O_2. Therefore, the use of SoLoNOx technology and SCR is considered BACT for reducing NOx emissions from the proposed Lambert Compressor Station turbines.

Similarly, the Capstone microturbines use lean premix combustion technology which achieves NOx emission rates of 9 ppmvd at 15% O_2. for these units. The proposed DLN technology is considered BACT for NOx for these microturbines.

Table 5-1. Summary of BACT Impact Analysis Results

			Emissions per Turbine		Economic Impacts						Environmental Impacts
Pollutant	**Emission Unit**	**Control Alternative**	**Emissions (tpy)[h]**	**Emissions Reductions from Baseline [a] (tpy)**	**Total Installed Capital Cost [b] ($)**	**Relative Installed Capital Cost [c] ($)**	**Total Annualized Cost[d] ($/yr)**	**Total Annualized Cost relative to Baseline[e] ($/yr)**	**Cost Effectiveness Over Baseline[f] ($/ton removed)**	**Incremental Cost Effectiveness[g] ($/ton)**	**Adverse Environmental Impacts (Yes/No)**
PM2.5 BACT Summary											
PM2.5	Mars 100/Taurus 70	Baseline (9 ppm NOx)[i]	10.01	NA	$20,759,091	-	$7,716,029	NA			No
PM2.5	Mars 100/Taurus 70	Electric Turbines	0.00	10.01	$50,348,000	$29,588,909	$13,194,212	$5,478,183	**$547,271**		Yes
Formaldehyde BACT Summary											
Formaldehyde	Mars 100/Taurus 70	Baseline (9 ppm NOx)[i]	3.34	NA	$20,759,091		$7,716,029	NA			No
Formaldehyde	Mars 100/Taurus 70	Oxidation Catalyst	0.67	2.67	$21,179,091	$420,000	$7,857,455	$141,426	**$53,017**		Yes
Formaldehyde	Mar 100/Taurus 70 Electric Equivalent	Electric Turbines	0.00	3.34	$50,348,000	$29,588,909	$13,194,212	$5,478,183	**$1,639,713**	$7,925,327	Yes
NOx BACT Summary											
NOx	Mars 100/Taurus 70	Baseline (15 ppm NOx)	53.47	NA	$20,145,455		$7,657,342	NA			No
NOx	Mars 100/Taurus 70	Ultra Low NOx (9 ppm NOx)	32.93	20.54	$20,759,091	$613,636	$7,716,029	$58,686	**$2,857**		No
NOx	Mars 100/Taurus 70	SCR	9.62	43.85	$27,145,455	$7,000,000	$8,764,964	$1,107,621	**$25,262**	$45,008	Yes
NOx	Mars 100/Taurus 70	ULN (9ppm) + SCR	10.25	43.22	$26,759,091	$6,613,636	$8,682,822	$1,025,480	**$23,727**	$131,343	Yes
NOx	Mar 100/Taurus 70 Electric Equivalent	Electric Turbines	0	53.47	$50,348,000	$30,202,545	$13,194,212	$5,536,869.22	**$103,551**	$440,136	Yes

Table 5-1 Summary of BACT Impact Summary (Continued)

Notes for Table 5-1:

(a) Emissions reduction over baseline control level.

(b) Total installed capital cost for each alternative.

(c) Installed capital cost relative to baseline.

(d) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.

(e) Total annualized cost relative to baseline (Annualize cost of alternative - Annualize cost of baseline).

(f) Cost Effectiveness over baseline is equal to total annualized cost for the control option divided by the emissions reductions resulting from the uncontrolled baseline.

The cost effectiveness is based on the installation of 2 turbines. A separate cost for each turbine was not determined because when looking at electric compression, it is difficult to fairly assess the capital cost resulting from only one turbine. The capital cost for electric compression includes the cost of construction related to upgrading the transmission system and adding a new transmission line. These costs will be basically the same whether one compressor or two compressors are added. Thus, it cannot just be halved for analyzing each turbine. Accordingly, it was determined that the best way to fairly show the cost of this alternative and compare it to the other alternatives was to consider the addition of the 2 turbines together as well as the emissions reductions resulting from both units.

(g) The optional incremental cost effectiveness criteria is the same as the total cost effectiveness criteria except that the control alternative is considered relative to the next most stringent alternative rather than the baseline control alternative.

(h) The emissions shown for the electric compressor turbines are shown as zero. This is because the turbine themselves will not have stack emissions for the pollutants considered in this analysis. However, this alternative does have emissions associated with the generation of the power needed to run the turbines. These emissions will be emitted elsewhere, and were therefore not included as part of the cost effectiveness analysis. These emissions, however, are disccussed in more detail in Section 5.6.1 and Table 5-2.

(i) Using a 9 ppm NOx turbine as the baseline for PM2.5 and formaldehyde is more conservative as the emissions for these pollutants are about the same for either the 9 ppm or the 15 ppm turbine but the cost of the 9 ppm turbine is higher.

5.5 Consideration of Inherently Lower Polluting Processes/Practices

In other contexts, VADEQ has looked at whether or not electric compression should be included in the BACT analysis. For the following three reasons, the Project does not believe electric compression should be considered in the BACT analysis.

First, it is not clear that the use of electric compression as an alternative technology for the Project would result in any reduction in emissions, and therefore it is not inherently less polluting. While electric compression does not produce any on-site emissions, a greater amount of energy must be generated at a nearby electrical generating station to provide the electricity to power the electric compressors. The emissions from that generating station are at best equivalent to that of on-site natural gas fuel compression and likely higher due to:

- the electrical losses of transmission, requiring more electricity to be generated than needed for the project;
- the fact that the regional electrical generation fuel mix includes higher polluting coal-fired generation in combination with natural gas generation; and
- the contrasting highly efficient and well-controlled natural gas compressors proposed for the Project, at the site, with no transmission losses.

Projected emissions comparing on-site natural gas compression to offsite power generation are provided in Table 5-1. This comparison demonstrates that off-site electric generation could actually end up producing more emissions in powering on-site electric compression than using on-site natural gas compression; therefore, electric generation is not an inherently lower emitting technology and need not be considered in the BACT analysis.

Second, under the applicable Article 6 regulations, VADEQ has not required the BACT analysis to include consideration of technologies that would fundamentally change the nature of the affected unit proposed by the permit applicant or that would prevent the Project from meeting its intended purpose. The regulatory basis and policy supporting the VADEQ's policy is discussed in Appendix D.

Finally, the use of electric compression would prevent the Project from meeting its purposes and goals as articulated in its FERC application to supply reliable natural gas to customers in a timely manner, as further described below.

(i) Reliability

Unlike gas compression, electric compression does not provide the reliability required to meet public need for natural gas.

One of the fundamental purposes of the MVP Southgate Project and the compressor station is to provide reliable gas service to customers and residential and institutional heating needs via Mountain Valley's customer, DENC (formally PSNC). Thus, the compressor station must be able to operate at all times except for scheduled maintenance outages. If inclement weather or other unavoidable incidents disturb the power grid, electrical compression would not be able to remain operational and transportation of natural gas will be interrupted. Any evaluation of this risk should recognize that the loss of natural gas pressure will not only affect residences and business but could also impact hospitals, nursing care facilities, first responders and military installations.

Additionally, with the expected growth of the region and environmental benefits of natural gas, it is reasonable to assume that natural gas will continue to replace coal fired power generation plants, and new power generation facilities or peak facilities will utilize natural gas that will now be more accessible in the project vicinity. Given the changes in generation from coal to gas and the reversal of flow of natural gas in the existing Transco lines from the Gulf Coast (south to north flow) in the past to flow from the Marcellus south, the North Carolina Utility Commission (NCUC) has recognized the need for MVP Southgate to provide reliability in the system, which is noted on Section 7, page 20 of the "Annual Report Regarding Long Range Needs For Expansion Of Electric Generation Facilities For Service In North Carolina" (December 31, 2019), provided in Appendix E.

As proposed, a series of natural gas turbines will provide compression for the station, and a series of micro turbines will provide primary power for the station ancillary equipment and maintain necessary building functions. Electric power from the grid will be used only to run ancillary equipment and maintain necessary building functions on a backup basis. Therefore, based on the minimal electric power requirements for the natural gas compressor station, the station as designed will require only an approximate 0.3-mile-long distribution line (12kV).

In contrast, for electric compression of equivalent horsepower, voltage and amperage, using the nearest appropriate transmission/distribution lines, the following new infrastructure would be required:

- New distribution substation to provide the correct power requirements to the compressor station, including 2 large power transformers;

- Construction of distribution lines from Lambert compressor station to new substation;
- Upgrades to seven existing substations to accommodate higher voltage requirements;
- Upgrades of existing 69kV sub-transmission lines to 115kV to increase local transmission capacity to accommodate the increased load;
- New transmission substation and new 115kV line construction of approximately 9 miles of transmission line in a new 100 feet corridor to provide looping; and
- Additional upstream electrical upgrades to bring the required power to distribution power lines in the area of the Lambert CS.

Even after these upgrades, there are numerous components involved, the failure of any one of which would cause the compressor station to fail. Such failures could be the result of weather or component failure to name just two reasons. In contrast, by design, natural gas will always be available at the facility any time there is natural gas to compress. Thus, fuel reliability to power the station would not be a concern, whereas electric power reliability for electric compression would be a concern.

While electric reliability could be improved by construction of a new transmission line loop with redundant service, the time required to design, permit and construct such a line, and the cost of such a system is prohibitive as explained below.

(ii) <u>Timing</u>

Electric compression cannot be implemented in a timely manner to meet the project timelines and commitments. Evaluation of any alternative to the proposed project must consider its goals and any constraints imposed by the alternative. The goals of MVP Southgate include providing reliable natural gas to the customer in a timely manner. As explained in Section 1.1, MVP Southgate has been issued a FERC Certificate and FERC has issued its FEIS. The Project filed its initial air application in November of 2018 and a revised application in April of 2019.

The MVP Southgate Project currently has an in-service date of second half of 2021. The permitting and construction of new electrical infrastructure required for electric compression cannot be completed until at least the third quarter of 2022. In order to upgrade the existing electric service that Lambert would require, the local utility has quoted a 24-month timeframe for design and complete necessary infrastructure upgrades once contractual terms are agreed upon. Therefore, completion of Lambert could foreseeably be pushed past July of 2022, assuming contract negotiations will take several months. That schedule is for the far less reliable upgrades. A complete transmission line loop would require approval by the state Corporation Commission prior to construction, adding years to that schedule. Furthermore, these types of permits are not guaranteed, which adds additional timing uncertainty to this alternative.

So not only would electric compression be unreliable and require construction of new infrastructure, but also the extended time required for design, permitting and construction would prohibit the project from meeting the critical project needs identified by the NCUC in its report to the legislature for prompt service (Annual Report Regarding Long Range Needs For Expansion Of Electric Generation Facilities For Service In North Carolina, pg. 20, December 31, 2019) (See Appendix E). Moreover, it is not clear that the required approvals would be granted.

Because a requirement to use electric compression for the Project would frustrate its goals and purposes of providing reliable timely natural gas service, electric compression need not be considered in the BACT analysis

5.6 Even if Electric Compression were fully evaluated in the BACT analysis, Electric Compression is Not BACT

There is at least one impediment to selecting electric compression at each step of the BACT analysis for $PM_{2.5}$ and NOx. Since power required for electric compression is not currently available at the site in sufficient voltage or amperage, it is questionable whether electric compression is a commercially available technology for this site. Therefore, electric compression would be rejected in Step 1 because it is not an available technology for consideration.

In Step 2, technically infeasible technologies are eliminated from consideration. As discussed in Section 5.5, because electric compression is incapable of providing reliable and timely service for the Project, it is not a technically feasible technology.

In step 3, the remaining alternatives are evaluated and ranked in order of their effectiveness. Because emissions from electric compression (including emissions from power generation to run the electric compressors) are estimated to be similar or higher than those for natural gas compression, electric compression is eliminated from the ranking process.

In step 4, if electric compression were somehow to survive to that point, the energy, economic, and environmental impacts so far outweigh those of natural gas compression; thus, it would not be selected as BACT in step 5. More specifically,

(iv) energy impacts - electrical energy losses put electric compression at a disadvantage compared to highly efficient, well controlled natural gas compression;

(v) environmental impacts: not only are emissions estimated to be similar or higher for electric compression, but also there is a far greater impact to lands and state waters due to the required construction of new electrical infrastructure; and

(vi) economic impact: the extraordinary cost associate with new electrical infrastructure and the projected miniscule reduction in onsite emissions when offsite emissions are ignored renders electric compression economically unfeasible.

5.6.1 Environmental Impacts Evaluation

Comparison of air emissions

A comparison of the stack emissions resulting from a natural gas-driven turbine versus an electrical-driven turbine, indicates that the maximum potential stack emissions of the natural gas turbines are 10.3 tpy for $PM_{2.5}$ and 34.7 tpy for NOx (see Table 4-3) while the onsite $PM_{2.5}$ and NOx emissions from electric turbines would be zero. But that superficial evaluation ignores the very real emissions that result from the generation of power for electric compression. Not only is more energy required to cover for transmission losses, but also the electricity that would need to be provided to the site to operate the electric-driven engines could come from a variety of sources, including coal-fired, oil-fired or gas-fired power plants and/or renewable generation sources. Table 5-2 indicates those off-site emissions resulting from electric generation could exceed those resulting from on-site natural gas compression.

The energy needed to run electric-driven compressors would be generated in the region, which includes a variety of power generation sources. VADEQ has also recognized that fossil fuel combustion required for electrical generation needed to power electric compression produces emissions. If that electricity is produced from efficient natural gas, the emissions are a wash at best, therefore it is not clear that electric compression is a lower emitting technology even if it were considered as BACT. A comparison between the emissions associated with the gas-fired turbines and the emissions associated with imported power from the grid is complicated because grid power could be obtained from a variety of power sources such as fossil fuel, nuclear and renewable fuels. Further, there would be differences in the contributing fossil fuel-fired generating stations: they may use gas, oil, or coal for fuel; they would have different plant configurations (simple cycle or combined cycle power generation); and the plants would likely have different emission control systems. However, it is possible to provide a generic estimate of the emissions of grid power using EPA's emission factors for grid supplied power for the region. (FERC, 2020).

FERC utilized the EPA's Emissions & Generation Resource Integrated Database (eGRID) as well as EPA's Avoided Emissions and Generation Tool (AVERT) to estimate the hypothetical regional CO_2, NOx, $PM_{2.5}$, and SO_2 emissions that would occur if electric-driven compressor units were installed rather than natural gas-fired compressor units. The eGRID integrates many different federal data sources on power plants to allow for comparison of environmental attributes of electric generation within defined regions of the United States. AVERT uses data that "represents the dynamics of electricity dispatch based on the historical patterns of actual generation in one selected year." (US EPA AVERT). Currently, AVERT has data for 2007-2018. A comparison of emissions is provided in Table 5-2 below for 21.6 megawatt (MW) of power, compared with two Solar turbines and associated equipment that would be used for the compression and transmission of natural gas (FERC, 2020).

Table 5-2: Comparison of Direct and Indirect Power Generation Emissions for the Lambert Compression Station

Power Option	Annual Pollutant Emissions (tpy)			
	NOx	SO_2	$PM_{2.5}$	CO_2e
Natural Gas Turbine Emissions (Direct, uncontrolled) (1)	35.0	5.4	10.4	126,349
Natural Gas Turbine Emissions (Direct, controlled) (1)	12.4	5.4	10.4	125,377
Purchase Power Emissions – eGRID (Indirect) (2)	47.3	28.4	NA	76,641
Purchase Power Emissions – AVERT (Indirect) (3)	79.3	87.0	9.6	142,000

(1) See Table 3-3 for detailed information on emissions from each type of source at the Lambert Compressor Station.
(2) The indirect emission factors for GHG, NOx, and SO_2 are based on EPA data for 2016 for the SRVC eGRID subregion (SERC Virginia/Carolina). eGrid does not have standard factors for $PM_{2.5}$. Data results from eGRID were obtained from FERC FEIS.
(3) The indirect emissions were calculated using EPA AVERT and are based upon 2018 data for the AVERT Southeast Region. Data results from AVERT were obtained from FERC FEIS.

Emissions of NO_2 and SO_2 were significantly higher using purchased power, while emissions of $PM_{2.5}$ would be about the same. Greenhouse gas (GHG) emissions (as CO_2e) varied depending upon the model used. eGRID assumes more of baseload case and would be more accurate if the Lambert Compressor Station was constantly in use while AVERT assumed that the station would run intermittently. It is likely that the electrical power generation would be more than 21.6 MW due to line loss in the electrical transmission system which obviously varies. This would result in a slight increase in purchased power requirements. (FERC, 2020)

Based on this analysis, FERC concluded the following:

> "Although the use of electric units would reduce local environmental impacts, it would result in increased power generation (and emissions) from the regional grid that stretches across 11 southeastern states. These generation sources, if fossil-fuel fired, would increase utilization and/or emissions in those local areas. Based on the available past data for electrical power generation emissions, we cannot conclude that the alternative of using purchased power and electric driven compression offers a significant environmental advantage over the proposed use of gas-fired turbines." (FERC, 2020, Page 3-45)

Comparison of infrastructure impacts to the environment

The required power infrastructure is not readily available at the site to operate the alternative option of electric engines; and it would require several electrical systems upgrades and additional construction to get enough power to the site for electric-driven compression, all of which come with their own suite of environmental impacts. In contrast, the site will have natural gas as a readily available fuel to operate the natural gas driven engines and very minimal additional environmental impacts would result from new transmission line construction and transmission system upgrades. Electric distribution upgrades impacting 0.3 miles of 50 ft right of way are the only transmission changes required for the natural gas-driven compressors.

As provided in the FEIS, the FERC evaluated the feasibility of using electric motor-driven compressors at the compression station as an alternative to the proposed natural gas-fired turbines. FERC concluded that installation of electric compression is not currently feasible due to electric transmission constraints. As noted in the FERC analysis, an existing system is located approximately 1 mile from the site. Its use would require several system upgrades and additional construction (FERC, 2020). Specifically, in order to provide the necessary power at the site, the following upgrades and construction on the utility side would be required:

- new distribution substation to provide the correct power requirements to the compressor station, including 2 large power transformers located on a 200 ft x 200 ft cleared site;
- construction of distribution lines from Lambert compressor station to new substation;
- upgrades to 7 existing substations to accommodate higher voltage requirements;

- upgrades of existing 69kV sub-transmission lines to 115kV to increase local transmission capacity to accommodate the increased load;
- new transmission substation and new 115kV line construction of approximately 9 miles of transmission line in a new 100 feet corridor to provide looping; and
- additional upstream electrical upgrades to bring the required power to distribution power lines in the area of the Lambert CS

This new infrastructure would have a greater footprint, and is expected to affect the following:

- 17 new streams impacted
- 2 Pond/Lakes crossed
- 21.4 (+0.82) acres permanent upland forested clearing
- 1.15 acre permanent fill in palustrine forested (PFO) wetlands (mitigation required)
- 0.685 acre permanent conversion from PFO to palustrine emergent (PEM) wetlands (mitigation required)

As explained above, the extensions of power lines would have the disadvantages of its own set of environmental impacts with likely clearing of forest, modification of wildlife habitat, ground disturbance for installation of power poles, changes to visual setting, and permanent maintenance of a linear corridor in a grassy or scrub-shrub condition. Construction and upgrades of substations would also result in potential environmental impacts related to land disturbance, construction traffic, and risks of oil spills during operation of the substations.

5.6.2 Economic Feasibility Evaluation

The economic feasibility evaluation includes the estimate of the average cost effectiveness ($ per tons of pollutant removed) for the electric compression alternative compared to the gas compression alternative, which is considered the baseline option.

As previously noted, the use of electric compression in lieu of natural gas compression does not represent a typical BACT comparison scenario because it does not simply include the addition of an “add-on” control device to the current process. Instead, the electric compression alternative would represent a complete change in the process, which requires the change of the actual compressor turbines selected as they will need to operate on a different “fuel/power” source and it will also require system upgrades to the power transmission system to deliver the necessary power to the site to be able to operate these electric turbines. The power transmission system is not within the fence line of this project. However, given that an adequate system does not currently exist for this site and is not necessary for the gas compression alternative, the costs related to the construction and upgrades of such system would have to be absorbed by the Lambert Compressor Station. Therefore, those costs are being included in the economic feasibility analysis of the electric compression alternative.

The summary of the costs included in the analysis is provided in Table 5-3. The detailed cost analysis is provided in Appendix E.

Table 5-3: Summary of Costs for Electric Compression Alternative for 2 Turbines

Cost Category	Component	Total Cost ($)	Annualized Cost ($/yr)(1)
Total Capital Investment	Equipment Cost (2)	$15,500,000	$1,595,923
	Substation Electric Cost (3)	$34,848,000	$3,588,046
Direct and Indirect Annual Costs	Fuel/Electricity Costs (4)		$7,514,280
	O&M Costs (5)		$495,962
Total Annual Cost			**$13,194,212**

(1) Annualized costs are based on 6% interest rate and 15 years for the life of the equipment.
(2) The equipment cost is the installed capital cost of purchasing electrical-driven compressor turbines that are comparable to the Solar Mars 100 and Taurus 70.
(3) Substation electric costs include substation upgrades and additional transmission line construction and upgrades listed in Section 5.6.1 that are required for the electric turbines option. Electricity costs include the electric utility rates to deliver electricity to the site to operate the electric-driven turbines. This cost is not covered by the natural gas rate, so it would be an additional cost to the site that is not covered by the pipeline customers.
(4) The O&M cost is the cost for the electrical-driven compressor turbines annual operation and maintenance.

The total annual cost for the electric compression alternative is **$13,194,212 per year**. This cost is the annualized cost for the two combustion turbines. A cost of each turbine separately was not determined since it makes it difficult for a fair comparison. The cost of the required electric transmission system would be the same whether one or two turbines are included. Therefore, it cannot be divided between the two turbines for a single turbine comparison, and it would also not be appropriate to use the full cost for each turbine. Using either approach would grossly underestimate or overestimate the cost of this alternative. Therefore, for a fair evaluation of alternatives, the addition of two turbines was compared for all the scenarios compared in the BACT evaluation (See Table 5-1). In the same way, the emissions resulting from the two turbines were used in the cost effectiveness comparisons. Note that the cost provided in Table 5-3 is the full cost of the electric alternative. Based on the total annual cost for the electric compression alternative of $13,194,212, the average cost effectiveness was calculated for both turbines. The results were provided in Table 5-1 and are summarized for electric compression only in Table 5-4.

Table 5-4. Cost Effectiveness for Electric Compression Alternative

Pollutant	Emissions Reductions from Baseline (tpy)	Annualized Cost Relative to Baseline ($/yr)	Cost Effectiveness ($/ton removed)
$PM_{2.5}$	10.01	$5,478,183	$547,271
Formaldehyde	3.34	$5,478,183	$1,639,713
NOx	53.47	$5,536,869	$103,551

Note: Details on baseline emissions and how cost effectiveness was calculated are provided in Table 5-1 and Appendix E.

The total onsite and offsite emissions from electric generation are higher than the emissions from natural gas compression. Therefore, the cost effectiveness of electric compression is negative – it costs more and controls less and would be rejected on that basis. Looking just at onsite emissions, as shown in Table 5-4, the cost effectiveness for the electric compression alternative that would result in the removal of a total of 10.01 tons per year of $PM_{2.5}$ is **$547,271 per ton of $PM_{2.5}$ removed**. The cost effectiveness for the electric compression alternative that would result in the removal of a total of 3.34 tons per year of formaldehyde is **$1,639,713 per ton of formaldehyde removed;** and the cost effectiveness for the electric compression alternative that would result in the removal of a total of 53.47 tons per year of NOx is **$103,551 per ton of NOx removed.** The incremental cost effectiveness for NOx when using electric turbines versus the proposed gas turbines rated at 9 ppm NOx and using a SCR is $440,136 per additional ton removed. The difference in NOx emissions between the proposed control technology and electric turbines is 10.25 tons of NOx.

Given the prohibitive cost effectiveness for the electric compression alternative, this control alternative cannot be considered cost effective and thus, even if it were subject to a BACT analysis, it would not be BACT.

In summary, given the unclear environmental benefits, if any, of using electric compression over natural gas compression, the prohibitive cost effectiveness and the issue related to the timing required for the implementation of the transmission upgrades that will not allow the project to meet its construction timeline and delivery commitments, it is clear that this alternative should not be considered BACT for the Lambert Compressor Station and is thus removed from further consideration.

Accordingly, as previously indicated, Mountain Valley's proposed BACT for $PM_{2.5}$ emissions from the combustion turbines is the use of clean-burning low sulfur fuels, filtering the inlet air to reduce the incoming particulate, and good combustion practices; for formaldehyde is the use of combustion controls (SoLoNOx technology) and the addition of an oxidation catalyst with 90% efficiency for VOCs; and for NOx is the use of SoLoNOx technology and the SCR system with 70% efficiency.

5.7 Evaluation of the Use of Renewable Energy to Power Electric Driven Compressors Alternative

The previous BACT evaluation for electric compression is based on the use of existing electric power generation facilities, which include a variety of fuel-mix options and the closest transmission available.

In order to make the electric compression alternative emissions free, the compressors would need to be powered by a renewable energy source such as solar or wind energy with battery storage. Currently, there are no available renewable energy generation stations that could power the proposed site. The cost of building such facility is approximately **$238,598,000**. The average timeframe for the development and construction of this type of renewable projects is about 2.5 years. Furthermore, although once operational the project would be considered emissions free, there is a significant land impact related to the siting of such renewable projects. A solar/battery power plant with the capacity required to power the proposed compressor station would require approximately 690 acres of land for development of the project. Specific details on the cost and land requirements for the development of a renewable energy project that could power the Lambert Compressor Station are provided on Appendix E.

Accordingly, even an electric compression station powered by renewable generation sources would not be considered BACT as it is extremely cost prohibitive and would result in significant environmental impacts.

6.0 AIR QUALITY MODELING ANALYSIS

Because the emission increases from the Lambert Compressor Station equipment are less than applicable federal major source thresholds, the Project will not trigger federal NSR requirements for any regulated air pollutant under either PSD or NNSR permitting programs. The Project triggers air permitting under Article 6 as a minor source of air emissions and Mountain Valley conducted air dispersion modeling of the Lambert Compressor Station to demonstrate compliance with the NAAQS using EPA's atmospheric dispersion modeling system (AERMOD, version 18081).

The NAAQS are developed by EPA and reconsidered periodically using the latest scientific information to protect human health and the environment, including sensitive populations, with an adequate margin of safety. See Appendix F for a discussion of how NAAQS are developed and how they protect human health and the environment, including sensitive human populations, with an adequate margin of safety.

Consistent with applicable guidelines, the modeling was conducted using emission rates from a range of combustion turbine operating scenarios for the Lambert Compressor Station including startup and shutdown, as well as three load and seven ambient temperature scenarios. A summary of the maximum (worst-case emissions from the various parameter combinations) modeling results of the Lambert Compressor Station alone are provided in Table 6-1.

Details of the operating scenarios, along with methodologies and results, can be found in the modeling results report provided in Appendix G. Results indicate that the maximum modeled concentrations would be less than the applicable NAAQS for all criteria pollutants modeled. The NO_2 results for the Lambert Compressor Station are predicted to be 1.4 percent of the annual standard and 9.3 percent of the one-hour standard. Modeled ambient concentrations of $PM_{2.5}$ are less than 3 percent for the annual and one-hour NAAQS.

Table 6-1: Criteria Pollutant Modeling Results for Lambert CS

Pollutant	Averaging Period	Maximum Modeled Concentration (ug/m^3)	NAAQS (ug/m^3)	% of NAAQS
NO_2	1-hr	17.48	188	9.3%
	Annual	1.36	100	1.4%
CO	1-hr	156.4	40,000	0.4%
	8-hr	47.74	10,000	0.5%
$PM_{2.5}$	24-hr	0.79	35	2.3%
	Annual	0.14	12	1.2%
PM_{10}	24-hr	1.27	150	0.9%

The modeling analysis also included the Transco Compressor Stations 165/166 as nearby sources along with 24 additional facilities located within a 50 km radius of the proposed Lambert Compressor Station to determine the cumulative impact of all sources on the air quality of the area. Details of the methodologies used can be found in the modeling report in Appendix G. A summary of the cumulative emissions modeled for the scenario resulting in the highest emissions is provided in Table 6-2. The cumulative results from the dispersion modeling show that the facility when operating with all surrounding sources is in compliance with the NAAQS.

Table 6-2: Cummulative Criteria Pollutant Modeling Results for Lambert CS

Pollutant	Averaging Period	Background Concentration (ug/m^3)	Maximum Modeled Concentration (ug/m^3)	Cumulative Concentration (ug/m^3)	NAAQS (ug/m^3)
NO_2	1-hr	Variable	178.8	178.8	188
	Annual	13.2	21.8	35.0	100
CO	1-hr	2,300	2,151	4,451	40,000
	8-hr	1,380	1,106	2,486	10,000
$PM_{2.5}$	24-hr	17	6.0	23.0	35
	Annual	7.2	1.0	8.2	12
PM_{10}	24-hr	31	9.1	40.1	150

The cumulative modeling predicts that the ambient concentration of NO_2 would be closest to its respective NAAQS (95% of the 1-hr average standard). An isopleth showing the location of the highest impacts for NO_2 is provided in Figures 6-1 and 6-2 for the cumulative impacts and the impacts of the Lambert CS alone, respectively. Figure 6-1 shows that the highest cumulative impacts, taking in to account background from other sources, are limited to the area very close to the Transco Compressor Station 165/166 fence line with elevated levels decreasing to the north. This demonstrates that the operation of the Lambert Compressor Station in combination with other projects will not result in significant cumulative impacts on air local or regional air quality.

Mountain Valley also conducted air dispersion modeling of formaldehyde emissions since the emissions of formaldehyde at the compressor station would be greater than the Virginia exemption threshold in 9VAC5-60-300C. Although hexane emissions for the Lambert CS are below the exemption threshold, hexane was conservatively modeled as it has been considered a pollutant of concern for other compressor station projects, and, at the DEQ's request, modeling for hexane was also performed. The toxics modeling is also part of the modeling report provided in Appendix G. Modeling results were compared with the VADEQ's Significant Ambient Air Concentration (SAAC) for formaldehyde and hexane, The SAACs are designed to protect human health. As shown in Table 6-3, modeling results indicate that the maximum modeled concentrations are less than the Virginia formaldehyde and hexane SAAC.

Table 6-3: Air Toxics Model Results for Lambert CS

Pollutant	Averaging Period	Maximum Modeled Concentration (ug/m^3)	Significant Concentration (SAAC) (ug/m^3)
Formaldehyde	1-hr	9.9	62.5
	Annual	0.05	2.4
Hexane	1-hr	1,298	8,800
	Annual	0.28	352

In conclusion, the results of the air quality modeling analysis demonstrate that the proposed Project does not cause or contribute to any exceedance of the NAAQS for NO_2, $PM_{2.5}$, PM_{10} and CO, and does not exceed significant air toxics concentrations for formaldehyde and hexane.

Figure 6-1: Isopleth for 1-hr NO_2 for the Lambert CS and Surrounding Sources

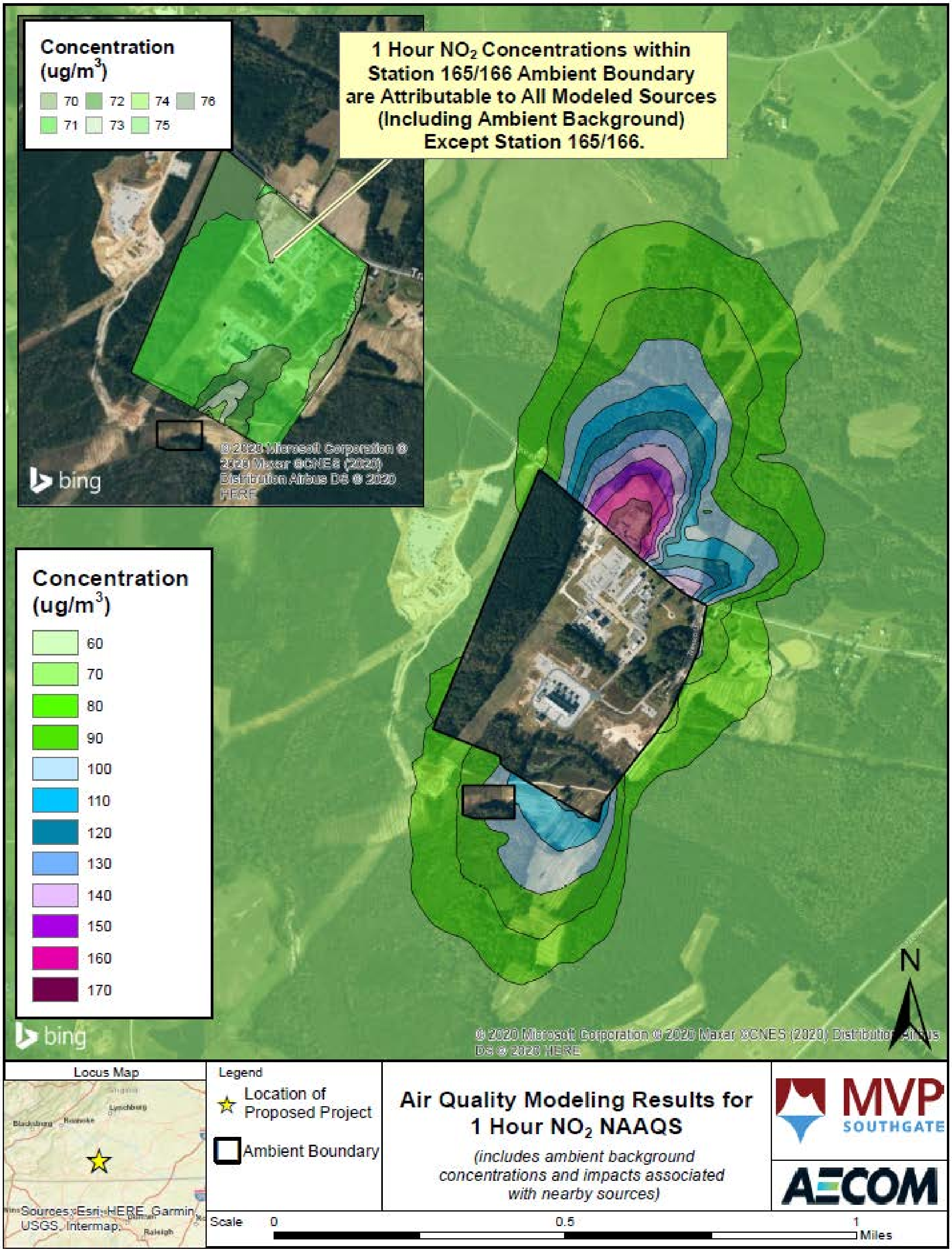
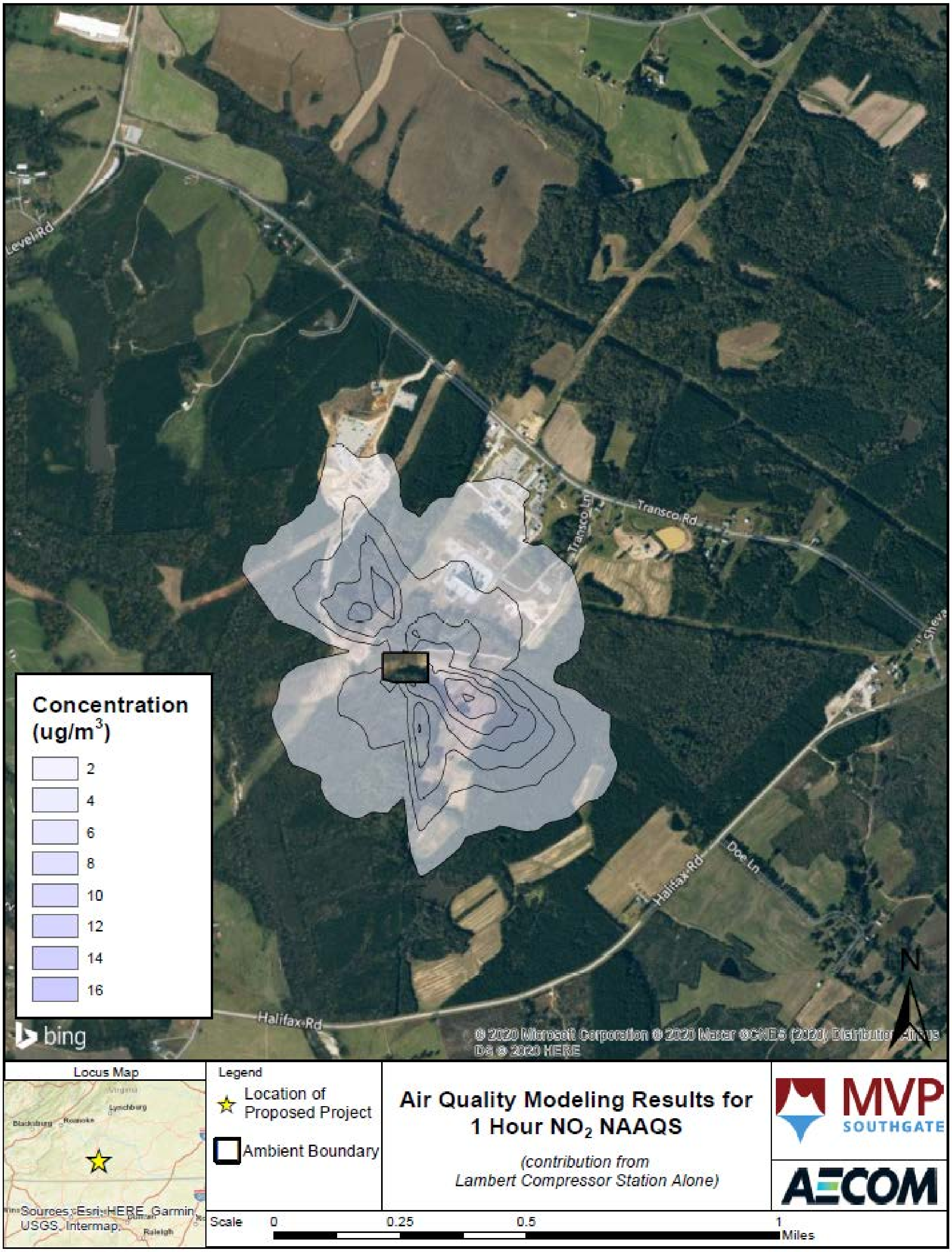


Figure 6-2: Isopleth for 1-hr NO_2 for the Lambert CS Project Alone



7.0 COMPLIANCE WITH §10.1-1307(E)

Va Code § 10.1-1307(E) requires the Board, in approving permits, to

> consider facts and circumstances relevant to the reasonableness of the activity involved and the regulations proposed to control it, including:
>
> 1. The character and degree of injury to, or interference with, safety, health, or the reasonable use of property which is caused or threatened to be caused;
>
> 2. The social and economic value of the activity involved;
>
> 3. The suitability of the activity to the area in which it is located; and
>
> 4. The scientific and economic practicality of reducing or eliminating the discharge resulting from such activity,

For the Board's consideration in compliance with Va Code 10.1-1307 E. MVP Southgate provides the following information:

7.1 The character and degree of injury to, or interference with, safety, health, or the reasonable use of property which is caused or threatened to be caused

Mountain Valley has taken significant measures to ensure that the proposed project does not cause injury to or interfere with safety, health and the reasonable use of property as explained below.

a. Safety

As part of an interstate pipeline, Lambert Compressor Station is subject to stringent requirements of and approval from the federal Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA administers the national regulatory pipeline safety program for the nation's interstate and intrastate pipelines and requires that pipeline operators design, construct, test, operate, and maintain their pipeline facilities in compliance with the federal pipeline safety regulations. The PHMSA pipeline standards are published in 49 CFR 190-199. Part 192 specifically addresses the minimum federal safety standards for transportation of natural gas by pipeline. Under a Memorandum of Understanding on Natural Gas Transportation Facilities dated January 15, 1993, between the DOT and the FERC, the DOT has the exclusive authority to promulgate federal safety standards used in the transportation of natural gas. Section 157.14(a)(9)(vi) of the FERC's regulations require that an applicant certify that it would design, install, inspect, test, construct, operate, replace, and maintain the facility in accordance with federal safety standards and plans for maintenance and inspection.

After considering the project and the applicable regulations, FERC concluded (FERC, 2020):

> The pipeline and aboveground facilities associated with the Project will be designed, constructed, operated, and maintained to meet the DOT Minimum Federal Safety Standards in 49 CFR 192 and other applicable federal and state regulations. These regulations include specifications for material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion. The DOT rules require regular inspection and maintenance, including repairs as necessary, to ensure the pipeline has adequate strength to transport natural gas safely. We received several comments about the potential effects of a pipeline rupture and natural gas ignition (the area of potential effect is sometimes referred to as the potential impact radius). While a pipeline rupture does not necessarily ignite, the DOT does publish rules that define HCAs where a gas pipeline accident could do considerable harm to people and their property and requires an IMP to minimize the potential for an accident. Mountain Valley would follow federal safety standards for pipeline class locations based on population density. The DOT regulations are designed to ensure adequate safety measures are implemented to protect all populations. We conclude that Mountain Valley's compliance with applicable design, construction and maintenance standards, and DOT safety regulations would be protective of public safety. (pg. 4-428)

Mountain Valley has taken numerous actions, in addition to those required by regulatory requirements, to ensure that the proposed project is safe. These are enumerated in Appendix H.

Pittsylvania County has hosted a compressor station owned and operated by Transco for many years. Mountain Valley representatives made a formal presentation on November 6, 2019 to the Tunstall Fire/Rescue, Blairs Fire/Rescue, Brosville Fire/Rescue, Bachelors Fire Hall, Mount Hermon Fire/Rescue, as well as representatives of the Virginia State Police, Virginia Department of Hazardous Materials, and the Pittsylvania Department of Public Safety. Because of the other existing pipeline-related facilities located there, the County has trained first responders capable of addressing any hazardous situations that might arise.

In addition, Mountain Valley will submit the Tier II reports to the State and County, as required under Section 312 of the Emergency Planning and Community Right to Know Act of 1986 (EPCRA). These reports provide State, local officials, and the public with specific information on potential hazards and give critical information to first responders in the event of an emergency.

All employees manning the Lambert Compressor Station will be trained to safely operate the station as part of Mountain Valley's Operator Qualification program. Training will include, but not be limited to topics such as daily operations procedures, emergency response, lock-out-tag-out procedures, and routine maintenance.

b. Effect on health

i. Air quality Modeling Results

Air quality modeling was conducted for the Lambert Compressor Station for evaluation of potential emissions from the site against federal air quality standards (NAAQS) and Virginia State air toxic standards (SAACs). As shown in Section 6.0 and Appendix G, the results of the air quality modeling analysis demonstrate that the proposed project does not cause or contribute to any exceedance of the NAAQS for NO_2, $PM_{2.5}$, PM_{10} and CO, and does not exceed significant air toxics concentrations for formaldehyde and hexane. Appendix F explains how the NAAQS and SAACs are developed and how they protect human health and the environment with an adequate margin of safety. The standards are specifically developed with conservative assumptions to protect all populations including those with respiratory illnesses and those sensitive to pollutants.

Emissions and ambient air quality impacts in the area have been reduced significantly by Transco's replacement of older equipment with new well controlled equipment at its compressor station adjacent to the proposed Lambert Compressor Station site. As shown in Table 7-1, the new potential to emit for the Transco Stations 165/166 ("Transco New PTE") is much lower than the previous facility PTE. The Transco New PTE is also lower than the actual emissions reported in 2018, for most pollutants. As shown in the last row of Table 7-1, the projected emissions from Lambert Compressor Station are a small fraction of the Transco New PTE. Also, the PTE for both Transco and LCS combined is lower than the Transco Past PTE, which represents the Transco facility without the recently permitted modifications. Furthermore, the maximum potential emissions from the modified Transco site and the Lambert Compressor Station combined will be lower than the actual emissions reported by Transco alone in 2018 for most pollutants.

Table 7-1. Comparison of Emissions from the Transco Station

Emissions	NO_X	CO	VOC	PM_{10}/ $PM_{2.5}$	SO_2	Total HAPs
Pittsylvania County 2018 Actual(1)	1,219	539	321	84/72	138	
Transco Past PTE(2)	3,746	1,026	251	60/60	10	73
Transco 2018 Actual(1)	956	233	60	15/15	2.4	
Transco New PTE(2)	549	373	101	36/36	14	24
Lambert CS PTE	12.4	17.3	3.3	10.4/10.4	5.4	1.1
LCS compared to Transco New PTE	2.2%	4.6%	3.3%	28.8%	38.6%	4.6%

(1) The total emissions and sources that make up the 2018 actual emissions in Pittsylvania County were obtained from VADEQ emissions inventory, which is provided in Appendix I.

(2) Transco Past and New PTE were obtained from the Transco permit application submitted to VADEQ on November 19, 2019.

c. Reasonable Use of Property

Three independent real estate appraisers reviewed information on the surrounding area to the Project site and provided the following opinions:

(1) From the Letter from Wesley Woods, MAI, Certified General Real Estate Appraiser, to Wade W Massie dated March 24, 2020 (See Appendix J)

> To recap, the purpose of my analysis was to consider the potential impacts of the proposed MVP compressor station on the surrounding areas. I have researched a wide variety of properties and have specifically considered the subject's neighborhood. I have not found any instances or data to support that the proposed MVP compressor station would have any negative impact on the surrounding properties. MVP owns the subject 154+/- acres which is located to the immediate south of the circa-1960s Transco facility. If any impact was done to the neighborhood, it certainly came when Transco constructed the original facility in the early 1960s and/or constructed their newer facility to the immediate south. Further emphasis is placed on the fact that in 2018 a new dwelling was constructed at 709 Transco Road, which is located to the immediate east of the Transco facility. Again, this dwelling located about 1,000 feet away from the existing Transco facility and is within immediate visual distance of the Transco facility.

(2) From the Letter of Joseph E. Thompson, MAI, Certified Commercial Investment Member (CCIM), to Seth Land dated June 2, 2020 (See Appendix J)

> The subject neighborhood and other neighborhoods surrounding compressor stations in the region have been reviewed. After this investigation, I have concluded that **the subject neighborhood will not realize adverse effects on property value resulting from Mountain Valley Pipeline's proposed natural gas compressor station.**

(3) From the Letter of Jared L. Schweitzer, MAI, Virginia Certified General Appraiser, to Wade W Massie dated June 3, 2020 (See Appendix J)

> In conclusion, after a thorough observation of the Mountain Valley Pipeline, LLC compressor station property, and the immediate market area, there is no evidence to suggest that the use and value of the surrounding properties will be negatively impacted by the Mountain Valley Pipeline compressor station. As stated previously, Williams Co. and Transco have operated a natural gas compressor station in the immediate area for many years. The first natural gas pipeline operated by Transco was installed c.1949. (pg. 9)

All 3 reports support the conclusion that the Project will not negatively impact real estate values near the Project site.

7.2 The social and economic value of the activity involved

a. Purpose of project

In 2017, PSNC Energy, now a part of DENC, solicited interest from existing and proposed interstate pipeline providers for additional natural gas transportation capacity. PSNC Energy is a local distribution company primarily engaged in the purchase, transportation, distribution, and sale of natural gas to more than 563,000 customers in North Carolina. Those customers include residential, commercial, industrial, health care, educational, emergency services and military customers. PSNC Energy solicited interest because it requires additional pipeline capacity to meet forecasted incremental demand on its distribution system. Over the past four years, PSNC Energy has experienced a 15 percent increase in peak daily throughput on its system. This trend will carry forward into the future, as PSNC Energy expects its design day requirements to increase an additional 11 percent over the next five years. This past, present, and future demand growth on PSNC Energy's system reflects, at least in part, the substantial population increase in North Carolina. North Carolina's population is expected to increase by nearly 2 million people between 2020 and 2035.

After consideration of other existing and proposed interstate pipeline providers, PSNC Energy committed to 300 million cubic feet per day ("MMcf/d") of firm transportation service to be made available by the Project. Mountain Valley and PSNC Energy entered into binding long-term agreements in December 2017 that made PSNC Energy an anchor shipper for the Project. In choosing the Southgate Project to provide its needed incremental pipeline capacity, PSNC Energy cited numerous reasons, including transportation cost, supply cost, supply diversity, reliability/resiliency, and operational efficiencies.

The Project has support from numerous organizations representing thousands of Virginians. These groups include the Virginia Chamber of Commerce, Virginia FREE, the Virginia Oil and Gas Association and the Virginia Petroleum Council.

MVP Southgate has also gained support from the Danville-Pittsylvania County Chamber of Commerce. This support is based in part on the essential need for economic development, which is highly dependent on access to reliable natural gas, in Southside Virginia.

> "Time and again we hear from manufacturers and other large companies that the availability of natural gas is a critical component in the site selection process. The Southern Virginia Mega Site at Berry Hill is the Commonwealth's biggest business park, and the MVP Southgate project's proximity to that site offers tremendous long-term economic development opportunities. The Virginia Chamber fully supports the project and the potential benefits its construction and operation could bring."

– Barry DuVal, president of the Virginia Chamber of Commerce.

Appendix K includes multiple letters publicly filed with FERC and other agencies displaying support for the project. As the cleanest-burning fossil fuel, natural gas plays an important role in reducing U.S. air pollution and greenhouse gas emissions from the high historical use of coal. Specifically, electric utilities are switching from coal to natural gas to improve air quality and combat climate change. Compared to coal, natural gas emits 44 percent less carbon dioxide, 80 percent less nitrogen oxides, and 99.9 percent less sulfur dioxide. Further, greenfield pipeline rights-of-way can be restored and returned to agricultural and recreational uses once construction is complete.

b. Public convenience and necessity

FERC, in its Order Issuing Certificate from June 18, 2020, noted in the Certificate Policy Statement Conclusion the following:

The proposed project will enable Mountain Valley to provide 375,000 Dth per day of incremental firm transportation service, of which 80% is subscribed. We find that Mountain Valley has demonstrated a need for the Southgate Project and further, that the project will not have adverse economic impacts on existing shippers or other pipelines and their existing customers, and that the project's benefits will outweigh any adverse economic effects on landowners and surrounding communities. Therefore, we conclude that the project is consistent with the criteria set forth in the Certificate Policy Statement and analyze the environmental impacts of the project below.[1] (FERC, 2020, Page 24)

c. Jobs created directly and indirectly

i. Construction of the MVP Southgate project is expected to support 570 jobs in Virginia, including direct, indirect and induced jobs. Direct jobs are those related to the construction of the pipeline and operation of the compressor station. Indirect jobs are those that would be created along the supply chain and induced jobs include those that would be created in the general economy.

ii. Access to a reliable supply of natural gas is an important factor in recruiting and retaining large employers. The additional supply of natural gas provided through MVP Southgate is expected to support existing jobs in the region and help support new jobs created by companies recruited to the region.

d. Tax Base

i. The MVP Southgate project team anticipates spending $68 million in Virginia directly on resources (equipment, materials, labor and services)

ii. During construction, the project will be a significant source of state and local tax revenue with approximately $4.1 million generated in Virginia

iii. During operation, the MVP Southgate project is expected to generate tax revenues to localities along the route. In Virginia, an estimated additional $1.2 million in new, annual local tax revenue is expected

See Appendix L for the economic benefit analysis associated with the project.

[1] *See* Certificate Policy Statement, 88 FERC at 61,745-46 (explaining that only when the project benefits outweigh the adverse effects on the economic interests will the Commission then complete the environmental analysis).

7.3 The suitability of the activity to the area in which it is located

a. Benefits of the Site

The current location of Lambert is suitable for many reasons. Hydraulically, the location of the compressor station is ideal as the next closest compressor station is approximately 150 miles away along the Mountain Valley Pipeline. At its current location, the gas is effectively relayed and pumped through the Southgate pipeline. From a physical location perspective, impacts, if any, are mitigated by the following facts:

i. The location and surrounding area is not densely populated
ii. The compressor station can be located just off the proposed pipeline route supporting colocation with Transco pipeline corridor and similar existing facilities
iii. Mountain Valley owns the property and it is sufficient in size to provide a significant buffer
iv. Nearest residences are 3,000 feet or more away, which is beneficial from a noise perspective
v. Construction and operation of a compressor station in this area will not be foreign to residents, the municipality, or the county as Williams' Transco Stations 165/166 are adjacent

b. Alternatives

As part of the FERC Application, Mountain Valley evaluated an alternative location 0.4 miles to the northwest, but it was eliminated from consideration due to closer proximity to more noise sensitive areas within 1 mile of the site and would result in greater environmental impacts to clear and grade the site. Additionally, during the FERC pre-filing process, the Project evaluated locations for a second compressor station further down the pipeline route, but rejected those locations as being unsuitable due to proximity to residences, locations within floodways and floodplains, or because they deviated significantly from the proposed pipeline, which would result in reduced colocation and increased environmental impacts. The evaluation of alternatives related to the location of the Lambert Compressor Station are provided in Appendix M

FERC evaluated alternative locations for the Lambert Compressor station and stated in the DEIS and FEIS that the proposed Lambert Compressor Station location was suitable. FERC also confirmed that they did not receive any comments from affected landowners concerning the siting of the compressor station. FERC states:

> "Although we considered alternate locations for the Lambert Compressor Station, we found the proposed location of the Lambert Compressor Station to be acceptable, and we did not receive suggested alternatives from affected stakeholders concerning the siting."

c. Compliance with local ordinances

Pittsylvania County has certified that the Project complies with local ordinances. See certification form in Appendix A.

d. Environmental Justice

Mountain Valley has retained a consultant who is preparing an environmental justice analysis and report consistent with the Virginia Environmental Justice Act and other legislation adopted in the 2020 session of the Virginia General Assembly. The COVID-19 pandemic and the protests and other activities resulting from the death of George Floyd have delayed the field work required to complete that analysis and report. Mountain Valley will submit it when it is complete.

7.4 The scientific and economic practicality of reducing or eliminating the discharge resulting from such activity

Section 5.0 of this application provides the BACT evaluation for the pollutants that triggered BACT requirements, which for the Lambert Compressor Station project was only $PM_{2.5}$.

In addition to implementing BACT for $PM_{2.5}$, the project is proposing to exceed regulatory pollution control requirements and voluntarily include addition of the most stringent pollution control technologies for NOx, CO and VOCs, including HAPs such as hexane, that are available for natural gas compression turbines and compressor stations. Specifically, the turbines and the site will be equipped with the following control technologies, which are not required by BACT, to ensure high levels of emissions reductions:

- SCR for NOx control in the gas turbines, capable of achieving 70% reduction efficiency
- Oxidation catalyst for CO and VOC control in the gas turbines, capable of achieving 92% reduction efficiency for CO and 90% reduction efficiency for VOCs.

- Pressure hold (PH) and vent gas recovery system (VGRS) for controlling natural gas emissions resulting from blowdowns
- Emergency blowdown (EBD) block valve to control emissions resulting from emergency shutdown tests

The proposed voluntary controls to minimize blowdown emissions, which include PH, VGRS and the use of a block valve to conduct ESD testing, will reduce GHG emissions from these blowdowns and venting events by more than 75% (using CO_2e in tons per year for the comparison). Furthermore, VOC and HAP emissions, specifically hexane emissions, will be reduced by approximately 78%, compared to the uncontrolled blowdown and venting events.

The overall facility-wide mass emissions reductions that will be achieved by the proposed controls are summarized in Table 7-2.

Table 7-2. Facility-wide emission reductions from emission controls proposed at the Lambert Compressor Station

Emissions	NOx	CO	VOC	CO_2e	Total HAPs
Uncontrolled Emissions (tpy)	35.04	67.65	9.40	126,349	4.53
Control Technology	SCR	Oxidation Catalyst	Oxidation Catalyst, PH, VGRS	PH and VGRS	Oxidation Catalyst, PH, VGRS
Controlled Emissions (tpy)	12.37	17.28	3.33	125,377	1.09
Emissions Reductions (tpy)	**22.67**	**50.37**	**6.07**	**972**	**3.44**

The feasibility of using electric compression instead of natural gas compression was also evaluated and discussed in Section 5.0 as part of the BACT analysis. As stated in that section, after thorough analysis, electric compression was rejected as BACT for several reasons. First, it is not a lower emitting source when offsite emissions are considered; second, it is not feasible because it does not meet the reliability and timing requirements for the project. Finally, it is not economically feasible because the cost per ton of pollutant removed is several orders of magnitude above the typical levels for cost effectiveness and would have greater overall environmental impacts from the need for additional infrastructure to support electric compression.

8.0 REFERENCES

Cooper, D. C., & Alley, F. (2011). *Air Pollution Control: A Design Approach*. Long Grove: Waveland Press, Inc.

EPA. (2000). *Emission Factor Documentation for AP-42 Section 3.1 Stationary Gas Turbines*. Retrieved from https://www3.epa.gov/ttn/chief/ap42/ch03/bgdocs/b03s01.pdf

EPA. (2005, February 18). Standards of Performance for Stationary Combustion Turbines. *Federal Register 70*, p. 8321. Retrieved from https://www.govinfo.gov/content/pkg/FR-2005-02-18/pdf/05-3000.pdf

EPA. (2020, March 3). National Emission Standards for Hazardous Air Pollutants: Stationary Combustion Turbines Residual Risk and Technology Review. *Federal Register*, p. 13524.

FERC. (2020). *Mountain Valley Pipeline, LLC Southgate Project Final Environmental Impact Statement (FEIS)*. FERC Docket No.: CP19-14-000.

FERC. (2020, June 18). *MVP Southrgate FERC Certificate*. Retrieved from Docket No.CP19-14-000: https://www.ferc.gov/sites/default/files/2020-06/C-6-061820.pdf

VADEQ. (2020, March). *VA DEQ Air Toxics*. Retrieved from Virginia Department of Environmental Quality: https://www.deq.virginia.gov/Programs/Air/PermittingCompliance/Permitting/AirToxics.aspx

APPENDIX A
VADEQ Application Forms

PITTSYLVANIA
COUNTY, VIRGINIA

BOARD OF SUPERVISORS
P.O. Box 426 • 1 Center Street
Chatham, Virginia 24531
Phone (434) 432-1987

February 19, 2019

VIA U.S. MAIL
Paul Jenkins
Air Permitting Manager
Virginia Department of Environmental Quality, Blue Ridge Regional Office
3019 Peters Creek Road
Roanoke, Virginia 24019

Re: *Mountain Valley Pipeline Southgate Lambert Compressor Station*

Dear Mr. Jenkins:

This letter confirms that Pittsylvania County, Virginia ("County"), shall consider all activities included in the FERC Permit issued for the Mountain Valley Pipeline ("MVP") Southgate Project, including the Lambert Compression Station, to be exempt from applicable County zoning rules and regulations due to federal preemption. This position is consistent with and supported by Pittsylvania County Code ("PCC") § 35-50, attached for your reference and review. Attached also please find the VA DEQ - Air Permit Local Governing Body Certification Form evincing the same.

In conclusion, all PCC requirements related to the MVP Southgate Project, including the Lambert Compression Station, will be met and satisfied by the issuance of the FERC Permit, and the County does not require any local land use permits for the same. Please contact the undersigned if you have any related questions.

Sincerely yours,

Robert W. Warren

Robert "Bob" W. Warren
Pittsylvania County Board of Supervisors Chairman

David M. Smitherman
Pittsylvania County Administrator

J. Vaden Hunt

J. Vaden Hunt, Esq.
Pittsylvania County Attorney

Karen N. Hayes

Karen N. Hayes
Pittsylvania County Deputy Community Development Director

Encls. (2)

SEC. 35-50. EXEMPTIONS.

The following structures and uses shall be exempt from the regulations of this Ordinance.

1. Wires, cables, conduits, vaults, laterals, pipes, mains, valves or other similar equipment for the distribution to consumers of telephone or other communications, electricity, gas, water or the collection of sewage or surface water operated or maintained by a governmental entity or a public utility or public service corporation including customer, meter pedestals, telephone pedestals, distribution transformers and temporary utility facilities required during building construction, whether any such facility is located underground or above ground, but only when such facilities are located in a street right-of-way or in an easement less that forty (40) feet in width. The exemption shall not include any substation located on or above the surface of the ground or any such distribution facility located in an easement of forty (40) feet or more in width.

2. Railroad tracks, signals, bridges and similar facilities and equipment located on a railroad right-of-way, and maintenance and repair work on such facilities and equipment.

3. Property owned by Pittsylvania County or any designated agent of Pittsylvania County which is devoted to or intended for government uses is exempt from this Zoning Ordinance.

4. Electrical transmission lines sized 138kv or less, constructed to serve a properly zoned industrial park shall be exempt from this Zoning Ordinance, with approval subject to a public hearing and vote by the Board of Supervisors. (B.S.M. 4/16/19)

5. Interstate natural gas transmission pipelines, compressor stations, metering stations, and related facilities certified by the Federal Energy Regulatory Commission under the Natural Gas Act. (B.S.M. 4/21/20)

The following structures shall be exempt from the minimum yard requirements set forth in this Ordinance: telephone booth and pedestals, underground utility equipment, mail boxes, or any similar structure or equipment which in the opinion of the Zoning Administrator is obviously intended to be otherwise located in the public interest and are not incongruent with the aesthetic standards of the surrounding area.

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY - AIR PERMITS

LOCAL GOVERNING BODY CERTIFICATION FORM

Facility Name: Lambert Compressor Station	Registration Number:
Applicant's Name: Mountain Valley Pipeline, LLC	Name of Contact Person at the site: Kristin Ryan
Applicant's Mailing address: 2200 Energy Drive, Canonsburg, PA 15317	Contact Person Telephone Number: 412-400-6887

Facility location (also attach map): Chatham, Pittsylvania County, Virginia (See Figures 2-1 and 2-2 of Application)

Facility type, and list of activities to be conducted: Natural Gas Compressor Station for MVP Southgate pipeline.

The applicant is in the process of completing an application for an air pollution control permit from the Virginia Department of Environmental Quality. In accordance with § 10.1-1321.1. Title 10.1, Code of Virginia (1950), as amended, before such a permit application can be considered complete, the applicant must obtain a certification from the governing body of the county, city or town in which the facility is to be located that the location and operation of the facility are consistent with all applicable ordinances adopted pursuant to Chapter 22 (§§ 15.2-2200 et seq.) of Title 15.2. The undersigned requests that an authorized representative of the local governing body sign the certification below.

Applicant's signature: [signature]	Date: 10/31/2018

The undersigned local government representative certifies to the consistency of the proposed location and operation of the facility described above with all applicable local ordinances adopted pursuant to Chapter 22 (§§15.2-2200 et seq.) of Title 15.2. of the Code of Virginia (1950) as amended, as follows:

(Check one block)

- [x] The proposed facility is **fully consistent** with all applicable local ordinances.
- [ ] The proposed facility is **inconsistent** with applicable local ordinances; see attached information.

Signature of authorized local government representative: Karen N. Hayes	Date: 2/19/20
Type or print name: Karen N. Hayes	Title: Deputy Community Development Director
County, city or town: Pittsylvania County, Virginia	

[THE LOCAL GOVERNMENT REPRESENTATIVE SHOULD FORWARD THE SIGNED CERTIFICATION TO THE APPROPRIATE DEQ REGIONAL OFFICE AND SEND A COPY TO THE APPLICANT.]

DOYLE
LAND SERVICES

TAX TITLE COVER SHEET

State:	Virginia
County:	Pittsylvania
Project Name:	MVP Southgate
Tract No.:	VA-PI-002.000
Assessor Parcel No.:	2436-60-1838

DEED OF ACQUISITION

Current Owner:	Mountain Valley Pipeline, LLC
Grantor on DOA:	Robert C. Lilley, Eve M. Thorson and Susan Hellebush Moses
Date:	March 14, 2018
Book:	18-01222
Page:	73
Instrument No:	180001222

Comments:

Tax Title Agent: Don Rich

Date: 3/29/2018

THORSON, EVE M ET ALS
LILLEY, PATTIE M ET ALS
C/O EVE MOSES THORSON
3 GROUSE LN
TOPSHAM, ME 04086

Acct : 227527 Dst: 05 AC:Tx 154.9800 Map #: 2436-60-1838
Date : 03/02/15 Cls: 6 Ap 154.98 Desc : HALIFAX RD/57
Bk/Pg: WF15/00179 Zon: A-1
Mb/Lt: B44/206E Nhd: 100 0% Lc : Util:
Cons : 0 Rd : 03 DIRT Topo :

Card 1 of 1
Printed:03/27/18
Updated:TMM
Att:

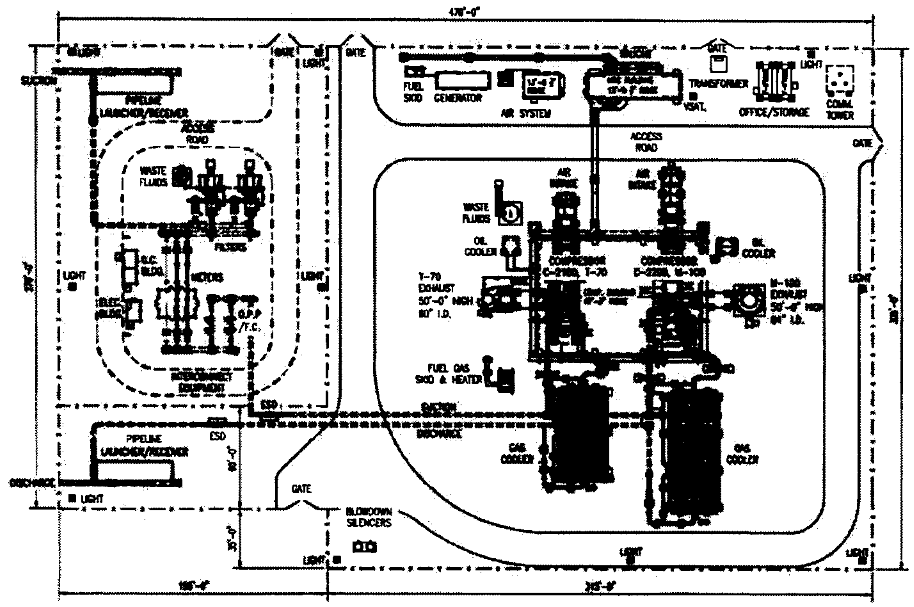
(A): OFF 832 (R): OFF 832

Appr: SS Date:10/11/16
Info: E Time: 3:49

BnBmUse MhCdDes Rem Ayb CndUnits Rate PdFo RsnEo RsnIcValue

SnLmSeg Type	Ac	Frnt	Dpth	Sf	TFctrLtUp	Adj%	Value	Remarks
1A 6000 CROPLAND	29.00				2500	0	72,500	
2A 8000 WOODLAND	125.98				1800	0	226,800	

Mkt Val L	299,300
Mkt Val B	0
Mkt Val T	299,300
Def Val	0
Net Val	299,300
Old Mkt L	247,000
Old Mkt B	0
Old Def	0
Old Net	247,000



TO THE BEST OF MY KNOWLEDGE, ALL COMPONENTS OF THIS DRAWING ARE DESIGNED IN ACCORDANCE WITH APPLICABLE GUIDELINES AND SPECIFICATIONS

DOUG MACE — MECHANICAL DESIGN ENGINEER — 8-14-2018 DATE

ELECTRICAL DESIGN ENGINEER — DATE

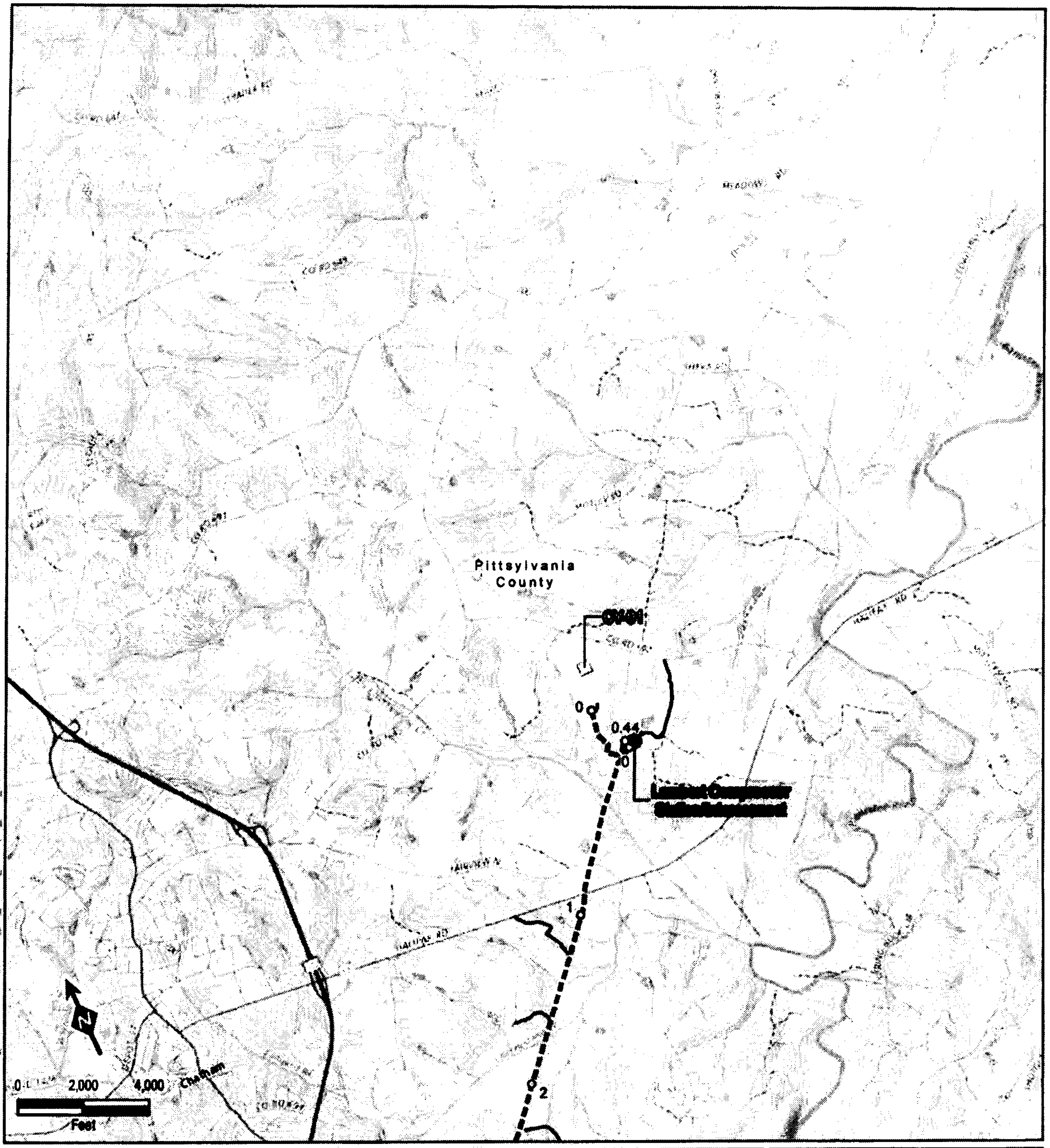
NOTE: ANY CHANGES TO THE DESIGN SHOWN ON THIS DRAWING MUST BE APPROVED BY THE DESIGN ENGINEER.

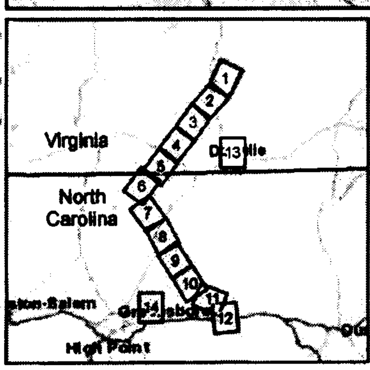
Mountain Valley PIPELINE

DRAWING TITLE:
LAMBERT COMPRESSOR STATION
MECHANICAL
PIPING
PLOT PLAN

DRAWING SCALE: 1/32" = 1'-0"

FACILITY	STATE	IDENTIFICATION	SERIES	SHEET	REVISION
C	V	LAM	1100	01	P





Legend

- Mileposts
- Compressor Station
- Contract Yard
- Meter Station
- Valve Site
- Permanent Access Road
- Temporary Access Road
- H-605 Pipeline
- H-650 Pipeline
- County Boundary
- State Boundary

1 inch = 4,000 feet
When Printed 8.5x11

Data Sources: ESRI, USGS, TRC, EQT

Mountain Valley PIPELINE

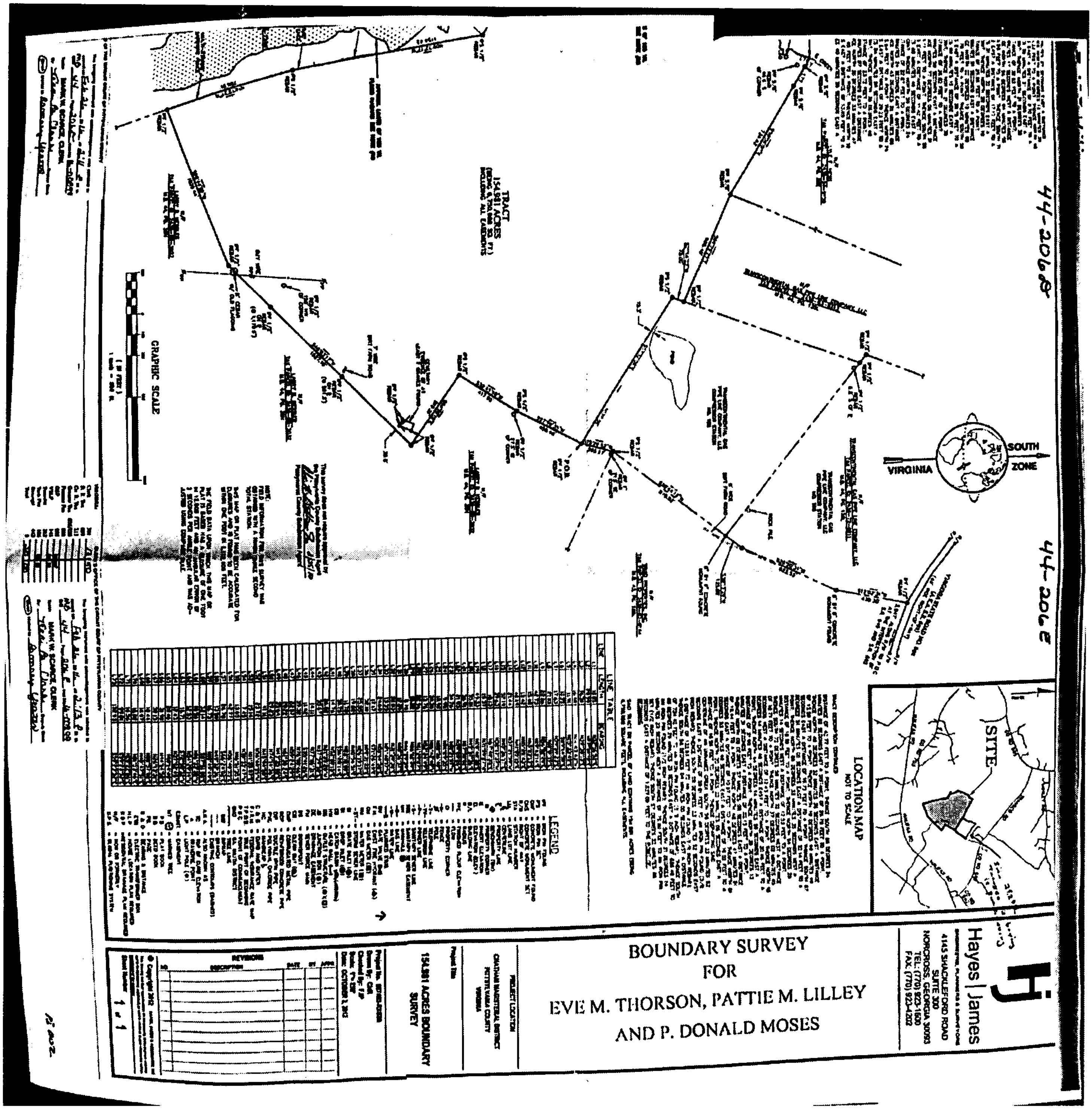
Appendix 1-B

USGS Quadrangle Excerpts

Sheet 1 of 14

TRC

600 Willowbrook Ln
West Chester, PA 19382
October 2018


44-2068
44-2068
TRACT
154.981 ACRES
GRAPHIC SCALE
VIRGINIA
SOUTH ZONE
LOCATION MAP
NOT TO SCALE
SITE
LINE TABLE
LEGEND
Hayes | James
4145 SHACKLEFORD ROAD
SUITE 300
NORCROSS, GEORGIA 30093
TEL: (770) 923-1600
FAX: (770) 923-4202
BOUNDARY SURVEY
FOR
EVE M. THORSON, PATTIE M. LILLEY
AND P. DONALD MOSES
154.981 ACRES BOUNDARY SURVEY

PERMIT FORMS
PURSUANT TO
REGULATIONS FOR THE CONTROL AND ABATEMENT OF AIR POLLUTION

COMMONWEALTH OF VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR PERMITS
FORM 7 APPLICATION

NEW SOURCE REVIEW PERMITS
and STATE OPERATING PERMITS

Return to "What Pages Do I Fill Out For My Facility?"

AIR PERMIT APPLICATION
CHECK ALL PAGES ATTACHED AND LIST ALL ATTACHED DOCUMENTS

1 Local Government Certification Form, Page 5
___ Application Fee Form, Pages 6-8
1 Document Certification Form, Page 9
1 General Information, Pages 10-11
1 Fuel Burning Equipment, Page 12
___ Stationary Internal Combustion Engines, Page 13
___ Incinerators, Page 14
___ Processing, Page 15
___ Inks, Coatings, Stains, and Adhesives, Page 16
1 VOC/Petroleum Storage Tanks, Pages 17-18
___ Loading Rack and Oil-Water Separators, Page 19
___ Fumigation Operations, Page 20
1 Air Pollution Control and Monitoring Equipment, Page 21
1 Air Pollution Control/Supplemental Information, Page 22
1 Stack Parameters and Fuel Data, Page 23
1 Proposed Permit Limits for Criteria Pollutants, Page 24
1 Proposed Permit Limits for Toxic Pollutants/HAPs, Page 25
___ Proposed Permit Limits for Other Reg. Pollutants, Page 26
___ Proposed Permit Limits for GHGs on Mass Basis, Page 27
___ Proposed Permit Limits for GHGs on CO_2e Basis, Page 28
___ BAE for Criteria Pollutants, Page 29
___ BAE for GHGs on Mass Basis, Page 30
___ BAE for GHGs on CO_2e Basis, Page 31
1 Operating Periods, Page 32

___ ATTACHED DOCUMENTS:
1 Map of Site Location
1 Facility Site Plan
___ Process Flow Diagram/Schematic
___ MSDS or CPDS Sheets
1 Estimated Emission Calculations
___ Stack Tests
1 Air Modeling Data
___ Confidential Information (see Instructions)
1 BACT Analysis
1 Permit application narrative
1 Equipment vendor specifications
___ ___

Check added form sheets above; also indicate the number of copies of each form in blank provided.

DOCUMENT CERTIFICATION FORM

I certify under penalty of law that this document and all attachments [as noted above] were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering and evaluating the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

I certify that I understand that the existence of a permit under [Article 6 of the Regulations] does not shield the source from potential enforcement of any regulation of the board governing the major NSR program and does not relieve the source of the responsibility to comply with any applicable provision of the major NSR regulations.

SIGNATURE:		DATE:	6-2-2020
NAME:	Jack Mackin	REGISTRATION NO:	
TITLE:	VP of Operations	COMPANY:	Mountain Valley Pipeline, LLC
PHONE:	412-670-0726	ADDRESS:	2200 Energy Drive
EMAIL:	jmackin@equitransmidstream.com		Canonsburg, PA 15317

References: Virginia Regulations for the Control and Abatement of Air Pollution (Regulations), 9VAC5-20-230B and 9VAC5-80-1140E.

Return to **[“What Pages Do I Fill Out For My Facility?”]**

GENERAL INFORMATION

Person Completing Form: Christina Akly		Date: 6/1/2020	Registration Number:
Company and Division Name: Mountain Valley Pipeline, LLC			FIN:
Mailing Address: 625 Liberty Ave, Suite 1700, Pittsburgh, PA 15222			
Exact Source Location – Include Name of City (County) and Full Street Address or Directions: Chatham, Pittsylvania County, Virginia (See Figures 1-1 and 2-1 of Application)			
Telephone Number:	No. of Employees:		Property Area at Site: 3.8 acres
Person to Contact on Air Pollution Matters – Name and Title: Christina Akly Project Manager		Phone Number: 561-691-7065 Fax: Email: Christina.Akly@nee.com	
Latitude and Longitude Coordinates **OR** UTM Coordinates of Facility: 647,900 meters East, 4,076,900 meter North (UTM – NAD83, Zone 17)			

Reason(s) for Submission (Check all that apply):

☐ State Operating Permit — This permit is applied for pursuant to provisions of the Virginia Administrative Code, 9 VAC 5 Chapter 80, Article 5 (SOP)

☒ New Source

☐ Modification of a Source

☐ Relocation of a Source

This permit is applied for pursuant to the following provisions of the Virginia Administrative Code:
- ☒ 9 VAC 5 Chapter 80, Article 6 (Minor Sources)
- ☐ 9 VAC 5 Chapter 80, Article 8 (PSD Major Sources)
- ☐ 9 VAC 5 Chapter 80, Article 9 (Non-Attainment Major Sources)

☐ Amendment to a Permit Dated: ________ Permit Type: ☐ SOP (Art. 5) ☐ NSR (Art. 6, 8, 9)

Amendment Type:
- ☐ Administrative Amendment
- ☐ Minor Amendment
- ☐ Significant Amendment

This amendment is requested pursuant to the provisions of:

☐ 9 VAC 5-80-970 (Art. 5 Adm.)	☐ 9 VAC 5-80-1935 (Art. 8 Adm.)
☐ 9 VAC 5-80-980 (Art. 5 Minor)	☐ 9 VAC 5-80-1945 (Art. 8 Minor)
☐ 9 VAC 5-80-990 (Art. 5 Sig.)	☐ 9 VAC 5-80-1955 (Art. 8 Sig.)
☐ 9 VAC 5-80-1270 (Art. 6 Adm.)	☐ 9 VAC 5-80-2210 (Art. 9 Adm.)
☐ 9 VAC 5-80-1280 (Art. 6 Minor)	☐ 9 VAC 5-80-2220 (Art. 9 Minor)
☐ 9 VAC 5-80-1290 (Art. 6 Sig.)	☐ 9 VAC 5-80-2230 (Art. 9 Sig.)

☐ Other (specify): ________

Explanation of Permit Request (attach documents if needed):

Mountain Valley Pipeline, LLC (“Mountain Valley”) is proposing to construct and operate the MVP Southgate Project (“Project”). The Project will be located in Pittsylvania County, Virginia and Rockingham and Alamance counties, North Carolina. Mountain Valley proposes to construct approximately 75 miles of 24- and 16-inch diameter natural gas pipeline. In addition to the pipeline, Mountain Valley proposes to construct and operate a new compressor station (Lambert Compressor Station) near the beginning of the pipeline at milepost 0.0.
The proposed Project involves the installation of new emission units and will be considered a minor source with respect to New Source Review (NSR) permitting requirements at 9 VAC 5-80-1100 and Title V major source permitting requirements at 9 VAC-5-80-50.
See Application Narrative for Additional Details.

Return to "What Pages Do I Fill Out For My Facility?"

FUEL BURNING EQUIPMENT: (Boilers, Turbines, Kilns, and Other External Combustion Units)

Company Name: Mountain Valley Pipeline, LLC	Date: 6/1/2020	Registration Number:

Unit Ref. No.	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Max. Rated Input Heat Capacity For Each Fuel (Million Btu/hr)	Type of Fuel	Type of Equip. (use Code A)	Usage (use Code B)	Requested Throughput* (hrs/yr OR fuel/yr)	Federal Regulations that Apply
CT-01	Solar, Mars 100		Q1-2021	136.0	Natural Gas	19	8	8760 hrs/yr	NSPS subpart KKKK NSPS subpart OOOOa 40 CFR part 98
CT-02	Solar, Taurus 70		Q1-2021	92.63	Natural Gas	19	8	8760 hrs/yr	NSPS subpart KKKK NSPS subpart OOOOa 40 CFR part 98
MT-01	Capstone Microturbine, C200		Q1-2021	2.28	Natural Gas	19	6	8760 hrs/yr	40 CFR part 98
MT-02	Capstone Microturbine, C200		Q1-2021	2.28	Natural Gas	19	6	8760 hrs/yr	40 CFR part 98
MT-03	Capstone Microturbine, C200		Q1-2021	2.28	Natural Gas	19	6	8760 hrs/yr	40 CFR part 98
MT-04	Capstone Microturbine, C200		Q1-2021	2.28	Natural Gas	19	6	8760 hrs/yr	40 CFR part 98
MT-05	Capstone Microturbine, C200		Q1-2021	2.28	Natural Gas	19	6	8760 hrs/yr	40 CFR part 98
HT-01	Gas Heater, TBD		Q1-2021	0.77	Natural Gas	12	4	8760 hrs/yr	40 CFR part 98

[X] Estimated Emission Calculations Attached (include references of emission factors) and/or Stack Test Results if Available

Code A – Equipment

BOILER TYPE:
1. Pulverized Coal - Wet Bottom
2. Pulverized Coal - Dry Bottom
3. Pulverized Coal - Cyclone Furnace
4. Circulating Fluidized Bed
5. Spreader Stoke
6. Chain or Travelling Grate Stoker
7. Underfeed Stoker
8. Hand Fired Coal
9. Oil, Tangentially Fired
10. Oil, Horizontally Fired (except rotary cup)
11. Gas, Tangentially Fired
12. Gas, Horizontally Fired
13. Wood with Flyash Reinjection
14. Wood without Flyash Reinjection
15. Other (specify) ________________________

OTHER COMBUSTION UNITS:
16. Oven / Kiln
17. Rotary Kiln
18. Process Furnace
19. Other (specify) _Turbine_________________

Code B - Usage

1. Steam Production
2. Drying / Curing
3. Space Heating
4. Process Heat
5. Food Processing
6. Electrical Generation
7. Mechanical Work
8. Other (specify) ___Gas Compression__________

***Pick only one option for a requested throughput.**
NOTE: Dryers, kilns, and furnaces also have to fill out Page 15.

. Return to “What Pages Do I Fill Out For My Facility?”

VOLATILE ORGANIC COMPOUND (VOC)/PETROLEUM LIQUID STORAGE TANKS:

Company Name: Mountain Valley Pipeline, LLC	**Date:** 6/1/2020	**Registration Number:**

Unit Ref. No.	Tank Type (use Code H)	Source of Tank Contents (use Code I)	Date of Manuf.	Date of Const.	Material Stored - Name and CAS # (include Reid Vapor Pressure for Gasoline)	Max. True Vapor Pressure (psia)	Density* (lbs/gal)	Max. Average Storage Temp. (°F)	Tank Diameter (feet)	Tank Capacity (gal)	Requested Throughput (gal/yr)	Federal Regulations that Apply
TK-01	1a	5		Q1-2021	Condensate Liquids	10.6	Varies	Ambient	10	10,000	126,000	None
TK-02	1a	5		Q1-2021	Condensate Liquids	10.6	Varies	Ambient	10	10,000	126,000	None

[X] Estimated Emission Calculations Attached (include TANKS Program printouts)

Code H – Tank Type		Code I – Source of Tank Contents
1. Fixed Roof a. Vertical Tank b. Horizontal Tank 2. Floating Roof a. Internal (welded deck) b. Internal (bolted deck) – Specify Panel or Sheet c. External (welded deck) d. External (riveted deck)	3. Variable Vapor Space 4. Pressure Tank (over 15 psig) 5. Underground Splash Loading 6. Underground Submerged Loading 7. Underground Submerged Loading, Balanced 8. Other:______________________	1. Pipeline 2. Rail Car 3. Tank Truck 4. Ship or Barge 5. Process

*** Specify the ASTM temperature standard at which the density was measured.**

Return to “What Pages Do I Fill Out For My Facility?”

VOLATILE ORGANIC COMPOUND (VOC)/PETROLEUM LIQUID STORAGE TANKS (CONTINUED):

Company Name: Mountain Valley Pipeline, LLC	Date: 6/1/2020	Registration Number:

Unit Ref. No.	Tank Color		Fixed Roof Only					Floating Roof Only				
					External Fixed Roof					Internal Floating Roof		
											If no,	
	Shell	Roof	Internal Tank Height or Length (feet)	Max. Hourly Filling (gallons)	Type of Roof (cone or dome)	Cone height (ft) and slope (ft/ft)	Dome height (ft) and radius (ft)	Seal Type (use Code J)	Max. Hourly Withdrawal (gallons)	Self Supporting?	No. of Columns	Column Diameter (ft)
TK-01	Light Gray	Light Gray	15.5									
TK-02	Light Gray	Light Gray	15.5									

Code J – Seal Type (Pontoon External Only)

1. Mechanical Shoe
   a. Primary only
   b. Shoe mounted secondary
   c. Rim mounted secondary
2. Liquid Mounted
   a. Primary only
   b. Weather shield secondary
   c. Rim mounted secondary
3. Vapor Mounted
   a. Primary only
   b. Weather shield secondary
   c. Rim mounted secondary

(Double Deck External Only)

4. Mechanical Shoe
   a. Primary only
   b. Shoe mounted secondary
   c. Rim mounted secondary
5. Liquid Mounted
   a. Primary only
   b. Weather shield secondary
   c. Rim mounted secondary
6. Vapor Mounted
   a. Primary only
   b. Weather shield secondary
   c. Rim mounted secondary

(Internal Only)

7. Mechanical Shoe
   a. Primary only
   b. Shoe mounted secondary
   c. Rim mounted secondary
8. Liquid Mounted
   a. Primary only
   b. Rim mounted secondary
9. Vapor Mounted
   a. Primary only
   b. Rim mounted secondary

Return to “What Pages Do I Fill Out For My Facility?”

AIR POLLUTION CONTROL AND MONITORING EQUIPMENT:

Company Name: Mountain Valley Pipeline	Date: 6/1/2020	Registration Number:

Unit Ref. No.	Vent/ Stack No.	Device Ref. No.	Pollutant/Parameter	Air Pollution Control Equipment			Monitoring Instrumentation
				Manufacturer and Model No.	Type (use Code N)	Percent Efficiency (%)	Specify Type, Measured Pollutant, and Recorder Used
CT-01	CT-01		NOx		16	70	
CT-01	CT-01		CO, VOCs		21	92, 90	
CT-02	CT-02		NOx		16	70	
CT-02	CT-02		CO, VOCs		21	92, 90	

☐ Manufacturer Specifications Included

Code N – Type of Air Pollution Control Equipment

1. Settling Chamber
2. Cyclone
3. Multicyclone
4. Cyclone scrubber
5. Orifice scrubber
6. Mechanical scrubber
7. Venturi scrubber
   a. Fixed throat
   b. Variable throat
8. Mist eliminator
9. Filter
   a. Baghouse
   b. Other:____________________
10. Electrostatic Precipitator
   a. Hot side
   b. Cold side
   c. High voltage
   d. Low voltage
   e. Single stage
   f. Two stage
   g. Other:____________________
11. Catalytic Afterburner
12. Direct Flame Afterburner
13. Diesel Oxidation Catalyst (DOC)
14. Thermal Oxidizer
15. Regenerative Thermal Oxidizer (RTO)
16. Selective Catalytic Reduction (SCR)
17. Selective Non-Catalytic Reduction (SNCR)
18. Absorber
   a. Packed tower
   b. Spray tower
   c. Tray tower
   d. Venturi
   e. Other:____________________
19. Adsorber
   a. Activated carbon
   b. Molecular sieve
   c. Activated alumina
   d. Silica gel
   e. Other:____________________
20. Condenser (specify)
21. Other:____Oxidation Catalyst_____________

Return to **“What Pages Do I Fill Out For My Facility?”**

STACK PARAMETERS AND FUEL DATA:

Company Name: Mountain Valley Pipeline, LLC	**Date:** 6/1/2020	**Registration Number:**

Unit Ref. No.	Vent/ Stack No.	Vent/Stack or Exhaust Data						Fuel(s) Data				
		Vent/Stack Config. (use Code O)	Vent/Stack Height (feet)	Exit Diameter (feet)	Exit Gas Velocity (ft/sec)	Exit Gas Flow Rate (acfm)	Exit Gas Temp. (°F)	Type of Fuel	Heating Value* (Btu/____)	Max. Rated Burned/hr (specify units)	Max. Sulfur %	Max. Ash %
CT-01	CT-01	5	50	5	98.15	115,629	902	Natural Gas	1,098	136.0	2gr/100 scf	0
CT-02	CT-02	5	50	7	78.34	180,884	866	Natural Gas	1,098	92.63	2gr/100 scf	0
MT-01	MT-01	5	12.75	1	105.6	4,975	535	Natural Gas	1,098	2.28	2gr/100 scf	0
MT-02	MT-02	5	12.75	1	105.6	4,975	535	Natural Gas	1,098	2.28	2gr/100 scf	0
MT-03	MT-03	5	12.75	1	105.6	4,975	535	Natural Gas	1,098	2.28	2gr/100 scf	0
MT-04	MT-04	5	12.75	1	105.6	4,975	535	Natural Gas	1,098	2.28	2gr/100 scf	0
MT-05	MT-05	5	12.75	1	105.6	4,975	535	Natural Gas	1,098	2.28	2gr/100 scf	0
HT-01	HT-01	6	14.8	0.670	49.0	330	460	Natural Gas	1,098	0.77	2gr/100 scf	0

Code O – Vent/Stack Configuration

1. Stack discharging downward, or nearly download
2. Equivalent stack representing a combination of multiple actual stacks
3. Gooseneck stack
4. Stack discharging in a horizontal direction
5. Stack with an unobstructed opening discharge in a vertical direction
6. Vertical stack with a weather cap or similar obstruction in exhaust system

*** Specify units for each heating value in Btus per unit of fuel.**

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PROPOSED PERMIT LIMITS FOR CRITERIA POLLUTANTS:

Company Name: Mountain Valley Pipeline, LLC	**Date:** 6/1/2020	**Registration Number:**

Unit Ref. No.	Proposed Permit Limits for Criteria Pollutants															
	PM [a] (Particulate Matter)		PM-10 [a,b] (10 µM or smaller particulate matter)		PM 2.5 [a,b] (2.5 µM or smaller particulate matter)		SO_2 (Sulfur Dioxide)		NO_X (Nitrogen Oxides)		CO (Carbon Monoxide)		VOC [a] (Volatile Organic Compounds)		Pb (Lead)	
	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
CT-01 [1]	1.36	5.95	1.36	5.95	1.36	5.95	0.71	3.09	1.33	6.09	0.60	6.30	0.09	0.63	-	-
CT-02 [1]	0.93	4.06	0.93	4.06	0.93	4.06	0.48	2.11	0.90	4.16	0.41	5.93	0.58	0.32	-	-
MT-01	0.02	0.066	0.02	0.066	0.02	0.066	0.008	0.034	0.08	0.36	0.22	0.96	0.02	0.088	-	-
MT-02	0.02	0.066	0.02	0.066	0.02	0.066	0.008	0.034	0.08	0.36	0.22	0.96	0.02	0.088	-	-
MT-03	0.02	0.066	0.02	0.066	0.02	0.066	0.008	0.034	0.08	0.36	0.22	0.96	0.02	0.088	-	-
MT-04	0.02	0.066	0.02	0.066	0.02	0.066	0.008	0.034	0.08	0.36	0.22	0.96	0.02	0.088	-	-
MT-05	0.02	0.066	0.02	0.066	0.02	0.066	0.008	0.034	0.08	0.36	0.22	0.96	0.02	0.088	-	-
HT-01	0.005	0.023	0.005	0.023	0.005	0.023	0.004	0.017	0.07	0.31	0.06	0.26	0.004	0.017	-	-
TK-01													0.049	0.21		
TK-02													0.049	0.21		
Blowdowns														0.12	-	-
Station Fugitives														0.75	-	-
TOTAL:		10.36		10.36		10.36		5.39		12.37		17.28		3.33		

[X] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

[a] PM, PM-10, PM 2.5, and VOC should also be split up by component and reported under the Proposed Permit Limits for Toxic Pollutants/HAPs.
[b] PM-10 and PM 2.5 includes filterable and condensable.

Notes: [1] The lb/hr emissions presented are for steady state operation of the turbine. Startup, Shutdown, and extremely low temperature operation emissions are included in Appendix B. Emissions in tons per year include all operating modes. Emissions in tons per year are the CONTROLLED emissions.
[2] Total emissions include those from fugitives and natural gas blowdowns as provided in Appendix B

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PROPOSED PERMIT LIMITS FOR TOXIC POLLUTANTS/HAPS:

Company Name: Mountain Valley Pipeline, LLC									**Date:** 6/1/2020				**Registration Number:**			
Unit Ref. No.	**Proposed Permit Limits for Toxic/HAP Pollutants***															
	HAP Name: Formaldehyde **CAS #:** 50-00-0		**HAP Name:** **CAS #:**		**HAP Name:** **CAS #:**		**HAP Name:** **CAS #:**		**HAP Name:** **CAS #:**		**HAP Name:** **CAS #:**		**HAP Name:** **CAS #:**		**HAP Name:** **CAS #:**	
	lbs/hr	**tons/yr**	**lbs/hr**	**tons/yr**	**lbs/hr**	**tons/yr**	**lbs/hr**	**tons/yr**	**lbs/hr**	**tons/yr**	**lbs/hr**	**tons/yr**	**lbs/hr**	**tons/yr**	**lbs/hr**	**tons/yr**
CT-01	0.404	0.35														
CT-02	0.27	0.32														
MT-01	0.007	0.03														
MT-02	0.007	0.03														
MT-03	0.007	0.03														
MT-04	0.007	0.03														
MT-05	0.007	0.03														
HT-01	0.000057	0.00025														
TK-01	-	-														
TK-02	-	-														
TOTAL:		0.82														

[X] Estimated Emission Calculations Attached (totals and per Unit Ref. No.)

*** Specify the name of the toxic pollutant/HAP for each Unit Ref. No. along with the respective CAS Number**. Toxic Pollutant means a pollutant on the designated list in the Form 7 Instructions document. Particulate matter and volatile organic compounds are not toxic pollutants as generic classes of substances, but individual substances within these classes may be toxic pollutants because their toxic properties or because a TLV (tm) has been established.

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OPERATING PERIODS:

Company Name: Mountain Valley Pipeline, LLC	**Date:** 6/1/2020	**Registration Number:**

Unit Ref. No.	Percent Annual Use/Throughput by Season				Normal Process/Equipment Operating Schedule			Maximum Process/Equipment Operating Schedule		
	December – February	March – May	June – August	September – November	Hours per Day	Days per Week	Weeks per Year	Hours per Day	Days per Week	Weeks per Year
CT-01	25	25	25	25	24	7	52	24	7	52
CT-02	25	25	25	25	24	7	52	24	7	52
MT-01	25	25	25	25	24	7	52	24	7	52
MT-02	25	25	25	25	24	7	52	24	7	52
MT-03	25	25	25	25	24	7	52	24	7	52
MT-04	25	25	25	25	24	7	52	24	7	52
MT-05	25	25	25	25	24	7	52	24	7	52
HT-01	25	25	25	25	24	7	52	24	7	52
TK-01	25	25	25	25	24	7	52	24	7	52
TK-02	25	25	25	25	24	7	52	24	7	52

Maximum Facility Operating Schedule		
Hours per Day	**Days per Week**	**Weeks per Year**
24	**7**	**52**

APPENDIX B
Emissions Calculations and Vendor Data

MVP Southgate Project
Lambert Compressor Station
Table B-1. Total Facility Potential Emissions Summary

UNCONTROLLED Potential Emissions Summary

		Criteria Pollutants					Greenhouse Gases (GHGs)				HAPs
Proposed Sources	Unit Reference No.	NOx	CO	VOC	SO_2	$PM/PM_{10}/PM_{2.5}$	CO_2	CH_4	N_2O	CO_2e	Total HAPs
		(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Solar Mars 100	CT-01	19.58	36.26	3.99	3.09	5.95	69,632	1.31	0.13	69,704	2.54
Solar Taurus 70	CT-02	13.35	26.34	3.23	2.11	4.06	47,355	0.89	0.09	47,404	1.65
Capstone C200 Microturbines (5 Units)	MT-01 to MT-05	1.81	4.79	0.44	0.17	0.33	5,841.0	0.11	0.011	5,847	0.21
Fuel Gas Heater	HT-01	0.31	0.26	0.02	0.018	0.02	394.5	0.01	0.001	395	0.01
Produced Fluids Tanks	TK-01, TK-02	-	-	0.43	-	-	-	-	-	4.2	0.004
Blowdowns	BDE	-	-	0.54	-	-	0.26	50.13	-	1,254	0.05
Station Fugitives	FUG	-	-	0.75	-	-	0.36	69.59	-	1,740	0.07
Totals (tons/year)		**35.04**	**67.65**	**9.40**	**5.39**	**10.36**	**123,224**	**122.04**	**0.23**	**126,349**	**4.53**

Turbine Control Efficiencies

Control Technology	NOx	CO	VOC
Selective Catalytic Reduction	70%	-	-
Oxidation Catalyst	-	92%	90%

CONTROLLED Potential Emissions Summary

		Criteria Pollutants					Greenhouse Gases (GHGs)				HAPs
Proposed Sources	Unit Reference No.	NOx	CO	VOC	SO_2	$PM/PM_{10}/PM_{2.5}$	CO_2	CH_4	N_2O	CO_2e	Total HAPs
		(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Solar Mars 100	CT-01	6.09	6.30	0.63	3.09	5.95	69,632	1.31	0.13	69,704	0.42
Solar Taurus 70	CT-02	4.16	5.93	0.94	2.11	4.06	47,355	0.89	0.09	47,404	0.36
Capstone C200 Microturbines (5 Units)	MT-01 to MT-05	1.81	4.79	0.44	0.17	0.33	5,841	0.11	0.011	5,847	0.21
Fuel Gas Heater	HT-01	0.31	0.26	0.02	0.02	0.02	395	0.01	0.001	395	0.01
Produced Fluids Tanks	TK-01, TK-02	-	-	0.43	-	-	-	-	-	4.2	0.004
Blowdowns	BDE	-	-	0.12	-	-	0.06	11.29	-	282.2	0.011
Station Fugitives	FUG	-	-	0.75	-	-	0.36	69.59	-	1,740	0.07
Totals (tons/year)		**12.37**	**17.28**	**3.33**	**5.39**	**10.36**	**123,224**	**83.20**	**0.23**	**125,377**	**1.09**

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Lambert Compressor Station
Table B-2. Solar Mars 100 Potential to Emit (Uncontrolled)

UNCONTROLLED Solar Mars 100 Potential to Emit (9 ppm NOx | 25 ppm CO | 25 ppm UHC | 5 ppm VOC)

Operations	Normal Ambient Temperatures (>0 degrees F)		Startup[1,2]		Shutdown[1,2]		Potential to Emit Including Startup/Shutdown during Normal Temperature Operation	Low Ambient Temperatures (<0 degrees F)		Maximum Annual Potential to Emit (Includes Startup, Shutdown, and Low Temperature Operation)
Maximum Annual Combined Event Frequency	8,760 hrs/yr		52 Events/Yr (10 Minute Event Duration)		52 Events/Year (10 Minute Event Duration)		8,742.7 hrs/yr Normal 17.3 hrs/yr SU/SD	24 hrs/yr		8,718.7 hrs/yr Normal 17.3 hrs/yr SU/SD 24 hrs/yr Low Temp.
Pollutant	Hourly (lb/hr)	Maximum Annual (tpy)	Event (lb/event)	Maximum Annual (tpy)	Event (lb/event)	Maximum Annual (tpy)	Maximum Annual (tpy)	Hourly (lb/hr)	Maximum Annual (tpy)	**Maximum Annual (tpy)**
NO_X	4.42	19.36	1.00	0.03	1.00	0.03	19.37	21.28	0.26	**19.58**
CO	7.47	32.72	46.00	1.20	82.00	2.13	35.98	30.84	0.37	**36.26**
SO_2	0.71	3.10	0.02	0.00045	0.03	0.0008	3.09	0.73	0.01	**3.09**
$PM/PM_{10}/PM_{2.5}$	1.36	5.96	0.03	0.00086	0.06	0.0015	5.95	1.40	0.02	**5.95**
TOC (Total)	4.28	18.75	20.00	0.52	26.00	0.68	19.91	8.84	0.11	**19.96**
VOC (Total)	0.86	3.75	4.00	0.10	5.00	0.13	3.98	1.77	0.02	**3.99**
CO_2e	15,913	69,698	385.4	10.02	676.7	17.59	69,588	16,415	196.98	**69,704**
CO_2	15,896	69,626	385	10.01	676	17.58	69,516	16,398	196.78	**69,632**
N_2O	0.03	0.13	0.001	0.00002	0.001	0.000033	0.13	0.03	0.00	**0.13**
CH_4	0.30	1.31	0.01	0.00019	0.0127	0.00033	1.31	0.31	0.00	**1.31**

Notes:
(1) Start-up emissions of NOx, CO, VOC, and CO_2 based on Solar Turbines Incorporated PIL 170: Emission Estimates at Start-up, Shutdown, and Commissioning for SoLoNOx Combustion Products
(2) Emissions of SO_2, PM, N_2O, and CH_4 based on Solar estimated heat input during startup and shutdown events.
(3) NOx, CO and VOC emission factors used for "Normal Ambient Temperatures" conditions conservatively use the factors at 20°F and 100% load.
(4) The maximum annual potential to emit includes the combination of operating modes that results in the highest annual emissions total.

MVP Southgate Project
Lambert Compressor Station
Table B-2. Solar Mars 100 Potential to Emit (Uncontrolled)

CONTROLLED Solar Mars 100 Potential to Emit

Operations	Normal Ambient Temperatures (>0 degrees F)[1]		Startup[2]		Shutdown[2]		Potential to Emit Including Startup/Shutdown during Normal Temperature Operation	Low Ambient Temperatures[2] (<0 degrees F)		Maximum Annual Potential to Emit (Includes Startup, Shutdown, and Low Temperature Operation)[3]
Maximum Annual Combined Event Frequency	8,760 hrs/yr		52 Events/Yr (10 Minute Event Duration)		52 Events/Year (10 Minute Event Duration)		8,742.7 hrs/yr Normal 17.3 hrs/yr SU/SD	24 hrs/yr		8,718.7 hrs/yr Normal 17.3 hrs/yr SU/SD 24 hrs/yr Low Temp.
Pollutant	Hourly (lb/hr)	Maximum Annual (tpy)	Event (lb/event)	Maximum Annual (tpy)	Event (lb/event)	Maximum Annual (tpy)	Maximum Annual (tpy)	Hourly (lb/hr)	Maximum Annual (tpy)	**Maximum Annual (tpy)**
NO_X	1.33	5.81	1.00	0.03	1.00	0.03	5.85	21.28	0.26	**6.09**
CO	0.60	2.62	46.00	1.20	82.00	2.13	5.94	30.84	0.37	**6.30**
SO_2	0.71	3.10	0.02	0.00045	0.03	0.0008	3.09	0.73	0.01	**3.09**
$PM/PM_{10}/PM_{2.5}$	1.36	5.96	0.03	0.00086	0.06	0.0015	5.95	1.40	0.02	**5.95**
TOC (Total)	0.43	1.87	20.00	0.52	26.00	0.68	3.07	8.84	0.11	**3.17**
VOC (Total)	0.09	0.37	4.00	0.10	5.00	0.13	0.61	1.77	0.02	**0.63**
CO_2e	15,913	69,698	385.40	10.02	676.70	17.59	69,588	16414.94	196.98	**69,704**
CO_2	15,896	69,626	385.00	10.01	676.00	17.58	69,516	16397.99	196.78	**69,632**
N_2O	0.03	0.13	0.00	0.00002	0.0013	0.000033	0.13	0.03	0.00	**0.13**
CH_4	0.30	1.31	0.01	0.00019	0.0127	0.00033	1.31	0.31	0.00	**1.31**

Notes:
(1) Normal ambient temperature emissions of NOx assume 70% reduction due to SCR. CO and VOC emissions assume 92% and 90% reduction, respectively, due to oxidation catalyst.
(2) Emissions from startup, shutdown and low ambient temperatures assumed to be the same as uncontrolled emissions since the SCR and oxidation catalyst control are not effective on those conditions.
(3) The maximum annual potential to emit includes the combination of operating modes that results in the highest annual emissions total.

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Table B-3. Solar Mars 100 Specifications

Fuel	Natural Gas																				
Load (%)	50	50	50	50	50	50	50	75	75	75	75	75	75	75	100	100	100	100	100	100	100
Hp Output (Net)	8,305	8,305	8,051	7,721	7,295	6,777	6,201	12,458	12,458	12,077	11,581	10,944	10,165	9,302	16,610	16,610	16,600	15,441	14,591	13,554	12,402
Ambient Temperature (F)	below 0	0	20	40	60	80	100	below 0	0	20	40	60	80	100	below 0	0	20	40	60	80	100
% RH	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Elevation ft	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660
Heat Rate (Btu/HP hr)		9,044	11,837	11,823	11,952	12,166	12,560		9,308	9,245	9,247	9,310	9,458	9,703		7,622	7,622	7,662	7,760	7,927	8,182
Thermal Efficiency (%)		28	21	22	21	21	20		27	28	28	27	27	26		33	33	33	33	32	31
Fuel Flow (lbm/hr)		3,569	4,528	4,337	4,143	3,918	3,701		5,510	5,305	5,088	4,841	4,568	4,289		6,016	5,832	5,621	5,380	5,105	4,822
Fuel Flow (scfm)		1,264	1,604	1,536	1,468	1,388	1,311		1,952	1,879	1,802	1,715	1,618	1,519		2,131	2,066	1,991	1,906	1,808	1,708
Lower Heating Value (Btu/lbm)		21,046	21,046	21,046	21,046	21,046	21,046		21,046	21,046	21,046	21,046	21,046	21,046		21,046	21,046	21,046	21,046	21,046	21,046
Fuel LHV (Btu/scf)	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990	990.00	990	990	990.00	990.00	990.00	990.00	990.00	990.00	990.00
Heat Input LHV (MMBtu/hr) by volume	75.11	75.11	95.30	91.28	87.19	82.46	77.89	115.96	115.96	111.65	107.08	101.88	96.14	90.27	126.61	126.61	122.74	118.30	113.23	107.44	101.48
Heat Input HHV (MMBtu/hr) (=LHV*1.108)	83.23	83.23	105.59	101.13	96.61	91.36	86.30	128.49	128.49	123.71	118.65	112.89	106.52	100.02	140.29	140.29	136.00	131.08	125.46	119.04	112.44
Exhaust Flow (scfm)		64,120	65,737	62,417	59,369	55,888	52,600		76,600	73,605	70,405	66,842	63,059	59,317		79,181	77,279	74,987	72,166	68,955	65,275
Exhaust ACFM	140,400	140,400	175,186	169,751	165,067	158,653	152,332	200,787	200,787	195,111	188,748	181,418	173,741	166,640	206,842	206,842	203,900	199,950	194,779	188,305	180,884
Exhaust lb/hr	291,039	291,039	297,636	282,280	267,924	251,221	234,808	346,744	346,744	333,012	318,193	301,454	283,287	264,651	358,089	358,089	349,342	338,653	325,257	309,606	291,079
MW of Exhaust gas		28.7	28.6	28.6	28.6	28.4	28.2		28.6	28.6	29	28.53	28.42	28.22		28.6	28.6	28.6	28.5	28.4	28.2
Air to Fuel Ratio		85.0	68.3	67.6	67.2	66.6	65.9		63.8	63.7	63	63.13	62.86	62.56		58.7	59.1	59.4	59.6	59.8	59.5
Exhaust Temperature (F)	651	651	893	920	951	981	1010	871	871	886	901	918	938	966	866	866	879	893	910	926	947
Exhaust Temperature (K)	617.0	617.0	751.5	766.5	783.7	800.4	816.5	739.3	739.3	747.6	755.9	765.4	776.5	792.0	736.5	736.5	743.7	751.5	760.9	769.8	781.5
Stack Height (ft)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Stack Height (m)	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24
Stack Equiv Diameter (ft)	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
Stack Exhaust Velocity (m/s)	18.53	18.53	23.12	22.41	21.79	20.94	20.11	26.50	26.50	25.75	24.91	23.95	22.93	22.00	27.30	27.30	26.92	26.39	25.71	24.86	23.88
Exhaust M.W.	28.55	28.55	28.54	28.51	28.47	28.37	28.29	28.55	28.55	28.54	28.51	28.47	28.37	28.29	28.55	28.55	28.54	28.51	28.47	28.37	28.29
NO_X ppm@ 15% O_2	42	9	9	9	9	9	9	42	9	9	9	9	9	9	42	9	9	9	9	9	9
NO_X lb/hr	11.947	2.560	3.260	3.110	2.960	2.780	2.600	18.947	4.060	3.930	3.740	3.550	3.330	3.090	21.280	4.560	**4.420**	4.250	4.050	3.820	3.560
NO_X g/s	1.505	0.323	0.411	0.392	0.373	0.350	0.328	2.387	0.512	0.495	0.471	0.447	0.420	0.389	2.681	0.575	0.557	0.536	0.510	0.481	0.449
CO ppm@ 15% O_2	100	25	25	25	25	25	25	100	25	25	25	25	25	25	100	25	25	25	25	25	25
CO lb/hr	17.320	4.330	5.510	5.270	5.010	4.710	4.400	27.480	6.870	6.610	6.330	6.000	5.620	5.220	30.840	7.710	**7.470**	7.190	6.850	6.460	6.030
CO g/s	2.182	0.546	0.694	0.664	0.631	0.593	0.554	3.462	0.866	0.833	0.798	0.756	0.708	0.658	3.886	0.971	0.941	0.906	0.863	0.814	0.760
UHC ppm@ 15% O_2	50	25	25	25	25	25	25	50	25	25	25	25	25	25	50	25	25	25	25	25	25
UHC lb/hr	4.960	2.480	3.150	3.020	2.870	2.700	2.520	7.860	3.930	3.790	3.620	3.440	3.220	2.990	8.840	4.420	**4.280**	4.120	3.930	3.700	3.450
VOC ppm@ 15% O_2 (20% of UHC)	10	5	5	5	5	5	5	10	5	5	5	5	5	5	10	5	5	5	5	5	5
VOC lb/hr	0.992	0.496	0.630	0.604	0.574	0.540	0.504	1.572	0.786	0.758	0.724	0.688	0.644	0.598	1.768	0.884	**0.856**	0.824	0.786	0.740	0.690
VOC lb/MMBtu	0.0119	0.0060	0.0060	0.0060	0.0059	0.0059	0.0058	0.0122	0.0061	0.0061	0.0061	0.0061	0.0060	0.0060	0.0126	0.0063	0.0063	0.0063	0.0063	0.0062	0.0061
sulfur gr/100 scf	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
SO2 lb/hr	0.433	0.433	0.549	0.526	0.502	0.475	0.449	0.668	0.668	0.643	0.617	0.587	0.554	0.520	0.729	0.729	**0.707**	0.682	0.652	0.619	0.585
SO2 g/s	0.055	0.055	0.069	0.066	0.063	0.060	0.057	0.084	0.084	0.081	0.078	0.074	0.070	0.066	0.092	0.092	0.089	0.086	0.082	0.078	0.074
Particulates lb/MMBtu (HHV)	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
$PM_{10/2.5}$ lb/hr	0.83	0.83	1.06	1.01	0.97	0.91	0.86	1.28	1.28	1.24	1.19	1.13	1.07	1.00	1.40	1.40	**1.36**	1.31	1.25	1.19	1.12
$PM_{10/2.5}$ g/s	0.105	0.105	0.133	0.127	0.122	0.115	0.109	0.162	0.162	0.156	0.149	0.142	0.134	0.126	0.177	0.177	0.171	0.165	0.158	0.150	0.142
CO2 lb/mmBtu	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117
CO_2 lb/hr	9,728	9,728	12,342	11,821	11,293	10,679	10,088	15,019	15,019	14,460	13,869	13,195	12,451	11,691	16,398	16,398	**15,896**	15,321	14,664	13,915	13,143
CH_4 lb/MMBtu	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022
CH_4 lb/hr	0.1835	0.1835	0.2328	0.2230	0.2130	0.2014	0.1903	0.2833	0.2833	0.2727	0.2616	0.2489	0.2348	0.2205	0.3093	0.3093	**0.2998**	0.2890	0.2766	0.2624	0.2479
N_2O lb/mmBtu	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
N_2O lb/hr	0.0183	0.0183	0.0233	0.0223	0.0213	0.0201	0.0190	0.0283	0.0283	0.0273	0.0262	0.0249	0.0235	0.0220	0.0309	0.0309	**0.0300**	0.0289	0.0277	0.0262	0.0248
CO_2e lb/mmBtu	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CO_2e lb/hr	9,738	9,738	12,355	11,834	11,304	10,690	10,098	15,034	15,034	14,475	13,883	13,209	12,464	11,703	16,415	16,415	**15,913**	15,337	14,680	13,929	13,157

Notes
1. Data provided by Solar for 100%, 75%, and 50% load cases: net output power, fuel flow (MMBtu/hr, LHV), exhaust flow (lb/hr), exhaust temperature, NO X/CO/UHC concentrations and lb/hr.
2. Below zero and low load operation uses 0ºF for operating parameters and uses concentrations from Solar PIL 167. Data for Particulate Matter based upon Solar PIL 171.
3. Greenhouse gases are calculated using emission factors from Part 98, Tables C-1 and C-2 and global warming potentials from Table A-1 (CO_2 = 1, CH_4 = 25, N_2O = 298).
4. VOC as 20% of UHC based on Solar PIL 168 for natural gas.

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Table B-4. Solar Taurus 70 Potential to Emit

UNCONTROLLED Solar Taurus 70 Potential to Emit (9 ppm NOx | 25 ppm CO | 25 ppm UHC | 5 ppm VOC)

Operations	**Normal Ambient Temperatures (>0 degrees F)**		**Startup[1,2]**		**Shutdown[1,2]**		**Potential to Emit Including Startup/Shutdown during Normal Temperature Operation**	**Low Ambient Temperatures (<0 degrees F)**		**Maximum Annual Potential to Emit (Includes Startup, Shutdown, and Low Temperature Operation)**
Maximum Annual Combined Event Frequency	8,760 hrs/yr		52 Events/Yr (10 Minute Event Duration)		52 Events/Year (10 Minute Event Duration)		8,742.7 hrs/yr Normal 17.3 hrs/yr SUSD	24 hrs/yr		8,718.7 hrs/yr Normal 17.3 hrs/yr SU/SD 24 hrs/yr Low Temp.
Pollutant	Hourly (lb/hr)	Maximum Annual (tpy)	Event (lb/event)	Maximum Annual (tpy)	Event (lb/event)	Maximum Annual (tpy)	Maximum Annual (tpy)	Hourly (lb/hr)	Maximum Annual (tpy)	**Maximum Annual (tpy)**
NO_X	3.01	13.18	1.00	0.03	1.00	0.03	13.21	14.42	0.17	**13.35**
CO	5.09	22.29	88.00	2.29	62.00	1.61	26.15	20.92	0.25	**26.34**
SO_2	0.48	2.11	0.08	0.00	0.08	0.0021	2.11	0.49	0.01	**2.11**
$PM/PM_{10}/PM_{2.5}$	0.93	4.06	0.15	0.00	0.15	0.0040	4.06	0.95	0.01	**4.06**
TOC (Total)	2.91	12.75	88.00	2.29	40.00	1.04	16.05	6.00	0.07	**16.09**
VOC	0.58	2.55	18.0	0.47	8.00	0.21	3.22	1.20	0.01	**3.23**
CO_2e	10,838	47,473	382.9	9.95	474.9	12.35	47,401	11,133	133.59	**47,404**
CO_2	10,827	47,424	381.0	9.91	473	12.30	47,352	11,121	133.46	**47,355**
N_2O	0.02	0.09	0.003	0.00	0.003	0.0001	0.09	0.02	0.0003	**0.09**
CH_4	0.20	0.89	0.03	0.0009	0.0340	0.0009	0.89	0.21	0.0025	**0.89**

Notes:
(1) Start-up emissions of NOx, CO, VOC, and CO_2 based on Solar Turbines Incorporated PIL 170: Emission Estimates at Start-up, Shutdown, and Commissioning for SoLoNOx Combustion Products
(2) Emissions of SO_2, PM, N_2O, and CH_4 based on Solar estimated heat input during startup and shutdown events.
(3) NOx, CO and VOC emission factors used for "Normal Ambient Temperatures" conditions conservatively use the factors at 20°F and 100% load.
(4) The maximum annual potential to emit includes the combination of operating modes that results in the highest annual emissions total.

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Table B-4. Solar Taurus 70 Potential to Emit

CONTROLLED Solar Taurus 70 Potential to Emit

Operations	**Normal Ambient Temperatures (>0 degrees F)[1]**		**Startup[2]**		**Shutdown[2]**		**Potential to Emit Including Startup/Shutdown during Normal Temperature Operation**	**Low Ambient Temperatures (<0 degrees F)[2]**		**Maximum Annual Potential to Emit (Includes Startup, Shutdown, and Low Temperature Operation)[3]**
Maximum Annual Combined Event Frequency	8,760 hrs/yr		52 Events/Yr (10 Minute Event Duration)		52 Events/Year (10 Minute Event Duration)		8,742.7 hrs/yr Normal 17.3 hrs/yr SUSD	24 hrs/yr		8,718.7 hrs/yr Normal 17.3 hrs/yr SU/SD 24 hrs/yr Low Temp.
Pollutant	Hourly (lb/hr)	Maximum Annual (tpy)	Event (lb/event)	Maximum Annual (tpy)	Event (lb/event)	Maximum Annual (tpy)	Maximum Annual (tpy)	Hourly (lb/hr)	Maximum Annual (tpy)	**Maximum Annual (tpy)**
NO_X	0.90	3.96	1.00	0.03	1.00	0.03	4.00	14.42	0.17	**4.16**
CO	0.41	1.78	88.00	2.29	62.00	1.61	5.68	20.92	0.25	**5.93**
SO_2	0.48	2.11	0.08	0.00	0.08	0.0021	2.11	0.49	0.01	**2.11**
$PM/PM_{10}/PM_{2.5}$	0.93	4.06	0.15	0.00	0.15	0.0040	4.06	0.95	0.01	**4.06**
TOC (Total)	0.29	1.27	88.00	2.29	40.00	1.04	4.60	6.00	0.07	**4.67**
VOC	0.06	0.25	18.00	0.47	8.00	0.21	0.93	1.20	0.01	**0.94**
CO_2e	10,838	47,473	382.87	9.95	474.87	12.35	47,401	11,133	133.59	**47,404**
CO_2	10,827	47,424	381.00	9.91	473.00	12.30	47,352	11,121	133.46	**47,355**
N_2O	0.02	0.09	0.0034	0.00	0.0034	0.0001	0.09	0.02	0.0003	**0.09**
CH_4	0.20	0.89	0.0340	0.0009	0.0340	0.0009	0.89	0.21	0.0025	**0.89**

Notes:
(1) Normal ambient temperature emissions of NOx assume 70% reduction due to SCR. CO and VOC emissions assume 92% and 90% reduction, respectively, due to oxidation catalyst.
(2) Emissions from startup, shutdown and low ambient temperatures assumed to be the same as uncontrolled emissions since the SCR and oxidation catalyst control are not effective on those conditions.
(3) The maximum annual potential to emit includes the combination of operating modes that results in the highest annual emissions total.

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Table B-5. Solar Taurus 70 Specifications

Fuel	Natural Gas																				
Load (%)	50	50	50	50	50	50	50	75	75	75	75	75	75	75	100	100	100	100	100	100	100
Hp Output (Net)	5,573	5,573	5,550	5,508	5,093	4,622	4,086	8,360	8,360	8,325	8,263	7,640	6,933	6,130	11,146	11,146	11,100	11,017	10,187	9,244	8,173
Ambient Temperature (F)	below 0	0	20	40	60	80	100	below 0	0	20	40	60	80	100	below 0	0	20	40	60	80	100
% RH	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Elevation ft	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660	660
Heat Rate (Btu/HP hr)		11,622	11,352	11,099	11,270	11,608	12,221		9,318	9,101	8,898	8,999	9,272	9,690		7,704	7,531	7,397	7,556	7,793	8,153
Thermal Efficiency (%)		22	22	23	23	22	21		27	28	29	28	27	26		33	34	34	34	33	31
Fuel LHV (Btu/scf)	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00	990.00
Heat Input LHV (MMBtu/hr)	64.77	64.77	63.01	61.14	57.40	53.65	49.94	77.90	77.90	75.77	73.52	68.75	64.28	59.39	85.87	85.87	83.60	81.49	76.97	72.04	66.64
Heat Input HHV (MMBtu/hr) (=LHV*1.108)	71.77	71.77	69.82	67.74	63.60	59.44	55.33	86.31	86.31	83.95	81.46	76.18	71.22	65.80	95.14	95.14	92.63	90.29	85.28	79.82	73.84
Exhaust lb/hr	193,899	193,899	185,303	176,843	165,252	155,537	145,137	219,596	219,596	211,062	202,671	189,406	176,175	161,789	231,872	231,872	225,381	218,823	207,302	194,515	179,095
Exhaust ACFM	115,408	115,408	112,374	109,160	104,006	99,753	95,533	131,290	131,290	127,903	124,365	118,099	112,464	106,132	137,652	137,652	134,588	131,823	127,198	121,926	115,629
Stack Height (ft)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Stack Height (m)	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24	15.24
Stack Equiv Diameter (ft)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Stack Exhaust Velocity (m/s)	29.86	29.86	29.07	28.24	26.91	25.81	24.72	33.97	33.97	33.09	32.18	30.55	29.10	27.46	35.61	35.61	34.82	34.11	32.91	31.54	29.92
Exhaust M.W.	28.64	28.64	28.62	28.59	28.53	28.47	28.29	20.62	20.62	28.60	28.57	28.51	28.40	28.20	28.59	28.59	28.58	28.55	28.49	28.38	28.19
Exhaust Temperature (F)	908	908	933	956	981	1003	1031	913	913	931	946	966	994	1024	902	902	909	920	943	967	1000
Exhaust Temperature (K)	759.8	759.8	773.7	786.5	800.4	812.6	828.2	762.6	762.6	772.6	780.9	792.0	807.6	824.3	756.5	756.5	760.4	766.5	779.3	792.6	810.9
NO_x ppm@ 15% O_2	42	9	9	9	9	9	9	42	9	9	9	9	9	9	42	9	9	9	9	9	9
NO_x lb/hr	10.360	2.220	2.150	2.090	1.950	1.810	1.670	12.740	2.730	2.650	2.570	2.390	2.220	2.030	14.420	3.090	**3.010**	2.930	2.760	2.560	2.340
NO_x g/s	1.305	0.280	0.271	0.263	0.246	0.228	0.210	1.605	0.344	0.334	0.324	0.301	0.280	0.256	1.817	0.389	0.379	0.369	0.348	0.323	0.295
CO ppm@ 15% O_2	100	25	25	25	25	25	25	100	25	25	25	25	25	25	100	25	25	25	25	25	25
CO lb/hr	15.000	3.750	3.640	3.530	3.300	3.060	2.820	18.480	4.620	4.490	4.350	4.050	3.760	3.430	20.920	5.230	**5.090**	4.950	4.660	4.330	3.960
CO g/s	1.890	0.473	0.459	0.445	0.416	0.386	0.355	2.328	0.582	0.566	0.548	0.510	0.474	0.432	2.636	0.659	0.641	0.624	0.587	0.546	0.499
UHC ppm@ 15% O_2	50	25	25	25	25	25	25	50	25	25	25	25	25	25	50	25	25	25	25	25	25
UHC lb/hr	4.300	2.150	2.090	2.020	1.890	1.760	1.610	5.280	2.640	2.570	2.490	2.320	2.150	1.970	6.000	3.000	**2.910**	2.840	2.670	2.480	2.270
VOC ppm@ 15% O_2 (20% of UHC)	10	5	5	5	5	5	5	10	5	5	5	5	5	5	10	5	5	5	5	5	5
VOC lb/hr	0.860	0.430	0.418	0.404	0.378	0.352	0.322	1.056	0.528	0.514	0.498	0.464	0.430	0.394	1.200	0.600	**0.582**	0.568	0.534	0.496	0.454
VOC lb/MMBtu	0.0120	0.0060	0.0060	0.0060	0.0059	0.0059	0.0058	0.0122	0.0061	0.0061	0.0061	0.0061	0.0060	0.0060	0.0126	0.0063	0.0063	0.0063	0.0063	0.0062	0.0061
sulfur gr/100 scf	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
SO2 lb/hr	0.373	0.373	0.363	0.352	0.331	0.309	0.288	0.449	0.449	0.437	0.424	0.396	0.370	0.342	0.495	0.495	**0.482**	0.470	0.443	0.415	0.384
SO2 g/s	0.047	0.047	0.046	0.044	0.042	0.039	0.036	0.057	0.057	0.055	0.053	0.050	0.047	0.043	0.062	0.062	0.061	0.059	0.056	0.052	0.048
Particulates lb/MMBtu	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
$PM_{10/2.5}$ lb/hr	0.72	0.72	0.70	0.68	0.64	0.59	0.55	0.86	0.86	0.84	0.81	0.76	0.71	0.66	0.95	0.95	**0.93**	0.90	0.85	0.80	0.74
$PM_{10/2.5}$ g/s	0.090	0.090	0.088	0.085	0.080	0.075	0.070	0.109	0.109	0.106	0.103	0.096	0.090	0.083	0.120	0.120	0.117	0.114	0.107	0.101	0.093
CO2 lb/mmBtu	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117
CO_2 lb/hr	8,389	8,389	8,161	7,918	7,434	6,948	6,468	10,089	10,089	9,813	9,522	8,904	8,325	7,692	11,121	11,121	**10,827**	10,554	9,969	9,330	8,631
CH_4 lb/mmBtu	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022	0.0022
CH_4 lb/hr	0.1582	0.1582	0.1539	0.1493	0.1402	0.1311	0.1220	0.1903	0.1903	0.1851	0.1796	0.1679	0.1570	0.1451	0.2098	0.2098	**0.2042**	0.1991	0.1880	0.1760	0.1628
N_2O lb/mmBtu	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
N_2O lb/hr	0.0158	0.0158	0.0154	0.0149	0.0140	0.0131	0.0122	0.0190	0.0190	0.0185	0.0180	0.0168	0.0157	0.0145	0.0210	0.0210	**0.0204**	0.0199	0.0188	0.0176	0.0163
CO_2e lb/mmBtu	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CO_2e lb/hr	8,397	8,397	8,169	7,927	7,442	6,956	6,475	10,099	10,099	9,823	9,532	8,913	8,334	7,700	11,133	11,133	**10,838**	10,565	9,979	9,340	8,640

Notes
1. Data provided by Solar for 100%, 75%, and 50% load cases: net output power, fuel flow (MMBtu/hr, LHV), exhaust flow (lb/hr), exhaust temperature, NOX/CO/UHC concentrations and lb/hr.
2. Below zero and low load operation uses 0ºF for operating parameters and uses concentrations from Solar PIL 167. Data for Particulate Matter based upon Solar PIL 171.
3. Greenhouse gases are calculated using emission factors from Part 98, Tables C-1 and C-2 and global warming potentials from Table A-1 (CO_2 = 1, CH_4 = 25, N_2O = 298).
4. VOC as 20% of UHC based on Solar PIL 168 for natural gas.

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Table B-6. Capstone Microturbine Potential Emissions Summary (C200)

Engine parameters

Power output base load	268.2	hp
Power output base load	200	kW
Heat Input Capacity (HHV)	2.28	MMBtu/hr
Maximum Annual Operation	8760	hr/yr
Number of Units	5	Units

Pollutant	Potential Emissions				
	g/bhp-hr[1]	lb/MMBtu[2]	lb/hr	PTE per Unit (tpy)	Total Annual for 5 Units[3] (tpy)
NO_x	0.14		0.08	0.36	1.81
CO	0.37		0.22	0.96	4.79
VOC	0.03		0.02	0.088	0.44
$PM/PM_{10}/PM_{2.5}$		0.0066	0.02	0.066	0.330
SO_2		0.0034	0.008	0.034	0.1698
CO_2e		117.1	267.0	1,169	5,847
CO_2		117.0	266.7	1,168	5,841
CH_4		0.0022	0.005	0.02	0.11
N_2O		0.0002	0.001	0.00	0.011

Notes:
[1] NOx, CO, VOC based on vendor data (Table 2 in vendor's Technical Reference)
[2] Emissions for $PM/PM_{10}/PM_{2.5}$ and SO_2 calculated using AP-42 emission factors (Table 3.1-2a).
Emission for GHGs based upon 40 CFR Part 98, Subpart C.
[3] Represents 5 x Capstone C200 Microturbines, each limited to 8,760 hours / year.

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Table B-7. Gas-Fired Heater Potential Emissions Summary

Heater parameters

Heat Input Capacity (HHV)	0.77	MMBtu/hr
Fuel Firing Rate	699	SCF/hr
Maximum Annual Operation	8,760	hr/yr

Pollutant	Potential Emissions		
	lb/mmscf	lb/hr	Total Annual (ton/yr)
NO_x	100	0.07	0.31
CO	84	0.06	0.26
VOC	5.5	0.004	0.017
$PM/PM_{10}/PM_{2.5}$	7.6	0.005	0.023
SO_2	5.71	0.0040	0.017
CO_2e	128,972	90.17	394.93
CO_2	128,839	90.07	394.53
CH_4	2.43	0.0017	0.01
N_2O	0.24	0.00017	0.0007

Notes:
(1) NOx, CO, VOC and PM emissions are based upon AP-42 Emission Factors, Chapter 1.4.
(2) Emissions of SO2 from based on mass balance of sulfur in fuel:

Sulfur Content =	2.0	grains/100 SCF
Higher Heating Value =	1,101	Btu/SCF
Molecular Weight of S =	32	lb/lbmol
Molecular Weight of SO_2 =	64	lb/lbmol

(3) GHG Emissions are based upon 40 CFR Part 98, Subpart C

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Table B-8. Fugitive Blowdowns Potential Emissions Summary

Natural Gas Specifications

Constituent	Mol Percent (%mol)	Molecular Weight	Lb/Lb-Mol NG	Mass Percent	VOC?	HAP?
CO_2	0.165	44.01	0.073	0.41%	No	No
Nitrogen	0.396	28.01	0.111	0.62%	No	No
Methane	87.823	16.04	14.089	79.08%	No	No
Ethane	11.303	30.07	3.399	19.08%	No	No
Oxygen	0.00	16.00	0.000	0.00%	No	No
Propane	0.28	44.10	0.123	0.69%	Yes	No
i-Butane	0.009	58.12	0.005	0.03%	Yes	No
i-Pentane	0.003	72.15	0.002	0.01%	Yes	No
N-Pentane	0.003	72.15	0.002	0.01%	Yes	No
N-Hexane	0.008	86.18	0.007	0.04%	Yes	Yes
N-Butane	0.01	58.12	0.006	0.03%	Yes	No

Notes: Based upon representative gas analyses for Project.
Hexane mass percentage increased by 100% to provide conservative HAP emissions potential. Hexane mass percent used = 0.(

Natural Gas Properties	
Molecular Weight	17.817
Specific Gravity	0.615
lb/Scf	0.047
Scf/lb	21.26
HAP Content (% mass)	0.08%
VOC Content (%mass)	0.86%

Parameter	Blowdown Events								
	Taurus 70 Shutdown	Mars 100 Shutdown	Pig Receiver	Pig Launcher	Suction Filter	Miscellaneous Filters	Emergency Station Shutdown (ESD) Test[2]	Actual Emergency Station Shutdown (ESD)[3]	Total Blowdown Emissions[4]
Uncontrolled Emissions									
Gas Blowdown (scf/event)	54,065	86,100	6,591	9,632	37,749	601	276,183	276,183	470,921
Gas Blowdown with Purge Post Blowdown (scf/event)[1]	59,472	94,710	7,250	10,595	41,524	661	303,801	303,801	518,013
Blowdowns per Year	12	12	2	2	12	12	1	1	54.0
Total Blowdown Volume Vented (scf)	713,658	1,136,520	14,500	21,190	498,287	7,933	303,801	303,801	2,695,890
VOC Emissions (lb/event)	24.0	38.2	2.9	4.3	16.7	0.3	122.4	122.4	209
CO_2 Emissions (lb/event)	11.4	18.2	1.4	2.0	8.0	0.1	58.2	58.2	99
CH_4 Emissions (lb/event)	2,211.8	3,522.3	269.6	394.0	1,544.3	24.6	11,298.5	11,298.5	19,265
CO_2e Emissions (lb/event)	55,306	88,076	6,742	9,853	38,615	615	282,521	282,521	481,728
HAP Emissions (lb/event)	2.16	3.45	0.26	0.39	1.51	0.02	11.06	11.06	18.9
VOC Emissions (tpy)	0.1438	0.2289	0.0029	0.0043	0.1004	0.0016	0.0612	0.0612	0.54
CO_2 Emissions (tpy)	0.0684	0.1089	0.0014	0.0020	0.0478	0.0008	0.0291	0.0291	0.26
CH_4 Emissions (tpy)	13.3	21.1	0.3	0.4	9.3	0.1	5.6	5.6	50.1
CO_2e Emissions (tpy)	331.8	528.5	6.7	9.9	231.7	3.7	141.3	141.3	1,254
HAP Emissions (tpy)	0.013	0.021	2.64E-04	3.86E-04	9.07E-03	1.44E-04	5.53E-03	5.53E-03	0.05
Controlled Emissions									
Control	**VGRS**	**VGRS**	**NA**	**NA**	**NA**	**NA**	**EBD Block Valve**	**NA**	
Gas Blowdown (scf/event)	1,868	3,059	6,591	9,632	37,749	601	0	276,183	59,500
Gas Blowdown with Purge Post Blowdown (scf/event)[1]	2,055	3,365	7,250	10,595	41,524	661	0	303,801	65,450
Blowdowns per Year	12	12	2	2	12	12	1	1	54
Total Blowdown Volume Vented (scf)	24,658	40,379	14,500	21,190	498,287	7,933	0	303,801	606,947
VOC Emissions (lb/event)	0.8	1.4	2.9	4.3	16.7	0.3	0.0	122.4	26
CO_2 Emissions (lb/event)	0.4	0.6	1.4	2.0	8.0	0.1	0.0	58.2	13
CH_4 Emissions (lb/event)	76.4	125.1	269.6	394.0	1,544.3	24.6	0.0	11,298.5	2,434
CO_2e Emissions (lb/event)	1,911	3,129	6,742	9,853	38,615	615	0	282,521	60,865
HAP Emissions (lb/event)	0.07	0.12	0.26	0.39	1.51	0.02	0.00	11.06	2.4
VOC Emissions (tpy)	0.0050	0.0081	0.0029	0.0043	0.1004	0.0016	0.0000	0.0612	0.12
CO_2 Emissions (tpy)	0.0024	0.0039	0.0014	0.0020	0.0478	0.0008	0.0000	0.0291	0.06
CH_4 Emissions (tpy)	0.5	0.8	0.3	0.4	9.3	0.1	0.0	5.6	11.3
CO_2e Emissions (tpy)	11.5	18.8	6.7	9.9	231.7	3.7	0.0	141.3	282.2
HAP Emissions (tpy)	0.000	0.001	0.000	0.000	0.009	0.000	0.000	0.006	0.011

Notes:

(1) All blowdown volumes take into account the gas volume that is purged after equipment or piping is blown down. This purge volume was conservatively assume to be 10% of the event total blowdown volume.

(2) Facility-wide blowdown events may occur for unplanned reasons (e.g. when an unsafe operating condition is detected). To prepare for such events, Mountain Valley Pipeline, LLC must perform ESD testing once every 2 years or so to ensure proper operation of the ESD system. An annual ESD testing event will use an emergency blowdown (EBD) valve, so no emissions will be vented during this test. Therefore, the emissions calculated for this blowdown event are shown as 0. However, uncontrolled emissions for this event are included in the total tpy emissions in Table B-1 to establish total uncontrolled emissions rate for the site.

(3) Actual emergency events are expected to be very infrequent and cannot be predicted. The emissions in the case of an actual emergency event are included under actual ESD emissions, and these were conservatively estimated to occur once a year.

(4) Total blowdown emissions in tpy include "uncontrolled" emissions from ESD test, which would normally be zero as these will be controlled by an EDB valve.

(5) The vent gas recovery system (VGRS) maintains pressurized hold when compressor shuts down to avoid unit blowdowns and venting of the natural gas contained within unit; thus decreasing emissions related to unit shutdowns.

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Table B-9. Produced Fluids Tank Potential Emissions Summary

Storage Tank Design Data

Capacity (gal)	10,080
Liquids Input Rate (gal/yr)	126,000
Number of Turnovers	12.5
Daily Input Rate (bbl/day)	8
Percent Condensate (%)	1
Condensate Throughput (bbl/day)	0.1
Number of Tanks	2
Max. Hours of Operation	8760

Pollutant	Single Tank Total Emissions (Working + Breathing + Flashing)			Combined Produced Fluids Tanks Emissions
	lbs/hr	lbs/year	tons/year	tons/year
VOC (Total)	0.049	429.2	0.21	0.43
Total HAPs	0.0005	4.0	0.002	0.004
CO_2e	0.475	4161.0	2.10	4.20

Notes:
(1) Calculations conducted using E&P Tanks 2.0

Emissions Composition from E&P Tanks 2.0 Software

Components	Total Emissions		HAP?
	lb/hr	tpy	tpy
CO_2	0	0.002	No
C1 (Methane)	0.019	0.084	No
C3	0.025	0.109	No
i-C4	0.005	0.023	No
n-C4	0.01	0.045	No
i-C5	0.003	0.014	No
n-C5	0.003	0.012	No
C6	0.001	0.003	No
C7	0.001	0.004	No
C8	0	0.001	No
C9	0	0	No
C10+	0	0	No
Benzene	0	0	Yes
Toluene	0	0	Yes
E-benzene	0	0	Yes
Xylenes	0	0	Yes
n-C6	0.00046	0.002	Yes

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Table B-10. Summary of Potential Fugitive Emissions from Equipment Leaks

Component	CH_4 Emission Factor[1,2]	CO_2 Emission Factor[1,2]	Units
Compressor Station Fugitives	135,260.0	7,813.1	lb/station-yr
Centrifugal Compressor Fugitives	467,660.0	27,013.7	lb/compressor-yr

Notes:
(1) Greenhouse Gas Emission Estimation Guidelines for Natural Gas Transmission and Storage, Volume 1 - GHG Emission Estimation Methodologies and Procedures , Interstate Natural Gas Association of America (INGAA), September 28, 2005. See Table 4.4.
(2) Based on 93.4 vol% CH_4 and 2 vol% CO_2 in natural gas, per INGAA Guideline

Natural Gas Specifications

Constituent	Mol Percent	Molecular Weight	Lb/Lb-Mol NG	Mass Percent	VOC	HAP?
CO_2	0.165	44.01	0.073	0.41%	No	No
Nitrogen	0.396	28.01	0.111	0.62%	No	No
Methane	87.823	16.04	14.089	79.08%	No	No
Ethane	11.303	30.07	3.399	19.08%	No	No
Propane	0.28	44.10	0.123	0.69%	Yes	No
i-Butane	0.009	58.12	0.005	0.03%	Yes	No
i-Pentane	0.003	72.15	0.002	0.01%	Yes	No
N-Pentane	0.003	72.15	0.002	0.01%	Yes	No
N-Hexane	0.008	86.18	0.007	***0.08%***	Yes	Yes
N-Butane	0.01	58.12	0.006	0.03%	Yes	No

Notes: Hexane mass percentage increased by 100% to provide conservative HAP emissions potential.

Natural Gas Properties	
Molecular Weight (lb/mol)	17.817
Specific Gravity	0.615
lb/Scf	0.047
Scf/lb	21.26
HAP Content (% mass)	0.08%
VOC Content (%mass)	0.86%

Fugitive Component Leak Emissions

Component Type	Estimated Component Count	Gas Leak Emission Factor		Hourly Average Gas Leak Rate	Annual Gas Leak Rate		Potential VOC Emissions	Potential HAP Emissions	CO_2 Emissions	CH_4 Emissions	CO_2e Emissions
		(scf/hr/component)	Factor Source	(scf/hr)	(scf/year)	lb/year	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
Connectors	1000	0.003	40 CFR 98, Table W-1A	3.00	26,280	1,236	0.01	0.0005	0.003	0.49	12.22
Flanges	500	0.003	40 CFR 98, Table W-1A	1.50	13,140	618	0.00	0.0002	0.001	0.24	6.11
Open-Ended Lines	0	0.061	40 CFR 98, Table W-1A	0	0	0	0	0	0	0	0
Pump Seals	0	13.300	40 CFR 98, Table W-1A	0	0	0	0	0	0	0	0
Valves	100	0.027	40 CFR 98, Table W-1A	2.70	23,652	1,112	0.00	0.0004	0.002	0.44	11.00
Other	0	0.040	40 CFR 98, Table W-1A	0	0	0	0	0	0	0	0

Notes:
1. "Other" equipment types include compressor seals, relief valves, diaphragms, drains, meters, etc
2. The component count is a preliminary estimate based on the proposed design of the station
3. VOC, HAP, CO2, and CH4 emissions are based on fractions of these pollutants in the site -specific gas analysis
4. CO2e calculated using global warming potentials from Part 98, Table A -1 (CO2 = 1, CH4 = 25)

Dry Seal Emissions

Number of Compressors	Leak Rate (scf/hr/compressor)	Annual Natural Gas Released (scf/yr)	Annual Natural Gas Released (lb/yr)	Potential VOC Emissions (tpy)	Potential HAP Emissions (tpy)	CO_2 Emissions (tpy)	CH_4 Emissions (tpy)	CO_2e Emissions (tpy)
2	210	3,679,200	173,037	0.74	0.07	0.35	68.4	1,710.7

Notes:
1. Leak rate and seal information from EPA Natural Gas Star Program (https://www.epa.gov/sites/production/files/2016-06/documents/ll_wetseals.pdf)
2. VOC, HAP, CO_2, and CH_4 emissions are based on fractions of these pollutants in the site -specific gas analysis
3. CO_2e calculated using global warming potentials from Part 98, Table A -1 (CO_2 = 1, CH_4 = 25)

Fugitive Emissions Summary

Segment	Potential VOC Emissions (tpy)	Potential HAP Emissions (tpy)	CO_2 Emissions (tpy)	CH_4 Emissions (tpy)	CO_2e Emissions (tpy)
Compressor Station Fugitives	0.01	0.001	0.01	1.2	29.3
Dry Seal Emissions	0.74	0.07	0.35	68.4	1,710.7
Total	**0.75**	**0.07**	**0.36**	**69.6**	**1,740.1**

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Table B-11. Proposed Project Potential HAP Emissions Summary

		Solar Taurus 70						Solar Mars 100						Fuel Gas Heater			Capstone Microturbines				
Hazardous Air Pollutants (HAPs)	AP-42 Emission Factor [1] lb/MMBtu	Emission Factor Basis[1] lb/MMBtu	Max Hourly lb/hr	Startup lb/event	Shutdown lb/event	Annual Potential (Uncontrolled) tons/year	Annual Potential (Controlled) tons/year	Emission Factor Basis[1] lb/MMBtu	Max Hourly lb/hr	Startup lb/event	Shutdown lb/event	Annual Potential (Uncontrolled) tons/year	Annual Potential (Controlled) tons/year	Emission Factor Basis[2] lb/MMBtu	Max Hourly lb/hr	Annual Potential tons/year	EF Basis[3] lb/MMBtu	Max Hourly lb/hr	Annual Potential tons/year	Facility PTE Uncontrolled tons/yr	Facility PTE Controlled tons/yr
VOC-HAP																					
Acetaldehyde	4.00E-05	7.24E-05	6.89E-03	3.78E-02	2.52E-02	3.17E-02	4.65E-03	1.20E-04	1.68E-02	2.52E-02	3.78E-02	7.52E-02	9.00E-03				1.68E-04	3.82E-04	8.37E-03	1.15E-01	2.20E-02
Acrolein	6.40E-06	1.16E-05	1.10E-03	6.05E-03	4.03E-03	5.08E-03	7.44E-04	1.92E-05	2.69E-03	4.03E-03	6.05E-03	1.20E-02	1.44E-03				2.68E-05	6.11E-05	1.34E-03	1.85E-02	3.52E-03
Benzene	1.20E-05	2.17E-05	2.07E-03	1.13E-02	7.56E-03	9.52E-03	1.39E-03	3.60E-05	5.05E-03	7.56E-03	1.13E-02	2.26E-02	2.70E-03	2.06E-06	1.59E-06	6.94E-06	5.03E-05	1.15E-04	2.51E-03	3.46E-02	6.61E-03
1,3-Butadiene	4.30E-07	7.78E-07	7.40E-05	4.07E-04	2.71E-04	3.41E-04	5.00E-05	1.29E-06	1.81E-04	2.71E-04	4.07E-04	8.09E-04	9.67E-05				1.80E-06	4.11E-06	9.00E-05	1.24E-03	2.37E-04
Ethylbenzene	3.20E-05	5.79E-05	5.51E-03	3.03E-02	2.02E-02	2.54E-02	3.72E-03	9.60E-05	1.35E-02	2.02E-02	3.03E-02	6.02E-02	7.20E-03				1.34E-04	3.06E-04	6.70E-03	9.23E-02	1.76E-02
Formaldehyde	7.10E-04	2.88E-03	2.74E-01	4.60E+00	3.20E+00	1.40E+00	3.23E-01	2.88E-03	4.04E-01	2.40E+00	4.30E+00	1.94E+00	3.51E-01	7.35E-05	5.66E-05	2.48E-04	2.98E-03	6.78E-03	1.49E-01	3.49E+00	8.22E-01
Hexane													0.00E+00	1.76E-03	1.36E-03	5.95E-03				5.95E-03	5.95E-03
Naphthalene	1.30E-06	2.35E-06	2.24E-04	1.23E-03	8.19E-04	1.03E-03	1.51E-04	3.90E-06	5.47E-04	8.19E-04	1.23E-03	2.44E-03	2.92E-04	5.98E-07	4.60E-07	2.02E-06	5.45E-06	1.24E-05	2.72E-04	3.75E-03	7.18E-04
PAH	2.20E-06	3.98E-06	3.79E-04	2.08E-03	1.39E-03	1.75E-03	2.56E-04	6.60E-06	9.26E-04	1.39E-03	2.08E-03	4.14E-03	4.95E-04				9.22E-06	2.10E-05	4.60E-04	6.34E-03	1.21E-03
Propylene Oxide	2.90E-05	5.25E-05	4.99E-03	2.74E-02	1.83E-02	2.30E-02	3.37E-03	8.70E-05	1.22E-02	1.83E-02	2.74E-02	5.45E-02	6.52E-03				1.22E-04	2.77E-04	6.07E-03	8.36E-02	1.60E-02
Toluene	1.30E-04	2.35E-04	2.24E-02	1.23E-01	8.19E-02	1.03E-01	1.51E-02	3.90E-04	5.47E-02	8.19E-02	1.23E-01	2.44E-01	2.92E-02	3.33E-06	2.57E-06	1.12E-05	5.45E-04	1.24E-03	2.72E-02	3.75E-01	7.16E-02
Xylenes	6.40E-05	1.16E-04	1.10E-02	6.05E-02	4.03E-02	5.08E-02	7.44E-03	1.92E-04	2.69E-02	4.03E-02	6.05E-02	1.20E-01	1.44E-02				2.68E-04	6.11E-04	1.34E-02	1.85E-01	3.52E-02
Dichlorobenzene													0.00E+00	1.18E-06	9.06E-07	3.97E-06				3.97E-06	3.97E-06
Polycyclic Organic Compounds (POM)																					
Acenaphthene														1.76E-09	1.36E-09	5.95E-09	0.00E+00	0.00E+00	0.00E+00	5.95E-09	5.95E-09
Acenaphthylene														1.76E-09	1.36E-09	5.95E-09	0.00E+00	0.00E+00	0.00E+00	5.95E-09	5.95E-09
Anthracene														2.35E-09	1.81E-09	7.94E-09	0.00E+00	0.00E+00	0.00E+00	7.94E-09	7.94E-09
Benz(a)anthracene														1.76E-09	1.36E-09	5.95E-09	0.00E+00	0.00E+00	0.00E+00	5.95E-09	5.95E-09
Benzo(a)pyrene														1.18E-09	9.06E-10	3.97E-09	0.00E+00	0.00E+00	0.00E+00	3.97E-09	3.97E-09
Benzo(b)fluoranthene														1.76E-09	1.36E-09	5.95E-09	0.00E+00	0.00E+00	0.00E+00	5.95E-09	5.95E-09
Benzo(g,h,i)perylene														1.18E-09	9.06E-10	3.97E-09	0.00E+00	0.00E+00	0.00E+00	3.97E-09	3.97E-09
Benzo(k)fluoranthene														1.76E-09	1.36E-09	5.95E-09	0.00E+00	0.00E+00	0.00E+00	5.95E-09	5.95E-09
Chrysene														1.76E-09	1.36E-09	5.95E-09	0.00E+00	0.00E+00	0.00E+00	5.95E-09	5.95E-09
Dibenzo(a,h)anthracene														1.18E-09	9.06E-10	3.97E-09	0.00E+00	0.00E+00	0.00E+00	3.97E-09	3.97E-09
7,12-Dimethylbenz(a)anthracene														1.57E-08	1.21E-08	5.29E-08	0.00E+00	0.00E+00	0.00E+00	5.29E-08	5.29E-08
Fluoranthene														2.94E-09	2.26E-09	9.92E-09	0.00E+00	0.00E+00	0.00E+00	9.92E-09	9.92E-09
Fluorene														2.75E-09	2.11E-09	9.26E-09	0.00E+00	0.00E+00	0.00E+00	9.26E-09	9.26E-09
3-Methylchloranthrene														1.76E-09	1.36E-09	5.95E-09	0.00E+00	0.00E+00	0.00E+00	5.95E-09	5.95E-09
2-Methylnaphthalene														2.35E-08	1.81E-08	7.94E-08	0.00E+00	0.00E+00	0.00E+00	7.94E-08	7.94E-08
Indeno(1,2,3-cd)pyrene														1.76E-09	1.36E-09	5.95E-09	0.00E+00	0.00E+00	0.00E+00	5.95E-09	5.95E-09
Phenanthrene														1.67E-08	1.28E-08	5.62E-08	0.00E+00	0.00E+00	0.00E+00	5.62E-08	5.62E-08
Pyrene														4.90E-09	3.77E-09	1.65E-08	0.00E+00	0.00E+00	0.00E+00	1.65E-08	1.65E-08
Total POM														8.65E-08	6.66E-08	2.92E-07	0.00E+00	0.00E+00	0.00E+00	2.92E-07	2.92E-07
Total HAPs (tpy)						**1.65**	**0.36**					**2.54**	**0.42**			**0.01**			**0.21**	**4.4**	**1.0**
																			Maximum Individual HAP:	**3.5**	**0.82**
																			Total Project HAPs:	**4.4**	**1.0**

[1] Emissions based on AP-42 5th Edition, Section 3.1, except for formaldehyde. Formaldehyde emissions obtained from PIL 168, Table 1. All other HAP emissions based on scaling of AP-42 values using Vendor Guarantee for VOC. AP-42 VOC factor = 0.0021 lb/MMBTU (AP-42 Table 3.1-2a). Taurus 70 VOC Factor = 0.0038 lb/MMBtu. Mars 100 VOC Factor = 0.0063 lb/mmBtu
[2] Emissions based on AP-42 5th Edition, Section 1.4.
[3] Emissions based on AP-42 5th Edition, Section 3.1.
[4] Emissions based on Solar Estimates
[5] Calculated based on AP-42 Chapter 3, Section 3.1, Table 3.1-3 emission factors.

Solar Turbine Emissions - Startup			
Pollutant		Emission Rates (lb/event)[4]	
		Mars 100	Taurus 70
Total HAP		2.6	4.9
Formaldehyde		2.4	4.6
Non-Formaldehyde HAP		0.2	0.3

Solar Turbine Emissions - Shutdown			
Pollutant		Emission Rates (lb/event)[4]	
		Mars 100	Taurus 70
Total HAP		4.6	3.4
Formaldehyde		4.3	3.2
Non-Formaldehyde HAP		0.3	0.2

Solar Turbine Emissions - Startup			
Pollutant	Non-Formaldehyde HAP Composition[5]	Emission Rates (lb/event)	
		Mars 100	Taurus 70
Acetaldehyde	12.605%	2.52E-02	3.78E-02
Acrolein	2.017%	4.03E-03	6.05E-03
Benzene	3.782%	7.56E-03	1.13E-02
1,3-Butadiene	0.136%	2.71E-04	4.07E-04
Dichlorobenzene	0.000%	0.00E+00	0.00E+00
Ethylbenzene	10.084%	2.02E-02	3.03E-02
Formaldehyde	---	2.40E+00	4.60E+00
Hexane	0.000%	0.00E+00	0.00E+00
Naphthalene	0.410%	8.19E-04	1.23E-03
PAH	0.693%	1.39E-03	2.08E-03
Propylene Oxide	9.139%	1.83E-02	2.74E-02
Toluene	40.967%	8.19E-02	1.23E-01
Xylenes	20.168%	4.03E-02	6.05E-02

Solar Turbine Emissions - Shutdown			
Pollutant	Non-Formaldehyde HAP Composition[5]	Emission Rates (lb/event)	
		Mars 100	Taurus 70
Acetaldehyde	12.605%	3.78E-02	2.52E-02
Acrolein	2.017%	6.05E-03	4.03E-03
Benzene	3.782%	1.13E-02	7.56E-03
1,3-Butadiene	0.136%	4.07E-04	2.71E-04
Dichlorobenzene	0.000%	0.00E+00	0.00E+00
Ethylbenzene	10.084%	3.03E-02	2.02E-02
Formaldehyde	---	4.30E+00	3.20E+00
Hexane	0.000%	0.00E+00	0.00E+00
Naphthalene	0.410%	1.23E-03	8.19E-04
PAH	0.693%	2.08E-03	1.39E-03
Propylene Oxide	9.139%	2.74E-02	1.83E-02
Toluene	40.967%	1.23E-01	8.19E-02
Xylenes	20.168%	6.05E-02	4.03E-02

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Table B-12. Toxic Air Pollutant (TAP) Emissions comparison to VADEQ TAP Exemption Rates

Pollutant	CAS No.	TLV (mg/m³)[1]			Exemption Threshold (ET)[1]	
					Hourly	Annual
		TWA	STEL	CEIL	lb/hr	ton/yr
Acetaldehyde	75070	180	270	-	8.91	26.1
Acrolein	107028	0.23	0.69	-	0.02277	0.03335
Benzene	71432	32	-	-	2.112	4.64
1,3-Butadiene	106990	22	-	-	1.452	3.19
Ethylbenzene	100414	434	543	-	17.919	62.93
Formaldehyde	50000	1.2	2.5	-	0.0825	0.174
Hexane	110543	176	-	-	11.616	25.52
Naphthalene	91203	52	79	-	2.607	7.54
PAH[2]	---	52	79	-	2.607	7.54
Propylene Oxide	75569	48	-	-	3.168	6.96
Toluene	108883	377	565	-	18.645	54.665
Xylenes	1330207	434	651	-	21.483	62.93

Potential Controlled Hourly Emissions (lb/hr)[3]

Pollutant	Mars 100	Taurus 70	Microturbines	Gas Heater	Condensate Tanks	Fugitive Leaks	Blowdown Events								Total (lb/hr)	ET (lb/hr)
							Taurus 70 Shutdown	Mars 100 Shutdown	Pig Receiver	Pig Launcher	Suction Filter	Miscellaneous Filters	ESD Test (Controlled)	Actual ESD		
Acetaldehyde	3.92E-02	3.84E-02	1.91E-03	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.080	8.91
Acrolein	6.27E-03	6.14E-03	3.06E-04	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.013	0.02277
Benzene	1.18E-02	1.15E-02	5.73E-04	1.59E-06	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.024	2.112
1,3-Butadiene	4.22E-04	4.13E-04	2.05E-05	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.001	1.452
Ethylbenzene	3.14E-02	3.07E-02	1.53E-03	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.064	17.919
Formaldehyde	4.33E+00	4.62E+00	3.39E-02	5.66E-05	0.00E+00	0.00E+00	---	---	---	---	---	---		---	8.990	0.0825
Hexane[4]	0.00E+00	0.00E+00	0.00E+00	1.36E-03	4.57E-04	1.55E-02	0.075	0.122	0.264	0.386	1.511	0.024	0.000	11.058	2.4 / 11.06	11.616
Naphthalene	1.27E-03	1.25E-03	6.21E-05	4.60E-07	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.003	2.607
PAH	2.16E-03	2.11E-03	1.05E-04	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.004	2.607
Propylene Oxide	2.84E-02	2.78E-02	1.39E-03	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.058	3.168
Toluene	1.27E-01	1.25E-01	6.21E-03	2.57E-06	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.258	18.645
Xylenes	6.27E-02	6.14E-02	3.06E-03	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.127	21.483

Potential Controlled Annual Emissions (ton/yr)[3]

Pollutant	Mars 100	Taurus 70	Microturbines	Gas Heater	Condensate Tanks	Fugitive Leaks	Blowdown Events								Total (tpy)	ET (tpy)
							Taurus 70 Shutdown	Mars 100 Shutdown	Pig Receiver	Pig Launcher	Suction Filter	Miscellaneous Filters	ESD Test	Actual ESD		
Acetaldehyde	9.00E-03	4.65E-03	8.37E-03	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.022	26.1
Acrolein	1.44E-03	7.44E-04	1.34E-03	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.004	0.03335
Benzene	2.70E-03	1.39E-03	2.51E-03	6.94E-06	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.007	4.64
1,3-Butadiene	9.67E-05	5.00E-05	9.00E-05	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.000	3.19
Ethylbenzene	7.20E-03	3.72E-03	6.70E-03	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.018	62.93
Formaldehyde	3.51E-01	3.23E-01	1.49E-01	2.48E-04	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.822	0.174
Hexane	0.00E+00	0.00E+00	0.00E+00	5.95E-03	2.00E-03	6.81E-02	4.49E-04	7.35E-04	2.64E-04	3.86E-04	9.07E-03	1.44E-04	0.00E+00	5.53E-03	0.093	25.52
Naphthalene	2.92E-04	1.51E-04	2.72E-04	2.02E-06	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.001	7.54
PAH	4.95E-04	2.56E-04	4.60E-04	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.001	7.54
Propylene Oxide	6.52E-03	3.37E-03	6.07E-03	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.016	6.96
Toluene	2.92E-02	1.51E-02	2.72E-02	1.12E-05	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.072	54.665
Xylenes	1.44E-02	7.44E-03	1.34E-02	0.00E+00	0.00E+00	0.00E+00	---	---	---	---	---	---		---	0.035	62.93

Key:

Potential Emissions Exceed Exemption Threshold

Notes:

1. TLV and ET values from "Toxics_Spreadsheet.xlsx", downloaded from the Virginia DEQ - Air Toxics website, and calculated as per Rule 9VAC5-60-300.C
2. PAH not listed in Virginia DEQ toxics spreadsheet; to be conservative, assumed the same TLV and ET values as naphthalene.
3. Based on maximum emissions per Table B11. The Mars 100 and Taurus 70 CT lb/hr emissions include the maximum emissions from startup and shutdown events with the balance of the hour at the maximum potential normal operating emission rate.
4. Conservatively assumes that all blowdown emissions could occur within the same hour. Blowdowns from an actual ESD are not included in the lb/hr total as ESD emissions in the case of a true emergency will not occur during the same hour as all other blowdowns.
Actual ESD blowdowns lb/hr emissions for hexane (11.05 lb/hr) are more than the sum of all other blowdown emissions (2.4 lb/hr), but still below the threshold. Actual ESD blowdown emissions in tpy are included with the total hexane emissions.

Midstream Data Sheet

Project: **Lambert Compressor Station**

Rev 0: 10 Oct 2018
Rev 1: 25 Oct 2018
Rev 2: 18 Mar 2020
Rev 3: 07 May 2020

Gas Sample:

Design / Operating Conditions			
Ambient Temperature Range:		-20 F to 100 F	
Site Elevation above Sea Level:		660 ft	
Site Address:		Transco Ln, Chatham, VA 24531	
Site Coordinates:	36.8269°, -79.3416°	**County**:	Pittsylvania
Electric Service	3/60/460V		
Media:	Natural Gas	S.G.	0.62
Gas Composition:			
ETRN Project Engineer	Doug Mace	Email: dmace@equitransmidstream.com	

GAS PROPERTIES	JEFFERSON I.C.		SAMPLE ID: 2016-PITT-000863-001
COMPONENT	**MOLE %**		
NITROGEN	0.396		**BTU/SCF (DRY)**
CARBON DIOXIDE	0.165		1097.6
OXYGEN	0.000		
METHANE	87.823		**BTU/SCF (SAT)**
ETHANE	11.303		1078.9
PROPANE	0.280		
ISO-BUTANE	0.009		**IDEAL GRAVITY**
N-BUTANE	0.010		.6152
ISO-PENTANE	0.003		
N-PENTANE	0.003		**REAL GRAVITY**
HEXANES (PLUS)	0.008		.6164
TOTAL	100		
SULFUR CONTENT	<1.1 grains of sulfur per 100 standard cubic feet of gas		

****
*   Project Setup Information   *
****

Project File : \\Pit-dc1\p\Client\EQT Corporation\Corporate\02 Projects\143901.0087 Mountain Valley

Flowsheet Selection : Oil Tank with Separator
Calculation Method : RVP Distillation
Control Efficiency : 0.0%
Known Separator Stream : Low Pressure Oil
Entering Air Composition : No

Filed Name :
Well Name : PTE
Date :

****
*   Data Input   *
****

Separator Pressure : 414.00[psig]
Separator Temperature : 60.00[F]
Ambient Pressure : 14.70[psia]
Ambient Temperature : 55.00[F]
C10+ SG : 0.8024
C10+ MW : 163.342

-- Low Pressure Oil ---

No.	Component	mol %
1	H2S	0.0000
2	O2	0.0000
3	CO2	0.0840
4	N2	0.0000
5	C1	9.9570
6	C2	8.1140
7	C3	6.8240
8	i-C4	1.8640
9	n-C4	4.8700
10	i-C5	2.9440
11	n-C5	3.3610
12	C6	2.2410
13	C7	9.7080
14	C8	11.4500
15	C9	8.4380
16	C10+	25.3730
17	Benzene	0.0910
18	Toluene	0.7580
19	E-Benzene	0.1130
20	Xylenes	1.3570
21	n-C6	2.4330
22	224Trimethylp	0.0200

-- Sales Oil ---
Production Rate : 0.1[bbl/day]
Days of Annual Operation : 365 [days/year]
API Gravity : 59.11
Reid Vapor Pressure : 10.60[psia]

****
* Calculation Results *
****

-- Emission Summary ---

Item	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]	Controlled [ton/yr]	Controlled [lb/hr]
Total HAPs	0.000	0.000	0.000	0.000

Page 1-- E&P TANK

Item	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]	Controlled [ton/yr]	Controlled [lb/hr]
Total HC	0.423	0.097	0.423	0.097
VOCs, C2+	0.339	0.077	0.339	0.077
VOCs, C3+	0.213	0.049	0.213	0.049

Uncontrolled Recovery Info.
Vapor 28.1600 x1E-3 [MSCFD]
HC Vapor 28.0700 x1E-3 [MSCFD]
GOR 281.60 [SCF/bbl]

-- Emission Composition ---

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]	Controlled [ton/yr]	Controlled [lb/hr]
1	H2S	0.000	0.000	0.000	0.000
2	O2	0.000	0.000	0.000	0.000
3	CO2	0.002	0.000	0.002	0.000
4	N2	0.000	0.000	0.000	0.000
5	C1	0.084	0.019	0.084	0.019
6	C2	0.125	0.029	0.125	0.029
7	C3	0.109	0.025	0.109	0.025
8	i-C4	0.023	0.005	0.023	0.005
9	n-C4	0.045	0.010	0.045	0.010
10	i-C5	0.014	0.003	0.014	0.003
11	n-C5	0.012	0.003	0.012	0.003
12	C6	0.003	0.001	0.003	0.001
13	C7	0.004	0.001	0.004	0.001
14	C8	0.001	0.000	0.001	0.000
15	C9	0.000	0.000	0.000	0.000
16	C10+	0.000	0.000	0.000	0.000
17	Benzene	0.000	0.000	0.000	0.000
18	Toluene	0.000	0.000	0.000	0.000
19	E-Benzene	0.000	0.000	0.000	0.000
20	Xylenes	0.000	0.000	0.000	0.000
21	n-C6	0.002	0.000	0.002	0.000
22	224Trimethylp	0.000	0.000	0.000	0.000
	Total	0.424	0.097	0.424	0.097

-- Stream Data --

No. Component MW LP Oil Flash Oil Sale Oil Flash Gas W&S Gas Total Emissions

			mol %	mol %	mol %	mol %	mol %	mol %
1	H2S	34.80	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	O2	32.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	CO2	44.01	0.0840	0.0069	0.0001	0.3251	0.3289	0.3254
4	N2	28.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	C1	16.04	9.9570	0.2491	0.0001	40.3145	12.0792	38.6045
6	C2	30.07	8.1140	1.3061	0.2375	29.4027	52.0759	30.7759
7	C3	44.10	6.8240	3.2946	2.8877	17.8607	22.6275	18.1494
8	i-C4	58.12	1.8640	1.5368	1.5034	2.8873	3.1206	2.9014
9	n-C4	58.12	4.8700	4.6049	4.5743	5.6989	6.0623	5.7209
10	i-C5	72.15	2.9440	3.4237	3.4639	1.4439	1.5163	1.4483
11	n-C5	72.15	3.3610	4.0550	4.1140	1.1907	1.2521	1.1944
12	C6	86.16	2.2410	2.8819	2.9372	0.2370	0.2510	0.2378
13	C7	100.20	9.7080	12.7165	12.9774	0.3002	0.3211	0.3015
14	C8	114.23	11.4500	15.0807	15.3960	0.0965	0.1043	0.0969
15	C9	128.28	8.4380	11.1296	11.3633	0.0212	0.0250	0.0215
16	C10+	163.34	25.3730	33.4860	34.1908	0.0030	0.0034	0.0030
17	Benzene	78.11	0.0910	0.1181	0.1204	0.0064	0.0068	0.0064
18	Toluene	92.13	0.7580	0.9963	1.0170	0.0128	0.0138	0.0128
19	E-Benzene	106.17	0.1130	0.1490	0.1521	0.0005	0.0006	0.0005
20	Xylenes	106.17	1.3570	1.7892	1.8267	0.0056	0.0061	0.0056
21	n-C6	86.18	2.4330	3.1494	3.2114	0.1926	0.2046	0.1933
22	224Trimethylp	114.24	0.0200	0.0262	0.0268	0.0005	0.0005	0.0005

MW		95.74	116.43	118.13	31.04	35.93	31.33
Stream Mole Ratio		1.0000	0.7577	0.7421	0.2423	0.0156	0.2579
Heating Value	[BTU/SCF]				1808.07	2072.28	1824.07
Gas Gravity	[Gas/Air]				1.07	1.24	1.08
Bubble Pt. @ 100F	[psia]	406.75	28.61	13.23			
RVP @ 100F	[psia]	101.88	15.92	10.81			

Spec. Gravity @ 100F		0.685	0.715	0.717

LAFAYETTE AREA LABORATORY
4790 N.E. EVANGELINE THRUWAY
CARENCRO, LA 70520
PHONE (337) 896-3055
FAX (337) 896-3077

Certificate of Analysis : 13050161-002A

Company:	Gas Analytical Services	**For:**	Gas Analytical Services
Well:	OXF 131 Pad		Alan Ball
Field:	EQT Production		PO Box 1028
Sample of:	Condensate-Spot		
Conditions:	414 @ N.G.		Bridgeport, WV, 26330
Sampled by:	GR-GAS		
Sample date:	5/14/2013	**Report Date:**	5/29/2013
Remarks:	Cylinder No.: GAS		
Remarks:			

Analysis: (*GPA 2186M*)	**Mol. %**	**MW**	**Wt. %**	**Sp. Gravity**	**L.V. %**
Nitrogen	0.000	28.013	0.000	0.8094	0.000
Methane	9.957	16.043	1.664	0.3000	3.884
Carbon Dioxide	0.084	44.010	0.039	0.8180	0.033
Ethane	8.114	30.070	2.542	0.3562	4.991
Propane	6.824	44.097	3.135	0.5070	4.324
Iso-butane	1.864	58.123	1.129	0.5629	1.403
N-butane	4.870	58.123	2.948	0.5840	3.533
Iso-pentane	2.944	72.150	2.213	0.6244	2.479
N-pentane	3.361	72.150	2.526	0.6311	2.801
i-Hexanes	2.241	86.177	1.990	0.6795	2.104
n-Hexane	2.433	85.734	2.184	0.6640	2.288
2,2,4 trimethylpentane	0.020	114.231	0.024	0.6967	0.024
Benzene	0.091	78.114	0.065	0.8846	0.059
Heptanes	9.708	98.181	9.953	0.7010	9.943
Toluene	0.758	92.141	0.641	0.8719	0.588
Octanes	11.450	107.956	13.087	0.7510	12.206
E-benzene	0.113	106.167	0.053	0.8718	0.102
M-,O-,P-xylene	1.357	106.167	1.501	0.8731	1.214
Nonanes	8.438	122.962	11.137	0.7603	10.366
Decanes Plus	25.373	163.342	43.169	0.8024	37.658
	100.000		100.000		100.000

Calculated Values	**Total Sample**	**Decanes Plus**
Specific Gravity at 60 °F	0.6999	0.8024
Api Gravity at 60 °F	70.675	44.841
Molecular Weight	96.001	163.342
Pounds per Gallon (in Vacuum)	5.835	6.690
Pounds per Gallon (in Air)	5.829	6.683
Cu. Ft. Vapor per Gallon @ 14.73 psia	23.120	15.507

Brian Gaspard

Southern Petroleum Laboratories, Inc.

Solar Turbines

A Caterpillar Company

Submitted Electronically

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123
Tel: (858) 694-1616

May 20, 2020

Attn: Doug Mace, Principal Compression Engineer
Equitrans Midstream

Subject: Particular Matter Warranty
MVP Lambert– Engine Serial Number 0985B

Solar is granting a $PM_{10/2.5}$ warranty for the Taurus 70, Engine Serial Number 0985B, intended for installation at MVP Lambert in Chatham, VA subject to the following conditions:

$PM_{10/2.5}$ Warranty Conditions

• All standard warranty conditions, i.e., engine warranty, apply.
• The PM10/2.5 warranty is valid for steady-state conditions at ambient temperatures 0°F (-20°C) and above, and limited from 50 to 100% load for SoLoNOx™ on pipeline natural gas fuel (40 to 100% on the Titan™ 250); 80 to 100% load on landfill/digester gas, conventional combustion on pipeline natural gas, and conventional combustion on liquid fuel; and 65 to 100% load for SoLoNOx on liquid fuel.
• Pipeline natural gas PM10/2.5 emissions factors will not exceed 0.01 on a lb/MMBtu (HHV) basis.
• Intake air quality, gas fuel, and liquid fuel shall meet the requirements as specified in Solar's Engineering Specification ES 9-98. Natural gas fuel sulfur content shall be no greater than 1 gr/scf. Liquid fuel sulfur content shall be no greater than 500 ppm. Liquid fuel ash content shall be no greater than 0.005% by weight. The landfill/digester gas sulfur content shall be less than 0.15 lb SO2/MMBtu heat input.
• EPA Methods 201/201a and Method 202, with nitrogen purge and field blanks, shall be used to measure PM10/2.5 emissions. EPA Method 5 may be substituted. Three test runs shall be made with a minimum duration of four hours each. The three test runs should be completed within a 5 calendar day period.
• The PM10/2.5 emissions warranty expires simultaneously with the engine warranty.
• Solar does not conduct PM10/2.5 testing. Any PM10/2.5 testing will be conducted by the customer or its representative at site.
• The turbine should have a minimum of 300 operating hours prior to conducting particulate matter source testing. In addition, the turbine should be running for 3-4 hours prior to conducting a particulate matter source test so that the turbine and auxiliary equipment is in a sustained "typical" operating mode prior to gathering samples.

Please call me at 724.759.7812 if you have any questions.

Sincerely,

Kayla Lawler
Solar Turbines Incorporated

cc: Anthony Pocengal, Solar Turbines Incorporated

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	Engine Model **MARS 100-16000S** **CS/MD STANDARD**
Job ID	
Inquiry Number	Fuel Type: **CHOICE GAS** / Water Injection: **NO**
Run By: **David Anthony Pocengal** / Date Run: **21-Feb-20**	Engine Emissions Data: **REV. 1.0**

1 — 8305 HP, 50.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 0 Deg. F

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	11.22	18.98	10.87
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.41	0.70	0.40
lbm/hr	2.56	4.33	2.48

2 — 8051 HP, 50.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 20.0 Deg. F

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	14.26	24.12	13.82
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.54	0.92	0.53
lbm/hr	3.26	5.51	3.15

3 — 7721 HP, 50.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 40.0 Deg. F

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	13.64	23.07	13.21
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.54	0.91	0.52
lbm/hr	3.11	5.27	3.02

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	
Job ID	
Inquiry Number	
Run By: **David Anthony Pocengal**	Date Run: **21-Feb-20**

Engine Model: **MARS 100-16000S CS/MD STANDARD**	
Fuel Type: **CHOICE GAS**	Water Injection: **NO**
Engine Emissions Data: **REV. 1.0**	

4	7295 HP 50.0% Load	Elev. 660 ft	Rel. Humidity 60.0%	Temperature 60.0 Deg. F

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	12.98	21.96	12.58
lbm/MMBtu (Fuel LHV)	0.036	0.060	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.54	0.92	0.53
lbm/hr	2.96	5.01	2.87

5	6777 HP 50.0% Load	Elev. 660 ft	Rel. Humidity 60.0%	Temperature 80.0 Deg. F

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	12.20	20.63	11.81
lbm/MMBtu (Fuel LHV)	0.036	0.060	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.55	0.93	0.53
lbm/hr	2.78	4.71	2.70

6	6201 HP 50.0% Load	Elev. 660 ft	Rel. Humidity 60.0%	Temperature 100.0 Deg. F

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	11.39	19.26	11.03
lbm/MMBtu (Fuel LHV)	0.035	0.059	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.56	0.95	0.54
lbm/hr	2.60	4.40	2.52

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer	Model: MARS 100-16000S
	Package Type: CS/MD
Job ID	Match: STANDARD
Run By: David Anthony Pocengal — Date Run: 21-Feb-20	Fuel System: GAS
Engine Performance Code: REV. 4.20.1.24.13 — Engine Performance Data: REV. 1.0	Fuel Type: CHOICE GAS

DATA FOR MINIMUM PERFORMANCE

Elevation	feet	660
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	5.0
Accessory on GP Shaft	HP	27.8

		1	2	3	4	5	6
Engine Inlet Temperature	deg F	0	20.0	40.0	60.0	80.0	100.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	6802	7506	7365	7173	7003	6853
Specified Load	HP	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Net Output Power	HP	8305	8051	7721	7295	6777	6201
Fuel Flow	mmBtu/hr	75.11	95.31	91.28	87.20	82.45	77.89
Heat Rate	Btu/HP-hr	9044	11837	11823	11952	12166	12560
Therm Eff	%	28.135	21.495	21.521	21.289	20.914	20.258
Engine Exhaust Flow	lbm/hr	291039	297636	282280	267924	251221	234808
PT Exit Temperature	deg F	651	963	980	1004	1028	1054
Exhaust Temperature	deg F	651	893	920	951	981	1010

Fuel Gas Composition (Volume Percent)

Methane (CH4)	87.71
Ethane (C2H6)	11.29
Propane (C3H8)	0.30
I-Butane (C4H10)	0.10
Carbon Dioxide (CO2)	0.20
Nitrogen (N2)	0.40
Sulfur Dioxide (SO2)	0.0001

Fuel Gas Properties

LHV (Btu/Scf)	990.3	Specific Gravity	0.6165	Wobbe Index at 60F	1261.3

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	Engine Model **MARS 100-16000S** **CS/MD STANDARD**
Job ID	
Inquiry Number	Fuel Type: **CHOICE GAS** / Water Injection: **NO**
Run By: **David Anthony Pocengal** / Date Run: **21-Feb-20**	Engine Emissions Data: **REV. 1.0**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 12458 HP, 75.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	17.79	30.09	17.23
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.44	0.74	0.42
lbm/hr	4.06	6.87	3.93
2 — 12077 HP, 75.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 20.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	17.12	28.95	16.58
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.43	0.73	0.42
lbm/hr	3.91	6.61	3.79
3 — 11581 HP, 75.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 40.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	16.39	27.72	15.87
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.43	0.73	0.42
lbm/hr	3.74	6.33	3.62

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar’s typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer		Engine Model	MARS 100-16000S CS/MD STANDARD
Job ID		Fuel Type: CHOICE GAS	Water Injection: NO
Inquiry Number		Engine Emissions Data	REV. 1.0
Run By: David Anthony Pocengal	Date Run: 21-Feb-20		

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
4 — 10944 HP, 75.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 60.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	15.54	26.28	15.05
lbm/MMBtu (Fuel LHV)	0.036	0.060	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.43	0.74	0.42
lbm/hr	3.55	6.00	3.44
5 — 10165 HP, 75.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 80.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	14.57	24.63	14.11
lbm/MMBtu (Fuel LHV)	0.036	0.060	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.44	0.74	0.42
lbm/hr	3.33	5.62	3.22
6 — 9302 HP, 75.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 100.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	13.51	22.85	13.09
lbm/MMBtu (Fuel LHV)	0.035	0.059	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.44	0.75	0.43
lbm/hr	3.09	5.22	2.99

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
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PREDICTED ENGINE PERFORMANCE

Customer	Model **MARS 100-16000S**
	Package Type **CS/MD**
Job ID	Match **STANDARD**
Run By **David Anthony Pocengal** / Date Run **21-Feb-20**	Fuel System **GAS**
Engine Performance Code **REV. 4.20.1.24.13** / Engine Performance Data **REV. 1.0**	Fuel Type **CHOICE GAS**

DATA FOR MINIMUM PERFORMANCE

Elevation	feet	660
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	5.0
Accessory on GP Shaft	HP	27.8

		1	2	3	4	5	6
Engine Inlet Temperature	deg F	0	20.0	40.0	60.0	80.0	100.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	8663	8559	8423	8249	8032	7778
Specified Load	HP	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
Net Output Power	HP	12458	12077	11581	10944	10165	9302
Fuel Flow	mmBtu/hr	115.96	111.66	107.09	101.89	96.15	90.26
Heat Rate	Btu/HP-hr	9308	9245	9247	9310	9458	9703
Therm Eff	%	27.336	27.521	27.516	27.330	26.901	26.222
Engine Exhaust Flow	lbm/hr	346744	333012	318193	301454	283287	264651
PT Exit Temperature	deg F	903	911	920	933	950	976
Exhaust Temperature	deg F	871	886	901	918	938	966

Fuel Gas Composition (Volume Percent)

Methane (CH4)	87.71
Ethane (C2H6)	11.29
Propane (C3H8)	0.30
I-Butane (C4H10)	0.10
Carbon Dioxide (CO2)	0.20
Nitrogen (N2)	0.40
Sulfur Dioxide (SO2)	0.0001

Fuel Gas Properties

LHV (Btu/Scf)	990.3	Specific Gravity	0.6165	Wobbe Index at 60F	1261.3

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Solar Turbines
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PREDICTED EMISSION PERFORMANCE

Customer	
Job ID	
Inquiry Number	
Run By: **David Anthony Pocengal**	Date Run: **21-Feb-20**

Engine Model	**MARS 100-16000S CS/MD STANDARD**
Fuel Type: **CHOICE GAS**	Water Injection: **NO**
Engine Emissions Data	**REV. 1.0**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 16610 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	19.97	33.77	19.34
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.37	0.62	0.36
lbm/hr	4.56	7.71	4.42
2 — 16102 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 20.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	19.34	32.71	18.73
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.37	0.62	0.36
lbm/hr	4.42	7.47	4.28
3 — 15441 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 40.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	18.61	31.47	18.03
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.37	0.62	0.36
lbm/hr	4.25	7.19	4.12

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
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PREDICTED EMISSION PERFORMANCE

Customer	Engine Model **MARS 100-16000S** **CS/MD STANDARD**
Job ID	
Inquiry Number	Fuel Type: **CHOICE GAS** — Water Injection: **NO**
Run By: **David Anthony Pocengal** — Date Run: **21-Feb-20**	Engine Emissions Data: **REV. 1.0**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
4 — 14591 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 60.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	17.75	30.02	17.19
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.37	0.63	0.36
lbm/hr	4.05	6.85	3.93
5 — 13554 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 80.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	16.73	28.29	16.20
lbm/MMBtu (Fuel LHV)	0.036	0.060	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.38	0.64	0.37
lbm/hr	3.82	6.46	3.70
6 — 12402 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 100.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	15.61	26.41	15.12
lbm/MMBtu (Fuel LHV)	0.035	0.059	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.39	0.65	0.37
lbm/hr	3.56	6.03	3.45

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
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PREDICTED ENGINE PERFORMANCE

Customer	Model **MARS 100-16000S**
	Package Type **CS/MD**
Job ID	Match **STANDARD**
Run By **David Anthony Pocengal** — Date Run **21-Feb-20**	Fuel System **GAS**
Engine Performance Code **REV. 4.20.1.24.13** — Engine Performance Data **REV. 1.0**	Fuel Type **CHOICE GAS**

DATA FOR MINIMUM PERFORMANCE

Elevation	feet	660
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	5.0
Accessory on GP Shaft	HP	27.8

		1	2	3	4	5	6
Engine Inlet Temperature	deg F	0	20.0	40.0	60.0	80.0	100.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	9382	9308	9200	9042	8844	8608
Specified Load	HP	FULL	FULL	FULL	FULL	FULL	FULL
Net Output Power	HP	16610	16102	15441	14591	13554	12402
Fuel Flow	mmBtu/hr	126.61	122.73	118.31	113.23	107.44	101.48
Heat Rate	Btu/HP-hr	7622	7622	7662	7760	7927	8182
Therm Eff	%	33.381	33.382	33.209	32.788	32.098	31.097
Engine Exhaust Flow	lbm/hr	358089	349342	338653	325257	309606	291079
PT Exit Temperature	deg F	866	879	893	910	926	947
Exhaust Temperature	deg F	866	879	893	910	926	947

Fuel Gas Composition (Volume Percent)

Methane (CH4)	87.71
Ethane (C2H6)	11.29
Propane (C3H8)	0.30
I-Butane (C4H10)	0.10
Carbon Dioxide (CO2)	0.20
Nitrogen (N2)	0.40
Sulfur Dioxide (SO2)	0.0001

Fuel Gas Properties

LHV (Btu/Scf)	990.3	Specific Gravity	0.6165	Wobbe Index at 60F	1261.3

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Solar Turbines
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PREDICTED EMISSION PERFORMANCE

Customer	Engine Model **TAURUS 70-10802S** **CS/MD STANDARD**
Job ID	
Inquiry Number	Fuel Type: **CHOICE GAS** — Water Injection: **NO**
Run By: **David Anthony Pocengal** — Date Run: **21-Feb-20**	Engine Emissions Data: **REV. 0.1**

1	5573 HP 50.0% Load	Elev. 660 ft	Rel. Humidity 60.0%	Temperature 0 Deg. F
		NOx EMISSIONS	**CO EMISSIONS**	**UHC EMISSIONS**
PPMvd at 15% O2		9.00	25.00	25.00
ton/yr		9.70	16.41	9.40
lbm/MMBtu (Fuel LHV)		0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)		0.53	0.90	0.52
lbm/hr		2.22	3.75	2.15

2	5550 HP 50.0% Load	Elev. 660 ft	Rel. Humidity 60.0%	Temperature 20.0 Deg. F
		NOx EMISSIONS	**CO EMISSIONS**	**UHC EMISSIONS**
PPMvd at 15% O2		9.00	25.00	25.00
ton/yr		9.43	15.95	9.14
lbm/MMBtu (Fuel LHV)		0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)		0.52	0.88	0.50
lbm/hr		2.15	3.64	2.09

3	5508 HP 50.0% Load	Elev. 660 ft	Rel. Humidity 60.0%	Temperature 40.0 Deg. F
		NOx EMISSIONS	**CO EMISSIONS**	**UHC EMISSIONS**
PPMvd at 15% O2		9.00	25.00	25.00
ton/yr		9.14	15.45	8.85
lbm/MMBtu (Fuel LHV)		0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)		0.51	0.86	0.49
lbm/hr		2.09	3.53	2.02

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
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PREDICTED EMISSION PERFORMANCE

Customer	Engine Model **TAURUS 70-10802S** **CS/MD STANDARD**
Job ID	
Inquiry Number	Fuel Type: **CHOICE GAS** — Water Injection: **NO**
Run By: **David Anthony Pocengal** — Date Run: **21-Feb-20**	Engine Emissions Data: **REV. 0.1**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
4 — 5093 HP, 50.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 60.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	8.55	14.46	8.28
lbm/MMBtu (Fuel LHV)	0.036	0.060	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.51	0.87	0.50
lbm/hr	1.95	3.30	1.89
5 — 4622 HP, 50.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 80.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	7.94	13.42	7.69
lbm/MMBtu (Fuel LHV)	0.036	0.060	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.53	0.89	0.51
lbm/hr	1.81	3.06	1.76
6 — 4086 HP, 50.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 100.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	7.30	12.35	7.07
lbm/MMBtu (Fuel LHV)	0.035	0.059	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.55	0.93	0.53
lbm/hr	1.67	2.82	1.61

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
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PREDICTED ENGINE PERFORMANCE

Customer	Model: **TAURUS 70-10802S**
	Package Type: **CS/MD**
Job ID	Match: **STANDARD**
Run By: **David Anthony Pocengal** — Date Run: **21-Feb-20**	Fuel System: **GAS**
Engine Performance Code: **REV. 4.20.1.24.13** — Engine Performance Data: **REV. 1.0**	Fuel Type: **CHOICE GAS**

DATA FOR MINIMUM PERFORMANCE

Elevation	feet	660
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	5.0
Accessory on GP Shaft	HP	23.8

		1	2	3	4	5	6
Engine Inlet Temperature	deg F	0	20.0	40.0	60.0	80.0	100.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	9633	9558	9465	9157	8888	8528
Specified Load	HP	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Net Output Power	HP	5573	5550	5508	5093	4622	4086
Fuel Flow	mmBtu/hr	64.77	63.01	61.14	57.40	53.65	49.94
Heat Rate	Btu/HP-hr	11622	11352	11099	11270	11608	12221
Therm Eff	%	21.892	22.413	22.925	22.578	21.920	20.820
Engine Exhaust Flow	lbm/hr	193899	185303	176843	165252	155537	145137
PT Exit Temperature	deg F	1006	1010	1014	1028	1043	1067
Exhaust Temperature	deg F	908	933	956	981	1003	1031

Fuel Gas Composition (Volume Percent)

Methane (CH4)	87.71
Ethane (C2H6)	11.29
Propane (C3H8)	0.30
I-Butane (C4H10)	0.10
Carbon Dioxide (CO2)	0.20
Nitrogen (N2)	0.40
Sulfur Dioxide (SO2)	0.0001

Fuel Gas Properties

LHV (Btu/Scf)	990.3	Specific Gravity	0.6165	Wobbe Index at 60F	1261.3

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Solar Turbines
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PREDICTED EMISSION PERFORMANCE

Customer	Engine Model **TAURUS 70-10802S** **CS/MD STANDARD**
Job ID	
Inquiry Number	Fuel Type: **CHOICE GAS** — Water Injection: **NO**
Run By: **David Anthony Pocengal** — Date Run: **21-Feb-20**	Engine Emissions Data: **REV. 0.1**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 8360 HP, 75.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	11.95	20.21	11.58
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.44	0.74	0.42
lbm/hr	2.73	4.62	2.64
2 — 8325 HP, 75.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 20.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	11.62	19.65	11.25
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.43	0.72	0.41
lbm/hr	2.65	4.49	2.57
3 — 8263 HP, 75.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 40.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	11.26	19.03	10.90
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.42	0.71	0.40
lbm/hr	2.57	4.35	2.49

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	
Job ID	
Inquiry Number	
Run By: **David Anthony Pocengal**	Date Run: **21-Feb-20**

Engine Model: **TAURUS 70-10802S CS/MD STANDARD**	
Fuel Type: **CHOICE GAS**	Water Injection: **NO**
Engine Emissions Data: **REV. 0.1**	

4	7640 HP 75.0% Load	Elev. 660 ft	Rel. Humidity 60.0%	Temperature 60.0 Deg. F
		NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2		9.00	25.00	25.00
ton/yr		10.49	17.74	10.16
lbm/MMBtu (Fuel LHV)		0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)		0.42	0.71	0.41
lbm/hr		2.39	4.05	2.32

5	6933 HP 75.0% Load	Elev. 660 ft	Rel. Humidity 60.0%	Temperature 80.0 Deg. F
		NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2		9.00	25.00	25.00
ton/yr		9.74	16.47	9.44
lbm/MMBtu (Fuel LHV)		0.036	0.060	0.034
lbm/(MW-hr) (gas turbine shaft pwr)		0.43	0.73	0.42
lbm/hr		2.22	3.76	2.15

6	6130 HP 75.0% Load	Elev. 660 ft	Rel. Humidity 60.0%	Temperature 100.0 Deg. F
		NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2		9.00	25.00	25.00
ton/yr		8.90	15.04	8.62
lbm/MMBtu (Fuel LHV)		0.035	0.059	0.034
lbm/(MW-hr) (gas turbine shaft pwr)		0.44	0.75	0.43
lbm/hr		2.03	3.43	1.97

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer	
Job ID	
Run By: David Anthony Pocengal	Date Run: 21-Feb-20
Engine Performance Code: REV. 4.20.1.24.13	Engine Performance Data: REV. 1.0

Model	TAURUS 70-10802S
Package Type	CS/MD
Match	STANDARD
Fuel System	GAS
Fuel Type	CHOICE GAS

DATA FOR MINIMUM PERFORMANCE

Elevation	feet	660
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	5.0
Accessory on GP Shaft	HP	23.8

		1	2	3	4	5	6
Engine Inlet Temperature	deg F	0	20.0	40.0	60.0	80.0	100.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	10960	10911	10853	10559	10220	9758
Specified Load	HP	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
Net Output Power	HP	8360	8325	8263	7640	6933	6130
Fuel Flow	mmBtu/hr	77.90	75.77	73.52	68.75	64.28	59.39
Heat Rate	Btu/HP-hr	9318	9101	8898	8999	9272	9690
Therm Eff	%	27.307	27.958	28.596	28.275	27.443	26.259
Engine Exhaust Flow	lbm/hr	219596	211062	202671	189406	176175	161789
PT Exit Temperature	deg F	963	966	970	984	1010	1038
Exhaust Temperature	deg F	913	931	946	966	994	1024

Fuel Gas Composition (Volume Percent)

Methane (CH4)	87.71
Ethane (C2H6)	11.29
Propane (C3H8)	0.30
I-Butane (C4H10)	0.10
Carbon Dioxide (CO2)	0.20
Nitrogen (N2)	0.40
Sulfur Dioxide (SO2)	0.0001

Fuel Gas Properties

LHV (Btu/Scf)	990.3	Specific Gravity	0.6165	Wobbe Index at 60F	1261.3

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	
Job ID	
Inquiry Number	
Run By: **David Anthony Pocengal**	Date Run: **21-Feb-20**

Engine Model	
TAURUS 70-10802S CS/MD STANDARD	
Fuel Type: **CHOICE GAS**	Water Injection: **NO**
Engine Emissions Data: **REV. 0.1**	

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 11146 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	13.54	22.91	13.12
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.37	0.63	0.36
lbm/hr	3.09	5.23	3.00
2 — 11100 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 20.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	13.18	22.28	12.76
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.36	0.61	0.35
lbm/hr	3.01	5.09	2.91
3 — 11017 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 40.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	12.82	21.68	12.42
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.36	0.60	0.35
lbm/hr	2.93	4.95	2.84

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	Engine Model **TAURUS 70-10802S** **CS/MD STANDARD**
Job ID	
Inquiry Number	Fuel Type: **CHOICE GAS** — Water Injection: **NO**
Run By: **David Anthony Pocengal** — Date Run: **21-Feb-20**	Engine Emissions Data: **REV. 0.1**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
4 — 10187 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 60.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	12.07	20.41	11.69
lbm/MMBtu (Fuel LHV)	0.036	0.061	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	0.36	0.61	0.35
lbm/hr	2.76	4.66	2.67
5 — 9244 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 80.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	11.22	18.97	10.87
lbm/MMBtu (Fuel LHV)	0.036	0.060	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.37	0.63	0.36
lbm/hr	2.56	4.33	2.48
6 — 8173 HP, 100.0% Load, Elev. 660 ft, Rel. Humidity 60.0%, Temperature 100.0 Deg. F			
PPMvd at 15% O2	9.00	25.00	25.00
ton/yr	10.26	17.34	9.93
lbm/MMBtu (Fuel LHV)	0.035	0.059	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	0.38	0.65	0.37
lbm/hr	2.34	3.96	2.27

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg F, and between 50% and 100% load for gas fuel, and between 65% and 100% load for liquid fuel (except for the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer	Model **TAURUS 70-10802S**
	Package Type **CS/MD**
Job ID	Match **STANDARD**
Run By **David Anthony Pocengal** / Date Run **21-Feb-20**	Fuel System **GAS**
Engine Performance Code **REV. 4.20.1.24.13** / Engine Performance Data **REV. 1.0**	Fuel Type **CHOICE GAS**

DATA FOR MINIMUM PERFORMANCE

Elevation	feet	660
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	5.0
Accessory on GP Shaft	HP	23.8

		1	2	3	4	5	6
Engine Inlet Temperature	deg F	0	20.0	40.0	60.0	80.0	100.0
Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	11966	11890	11765	11495	11189	10796
Specified Load	HP	FULL	FULL	FULL	FULL	FULL	FULL
Net Output Power	HP	11146	11100	11017	10187	9244	8173
Fuel Flow	mmBtu/hr	85.87	83.60	81.49	76.97	72.04	66.64
Heat Rate	Btu/HP-hr	7704	7531	7397	7556	7793	8153
Therm Eff	%	33.027	33.785	34.398	33.673	32.650	31.208
Engine Exhaust Flow	lbm/hr	231872	225381	218823	207302	194515	179095
PT Exit Temperature	deg F	911	913	920	943	967	1000
Exhaust Temperature	deg F	902	909	920	943	967	1000

Fuel Gas Composition (Volume Percent)

Methane (CH4)	87.71
Ethane (C2H6)	11.29
Propane (C3H8)	0.30
I-Butane (C4H10)	0.10
Carbon Dioxide (CO2)	0.20
Nitrogen (N2)	0.40
Sulfur Dioxide (SO2)	0.0001

Fuel Gas Properties

LHV (Btu/Scf)	990.3	Specific Gravity	0.6165	Wobbe Index at 60F	1261.3

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Capstone

Capstone Turbine Corporation • 21211 Nordhoff Street • Chatsworth • CA 91311 • USA
Phone: (818) 734-5300 • Fax: (818) 734-5320 • Web: www.microturbine.com

Technical Reference

Capstone MicroTurbine™ Systems Emissions

Summary

Capstone MicroTurbine™ systems are inherently clean and can meet some of the strictest emissions standards in the world. This technical reference is to provide customers with information that may be requested by local air permitting organizations or to compare air quality impacts of different technologies for a specific project. The preferred units of measure are "output based"; meaning that the quantity of a particular exhaust emission is reported relative to the useable output of the microturbine – typically in pounds per megawatt hour for electrical generating equipment. This technical reference also provides volumetric measurements in parts per million and milligrams per normal cubic meter. A conversion between several common units is also provided.

Maximum Exhaust Emissions at ISO Conditions

Table 1 below summarizes the exhaust emissions at full power and ISO conditions for different Capstone microturbine models. Note that the fuel can have a significant impact on certain emissions. For example landfill and digester gas can be made up of a wide variety of fuel elements and impurities, and typically contains some percentage of carbon dioxide (CO_2). This CO_2 dilutes the fuel, makes complete combustion more difficult, and results in higher carbon monoxide emissions (CO) than for pipeline-quality natural gas.

Table 1. Emission for Different Capstone Microturbine Models in [lb/MWhe]

Model	Fuel	NOx	CO	VOC (5)
C30 NG	Natural Gas (1)	0.64	1.8	0.23
CR30 MBTU	Landfill Gas (2)	0.64	22.0	1.00
CR30 MBTU	Digester Gas (3)	0.64	11.0	1.00
C30 Liquid	Diesel #2 (4)	2.60	0.41	0.23
C65 NG Standard	Natural Gas (1)	0.46	1.25	0.10
C65 NG Low NOx	Natural Gas (1)	0.17	1.30	0.10
C65 NG CARB	Natural Gas (1)	0.17	0.24	0.05
CR65 Landfill	Landfill Gas (2)	0.46	4.0	0.10
CR65 Digester	Digester Gas (3)	0.46	4.0	0.10
C200 NG	Natural Gas (1)	0.40	1.10	0.10
C200 NG CARB	Natural Gas (1)	0.14	0.20	0.04
CR200 Digester	Digester Gas (3)	0.40	3.6	0.10

Notes:

(1) Emissions for standard natural gas at 1,000 BTU/scf (HHV) or 39.4 MJ/m3 (HHV)
(2) Emissions for surrogate gas containing 42% natural gas, 39% CO2, and 19% Nitrogen
(3) Emissions for surrogate gas containing 63% natural gas and 37% CO2
(4) Emissions for Diesel #2 according to ASTM D975-07b
(5) Expressed as Methane

Table 2 provides the same output-based information shown in Table 1, but expressed in grams per horsepower hour (g/hp-hr).

Table 2. Emission for Different Capstone Microturbine Models in [g/hp-hr]

Model	Fuel	NOx	CO	VOC (5)
C30 NG	Natural Gas (1)	0.22	0.60	0.078
CR30 MBTU	Landfill Gas (2)	0.22	7.4	0.340
CR30 MBTU	Digester Gas (3)	0.22	3.7	0.340
C30 Liquid	Diesel #2 (4)	0.90	0.14	0.078
C65 NG Standard	Natural Gas (1)	0.16	0.42	0.034
C65 NG Low NOx	Natural Gas (1)	0.06	0.44	0.034
C65 NG CARB	Natural Gas (1)	0.06	0.08	0.017
CR65 Landfill	Landfill Gas (2)	0.16	1.4	0.034
CR65 Digester	Digester Gas (3)	0.16	1.4	0.034
C200 NG	Natural Gas (1)	0.14	0.37	0.034
C200 NG CARB	Natural Gas (1)	0.05	0.07	0.014
CR200 Digester	Digester Gas (3)	0.14	1.3	0.034

Notes: - same as for Table 1

Emissions may also be reported on a volumetric basis, with the most common unit of measurement being parts per million. This is typically a measurement that is corrected to specific oxygen content in the exhaust and without considering moisture content. The abbreviation for this unit of measurement is "ppmvd" (parts per million by volume, dry) and is corrected to 15% oxygen for electrical generating equipment such as microturbines. The relationship between an output based measurement like pounds per MWh and a volumetric measurement like ppmvd depends on the characteristics of the generating equipment and the molecular weight of the criteria pollutant being measured. Table 3 expresses the emissions in ppmvd at 15% oxygen for the Capstone microturbine models shown in Table 1. Note that raw measurements expressed in ppmv will typically be lower than the corrected values shown in Table 3 because the microturbine exhaust has greater than 15% oxygen.

Another volumetric unit of measurement expresses the mass of a specific criteria pollutant per standard unit of volume. Table 4 expresses the emissions in milligrams per normal cubic meter at 15% oxygen. Normal conditions for this purpose are expresses as one atmosphere of pressure and zero degrees Celsius. Note that both the ppmvd and mg/m3 measurements are for specific oxygen content. A conversion can be made to adjust either unit of measurement to other reference oxygen contents, if required. Use the equation below to convert from one reference oxygen content to another:

$$\text{Emissions at New } O_2 = \frac{(20.9 - \text{New } O_2 \text{ Percent})}{(20.9 - \text{Current } O_2 \text{ Percent})} \text{ X Emissions at Current } O_2$$

For example, to express 9 ppmvd of NOx at 15% oxygen to ppmvd at 3% oxygen:

$$\text{Emissions at 3\% } O_2 = \frac{(20.9 - 3.0)}{(20.9 - 15.0)} \text{ X } 9 = 27 \text{ ppmvd}$$

Table 3. Emission for Different Capstone Microturbine Models in [ppmvd] at 15% O_2

Model	Fuel	NOx	CO	VOC
C30 NG	Natural Gas (1)	9	40	9
CR30 MBTU	Landfill Gas (2)	9	500	40
CR30 MBTU	Digester Gas (3)	9	250	40
C30 Liquid	Diesel #2 (4)	35	9	9
C65 NG Standard	Natural Gas (1)	9	40	7
C65 NG Low NOx	Natural Gas (1)	4	40	7
C65 NG CARB	Natural Gas (1)	4	8	3
CR65 Landfill	Landfill Gas (2)	9	130	7
CR65 Digester	Digester Gas (3)	9	130	7
C200 NG	Natural Gas (1)	9	40	7
C200 NG CARB	Natural Gas (1)	4	8	3
CR200 Digester	Digester Gas (3)	9	130	7

Notes: same as Table 1

Table 4. Emission for Different Capstone Microturbine Models in [mg/m3] at 15% O_2

Model	Fuel	NOx	CO	VOC (5)
C30 NG	Natural Gas (1)	18	50	6
CR30 MBTU	Landfill Gas (2)	18	620	30
CR30 MBTU	Digester Gas (3)	18	310	30
C30 Liquid	Diesel #2 (4)	72	11	6
C65 NG Standard	Natural Gas (1)	19	50	5
C65 NG Low NOx	Natural Gas (1)	8	50	5
C65 NG CARB	Natural Gas (1)	8	9	2
CR65 Landfill	Landfill Gas (2)	18	160	5
CR65 Digester	Digester Gas (3)	18	160	5
C200 NG	Natural Gas (1)	18	50	5
C200 NG CARB	Natural Gas (1)	8	9	2
CR200 Digester	Digester Gas (3)	18	160	5

Notes: same as Table 1

The emissions stated in Tables 1, 2, 3 and 4 are guaranteed by Capstone for new microturbines during the standard warranty period. They are also the expected emissions for a properly maintained microturbine according to manufacturer's published maintenance schedule for the useful life of the equipment.

Emissions at Full Power but Not at ISO Conditions

The maximum emissions in Tables 1, 2, 3 and 4 are at full power under ISO conditions. These levels are also the expected values at full power operation over the published allowable ambient temperature and elevation ranges.

Emissions at Part Power

Capstone microturbines are designed to maintain combustion stability and low emissions over a wide operating range. Capstone microturbines utilize multiple fuel injectors, which are switched on or off depending on the power output of the turbine. All injectors are typically on when maximum power is demanded, regardless of the ambient temperature or elevation. As the load requirements of the microturbine are decreased, injectors will be switched off to maintain stability and low emissions. However, the emissions relative to the lower power output may increase. This effect differs for each microturbine model.

Emissions Calculations for Permitting

Air Permitting agencies are normally concerned with the maximum amount of a given pollutant being emitted per unit of time (for example pounds per day of NOx). The simplest way to make this calculation is to use the maximum microturbine full electrical power output (expressed in MW) multiplied by the emissions rate in pounds per MWhe times the number of hours per day. For example, the C65 CARB microturbine operating on natural gas would have a NOx emissions rate of:

NOx = .17 X (65/1000) X 24 = .27 pounds per day

This would be representative of operating the equipment full time, 24 hours per day, at full power output of 65 kWe.

As a general rule, if local permitting is required, use the published agency levels as the stated emissions for the permit and make sure that this permitted level is above the calculated values in this technical reference.

Consideration of Useful Thermal Output

Capstone microturbines are often deployed where their clean exhaust can be used to provide heating or cooling, either directly or using hot water or other heat transfer fluids. In this case, the local permitting or standards agencies will usually consider the emissions from traditional heating sources as being displaced by the useful thermal output of the microturbine exhaust energy. This increases the useful output of the microturbine, and decreases the relative emissions of the combined heat and power system. For example, the CARB version C65 ICHP system with integral heat recovery can achieve a total system efficiency of 70% or more, depending on inlet water temperatures and other installation-specific characteristics. The electric efficiency of the CARB version C65 microturbine is 28% at ISO conditions. This means that the total NOx output based emissions, including the captured thermal value, is the electric-only emissions times the ratio of electric efficiency divided by total system efficiency:

NOx = .17 X 28/70 = .068 pounds per MWh (based on total system output)

This is typically much less than the emissions that would result from providing electric power using traditional central power plants, plus the emissions from a local hot water heater or boiler. In fact microturbine emissions are so low compared with traditional hot water heaters that installing a Capstone microturbine with heat recovery can actually decrease the local emissions of NOx and other criteria pollutants, without even considering the elimination of emissions from a remote power plant.

Greenhouse Gas Emissions

Many gasses are considered "greenhouse gasses", and agencies have ranked them based on their global warming potential (GWP) in the atmosphere compared with carbon dioxide (CO_2), as well as their ability to maintain this effect over time. For example, methane is a greenhouse gas with a GWP of 21. Criteria pollutants like NOx and organic compounds like methane are monitored by local air permitting authorities, and are subject to strong emissions controls. Even though some of these criteria pollutants can be more troublesome for global warming than CO_2, they are released in small quantities – especially from Capstone microturbines. So the major contributor of concern is carbon dioxide, or CO_2. Emission of CO_2 depends on two things:

1. Carbon content in the fuel
2. Efficiency of converting fuel to useful energy

It is for these reasons that many local authorities are focused on using clean fuels (for example natural gas compared with diesel fuel), achieving high efficiency using combined heat and power systems, and displacing emissions from traditional power plants using renewable fuels like waste landfill and digester gasses.

Table 5 shows the typical CO_2 emissions due to combustion for different Capstone microturbine models at full power and ISO conditions. The values do not include CO_2 that may already exist in the fuel itself, which is typical for renewable fuels like landfill and digester gas. These values are expressed on an output basis, as is done for criteria pollutants in Table 1. The table shows the pounds per megawatt hour based on electric power output only, as well as considering total useful output in a CHP system with total 70% efficiency (LHV). As for criteria pollutants, the relative quantity of CO_2 released is substantially less when useful thermal output is also considered in the measurement.

Table 5. CO_2 Emission for Capstone Microturbine Models in [lb/MWh]

Model	Fuel	CO_2	
		Electric Only	70% Total CHP
C30 NG	Natural Gas (1)	1,690	625
CR30 MBTU	Landfill Gas (1)	1,690	625
CR30 MBTU	Digester Gas (1)	1,690	625
C30 Liquid	Diesel #2 (2)	2,400	855
C65 NG Standard	Natural Gas (1)	1,520	625
C65 NG Low NOx	Natural Gas (1)	1,570	625
C65 NG CARB	Natural Gas (1)	1,570	625
CR65 Landfill	Landfill Gas (1)	1,520	625
CR65 Digester	Digester Gas (1)	1,520	625
C200 NG	Natural Gas (1)	1,330	625
C200 NG CARB	Natural Gas (1)	1,330	625
CR200 Digester	Digester Gas (1)	1,330	625

Notes:

(1) Emissions due to combustion, assuming natural gas with CO_2 content of 117 lb/MMBTU (HHV)

(2) Emissions due to combustion, assuming diesel fuel with CO_2 content of 160 lb/MMBTU (HHV)

Useful Conversions

The conversions shown in Table 6 can be used to obtain other units of emissions outputs. These are approximate conversions.

Table 6. Useful Unit Conversions

From	Multiply By	To Get
lb/MWh	0.338	g/bhp-hr
g/bhp-hr	2.96	lb/MWh
lb	0.454	kg
kg	2.20	lb
kg	1,000	g
hp (electric)	.746	kW
kW	1.34	hp (electric)
MW	1,000	kW
kW	0.001	MW

Definitions

- ISO conditions are defined as: 15 °C (59 °F), 60% relative humidity, and sea level pressure of 101.3 kPa (14.696 psia).
- HHV: Higher Heating Value
- LHV: Lower Heating Value
- kW_{th}: Kilowatt (thermal)
- kW_e : Kilowatt (electric)
- MWh: Megawatt-hour
- hp-hr: horsepower-hour (sometimes referred to as "electric horsepower-hour")
- Scf: Standard cubic foot (standard references ISO temperature and pressure)
- m3: Normal cubic meter (normal references 0 °C and one atmosphere pressure)

Capstone Contact Information

If questions arise regarding this technical reference, please contact Capstone Turbine Corporation for assistance and information:

Capstone Applications

Toll Free Telephone: (866) 4-CAPSTONE or (866) 422-7786

Fax: (818) 734-5385

E-mail: applications@capstoneturbine.com

SoLoNOx Products: Emissions in Non-SoLoNOx Modes

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

Solar's gas turbine dry low NOx emissions combustion systems, known as *SoLoNOx*™, have been developed to provide the lowest emissions possible during normal operating conditions. In order to optimize the performance of the turbine, the combustion and fuel systems are designed to reduce NOx, CO and unburned hydrocarbons (UHC) without penalizing stability or transient capabilities. At very low load and cold temperature extremes, the *SoLoNOx* system must be controlled differently in order to assure stable operation. The required adjustments to the turbine controls at these conditions cause emissions to increase.

The purpose of this Product Information Letter is to provide emissions estimates, and in some cases warrantable emissions for NOx, CO and UHC, at off-design conditions.

The expected emissions values that follow are typically used to estimate emissions for annual emissions inventory purposes, for New Source Review applicability determinations, for air dispersion modeling, and for air permitting.

EMISSIONS ESTIMATES IN NON-SOLONOX MODE (LOW LOAD)

At operating loads < ~50%[1] on natural gas fuel and < ~65%[2] on liquid fuels, *SoLoNOx* engines are controlled to increase stability and transient response capability. The control steps that are required affect emissions in two ways: 1) pilot fuel flow is increased, increasing NOx emissions, and 2) airflow through the combustor is increased, increasing CO emissions. Engine controls are triggered either by power output for single-shaft engines or gas producer speed for two-shaft engines.

Emissions at lower loads vary by model and by the generation of control system. NOx can range from 40 to 70 ppm (raw) and CO and UHC emissions can vary from 25 to 10000 ppm (raw).

For emissions estimates at part-load conditions (idle to SoLoNOx mode) contact Solar's Environmental Programs Group (Anthony Pocengal 858.505.8554 or Leslie Witherspoon 858.694.6609).

As an alternative, a conservative method for estimating emissions of NOx at low loads is to use the applicable New Source Performance Standard (NSPS): 40CFR60 subpart GG or KKKK. For projects that commence construction after February 18, 2005, subpart KKKK is the applicable NSPS and contains a NOx level of 150 ppm @ 15% O_2 for operating loads less than 75%.

[1] <~40% load for the *Titan* 250
[2] < ~80% load for *Centaur* 40

COLD AMBIENT EMISSIONS ESTIMATES

Solar's standard temperature range warranty for gas turbines with *SoLoNOx* combustion is ≥ 0°F. At ambient temperatures below 0°F, Solar's turbine models are controlled to increase pilot fuel which improves flame stability but leads to higher emissions. Without the increase in pilot fuel at temperatures below 0°F the turbine may exhibit combustor rumble, as operation may be near the lean stability limit. The *Titan*™ 250 is an exception, with a lower standard warranty at ≥ –20°F.

If a cold ambient emissions warranty is requested, the turbine must be configured with the appropriate combustion hardware and software. For new production hardware this refers to the inclusion of "Pilot Active Control Logic". Pilot Active Control Logic employs active oscillations feedback to increase pilot and reduce oscillations.

A cold ambient emissions warranty is only available on gas turbines being fired on natural gas and is not offered for ambient temperatures below –20°F. Standard natural gas as defined in Solar's fuel spec, ES9-98, is required to offer a cold ambient warranty, but non-standard fuels on a project basis can be reviewed by Solar to determine applicability. Cold ambient emissions warranties cannot be offered for the *Centaur*® 40 turbine. In addition, a cold ambient warranty cannot be offered for liquid fuel operation at this time.

Table 1 provides expected and warrantable cold ambient emissions levels for Solar's *SoLoNOx* combustion turbines. Refer to Product Information Letter 205 for *Mercury*™ 50 turbine emissions estimates.

Table 1. ***Expected and/or Warrantable Emissions Between 0°F and –20°F for Turbines Equipped with Pilot Active Control Logic***
Natural Gas Fuel
NOx ppm values corrected to 15% O2

Turbine Model	Fuel System	Fuel	Applicable Load	NOx, ppm	CO, ppm	UHC, ppm
Centaur 50	Gas Only	Gas	50 to 100% load	42	100	50
	Dual Fuel	Gas	50 to 100% load	72	100	50
Taurus™ 60	Gas Only or Dual Fuel	Gas	50 to 100% load	42	100	50
Taurus 65	Gas Only	Gas	50 to 100% load	42	100	50
Taurus 70	Gas Only or Dual Fuel	Gas	50 to 100% load	42	100	50
Mars® 90	Gas Only	Gas	50 to 100% load	42	100	50
Mars 100	Gas Only or Dual Fuel	Gas	50 to 100% load	42	100	50
Titan 130	Gas Only or Dual Fuel	Gas	50 to 100% load	42	100	50
Titan 250	Gas Only	Gas	40 to 100% load	25	50	25
	Gas Only	Gas	40 to 100% load	15	25	25

A cold ambient warranty is available for new equipment and will expire along with the new equipment warranty. A cold ambient warranty is available for existing equipment if the cold ambient upgrade is done at the time of overhaul. If an existing eligible turbine undergoes a "field retrofit" of the Pilot Active Control Logic, emissions values as shown in Table 1 are "expected" but not warranted. A warranty can be activated at the next engine overhaul and will expire along with the engine overhaul warranty. **Not all legacy models/ratings will have a cold ambient warranty option.**

For information on the availability and approvals for cold ambient temperature emissions warranties, please contact Solar's sales representatives.

Table 2 summarizes "expected" emissions levels for ambient temperatures below 0°F for Solar's *SoLoNOx* turbines that are not equipped with the Pilot Active Control Logic or do not have the a generation of hardware that can be equipped with Pilot Active Control Logic. The emissions levels are extrapolated from San Diego factory tests and may vary at extreme temperatures and as a result of variations in other parameters, such as fuel composition, fuel quality, etc.

Table 3 summarizes "expected" emissions levels for ambient temperatures below –20°F for the *Titan* 250.

Table 2. Expected Emissions below 0°F for SoLoNOx Combustion Turbines without Pilot Active Control Logic
NOx ppm values corrected to 15% O2

Turbine Model	Fuel	Applicable Load	NOx, ppm	CO, ppm	UHC, ppm
Centaur 40	Gas	50 to 100% load	120	150	50
Centaur 50	Gas	50 to 100% load	120	150	50
	Gas	50 to 100% load	120	150	50
Taurus 60	Gas	50 to 100% load	120	150	50
Taurus 65	Gas	50 to 100% load	120	150	50
Taurus 70	Gas	50 to 100% load	120	150	50
Mars 90	Gas	50 to 100% load	120	150	50
Mars 100	Gas	50 to 100% load	120	150	50
Titan 130	Gas	50 to 100% load	120	150	50
Centaur 40	Liquid	80 to 100% load	150	150	75
Centaur 50	Liquid	65 to 100% load	150	150	75
Taurus 60	Liquid	65 to 100% load	150	150	75
Taurus 70	Liquid	65 to 100% load	150	150	75
Mars 100	Liquid	65 to 100% load	150	150	75
Titan 130	Liquid	65 to 100% load	150	150	75

Table 3. Expected Emissions below –20°F for the Titan 250 SoLoNOx Combustion Turbine
NOx ppm values corrected to 15% O2

Turbine Model	Fuel	Applicable Load	NOx, ppm	CO, ppm	UHC, ppm
Titan 250	Gas	40 to 100% load	70	150	50

For a more conservative NOx emissions estimate than shown in Table 2 or 3, customers can refer to the NSPS 40CFR60, Subpart KKKK, where the allowable NOx emissions level for ambient temperatures < 0°F is 150 ppm NOx at 15% O_2. For pre-February 18, 2005, *SoLoNOx* combustion turbines subject to 40CFR60 subpart GG, a conservative estimate is the appropriate subpart GG emissions level. Subpart GG levels range from 150 to 214 ppm NOx at 15% O_2 on natural gas (and 150-210 on liquid fuel) depending on the turbine model.

COLD AMBIENT PERMITTING STRATEGY OPTIONS

When permitting in cold ambient climates, customers can use a “tiered emissions” permitting approach, choose to permit a single emission rate over all temperatures, use 40CFR60 Subpart KKKK, or develop another strategy to satisfy air permitting requirements.

In a “tiered” approach, a digital thermometer is installed to record ambient temperature. The amount of time is recorded that the ambient temperature falls below 0°F. The amount of time below 0°F is then used with the emissions estimates shown in Tables 1 and 2 to estimate “actual” emissions during sub-zero operation.

For customers who wish to permit at a single emission rate over all ambient temperatures, inlet air heating can be used to raise the engine inlet air temperature (T_1) above 0°F. With inlet air heating to keep T_1 above 0°F, standard emission warranty levels may be offered. Inlet air heating technology options include an electric resistance heater, an inlet air to exhaust heat exchanger and a glycol heat exchanger.

A conservative alternative to using the NOx values in Tables 1, 2 and 3 is to reference 40CFR60 subpart KKKK, which allows 150 ppm NOx at 15% O_2 for sub-zero operation.

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123-5398

Volatile Organic Compound, Sulfur Dioxide, and Formaldehyde Emission Estimates

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

This Product Information Letter (PIL) summarizes recommended emission factors often utilized to estimate emissions of volatile organic compounds (VOC), sulfur dioxide (SO_2), and formaldehyde from gas turbines.

INTRODUCTION

Emissions estimates of VOC, SO2, and formaldehyde are often necessary during the air permitting process. In absence of manufacturer, site-specific or representative source test data, gas turbine users often refer to EPA (or state) reference documents or databases. The emissions estimates in this PIL are assumed valid at ambient temperatures >0 °F and for natural gas from 50-100% load (40-100% load for the *Titan*™ 250 and 80-100% load for the *Saturn*® 20) or for liquid fuel from 65-100% load (80-100% for the *Saturn* 20 and *Centaur*® 40).

Volatile Organic Compounds

Permitting agencies usually require gas turbine users to include emissions of VOC, a subpart of the unburned hydrocarbon (UHC) emissions, during the air permitting process. Volatile organic compounds, non-methane hydrocarbons (NMHC), and reactive organic gases (ROG) are some of the ways of referring to the non-methane (and non-ethane) portion of an “unburned hydrocarbon” emission estimate.

For natural gas fuel, most Solar customers use a 5 ppm VOC level to estimate emissions for the air permit. For liquid fuel, Solar’s customers usually assume UHC emissions equal VOC emissions. The UHC/VOC value typically used is 25 ppm.

EPA’s AP-42[1] document and WebFIRE[2] database also contain VOC emissions estimates for gas turbines. These sources are seldom used by Solar’s customers.

Sulfur Dioxide

Sulfur dioxide emissions are produced by conversion of sulfur in the fuel to SO_2. Solar customers usually either use a mass balance calculation or AP-42/WebFIRE to estimate SO_2 emissions. Because Solar does not control the amount of sulfur in the fuel, no SO_2 emissions warranty is available.

The mass balance method assumes that any sulfur in the fuel converts to SO_2. For reference, the typical mass balance equation is shown below.

$$\frac{\text{lb } SO_2}{\text{hr}} = \left(\frac{\text{wt\% Sulfur}}{100}\right)\left(\frac{\text{lb fuel}}{\text{Btu}}\right)\left(\frac{10^6 \text{ Btu}}{\text{MMBtu}}\right)\left(\frac{\text{MMBtu fuel}}{\text{hr}}\right)\left(\frac{\text{MW } SO_2}{\text{MW Sulfur}}\right)$$

[1] AP-42 is an EPA document containing a compilation of air pollutant emission factors by source category.
[2] WebFIRE is an EPA electronic based repository and retrieval tool for emission factors.

Variables: wt % of sulfur in fuel
Btu/lb fuel (LHV)
MMBtu/hr fuel flow (LHV)

As an alternative to the mass balance calculation, EPA's AP-42 document can be used. AP-42 (Table 3.1-2a, April 2000) suggests emission factors of 0.94S lb/MMBtu (HHV) (where S=sulfur % in fuel) or 0.0034 lb/MMBtu (HHV) for gas fuel and 1.01S lb/MMBtu (HHV) (where S=sulfur % in fuel) or 0.033 lb/MMBtu (HHV) for liquid fuel.

Formaldehyde

For gas turbines, formaldehyde emissions are a result of incomplete combustion. Formaldehyde in the exhaust stream is unstable and difficult to measure. In addition to turbine characteristics including combustor design, size, maintenance history, and load profile, the formaldehyde emissions level is also affected by: ambient temperature, humidity, atmospheric pressure, fuel quality, formaldehyde concentration in the ambient air, test method measurement variability, and operational factors.

The emission factor data in Table 1 is an excerpt from an EPA memo: "Revised HAP Emission Factors for Stationary Combustion Turbines, 8/22/03." The memo presents hazardous air pollutant (HAP) emission factor data in several categories. The emission factors in the memo are a compilation of the HAP data EPA collected during the Maximum Achievable Control Technology (MACT) standard development process. The emission factor documentation shows there is a high degree of variability in formaldehyde emissions from gas turbines, depending on the manufacturer, rating size of equipment, combustor design, and testing events.

Table 1. EPA's Total HAP and Formaldehyde Emission Factors for <50 MW Lean-Premix Gas Turbines burning Natural Gas

(Source: Revised HAP Emission Factors for Stationary Combustion Turbines, OAR-2002-0060, IV-B-09, 8/22/03)

Pollutant	Engine Load	95% Upper Confidence of Mean, lb/MMBtu HHV	95% Upper Confidence of Data, lb/MMBtu HHV	Memo Reference
Total HAP	> 90%	0.00144	0.00258	Table 19
Total HAP	All	0.00160	0.00305	Table 16
Formaldehyde	> 90%	0.00127	0.00241	Table 19
Formaldehyde	All	0.00143	0.00288	Table 16

AP-42 and the California Air Toxics Emission Factor (CATEF) database also contain formaldehyde emission factors. Both sources reference data that is older than the data summarized in Table 1.

To estimate formaldehyde emissions from gas turbines, users should use the emission factor that best represents the gas turbine's actual/planned operating profile. Solar does not offer a formaldehyde emissions warranty.

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123-5398

Emission Estimates at Start-up, Shutdown, and Commissioning for SoLoNOx Combustion Products

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

The purpose of this Product Information Letter (PIL) is to provide emission estimates for start-up and shutdown events for *Solar*® gas turbines with *SoLoNOx*™ dry low emissions combustion systems.[1] For start-up and shutdown emissions estimates for conventional combustion turbines, landfill gas, digester gas, or other alternative fuel applications, contact Solar's Environmental Programs Department.

INTRODUCTION

The information presented in this document is representative for both generator set (GS) and compressor set / mechanical drive (CS/MD) combustion turbine applications. Operation of duct burners and/or any add-on control equipment is not accounted for in the emissions estimates. Emissions estimates related to the start-up, shutdown, and commissioning of combustion turbines will not be warranted. The estimates in this document are based on limited engine testing and analysis. The engine testing was conducted at idle and other non-*SoLoNOx* mode load points. An actual SU/SD event was not measured.

The estimates are most commonly used for potential to emit calculations to determine air permitting status. **Solar discourages customers from accepting the estimates as start-up and shutdown event permit limits with or without source testing requirements.** Accurately measuring emissions during a – non-steady state - start-up or shutdown event with steady state source test methods may prove to be very challenging. In the event customers take permit limits and accept compliance testing permit conditions, Solar recommends adding significant margin to the estimates in this document.

START-UP PROCESS

The duration of a nominal start-up is the same for a cold start, warm start, or hot start (e.g. a Solar Turbine is programmed to start-up in "x" minutes whether it's a cold, warm, or hot start).

The start-up and shutdown time for a *Solar* turbine in a simple-cycle or combined heat and power application is the same. Heat recovery steam generator (HRSG) steam pressure is usually 250 psig or less. At 250 psig or less, thermal stress within the HRSG is minimized and, therefore, firing ramp-up/ramp-down is not limited. However, some combined heat and power plant applications will desire or dictate longer start-up/shutdown times due to external requirements.

The start-up sequence and attaining *SoLoNOx* combustion mode, takes three steps:

1. Purge-crank
2. Ignition and acceleration to idle
3. Loading / thermal stabilization

[1] Start-up and shutdown emissions estimates for the *Mercury*™ 50 engine are found in PIL 205.

During the "purge-crank" step, rotation of the turbine shaft is accomplished with a starter motor to remove any residual fuel gas in the engine flow path and exhaust. During "ignition and acceleration to idle," fuel is introduced into the combustor and ignited in a diffusion flame mode and the engine rotor is accelerated to idle speed.

The third step consists of applying up to 50% load[2] while allowing the combustion flame to transition and stabilize. Once 50% load is achieved, the turbine transitions to *SoLoNOx* combustion mode and the engine control system begins to maintain the combustion primary zone temperature and limit pilot fuel to achieve the targeted nitrogen oxides (NOx), carbon monoxide (CO), and unburned hydrocarbons (UHC) emission levels.

SHUTDOWN PROCESS

Normal, planned cool down/shutdown duration varies by engine model. Once the shutdown process starts the engine unloads and moves into a cooldown mode.

START-UP AND SHUTDOWN EMISSIONS ESTIMATES

Tables 1 through 5 summarize the estimated pounds of emissions per start-up and shutdown event for *SoLoNOx* products. The mass emissions estimates are calculated using exhaust characteristics at ISO conditions in conjunction with ppm emissions estimates at various load points. The estimates in Tables 1 and 2 are representative of new production units ordered from 2006 up until the implementation of Enhanced Emissions Control. Tables 3 and 4 summarize emissions estimates for turbine models and ratings equipped with Enhanced Emissions Control. Enhanced Emissions Control is a new control regime that will result in lower CO and UHC values at lower loads thus reducing the estimated emissions per start-up and shutdown sequence. The *Titan*™ 250 and the *Titan* 130 23001/23502 (and 22401/22402) ratings have always been equipped with Enhanced Emissions Control. As testing is completed and other models/ratings are qualified and able to be equipped with the updated controls, PIL170 will be updated. Reference PIL 220, specifically pages 7 and 8, for additional information about Enhanced Emissions Control. Table 5 summarizes start-up and shutdown emissions estimates for liquid fuel applications.

Please contact Environmental Programs, Leslie Witherspoon (858.694.6609) or Anthony Pocengal (858.505.8554) for support.

COMMISSIONING EMISSIONS

Commissioning generally takes place over a two-week period. Static testing, where no combustion occurs, usually requires one week and no emissions are expected. Dynamic testing, where combustion will occur, typically includes a number of engine start and shutdown cycles and a variety of loads will be placed on the system. It is impossible to predict how long the turbine will run and in what combustion / emissions mode it will be running. The dynamic testing period is generally followed by one to two days of final commissioning during which the turbine is running at various loads.

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123-5398

[2] 40% load for the *Titan* 250 engine on natural gas. 65% load for all engines on liquid fuel (except 80% load for the *Centaur* 40).

Table 1. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set Applications
Nominal Start-up and Shutdown, Natural Gas Fuel

Production Units from 2006 and without Enhanced Emissions Control

Emissions estimates will NOT be warranted.

	Centaur 40 4701S					Centaur 50 6201S					Taurus 60 7901S					Taurus 65 8701S				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Total Emissions per Start (lbs)	2	158	83	17	247	1	67	84	17	333	1	86	110	22	338	1	74	67	13	376
Total Emissions per Shutdown (lbs)	2	149	74	15	286	1	65	75	15	367	1	79	92	18	392	1	73	54	11	435

	Taurus 70 10801S					Mars 90 13000S GSC					Mars 100 15000/16000S GSC					Titan 130 20501S				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Total Emissions per Start (lbs)	1	78	67	13	544	1	84	41	8	640	1	81	39	8	669	3	172	138	28	832
Total Emissions per Shutdown (lbs)	1	77	52	10	513	1	91	33	7	711	1	91	33	7	775	3	169	111	22	961

Assumes ISO conditions: 59F, 60% RH, sea level, no losses

Assumes unit is operating at >50% load prior to shutdown.

Assumes natural gas fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Table 2. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx CS/MD Applications
Nominal Start-up and Shutdown, Natural Gas Fuel

Production Units from 2006 and without Enhanced Emissions Control

Emissions estimates will NOT be warranted.

	Centaur 40 4702S					Centaur 50 6102S					Taurus 60 7802S				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Total Emissions per Start (lbs)	1	48	24	5	188	0.3	21	17	3	184	0.4	22	17	3	180
Total Emissions per Shutdown (lbs)	1	81	37	7	285	1	37	23	5	318	1	40	25	5	319

	Taurus 70 10802S					Mars 90 13000S CS/MD					Mars 100 15000S/16000S CS/MD				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Total Emissions per Start (lbs)	1	88	88	18	381	1	45	20	4	437	1	46	20	4	385
Total Emissions per Shutdown (lbs)	1	62	40	8	473	1	79	26	5	674	1	82	26	5	676

	Titan 130 20502S				
	NOx	CO	UHC	VOC	CO2
Total Emissions per Start (lbs)	1	55	37	7	662
Total Emissions per Shutdown (lbs)	2	91	46	9	945

Assumes ISO conditions: 59F, 60% RH, sea level, no losses.

Assumes unit is operating at >50% load prior to shutdown.

Assumes natural gas fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Table 3. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set Applications
Nominal Start-up and Shutdown, Natural Gas Fuel

Production Units with Enhanced Emissions Control

Emissions estimates will NOT be warranted.

	Taurus 70 10801S* / 11101S GSC (Post 2/2018 Orders)					Mars 100 16000S GSC (Post 8/2017 Orders)				
	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	1	39	50	10	544	1	31	23	5	669
Total Emissions per Shutdown (lbs)	1	26	32	6	513	1	24	20	4	775

* For <15 ppm NOx 10801S units, use Table 1. PIL170 will be updated when Enhanced Emissions Control is available on <15 ppm NOx warranted 10801S units.

	Titan 130 20501S GSC (Post 2/2018 Orders)					Titan 130 23001S GSC (All Units)					Titan 250 30000S GSC (All Units)					Titan 250 31900S GSC (All Units)				
	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	2	78	89	18	832	1	41	46	9	905	2	38	14	3	1445	2	38	14	3	1455
Total Emissions per Shutdown (lbs)	2	56	64	13	961	2	30	34	7	1030	2	23	9	2	1200	2	23	9	2	1217

Assumes ISO conditions: 59F, 60% RH, sea level, no losses

Assumes unit is operating at >50% load prior to shutdown.

Assumes natural gas fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Table 4. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx CS/MD Applications
Nominal Start-up and Shutdown, Natural Gas Fuel

Production Units with Enhanced Emissions Control

Emissions estimates will NOT be warranted.

	Taurus 70 10802S* CS/MD (Post 2/2018 Orders)				
	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	1	37	52	10	381
Total Emissions per Shutdown (lbs)	1	13	17	3	473

* For <15 ppm NOx 10801S units, use Table 1. PIL170 will be updated when Enhanced Emissions Control is available on <15 ppm NOx warranted 10801S units.

	Mars 100 16000S CS/MD (Post 8/2017 Orders)					Titan 130 22402S CS/MD (All Units)					Titan 130 23502S CS/MD (All Units)				
	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	1	17	12	2	385	1	27	31	6	690	1	22	25	5	717
Total Emissions per Shutdown (lbs)	1	23	16	3	676	1	24	27	5	1044	1	21	24	5	1064

	Titan 250 30000S CS/MD (All Units)					Titan 250 31900S CS/MD (All Units)				
	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	VOC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	2	32	12	2	1135	2	32	12	2	1130
Total Emissions per Shutdown (lbs)	2	21	8	2	1122	2	20	8	2	1111

Assumes ISO conditions: 59F, 60% RH, sea level, no losses.

Assumes unit is operating at >50% load prior to shutdown.

Assumes natural gas fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Table 5. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set Applications Nominal Start-up and Shutdown, Liquid Fuel (Diesel #2)

Emissions estimates will NOT be warranted.

	Centaur 40 4701S					Centaur 50 6201S					Taurus 60 7901S				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Total Emissions per Start (lbs)	4	140	23	23	419	3	130	22	22	472	4	147	25	25	483
Total Emissions per Shutdown (lbs)	4	126	21	21	452	3	103	17	17	536	4	116	19	19	580

	Taurus 70 10801S					Mars 100 16000S GSC					Titan 130 20501S				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Total Emissions per Start (lbs)	6	251	42	42	754	4	119	20	20	854	8	336	57	57	1164
Total Emissions per Shutdown (lbs)	4	144	24	24	737	5	128	20	20	1135	8	265	44	44	1374

	Titan 130 23001S					Titan 250 30000S					Titan 250 31900S				
	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2	NOx	CO	UHC	VOC	CO2
Total Emissions per Start (lbs)	8	321	54	54	1206	9	320	53	53	2189	8	291	48	48	2112
Total Emissions per Shutdown (lbs)	7	239	39	39	1444	8	215	34	34	2076	8	204	32	32	2080

Assumes ISO conditions: 59F, 60% RH, sea level, no losses.

Assumes unit is operating at >50% load prior to shutdown.

Assumes #2 Diesel fuel; ES 9-98 (Fuel Air and Water or Steam for Solar Gas Turbine Engines) compliant.

Particulate Matter Emission Estimates

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

This document summarizes Solar's recommended $PM_{10/2.5}$ emission levels for our combustion turbines. The recommended levels are based on an analysis of emissions tests collected from customer sites.

Particulate Matter Definition

National Ambient Air Quality Standards (NAAQS) for particulate matter were first set in 1971. Total suspended particulate (TSP) was the first indicator used to represent suspended particles in the ambient air. Since July 1, 1987, the Environmental Protection Agency (EPA) has used the indicator PM_{10}, which includes only the particles with aerodynamic diameter smaller than 10 micrometers (µm). PM_{10} (coarse particles) come from sources such as windblown dust from the desert or agricultural fields and dust kicked up on unpaved roads by vehicle traffic.

The EPA added a $PM_{2.5}$ ambient air standard in 1997. $PM_{2.5}$ includes particles with an aerodynamic diameter less than 2.5 µm. $PM_{2.5}$ (fine particles) are generally emitted from industrial and residential combustion and from vehicle exhaust. Fine particles are also formed in the atmosphere when gases such as sulfur dioxide, nitrogen oxides, and volatile organic compounds, emitted by combustion activities, are transformed by chemical reactions.

Nearly all particulate matter from gas turbine exhaust is less than one micrometer (micron) in diameter. Thus the emission rates of TSP, PM_{10}, and $PM_{2.5}$ from gas turbines are theoretically equivalent although source testing will show variation due to test method detection levels and processes.

TESTING FOR PARTICULATE MATTER

The turbine combustion process has little effect on the particulate matter generated and measured. The largest contributor to particulate matter emissions for gas and liquid fired combustion turbines is measurement technique and error. Other, minor contributing, sources of particulate matter emissions include carbon, ash, fuel-bound sulfur, artifact sulfate formation, compressor/lubricating oils, and inlet air.

Historical customer particulate matter source test data show that there is significant variability from test to test. The source test results support the common industry argument that particulate matter from natural gas fired combustion sources is difficult to measure accurately. The reference test methods for particulate matter were developed primarily for measuring emissions from coal-fired power plants and other major emitters of particulates. Particulate concentrations from gas turbine can be 100 to 10,000 times lower than the "traditional" particulate sources. The test methods were not developed or verified for low emission levels. There are interferences, insignificant at higher exhaust particulate matter concentrations that result in emissions greater than the actual emissions from gas turbines. New methods are being developed to address this problem.

Due to measurement and procedural errors, the measured results may not be representative of actual particulate matter emitted. There are many potential error sources in measuring particulate matter. Most of these have to do with contamination of the samples, material from the sampling apparatus getting into the samples, and human error in samples and analysis. Over the past few years, source test firms are gaining experience in measuring particulate matter and the historical variability from test to test and the emissions levels measured have decreased.

Recommended Particulate Matter Emission Factors

When necessary to support the air permitting process Solar recommends the following $PM_{10/2.5}$ emission factors for all models and ratings except for the *Mercury* 50. Please refer to PIL 205 for the *Mercury* 50. The emission factors below are intended to include both the front half (filterable) and the back half (condensable).

- Pipeline Natural Gas*: 0.01 lb/MMBtu fuel input (HHV)
- Landfill/Digester Gas†: 0.03 lb/MMBtu fuel input (HHV)
- Liquid Fuel#: 0.02 lb/MMBtu fuel input (HHV)

* Pipeline natural gas emissions factor assumes <1 grains of Sulfur per 100 standard cubic feet.
† Landfill/digester gas emissions factor assumes <0.15 lb SO2/MMBtu heat input.
\# Liquid fuel emission factor assumes fuel sulfur content is <500 ppm and ash content is <0.005% by wt.

Contact Solar's Environmental Programs group for particulate matter emissions estimates for fuels not listed above.

The conversion of a particulate matter emissions request from mg/Nm^3 to lb/MMBtu (HHV) units involves several specific turbine parameters. Please contact Solar if you need the calculation performed.

Recent customer source testing has shown that AP-42 (EPA AP-42 "Compilation of Air Pollutant Emission Factors.") emission factors for natural gas are achievable in the field, when the test method recommendations shown below are followed. Customers generally choose a particulate matter emissions factor at or above the AP-42 level that works for their site permitting recognizing that the lower the emissions factor the higher the risk for source testing.

Test Method Recommendation

Solar recommends that EPA Methods 201/201A[1] be used to measure the "front half". "Front half" represents filterable particulate matter.

EPA Method 202[2] (with nitrogen purge and field blanks) should be used to measure the "back half". "Back half" measurements represent the condensable portion of particulate matter.

EPA Method 5[3], which measures the front and back halves may be substituted (e.g. where exhaust temperatures do not allow the use of Method 202).

The turbine should have a minimum of 300 operating hours prior to conducting particulate matter source testing. The turbine should be running for 3-4 hours prior to conducting a particulate matter source test so that the turbine and auxiliary equipment is in a sustained "typical" operating mode prior to gathering samples.

Testing should include three 4-hour test runs.

Solar recommends using the aforementioned test methods until more representative test methods are developed and widely commercially available.

References

[1] EPA Method 201, Determination of PM10 Emissions, Exhaust Gas Recycle Procedure. EPA Method 201A, Determination of PM10 Emissions, Constant Sampling Rate Procedure, 40 CFR 60, Part 60, Appendix A.

[2] EPA Method 202, Determination of Condensible Particulate Emissions from Stationary Sources, 40 CFR 60, Part 60, Appendix A.

[3] EPA Method 5, Determination of Particulate Emissions from Stationary Sources, 40 CFR 60, Part 60, Appendix A.

Solar Turbines Incorporated
9330 Sky Park Court
San Diego, CA 92123-5398

APPENDIX C
RBLC Database Search Results

Appendix C
RBLC Database Search Results - PM2.5 Controls for Small Turbines
Lambert Compressor Station

RBLC ID	PERMIT NO.	PERMIT DATE	FACILITY NAME	COMPANY NAME	TURBINE SIZE	UNITS	TURBINE TYPE	CONTROL METHOD	EMISSION LIMIT #1	EMISSION LIMIT UNITS	EMISSION LIMIT #2	EMISSION LIMIT UNITS	CASE-BY-CASE BASIS
AK-0080	AQ0203CPT02	6/6/2013	ANCHORAGE MUNICIPAL LIGHT & POWER	MUNICIPALITY OF ANCHORAGE	408.2	MMBTU/H	NATURAL GAS TURBINES (2)	GOOD COMBUSTION AND OPERATING PRACTICES	0.0066	LB/MMBTU			OTHER CASE-BY-CASE
AK-0081	AQ1201CPT02	6/12/2013	POINT THOMSON PRODUCTION FACILITY	EXXONMOBIL CORPORATION	7.52	MW	Solar Turbine with SoLoNOx	GOOD COMBUSTION AND OPERATING PRACTICES	0.0066	LB/MMBTU			BACT-PSD
AK-0083	AQ0083CPT06	1/6/2015	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	37.6	MMBTU/H	SOLAR TURBINES (5)	NONE INDICATED	0.0074	LB/MMBTU			BACT-PSD
LA-0287	PSD-LA-787	7/21/2014	ALEXANDRIA COMPRESSOR STATION	COLUMBIA GULF TRANSMISSION COMPANY	20,405.0	HP	SOLAR TITAN 130	GOOD COMBUSTION PRACTICES	0.0180	LB/MMBTU	3.060	LB/H	BACT-PSD
LA-0287	PSD-LA-787	7/21/2014	ALEXANDRIA COMPRESSOR STATION	COLUMBIA GULF TRANSMISSION COMPANY	13,699.0	HP	SOLAR MARS 90	GOOD COMBUSTION PRACTICES	0.0180	LB/MMBTU	2.220	LB/H	BACT-PSD
LA-0331	PSD-LA-805	9/21/2018	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	263	MMBTU/H	AERODERIVATIVE SIMPLE CYCLE	GOOD COMBUSTION AND OPERATING PRACTICES			4.50	LB/H	BACT-PSD
LA-0331	PSD-LA-805	9/21/2018	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	921 (80)	MMBTU/H (MW)	COMBINED CYCLE (5 ON 2)	GOOD COMBUSTION AND OPERATING PRACTICES			9.53	LB/H	BACT-PSD
LA-0331	PSD-LA-805	9/21/2018	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	927	MMBTU/H	SIMPLE CYCLE TURBINES (3)	GOOD COMBUSTION AND OPERATING PRACTICES			8.00	LB/H	BACT-PSD
LA-0349	PSD-LA-824	7/10/2018	DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	540	MMBTU/H	COMPRESSOR TURBINES	GOOD COMBUSTION PRACTICES	0.0066	LB/MMBTU			BACT-PSD
LA-0316	PSD-LA-766(M3)	2/17/2017	CAMERON LNG FACILITY	CAMERON LNG, LLC	1,069	MMBTU/H	GAS TURBINES (9)	GOOD COMBUSTION PRACTICES	0.0076	LB/MMBTU			BACT-PSD
MI-0410	191-12	5/4/2016	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	171 (13)	MMBTU/H (MW)	Simple Cycle Combustion Turbines	GOOD COMBUSTION PRACTICES	0.0200	LB/MMBTU			BACT-PSD
MI-0420	185-15	6/3/2016	DTE GAS COMPANY--MILFORD COMPRESSOR	DTE GAS COMPANY	10,504	HP	Simple Cycle Combustion Turbines	GOOD COMBUSTION PRACTICES, PNG, AIR INLET FILTER	0.015	LB/MMBTU			BACT-PSD
MI-0426	185-15A	3/24/2017	DTE GAS COMPANY - MILFORD COMPRESSOR	DTE GAS COMPANY	10,504	HP	Simple Cycle Combustion Turbines	GOOD COMBUSTION PRACTICE, PNG, AIR INLET FILTER	0.015	LB/MMBTU			BACT-PSD
MI-0441	74-18	12/21/2018	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	667	MM BTU/h	Simple Cycle Combustion Turbine	Pipeline quality natural gas, inlet air conditioning and good combustion practices			4.500	LB/H	BACT-PSD
OK-0148	2012-1026-C PSD	9/12/2012	BUFFALO CREEK PROCESSING PLANT	MARKWEST BUFFALO CREEK GAS CO LLC	10,179	HP	SOLAR TAURUS 70-10802S	NONE INDICATED	0.0066	LB/MMBTU			BACT-PSD
OK-0153	2012-1393-C PSD	3/1/2013	ROSE VALLEY PLANT	SEMGAS LP	9,443	HP	SIEMENS SGT-200-2S	NATURAL GAS COMBUSTION	0.0066	LB/MMBTU			BACT-PSD
PA-0314	63-00922D	12/27/2017	BEECH HOLLOW	ROBINSON POWER COMPANY, LCC	2,433	MMBTU/H	TURBINED WITH DUCT BURNER	NONE INDICATED			18.20	LB/H	BACT-PSD
TX-0685	106011 PSDTX1310	5/916	GUADALUPE GENERATING STATION	GUADALUPE POWER PARTNERS LP	190	MW	GE OR SIEMENS (2)	NATURAL GAS COMBUSTION			NA		BACT-PSD
TX-0816	139479, PSDTX1496,	2/14/2017	CORPUS CHRISTI LIQUEFACTION	CORPUS CHRISTI LIQUEFACTION STAGE III,	40,000	HP	GE LM2500+ DLE TURBINES (2)	NONE INDICATED			0.75	LB/H	BACT-PSD
Recent Compressor Station Turbines BACT Determinations (Not in RBLC Database)													
	VA	1/28/2020	TRANSCO STATIONS 165 & 166	TRANSCONTINENTAL GAS PIPELINE CO.	23,150	HP	SOLAR TITAN 130	GOOD COMBUSTION PRACTICE, PNG, AIR INLET FILTER	0.01	LB/MMBTU	1.33	lb/hr	BACT
	VA	1/9/2019 (Vacated & Remanded)	BUCKINGHAM COMPRESSOR STATION	ATLANTIC COAST PIPELINE. LLC	15,900	HP	SOLAR MARS 100	GOOD COMBUSTION PRACTICE, PNG, AIR INLET FILTER	0.01	LB/MMBTU	0.83	lb/hr	BACT
	VA	1/9/2019 (Vacated & Remanded)	BUCKINGHAM COMPRESSOR STATION	ATLANTIC COAST PIPELINE. LLC	11,107	HP	SOLAR TAURUS 70	GOOD COMBUSTION PRACTICE, PNG, AIR INLET FILTER	0.01	LB/MMBTU	0.56	lb/hr	BACT
	VA	1/9/2019 (Vacated & Remanded)	BUCKINGHAM COMPRESSOR STATION	ATLANTIC COAST PIPELINE. LLC	20,500	HP	SOLAR TITAN 130	GOOD COMBUSTION PRACTICE, PNG, AIR INLET FILTER	0.01	LB/MMBTU	1.00	lb/hr	BACT
	VA	1/9/2019 (Vacated & Remanded)	BUCKINGHAM COMPRESSOR STATION	ATLANTIC COAST PIPELINE. LLC	6,276	HP	CENTAUR 50	GOOD COMBUSTION PRACTICE, PNG, AIR INLET FILTER	0.01	LB/MMBTU	0.35	lb/hr	BACT
	NC	2/27/2018	NORTHAMPTOM COMRPESSOR STATION	ATLANTIC COAST PIPELINE. LLC	11,107	HP	SOLAR TAURUS 70	GOOD COMBUSTION PRACTICE, PNG, AIR INLET FILTER	0.02	LB/MMBTU	1.92	lb/hr	BACT
	NC	2/27/2018	NORTHAMPTOM COMRPESSOR STATION	ATLANTIC COAST PIPELINE. LLC	6,276	HP	CENTAUR 50	GOOD COMBUSTION PRACTICE, PNG, AIR INLET FILTER	0.02	LB/MMBTU	1.2	lb/hr	BACT
	NC	2/27/2018	NORTHAMPTOM COMRPESSOR STATION	ATLANTIC COAST PIPELINE. LLC	4,427	HP	CENTAUR 50	GOOD COMBUSTION PRACTICE, PNG, AIR INLET FILTER	0.02	LB/MMBTU	1.02	lb/hr	BACT

Appendix C
RBLC Database Search Results - VOC Controls for Small Turbines
Lambert Compressor Station

RBLC ID	COUNTY	PERMIT NO.	PERMIT DATE	FACILITY NAME	COMPANY NAME	TURBINE SIZE	UNITS	TURBINE TYPE	CONTROL METHOD	EMISSION LIMIT #1	EMISSION LIMIT #1 UNITS	EMISSION LIMIT #2	EMISSION LIMIT #2 UNITS	CASE-BY-CASE BASIS
AK-0083		AQ0083CPT06	1/6/2015	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	37.6	MMBTU/H	SOLAR TURBINES (5)		0.0021	LB/MMBTU			BACT-PSD
AL-0251	TALLAPOOSA	310-0022-X001	9/24/2008	HILLABEE ENERGY CENTER	CER GENERATION	2,140.0	MMBTU/H	COMBUSTION TURBINE	GOOD COMBUSTION PRACTICES	0.0068	LB/MMBTU	18.1	LB/HR	BACT-PSD
CA-0954	FRESNO	C-3811-1-0	5/21/2001	CALPEAK POWER --PANOCHE	CALPEAK POWER --PANOCHE	24.7	MW	PRATT & WHITNEY FT8 GAS TURBINES (2)	OXIDATION CATALYST	2	PPMVD @15% O2			LAER
CA-1215	SAN DIEGO	2012--APP-002100	7/9/2012	QUALCOMM INC.	QUALCOMM INC.	4.37	MW	SOLAR MERCURY 50-6400R	NONE	7	PPMVD @15% O2			OTHER CASE-BY-CASE
CO-0058	WELD	03WE0910303-	6/12/2004	CHEYENNE STATION	CHEYENNE PLAINS GAS PIPELINE COMPANY	6,536	HP	SOLAR TAURUS 60-7800S	GOOD COMBUSTION PRACTICES	3	PPMVD @15% O2			BACT-PSD
CO-0058	WELD	03WE0910303-	6/12/2004	CHEYENNE STATION	CHEYENNE PLAINS GAS PIPELINE COMPANY	9,816	HP	SOLAR TAURUS 70-10302S	GOOD COMBUSTION PRACTICES	3	PPMVD @15% O2			BACT-PSD
CO-0059	WELD	04WE1390	3/29/2005	CHEYENNE STATION	CHEYENNE PLAINS GAS PIPELINE COMPANY	9,816	HP	SOLAR TAURUS 70-10302S	GOOD COMBUSTION PRACTICES	3	PPMVD @15% O2			BACT-PSD
FL-0266	HARDEE	PSD-FL-344 0490340-003-AC	6/29/2005	PAYNE CREEK GENERATING STATION/SEMINOLE	SEMINOLE ELECTRIC COMPANY	30	MW	SIMPLE CYCLE TURBINES (2)	OXIDATION CATALYST	90%	REMOVAL			BACT-PSD
ID-0011	BONNER	017-00037	4/4/2002	COMPRESSOR STATION NO. 4	PG&E GAS TRANSMISSION NORTHWEST CORP.	19,500	HP	SOLONOX TURBINE	NONE	0.31	LB/MMBTU			OTHER CASE-BY-CASE
LA-0257	CAMERON	PSD-LA-703(M3)	12/6/2011	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	286.0	MMBTU/H	GE LM2500+G4	GOOD COMBUSTION PRACTICES			0.66	LB/HR	BACT-PSD
LA-0316	CAMERON	PSD-LA-766(M3)	2/17/2017	CAMERON LNG FACILITY	CAMERON LNG, LLC	1,069	MMBTU/H	GAS TURBINES (9)	GOOD COMBUSTION PRACTICES	1.6	PPMVD @15% O2			BACT-PSD
LA-0331	CAMERON	PSD-LA-805	9/21/2018	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	263	MMBTU/H	AERODERIVATIVE SIMPLE CYCLE	GOOD COMBUSTION PRACTICES	1.5	PPMVD @15% O2			BACT-PSD
LA-0331	CAMERON	PSD-LA-805	9/21/2018	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	921 (80)	MMBTU/H (MW)	COMBINED CYCLE (5 ON 2)	OXIDATION CATALYST	1.1	PPMVD @15% O2			BACT-PSD
LA-0331	CAMERON	PSD-LA-805	9/21/2018	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	927	MMBTU/H	SIMPLE CYCLE TURBINES (3)	GOOD COMBUSTION PRACTICES	1.4	PPMVD @15% O2			BACT-PSD
LA-0349	CALCASIEU	PSD-LA-824	7/10/2018	DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	540	MMBTU/H	COMPRESSOR TURBINES	GOOD COMBUSTION PRACTICES	0.002	LB/MMBTU			BACT-PSD
MD-0035	CALVERT	009-5-0049	8/12/2005	DOMINION	DOMINION COVE POINT LNG, L.P.	21.7	MW	COMBUSTION TURBINES (2)	OXIDATION CATALYST	0.003	LB/MMBTU			LAER
MD-0036	CALVERT	CPCN 9055	3/10/2006	DOMINION	DOMINION COVE POINT LNG, L.P.	12.2	MW	SOLAR TITAN 130S	OXIDATION CATALYST			0.6	LB/HR	LAER
MI-0269	BERRIEN	4-98	2/16/2000	ANR PIPELINE CO./BRIDGMAN COMPRESSOR STATION	ANR PIPELINE CO.	13,803	HP	SOLAR MARS	STAGED COMBUSTION			8.9	LB/HR	BACT-PSD
MI-0410	GENESEE	191-12	5/4/2016	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	171 (13)	MMBTU/H (MW)	SIMPLE CYCLE TURBINE (2)	EFFICIENT COMBUSTION	0.017	LB/MMBTU			BACT-PSD
MI-0441	EATON	74-18	12/21/2018	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	667	MM BTU/h	SIMPLE CYCLE TURBINE	GOOD COMBUSTION PRACTICES			5	LB/HR	BACT-PSD
NJ-0055		PCP010001	4/5/2002	ALGONQUIN GAS	ALGONQUIN GAS TRANSMISSION COMPANY	7,520	HP	SOLAR TAURUS (2)	NONE			0.21	LB/HR	OTHER CASE-BY-CASE
NV-0048	CLARK	468	5/16/2006	GOODSPRINGS COMPRESSOR STATION	KERN RIVER GAS TRANSMISSION COMPANY	11.5	MW	SOLAR MARS 100-T15000S (3)	GOOD COMBUSTION PRACTICES	0.0069	LB/MMBTU	0.84	LB/HR	OTHER CASE-BY-CASE
NV-0050	CLARK	8250.00	11/30/2009	MGM MIRAGE	MGM MIRAGE	4.60	MMBTU/H	SOLAR MERCURY	GOOD COMBUSTION PRACTICES	0.24	LB/MMBTU	0.11	LB/HR	OTHER CASE-BY-CASE
OK-0148	BECKHAM	2012-1026-C PSD	9/12/2012	BUFFALO CREEK PROCESSING PLANT	MARKWEST BUFFALO CREEK GAS CO LLC	10,179	HP	SOLAR TAURUS 70-10802S	NONE	25	PPMVD @15% O2			BACT-PSD
OK-0153	WOODS	2012-1393-C PSD	3/1/2013	ROSE VALLEY PLANT	SEMGAS LP	9,443	HP	SIEMENS SGT-200-2S	GOOD COMBUSTION PRACTICES	10	PPMVD @15% O2	2.85	LB/HR	BACT-PSD
PA-0314	WASHINGTON	63-00922D	12/27/2017	BEECH HOLLOW	ROBINSON POWER COMPANY, LCC	2,433	MMBTU/H	TURBINE WITH DUCT BURNER	NONE	1.3	PPMVD @15% O2			LAER
TX-0454	HUDSPETH	P1030	10/31/2003	EL PASO NATURAL GAS CORNUDAS COMPRESSOR	EL PASO NATURAL GAS COMPANY	10,011	HP	SOLAR TAURUS 70 (2)	NONE			0.26	LB/HR	BACT-PSD
TX-0468	GALVESTON	P841	1/23/2003	UNION CARBIDE TEXAS CITY OPERATIONS	UNION CARBIDE CORPORATION - A SUBSIDIARY OF DOW CC	12,000	LB/H	SIEMENS	GOOD COMBUSTION PRACTICES			0.16	LB/HR	BACT-PSD
TX-0816	SAN PATRICIO	139479, PSDTX1496,	2/14/2017	CORPUS CHRISTI LIQUEFACTION	CORPUS CHRISTI LIQUEFACTION STAGE III, LLC	40,000	HP	GE LM2500+ DLE TURBINES (2)	GOOD COMBUSTION PRACTICES			0.68	LB/HR	BACT-PSD
WY-0067	CARBON	MD-7837	4/1/2009	LBWL--ERICKSON STATION	WILLIAMS FIELD SERVICES COMPANY	3,856	HP	SOLAR CENTAUR 40-T4700S	GOOD COMBUSTION PRACTICES	50	PPMVD @15% O2			BACT-PSD
WY-0067	CARBON	MD-7837	4/1/2009	LBWL--ERICKSON STATION	WILLIAMS FIELD SERVICES COMPANY	16,162	HP	SOLAR TITAN 130	GOOD COMBUSTION PRACTICES	25	PPMVD @15% O2			BACT-PSD
WY-0067	CARBON	MD-7837	4/1/2009	LBWL--ERICKSON STATION	WILLIAMS FIELD SERVICES COMPANY	12,555	HP	SOLAR MARS 100-15000S	GOOD COMBUSTION PRACTICES	25	PPMVD @15% O2			BACT-PSD

Appendix C
RBLC Database Search Results - NOx Controls for Small Turbines
Lambert Compressor Station

RBLC ID	COUNTY	PERMIT NO.	PERMIT DATE	FACILITY NAME	COMPANY NAME	TURBINE SIZE	UNITS	TURBINE TYPE	CONTROL METHOD	EMISSION LIMIT #1	EMISSION LIMIT #1 UNITS	EMISSION LIMIT #2	EMISSION LIMIT #2 UNITS	CASE-BY-CASE BASIS
AK-0045		0023-AC007	6/6/2000	NORTH COOK INLET UNIT	PHILLIPS PETROLEUM COMPANY	4,700	HP	SOLAR CENTAUR T-4700 (2)	NONE INDICATED	115.00	PPMVD @ 15% O2	0.43	LB/MMBTU	N/A
AK-0045		0023-AC007	6/6/2000	NORTH COOK INLET UNIT	PHILLIPS PETROLEUM COMPANY	6,749	HP	SOLAR TAURUS 60 T-7300S (2)	DLN	25.00	PPMVD @ 15% O2	6.20	LB/H	BACT-PSD
AK-0047		0073-AC023	7/13/2001	MILNE POINT PRODUCTION FACILITY	BP EXPLORATION (ALASKA) INC.	29,500	HP	GE LM-2500 TURBINES (2)	WATER INJECTION	184.00	PPMVD @ 15% O2	206.70	PPM @ 15% O2	N/A
AK-0062	NORTH SLOPE BOROUGH	AQ0417CPT05, REVISION 1	8/19/2005	BADAMI DEVELOPMENT FACILITY	BP EXPLORATION ALASKA	11.86	MW	SOLAR MARS 90 TURBINE	DLN (SOLONOX)	85.00	PPMVD @ 15% O2	28.40	LB/H	BACT-PSD
AK-0083		AQ0083CPT06	1/6/2015	KENAI NITROGEN OPERATIONS	AGRIUM U.S. INC.	37.6	MMBTU/H	SOLAR TURBINES (5)	SCR	7.00	PPMVD @ 15% O2			BACT-PSD
AL-0251	TALLAPOOSA	310-0022-X001	9/24/2008	HILLABEE ENERGY CENTER	CER GENERATION	2,140.0	MMBTU/H	COMBUSTION TURBINE	DLN & SCR	24.60	LB/HR	0.009	LB/MMBTU	BACT-PSD
AR-0075	COLUMBIA	0697-AOP-R4	8/20/2003	DELTIC TIMBER CORPORATION	DELTIC TIMBER CORPORATION	64.32	MMBTU/H	SIMPLE CYCLE TURBINE	DLN	14.00	PPMVD @ 15% O2			BACT-PSD
CA-0954	FRESNO	C-3811-1-0	5/21/2001	CALPEAK POWER --PANOCHE	CALPEAK POWER --PANOCHE	24.7	MW	PRATT & WHITNEY FT8 GAS TURBINES (2)	DLN & SCR	3.40	PPMVD @ 15% O2			LAER
CA-1215	SAN DIEGO	2012--APP-002100	7/9/2012	QUALCOMM INC.	QUALCOMM INC.	4.37	MW	SOLAR MERCURY 50-6400R	DLN (SOLONOX)	5.00	PPMVD @ 15% O2			OTHER CASE-BY-CASE
CO-0058	WELD	03WE0910303-	6/12/2004	CHEYENNE STATION	CHEYENNE PLAINS GAS PIPELINE COMPANY	6,536	HP	SOLAR TAURUS 60-7800S	DLN (SOLONOX)	15.00	PPMVD @ 15% O2			BACT-PSD
CO-0058	WELD	03WE0910303-	6/12/2004	CHEYENNE STATION	CHEYENNE PLAINS GAS PIPELINE COMPANY	9,816	HP	SOLAR TAURUS 70-10302S	DLN (SOLONOX)	24.50	PPMVD @ 15% O2			BACT-PSD
CO-0059	WELD	04WE1390	3/29/2005	CHEYENNE STATION	CHEYENNE PLAINS GAS PIPELINE COMPANY	9,816	HP	SOLAR TAURUS 70-10302S	DLN (SOLONOX)	15.00	PPMVD @ 15% O2			BACT-PSD
FL-0266	HARDEE	PSD-FL-344 0490340-003-AC	6/29/2005	PAYNE CREEK GENERATING STATION/SEMINOLE ELECTRIC	SEMINOLE ELECTRIC COMPANY	30	MW	SIMPLE CYCLE TURBINES (2)	WATER INJECTION AND LOW OPERATING HOURS	20.00	PPMVD @ 15% O2			Other Case-by-Case
ID-0011	BONNER	017-00037	4/4/2002	COMPRESSOR STATION NO. 4	PG&E GAS TRANSMISSION NORTHWEST CORP.	19,500	HP	SOLONOX TURBINE	DLN (SOLONOX)	25.00	PPMVD @ 15% O2	0.16	LB/MMSCF	BACT-PSD
IL-0076	WILL	1030010	10/3/2001	NG PIPELINE COMPANY OF AMERICA (STA 113)	NATURAL GAS PIPELINE COMPANY OF AMERICA	72.70	MMBTU/H	SOLAR TAURUS 70-T10302S	DLN	25.00	PPMVD @ 15% O2	0.10	LB/MMBTU	BACT-PSD
IL-0076	WILL	1030010	10/3/2001	NG PIPELINE COMPANY OF AMERICA (STA 113)	NATURAL GAS PIPELINE COMPANY OF AMERICA	16.75	MMBTU/H	TURBINES (9)	GOOD OPERATING PRACTICES	110.00	PPMVD @ 15% O2	0.44	LB/MMBTU	BACT-PSD
LA-0232	OACHITA	PSD-LA-729	6/24/2008	STERLINGTON COMPRESSOR STATION	GULF CROSSING PIPELINE CO. LLC.	10,311	HP	79.1 MMBTUH TURBINE (2)	DLN	15.00	PPMVD @ 15% O2	0.057	LB/MMBTU	BACT-PSD
LA-0257	CAMERON	PSD-LA-703(M3)	12/6/2011	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	286.0	MMBTU/H	GE LM2500+G4	water injection	20.00	PPMVD @ 15% O2	22.94	LB/H	BACT-PSD
LA-0287	RAPIDES	PSD-LA-787	7/21/2014	ALEXANDRIA COMPRESSOR STATION	COLUMBIA GULF TRANSMISSION COMPANY	20,405	HP	SOLAR TITAN 130	DLN	15.00	PPMVD @ 15% O2	9.23	LB/H	BACT-PSD
LA-0287	RAPIDES	PSD-LA-787	7/21/2014	ALEXANDRIA COMPRESSOR STATION	COLUMBIA GULF TRANSMISSION COMPANY	13,699	HP	SOLAR MARS 90	DLN	15.00	PPMVD @ 15% O2	6.64	LB/H	BACT-PSD
LA-0316	CAMERON	PSD-LA-766(M3)	2/17/2017	CAMERON LNG FACILITY	CAMERON LNG, LLC	1,069	MMBTU/H	GAS TURBINES (9)	DLN	15.00	PPMDV @15% O2			BACT-PSD
LA-0331	CAMERON	PSD-LA-805	9/21/2018	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	263	MMBTU/H	AERODERIVATIVE SIMPLE CYCLE	SCR	25.00	PPMVD @ 15% O2			BACT-PSD
LA-0331	CAMERON	PSD-LA-805	9/21/2018	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	921 (80)	MMBTU/H (MW)	COMBINED CYCLE (5 ON 2)	DLN & SCR	2.50	PPMVD @ 15% O2			BACT-PSD
LA-0331	CAMERON	PSD-LA-805	9/21/2018	CALCASIEU PASS LNG PROJECT	VENTURE GLOBAL CALCASIEU PASS, LLC	927	MMBTU/H	SIMPLE CYCLE TURBINES (3)	DLN	9.00	PPMVD @ 15% O2			BACT-PSD
LA-0349	CALCASIEU	PSD-LA-824	7/10/2018	DRIFTWOOD LNG FACILITY	DRIFTWOOD LNG LLC	540	MMBTU/H	Compressor Turbines	DLN and SCR	5.00	PPMDV @15% O2			BACT-PSD
MD-0035	CALVERT	009-5-0049	8/12/2005	DOMINION	DOMINION COVE POINT LNG, L.P.	21.7	MW	COMBUSTION TURBINES (2)	DLN & SCR	2.50	PPMVD @ 15% O2	1.00	LB/MW-H	BACT-PSD
MD-0036	CALVERT	CPCN 9055	3/10/2006	DOMINION	DOMINION COVE POINT LNG, L.P.	12.2	MW	SOLAR TITAN 130S	DLN & SCR	5.00	PPMDV @15% O2	1.20	LB/MW-H	LAER
MI-0269	BERRIEN	4-98	2/16/2000	ANR PIPELINE CO./BRIDGMAN COMPRESSOR STATION	ANR PIPELINE CO.	13,803	HP	SOLAR MARS	DLN	35.00	PPMDV @15% O2	17.10	LB/H	BACT-PSD
MI-0410	GENESEE	191-12	5/4/2016	THETFORD GENERATING STATION	CONSUMERS ENERGY COMPANY	171 (13)	MMBTU/H (MW)	SIMPLE CYCLE TURBINE (2)	DLN	0.09	LB/MMBTU			BACT-PSD
MI-0420	OAKLAND	185-15	6/3/2016	DTE GAS COMPANY--MILFORD COMPRESSOR STATION	DTE GAS COMPANY	10,504	HP	SIMPLE CYCLE TURBINES (5)	DLN	15.00	PPM			BACT-PSD
MI-0426	OAKLAND	185-15A	3/24/2017	DTE GAS COMPANY - MILFORD COMPRESSOR STATION	DTE GAS COMPANY	10,504	HP	SIMPLE CYCLE TURBINES (5)	DLN	15.00	PPM			BACT-PSD
MI-0441	EATON	74-18	12/21/2018	LBWL--ERICKSON STATION	LANSING BOARD OF WATER AND LIGHT	667	MM BTU/h	SIMPLE CYCLE TURBINE	DLN	25.00	PPMVD@15% O2	60.00	LB/H	BACT-PSD
NJ-0055		PCP010001	4/5/2002	ALGONQUIN GAS	ALGONQUIN GAS TRANSMISSION COMPANY	7,520	HP	SOLAR TAURUS (2)	DLN	24.50	PPMDV @15% O2	0.09	LB/MMBTU	BACT-PSD
NV-0048	CLARK	468	5/16/2006	GOODSPRINGS COMPRESSOR STATION	KERN RIVER GAS TRANSMISSION COMPANY	11.5	MW	SOLAR MARS 100-T15000S (3)	DLN (SOLONOX)	25.00	PPMDV @15% O2	0.10	LB/MMBTU	BACT-PSD
NV-0050	CLARK	8250.00	11/30/2009	MGM MIRAGE	MGM MIRAGE	4.60	MMBTU/H	SOLAR MERCURY	DLN	5.0000	PPMDV @15% O2	0.1780	LB/MMBTU	BACT-PSD
OK-0148	BECKHAM	2012-1026-C PSD	9/12/2012	BUFFALO CREEK PROCESSING PLANT	MARKWEST BUFFALO CREEK GAS CO LLC	10,179	HP	SOLAR TAURUS 70-10802S	DLN	15.00	PPMVD@15% O2			BACT-PSD
OK-0153	WOODS	2012-1393-C PSD	3/1/2013	ROSE VALLEY PLANT	SEMGAS LP	9,443	HP	SIEMENS SGT-200-2S	DLN	15.00	PPMVD @15% O2	4.47	LB/HR	BACT-PSD
OR-0027	DESCHUTES	09-0035	2/5/2002	COMPRESSOR STATION 12	PG&E GAS TRANSMISSION, NORTHWEST CORPORATION	19,200	HP	GENERAL ELECTRIC LM1600-19200 HP	NONE INDICATED	42.00	PPM @ 15% O2			BACT-PSD
OR-0027	DESCHUTES	09-0035	2/5/2002	COMPRESSOR STATION 12	PG&E GAS TRANSMISSION, NORTHWEST CORPORATION	19,500	HP	SOLAR TITAN 19500 HP	NONE INDICATED	25.00	PPM @ 15% O2			BACT-PSD
OR-0033	SHERMAN	28-0003	2/3/2002	COMPRESSOR STATION 10	PG& E GAS TRANSMISSION NORTHWEST CORPORATION	19,500	HP	GAS TURBINE	NONE INDICATED	25.00	PPM @ 15% O2			BACT-PSD

Appendix C
RBLC Database Search Results - NOx Controls for Small Turbines
Lambert Compressor Station

RBLC ID	COUNTY	PERMIT NO.	PERMIT DATE	FACILITY NAME	COMPANY NAME	TURBINE SIZE	UNITS	TURBINE TYPE	CONTROL METHOD	EMISSION LIMIT #1	EMISSION LIMIT #1 UNITS	EMISSION LIMIT #2	EMISSION LIMIT #2 UNITS	CASE-BY-CASE BASIS
OR-0033	SHERMAN	28-0003	2/3/2002	COMPRESSOR STATION 10	PG& E GAS TRANSMISSION NORTHWEST CORPORATION	14,000	HP	GAS TURBINE	NONE INDICATED	25.00	PPM @ 15% O2			BACT-PSD
PA-0314	WASHINGTON	63-00922D	12/27/2017	BEECH HOLLOW	ROBINSON POWER COMPANY, LCC	2,433	MMBTU/H	TURBINE WITH DUCT BURNER	SCR	2.00	PPMVD @ 15% O2			LAER
TX-0454	HUDSPETH	P1030	10/31/2003	EL PASO NATURAL GAS CORNUDAS COMPRESSOR	EL PASO NATURAL GAS COMPANY	10,011	HP	SOLAR TAURUS 70 (2)	DLN			7.60	LB/H	BACT-PSD
TX-0468	GALVESTON	P841	1/23/2003	UNION CARBIDE TEXAS CITY OPERATIONS	UNION CARBIDE CORPORATION - A SUBSIDIARY OF DOW CC	12,000	LB/H	SIEMENS	DLN	25.00	PPMVD @ 15% O2	24.00	LB/H	BACT-PSD
TX-0642	SAN PATRICIO	PSDTX1304	12/20/2013	SINTON COMPRESSOR STATION	CHENIERE CORPUS CHRISTI PIPELINE	20,000	hp	SOLAR TITAN 130 S	DLN (SOLONOX)	25.00	PPMVD @ 15% O2			BACT-PSD
TX-0685	GUADALUPE	106011 PSDTX1310	10/4/2013	GUADALUPE GENERATING STATION	GUADALUPE POWER PARTNERS LP	190	MW	GE OR SIEMENS (2)	DLN	9.00	PPMVD @ 15% O2			BACT-PSD
TX-0816	SAN PATRICIO	139479, PSDTX1496,	2/14/2017	CORPUS CHRISTI LIQUEFACTION	CORPUS CHRISTI LIQUEFACTION STAGE III, LLC	40,000	HP	GE LM2500+ DLE TURBINES (2)	DLN	25.00	PPMVD @ 15% O2			BACT-PSD
WA-0297	SKAGIT	PSD 01-09	8/30/2002	NORTHWEST PIPELINE CORPORATION MT. VERNON	NORTHWEST PIPELINE CORPORATION	12,787	HP	MARS 90-T13002S	DLN (SOLONOX)	25.00	PPM @ 15% O2	258.00	LB/D	BACT-PSD
WA-0297	SKAGIT	PSD 01-09	8/30/2002	NORTHWEST PIPELINE CORPORATION MT. VERNON	NORTHWEST PIPELINE CORPORATION	5,950	HP	CENTAUR 50-T6100S	DLN (SOLONOX)	25.00	PPM @ 15% O2	129.00	LB/D	BACT-PSD
WA-0304		NC-8473	7/3/2001	FREDERICKSON PLANT	PIERCE POWER LLC	22	MW	GE TM2500	SCR	9.00	PPMVD @ 15% O2			Other Case-by-Case
WA-0316	SKAGIT	PSD-01-09 AMENDMENT	6/14/2006	NORTHWEST PIPELINE CORP.-MT VERNON COMPRESSOR	NORTHWEST PIPELINE CORP.	12,787	HP	MARS 90-TI3002S	DLN	25.00	PPMDV	258.00	LB/D	BACT-PSD
WA-0316	SKAGIT	PSD-01-09 AMENDMENT	6/14/2006	NORTHWEST PIPELINE CORP.-MT VERNON COMPRESSOR	NORTHWEST PIPELINE CORP.	5,950	HP	CENTAUR 50-T6100S	DLN	25.00	PPMVD @ 15% O2	129.00	LB/D	BACT-PSD
WY-0059	LINCOLN	MD-783	7/30/2002	KERN RIVER GAS TRANSMISSION CO./MUDDY CREEK	KERN RIVER GAS TRANSMISSION CO.	13,192	HP	SIMPLE CYCLE TURBINES (3)	DLN (SOLONOX)	25.00	PPMVD @ 15% O2	9.80	LB/H	BACT-PSD
WY-0060	CARBON	MD-606	3/21/2001	WILLIAMS FIELD SERVICES CO./ECHO SPRINGS GAS PLANT	WILLIAMS FIELD SERVICES CO.	3,246	HP	SIMPLE CYCLE TURBINES (2)	DLN (SOLONOX)	25.00	PPMVD @ 15% O2	3.62	LB/H	BACT-PSD
WY-0067	CARBON	MD-7837	4/1/2009	LBWL--ERICKSON STATION	WILLIAMS FIELD SERVICES COMPANY	3,856	HP	SOLAR CENTAUR 40-T4700S	DLN (SOLONOX)	25.00	PPMVD @ 15% O2			BACT-PSD
WY-0067	CARBON	MD-7837	4/1/2009	LBWL--ERICKSON STATION	WILLIAMS FIELD SERVICES COMPANY	16,162	HP	SOLAR TITAN 130	DLN (SOLONOX)	15.00	PPMVD @ 15% O2			BACT-PSD
WY-0067	CARBON	MD-7837	4/1/2009	LBWL--ERICKSON STATION	WILLIAMS FIELD SERVICES COMPANY	12,555	HP	SOLAR MARS 100-15000S	DLN (SOLONOX)	15.00	PPMV			BACT-PSD
Recent Compressor Station Turbines BACT Determinations (Not in RBLC Database)														
	PITTSYLVANIA	VA	1/28/2020	TRANSCO STATIONS 165 & 166	TRANSCONTINENTAL GAS PIPELINE CO.	23,150	HP	SOLAR TITAN 130	DLN (SOLONOX) & SCR	3.75	PPMVD @ 15% O2	2.59	LB/H	BACT
	BUCKINGHAM	VA	1/9/2019 (Vacated & Remanded)	BUCKINGHAM COMPRESSOR STATION	ATLANTIC COAST PIPELINE. LLC	15,900	HP	SOLAR MARS 100	DLN (SOLONOX) & SCR	3.75	PPMVD @ 15% O2	9.09	LB/H	BACT
	BUCKINGHAM	VA	1/9/2019 (Vacated & Remanded)	BUCKINGHAM COMPRESSOR STATION	ATLANTIC COAST PIPELINE. LLC	11,107	HP	SOLAR TAURUS 70	DLN (SOLONOX) & SCR	3.75	PPMVD @ 15% O2	6.01	LB/H	BACT
	BUCKINGHAM	VA	1/9/2019 (Vacated & Remanded)	BUCKINGHAM COMPRESSOR STATION	ATLANTIC COAST PIPELINE. LLC	20,500	HP	SOLAR TITAN 130	DLN (SOLONOX) & SCR	3.75	PPMVD @ 15% O2	11.03	LB/H	BACT
	BUCKINGHAM	VA	1/9/2019 (Vacated & Remanded)	BUCKINGHAM COMPRESSOR STATION	ATLANTIC COAST PIPELINE. LLC	6,276	HP	CENTAUR 50	DLN (SOLONOX) & SCR	3.75	PPMVD @ 15% O2	3.86	LB/H	BACT
	NORTHAMPTON	NC	2/27/2018	NORTHAMPTOM COMRPESSOR STATION	ATLANTIC COAST PIPELINE. LLC	11,107	HP	SOLAR TAURUS 70	DLN (SOLONOX) & SCR	5	PPMVD @ 15% O2			
	NORTHAMPTON	NC	2/27/2018	NORTHAMPTOM COMRPESSOR STATION	ATLANTIC COAST PIPELINE. LLC	6,276	HP	CENTAUR 50	DLN (SOLONOX) & SCR	5	PPMVD @ 15% O2			
	NORTHAMPTON	NC	2/27/2018	NORTHAMPTOM COMRPESSOR STATION	ATLANTIC COAST PIPELINE. LLC	4,427	HP	CENTAUR 50	DLN (SOLONOX) & SCR	5	PPMVD @ 15% O2			

DLN - DRY LOW NOX BURNERS
SCR - SELECTIVE CATALYTIC REDUCTION

APPENDIX D
Legal Analysis of Electric Compression in BACT Determination

Appendix D

Electric Compression need not be considered as Best Available Control Technology for Lambert Compressor Station

This attachment addresses the legal question whether electric compression must be considered in evaluating Best Available Control Technology ("BACT") for a natural gas compressor station. While electric compression has been used to meet Lowest Available Emission Rate requirements in non-attainment areas, Lambert Compressor Station is located in an attainment area, where BACT applies. At Lambert Compressor Station, electric compression need not be considered as BACT based on regulatory language, how BACT is implemented in practice and common sense, electric compression need not be considered as an alternative.

Virginia Regulatory Language

Virginia minor sources BACT requirements apply to "affected facilities." 9 VAC 5-50-260.A. Permits, including BACT standards, are issued for "affected emissions units." 9 VAC5-50-260.B. "Affected facility," however, means, with reference to a stationary source, any part, equipment, facility, installation, apparatus, process or operation to which an emission standard is applicable or any other facility so designated. 9 VAC 5-80-20. Natural gas compressors are emission units and affected units subject to standards for turbine compressors established under Part 60 and 63 of Title 40 of the Federal Code of Regulations. Electric compressors are inherently different, have no emission standards (they have no point-source emissions) and are neither emissions units nor affected facilities and would not require a permit or trigger BACT in the first place.

How BACT is implemented

DEQ has developed two manuals for minor source permitting: Article 6 Minor Source Permitting Manual (2005)(Draft) (https://townhall.virginia.gov/L/ViewGDoc.cfm?gdid=2844), and New Source Permitting Manual (https://townhall.virginia.gov/L/ViewGDoc.cfm?gdid=2188). Both of these manuals state that BACT analyses are to be performed using EPA's NSR Permit Workshop Manual (1990)(Draft) Chapter B. Id. pg. 59. *Ibid*. Pg. 8-2. The EPA Manual adopts a "top-down" BACT review process that allows, but does not require, consideration of lower emitting alternative technologies that serve the same function and achieve the same goals and purposes. As explained in Section 5 of the Application, in step three of the BACT process, alternatives are ranked in order of emissions. In this case, it is highly unlikely that the use of electric compression as an alternative technology for the Project would result in any reduction in emissions; and therefore, it is not an inherently less polluting alternative. While electric compression does not produce any on-site emissions, a greater amount of energy must be consumed at an electrical generating station nearby to produce the electricity to power the electric compressors. The emissions from that generating station are at best equivalent to that of on-site natural gas fuel compression and likely higher due to:

(i) the electrical losses of transmission;

(ii) the highly efficient and well-controlled natural gas compressors proposed for the Project; and

(iii) the fact that electrical generation is likely to be at least in part from coal-fired generation and natural gas.

Projected emissions comparing on-site natural gas compression to offsite power generation is provided in Table 5-1. It demonstrates that off-site electric generation could actually end up producing more emissions in powering on-site electric compression than on-site natural gas compression; therefore, electric generation is not an inherently lower emitting technology and need not be considered in the BACT analysis.

Moreover, MVP Southgate's proposed use of natural gas compression provides important practical advantages that allows it to meet the project's purposes and goals that electric compression does not offer. These advantages include increased reliability, one of the main goals of the project, because natural gas will always be available at the site when compression is required. In stark contrast, sufficient electrical voltage and amperage are not available at the site to power electric compression. Even if appropriate infrastructure were installed, electrical lines are subject to weather and overloading which can cause outages. Moreover, the projects goals and purposes would be further frustrated by the time required to design, permit, procure and construct the necessary electrical infrastructure, and the in-service date would be delayed far beyond that imposed by MVPs customers who have documented the need for prompt delivery of natural gas.

Common Sense

As for common sense, the Seventh Circuit has explained, a requirement to consider *any* lower emitting possibility would result in endless challenges.

> That approach would invite a litigation strategy that would make seeking a permit for a new power plant a Sisyphean labor, for there would always be one more option to consider.

In re Prairie State, 499 F 3d at 654. *Prairie State* is particularly relevant to Lambert Compressor Station because sufficient electrical power is not available at the site. Thus, substantial electrical infrastructure would be required to be constructed, by a third party utility company, to supply adequate power even though natural gas would always be present at Lambert Compressor Station when compression is required. Such a rejection of the use of available on-site fuel and a requirement to use electricity from offsite is similar to the situation recognized as unacceptable by the Seventh Circuit in *Prairie State;*

> But to convert the design from that of a mine-mouth plant to one that burned coal obtained from a distance would require that the plant undergo significant modifications—concretely, the half-mile-long conveyor belt, and its interface with the mine and the plant, would be superfluous and instead there would have to be a rail spur and facilities for unloading coal from rail cars and feeding it into the plant.

In addition, a requirement to use electric compression could make some project purposes impossible to achieve. At Lambert Compressor Station, for example, electric compression would be inherently less reliable in delivering natural gas to markets that demand such reliability. Finally, a requirement to use the lowest emitting source would eliminate the diversification of technologies, forcing society to put all its eggs in one basket and creating vulnerabilities in the system. So for example, a requirement to use only solar power would create the risk of catastrophic failure on a cloudy day.

APPENDIX E:
Supplemental Information on Electric vs. Gas Compression Analysis

North Carolina Utilities Commission (NCUC) Annual Report Regarding Long Range Needs for Expansion of Electric Generation Facilities for Service in North Carolina

ANNUAL REPORT REGARDING LONG RANGE NEEDS FOR EXPANSION OF ELECTRIC GENERATION FACILITIES FOR SERVICE IN NORTH CAROLINA

REQUIRED PURSUANT TO N.C. Gen. Stat. § 62-110.1(c)

DATE DUE: DECEMBER 31, 2019
SUBMITTED: DECEMBER 31, 2019

RECEIVED BY
THE GOVERNOR OF NORTH CAROLINA
AND
THE JOINT LEGISLATIVE COMMISSION ON GOVERNMENTAL OPERATIONS

SUBMITTED BY
THE NORTH CAROLINA UTILITIES COMMISSION

ABBREVIATIONS AND ACRONYMS

ACE EPA's Affordable Clean Energy Rule
CC combined-cycle
CECPCN Certificate of Environmental Compatibility and Public Convenience and Necessity
CIGFUR Carolina Industrial Group for Fair Utility Rates
COL combined construction and operating license
CPCN Certificate of Public Convenience and Necessity
CPP EPA's Clean Power Plan
CT combustion turbine/s
CUCA Carolina Utility Customers Association, Inc.
DOE U.S. Department of Energy
DSM demand-side management
Duke Duke Energy Carolinas, LLC
Dominion Dominion Energy North Carolina
EDF Environmental Defense Fund
EE energy efficiency
EMC electric membership corporation
EnergyUnited EnergyUnited EMC
EPA U.S. Environmental Protection Agency
EPAct 2005 Energy Policy Act of 2005
FERC Federal Energy Regulatory Commission
GreenCo GreenCo Solutions, Inc.
GridSouth GridSouth Transco, LLC
G.S. General Statute
GWh gigawatt-hour/s
Halifax Halifax EMC
IOU investor-owned electric utility
IRP integrated resource planning/integrated resource plans
kWh kilowatt-hour/s
LEE CC Lee combined-cycle plant in SC
Lee Nuclear William States Lee III nuclear station in SC
MAREC Mid-Atlantic Renewable Energy Coalition
MW megawatt/s
MWh megawatt-hour/s
NCDEQ North Carolina Department of Environmental Quality
NCEMC North Carolina Electric Membership Corporation

ABBREVIATIONS AND ACRONYMS (continued)

NCEMPA North Carolina Eastern Municipal Power Agency
NCMPA1 North Carolina Municipal Power Agency No. 1
NC-RETS North Carolina Renewable Energy Tracking System
NCSEA North Carolina Sustainable Energy Association
NCTPC North Carolina Transmission Planning Collaborative
NC WARN North Carolina Waste Awareness and Reduction Network
NERC North American Electric Reliability Corporation
NOPR Notice of Proposed Rulemaking
NRC Nuclear Regulatory Commission
OASIS Open Access Same-time Information System
OATT open access transmission tariff
OPSI Organization of PJM States, Inc.
PJM PJM Interconnection, LLC
PPA purchase power agreement/s
Progress Duke Energy Progress, LLC
PURPA Public Utility Regulatory Policies Act of 1978
PV photovoltaic
REC renewable energy certificate/s
REPS Renewable Energy and Energy Efficiency Portfolio Standard
RFP request for proposals
ROE return on equity
RTO regional transmission organization
SACE Southern Alliance for Clean Energy
SCC State Corporation Commission of Virginia
SCE&G South Carolina Electric & Gas
Senate Bill 3 Session Law 2007-397
SEPA Southeastern Power Administration
SERC SERC Reliability Corporation
SERTP Southeastern Regional Transmission Planning
TOU time-of-use
TRANSCO Transcontinental Gas Pipe Line Company, LLC
TVA Tennessee Valley Authority
VEPCO Virginia Electric and Power Company
VOWTAP Virginia Offshore Wind Technology Advancement Project
WPSA Wholesale Power Supply Agreement

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APPENDIX

1. EXECUTIVE SUMMARY

This annual report to the Governor and the General Assembly is submitted pursuant to N.C. Gen. Stat. § 62-110.1(c), which specifies that each year the North Carolina Utilities Commission shall submit to the Governor and appropriate committees of the General Assembly a report of its analysis of the long-range needs for the expansion of facilities for the generation of electricity in North Carolina and a report on its plan for meeting those needs. Much of the information contained in this report is based on reports to the Commission by the electric utilities regarding their analyses and plans for meeting the demand for electricity in their respective service areas. It also reflects information from other records and files of the Commission.

There are three regulated investor-owned electric utilities (IOUs) operating under the laws of the State of North Carolina and subject to the jurisdiction of the Commission. All three of the IOUs own generating facilities. They are Duke Energy Progress, LLC (Progress), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (Duke), whose corporate office is in Charlotte; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and which does business in North Carolina under the name Dominion Energy North Carolina (Dominion).

Duke and Progress, the two largest electric IOUs in North Carolina, together provide approximately 96% of the utility-supplied electricity consumed in the state. Approximately 23% of the IOUs' 2018 electric sales in North Carolina were to the wholesale market, consisting primarily of electric membership corporations and municipally-owned electric systems.

Table ES-1 shows the gigawatt-hour (GWh) sales of the regulated electric utilities in North Carolina.

Table ES-1: 2018 Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2018	2017	2018	2017	2018	2017
Progress	38,362	37,023	21,914	21,051	69,333	66,823
Duke	59,157	56,283	6,892	6,256	92,280	87,307
VEPCO	4,401	4,167	1,158	1,172	88,038	84,970

*GWh = 1 Million kWh (kilowatt-hours)

During the 2019 to 2033 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be approximately 1.0% compared to 0.9% for winter peak load growth. Table ES-2 illustrates the system wide average annual growth rates forecast by the IOUs that operate in North Carolina. Each uses generally accepted forecasting methods and, although their forecasting models are different, the econometric techniques employed by each are widely used for projecting future trends.

Table ES-2: Forecast Annual Growth Rates for Progress, Duke, and VEPCO (With Energy Efficiency (EE) Included) (2019 – 2033)

	Summer Peak	Winter Peak	Energy Sales
Progress	0.9%	0.8%	0.6%
Duke	0.1%	1.0%	0.9%
VEPCO	0.8%	0.8%	0.9%

As illustrated in Table ES-3, North Carolina's IOUs rely on a balanced mix of generating resources to ensure reliable energy to their customers.

Table ES-3: Total Energy Resources by Fuel Type for 2018

	Progress	Duke	VEPCO
Coal	12%	23%	16%
Nuclear	38%	46%	37%
Net Hydroelectric*	1%	2%	1%
Natural Gas and Oil	34%	17%	40%
Non-Hydro Renewable	7%	2%	3%
Other Purchased Power	8%	10%	3%

* See discussion of pumped storage in Section 6.

In 2007, North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard. Under the REPS Statute, codified at N.C. Gen. Stat. § 62-133.8, investor-owned electric utilities are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their NC retail sales in 2021. EMCs and municipal electric suppliers are required to meet a similar requirement of 10% of their NC retail sales in 2018 and thereafter. The requirements under the law phase in over time, with the most recent increase in 2018, requiring investor-owned utilities to meet 10% of their prior year's NC retail sales through renewable energy and EE sources. This issue is discussed further in Section 8.

The electric utilities are subject to federal, state and local laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental laws and regulations. Environmental compliance directly impacts existing generation portfolios and choices for new generation resources. For example, the utilities evaluate how robust their plans are relative to potential greenhouse gas regulations as well as their own sustainability goals.

In addition, on October 29, 2018, Governor Roy Cooper signed an executive order calling for a 40% reduction in statewide greenhouse gas emissions by 2030. The order tasked the Department of Environmental Quality with developing a Clean Energy Plan (CEP) for North Carolina. After an extensive stakeholder engagement process, including meetings and public comment periods, the CEP was presented to Governor Cooper on September 27, 2019 and subsequently published in October, 2019. The plan includes Clean Energy Goals as follows:

- Reduce electric power sector greenhouse gas emissions by 70% below 2005 levels by 2030 and attain carbon neutrality by 2050.
- Foster long-term energy affordability and price stability for North Carolina's residents and businesses by modernizing regulatory and planning processes.
- Accelerate clean energy innovation, development, and deployment to create economic opportunities for both rural and urban areas of the state.

The utilities' existing plans, as reflected in their IRPs, already account for significant CO_2 reductions that complement these goals. Stakeholders, such as the utilities and the North Carolina Utilities Commission, are actively participating in the on-going work to develop carbon and clean energy policy designs as recommended in the CEP. The IRPs may ultimately be modified to reflect the state's clean energy policies as they evolve.

A map showing the service areas of the North Carolina IOUs can be found at the back of this report.

2. INTRODUCTION

The General Statutes of North Carolina require that the Utilities Commission analyze the probable growth in the use of electricity and the long-range need for future generating capacity in North Carolina. The General Statutes also require the Commission to submit an annual report to the Governor and to the General Assembly regarding future electricity needs. North Carolina General Statute § 62-110.1(c) provides, in part, as follows:

> The Commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC) and other arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of North Carolina, and shall consider such analysis in acting upon any petition by any utility for construction . . . Each year, the Commission shall submit to the Governor and to the appropriate committees of the General Assembly a report of its analysis and plan, the progress to date in carrying out such plan, and the program of the Commission for the ensuing year in connection with such plan.

Some of the information necessary to conduct the analysis of the long-range need for future electric generating capacity required by N.C.G.S. § 62-110.1(c) is filed by each regulated utility as a part of the Least Cost Integrated Resource Planning process. Commission Rule R8-60 defines an overall framework within which least cost integrated resource planning takes place. Commonly called integrated resource planning (IRP), it is a process that takes into account conservation, energy efficiency, load management, and other demand-side options along with new utility-owned generating plants, non-utility generation, renewable energy, and other supply-side options in order to identify the resource plan that will be most cost-effective for ratepayers consistent with the provision of adequate, reliable service.

Prior to July 1, 2013, Commission Rule R8-60(b) specified that the IRP process was applicable to the North Carolina Electric Membership Corporation (NCEMC) and any individual electric membership corporation (EMC) to the extent that it is responsible for procurement of any or all of its individual power supply resources. However, with the ratification of Session Law 2013-187 on June 26, 2013, the individual EMCs and NCEMC have been exempted from filing IRPs with the Commission, effective July 1, 2013.

This report is an update of the Commission's December 21, 2018 Annual Report. It is based primarily on reports to the Commission by the regulated electric utilities serving North Carolina, but also includes information from other records and Commission files.

3. OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA

There are three regulated investor-owned electric utilities (IOUs) operating in North Carolina subject to the jurisdiction of the Commission. All three of the IOUs own generating facilities. They are Duke Energy Progress, LLC (Progress), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (Duke), whose corporate office is in Charlotte; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and which does business in North Carolina under the name Dominion Energy North Carolina (Dominion). A map outlining the areas served by the IOUs can be found at the back of this report.

Duke and Progress, the two largest IOUs, together provide approximately 96% of the utility-supplied electricity consumed in the state. Duke provided electricity to 2,005,000 North Carolina customers in 2018 and Progress to 1,402,000 customers. Each of the Duke utilities also has customers in South Carolina. Dominion supplies approximately 4% of the State's utility-generated electricity. It has 121,000 customers in North Carolina. The large majority of its corporate operations are in Virginia, where it does business under the name of Virginia Electric and Power Company. About 23% of the IOUs' North Carolina electric sales were to the wholesale market, consisting primarily of EMCs and municipally-owned electric systems.

Based on annual reports submitted to the Commission for the 2018 reporting period, the gigawatt-hour (GWh) sales for the electric utilities in North Carolina are summarized in Table 1.

Table 1: 2018 Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2018	2017	2018	2017	2018	2017
Progress	38,362	37,023	21,914	21,051	69,333	66,823
Duke	59,157	56,283	6,892	6,256	92,280	87,307
VEPCO	4,401	4,167	1,158	1,172	88,038	84,970

*GWh = 1 Million kWh (kilowatt-hours)

EMCs are independent, not-for-profit corporations that operate distribution grids. There are 31 EMCs serving metered customers in North Carolina. EMCs serve approximately 25% of the State's population. Twenty-six EMCs are headquartered in the State, and these twenty-six EMCs served 1,062,770 metered customers in 2018. The other five EMCs are headquartered in adjacent states and provide service in limited areas across the border into North Carolina. EMCs serve customers in 95 of the State's 100 counties. Twenty-five EMCs are members of North Carolina Electric Membership Corporation (NCEMC), a generation and transmission services cooperative, centrally located in Raleigh, which provides its member EMCs with wholesale power and other services. All 25 NCEMC members are headquartered and incorporated in North Carolina.

Since 1980, NCEMC has been a part owner in the Catawba Nuclear Station located in York County, South Carolina. Duke operates and maintains the station, which has been operational since 1985. NCEMC's ownership interests consist of 61.51% of Unit 1, approximately 700 megawatts (MW), and 30.754% in the common support facilities of the station. NCEMC's ownership entitlement is bolstered by a reliability exchange between the Catawba Nuclear Station and Duke's McGuire Nuclear Station located in Mecklenburg County, NC.

NCEMC is also a part owner in the 750 MW Lee Combined Cycle Plant located in Anderson, South Carolina. Duke owns approximately 650 MWs of the plant and NCEMC owns approximately 100 MWs. Duke is responsible for project operation.

Additionally, NCEMC owns and operates about 680 MW of combustion turbine (CT) generation at sites in Anson and Richmond Counties. These peaking resources operate on natural gas as primary fuel, with diesel storage on-site as a secondary fuel. NCEMC also owns and operates two diesel-powered generating stations on the Outer Banks of North Carolina (located on Ocracoke Island and in Buxton), with a combined capacity of 18 MW, which are used primarily for peak shaving and voltage support. Most EMCs also receive an allocation of hydroelectric power from the Southeastern Power Administration (SEPA).

Finally, NCEMC and the EMCs have facilitated the development of 19 community solar facilities; operate microgrids located on Ocracoke Island and at Butler Farm in Harnett County; and partner to implement:

1. Aggregated demand response (DR) programs that, as of Q4 2019, reduce peak load via deployment of:
   (a) over 3,600 member-owner Wi-Fi enabled thermostats, and
   (b) over 1,000 smart controllers on existing electric resistance water heaters;
2. Energy efficiency (EE) programs that, in 2018, collectively produced 266,580 EE credits (the equivalent of 266,580 MWHs, or 2.06% of the prior year's retail sales, in reduced consumption by member-owners);
3. Approximately 50 MW of conservation voltage reduction capability; and
4. Other emerging technology, such as electric vehicle charging infrastructure including, as of Q4 2019:
   (a) 6 DC fast chargers (with 6 charging ports), and
   (b) 28 "level 2" chargers (with 40 charging ports).

There are five NCEMC members that have assumed responsibility for their own future power supply resources. These "Independent Members" include Blue Ridge EMC, EnergyUnited EMC, Piedmont EMC, Rutherford EMC, and Haywood EMC. Under a Wholesale Power Supply Agreement (WPSA), NCEMC supplies Independent Members from existing contract and generation resources. To the extent that the power supplied under the WPSA is not sufficient to meet the requirements of its customers, the Independent Members must independently arrange for additional purchases.

The service territories of NCEMC's member EMCs are located within the balancing authority areas of Duke, Progress, and Dominion. The Dominion control area is situated within the footprint of PJM Interconnection, the regional transmission organization (RTO) serving a portion of North Carolina. Six of NCEMC's members fall within that footprint, thus NCEMC is also a PJM member. Though NCEMC's system is spread across these three distinct control areas, NCEMC continues to serve all its members as a single integrated system using a combination of its owned resources, controlled resources, and purchases of wholesale electricity.

In addition to the EMCs, there are about 75 municipal and university-owned electric distribution systems serving approximately 599,000 customers in North Carolina. Most of these systems are members of ElectriCities, an umbrella service organization. ElectriCities is a non-profit organization that provides many of the technical, administrative, and management services needed by its municipally-owned electric utility members in North Carolina, South Carolina, and Virginia.

New River Light and Power, located in Boone, and Western Carolina University, located in Cullowhee, are both university-owned members of ElectriCities. Unlike other members of ElectriCities, the rates charged to customers by these two small distribution companies require Commission approval.

ElectriCities is a service organization for its members, not a power supplier. Fifty-one of the North Carolina municipals are participants in one of two municipal power agencies which provide wholesale power to their membership. ElectriCities' largest activity is the management of these two power agencies. The remaining members buy their own power at wholesale.

One agency, the North Carolina Eastern Municipal Power Agency (NCEMPA), is the wholesale supplier to 32 cities and towns in eastern North Carolina. From April 1982 through July 2015, NCEMPA jointly owned portions of five Progress generating units (about 700 MW of coal and nuclear capacity). On July 28, 2014, Progress filed notice with the Commission of its intent to file with the FERC a request for approval to purchase NCEMPA's ownership in these generating facilities together with associated assets pursuant to a proposed Asset Purchase Agreement. As provided in the Agreement, the final purchase and sale was subject to approval by the FERC, approval by the Commission, and enactment of legislation by the North Carolina General Assembly.

On May 12, 2015, in Docket Nos. E-2, Sub 1067 and E-48, Sub 8, the Commission issued an Order Approving Transfer of Certificate and Ownership Interests in Generating Facilities. The transaction between Progress and NCEMPA closed on July 31, 2015. On August 13, 2015, the Commission issued an Order Transferring Certificate of Public Convenience and Necessity.

The other power agency is North Carolina Municipal Power Agency No. 1 (NCMPA1), which is the wholesale supplier to 19 cities and towns in the western portion of the state. NCMPA1 has a 75% ownership interest (832 MW) in Catawba Nuclear Unit 2, which is operated by Duke. It also has an exchange agreement with Duke that gives NCMPA1 access to power from the McGuire Nuclear Station and Catawba Unit 1.

Both agencies purchase supplemental power as needed above their own generating resources, usually from investor-owned utilities and federally owned hydro-electric systems.

The Tennessee Valley Authority (TVA) sells energy directly to the Murphy Power Board and to three out-of-state cooperatives that supply power to portions of North Carolina: Blue Ridge Mountain EMC, Tri-State Membership Corporation, and Mountain Electric Cooperative. These distributors of TVA power are located in six North Carolina counties and serve over 34,000 households and 9,000 commercial and industrial customers. The North Carolina counties served by distributors of TVA power are Avery, Burke, Cherokee, Clay, McDowell, and Watauga.

TVA owns and operates four hydroelectric dams in North Carolina with a combined generation capacity of 523 MW. The dams are Apalachia and Hiwassee in Cherokee County, Chatuge in Clay County, and Fontana in Swain and Graham counties.

4. THE HISTORY OF INTEGRATED RESOURCE PLANNING IN NORTH CAROLINA

Integrated resource planning is an overall planning strategy which examines conservation, energy efficiency, load management, and other demand-side measures in addition to utility-owned generating plants, non-utility generation, renewable energy, and other supply-side resources in order to determine the least cost way of providing electric service. The primary purpose of integrated resource planning is to integrate both demand-side and supply-side resource planning into one comprehensive procedure that weighs the costs and benefits of all reasonably available options in order to identify those options which are most cost-effective for ratepayers consistent with the obligation to provide adequate, reliable service in compliance with applicable statutory and regulatory requirements.

Initial IRP Rules

By Commission Order dated December 8, 1988, in Docket No. E-100, Sub 54, Commission Rules R8-56 through R8-61 were adopted to define the framework within which integrated resource planning takes place. Those rules incorporated the analysis of probable electric load growth with the development of a long-range plan for ensuring the availability of adequate electric generating capacity in North Carolina as required by N.C.G.S. § 62-110.1(c).

The initial IRPs were filed with the Commission in April 1989. In May of 1990, the Commission issued an Order in which it found that the initial IRPs of Progress, Duke, and NC Power were reasonable for purposes of that proceeding and that NCEMC should be required to participate in all future IRP proceedings. By an Order issued in December 1992, Rule R8-62 was added. It covers the construction of electric transmission lines.

The Commission subsequently conducted a second and third full analysis and investigation of utility IRP matters, resulting in the issuance of Orders Adopting Least Cost Integrated Resource Plans on June 29, 1993, and February 20, 1996. A subsequent round of comments included general endorsement of a proposal that the two/three year IRP filing cycle, plus annual updates and short-term action plans, be replaced by a single annual filing. There was also general support for a shorter planning horizon than the 15 years required at that time.

Streamlined IRP Rules (1998)

In April 1998, the Commission issued an Order in which it repealed Rules R8-56 through R8-59 and revised Rules R8-60 through R8-62. The new rules shortened the reported planning horizon from 15 to 10 years and streamlined the IRP review process while retaining the requirement that each utility file an annual plan in sufficient detail to allow the Commission to continue to meet its statutory responsibilities under N.C.G.S. § 62-110.1(c) and N.C. G.S. § 62-2(a)(3a).

These revised rules allowed the Public Staff and any other intervenor to file a report, evaluation, or comments concerning any utility's annual report within 90 days after the utility filing. The new rules further allowed for the filing of reply comments 14 days after any initial comments had been filed and required that one or more public hearings be held. An evidentiary hearing to address issues raised by the Public Staff or other intervenors could be scheduled at the discretion of the Commission.

In September 1998, the first IRP filings were made under the revised rules. The Commission concluded, as a part of its Order ruling on these filings, that the reserve margins forecast by Progress, Duke, and NC Power indicated a much greater reliance upon off-system purchases and interconnections with neighboring systems to meet unforeseen contingencies than had been the case in the past. The Commission stated that it would closely monitor this issue in future IRP reviews.

In June 2000, the Commission stated in response to the IOUs' 1999 IRP filings that it did not believe that it was appropriate to mandate the use of any particular reserve margin for any jurisdictional electric utility at that time. The Commission concluded that it would be more prudent to monitor the situation closely, to allow all parties the opportunity to address this issue in future filings with the Commission, and to consider this matter further in subsequent integrated resource planning proceedings. The Commission did, however, want the record to clearly indicate its belief that providing adequate service is a fundamental obligation imposed upon all jurisdictional electric utilities, that it would be actively monitoring the adequacy of existing electric utility reserve margins, and that it would take appropriate action in the event that any reliability problems developed.

Further orders required that IRP filings include a discussion of the adequacy of the respective utility's transmission system and information concerning levelized costs for various conventional, demonstrated, and emerging generation technologies.

Order Revising Integrated Resource Planning Rules – July 11, 2007

A Commission Order issued on October 19, 2006, in Docket No. E-100, Sub 111, opened a rulemaking proceeding to consider revisions to the IRP process as provided for in Commission Rule R8-60. On May 24, 2007, the Public Staff filed a Motion for Adoption of

Proposed Revised Integrated Resource Planning Rules setting forth a proposed Rule R8-60 as agreed to by the various parties in that docket. The Public Staff asserted that the proposed rule addressed many of the concerns about the IRP process that were raised in the 2005 IRP proceeding and balanced the interests of the utilities, the environmental intervenors, the industrial intervenors, and the ratepayers. Without detailing all of the changes recommended in its filing, the Public Staff noted that the proposed rule expressly required the utilities to assess on an ongoing basis both the potential benefits of reasonably available supply-side energy resource options, as well as programs to promote demand-side management. The proposed rule also substantially increased both the level of detail and the amount of information required from the utilities regarding those assessments. Additionally, the proposed rule extended the planning horizon from 10 to 15 years, so the need for additional generation would be identified sooner. The information required by the proposed rule would also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the 15-year period. The Public Staff also noted that the proposed rule provided for a biennial, as opposed to annual or triennial, filing of IRP reports with an annual update of forecasts, revisions, and amendments to the biennial report. The Public Staff further noted that adoption of the proposed Rule R8-60 would necessitate revisions to Rule R8-61(b) to reflect the change in the frequency of the filing of the IRP reports.

With the addition of certain other provisions and understandings, the Commission ordered that revised Rules R8-60 and R8-61(b), attached to its Order as Appendix A, should become effective as of the date of its Order, which was entered on July 11, 2007. However, since the utilities might not have been able to comply with the new requirements set out in revised Rule R8-60 in their 2007 IRP filings, revised Rule R8-60 was ordered to be applied for the first time to the 2008 IRP proceedings in Docket No. E-100, Sub 118. These new rules were further refined in Docket No. E-100, Sub 113 to address the implementation of requirements imposed by the 2007 REPS legislation.

2018 Biennial IRP Reports and Related 2018 REPS Compliance Plans
(Docket No. E-100, Sub 157)

In the 2018 IRP Reports and REPS compliance plans filed by Progress, Duke and Dominion the IOU's provided their current IRPs (Docket E-100, Sub 157). A public hearing in this docket was held in Raleigh on February 4, 2019 for the purpose of receiving non-expert public testimony. Forty-nine public witnesses attended the hearing.

Based upon the full record in the proceeding, the Commission issued an Order on August 27, 2019 accepting integrated resource plans and REPS compliance plans, scheduling oral argument, and requiring additional analyses. The Commission's Order can be found in the back of this report as Appendix 1. The ordering paragraphs state:

1. That the IRP filed herein by Dominion Energy North Carolina is adequate for planning purposes, subject to DENC's 2019 IRP Update, and the Commission hereby accepts DENC's IRP.

2. That the IRPs filed herein by Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, are adequate for planning purposes during the remainder of

2019 and for 2020, subject to DEC's and DEP's 2019 IRP Updates, and the Commission hereby accepts the IRPs, subject to the questions raised in this Order concerning the underlying assumptions upon which the IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020.

3. That the 2018 REPS compliance plans filed by the IOUs are hereby accepted.

4. That pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost Integrated Resource Planning and file separate IRPs until otherwise required or allowed to do so by Commission order, or until a combination of the utilities is approved by the Commission.

5. That NC WARN's motion for an expert witness hearing, and the other requests for expert witness and additional public witness hearings on the 2018 IRPs, are denied.

6. That on Wednesday, January 8, 2020, at 10:00 a.m., the Commission will hold an oral argument to address reserve margin and load forecasting issues in DEC’s and DEP’s IRPs, as specified in the body of this Order. The oral argument will be held in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

7. That on or before November 4, 2019, DEC, DEP, and the Public Staff shall file responses to the information requested in Appendix A, as specified in the body of this Order.

8. That in their 2020 IRPs DEC and DEP shall include the information, analyses, and modeling regarding economic retirement of coal-fired units and consideration of all resource options, as specified in the body of this Order.

IRP Update Reports and REPS compliance plans were filed by Progress, Duke and Dominion in 2019. These are currently under review by the Commission.

5. LOAD FORECASTS AND PEAK DEMAND

Forecasting electric load growth into the future is, at best, an imprecise undertaking. Virtually all forecasting tools commonly used today assume that certain historical trends or relationships will continue into the future and that historical correlations give meaningful clues to future usage patterns. As a result, any shift in such correlations or relationships can introduce significant error into the forecast. Progress, Duke, and VEPCO each utilize generally accepted forecasting methods. Although their respective forecasting models are different, the econometric techniques employed by each utility are widely used for projecting future trends. Each of the models requires analysis of large amounts of data, the selection of a broad range of demographic and economic variables, and the use of advanced statistical techniques.

With the inception of integrated resource planning, North Carolina's electric utilities have attempted to enhance forecasting accuracy by performing limited end-use forecasts. While this approach also relies on historical information, it focuses on information relating to specific electrical usage and consumption patterns in addition to general economic relationships.

Table 2 illustrates the system wide average annual growth rates in energy sales and peak loads anticipated by Progress, Duke, and VEPCO. These growth rates are based on the utilities' system peak load requirements.

Table 2: Forecast Annual Growth Rates for Progress, Duke, and VEPCO (With Energy Efficiency (EE) Included) (2019– 2033)

	Summer Peak	Winter Peak	Energy Sales
Progress	0.9%	0.8%	0.6%
Duke	1.1%	1.0%	0.9%
VEPCO	0.8%	0.8%	0.9%

North Carolina utility forecasts of future peak demand growth rates are in the range of forecasts for the southeast as a whole if not slightly higher. The 2018 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates a forecast of average annual growth in peak demand of approximately 0.5% through 2028.

Table 3 provides historical peak load information for Progress, Duke, and VEPCO.

Table 3: Summer and Winter Systemwide Peak Loads for Progress, Duke, and VEPCO Since 2014 (in MW)

	Progress		Duke		VEPCO	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2014	12,364	15,569	18,993	21,101	18,692	21,651
2015	12,849	13,298	20,003	19,377	18,980	18,948
2016	13,130	14,534	20,671	19,183	19,538	19,661
2017	12,784	15,519	20,120	21,620	18,902	21,232
2018	13,090	13,669	20,379	19,286	19,244	19,930

**Winter peak following summer peak*

6. GENERATION RESOURCES

Traditionally, the regulated electric utilities operating in North Carolina have met most of their customer demand by installing their own generating capacity. However, purchases including renewables now make up a significant percentage of summer load resources. Generating plants are usually classified by fuel type (nuclear, coal, gas/oil, hydro, renewable, etc.) and placed into three categories based on operational characteristics:

(1) Baseload – operates nearly full cycle;
(2) Intermediate (also referred to as load following) – cycles with load increases and decreases; and
(3) Peaking – operates infrequently to meet system peak demand.

Nuclear, combined-cycle natural gas units, and some large coal facilities, serve as baseload plants and typically operate more than 5,000 hours annually. Smaller and older coal and oil/gas plants are used as intermediate load plants and typically operate between 1,000 and 5,000 hours per year. Finally, combustion turbines and other peaking plants usually operate less than 1,000 hours per year.

All of the nuclear generation units operated by the utilities serving North Carolina have been relicensed so as to extend their operational lives. Duke has three nuclear facilities with a combined total of seven individual units. The McGuire Nuclear Station located near Huntersville is the only one located in North Carolina, and it has two generating units. The other Duke nuclear facilities are located in South Carolina. All of Duke's nuclear units have been granted extensions of their original operating licenses by the Nuclear Regulatory Commission (NRC). The new license expiration dates fall between 2033 and 2043.

Progress has four nuclear units divided among three locations. Two of the locations are in North Carolina. The Brunswick facility, near Southport, has two units, and the Harris Plant, near New Hill, has one unit. The Robinson facility, which also has one unit, is located in South Carolina. The NRC has renewed the operating licenses for all of Progress's nuclear units. The new renewal dates run from 2030 to 2046.

VEPCO operates two nuclear power stations with two units each. Both stations are located in Virginia. All four units have been issued license extensions by the NRC. The new license expiration dates range from 2032 to 2040. On October 16, 2018 Dominion Energy Virginia filed an application with the U.S. Nuclear Regulatory Commission to renew its operating licenses for the Surry nuclear plant for an additional 20 years which would keep the plant on line beyond 2050.

Hydroelectric generation facilities are of two basic types: conventional and pumped storage. With a conventional hydroelectric facility, which may be either an impoundment or run-of-river facility, flowing water is directed through a turbine to generate electricity. An impoundment facility uses a dam to create a barrier across a waterway to raise the level of the water and control the water flow; a run-of-river facility simply diverts a portion of a river's flow without the use of a dam.

Pumped storage is similar to a conventional impoundment facility and is used by Duke and VEPCO for large-scale storage. Excess electricity produced at times of low demand is used to pump water from a lower elevation reservoir into a higher elevation reservoir. When demand is high, this water is released and used to operate hydroelectric generators that produce supplemental electricity. Pumped storage produces only two-thirds to three-fourths of the electricity used to pump the water up to the higher reservoir, but it costs less than an equivalent amount of additional generating capacity. This overall loss of energy is also the reason why the total "net" hydroelectric generation reported by a utility with pumped storage can be significantly less than that utility's actual percentage of hydroelectric generating capacity.

Some of the electricity produced in North Carolina comes from non-utility generation. In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA), which established a national policy of encouraging the efficient use of renewable fuel sources and cogeneration (production of electricity as well as another useful energy byproduct – generally steam – from a given fuel source). North Carolina electric utilities regularly utilize non-utility, PURPA-qualified, purchased power as a supply resource.

Another type of non-utility generation is power generated by merchant plants. A merchant plant is an electric generating facility that sells energy on the open market. It is often constructed without a native load obligation, a firm long-term contract, or any other assurance that it will have a market for its power. These generating plants are generally sited in areas where the owners see a future need for an electric generating facility, often near a natural gas pipeline, and are owned by developers willing to assume the economic risk associated with the facility's construction.

The current capacity mix generated by each IOU is shown in Table 4.

Table 4: Installed Utility-Owned Generating Capacity by Fuel Type

(Summer Ratings) for 2018

	Progress	Duke	VEPCO
Coal	28%	34%	20%
Nuclear	27%	26%	18%
Hydroelectric	2%	16%	12%
Natural Gas and Oil	42%	24%	49%
Non-Hydro Renewable	1%	0%	1%

The actual generation usage mix, based on the megawatt-hours (MWh) generated by each utility, reflects the operation of the capacity shown above, plus non-utility purchases, and the operating efficiencies achieved by attempting to operate each source of power as close to the optimum economic level as possible.

Generally, actual plant use is determined by the application of economic dispatch principles, meaning that the start-up, shutdown, and level of operation of individual generating units is tied to the incremental cost incurred to serve specific loads in order to attain the most cost effective production of electricity. The actual generation produced and power purchased for each utility, based on monthly fuel reports filed with the Commission for 2018, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2018

	Progress	Duke	VEPCO
Coal	12%	23%	16%
Nuclear	38%	46%	37%
Net Hydroelectric*	1%	2%	1%
Natural Gas and Oil	34%	17%	40%
Non-Hydro Renewable	7%	2%	3%
Other Purchased Power	8%	10%	3%

* See the paragraph on pumped storage in this section.

The Commission recognizes the need for a mix of baseload, intermediate, and peaking facilities and believes that conservation, energy efficiency, peak-load management, and renewable energy resources must all play a significant role in meeting the capacity and energy needs of each utility. In addition, the utilities continue to address all aspects of environmental compliance, including greenhouse gas regulation, in their resource planning. The following highlights from utility generation planning exercises reflect information contained in the 2019 IRP Updates filed with the Commission.

Progress Generation

As of January 2019, Progress had 13,942 MW of installed generating capacity (winter rating). This does not include purchases and non-utility owned capacity.

NCEMPA previously owned partial interest in several Progress plants, including Brunswick Nuclear Plant Units 1 and 2, Mayo Plant, Roxboro Plant Unit 4 and the Harris Nuclear Plant. The Power Agency's ownership interest in these plants represented approximately 700 MW of generating capacity. The boards of directors of Duke Energy and the NCEMPA approved an agreement for Progress to purchase the Power Agency's ownership in these generating assets. All required regulatory approvals were completed and the agreement closed on July 31, 2015. Progress is now 100% owner of these previously jointly owned assets. Under the agreement, Progress will continue meeting the needs of NCEMPA customers previously served by the Power Agency's interest in the Progress plants.

As part of the Western Carolinas Modernization Project (WCMP), the combined 384 MW Asheville 1 and 2 coal units are planned to be retired by year-end 2019. The retired units will be replaced with two 280 MW natural gas combined-cycle (CC) units. Additionally, an undetermined amount of solar generation is planned for installation at the same site. The application for a Certificate of Public Convenience and Necessity (CPCN) for the new CC units was filed with the Commission in January 2016 and subsequently approved in March 2016.

Other capacity additions include:

- Planned nuclear uprates totaling 26 MW in 2020 through 2030.
- Addition of 112 MW of storage capacity in 2020 through 2027.
- Addition of 2,682 MW of combined-cycle capacity in 2025 through 2026.
- Addition of 5,170 MW of combustion turbine capacity in 2027 through 2033.

Other planned retirements include:

- Darlington combustion turbine units 1-6, 8 and 10 by December 2020 (497 MW).
- Blewett combustion turbine units and Weatherspoon combustion turbine units in December 2024 (232 MW).
- Roxboro coal units 1-2 in December 2028 (1,053 MW).
- Roxboro coal units 3-4 in December 2033 (1,409 MW).

Planning assumptions for nuclear stations assume subsequent license renewal at the end of their current license extension including Robinson 2 in 2030 (797 MW).

The ultimate timing of unit retirements can be influenced by factors that impact the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs to comply with evolving environmental regulations. As such, unit retirement schedules are expected to change over time as market conditions change.

Duke Generation

As of January 2019, Duke had 23,164 MW of installed generating capacity (winter rating), excluding purchases and non-utility owned capacity. That total includes generation jointly-owned with NCMPA1, NCEMC, and Piedmont Municipal Power Agency produced at Duke's Catawba Nuclear Facility in South Carolina.

Duke received the Combined Construction and Operating License (COL) for the W.S. Lee Nuclear Station (Lee Nuclear) on December 19, 2016. On August 25, 2017, Duke filed a request to cancel the Lee Nuclear Project as that project was originally envisioned and included in prior IRPs. That request was approved by the North Carolina Utilities Commission in its Order dated June 22, 2018.

Other capacity additions include:

- Addition of 15 MW of cogeneration in 2020.
- Addition of 260 MW Bad Creek pumped storage uprates in 2020 through 2023.

- Addition of 45 MW Oconee uprates in 2022-2024.
- Addition of 120 MW of energy storage in 2020 through 2026.
- Addition of 402 MW of combustion turbine capacity in 2025 at Lincoln County.
- Addition of 1,341 MW of combined-cycle capacity in 2027.
- Addition of 470 MW of combustion turbine capacity in 2025.
- Addition of 470 MW of combustion turbine capacity in 2030-2031.
- Addition of 940 MW of combustion turbine capacity in 2032.

Retirements include:

- Allen coal units 1-3 (604 MW) and units 4-5 (526 MW) in 2024 and 2028, respectively.
- Lee Unit 3 natural gas (173 MW) in 2030.
- Cliffside unit 5 (546 MW) in 2032.
- Marshall units 1-4 (2,078 MW) in 2034.

Planning assumptions for nuclear stations assume subsequent license renewal at the end of their current license including Oconee in 2033 and 2034 (2,618 MW).

The ultimate timing of unit retirements can be influenced by factors that impact the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs to comply with evolving environmental regulations. As such, unit retirement schedules are expected to change over time as market conditions change.

VEPCO Generation

As of August 2019, VEPCO had 21,041 MW of installed generating capacity (winter rating). This excludes purchases and non-utility capacity. Of this total, only 480 MW is located in North Carolina.

The Company obtained a Combined Operating License (COL) from the NRC in June 2017 to support a new nuclear unit, North Anna 3, at its existing North Anna Power Station located in Louisa County in central Virginia. However, based on the uncertainties of future carbon regulation, the Company determined it prudent to pause material development activities for North Anna 3. Going forward, the Company will continue to maintain the COL, which provides a valuable option in the future for a base load carbon-free generation resource.

Other capacity additions include:

- Addition of 142 MW utility-scale solar (US-3 Solar 1) by 2020.
- Addition of 12 MW offshore wind (Coastal Virginia Offshore Wind) by 2021.
- Addition of 198 MW utility-scale solar (US-3 & 4 Solar 2) by 2021.
- Addition of 26 MW battery energy storage by 2023.
- Addition of 852 MW offshore wind by 2025.
- Addition of 2,425 MW combustion turbines by 2026.
- Addition of 100 MW pump storage by 2030.
- Addition of 3,180 MW solar by 2034.

Retirements include:

- Bellemeade combined cycle in 2019 (267 MW).
- Bremo natural gas units 3 and 4 in 2019 (227 MW).
- Chesterfield coal units 3 and 4 in 2019 (261 MW).
- Mecklenburg coal units 1 and 2 in 2019 (138 MW).
- Pittsylvania biomass in 2019 (83 MW).
- Possum Point natural gas units 3 and 4 in 2019 (316 MW).
- Possum Point 5 heavy fuel oil in 2021 (786 MW).
- Chesterfield coal units 5 & 6 in 2023 (1,014 MW).*
- Clover coal units 1 & 2 in 2025 (439 MW).*
- Yorktown 3 heavy fuel oil in 2022 (790 MW).*

*The generating units listed should be considered as tentative for retirement only. The Company's final decisions regarding any unit retirement will be made at a future date.

Planning assumptions for nuclear stations assume subsequent license renewal at the end of their current license extension including Surry in 2032 and 2033 (1,750 MW).

7. RELIABILITY AND RESERVE MARGINS

Resource adequacy refers to the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Utilities require a margin of reserve generating capacity in order to provide reliable service. Periodic scheduled outages are required to perform maintenance, inspections of generating plant equipment, and to refuel nuclear plants. Unanticipated mechanical failures may occur at any given time, which may require shutdown of equipment to repair failed components. Adequate reserve capacity must be available to accommodate these unplanned outages and to compensate for higher than projected peak demand due to forecast uncertainty and weather extremes. The Companies utilize reserve margin targets in their IRP processes to help ensure resource adequacy. Reserve margin is defined as total resources minus peak demand, divided by peak demand. The reserve margin target for planning is established based on probabilistic assessments. The Commission continues to evaluate in the IRP proceedings the appropriate reserve margins for planning which is the primary issue for discussion at the hearing scheduled for January 8, 2020.

The reserve margins currently projected by each IOU are shown in Table 6.

Table 6: Projected Winter Reserve Margins for Progress & Duke, and Summer for VEPCO (2019-2033, after DSM)

	Reserve Margins
Progress	17% – 25%
Duke	17% – 24%
VEPCO	12% – 14%[1]

[1] VEPCO is a PJM member and signatory to PJM's Reliability Assurance Agreement. The Company is obligated to maintain a reserve margin (11.7%) for its portion of the PJM coincident peak load. Also, the Company participates in PJM's capacity auction which results in short-term reserves in excess of the target level.

The amount of energy provided by the three utilities utilizing gas technologies is greater than the energy provided by coal. This highlights the importance of the infrastructure that delivers natural gas to the generating stations. The State has historically been heavily dependent on one interstate pipeline, Transcontinental Gas Pipe Line Company, LLC (Transco) for its natural gas requirements. While two other interstate pipelines (Columbia and Patriot) provide limited volumes, only Transco crosses the State, generally along the I-85 corridor, which means that long intrastate lines have had to be built to serve generating plants in other parts of the State. Pursuant to N.C. Gen. Stat. § 62-36.01, the Commission may, under some circumstances, order the State's natural gas local distribution companies (LDCs) to enter into natural gas service agreements (including "backhaul" agreements) with other pipeline suppliers to increase competition.

Transco historically delivered gas up from the Gulf Coast. Transco is reversing the flow on its pipelines to bring shale gas to the State from the north. While this provides

North Carolina with another source of interstate gas, it has one significant negative impact. Historically, North Carolina customers have been able to contract for gas to be delivered to Transco north of the State, either from other interstate pipelines or from market-area storage facilities, and have had that gas “backhauled” on Transco. The gas delivered upstream on Transco on behalf of N.C. customers would be physically delivered to other customers to the north, and swapped for their gas out of Transco as it passes through North Carolina. Since Transco is physically reversing the flow on its pipelines, North Carolina customers can no longer count on cheap backhaul service and must pay for expensive firm forward-haul service on Transco, or find other ways to get gas to the State.

The amount of firm capacity needed to replace backhaul is significant. North Carolina LDCs have been contracting with Transco to obtain some capacity to deliver supplies that were previously backhauled. They are also seeking capacity on new interstate pipeline projects into the State.

Two major new interstate pipeline projects into North Carolina are being built to serve both gas and electric generation customers. They are the Atlantic Coast Pipeline, LLC (ACP) and MVP Southgate, an extension of the Mountain Valley Pipeline LLC (MVP) project. ACP will come down along the I-95 corridor and will bring shale gas from the north to serve both gas and electric generation customers. It will provide a better interstate pipeline footprint in the State. ACP is scheduled to go on line in late 2021. However, ACP is currently stalled, and the Supreme Court has agreed to hear the case on whether the US Forest Service has authority under the Mineral Leasing Act to grant ACP the authority to cross the Appalachian Trail. MVP Southgate extends the MVP project from southern Pittsylvania County, Virginia down into Alamance County, North Carolina. The MVP pipeline, which terminates in Virginia, is scheduled to come on line in late 2020. The MVP Southgate pipeline down into North Carolina is also scheduled to come on line in late 2020. Until these projects come on line, LDCs will have to contract for short-term capacity. This capacity will be expensive and cannot be depended upon to meet long-term needs. Further delays in ACP and MVP Southgate are a matter of serious concern.

Another major development is the announcement by Piedmont Natural Gas of a decision to build a liquefied natural gas storage facility in Robeson County. This facility is anticipated to be completed in the summer of 2021 and filled in time to provide peaking support in the winter of 2021-2022. This will help meet both gas- and electric-peak demand.

8. RENEWABLE ENERGY AND ENERGY EFFICIENCY

Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

In 2007, North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard. Under the REPS statute, codified at N.C.G.S. § 62-133.8, investor-owned electric utilities are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their NC retail sales in 2021. EMCs and municipal electric suppliers are required to meet a similar requirement of 10% of their NC retail sales in 2018 and thereafter. The requirements under the law phase in over time, with the most recent increase in 2018, requiring investor-owned utilities to meet 10% of their prior year's NC retail sales through renewable energy and EE sources. Within the overall percentage requirements, electric power suppliers must meet a specified portion of their total REPS requirements by producing or purchasing electricity produced from solar, swine-waste, and poultry-waste resources. As detailed in the following section, these specified source requirements also increase over time, however the Commission has modified and delayed the swine and poultry waste requirements several times.

The REPS statute requires the Commission to monitor compliance with REPS and to develop procedures for tracking and accounting for renewable energy certificates (RECs), which represent units of electricity or energy produced or saved by a renewable energy facility or an implemented EE measure. In 2008 the Commission opened Docket No. E-100, Sub 121 and established a stakeholder process to propose requirements for a North Carolina Renewable Energy Tracking System (NC-RETS). On October 19, 2009, the Commission issued a request for proposals (RFP) via which it selected a vendor, APX, Inc., to design, build, and operate the tracking system. NC RETS began operating July 1, 2010, consistent with the requirements of Session Law 2009-475.

Members of the public can access the NC-RETS website at www.ncrets.org. The site's "resources" tab provides public reports regarding REPS compliance and NC RETS account holders. NC-RETS also provides an electronic bulletin board where RECs can be offered for purchase.

On October 1, 2019, the Commission submitted its 12th Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina required pursuant to N.C.G.S. § 62-133.8. The report details Commission implementation of the REPS Statute since its enactment in 2007. As described in more detail below, the report concluded that all of the electric power suppliers have met, or appear to have met, the 2012-2018 general REPS requirements and appear on track to meet the 2019 solar set-aside requirement. The Commission granted a joint motion to delay implementation of the 2018 swine waste set-aside requirement for one year – except for the electric public utilities – requiring them to meet a 0.02% swine waste set-aside for 2018. Most electric power suppliers have indicated that they will have difficulty meeting the swine waste set-aside requirements for 2019, as well as a delay in future increases in these requirements. Electric power suppliers cite the lack of technological progress for power production from swine waste and failure of counter parties to deliver RECs as anticipated as impediments to meeting future swine waste set-aside requirements. The report is available on the Commission's web site, www.ncuc.net.

Competitive Procurement of Renewable Energy

On July 27, 2017, the Governor signed into law House Bill 589 (S.L. 2017-192). Part II of S.L. 2017-192 enacted N.C.G.S. § 62-110.8, which required DEC and DEP to file for Commission approval on or before November 27, 2017, a program for the competitive procurement of energy and capacity from renewable energy facilities with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to continue to reliably and cost-effectively serve customers' future energy needs (CPRE Program). Under the CPRE Program, DEC and DEP are required to issue requests for proposals to procure energy and capacity from renewable energy facilities in the aggregate amount of 2,660 MW, over the course of the 45-month program. This aggregate amount of capacity may be reduced based on certain provisions in the statute. Since House Bill 589 was signed into law, the Commission has adopted rules implementing the requirements of the CPRE Program and approved, with modifications, the CPRE Program proposed by DEC and DEP. In addition, the Commission approved Accion Group, LLC, as the Independent Administrator (IA) of the CPRE Program.

On July 10, 2018, the Independent Administrator opened the period for the submission of proposals for the first RFP Solicitation under the CPRE Program, seeking proposals for 600 MW in DEC's service territories and 80 MW in DEP's service territories. Proposals were received through October 9, 2018, when the Proposal submission period closed. Proposals included a balanced representation from North Carolina and South Carolina and ranged in size from seven to 80 MW. While market participants had the ability to provide renewable energy from a number of technologies, the IA received proposals for only solar photovoltaic generation. Four of the projects proposed storage integration. The IA evaluated the bids resulting in 465.50 MW procured in DEC and 85.72 MW procured in DEP.

The CPRE Tranche 2 RFP opened on October 15, 2019 and reflects modifications based on stakeholder input and lessons learned in Tranche 1.

Energy Efficiency

Electric power suppliers in North Carolina are required to implement demand-side management (DSM) and energy efficiency (EE) measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of their customers. Energy reductions through the implementation of DSM and EE measures may also be used by the electric power suppliers to comply with REPS. Duke, Progress, Dominion, EnergyUnited, Halifax, and NCEMC (which has assumed compliance responsibility from the now-dissolved GreenCo for REPS compliance for its member cooperatives) all administer EE and DSM programs.

NC GreenPower

NC GreenPower's mission is to expand public knowledge and acceptance of cleaner energy technologies to all North Carolinians through local, community-based initiatives. Founded in 2003, the nonprofit, a subsidiary of Advanced Energy Corporation, was launched by the NC Utilities Commission as a voluntary program to supplement the state's existing power supply with more green energy. NC GreenPower works to improve the state's environment by supporting renewable energy and carbon offset projects and by providing grants for solar installations at North Carolina K-12 schools.

Introduced on April 1, 2015, NC GreenPower Solar Schools uses a portion of its donations to provide grants for educational solar PV packages at North Carolina schools.

All K-12 schools are eligible, though preference may be given to those in economically distressed counties as defined by the NC Department of Commerce. Through the program, schools receive partial grant funding and are then tasked with raising the remainder of the costs. Partnering with the State Employees' Credit Union (SECU) Foundation, selected public schools may receive a $10,000-$20,000 challenge grant from SECU Foundation, enabling them to increase their system from 3 kilowatts (kW) to 5 kW.

The NC GreenPower Solar Schools program gives teachers valuable tools to educate students about renewable energy. Currently in its fifth year, the program now offers top-of-pole mounted systems and roof-mounted systems. Each educational solar package includes a 5 kW solar PV array, a weather station, data monitoring equipment, a STEM curriculum and training for educators.

Contributions to NC GreenPower continue to help support the local generation of green energy and reduction of greenhouse gases but also help to provide solar PV systems at schools across North Carolina. Statewide efforts of NC GreenPower also include community outreach and awareness. Voluntary donations to the program can be made by individuals or businesses through their electric bill or directly to NC GreenPower on their website: www.ncgreenpower.org. NC GreenPower is a 501(c)(3) nonprofit organization and all current projects are located within North Carolina.

By the end of 2019, the NC GreenPower Solar Schools program (including the Duke Energy Schools Going Solar initiative, administered by NC GreenPower) will have reached a total of 32 North Carolina schools in 27 counties, bringing solar and energy education to nearly 26,000 students. To date, the schools have collectively produced about 223,755 kilowatt hours of green energy, a savings of about $22,000.

9. TRANSMISSION AND GENERATION INTERCONNECTION ISSUES

Transmission Planning

The North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005. Participants (transmission-owning utilities, such as Duke and Progress, and transmission-dependent utilities, such as municipal electric systems and EMCs) identify the electric transmission projects that are needed to be built for reliability and estimate the costs of those upgrades. The NCTPC's January 17, 2019 report stated that 19 major (greater than $10 million each) transmission projects are needed in North Carolina by the end of 2028 at an estimated cost of $657 million. For more information, visit the NCTPC's website at www.nctpc.org.

On July 21, 2011, the FERC issued Order No. 1000, entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities." [1] This Order requires transmission owners to participate in regional and inter-regional

[1] FERC issued Order No. 1000 on July 21, 2011, in its Docket No. RM10-23-000.

transmission planning efforts. Duke and Progress have complied with Order No. 1000 by participating in the Southeastern Regional Transmission Planning (SERTP)[2] process.

On July 3, 2013, Session Law 2013-232 was enacted. This law states that only a public utility may obtain a certificate to build a new transmission line (except a line for the sole purpose of interconnecting an electric power plant). In this context, a public utility includes IOUs, EMCs, joint municipal power agencies, and cities and counties that operate electric utilities.

State Generator Interconnection Standards

On June 4, 2004, in Docket No. E-100, Sub 101, Progress, Duke, and Dominion jointly filed a proposed model small generator interconnection standard, application, and agreement to be applicable in North Carolina. In 2005, the Commission approved small generator interconnection standards for North Carolina.

In 2007 as part of REPS legislation codified at N.C.G.S. § 62-133.8(i), the General Assembly provided that the Commission shall "[e]stablish standards for interconnection of renewable energy facilities and other nonutility-owned generation with a generation capacity of 10 megawatts or less to an electric public utility's distribution system; provided, however, that the Commission shall adopt, if appropriate, federal interconnection standards."

In compliance, on June 9, 2008, the Commission issued an Order revising North Carolina's Interconnection Standard. The Commission used the federal standard as the starting point for all state-jurisdictional interconnections (regardless of the size of the generator), and made modifications to retain and improve upon the policy decisions made in 2005. The Commission's Order required regulated utilities to update any affected rate schedules, tariffs, riders, and service regulations to conform with the revised standard.

The Commission issued an Order Approving Revised Interconnection Standard on May 15, 2015. That Order made substantial changes to the procedures for requesting to interconnect a generator to the electric grid. Most of these changes were recommended by the stakeholders with the intent of addressing a back-log of interconnection requests. The more significant changes in the State's interconnection standards were: 1) a project's ability to be expedited is now based not only on the project's size, but also on the size of the line it would connect to, and its distance from a substation; 2) a new process for addressing "interdependent" projects was added, where one generator needs to decide whether it is going to move ahead in order for the utility to determine that capacity exists to interconnect a second generator; 3) developers must provide a deposit of at least $20,000; 4) developers must demonstrate that they have site control; and 5) developers must pay for upgrades before the utility begins construction. The utilities are required to file a quarterly report to the Commission reporting on their progress in addressing the

[2] For more information about the Southeastern Regional Transmission Planning process, see http://southeasternrtp.com/. Other members of the SERTP are: Southern Company, Dalton Utilities, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company, Kentucky Utilities Company, Associated Electric Cooperative, Inc., and the Tennessee Valley Authority.

interconnection queue backlog.

The Public Staff was required to convene a workgroup of interested parties on or before May 2017 to discuss whether the State's small generator interconnection standards required additional revisions. Following that stakeholder process, on December 20, 2017, the Commission issued an Order Requesting Comments regarding modifications to the North Carolina Interconnection Procedures, Forms, and Agreements (collectively referred to as the NC Interconnection Standard). On August 10, 2018, the Commission issued an Order Scheduling Hearing, Requesting Comments, and Extending Tranche 1 CPRE RFP Solicitation Response Deadline. The order established an evidentiary hearing to consider modifications to the NC Interconnection Standard. On October 5, 2018, the Commission issued an Order approving modifications to the NC Interconnection Standard in order to accommodate Tranche 1 of the CPRE program.

On June 14, 2019, the Commission issued an order modifying the NC Interconnection Standard that made fairly minor changes while establishing deadlines for considering more substantial changes. These include:

(1) The utilities were required to file additional information explaining their need for generators' production profiles. The Commission subsequently approved this new requirement on September 23, 2019.

(2) Duke was required to file a proposal for an expedited study process for battery storage being added to an existing solar generator. This issue remains pending.

(3) Duke was required to consult with the Electric Power Research Institute as to ways to improve the fast track / supplemental review processes and file a report with the Commission. Duke filed that report October 23, 2019.

(4) Duke was required to establish a stakeholder process to discuss transitioning the interconnection process from a first-come first-served process to a grouping study process. On October 15, 2019, Duke filed a preliminary proposal. Its final queue reform proposal is due February 28, 2020.

(5) The utilities are required to host stakeholder meetings about the adoption of Interconnection Standard IEEE-1547 and file a report with the Commission by April 1, 2020.

Net Metering

"Net metering" refers to a billing arrangement whereby a customer that owns and operates an electric generating facility is billed according to the difference over a billing period between the amount of energy the customer consumes and the amount of energy it generates. As part of REPS legislation, codified at N.C.G.S. § 62.133.8(i)(6), the General Assembly required the Commission to consider whether it is in the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one megawatt or less.

On March 31, 2009, in Docket No. E-100, Sub 83, following hearings on its then-current net metering rule, the Commission issued an Order requiring Duke, Progress, and Dominion to file revised riders or tariffs that allow net metering for any customer that owns and operates a renewable energy facility that generates electricity with a capacity of up to one megawatt. The customer shall be required to interconnect pursuant to the approved generator interconnection standard, which includes provisions regarding the study and implementation of any improvements to the utility's electric system required to accommodate the customer's generation, and to operate in parallel with the utility's electric distribution system. The customer may elect to take retail electric service pursuant to any rate schedule available to other customers in the same rate class and may not be assessed any standby, capacity, metering, or other fees other than those approved for all customers on the same rate schedule. Standby charges shall be waived, however, for any net-metered residential customer with electric generating capacity up to 20 kW and any net-metered non-residential customer up to 100 kW. Credit for excess electricity generated during a monthly billing period shall be carried forward to the following monthly billing period, but shall be granted to the utility at no charge and the credit balance reset to zero at the beginning of each summer billing season. If the customer elects to take retail electric service pursuant to any time-of-use (TOU) rate schedule, excess on-peak generation shall first be applied to offset on peak consumption and excess off-peak generation to offset off-peak consumption; any remaining on-peak generation shall then be applied against any remaining off-peak consumption. If the customer chooses to take retail electric service pursuant to a TOU demand rate schedule, it shall retain ownership of all RECs associated with its electric generation. If the customer chooses to take retail electric service pursuant to any other rate schedule, RECs associated with all electric generation by the facility shall be assigned to the utility as part of the net-metering arrangement. Since the Commission's March 31, 2009 Order, the Commission has not altered the substantive net-metering policy for the State's electric public utilities.

On July, 2017, the Governor signed into law House Bill 589 (S.L. 2017-192). Section six of that legislation enacted G.S. 62-126.4, which directs DEC and DEP to file for Commission approval revised net metering rates. To date, revised net metering rates have not been filed with the Commission.

10. FEDERAL ENERGY INITIATIVES

Open Access Transmission Tariff (OATT)

In April 1996, the FERC issued Order Nos. 888 and 889, which established rules governing open access to electric transmission systems for wholesale customers and required the construction and use of an Open Access Same-time Information System (OASIS) for reserving transmission service. In Order No. 888, the FERC also required utilities to file standard, non-discriminatory OATTs under which service is provided to wholesale customers such as electric cooperatives and municipal electric providers. As part of this decision, the FERC asserted federal jurisdiction over the rates, terms, and conditions of the transmission service provided to retail customers receiving unbundled service while leaving the transmission component of bundled retail service subject to state control. In Order No. 889, the FERC required utilities to separate their transmission and wholesale power marketing functions and to obtain information about their own transmission system for their own wholesale transactions through the use of an OASIS system on the Internet, just like their competitors. The purpose of this rule was to ensure that transmission owners do not have an unfair advantage in wholesale generation markets.

Regional Transmission Organizations (RTOs)

In December 1999, the FERC issued Order No. 2000 encouraging the formation of RTOs, independent entities created to operate the interconnected transmission assets of multiple electric utilities on a regional basis. In compliance with Order No. 2000, Duke, Progress, and SCE&G filed a proposal to form GridSouth Transco, LLC (GridSouth), a Carolinas-based RTO. The utilities put their GridSouth-related efforts on hold in June 2002, citing regulatory uncertainty at the federal level. The GridSouth organization was formally dissolved in April 2005.

Dominion filed an application with the Commission on April 2, 2004, in Docket No. E-22, Sub 418, seeking authority to transfer operational control of its transmission facilities located in North Carolina to PJM Interconnection, an RTO headquartered in Pennsylvania. The Commission approved the transfer subject to conditions on April 19, 2005. On March 31, 2016, Dominion filed a rate increase request with the Commission (Docket No. E-22, Sub 532) in which it requested relief from all of the conditions that had been imposed upon the Company (and that it had agreed to) pursuant to its joining PJM. The Commission relieved Dominion of compliance with most of the PJM conditions in the Commission's order dated December 22, 2016.

The Commission has continued to provide oversight over Dominion and PJM by using its own regulatory authority, through regional cooperation with other State commissions, and by participating in proceedings before the FERC. Together with the other State commissions with jurisdiction over utilities in the PJM area, the Commission is involved in the activities of the Organization of PJM States, Inc. (OPSI).

PURPA Reform

In September, 2019, the Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking (NOPR) that constitutes the FERC's first comprehensive review of its PURPA regulations. The proposed changes are intended to continue encouraging development of QFs while addressing concerns regarding how the current regulations work in today's competitive wholesale power markets.

The NOPR focuses on providing flexibility to state regulatory authorities so they can accommodate recent wholesale power market developments and streamlines the Commission's policies and practices. Specifically, the proposal allows states to incorporate market pricing into avoided cost energy rates in various ways, allows states to require energy rates (but not capacity rates) to vary during the life of QF contracts, modifies the "one-mile rule," and lowers the threshold presumption for nondiscriminatory access to power markets from 20 megawatts to 1 megawatt for small power production, but not cogeneration, facilities. It also requires states to establish objective and reasonable standards for QFs to obtain legally enforceable obligations for the purchase of their power. Finally, the proposal permits protests of a QF's self-certification or self-recertification without the need to file and pay for a separate petition for declaratory order.

Physical and Cyber Security

Federal and State regulators are increasingly concerned about cyber security and physical threats to the nation's bulk power system. North Carolina's utilities are working on many fronts to help ensure security and resilience of transmission and other critical infrastructure against people engaging in physical or cyber attacks and natural disasters. This includes compliance with NERC mandatory standards. The NC Utilities Commission meets with utility officials periodically to understand the threats the utilities are facing and the actions they are taking to address these threats.

Greenhouse Gas Regulation

On August 3, 2015, the U.S. Environmental Protection Agency (EPA) finalized regulations for reducing CO_2 emissions from existing power plants, relying on authority from the Clean Air Act. These regulations establish CO_2 emission levels for existing power plants in each State based upon three "building blocks": (1) altering coal-fired power plants to increase their efficiency; (2) substituting natural gas combined cycle generation for generation from coal; and (3) substituting generation from low or zero-carbon energy generation, such as wind and solar, for generation from fossil fuels. On October 23, 2015, the EPA published its final Clean Power Plan (CPP) rule to regulate emissions of greenhouse gases, specifically carbon dioxide from existing fossil fuel-fired power plants.

In North Carolina, the Department of Environmental Quality (NCDEQ) is the lead agency for compliance with the Clean Air Act. NCDEQ joined with 24 other like states to petition the US Court of Appeals for a stay of the regulations, as well as expedited consideration of a petition for review of those regulations. These states argue that EPA over-stepped its authority in promulgating the rules, that EPA lacks expertise and authority to regulate the energy grid, and that these states will experience irreparable harm if they must begin to comply with the regulations pending the outcome of legal challenges. The outcome of this litigation, and the ultimate disposition of federal CO_2 controls, could have a major impact on the electric generation fleet, reliability of service, and electricity prices in North Carolina. On February 9, 2016, the U.S. Supreme Court placed a "stay" on EPA's implementation of the rule, until an appeals court can consider its legality. The case was argued before the D.C. Circuit Court of Appeals on September 27, 2016.

On March, 28, 2017, President Trump issued an Executive Order establishing a national policy in favor of energy independence, economic growth, and the rule of law. The purpose of that Executive Order is to facilitate the development of U.S. energy resources and to reduce unnecessary regulatory burdens associated with the development of those resources. Pursuant to the Executive Order, EPA initiated its review of the CPP and on October 10, 2017, the EPA proposed to repeal the CPP. In August 2018, EPA issued the proposed Affordable Clean Energy (ACE) rule.

The EPA released the final version of the ACE Rule, the replacement of the CPP on June 19, 2019. The final ACE rule combines three distinct EPA actions.

First, through the ACE rule, the EPA finalized the repeal of the CPP. It also asserted that the repeal is intended to be severable, such that it will survive even if the remainder of the ACE rule is invalidated.

Second, through this action, the EPA finalized the ACE rule, which comprises EPA's determination of the Best System of Emissions Reduction (BSER) for existing coal-fired power plants and establishment of the procedures that will govern states' promulgation of standards of performance for existing electric generating units (EGUs) within their borders. The EPA sets the final BSER as heat rate efficiency improvements based on a range of candidate technologies that can be applied inside the fence-line of an EGU. Rather than setting a specific numerical standard of performance for these units, the EPA's rule requires that each state determine which of the candidate technologies apply to each coal-fired unit based on consideration of remaining useful plant life and other factors, such as reasonableness of cost. Each state must then establish standards of performance based on the degree of emission reduction achievable with the application of the applicable elements of BSER.

Third, through the ACE rule, the EPA finalized a number of changes to the implementing regulations for the timing of state plans for this and future Section 111(d) rulemakings of the Clean Air Act. Based on the changes, states will have three years from when the rule was finalized to submit a plan to the EPA, at which point the EPA has one year to determine whether the plan is acceptable. If states do not submit a plan or if their submitted plan is not acceptable, the EPA will have two years to develop a federal plan.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans	)))))	ORDER ACCEPTING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS, SCHEDULING ORAL ARGUMENT, AND REQUIRING ADDITIONAL ANALYSES

HEARD: Monday, February 4, 2019, at 7:00 p.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, [1] Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell.

APPEARANCES:

For Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC (Duke):

Robert W. Kaylor, Law Office of Robert W. Kaylor, PA, 353 East Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina:

E. Brett Breitschwerdt, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

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[1] Chairman Edward S. Finley, Jr., resigned from the Commission effective June 1, 2019, and Commissioners Jerry C. Dockham and James G. Patterson resigned from the Commission effective June 30, 2019.

For NC WARN, INC.:

Kristen Wills, Post Office Box 61051, Durham, North Carolina 27715-105

For the Using and Consuming Public:

Teresa Townsend, Special Deputy Attorney General, Department of Justice, 114 West Edenton Street, Raleigh, North Carolina 27603

Dianna Downey, Heather Fennell, and Bob Gillam, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to N.C. Gen. Stat. § 62-110.1 is included in the Rule as a part of the IRP process.

North Carolina General Statute § 62-110.1(c) requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, N.C.G.S. § 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, the statute requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. N.C. Gen. Stat. § 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to N.C.G.S. § 62-110.1.

North Carolina General Statute § 62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including

consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills....

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended N.C. Gen. Stat. § 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which N.C. Gen. Stat. § 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[2]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[3] Energy Efficiency measures do not include DSM.

To meet the requirements of N.C.G.S. § 62-110.1 and N.C.G.S. § 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources,[4] furnish the Commission with a biennial report in even-numbered years that contains the specific information set out in Rule R8-60. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports, and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

[2] N.C. Gen. Stat. § 62-133.9(c).

[3] N.C. Gen. Stat. §§ 62-133.8(a)(2) and (4).

[4] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of N.C. Gen. Stat. § 62-110.1(c) and N.C. Gen. Stat. § 62-42, effective July 1, 2013. As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2018 BIENNIAL REPORTS

This Order addresses the 2018 biennial reports (2018 IRPs) filed in Docket No. E-100, Sub 157, by Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion Energy North Carolina (DENC) (collectively, the investor-owned utilities, utilities or IOUs). In addition, this Order also addresses the REPS compliance plans filed by the IOUs.

The following parties have been allowed to intervene in this docket: North Carolina Sustainable Energy Association (NCSEA); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); North Carolina Waste Awareness and Reduction Network (NC WARN); North Carolina Clean Energy Business Alliance (NCCEBA); Carolina Utility Customers Association, Inc. (CUCA); Environmental Defense Fund (EDF); jointly, Southern Alliance for Clean Energy, the Sierra Club, and the Natural Resources Defense Council (SACE, the Sierra Club, and NRDC); Ecoplexus, Inc. (Ecoplexus); and Broad River Energy, LLC (Broad River). The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e). The Attorney General's intervention is recognized pursuant to N.C. Gen. Stat. § 62-20.

PROCEDURAL HISTORY

On May 1, 2018, DENC filed its 2018 biennial IRP report and REPS compliance plan. DEC and DEP (collectively, Duke) filed their 2018 biennial IRP reports and REPS compliance plans on September 5, 2018.

On September 27, 2018, the Commission issued an Order Scheduling Public Hearing on 2018 IRP Reports and Related 2018 REPS Compliance Plans. That Order set the public witness hearing for 7:00 p.m. on February 4, 2019, in Raleigh.

On November 8, 2018, NC WARN filed a motion for an expert witness hearing.

On November 15, 2018, DEC and DEP filed a response in opposition to NC WARN's motion for an expert witness hearing, as did DENC on November 27, 2018.

On December 14, 2018, NC WARN filed initial comments on the utilities' 2018 IRPs.

On December 19, 2018, Duke filed notification of the retirement of its 99 Islands hydroelectric units 5 and 6 located near Gaffney, South Carolina.

On January 17, 2019, NCSEA filed a motion for extension of time to file initial comments and reply comments, which the Commission granted on January 24, 2019.

On January 22, 2019, the Public Staff and DENC filed a joint motion for an additional sixty (60) days after DENC files its corrected 2018 IRP in early March 2019 for the filing of initial comments and 60 days after the initial comments for the filing of reply comments. On January 24, 2019, the Commission granted the joint motion of the Public Staff and DENC.

On February 4, 2019, the public hearing was held in Raleigh, as scheduled, with forty-nine (49) public witnesses in attendance. In summary, the public witnesses focused on the need to encourage energy efficiency and clean renewable resources, such as solar and wind. A few witnesses commented on the value of integrating batteries, and other storage technologies, with the utilities' distributed resources. In addition, the witnesses encouraged the Commission to promote an economy and energy future focused on renewables and distributed energy systems. Other witnesses contended that coal and gas perpetuate climate issues because of greenhouse gas emissions, and further, that the utilities should stop investing in hydraulic fracked gas infrastructure, including the Atlantic Coast Pipeline.

On February 7, 2019, the Public Staff filed a motion for extension of time for all parties to file comments on Duke's 2018 IRPs, which the Commission granted on February 8, 2019.

On February 15, 2019, EDF filed initial comments on the utilities' 2018 IRPs.

On February 21, 2019, the City of Charlotte and Mecklenburg County Local Government Officials requested an additional public hearing and an expert witness hearing on the 2018 IRPs, as did members of the General Assembly from Western North Carolina on March 11, 2019 and Representative Verla Insko from Orange County on March 22, 2019.

On March 7, 2019, initial comments were filed by the Public Staff, the Attorney General's Office, NCSEA, and jointly by SACE, NRDC and the Sierra Club. On March 12, 2019 and May 24, 2019, the Public Staff filed corrections to its initial comments.

On March 7, 2019, DENC filed corrections to its 2018 IRP and REPS Compliance Plan.

On April 29, 2019, Duke filed a motion for extension of time to file reply comments, which the Commission granted on May 1, 2019.

On May 6, 2019, the Public Staff filed initial comments on DENC's 2018 IRP.

On May 20, 2019, Duke filed reply comments, as did the Attorney General and NC WARN.

On June 16, 2019, the Commission issued an order requiring the filing of proposed orders.

On July 5, 2019, DENC filed reply comments.

On July 23, 2019, the Commission issued an order scheduling a technical conference on Integrated Systems and Operations Planning for August 28, 2019. The Order also included several Commission questions to be answered by Duke on or before August 21, 2019.

On July 26, 2019, proposed orders were filed by Duke, DENC, the Public Staff, AGO, NCSEA, and jointly by SACE, NRDC and Sierra Club.

PUBLIC HEARING

Pursuant to N.C.G.S. § 62-110.1(c) the Commission held a public hearing in Raleigh on Monday, February 4, 2019, at 7:00 p.m., where 49 public witnesses provided testimony. In summary, the testimonies of the public witnesses focused on the need to encourage energy efficiency and clean renewable resources, such as solar and wind. A few of the witnesses commented on the value of integrating batteries, and other storage technologies, with the utilities' distributed resources. In addition, the witnesses encouraged the Commission to promote an economy and energy future focused on renewables and distributed energy systems. Many of the witnesses discussed the imminent danger that climate change presents and the failure of the IOUs' IRPs to address the need for aggressive action. Other witnesses contended that coal and gas perpetuate climate issues because of greenhouse gas emissions, and further, that the utilities should stop investing in hydraulic fracked gas infrastructure, including the Atlantic Coast Pipeline. Several owners of independent small hydroelectric plants testified in opposition to the assumption in Duke's IRPs that no existing PURPA small hydroelectric contracts would be renewed.

CONSUMER STATEMENTS OF POSITION

As of August 21, 2019, the Commission has received and filed in this docket approximately 1,789 consumer statements of position on a variety of topics from people all across the state. A sampling of 705 statements found 56 from Asheville, 21 from Winston-Salem, 35 from Chapel Hill, 17 from Wilmington, 3 from Sylva, 40 from Charlotte, 51 from Durham, 11 from Brevard, 8 from Black Mountain, 7 from Boone, 7 from High Point 4 from Waynesville, 3 from Murphy, 6 from Hendersonville, 18 from Greensboro, 5 from Salisbury, 3 from Pffaftown, and 3 from Concord.

SUMMARY CONCLUSION

The Commission has carefully considered the full record in this proceeding, including the public witness testimony, the consumer statements of position, the various consultants' reports, and the parties' comments. The Commission concludes that the record raises several issues that are worthy of more in-depth examination. Within an IRP that spans a 15-year planning horizon, there are a myriad of policy issues, technology choices, models and other components that could be examined. The Commission has identified several topics and sub-topics that it deems to merit additional analysis and examination. The Commission believes that a focused inquiry into these specific topics and sub-topics in the 2020 IRPs will yield a more useful outcome than could be achieved by holding further hearings in the present proceeding relating to the 2018 biennial IRPs. The Commission will accept DENC's 2018 IRP as adequate for planning purposes, subject to DENC's 2019 IRP Update. The Commission will accept DEC’s and DEP’s 2018 IRPs as adequate to be used for planning purposes during the remainder of 2019 and in 2020, subject to DEC’s and DEP’s 2019 IRP Updates. However, the Commission does not accept some of the underlying assumptions upon which DEC’s and DEP’s IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020. Instead, the Commission will use the 2018 IRPs and this Order as an opportunity to provide direction to the IOUs, the Public Staff and intervenors for an orderly presentation of answers to the specific topics and sub-topics identified herein by the Commission and for preparation of the 2020 biennial IRP reports by the utilities. The Commission commends the utilities, intervenors, public witnesses, and authors of position statements for the quality of presentation and analyses. The following sections summarize issues significant to the Integrated Resource Plans filed by the utilities and reflect the full record in the proceeding.

I. PEAK AND ENERGY FORECASTS

Summary of Growth Rates

The following table summarizes the growth rates for the IOUs’ system peak and energy sales forecasts in their IRP filings.

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	0.8%	0.7%	1.0%	127
DEC	1.0%	1.0%	0.9%	186
DENC	0.7%	1.5%	0.7%	124

A. Public Staff Initial Comments – Peak and Energy Forecasts

The Public Staff reviewed the 15-year peak and energy forecasts (2019–33) of DEP, DEC, and DENC. The compound annual growth rates (CAGRs) for the forecasts are within the range of 0.7% to 1.0% for DEC and DEP and 0.7% to 1.5% for DENC. The Public Staff noted that all the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs. They commented that with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future. The Public Staff noted that in its Compliance Filing, DENC revised the peak demand forecasts it filed in its May 1, 2018 IRP, modeling them using the PJM DOM Zone non-coincident peak forecast, which resulted in a significant reduction of peak demand over the forecast horizon.

In assessing the reasonableness of the forecasts, the Public Staff first compared the utilities' most recent weather-normalized peak loads to those forecasted in their 2017 IRP updates. The Public Staff then analyzed the accuracy of the utilities' peak demand and energy sales predictions in their 2012 IRPs by comparing them to their actual peak demands and energy sales. They commented that a review of past forecast errors can identify trends in the IOUs' forecasting and assist in assessing the reasonableness of the utilities' current and future forecasts. Finally, in reviewing DEC and DEP's IRPs, the Public Staff reviewed the forecasts of other adjoining utilities in the VACAR region and the SERC Reliability Corporation.

In regard to DEC and DEP, the Public Staff commented that except for a brief time in the 1980's, the dominant seasonal peak has occurred during summer afternoons. The Public Staff noted that the Companies' annual peak sporadically occurred in the winter season, but since 2013, all of DEP's annual peaks have been during January or February, while DEC's annual peaks have occurred during both the winter and the summer seasons. After DEC and DEP experienced their all-time system peaks in February 2015, they conducted a new reserve margin study, the results of which were incorporated in their 2016 and 2018 IRPs. The Public Staff stated that DEC's and DEP's 2018 IRPs forecast DEP to be a winter peaking system and DEC to be a summer peaking system; however, DEC's planning is based on the winter season. The Public Staff further noted that DEP's weather normalized winter peaks have grown at annual rates significantly greater than the growth rates in DEP's peak forecast. For DENC, the Public Staff commented that its 15-year forecast in the Compliance Filing is based on PJM's peak load and energy sales forecast, scaled down for the Dominion load serving entity, which predicts that DENC will become a winter peaking system in 2024.

1. Public Staff Initial Comments – DEP's Peak and Energy Forecasts

The Public Staff noted that since the 2016 IRP, DEP has projected that it will be a winter peaking system and winter planning utility. It stated that DEP's forecasted winter peak loads reflect a combined average growth rate (CAGR) of 0.7% over the forecast years of 2019 through 2033, which is significantly lower than the 1.2% CAGR in its 2016 IRP and the 1.2% CAGR in its 2014 IRP. The Public Staff pointed out that as with DEC's 2018 IRP and DEP's prior IRPs, relatively little demand reduction is forecasted as being available from EE and DSM programs during the winter seasons, a 0.2% reduction in the CAGR from EE through 2033 of DEP's system peaks and a reduction of the winter demands from DSM by approximately 4%. The Public Staff noted that DEP expects to have the ability to reduce its summer peak loads by 7% through DSM. According to the Public Staff, over the next 15 years, the average annual growth of DEP's winter peak is projected to be approximately 127 MW and the winter peaks are projected to be approximately 604 MW greater than the forecasted summer peaks.

The Public Staff noted that DEP's energy sales, including reductions associated with its EE programs, are predicted to grow at a CAGR of 0.5%, a significantly lower growth rate than the 0.9% in the 2016 IRP and the 1.0% in the 2014 IRP. Further, the Company's EE programs are predicted to reduce its energy sales by approximately 1% in 2019 to 3% in 2033 according to the Public Staff.

The Public Staff's review of DEP's actual and weather adjusted peak load forecasting accuracy for one year showed that DEP's 2017 IRP forecast underestimated the actual 2018 winter peak load by 17%, and by 11% using a weather-normalized peak. When the Public Staff compared the current forecast to the 2012 IRP forecasts for 2013 – 2018, DEP's forecasts indicate a mean average error (MAE) of 9%. Each of the six forecasts used to calculate the MAE was lower than the actual loads, reflecting forecast errors ranging from -18% in 2018 to -0.3% in 2014. The MAE fell to 6% when the forecasts were compared with weather-adjusted loads.

The Public Staff also reviewed DEP's 2012 energy sales forecast, based on the 2012 IRP forecasts for 2013 - 2018, calculating a 13% MAE, reflecting actual sales being significantly less than expected. The Public Staff noted that DEP predicts that over the next 15 years, its EE programs will reduce its annual energy sales by approximately 0.5% in 2019, increasing to 3% in 2033. In addition, the Public Staff found it noteworthy that DEP's predicted load factor is approximately 51% over the next 15 years, significantly lower than the average 55% load factor predicted in the 2016 IRP and the 56% load factor predicted in the 2014 IRP. According to the Public Staff, a decreasing load factor generally indicates a greater need for peaking plants.

The Public Staff found the economic, weather-related, and demographic assumptions underlying DEP's 2018 peak and energy forecasts to be reasonable, but stated that the excessive forecast errors associated with DEP's winter peak indicate that review and revision of DEP's statistical and econometric forecasting practices may be warranted. However, the Public Staff expressed concerns that DEP's actual winter peaks were significantly greater than predicted; such that the 9% MAE equates to an average forecast that is 1,456 MW lower than predicted.

2. Public Staff Initial Comments – DEC's Peak and Energy Forecasts

The Public Staff commented that DEC's forecasted winter peak loads reflect a significantly lower CAGR of 1.0% as compared to the 1.3% CAGR in its 2016 IRP and 1.4% CAGR in its 2014 IRP. The Public Staff pointed out that relatively little demand reduction is forecasted as being available from EE and DSM programs during the winter seasons: a forecasted 0.1% reduction in the CAGR of DEC's system peaks due to EE programs and a reduction in winter demand from DSM programs of approximately 2%. For summer peak loads, the Public Staff noted that DEC forecasts being able to reduce its summer peak loads by 6% through use of DSM. The Public Staff noted that the predicted average annual growth of DEC's winter peak is 186 MW over the next 15 years, as compared to 232 MW in the 2016 IRP and 286 MW in the 2014 IRP. The Public Staff stated that DEC's energy sales, including the effects of its EE programs, are expected to grow at a CAGR of 0.9%, as compared to a 1.0% growth rate in the 2016 IRP and 1.4%

in the 2014 IRP. Further, the Company's EE programs are expected to reduce energy sales by approximately 1% in 2019 and 4% in 2033.

The Public Staff's review of DEC's actual and weather adjusted peak load forecasting accuracy for one year indicated that DEC's 2017 IRP forecast was under-predicted by 4% and that on a weather-normalized basis, the actual peak was 2% greater than predicted. When the accuracy of DEC's forecasts is reviewed since 2012, the Public Staff's analysis shows the 2012 IRP yielded a MAE of 5%. It further showed that of the six predicted load forecasts comprising the MAE, two were higher than expected and four were lower than expected, and that the MAE fell to 4% when the forecasts were compared with peaks that were adjusted for abnormal weather.

The Public Staff made a similar review of DEC's 2012 energy sales forecast, which had a 13% MAE. The Public Staff noted that DEC predicts that over the next 15 years, its EE programs will reduce its annual energy sales by approximately 0.8% in 2019, increasing to 4% in 2033. Further it commented that DEC's predicted load factor remains reasonably constant at 58% over the next 15 years, similar to the 59% load factor in the 2016 IRP and the 57% load factor from the 2014 IRP.

The Public Staff concluded that the economic, weather-related, and demographic assumptions underlying DEC's 2018 peak and energy forecasts were reasonable, but that DEC has overestimated its energy sales relative to the 2012, 2014, and 2016 IRPs. The Public Staff noted that DEC had maintained in discussion that its retail energy sales forecast is reasonably accurate when adjusted for abnormal weather. The Public Staff stated that since the Company continues to reduce the predicted growth rates for its projected energy sales and as the peak demand forecast has a direct influence on its capacity expansion plans, the Public Staff places more weight on its review of the Company's peak demands. Noting that the MAE based on actual versus forecasted loads was 5%, but fell to 4% when compared using weather-normalized loads, the Public Staff concluded that DEC's peak load and energy sales forecasts were reasonable for planning purposes. The Public Staff recommended that both DEC and DEP continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff suggested that the Companies may wish to evaluate multiple approaches such as a single equation that relies on multiple observations that focus on customer's response to cold weather in January and February, in conjunction with a separate equation that examines responses during July and August. Given the different customer responses to extreme cold and winter temperatures, the use of separate equations for the summer peak and winter peak may allow for improved understanding of how customers respond to extreme temperatures, which is in contrast to Duke's current use of a single equation for all twelve months of the year.

3. Public Staff Initial Comments – DENC's Peak and Energy Forecasts

Noting that DENC will become a winter peaking system in 2024, the Public Staff pointed out the faster CAGR of 1.5% for DENC's winter peaks as compared to a 0.7% CAGR of its summer peaks. The Public Staff stated that the predicted winter peak CAGR is slightly higher than the 1.3% growth rate from the 2016 IRP, while the CAGR for the summer peak is significantly lower than the 1.5% CAGR from the 2016 IRP. It noted that while the DOM Zone is predicted to become a winter peaking system, PJM is a summer peaking system and thus the Company must procure adequate capacity for the summer peak demand forecast. To do so, the Company's IRP is modeled to procure both supply-side and demand-side resources with the annual forecast of summer peak demands. According to the Public Staff, on average over the 15-year forecast, the winter peaks are approximately 173 MW greater than the forecasted summer peaks, DENC's EE programs are predicted to provide approximately 1% to 2% reduction of the summer and winter peaks through 2033, and the activation of DSM programs is expected to reduce the peak demands by approximately 1% of MW load. The Public Staff commented that the average annual growth of DENC's winter peak is predicted to be 267 MW and 124 MW for the summer peak over the next 15 years, as compared to the 293 MW annual growth of its summer peaks from the 2016 IRP.

The Public Staff stated that DENC's Compliance Filing projected average annual energy sales growth of 0.7%, a significant decrease from the 1.5% growth rate of the 2016 IRP, and a decrease from the original IRP forecast of 1.4%. It noted DENC's estimate that its EE programs would reduce its energy sales by approximately 2% by 2033, as opposed to the 1% reduction in energy sales due to EE forecasted in its 2016 IRP.

The Public Staff's review of DENC's actual peak load forecasting accuracy for one year showed that DENC's 2017 IRP over-predicted the 2018 summer peak load by 7% and under-predicted the 2018 winter peak load by 15%. The Public Staff reviewed DENC's peak load forecasting accuracy based on the 2012 IRP forecasts for 2013 - 2018. Its review indicated that all of the predicted annual peak demands were greater than the actual peaks, with a MAE of 6%, while its energy sales from the 2012 IRP generated an 11% error rate, with four of the previous six annual peaks occurring during the winter season.

The Public Staff stated that based on its review of DENC's forecast accuracy and pattern of predicting loads greater than the actual loads, it supported DENC's use of the relatively lower PJM peak demand forecast as ordered by the VSCC. The Public Staff found DENC's revised peak load and energy sales forecasts to be reasonable for planning purposes, but noted the growing dominance of morning winter peaks, which appears to represent a shift in the use of electricity and warrants further examination of the Company's econometric and statistical forecast models.

4. Public Staff Areas of Concern and Recommendations – Peak and Energy Forecasts

In its comments on Duke's IRPs, the Public Staff identified several areas of concern, including peak load forecasts and use of smart meter data. In regard to peak load forecasts, the Public Staff expressed concern about DEP's forecast errors of its winter peaks. It noted a continuing pattern of under-forecasting, pointing out that DEP's weather-normalized winter peak of 15,165 MW for 2018 is over 1,000 MW greater than the predicted 2019 winter peak of 14,161 MW. The Public Staff also expressed concern regarding the predicted annual growth rate of DEP's winter peaks of 0.7%, which is a significant departure from the 3.0% CAGR of its actual winter peaks from 2013 through 2018, and 2.1% CAGR of its weather-normalized peaks. It noted the faster growth of DEP's winter peaks over its summer peaks, as opposed to the more balanced growth of DEC's summer and winter peaks.

A key area of concern for the Public Staff with DEP's winter forecasting accuracy was that all of the Company's peaks occurred in the winter season and all of the errors were due to forecasts being below the actual peak demands; as compared to DEC's errors being balanced between forecasts both too high and too low. The Public Staff posited that one reason for the growing dominance of DEP's winter peak may be the lack of heating alternatives to electric heat pumps in DEP's service area, pointing out that heat pumps rely on inefficient heat strips or resistance heating at certain operating conditions. It stated that a second reason may be that natural gas is relatively less available in DEP's service area than DEC's territory.

The Public Staff recommended that Duke evaluate alternative equations and modeling tools that would provide a check on forecasts based on monthly data, as it questioned whether the equation current used by Duke is accurately modeling customers' responsiveness to extreme weather, especially in relation to extreme cold temperatures in the DEP service territory. The Public Staff also noted that the data period used for the regression ended on December 31, 2017, excluding the extreme cold that occurred over several days in January 2018. The Public Staff stated that it may be appropriate to expand the data period to include the full winter season to better capture customers' response to extreme weather.

The Public Staff also noted that it had asked Duke how it used smart meter usage data in developing and informing the Companies' load forecasting models and developing improved rate designs, but neither of the utilities reported incorporating usage data obtained from smart meters in its load forecasting models. Additionally, the Public Staff stated that an Integrated Volt-Var Control (IVVC) program could be utilized to provide a variety of grid services to enhance the operability of the grid (e.g., peak reduction), as well as provide a cost savings aspect to ratepayers. IVVC is the process of optimally managing voltage levels and reactive power to achieve more efficient grid operation by reducing system losses, peak demand, energy consumption, or a combination of all three. The Public Staff indicated that while it had not fully reviewed the cost-benefit analysis and assumptions of an IVVC program installed on the DEC system, it recommended that DEC should continue to revise its estimates and cost benefit analysis for the IVVC program in future IRP filings, and consider scenarios that take into account the impact of multiple assumptions, including the installation of IVCC, on the capacity need. The Public Staff recommended that as smart meters are deployed and data from those meters becomes available, the utilities should include in their IRPs a discussion on how they are using that data to inform their load forecasting and improved rate designs.

The Public Staff also recommended that the Companies continue to review their winter peak equations in order to better quantify the response of customers to low temperatures. The Public Staff further recommended that DEC and DEP continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and use appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events.

In regard to DENC, the Public Staff recommended that the Company's 2020 IRP rely on the PJM coincident peak scaled down for the DENC load serving entity forecast for its baseline peak and energy forecasts and encouraged the Company to present its internal peak demand and energy forecasts as a comparison and to allow for a sensitivity analysis with an alternative expansion plan.

B. SACE, Sierra Club, and NRDC Initial Comments – Peak and Energy Forecasts

According to comments filed by SACE, NRDC and the Sierra Club (SACE et al.), the load forecast is a major factor determining a utility's need for new resources to meet system energy and demand. Overstating load growth will result in excess capacity on the system, and excess costs borne by ratepayers. In their comments, SACE et al. observed that over the 15-year planning horizon, DEC forecasts an annual average growth rate of 1.0% (summer) and 0.9% (winter) with energy growth of 0.8%. DEP forecasts an annual average growth rate of 0.8% (summer) and 0.7% (winter) with energy growth of 0.5%. SACE et al. retained James F. Wilson, an economist and independent consultant in the electric power and natural gas industries, to evaluate the peak load forecasts used in the 2018 IRPs.

Mr. Wilson concluded in his report that while the DEC and DEP load forecasts appear more reasonable than in the past, they should be carefully examined.[5] Moreover, it is too soon to draw a conclusion about the Companies' winter peak load forecasts because the instances of loads exceeding the forecasts have generally occurred under very unusual extreme cold events (such as "Polar Vortex" events). Mr. Wilson recommended that the Companies further research the drivers of sharp load spikes under extreme winter cold conditions, and develop demand response programs and other strategies for shifting load or shaving these spikes. In addition, DEC and DEP should develop a more sophisticated model of how extreme winter weather affects their loads. Mr. Wilson also recommended that the Companies further evaluate wholesale customers' contribution to system peak loads, which affect required reserve margins and capacity needs.

C. Environmental Defense Fund Initial Comments – Peak and Energy Forecasts

EDF points out that using load forecasts that are too high can lead to costly excess capacity. It recommends that the Commission carefully analyze the utilities' load growth

[5] James F. Wilson, Review and Evaluation of the Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans (March 7, 2019), Attachment 3 to the Comments of SACE, NRDC and Sierra Club.

assumptions, including a thorough backcast analysis, to determine whether the load growth assumptions are reasonable.

D. NCSEA Initial Comments – Peak and Energy Forecasts

NCSEA pointed out that while Duke continues to promote its grid improvement plans, the plans are not reflected in the IRPs. NCSEA noted that Duke's grid improvement plans include IVVC, which will allow Duke to manage distribution and allow the utilization of peak shaving and emergency modes of operation.

E. Attorney General's Office Initial Comments – Peak and Energy Forecasts

The AGO supported the Initial Comments of the Public Staff and other parties who recommended that the Integrated Volt-Var Control (IVVC) program be included in Duke's load forecasts developed in IRPs for future years of capacity planning.**F. Duke Reply Comments – Peak and Energy Forecasts**

As noted above, the Public Staff generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. The Public Staff, NCSEA, and the joint comments of SACE, NRDC and Sierra Club (SACE et al.) all made recommendations to the Commission regarding the load forecasts in the 2018 IRPs and future IRP load forecasting requirements, to which Duke replied as follows.

i. That DEC and DEP continue to review their winter peak equations in order to better quantify the response of customers to low temperatures.

Duke commented that it continues to review and improve the load forecast peak model specifications in accordance with the Commission's Order from the 2016 IRP proceeding (Docket No. E-100, Sub 147). Recently, Duke completed an extensive review of the entire peak load forecasting process, including load definition verification, peak weather methodology, and model specification. The results were summarized in the 2018 IRPs.

Duke stated that the peak forecast model objective is to provide a reasonable forecast of future peak demand under the assumption of normal peak conditions. Duke noted that extreme historical peak demand and weather conditions are captured both in the history used by the peak model, as well as in the weather normalization processes. Duke cautioned that any additional attempt to directly or intentionally model extreme peak conditions within the current IRP peak model process would increase the probability of over-forecasting peak demand.

ii. That DEC include in its forecasted load the projected impact of Integrated Volt-Var Control (IVVC) programs.

NCSEA alleged that Duke continues to promote its grid improvement plans, but does not reflect it in its IRPs.[6] NCSEA noted that Duke's grid improvement plans, which would prepare the grid for decentralized, distributed generation over a 10-year period, includes IVVC, a voltage management program, which will allow Duke to manage distribution circuits (to reduce impacts to customers with large motors sensitive to voltage control) and allow the utilization of peak shaving and emergency modes of operation. Duke commented that the original grid improvement plan proposed in DEC's last general rate case in Sub 1146 did not contain a DEC IVVC program. Duke noted that, based upon stakeholder feedback received through the subsequent grid improvement stakeholder workshops hosted by Duke, it has added a DEC IVVC program and plans to reflect the DEC IVVC program in future IRPs. The Commission expects to see the results of this program reflected in the 2020 biennial IRP filing.

iii. That DEC and DEP continue to review their load forecasting methodology to ensure that assumptions and inputs remain current and that appropriate models quantifying customers' response to weather, especially abnormally cold winter weather events, are employed.

Duke noted that, in response to the Commission's request in 2016, it completed a thorough review of the peak forecasting methodology in 2018, which led to raising the peak forecast significantly. Duke agreed with the Public Staff that the revised methodology provides a reasonable forecast of normal peak demand. Duke noted that the peak forecast process is also continuously adapting to changing weather and demand trends as it receives additional history. This process will result in higher forecasted peaks if extreme winter weather becomes more prevalent. The process will also prevent the models from over-reacting to one or two years where extreme winter weather was an outlying event. Duke explained that an example of this would be comparing the winter of 2017-18, which was a very extreme winter from a demand perspective, to the winter of 2018-19, which was very mild.

Finally, Duke cautioned against attempting to model extreme winter peaking conditions, noting that one of the key drivers of the Companies' 17% reserve margin is to cover such events. According to Duke, attempting to model customer responsiveness to extreme weather would force it to make broad assumptions about customers' actions during an extreme peak period that could lead to significant over-forecasting of peak demand.

iv. That Duke include in future IRPs and updates a discussion of their use of data from smart meters to inform their load forecasting, cost of service studies, and rate designs.

Duke noted its agreement that smart meter data has the potential to be very informative from a load forecasting perspective. Duke also noted that the Commission has initiated a rulemaking on certain data access issues in Docket No. E-100, Sub 161, which is pending and may help inform the load forecasting review. Duke further replied,

[6] NCSEA Comments, at p. 11.

however, that the Commission has existing Smart Grid Technology Plan dockets, which provide the Commission and parties with extensive information about smart meters and how DEC and DEP are utilizing this technology and data issues, so Duke does not believe that additional formal reporting should be required in the IRPs. Nonetheless Duke committed to update the Public Staff on their progress in incorporating smart meter data into the load forecasting process.

Duke stated that SACE et al. consultant, James F. Wilson of Wilson Energy Economics, generally found DEC and DEP's 2018 IRP load forecasts to be reasonable for planning purposes and compliant with Commission rules and requirements. On pages 21 to 23 of his Evaluation of Load Forecasts, Mr. Wilson summarized several recommendations to the Commission regarding the 2018 load forecasts, to which Duke responded to selected recommendations as set forth below:

v. Duke should research the drivers of the very high loads that have occurred in each service territory under very cold weather.

Duke commented that it agrees with the Public Staff's assessment in its 2018 IRP comments that primary drivers of high peak demand during extreme temperatures are the predominance of electric heat pumps, and the lack of availability of natural gas as a heating source. According to Duke, these factors are more significant in DEP's than in DEC's service territory, which is indicative by how much more sensitive the DEP region is to extreme winter weather. Duke noted that it will continue to share information on this topic with the Public Staff and other intervenors as more information becomes available.

. **vi. Duke should develop a more sophisticated model of how extreme winter weather affects their loads, drawing upon the experience gained over the past five years. The focus should be on accurately modeling not just the usual (that is, long-term typical) peak-producing weather, but also more extreme conditions, which have occurred in recent years and can cause loads well above the usual annual peaks. Detailed analysis might show, for example, that an average of temperatures over an extended period leading up to the morning peak hour (perhaps 12 preceding hours) better predicts the peak than the single hourly or daily average temperature, and that other conditions, such as wind speeds and cloud cover, also have predictive value. A similar model for extreme summer weather could also be developed.**

Duke noted that its understanding is that the peak forecast should provide a reasonable forecast of system demand, under the assumption of peak normal weather. According to Duke, the model does account for any historical extreme weather and peak conditions within the past 7 years for model specification, and the past 30 years for the development of peak weather normal conditions. Duke disagrees with the suggestion to modify the current peak model to capture extreme conditions, as this would conflict with the NCUC's Order from the 2016 IRP proceeding, Docket No. E-100, Sub 147. More specifically, such a modification would increase the standard errors of the peak model coefficients, resulting in a peak forecast that will not satisfy the Commission's mandate of a peak forecast that predicts probable growth. Duke noted that although both jurisdictions have seen several extreme winters recently, these few data points are clearly outliers. Structuring the peak model to model historical outliers would result in peak forecasts that may drastically over- or under-forecast peaks, even under normal circumstances. Finally, Duke commented that it does not share Mr. Wilson's perception regarding the lack of sophistication of the peak models. Duke explained that it continuously evaluates the peak model specifications to improve peak forecast accuracy, in accordance with the Commission's Order from the 2016 IRP proceeding, Docket No. E-100, Sub 147.

vii. Duke should provide more comprehensive documentation of their peak load forecasting methodology. Duke should consider enhancing their approach to make use of a broader set of high load data (not just monthly peaks), and an enhanced relationship between weather conditions and load as described above. Duke should also consider providing sensitivity analysis of the peak forecasts to key drivers and assumptions, to demonstrate whether the forecasts are likely to be stable over time, or instead may change substantially due to new data.

Duke noted that it is committed to transparency regarding all aspects of the load forecast methodology. Duke explained that it cannot endorse Mr. Wilson's recommendations suggested above, which would conflict with producing a reasonable peak forecast, as mandated by N.C. Gen. Stat. § 62-110.1(c). Finally, Duke questioned how Mr. Wilson defines "stability over time." Duke explained that its peak models use actual monthly peaks and the average daily weather on the day of peak as inputs. In recent years, some of these historical data points reflect extreme or mild peak conditions. According to Duke, while Mr. Wilson may perceive these extreme historical data points as instability, Duke views each historical data point as vital information that will provide guidance in identifying vital information that leads to improving load forecast accuracy.

viii. Duke should develop a more effective method for estimating historical weather-normalized peak loads. Weather-normalized values are very useful for understanding load trends, and Duke's new approach appears to have shortcomings (the approach used in the 2016 IRPs accounted for weather variation more completely). The more sophisticated model of how weather affects loads, recommended above, should contribute to a more accurate weather-normalization methodology.

Duke noted that it agrees with Mr. Wilson about the importance of the peak weather-normalization process in understanding peak history and evaluating peak forecasts. Duke also agreed that its methodology is "imperfect," as are all its processes (and those of every load forecaster who attempts to predict the future), due to the dynamic nature of load forecasting. However, Duke disagrees with Mr. Wilson's following assertions regarding their weather-normalization process:

- Mr. Wilson's comments inaccurately describe Duke's weather-normalization process via simplification, compared to the summary description provided in the 2018 IRPs.

- Mr. Wilson asserts that Duke recognizes that the weather normalization process is "imperfect" and does not fully remove the impact of actual weather. Duke agrees that the methodology is imperfect, primarily due to the natural chaotic behavior of weather. Specifically, the more extreme (normal) peak conditions are, the less (more) likely the peak normalization process will be to capture weather impacts accurately.

- Mr. Wilson refers to the previous weather-normalization process (2016 IRP) as being superior to the current methodology. According to Duke, Mr. Wilson mistakenly describes Duke's process as focusing solely on the peak day. Part of Duke's revised peak weather normalization process implicitly includes a "build-up" effect from the previous day(s) of the peak. This enhancement has proven to be more effective in generating peak weather normal than the previous methodology, which focused solely on the coldest day, which may or may not have aligned with the day of peak. Duke explained that it is important to note that Mr. Wilson's comments appear to be directed more at extreme peak events, which are outliers in history, versus the normal peak demand history that typically occurs.

- Duke disputes Mr. Wilson's assertions that the weather-normalization process does not produce a clear historical trend. Tables C-5 and C-6 of the 2018 IRPs provide annual historical trends of DEC and DEP actual and weather normal peak trends. In comparison, Mr. Wilson's charts (JFW-5 to JFW-8) provide an "alternate" view of this data by narrowing the magnitude of the Y-Axis, which gives the perception of nonlinearity. Finally, Mr. Wilson asserts that the Companies' peak weather normal history should be a steady linear trend. In his comments, he assumes that the underlying drivers of the peak weather-normalization history were relatively stable. However, according to Duke, from 2011 to 2018, both DEC and DEP saw various economic, weather, industrial, and jurisdictional load definition disruptions that impacted the weather normalization process.

ix. With respect to wholesale loads, Duke should provide historical aggregate wholesale firm commitments. Weather-normalized historical peaks should be estimated for the wholesale customer loads separately (and such estimates should exclude quantities associated with any short-term wholesale transactions that may have been in place at the time of the peak). The Companies should further evaluate wholesale customers' contribution to system peak loads, which affect required reserve margins and capacity needs.

Duke currently incorporates an energy and demand forecast methodology like the retail energy and peak forecasts, with the following exceptions:

- All forecasts are econometric models; and

- Duke does not forecast North Carolina Electric Membership Corporation (NCEMC) and North Carolina Eastern Municipal Power Agency (NCEMPA) contracts per agreement, and incorporate those forecasts into the system forecast as given.

G. DENC Reply Comments – Peak and Energy Forecasts

Chapter 2 of DENC's 2018 IRP describes DENC's methodology for forecasting its peak demand and energy sales needs. DENC presented its 15-year peak and energy forecasts (2019-2033) and compound annual growth rates (CAGRs) for the relevant years. In its Compliance Filing, DENC revised its peak demand forecast using the PJM Interconnection, L.L.C. (PJM) DOM Zone non-coincident peak forecast (the PJM load forecast), which resulted in a reduction of the 2018 IRP's peak demand forecast. This revision is addressed at Section 3.d of the Compliance Filing. DENC's 2018 IRP is modeled to procure both supply-side and demand-side resources with the annual forecast of summer peak demands. While PJM predicts that the DOM Zone will become a winter peaking system in 2024because DENC is part of PJM and the Compliance Filing uses the PJM load forecast, DENC continued to model its 2018 IRP based on summer peak demand. DENC predicted its energy sales to grow at an average annual rate of 0.7%, which is a decrease from the 1.5% growth rate predicted in DENC's 2016 IRP. Relatedly, DENC's 2018 IRP predicted that the savings from EE programs is anticipated to reduce energy sales by 2% by 2033, which is a greater reduction compared to the 1% reduction in energy sales predicted in DENC's 2016 IRP.

DENC stated in its reply comments that it is not opposed to showing both the PJM and Company load forecasts for the 2020 IRP. In addition, consistent with the Public Staff's recommendation, DENC stated that it is committed to studying the effects of the winter peak on its econometric and statistical forecast models either through its own analysis or that of an outside consultant. DENC noted that in its final order on its 2018 IRP and Compliance Filing,[7] the VSCC directed DENC to continue to use the PJM load forecast, reduced by the energy efficiency spending requirement of Virginia Senate Bill 966, both as an energy reduction and a supply resource, and separately identify the load associated with data centers in its 2020 IRP. Therefore, DENC noted, the PJM load forecast is now required to be used in DENC's future full IRP filings.

With regard to smart meter data, DENC noted that Virginia now requires it to evaluate "[l]ong-term electric distribution grid planning and proposed electric distribution grid transformation projects" in preparing its full IRPs beginning with the 2020 IRP, and that information about the use of smart meters will also be part of DENC's Grid Transformation Plan, which it intends to refile with the VSCC in 2019. DENC also noted that its ability to use smart meter data to inform load forecasting, cost of service studies, and rate designs will be limited until it can fully deploy smart meters throughout its service territory. Nevertheless, DENC stated that it intends to use data from its smart meters to inform these matters when sufficient data is available.

[7] In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq., Case No. PUR-2018-00065 (June 27, 2019) (VSCC Compliance Order).

II. RESERVE MARGINS

A. Public Staff Initial Comments – Reserve Margins

1. DEP and DEC

The Public Staff explained that based upon the 2016 Resource Adequacy Study performed by Astrapé (Resource Adequacy Study), both Companies used a combined 17% reserve margin for planning purposes. The Public Staff noted that the study was warranted due to extreme weather experienced in the Companies' service territories and was first presented during the 2017 IRP update in Docket E-100, Sub 147. The Public Staff pointed out that the use of peak system load for system planning is relevant in the context of the capacity value of solar resources. Both DEP and DEC have target reserves of 17%, with DEP having a 17% minimum reserve over the planning horizon and DEC at 16.8%, and DEP having a maximum reserve over the planning horizon of 33.8% in the summer of 2025 and DEC at 22.4% in the summer of 2023. For the planning period 2019 to 2033, the Public Staff stated that the range of reserve margins reported by the electric utilities continues to be similar to those seen in previous IRPs, i.e., a loss of load expectation (LOLE) of 0.1 days/year of 16.7% for DEC, 17.5% for DEP, and an average of 17.1% for the combined Companies.

The Public Staff noted that in its April 2, 2018, Joint Report with Duke discussing the Resource Adequacy Study, the Public Staff raised several concerns with the Astrapé study, including the use of forced outrage rates, load regression during extreme events, economic load growth error, load multiplier values, and joint utility operations. The Public Staff recommended a 16% reserve margin. On the other hand, Duke argued it was more appropriate to take a holistic view of the study's reasonableness as opposed to focusing on specific individual factors that could potentially result in a lower reserve margin. The Public Staff noted that the Commission's April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, concluded DEC and DEP could continue to use the minimum 17% winter reserve margin for planning purposes, but should present a sensitivity analysis in their resource plan discussion illustrating the impact of a 16% winter reserve margin for planning, including the risk impacts. Duke was also required to address how to model economic load forecast uncertainties in its 2018 IRPs.

The Public Staff explained that the Companies' 2018 IRPs examined the impact of a 16% reserve margin on the timing of future resource additions as well as on system LOLE. DEC found that a 16% reserve margin would not have any effect on future resource additions, and that LOLE would increase to 0.116 days/year, or one expected firm load shed event every 8.6 years. DEP found that the 16% reserve margin would reduce its short-term market purchases and defer a portion of the combustion turbine (CT) blocks in 2029 and 2032 by two years each. The Public Staff also noted that DEP calculated a LOLE of approximately 0.13 days/year based upon these changes, which is equivalent to one expected load shed event every 7.7 years.

In addition to the effects of a 16% reserve margin, the Public Staff noted that Duke's IRPs addressed load forecast error (LFE) assumptions involving uncertainty and probability distribution. With respect to LFE uncertainty, the Public Staff explained that the Companies presented additional Resource Adequacy Study results with no LFE that indicated that the required reserve margin is only 0.28% less than the Public Staff's recommendation of 16%. The Public Staff further noted the Companies' belief that there is meaningful load growth uncertainty over a two to four-year period, requiring reserves greater than 0.28%

With respect to LFE probability distribution, the Public Staff pointed out that the Companies predict a symmetrical probability distribution, where there is equal likelihood of a significant under or over-forecast. However, the Public Staff's LFE probability distribution used a log-normal distribution so that the probability of a lower-than-expected economic growth rate is greater than a higher-than-expected economic growth rate. The Public Staff noted that Duke indicated that it found it inappropriate to use the over-forecast bias recommended by the Public Staff.

The Public Staff stated that it continues to believe that use of a 2-year LFE is appropriate, given that IRPs are required to be filed every two years and that the effects of cold weather outages should be removed. The Public Staff noted that it agreed with Duke that several modeling and market assistance assumptions should be revisited in the next resource adequacy study. As such, the Public Staff continued to recommend a 16% reserve margin, but indicated its willingness to work with the Companies to reach consensus within the constructs of the next resource adequacy study.

2. DENC

The Public Staff noted that DENC, as a member of PJM, is a summer planning and summer peaking utility, and generally considers summer peak load as the load upon which the reserve margin is based. The Public Staff pointed out that in its original filing, DENC used PJM's reserve margin of 15.9%, adjusted based on the coincident factor between the DOM Zone coincidental and non-coincidental peak load, resulting in a reserve margin target of 11.7%. This reserve margin calculation is the same in both the original IRP and the Compliance Filing, but the Public Staff noted that the load forecast is reduced to comply with the VSCC Order in DENC's Compliance Filing. The Public Staff pointed out that the original IRP projected a deficit under Alternative Plan E of 5,275 MW, while the Compliance Filing projects a deficit of 3,028 MW – a 43% reduction in capacity need by 2033.

B. SACE, Sierra Club, and NRDC Initial Comments – Reserve Margins

According to comments filed by SACE et al., the planning reserve margin is a key element of an IRP because it determines how much extra capacity the utility maintains on its system to meet demand in the event of an outage or other unanticipated capacity gap. Both of the Duke 2018 IRPs use a 17% winter planning reserve margin, an increase relative to the 16% reserve margins used before the 2016 IRPs. These planning reserve margins used in developing the IRPs were, in turn, based on resource adequacy studies conducted by Astrapé Consulting in 2016 (2016 RA Studies). SACE et al. retained James F. Wilson, an economist and independent consultant in the electric power and natural gas industries, to evaluate reserve margins used in the 2018 IRPs. Mr. Wilson concluded that due to a number of flaws in the 2016 RA Studies, the DEC and DEP planning reserve margins are improperly inflated, and the 17% planning reserve margins should be rejected.

According to the SACE et al.'s summary of Mr. Wilson's findings, the 2016 RA Studies exaggerated the risk and magnitude of extreme winter peak loads, calling into question the shift by DEC and DEP to planning for "winter-peaking" systems. The RA Studies also substantially overstated the risk of very high loads under extreme cold, mainly due to a faulty approach to extrapolating the increase in load due to very low temperatures. In addition, due to the RA Studies' assumptions about demand response capacity and operating reserves applicable to winter peak conditions, the resource adequacy risk in winter was substantially overstated relative to the risk in summer and other periods of the year. Mr. Wilson also suggested that including multi-year economic load forecast uncertainty in the resource adequacy studies is not appropriate because many short lead-time actions could and very likely would be taken if load grows faster than expected. These findings, along with corresponding recommendations for improvement, are discussed in detail in the Wilson Energy Economics report.[8] Based on Mr. Wilson's analysis, SACE et al. commented that the use of overly high reserve margins in the IRPs means that DEC and DEP are planning to add too much new capacity on the system, which would add unnecessary costs for ratepayers.

C. NCSEA Initial Comments – Reserve Margins

NCSEA commissioned the Synapse Study in order to perform "a rigorous, scenario-based analysis to evaluate an alternative clean energy future compared to the more traditional portfolio of fossil-fueled resource additions included in Duke Energy Carolinas and Duke Energy Progress's (collectively Duke Energy) IRPs". Synapse Study, p. 1. The study found that the energy portfolio in Duke's 2018 IRPs is not the least cost mix of energy resources, and that the Synapse Study's Clean Energy Scenario was a more economical energy portfolio for the state. Id. As part of its least-cost analysis, Synapse evaluated the reserve margin that would achieve its Clean Energy Scenario.

> The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.

NCSEA Initial Comments, p. 8. As indicated above, according to Synapse's analysis, a 15% reserve margin achieves both aspects of an adequate reserve margin as defined by

[8] James F. Wilson, Review and Evaluation of Resource Adequacy and Solar Capacity Value Issues with Regard to the Duke Energy Carolinas and Duke Energy Progress 2018 Integrated Resource Plans and Avoided Cost Filing (February 12, 2019).

Duke: it is high enough to ensure reliable energy for Duke customers without burdening ratepayers.

D. DEC and DEP Reply Comments – Reserve Margins

DEC and DEP noted that they used a 17% minimum winter reserve margin target in development of their 2018 IRPs, consistent with results from the 2016 resource adequacy studies. DEC and DEP stated that since completion of the 2016 studies, they have worked extensively with the Public Staff and other intervenors to explain study results and methodology and respond to discovery in efforts to address intervenor questions and concerns.

As an initial matter, DEC and DEP stated that they have complied with all Commission orders regarding the 2016 resource adequacy studies. The NCUC's 2016 IRP Order in Docket No. E-100, Sub 147 concluded that the reserve margins included in the DEP and DEC 2016 IRPs are reasonable for planning purposes. They pointed out, however, that the Commission also directed DEP and DEC to work with the Public Staff to address outstanding concerns raised by the Public Staff and SACE consultant Wilson. The Commission further directed the DEC, DEP, and the Public Staff to file a Joint Report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP updates. The Joint Report was filed on April 2, 2018 and noted that although the discussions between the Public Staff, DEC and DEP were helpful, the parties did not reach agreement regarding the methodology used to incorporate economic load forecast uncertainty. Ultimately, the Public Staff recommended that DEC and DEP utilize a 16% reserve margin in their IRPs, and DEC and DEP recommended a minimum 17% winter reserve margin in their IRPs. The Commission's April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, in Docket No. E-100, Sub 147 (Sub 147), accepted the parties' Joint Report and concluded that DEC and DEP may continue to utilize the minimum 17% winter reserve margin for planning purposes in their 2018 IRPs. In addition, the Commission ordered DEC and DEP to further address the economic load forecast uncertainty issue in their 2018 IRPs. The Commission also required the Companies to present a sensitivity analysis in their 2018 IRPs that illustrates the impact of a 16% winter reserve margin, including the specific risk impact (LOLE) of using a 16% minimum reserve margin versus a 17% minimum reserve margin. DEC and DEP assert that they complied with the Commission orders in developing their 2018 IRPs.

1. Economic Load Forecast Uncertainty

In this docket, the Public Staff continues to support a 16% reserve margin target based on their PS-S2 scenario proposed in Sub 147 which reflects the removal of short duration cold weather-related outages primarily experienced during the winter of 2014, and also incorporates different economic load forecast uncertainty assumptions as compared to assumptions used in the 2016 studies. As a result of these differences, the PS-S2 scenario results in a reserve margin target of 16%, though DEC and DEP continue to support a reserve margin target of 17%.

DEC and DEP stated that they had previously demonstrated that removal of the cold weather outages, as requested by the Public Staff, is insignificant to the 2016 Resource Adequacy study results and impacts the average reserve margin by less than 0.1%. DEC and DEP explained that, as documented extensively in the Joint Report and the Companies' 2018 IRPs, the Companies believe that the Public Staff's load forecast uncertainty assumptions overstate the probability that actual load will be at or below the Companies' forecast levels. DEC and DEP commented that they are not comfortable with the over forecast bias that is assumed in the Public Staff's load forecast error assumptions, which reflect a probability of over forecasting load approximately 48% of the time and under forecasting load approximately 17% of the time.

Instead, DEC and DEP believe that because the load forecast represents a 50/50 forecast, the load forecast uncertainty should reflect possible loads that are equally likely to fall either above or below the forecast. That is, 50% of the time load growth is expected to be higher than projected, and 50% of the time it is expected to be lower than projected. This load forecast uncertainty distribution more reasonably captures expected fluctuations in load growth as compared to the PS-S2 scenario, which reflects an over-forecast of load the majority of the time.

Further, DEC and DEP commented that, as demonstrated in the Companies' 2018 IRPs, assuming perfect knowledge of its 50/50 weather normal forecast, the Public Staff's recommended 16% reserve margin is only 0.28% greater than the reserve margin needed with perfect forecasting knowledge. DEC and DEP believe that there is meaningful load growth uncertainty over a two to four-year period and that reserves of greater than 0.28% of load are required to manage that risk.

DEC and DEP explained that, given the disagreement in methodology and assumptions for incorporating load uncertainty in the resource adequacy studies, it is notable that the Public Staff expressed concerns in their IRP comments regarding DEP's projected annual peak demand growth rate reflecting a significant departure as compared to higher growth of actual winter peaks.[9] Through discovery[10] DEC and DEP asked the Public Staff to reconcile that concern with their position regarding the economic load forecast uncertainty included in the resource adequacy studies which reflects a significantly greater probability of over-forecasting load growth compared to under-forecasting load growth. The Public Staff explained that their concerns about the forecasting accuracy of DEP's winter peak demands relate to the inability of the forecasting process to adequately capture how customers' use of energy changes in response to extreme weather events. The Public Staff further noted that this issue is unrelated to the economic load uncertainty referred to in the Public Staff's scenario PS-S2. DEC and DEP noted that they appreciate and recognize this difference but also noted that this issue further illustrates the uncertainty in the non-weather-related load forecast,

[9] Reference page 78 of Public Staff's Comments which states: "The Public Staff is also concerned with the predicted annual growth rate of DEP's winter peaks of 0.7%, reflecting a significant departure from the historical growth of its actual winter peaks that have grown at a 3.0% CAGR from 2013 through 2018, while the weather-normalized peaks have grown at 2.1%."

[10] Public Staff response to DEC/DEP data request No. 1-1.

and that DEC and DEP believe that the uncertainty included in the resource adequacy studies is not unreasonable.

2. Multi-Year Economic Load Forecast Uncertainty

SACE et al. consultant Wilson suggests that including multi-year economic load forecast uncertainty in the resource adequacy studies is not appropriate and suggests that many short lead-time actions could and very likely would be taken if load grows faster than expected.[11] Mr. Wilson suggests that if the rate of load growth raised concerns about resource adequacy, utilities would have time adjust their plans and take actions such as accelerating the development of new resources, increasing demand response or energy efficiency programs, delaying a planned retirement, adjusting firm purchases or allowing wholesale contracts to expire. DEC and DEP commented that while these are all worthy ideas and actions that they would likely consider in the event of a significant increase in the load forecast due to economic or other uncertainty, such alternatives are not always sufficiently available or practical to satisfy a resource deficit. In particular, large quantities of demand response and energy efficiency programs are typically not achievable within a short timeframe.

According to DEC and DEP, the 2018 DEP IRP saw a 600 MW increase in winter peak demand from the 2017 IRP Update, which contributed to an approximate 2,000 MW near-term need for capacity and energy resources in DEP. As a result of that increase, and as identified in the IRP, DEP conducted a capacity and energy market solicitation that sought to extend existing purchase power contracts and identify new capacity proposals from similar operationally capable existing generation facilities or systems with firm transmission deliverability into DEP. While the response to the market solicitation was robust, the capacity need in DEP is significant, and additional steps may be needed to ensure that DEP can continue to meet its 17% minimum reserve margin requirement. DEC and DEP noted that options, including deferring unit retirements, are limited, however. Additionally, due to the influx of solar in the Carolinas, which has limited contribution to meeting winter peak capacity needs, the transmission interconnection queue is operating with a significant delay, which makes building new generation that requires transmission interconnection studies, very challenging to execute in an expedited manner. As the timing required to site new generation increases, and older generating units are asked to operate longer to meet capacity requirements, the need to include multi-year economic load forecast uncertainty in the resource adequacy studies only increases. The reality of these circumstances suggests that including only one year of load forecast uncertainty, as suggested by Mr. Wilson, to establish a long-term reliability planning target, is inadequate.

3. Relationship between Winter Load and Cold Temperatures

DEC and DEP noted that SACE et al. consultant Wilson echoes many of the same arguments he presented in the 2016 IRP proceeding concerning the Companies' 2016 Resource Adequacy studies. In particular, they stated that he again argues against the

[11] SACE et al. Comments, Attachment 4, at 15.

methodology used to capture the relationship between winter load and cold temperatures.[12] DEC and DEP asserted that they have complied with all Commission orders regarding the 2016 Resource Adequacy studies, including working with the Public Staff to address Mr. Wilson's concerns.

Mr. Wilson notes that including "more rather than less historical weather data is preferred" but also suggests that the 15-year period from 1982-1996 should be excluded because it results in flawed regressions and overstates winter resource adequacy risk.[13] This is also apparent from his statement "…the 2016 RA Studies results are very sensitive to the choice of 20 or 30 historical weather years…"[14] DEC and DEP commented that the purpose of a reserve margin is to cover uncertainties such as extreme load and generator outages and it would be irresponsible to ignore the potential for these extreme cold weather events when assessing resource adequacy. They argued that excluding 15 years of the 36-year weather history used in the study just because it reflects colder temperatures compared to other historical years is irresponsible. These are precisely the periods that the reserve margin is designed to cover. DEC and DEP explained that, in fact, as noted in the Joint Report, NCUC Rule R8-61 (CPCN) requires utilities to provide "a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area…"[15] DED and DEP noted that the Commission is concerned and expects utilities to provide reliable service to customers even during extreme weather events.

DEC and DEP explained that, pursuant to the Commission's June 27, 2017 Order accepting the Companies' 2016 IRPs, the Public Staff, DEC and DEP reviewed the cold weather load modeling in the 2016 studies and performed a sensitivity analysis that reduced the regression equations significantly for temperatures below the levels seen in recent years.[16] This sensitivity analysis showed a relatively small decrease in reserve margin (0.3%) given that the sensitivity reduced the cold weather impact by half of that assumed in the base case. According to DEC and DEP, the reason that the impact is not larger is because the sensitivity only impacts 7 occurrences in the 36-year weather history. As stated by the Public Staff in the Joint Report, after having further discussions with DEC and DEP, the Public Staff was satisfied that the approach taken in the 2016 studies by the Companies is reasonable.[17]

DEC and DEP further noted that the 2016 resource adequacy studies reflected a maximum summer peak that was 7.5% above the expected summer peak for both DEC and DEP. In comparison, the 2018 PJM Reserve Requirement Study reflects a maximum summer peak that is 24% higher than the expected summer peak.[18] For winter, the 2016

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[12] Id., at 6-13.

[13] Id., at 12.

[14] Id., at 25.

[15] Joint Report filed in Docket No. E-100, Sub 147, April 2, 2018, at slide 10.

[16] Id., at slide 20.

[17] Id., at 2.

[18] 2018 PJM Reserve Requirement Study: https://www.pjm.com/-/media/planning/res-adeq/2018-pjm-reserve-requirement-study.ashx?la=en

study for DEC reflected a maximum winter peak that was 18.3% greater than the expected winter peak while the DEP study reflected a winter peak that was 21.5% greater than the expected winter peak. In comparison, the 2018 PJM study reflected a maximum winter peak that was 21% higher than the expected winter peak. DEC and DEP explained that the variability in load due to temperature extremes that was modeled in the 2016 resource adequacy studies for DEC and DEP were at or below the peak load variability included in the 2018 PJM study.

DEC and DEP noted that they and Astrapé recognize that appropriately capturing the relationship between extreme cold weather and load are key drivers of the resource adequacy study results. Although there is limited data at extreme cold temperatures, DEC, DEP, and Astrapé believe that the modeling included in the 2016 studies was reasonable. DEC and DEP therefore asserted that Mr. Wilson's comments on this topic are not persuasive.

4. Operating Reserve Assumptions

DEC and DEP argued that Mr. Wilson initiated a new unfounded claim in SACE et al.'s comments by claiming that the 2016 Resource Adequacy studies exaggerate winter risk through the operating reserve assumptions. They asserted that Mr. Wilson's claim that over 1,000 MW for DEC, and about 750 MW for DEP, of operating reserves are held back in the SERVM model resulting in firm load curtailments is grossly inaccurate.[19] In fact, DEC and DEP noted that SERVM allows operating reserves to drop to the regulation requirement which was 216 MW in DEC and 134 MW in DEP for the resource adequacy and solar capacity value studies. DEC and DEP commented that it is interesting to note that they responded in detail to this exact question in response to DEC-DEP SACE DR 2-19 in Sub 147, yet Mr. Wilson still makes these unsubstantiated claims regarding the operating reserves policy used in the studies. DEC and DEP argued that Mr. Wilson's arguments have no basis in fact and should be rejected.

5. Demand Response Assumptions

SACE et al. consultant Wilson concludes that the DEC's and DEP's demand response winter assumptions should be "brought up to the summer level."[20] Although DEC and DEP agree that winter demand response programs are a reasonable tool for reducing winter peak demand and winter LOLE, when available, they note that the levels of reduction proposed by Mr. Wilson are extremely optimistic and not reasonably achievable in the near term, if at all. DEC and DEP commented that, as an example, the residential DEP EnergyWise Home program currently offers winter measures (Hot Water Heaters & Heat Pump Heat Strips) in its Western region in and around Asheville. These measures have been in place for 10 years and have been marketed aggressively with direct mail, email, outbound calling, and door-to-door canvassing. Over that 10-year period, the program has achieved 15 MW for a residential customer base of approximately 150,000. According to DEC and DEP, assuming the same level of

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[19] SACE et al. Comments, Attachment 4, at 20.

[20] Id., at pp. 19-20.

achievable potential in the rest of DEP and DEC, a more reasonable estimate of residential winter DSM would be 150 MW in each jurisdiction in 10 years, which would only be true if those measures remained cost-effective into the future.

DEC and DEP stated that, moreover, actual program experience from DEP EnergyWise Home has shown that winter residential program potential is actually more difficult to achieve than summer potential for several reasons. First, not all residential customers have electric resistance hot water heaters or heat pumps with electric resistance strip heat. Instead, almost all have compressorized cooling in the form of straight air conditioning or heat pumps. Second, residential winter measure installations require appointments to enter the customer's home that are often rescheduled and more costly than a summer air conditioning installation, which does not require an in-home installation.

DEC and DEP also noted their plans to implement new winter DSM programs as proposed in the 2018 IRPs, and to continue their work toward implementation of those programs. According to DEC and DEP, however, the extreme amounts of winter demand response programs anticipated to be cost-effective and reasonably achievable as cited by Mr. Wilson cannot prudently be included in the IRP forecast. They explained that Mr. Wilson attempts to support his claim by stating that the most recent Market Potential Study for DEC and DEP identified additional winter demand response technical and economic potential up to 2,300 MW;[21] however, the amount of potential that is reasonably achievable must be based on DEC's and DEP's experience with DSM program adoption and, in DEC and DEP's experience, adoption of high levels of DSM programs has been challenging despite significant effort by the Companies. According to DEC and DEP, therefore, Mr. Wilson's claim that winter demand response can be magically brought up to the summer level to reduce winter resource adequacy risk should be rejected.

6. Load Net of Solar Resources

Mr. Wilson makes the following assertion on page 22 of Attachment 4 to SACE et al.'s Comments:

> A more balanced seasonal weighting is also suggested by the simple fact that the vast majority of high load hours are in summer on both systems. According to DEC's load forecast, 83% of the highest load hours (top 1%) are in summer; for DEP's load forecast, 74% of the top 1% load hours are in summer.

DEC and DEP commented that, as Mr. Wilson points out, DEC and DEP do experience significant summer loads; however, summer peaks occur in late afternoon hours when solar has significantly greater energy contributions as compared to dark winter mornings where very little – if any -- solar is available at the time of peak. Thus, the summer peak loads net of solar output are reduced relative to winter peak loads net of solar. DEC and DEP explain that this load net of solar has a significant impact on summer versus winter LOLE values and represents the net load that the remainder of the

[21] Id., at 20.

Companies' resources must satisfy. They noted, however, that when asked whether Mr. Wilson's analysis of seasonal weighting reflected consideration of load net of solar resources, SACE et al. responded, "…that comment referred to load, not load net of any particular resources."[22] Further, when asked to provide a detailed explanation of why Mr. Wilson believes it is appropriate to exclude the impact of solar generation when evaluating seasonal loss of load risk, SACE et al. responded, "Not applicable."

DEC and DEP stated that they appreciate constructive feedback regarding their planning processes and studies. They argued, however, that misleading (winter load and temperature relationship), unachievable (demand response potential) and false (operating reserves policy) claims regarding the 2016 resource adequacy studies largely do not add value and are counter-productive. DEC and DEP also noted that their review of Mr. Wilson's comments was also limited by insufficient information and late responses to the Companies' data requests (SACE et al.'s responses to DEC/DEP Data Requests Nos. 4-2 and 4-5).

7. Resource Adequacy Summary Comments

DEC and DEP noted that, as stated in the 150 Day Joint Report and 2018 IRPs, they believe that a holistic review and consideration of resource adequacy study inputs and assumptions is appropriate when judging the reasonableness of the study results. DEC and DEP stated that while some parties may believe that certain study inputs and assumptions may have overstated the required reserve margin (i.e., resulting in a reserve margin that is too high), they believe that certain assumptions in the 2016 studies, including outage rate modeling and market assistance assumptions, may have been aggressive and understated the required reserve margin (resulted in a reserve margin that is too low). DEC and DEP agree with Mr. Wilson's comment that resource adequacy and reserve margin requirements can change over time and they note that this is precisely why DEC and DEP conduct periodic resource adequacy assessments in order to capture significant changes in inputs and assumptions that may impact study results. DEC and DEP expressed their plans to work with the Public Staff to refresh inputs and assumptions and complete new resource adequacy studies in support of their 2020 IRPs. According to DEC and DEP, it is prudent to maintain a minimum 17% winter reserve margin to provide adequate reliability and satisfy the target of less than one firm load shed event every 10 years. As a result, DEC and DEP recommend use of a 17% winter reserve margin until such time as a new study is completed.

E. DENC Reply Comments – Reserve Margins

Chapter 4 of DENC's 2018 IRP discusses its Planning Assumptions, and states that DENC participates in the PJM capacity planning process for short- and long-term capacity planning. As a PJM member, DENC is a signatory to PJM's Reliability Assurance Agreement, which obligates it to own or procure sufficient capacity to maintain overall system reliability. PJM determines these obligations for each zone through its annual load forecast and reserve margin guidelines, and then conducts a capacity auction through its

[22] SACE et al. response to Duke Data Request 4-5.

Short-Term Capacity Planning Process for meeting these requirements three years into the future. This auction process determines the reserve margin and the capacity price for each zone for the third year. DENC is obligated to obtain enough capacity to cover its PJM-determined capacity requirements either from the auction or through bilateral trades.

DENC uses PJM's reserve margin guidelines in conjunction with its own load forecast to determine its long-term capacity requirement. PJM's 2017 Reserve Requirement Study recommended using a reserve margin of 15.9%. DENC uses a coincidence factor to account for the historically different peak periods between DENC and PJM and determine the reserve margin needed to meet reliability targets. The coincidence factor reduces DENC's reserve margin requirement to 11.7%. The same 11.7% requirement was utilized in the Compliance Filing.

In its reply comments, DENC stated that it does not oppose the Public Staff's recommendation that, in future IRPs, DENC should provide information regarding PJM's capacity value for renewable resources as well as a justification for any difference between DENC's and PJM's calculated capacity values or methodology. Accordingly, DENC stated that it would provide such information in its 2019 IRP update. In addition, DENC noted that the VSCC has directed DENC to, in future full IRPs, model future solar PV tracking resources using two alternative capacity factor values: (a) the actual capacity performance of Company-owned solar tracking fleet in Virginia using an average of the most recent three-year period; and (b) 25%. Finally, DENC stated that it will evaluate incorporating a sub-hourly analysis into the 2020 IRP. DENC noted that because it uses internal information to establish the adjusted reserve margin and coincidence factor and the use of advanced analytical techniques requires a level of detail not provided in the PJM forecast, it will therefore use available internal data and forecasts when evaluating the feasibility and benefits of advanced analytical techniques in the 2020 IRP.

III. SYSTEM PEAKS, DEMAND-SIDE MANAGEMENT (DSM) AND ENERGY EFFICIENCY (EE)

A. System Peaks

1. Public Staff Initial Comments – System Peaks (DEP)

The Public Staff noted that DEP's 2018 annual system peak demand of 16,191 MW occurred on January 7, 2018, at the hour ending 7:00 a.m., at a system-wide temperature of 11 degrees Fahrenheit (ºF). DEP activated its DSM resources and reduced its winter peak hourly load by 225 MW. The Public Staff noted that during the Company's nine other highest hourly winter loads, DEP activated its DSM six more times when the average system temperature was between 15ºF and 24ºF.

Based on the Public Staff's comments, DEP's summer system peak of 13,403 MW occurred on June 19, 2018, at the hour ending 5:00 p.m., at a system-wide temperature of 94ºF. DEP activated its DSM resources and reduced its summer peak hourly load by 22 MW. During the Company's nine other highest hourly summer loads, the Public Staff noted that DEP activated its DSM program five more times between 91ºF and 93ºF.

2. Public Staff Initial Comments – System Peaks (DEC)

The Public Staff noted that DEC's 2018 annual system peak demand of 19,436 MW, occurred on January 5, 2018, at the hour ending 8:00 a.m., at a system-wide temperature of 12ºF. DEC's summer system peak was 18,008 MW occurred on June 19, 2018, at the hour ending 4:00 p.m., at a system-wide temperature of 94ºF. According to the Public Staff, DEC did not activate any of its DSM resources during either the winter system peak or the summer peak. During the Company's nine other highest hourly winter peak loads, DEC activated its DSM program during five of those hours when the average temperature at the peak was 10ºF and 13ºF .In regard to the nine other highest hourly summer loads, the Public Staff noted that DEC activated its DSM once during its ninth highest hourly load, when the average temperature was 91ºF.

In its recommendations regarding Duke's IRPs, the Public Staff recommended that the Companies maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high, as well as to ensure reliability. The Public Staff also recommended that the Companies' DSM resource forecast represent the reasonably expected load reductions that are available at the time the resource is called upon as capacity. Finally, the Public Staff proposed that DEC and DEP investigate the potential for new time-of-use rate designs that could encourage customers to shift usage from peak to off-peak periods, particularly during winter peaks.

3. Public Staff Initial Comments – System Peaks (DENC)

The Public Staff noted that DENC's 2018 annual system peak of 17,792 MW occurred on January 7, 2018, at the hour ending 8:00 a.m., at a system-wide temperature of 7ºF. DENC's summer system peak of 16,528 MW occurred on July 2, 2018, at the hour ending 5:00 p.m., at a system-wide temperature of 91°F. The Public Staff indicated that DENC activated DSM during both of these peaks. During its 15 highest peak loads from July 2017 through August 2018, the Public Staff noted that DENC activated its Residential AC Cycling program nine times and its Distributed Generation program 13 times over the 15 highest peak demands.

4. Public Staff Conclusions – System Peaks

The Public Staff acknowledges that load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations in determining which DSM resources should be deployed. Use of DSM resources is largely dependent on the circumstances and cannot be prescribed in any definitive manner. Nevertheless, the Public Staff concluded that the utilities should maximize the use of their DSM to reduce fuel costs, especially when marginal costs of energy are high.

In its review of DENC's DSM activations at the time of its 15 highest hourly peaks, the Public Staff notes an ongoing concern regarding the difference in DSM resources available in the winter and the summer due, in part, to the fact that winter season programs are typically not cost effective. The Public Staff stated that DENC activated its Distributed Generation program during the Company's 2018 winter peak and most of the other near peaks during the winter season; however, the activations only led to 4 - 6 MW of load reduction. As with DEC and DEP, the Public Staff recommends that each IOU investigate and implement any cost-effective DSM that would be available to respond to the growth of the winter peak demands.

B. DSM/EE

1. Public Staff Initial Comments – DEC and DEP'S DSM/EE

The Public Staff stated that its review of DEC and DEP's DSM/EE forecasts and programs indicated that the Companies had complied with the requirements of Commission Rule R8-60 and previous Commission orders regarding the forecasting of DSM and EE program savings, as well as the presentation of data related to those savings. DEC and DEP included information about their DSM/EE portfolios similar to the information reported in their 2017 IRP updates. The Public Staff opined that DEC and DEP appropriately addressed the changes in their forecasts of DSM and EE resources and the peak demand and energy savings from those programs. The Public Staff noted that while DEC's forecast did not change by more than 10%, DEP's forecast did vary by more than 10%.

The Public Staff noted several factors that will continue to affect the utilities' ability to develop and implement cost-effective EE programs: changes to federal standards for future lighting measures to take effect January 1, 2020, changes in other appliance standards, and efforts to modify building and energy codes. The Public Staff also pointed to recent decreases in the utilities' avoided costs that have decreased the value of avoided energy and capacity benefits from an EE program, making it more difficult to design, implement, and maintain cost-effective programs. Further, the large contribution of EE savings to portfolios from lighting measures are unlikely to continue beyond one to two more years. Additionally, technologies such as space heating/cooling and building envelop measures will continue to face similar headwinds.

The Public Staff stated its belief that an increased nationwide emphasis on EE is producing EE savings outside of utility-sponsored programs; these EE savings are being incorporated into the IRP load forecasts. Factors influencing load forecasts include the "roll-off" of utility EE savings, savings from more stringent appliance and lighting standards, more efficient heating and cooling equipment, greater emphasis on incorporating efficiency standards into building and energy codes, self-installation of EE measures by large commercial and industrial customers, and consumer adoption of EE. While measuring the EE embedded in the load forecasts is challenging, the Public Staff states its belief that EE has contributed to the lower sales growth rates identified in the utilities' IRPs, which is likely to continue into the near future.

The Public Staff pointed out that DEC does not offer any residential DSM program that can be used during winter peaking events, while DEP's EnergyWise program offers a limited DSM program for controlling water heaters and strip heat on heat pumps in its western service area. The Public Staff also noted that DEC had received Commission approval to cancel a pre-Senate Bill 3 water heater load control program in its most recent general rate case because the costs of continuing the program exceeded the benefits.

The Public Staff stated that it has worked with utilities to find new cost-effective programs to reduce residential demands during winter peaking events, but no program design has proven to be cost effective. The Public Staff indicated that it would continue to encourage utilities to look for new residential DSM opportunities, including the potential for new rate designs that incorporate a more dynamic pricing structure. According to the Public Staff, new time-of-use schedules have the greatest potential to help residential customers curtail loads during winter peaking events. Further, as smart meter technologies are deployed and more customer data become available, customers should have the opportunity to better understand their usage patterns and how those patterns impact system peaks, offering residential customers opportunities to curtail load.

The Public Staff indicated that DEC's and DEP's portfolios of EE programs are not materially different from those in their 2016 IRPs and 2017 IRP updates, and that they continue to align their new and existing DSM and EE programs. The Public Staff also noted that as observed in the last few DSM/EE rider proceedings, both utilities' portfolios continue to shift the source of EE savings away from lighting measures toward behavioral programs such as the My Home Energy Report. The Public Staff pointed out that DEC's projections of portfolio energy savings decline by approximately 9% and DEP's by 20% from the energy savings identified in their 2017 IRP updates. Both DEC and DEP continue to treat DSM as a capacity resource and EE as a reduction to their load forecast.

The Public Staff explained that both utilities produce EE-related savings through their respective portfolios of EE programs over the measure lives of each program. At the end of the measure's life, the utilities assume that as customers replace EE measures with other as or more efficient measures, those savings will continue in the form of reductions to the load forecast, which is designated as historical savings ("roll-off" savings). New measures are separately identified and incorporated into the load forecast tables as new savings. The Public Staff noted that the assumption that EE measures will be replaced with other or new measures differs from the assumptions Duke uses regarding non-utility generator (NUG) contract renewals as discussed *infra*. The Public Staff indicated that the use of these different assumptions may affect the timing and type of resources in the IRP.

As discussed in regard to peak forecasts, the Public Staff recommended that DEC and DEP put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands. Additionally, the Public Staff recommended that DEC and DEP continue to identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold for which a discussion is required.

2. Public Staff Initial Comments – DENC's DSM/EE

The Public Staff commented that DENC's portfolio of EE programs has undergone significant changes since the 2017 IRP update and that changes to the portfolio are greatly influenced by the DSM/EE activities of Dominion Energy Virginia and the decisions of the VSCC. The Public Staff indicated that DENC's 2018 IRP reduced the energy savings by 30% over the planning horizon from the savings identified in the 2017 IRP update, primarily due to the cancellation of several programs in Virginia that had been offered on a system-wide basis. The Public Staff noted that DENC requested approval for a North Carolina-only program from the Commission for any program that was cost-effective on a North Carolina-only basis.

The Public Staff also noted that DENC completed a market potential study in late 2017 that identified 3,042 GWhs of achievable savings over a ten-year period, but the measures identified in the market potential study have not been incorporated into DENC's 2018 IRP. The study found that the greatest economic potential for residential and non-residential sectors was in lighting and space heating and cooling measures. However, the Public Staff noted that there were no recommendations for specific measures that would contribute toward the achievable potential for either customer class, and the achievable potential excluded the impact of customers eligible to opt-out of utility-sponsored EE portfolios.

The Public Staff explained that while the market potential study would likely have limited influence on DENC's EE portfolio, Virginia Senate Bill 966, the "Grid Transformation and Security Act of 2018"(GTSA)[23] would more likely drive the Company's future EE deployment. Under the GTSA, the Company is required to spend $870 million over the next ten years on EE, including existing and new EE programs. The Public Staff noted that the Company had filed 11 DSM/EE programs for approval before the VSCC, which the Commission notes were approved by the VSCC in April.[24] The proposed portfolio of 11 new programs has a spending projection of approximately $262 million over the next five years, and the Company has indicated that this will count toward the $870 million targeted by the GTSA. The Public Staff stated that DENC's 2018 IRP does not include impacts from these proposed programs. DENC filed eight of the programs for approval before this Commission on July 13, 2019.[25]

As it recommended for DEC and DEP, the Public Staff recommended that DENC put a renewed emphasis on designing new DSM programs to meet winter peak demands, as well as summer peak demands, and that it continue to identify any changes in EE-related technologies, regulatory standards, or other drivers that would impact future projections of EE savings regardless of the 10% threshold for which a discussion is required. The Public Staff also recommended that the IOUs continue to pursue all

[23] 2018 Virginia Acts of Assembly, Ch. 296 (effective July 1, 2018).

[24] Petition of Virginia Electric and Power Company for approval to implement demand-side management programs and for approval of two updated rate adjustment clauses pursuant to § 56-585.1 A 5 of the Code of Virginia, Order Approving Programs and Rate Adjustment Clauses, Case No. PUR-2018-00168 (May 2, 2019).

[25] Docket Nos. E-22, Subs 567-574.

cost- effective EE and DSM. Finally, the Public Staff proposed that DENC should continue to evaluate the potential to cost-effectively implement an EE program on a North Carolina-only basis, should the program be denied approval by the VSCC to implement the program on a system-wide basis.

3. SACE, Sierra Club, and NRDC Initial Comments – DEC and DEP'S DSM/EE

SACE et al. commented that the 2018 IRP Plans underutilize cost-effective energy efficiency and demand-side management. They assert that Duke prematurely limited the amount of energy efficiency that its IRP model could select as an available resource. SACE et al. commented that screening out efficiency options prior to running the resource planning models biases the analysis in favor of supply-side options. They further commented that Duke's planning process does not allow energy efficiency to be easily compared with supply-side resources in a capacity expansion model. The underutilization of cost-effective energy efficiency results in a higher-cost "preferred" portfolio than necessary. SACE et al. recommended that EE and DSM be evaluated on a level playing field with supply-side resources by allowing the IRP planning models to "select" DSM or EE as a resource, or by modeling varying levels of efficiency without screening out a subset of efficiency potential based on flawed assumptions.

SACE et al. also commented that the 2018 IRP Plans assume declining savings from energy efficiency and demand-side management over the fifteen-year planning period. They stated that DEC assumes that no new demand-side management capacity will be added to help meet winter or summer peak demand or reserves after 2024, and projects decreasing reductions to peak from energy efficiency investments after 2027; And that DEC anticipates no additional growth in load impacts from its demand-side management programs on summer or winter peak after 2023. SACE et al. stated that DEP anticipates no growth in several of its demand response programs after 2024 and practically no growth in savings from its energy efficiency EnergyWise for Home program after 2022. They noted that Duke's EE and DSM projections are at odds with Duke's statement that it "is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth."

4. AGO Initial Comments – DEC and DEP'S DSM/EE

The AGO recommended that Duke's plans be supplemented to include a more robust consideration of modern EE and DSM measures that reduce consumption or shift load to off-peak times -- including measures that are targeted to winter peaks. The AGO discussed three concerns.

First, the AGO, like the Public Staff, identified as a major shortcoming in Duke's plans that they offer little to no residential demand-side measures to lower winter peaks. The lack of emphasis on winter EE/DSM measures is particularly problematic given the importance Duke placed on planning to meet winter peaks in the analysis of its requirements for additional generating resources.

According to the AGO, Duke evaluated a direct load control program as a possible DSM measure, and found it to be too costly. However, that result is not cause to overlook other opportunities. The AGO's consultant Strategen Consulting, LLC, commented that there are numerous advanced demand-side management programs that have been found to be cost effective in other jurisdictions; these programs could be used to shave winter peaks. Strategen gave examples of two such programs that are being designed with reasonable costs for ratepayers by encouraging customers to use their own devices (called "Bring Your Own Device" or BYOD measures). One such measure is a smart thermostat program where, instead of directly installing smart thermostats, the utility recruits and acquires participants who bring their own devices. Another example is a utility BYOD program in which the utility shares access with the customer's battery storage system to lower peaks on cold winter nights. Customers purchase the batteries and are provided incentives that are based on the amount of energy transferred from the customer's battery to the grid.

Strategen noted that Duke currently integrates smart thermostats into three of its energy efficiency offerings, but observed that Duke's offerings are limited, Duke's offerings do not include other types of devices, and Duke's offerings do not appear to focus on obtaining flexible (i.e. dispatchable) HVAC measures that could help address winter peaks. For example, one of the Duke programs provides an incentive for using a smart thermostat, but does not appear to make use of the device for demand response or load shifting. Another Duke program incentivizes winter demand reduction, but at a lower level than in summer, and has a small amount of participating winter capacity. None of the Duke programs allow for customers to bring other devices, such as energy storage, to increase flexible capacity in both the winter and summer. As such, more emphasis is needed in Duke's plans on the design and development of measures that address winter resource requirements.

The AGO also agreed with the Public Staff that new time-of-use schedules have great potential for helping residential customers curb loads during winter peaking events.

The second concern addressed in the AGO comments is about how DSM programs are evaluated in Duke's planning process. The AGO agreed with NCSEA, and SACE et al. that it would be valuable to model energy efficiency measures and demand-side management on a level playing field with other resources. Strategen noted that modeling demand-side resources alongside supply-side resources is considered a best practice in the industry. Without that approach, demand-side measures cannot be fairly compared to supply-side alternatives, potentially limiting the amount of cost-effective energy efficiency and demand-side measures selected, resulting in a higher cost portfolio.

The third concern raised by the AGO is that Duke's plans appear to assume that additional energy efficiency savings will not be achieved in future planning years once current measures have been tapped out. That assumption overlooks advances in technology, including automation and load controls. Strategen predicts that such advances will most likely "unlock new forms of cost-effective energy efficiency and demand management."

5. DEC and DEP Reply Comments – DSM/EE

Several intervenors commented or made recommendations regarding Duke's DSM and EE plans. In response, Duke stated it disagreed with the statement made by SACE et al., at pages 12-13 of their IRP Comments, that the Companies' projections of DSM/EE peak savings in the later years of the IRP are "inconsistent with its declared commitment to continue to grow the amount of DSM/EE resources to meet customer demand." Duke explained that, specifically for the DSM projections, the amounts of DSM included in the IRP forecast are based on Duke's past experience with customer acceptance of these programs and the expectation that the amount of DSM capacity savings will reach a steady-state level beyond the first few years of the IRP forecast is consistent with this experience. As explained in detail in the response to comments of NCSEA in the 2018 Avoided Cost proceeding, Docket No. E-100, Sub 158, Duke believes that the forecast of DSM program savings are reasonable and accurately reflect a continued effort to add new customers; however, the forecast recognizes customer response to these programs has been limited, despite targeted and ongoing efforts to increase participation.[26] According to Duke, DEC and DEP's forecast of additional increases in DSM peak savings for the next few years followed by a period of steady-state peak savings is reasonable and prudent and accurately reflects the amount of "customer demand" for these programs.

Also, regarding the impact of EE programs on peak demand, Duke disagreed with the intervenors' conclusion that Utility Energy Efficiency (UEE) program disinvestment occurs in the outer years of the IRP forecast. Duke commented that incremental annual UEE savings projection levels are similar throughout the entire forecast period as shown in the tables in Appendix D of the IRPs. However, as shown in the LCR tables in the IRPs (Tables 12-E and 12-F), the outer year UEE projections are being offset by UEE programs initiated 8 to 10 years prior that have reached the end of their useful life. Once UEE savings reach this stage, they no longer contribute to future UEE cumulative savings and are therefore removed from the cumulative savings amounts. Failure to remove these savings from the cumulative amounts would result in over-stating, or "double-counting" the impact of the Companies' UEE programs on sales.

6. DENC Reply Comments – DSM/EE

DENC stated that it will continue to identify and seek approval to implement DSM and EE programs that are cost effective or meet public policy goals. With respect to the design of DSM programs to meet winter as well as summer peak demands, DENC commented that its Distributed Generation program is currently available in Virginia during winter periods to non-residential customers who meet participation requirements based upon size. DENC further explained that it recently received approval for a demand response residential thermostat control program in Virginia and will be filing for approval of that program in North Carolina in July 2019. In addition, DENC commented that 10 new EE programs addressing both summer and winter peaks as well as energy requirements were approved by the VSCC in May 2019 and will be brought to the Commission for

[26] See Duke Energy Reply Comments, Docket No. E-100, Sub 158, at pp. 63-66 (Mar. 27, 2019).

approval in July 2019. DENC explained that while demand response programs can be used to reduce peak periods explicitly, EE programs can also provide reductions during winter hours. Nevertheless, DENC noted that these reductions are not dispatchable and instead occur because a measure installed through the program is providing energy savings during a peak hour and thus providing a winter peak reduction. DENC underscored that since the actual system peak drives the need for additional resources to meet reliability requirements, it is difficult for programs that provide benefits in mainly non-peak hours to provide a meaningful amount of benefits. Finally, DENC noted that it is participating in a stakeholder process required by the GTSA to help it identify potential opportunities for EE and demand response and is hopeful this will lead to additional DSM resources in the future that will address both summer and winter peak hours.

IV. NATURAL GAS ISSUES

For purposes of calculating longer-term avoided energy rates, DEC and DEP propose to use forward natural gas prices through 2028; transition to Duke's fundamental forecast through 2033, which shows little growth over the ten year period; and then use an assumption that natural gas prices will grow at 2.5% through 2040. This approach is similar to the approach proposed by DEC and DEP in recent years,[27] and has been the subject of extensive testimony and discussion before the Commission, most recently in the comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158.

DENC utilized natural gas prices derived from the forward market for natural gas for the first 18 months, and then it gradually (over the next 18 months) blends the monthly prices from the forward market with the monthly prices from the long-term price projection from ICF International, Inc. (ICF).

A. Public Staff Initial Comments – Natural Gas Issues

The Public Staff commented that it appreciates the difficulty in forecasting long-term prices of natural gas as well as other fuel prices, and found reasonable DENC's reliance on forecasts from ICF. However, the Public Staff expressed concerns with the natural gas price forecasts utilized by DEP and DEC in their 2018 IRPs. As discussed in its Initial Statement filed in Docket No. E-100, Sub 158, which were incorporated by reference, the Public Staff believes that the proposed use of forward natural gas prices for ten years by DEP and DEC leads to natural gas prices that are overly conservative and inappropriate for planning purposes. On page 22 of the Initial Statement, the Public Staff noted that Duke Energy Florida, Duke Energy Kentucky, and Duke Energy Indiana

[27] This issue was also addressed in Phase Two of the Sub 140 proceeding, but the focus during that time was primarily consistency between the methodologies used for avoided cost and IRP purposes. In its December 17, 2015, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities in Docket No. E-100, Sub 140 (Phase Two Order), the Commission directed DEC and DEP to recalculate their avoided energy rates using natural gas and coal price forecasts that were developed in a manner consistent with those utilized in their 2014 IRPs, which at the time relied on market data for the first five years before switching to their fundamental forecast.

each rely wholly on market prices for the first five years and blend market and fundamental prices for the next five years, before switching to the fundamental forecast for the remainder of the planning period in their IRPs. As in previous IRPs and avoided cost proceedings,[28] the Public Staff indicated its preference for DENC's approach with its use of three years of forward price data before transitioning to its long-term fundamental natural gas price forecast.

The Public Staff noted in its comments that the use of an excessively conservative natural gas price forecast is unlikely to alter DEP and DEC's generation expansion plans, however, the use of a low gas price forecast will depress the avoided energy costs that are paid to qualifying facilities, and also reduce the avoided energy costs that are used to evaluate the cost-effectiveness of DSM and EE programs. Duke's conservative natural gas price forecast is graphically displayed on page 27 of the Public Staff's Initial Statement relative to DENC's natural gas price forecast. Therefore, the Public Staff recommended that DEP and DEC, in future expansion models, reflect the use of no more than five years of forward natural gas prices before transitioning to their fundamental forecast.

B. AGO Comments – Natural Gas Issues

The AGO expressed concern that Duke's reliance on natural gas raises a risk that ratepayers will face unanticipated, unmodeled costs from natural gas price volatility.

C. DEC and DEP Reply Comments – Natural Gas Issues

In its reply comments, Duke responded to the comments and recommendations of the parties related to natural gas price issues as follows:

1. Duke disagrees with Public Staff's recommendation to revise the natural gas fuel price forecast used in developing the generation expansion plans to use no more than five years of forward market data before transitioning to the fundamental forecast.

As the Public Staff references in their comments, the duration that DEC and DEP use for forecasting market-based natural gas prices prior to transitioning to fundamental natural gas forecasts has been the subject of extensive testimony and discussion before the Commission, most recently in the initial comments filed by parties in the 2018 avoided cost proceeding in Docket No. E-100, Sub 158. The Public Staff references the "same arguments and perspectives it raised on pages 21-28 of its February 12, 2019, initial comments in Docket No. E-100, Sub 158"[29] where they argued that Duke should use five years of market data before switching to the fundamental forecast.

Duke similarly incorporated by reference their Reply Comments, filed on March 27, 2019 in Docket No. E-100, Sub 158 on pages 10-19, as evidence for continuing to rely

[28] Docket No. E-100, Sub 147, and Docket No. E-100, Sub 148.

[29] Public Staff Comments, at p. 71.

on 10 years of forward market data in the Duke filed IRPs. Specifically, the Commission directed Duke to maintain consistency between the fuel forecasts presented in their IRPs and those used in their avoided cost filings and that "to the extent the Utilities wish to propose changes in the way they utilize forward prices and long-term forecasts…these changes should be made in the Utilities' biennial [IRPs], and the same approach should be used in their biennial avoided cost filings for that same year."[30] Generally, Duke made the following arguments as part of a broader discussion of natural gas prices in the referenced reply comments:

- Duke's customers are facing a $4.5 billion long-term financial obligation and an approximately $2 billion overpayment risk as a consequence of an unprecedented number of Qualifying Facilities (QFs) obligating Duke to purchase their output, coupled with the use of lagging and inaccurate fundamental forecasts to calculate avoided cost rates.
- As demonstrated by the continued, regular purchase of 10 years of forward market natural gas, the market for purchasing 10 years of forward market natural gas is liquid.
- In these regular purchases of 10 years of forward market natural gas, Duke obtained multiple price quotes, each with similar prices, evidencing that there are multiple sellers in the current 10-year natural gas market, and there is a lack of price volatility in the 10-year forward natural gas market.
- Duke is not alone in North Carolina in its ability to purchase 10-year forward natural gas, as another market participant in North Carolina (name filed under seal in Docket No. E-100, Sub 158) purchased significant quantities of 10-year forward natural gas.

Duke commented that using 10 years of forward market natural gas prices in their IRPs is appropriate for evaluating future generation needs and allows for an appropriate head-to-head comparison of long-term purchase power obligations from QFs required under PURPA.

2. Contrary to the AGO's suggestion, Duke already considers the impacts and future costs from natural gas price volatility in their filed IRPs.

On page 10 of its comments, the AGO asserts as a concern that, "Duke's reliance on natural gas raises a risk that ratepayers will face unanticipated, unmodeled costs from natural gas price volatility." Duke noted that this concern, however, is precisely why Duke considers a range of future fuel price scenarios, including high and low natural gas prices, in the development of their IRPs. As described in Chapter 13 of the 2018 DEP IRP and Chapter 12 of the 2018 DEC IRP, and in greater detail in Appendix A of both IRPs, Duke considers natural gas prices that are both significantly lower and significantly higher than base assumptions in both the short- and long-term. The impacts of these sensitivities on each of the seven portfolios are detailed in the above referenced sections in the IRP. Duke noted that the AGO's suggestion that Duke does not "thoroughly

[30] Order Establishing Standard Rates and Contract Terms for Qualifying Facilities*,* Docket No. E-100, Sub 140, at 27 (Dec. 17, 2015).

evaluate…potential future costs from natural gas price volatility" is inconsistent with the analysis that is actually filed in the DEC and DEP IRPs. Duke stated that it should be noted the AGO does not mention the risk of falling gas prices that has contributed to the current projection of an approximately $2 billion customer overpayment for solar QF generation that was based on natural gas price forecasts significantly above the current market prices for natural gas.

V. CAPACITY VALUE OF SOLAR

A. Public Staff Initial Comments – Capacity Value of Solar

The Public Staff commented that the assumption of both DEP and DEC regarding the contribution of solar energy to peak capacity has a significant impact on future capacity requirements. According to the Public Staff, even a small adjustment in the percent of nameplate capacity available at peak demand has the potential to delay or even eliminate the need for additional capacity. As such, the Public Staff recommended that the issue of aggregate solar generation coincidence at peak for both winter and summer be evaluated further, given the growing importance of solar generation in North Carolina.

The Public Staff noted that in prior IRPs, DEC and DEP calculated the capacity value for solar facilities by averaging actual solar output at the typical peak load hour, using several years of historical load data. The Public Staff indicated that this methodology provided a reasonable estimate for how much intermittent, non-dispatchable capacity would be available during the system peak. For their 2018 IRPs, Duke retained Astrapé Consulting (Astrapé) to perform a reliability-based analysis using techniques similar to those used in resource adequacy planning. The Capacity Value of Solar study (CVS Study) modeled each Company's system at varying levels of solar capacity to identify the timing of projected firm load shed events for each level of solar penetration, and the contribution of solar during those hours. This analysis establishes the capacity value of solar resources, as well as the seasonal allocation of LOLE.

The CVS Study results are presented in the form of a seasonal capacity value for each level of solar penetration in DEC and DEP, with different values for fixed and tracking solar photovoltaic (PV) because tracking results in a higher capacity value. Using these findings, Duke then discounts the amount of installed solar capacity, both utility and third party-owned, by this capacity value in each utilities' Load, Capacity, and Reserves Tables (LCR Tables),[31] thereby reducing the amount of available capacity and increasing the need for traditional thermal resources to meet peak system load. Using the values from the CVS Study, as opposed to its previously used coincident peak method, the need for traditional resources in 2033 increases by 138 MW in DEC and 168 MW in DEP.

The Public Staff expressed concern regarding the difference between how Duke plans to meet its peak system load and how it values the capacity contribution of solar resources. In past IRPs, the Companies discounted the available solar capacity to match the estimated solar output during the hour of peak system load, and thus planned future

[31] DEC IRP, Tables 12-E and 12-F; DEP IRP, Tables 13-E and 13-F.

resource additions to meet the peak system load, and also considered the availability of solar resources during that same peak system load.

The Public Staff contended that use of the CVS Study results effectively bifurcates the treatment of solar resources and the treatment of traditional utility-owned thermal resources. By discounting the solar contribution based on its output during projected firm load shed events (High Risk Hours), yet planning future resource additions to meet the output needed during the hour of peak system load (Peak Load Hours), the actual contribution of solar resources during the Peak Load Hours is ignored. The Public Staff also pointed to the disparate treatment of solar resources versus dispatchable thermal resources, which receive a capacity value of 100%, despite their not having guaranteed availability at the time of all High Risk Hours due to planned and forced outages.

The Public Staff proposed that DEC and DEP either plan future capacity resource additions based upon the estimated load during High Risk Hours or discount the capacity value of solar resources by their output during the Peak Load Hours, rather than their output during High Risk Hours. The Public Staff proposed a coincident peak methodology that relies upon utility data and statistical analysis to determine the capacity value, and can be applied to any intermittent resource with a history of hourly generation data. According to the Public Staff, this methodology addresses the perceived disconnect between Peak Load Hours and High Risk Hour, and considers both the operational history of intermittent resources in each utility's service territory and forecasted system operational models that employ numerous assumptions related to load forecasting, solar output, and generation performance characteristics. The Public Staff stated that while it did not have access to the models used by Duke in determining the future resource need, it estimates that using the capacity values produced using its methodology would delay the need for future resource additions.

The Public Staff also noted that the CVS Study considers such factors as load uncertainty and unit outages when it calculates LOLE and capacity value, and that these factors may lower solar capacity value and increase the required minimum reserve margin. The Public Staff contends that these factors should cause either an increased reserve margin or a decreased solar capacity value, but not both. Thus, the Public Staff is concerned that the need for future resource additions may be overstated.

The Public Staff recommended that DEC and DEP utilize the coincident peak methodology for establishing the capacity value of solar, rather than the Astrapé Solar Capacity Value Study. For planning purposes in this IRP, the Public Staff recommended that DEC and DEP use a Capacity Value for solar of 3% in winter and 55% in summer. Finally, the Public Staff recommended that the Commission require DEC and DEP to file a report discussing the impact of this change, and if the first year of capacity need changes, in the 2018 avoided cost proceeding.

In regard to DENC, the Public Staff recommended that DENC continue to discuss mitigation strategies to address high levels of solar penetration and system operations, including revising and improving its estimates of both fixed and variable integration costs. Further, to the extent that the Company identifies required mitigation strategies to address the aggregate effect of distributed solar PV, such as the addition of a supplemental CT to address generation volatility or ramp rates, the Public Staff stated that those applicable costs should be assigned to the overall installed cost of solar.

The Public Staff pointed out that PJM publishes a methodology for calculating capacity values for non-dispatchable resources and recommends using a three-year average of historical wind and solar facility output during the summer peak hours to determine the applicable capacity value for use in reserve margin planning. For facilities less than three years old, PJM publishes "class average capacity factors" for use in the determination of capacity values. The Public Staff indicated that DENC's proposed capacity values for solar are significantly lower than the PJM class average, and recommended that DENC continue to evaluate renewable resources' contribution to coincident peak and update its models to reflect the additional research. The Public Staff also recommended that in future IRPs and updates, the Commission require DENC to provide PJM's capacity value for renewable resources as comparison benchmark, and to the extent that DENC's calculated capacity values or methodology differ from PJM's, provide a justification for the difference.

The Public Staff also noted that it had recommended in the avoided cost docket that DENC's proposed re-dispatch cost be reduced based on the Public Staff's proposed modifications. The Public Staff agreed that a re-dispatch or solar integration charge are important concepts as increasing levels of intermittent and non-dependable generation are added into the electrical grid. The Public Staff recommended that to the extent possible, the modeling programs used by the utilities within the IRP process for selection of future projects evaluate and use appropriate price signals to reasonably demonstrate the costs to ratepayers as new generation units are selected.

B. SACE, Sierra Club, and NRDC Initial Comments – Capacity Value of Solar

Like the Public Staff, SACE et.al. commented that Duke undervalued the capacity that solar resources provide to the DEC's and DEP's systems. They also commented that the 2018 IRPs under-project future solar and solar-plus-storage resources.

SACE et.al. commented that Duke has grossly undervalued the capacity value that solar provides by relying on the Astrapé study that relies on flawed data and methodology. SACE et.al. retained expert consulting firm Wilson Energy Economics to evaluate Duke's calculation of the capacity value of solar resources. The Wilson report concluded that Astrapé had overstated the winter resource adequacy risk, and that the winter/summer capacity values of solar resources on which the 2018 IRP Plans were based should be rejected.

SACE et.al. also commented that Duke's projections fail to account for likely improvements in solar technology and are on the low end of what has been observed from projects that have been put in service in recent years. For example, DEP projects summer solar PV capacity values of 8.2 to 12.4 percent, far lower than the weighted average of 27.6 percent observed in projects installed nationally over the last ten years.

SACE et.al. recommended that Duke reevaluate its projections for addition of new solar resources. DEP's 2018 IRP Plan projects the addition of 1,441 MW of solar over the next 15 years, with approximately 1,000 MW occurring in the next five years (a 36% increase), but with only an 11.6% increase between 2023 and 2033. DEC's 2018 IRP Plan projects the addition of 1,314 MW of solar between 2019 and 2023, but additions of only about 90 MW per year between 2023 and 2033. Duke assumes in its IRPs that it effectively stops adding significant solar resources after it has satisfied the procurement obligations in House Bill 589. The groups noted that these projections do not reflect the recent trends in accelerated solar installations in the Carolinas nor the continuing and steep cost declines for solar. SACE et.al. recommended that Duke reevaluate its projections for future solar installations using more realistic assessments of current and likely future cost declines and improved panel efficiencies.

In addition, SACE et.al. commented that the 2018 IRP Plans include only token amounts of solar-plus-storage resources and do not fairly evaluate the addition of these resources. Greater additions of grid-connected battery storage will support addition of solar and other clean energy resources on the DEC and DEP systems, as well as providing a new resource for balancing grid supply and demand, a new tool for peak shaving, and other benefits. SACE et.al. identified examples from across the country of the steadily declining costs of solar-plus-storage projects, including prices for battery energy storage that are less costly than fossil fuel-fired generation. They recommended that Duke incorporate higher levels of solar-plus-storage in its long-term plans, especially given North Carolina's position as a national leader in solar development.

C. AGO – Capacity Value of Solar

The AGO agreed with concerns expressed by the other intervenors about Duke's assessment of the capacity value of solar energy. To the extent that solar capacity is undervalued, that causes Duke's plans to include more traditional thermal capacity resources than are necessary, leading to increased costs to Duke's customers.

AGO consultant Strategen reviewed the Astrape analysis prepared for Duke and detailed multiple aspects of Astrape's capacity value calculation that could potentially undervalue solar resources. Strategen described the following flaws:

1. Underlying load and non-solar resources within each solar tranche

Duke's analysis shows declining capacity value as solar penetration increases in subsequent MW tranche additions. While this general trend is to be expected, it is not clear if each subsequent solar tranche also included changes to the underlying load and non-solar resources on Duke's system. In reality, higher MW solar scenarios would coincide with other changes. For example, a) load growth may occur predominately in the summer, thus shifting the share of loss of load expectation (LOLE) towards summer months, or b) the mix of non-solar generators may change towards those with fewer outages. Both of these could affect the calculated solar capacity value and potentially increase it relative to what has been portrayed.

2. Demand response availability in winter

In Duke's analysis, it is assumed that there are significantly less demand response resources available in winter versus summer (625 MW less for DEC, and 503 MW less for DEP). This has the effect of increasing LOLE during winter hours, and in turn could decrease solar capacity value. If in fact Duke's system is increasingly a winter peaking system, it is not clear why existing/new demand response resources couldn't be targeted more towards winter peak load hours instead and modeled accordingly.

3. Share of tracking PV resources

Duke's analysis assumes a 25% share of single-axis tracking systems versus 75% fixed tilt. While this appears consistent with historical deployment in NC, other jurisdictions have shown a greater trend towards tracking systems. It's possible this broader trend could also occur in NC going forward and would lead to a higher overall capacity value for the solar fleet.

4. Assistance from neighboring Balancing Areas

A critical underlying assumption in Duke's analysis is the availability of resources from neighboring balancing areas. The reported occurrence of a greater share of LOLE hours during winter signifies a greater unavailability of neighboring resources during this season. However, several of the balancing areas neighboring Duke not only have significant excess capacity exceeding their reserve margins but they are also summer peaking systems. Thus, it appears that there should be substantial winter resources available from neighboring systems. If the availability of neighboring resources in winter is modeled at too low a level it could have the effect of increasing LOLE at these times, and in turn reducing solar capacity value.

5. Outage rates for combustion turbines

Public Staff points out that in Duke's analysis, "Solar resources are also treated differently than dispatchable thermal resources in that those thermal resources receive a capacity value of 100%, despite the fact that even dispatchable thermal resources are not guaranteed to be available 100% of the time in High Risk Hours due to planned and forced outages." Strategen agrees with Public Staff's assessment that this reflects inconsistent treatment between resource types that should be remedied. Either capacity value of non-solar resources should be de-rated according to their outage rates, or a different methodology should be adopted.

6. Adjustment of combustion turbine versus load

As the Public Staff points out in their comments, Duke's approach of adjusting the combustion turbine value to determine capacity value "varies slightly from a traditional (effective load carrying capacity) study, where load is adjusted to achieve a (loss of load expectation) of 0.1 events/year." Strategen agrees with Public Staff's observation. Furthermore, since DEP is modeled as two load centers (east and west), Duke's approach could also lead to a lower solar capacity value than the traditional method, depending on where the combustion turbine is located in the model and what transmission constraints are assumed.

Strategen believes that, conceptually, an effective load carrying capability (ELCC) framework, such as that used by Duke can be a sound approach to determining the capacity value of solar for resource planning. However, before such a framework can be adopted, more information is needed regarding certain underlying assumptions in Duke's analysis. Thus, for the purposes of the 2018 IRP, the method proposed by Public Staff seems acceptable and would be consistent with past practice in North Carolina. An ELCC approach could be explored for future IRPs but stakeholders should have additional opportunities to review the evaluation framework proposed by Duke and the Commission should provide guidance on it as well. For these reasons, Strategen believes Public Staff's recommendations regarding solar capacity value are reasonable."[32]

D. DEC and DEP Reply Comments – Capacity Value of Solar

On page 85 of its Comments, the Public Staff states its concern that "there is a disconnect between how Duke plans to meet its peak system load and how it values the capacity contribution of solar resources." A remedy is proposed by the Public Staff to calculate the Capacity Value of Solar utilizing a Coincident Peak methodology which would address the perceived disconnect between Peak Load Hours and High Risk Hours.

Duke noted that, although it had not yet reviewed the models used by the Public Staff in determining the Coincident Peak methodology, it was trying to ascertain why the Public Staff's proposed capacity values in Table 11 remain static despite the fact that possibly over 10,000 MW of solar capacity could be installed in the Carolinas over the next 15 years. In Tables S5 and S6 of the Capacity Value of Solar (CVS) study completed by Astrapé Consulting, each additional tranche of solar capacity provides diminishing marginal capacity value to the system

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Duke explained that Astrapé calculated its results in the CVS study by modeling thousands of iterations in its proprietary Strategic Energy Risk Valuation Model (SERVM) using 36 different weather years developed from a National Renewable Energy Laboratory (NREL) dataset dating back to 1980. Both the seasonal and hourly pattern changes were captured across different solar penetration levels. As solar increases across the system resulting in optimal performance on sunny days, system Loss of Load Expectation (LOLE) shifts to the winter; firm load shed events no longer occur during solar hours and become more prominent during hours of little to no daylight. According to Duke,

[32] Strategen Attachment to the AGO Reply Comments, at 10-11.

it cannot ascertain from Figure 7, Table 10, or Table 11 in the Public Staff's comments that any research into the shift in LOLE has been performed, which therefore does not support fixed winter/summer capacity values that do not adapt to the level of solar installed on the DEC and DEP systems.

As further support for Duke's probabilistic approach to valuing solar capacity, Duke referred the Commission to the direct testimony of Brian Horii[33] on behalf of the South Carolina Office of Regulatory Staff in Public Service Commission of South Carolina (PSCSC) Docket No. 2019-2-E. On page 8 and beginning on line 17 of his testimony, Mr. Horii states as follows:

> E3 has been at the forefront of evaluating the impact of renewable resources on utility planning and operations. Through our work it is clear that resources such as wind and solar generation must be evaluated using probabilistic methods that evaluate all hours of a given period, not just a single peak hour. Moreover, the importance of probabilistic models is generally recognized across the industry, as noted by the North American Electric Reliability Corporation's (NERC) Probabilistic Adequacy and Measures Technical Reference Report (April, 2018)*:*
>
> There is a recognized need to support probability-based resource adequacy assessment resulting from the changing resource mix with significant increases in variable and energy-limited resources (intermittent in nature), changes in net demand profiles resulting in the shifting of the hour of the peak demand, and other factors can have an effect on resource adequacy. NERC, p. 6.

In his testimony, Mr. Horii disputes the appropriateness of using a coincident peak hour approach to valuing the capacity contribution of solar generation and notes that such an approach fails to recognize the capacity value provided not just by output at the time of the peak hour but also by the output during the myriad of other peak hours for which there is a non-zero risk of the utility being unable to meet all customer demand.[34] Mr. Horii further referenced the detailed hourly solar capacity value studies performed by Astrapé Consulting for DEC and DEP to infer a capacity value contribution for incremental solar for another utility's system.[35]

1. Duke disagrees with the AGO's assessment that the Companies may be undervaluing the peak load contribution of solar technologies.

The AGO disputes Duke's assertion that additional solar resources beyond those shown in the 2018 IRPs have limited value because additional solar capacity only

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[33] Mr. Horii is a Senior Partner with Energy and Environmental Economics, Inc. (E3) and was retained by the South Carolina Office of Regulatory Staff (ORS) to assist in the analysis of South Carolina Electric & Gas Company's avoided cost calculations, and review the Value of Distributed Energy Resource (DER) methodology, in PSCSC Docket No. 2019-2-E.

[34] Brian Horii Direct Testimony in PSCSC Docket No. 2019-2-E, at 8.

[35] Id., at 10-11.

provides negligible contribution to meeting peak load needs (AG) IRP Comments, pp. 3-4). The AGO cites a "study performed by the National Renewable Energy Lab [NREL] in California, where solar resources have a higher penetration rate" as the basis for the argument that solar resources may have more capacity value than that attributed by the Companies. Id. Duke notes that while North Carolina is number 2 in the U.S. in installed solar behind only California, the AGO's argument is flawed for two reasons: (1) California has significantly higher solar irradiance than North Carolina, and (2) California's electricity demand profile is significantly different than North Carolina's electricity demand profile simply based on the range of temperatures seen in California versus North Carolina, as well as different sources of heating and cooling in the two jurisdictions. Duke points out that consumers in North Carolina and South Carolina have significantly higher energy needs due to much greater electrical heating and cooling demand than California. Simply put, regional differences in solar output, as well as customer usage profiles make such a comparison meaningless. Duke noted its disappointment that the AGO used a study that is based on California electricity demand and solar conditions to criticize Duke for not placing enough value on solar in North Carolina - - when North Carolina is second only to California in installed solar capacity.

2. Duke acknowledges that inclusion of additional storage and solar plus storage resources in the IRPs may be warranted, as suggested by the AGO; however, Duke is committed to studying the true value of energy storage on the DEP and DEC systems before arbitrarily assigning value in the IRPs.

For the first time, Duke included battery storage as a resource in the 2018 IRPs. In total, DEC and DEP included nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders which were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity needs per the Electric Power Research Institute (EPRI) study cited in the 2018 IRPs. Additionally, Duke acknowledged in the IRPs that "Battery storage costs are expected to continue to decline, which may make this resource a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value."[36] Furthermore, despite the AGO's assertion that Duke "does not thoroughly evaluate [the downward trend of storage technology costs],"[37] to the contrary, the Duke IRPs assume that battery storage costs drop by nearly 40% by year 2025 in the IRP Base Case.[38] Additionally, Duke noted that its IRPs include an aggressive capital cost sensitivity that would further the decline in battery storage costs to 60% by 2025. Finally, Duke included a sensitivity of replacing a future undesignated CT with a grid-tied battery storage option in both the DEC and DEP IRPs.[39]

[36] DEC IRP, p. 33; DEP IRP, p. 33.

[37] AGO's Comments, p.5.

[38] DEC IRP, p. 101; DEP IRP, p. 102.

[39] Portfolio #7 (CT Centric / High Renewables with Battery Storage) is assessed in a variety of CO_2, fuel price, and capital cost scenarios.

Even though Duke acknowledged the potential benefits of storage, included steep cost declines for battery storage technologies, evaluated a sensitivity of replacing a future CT with battery technology, and went as far as to include upwards of 300 MW of battery storage as capacity assets in the DEC and DEP IRPs, the AGO argues the Companies did not go far enough by not evaluating multiple storage plus solar technologies. Duke commented that there is the potential for battery storage technologies to provide value to the DEP and DEC systems, but pairing storage with solar to allow "the storage component to benefit from federal investment tax credits"[40] as suggested by the AGO may not always be in the best interest of the Companies' customers. According to Duke because North Carolina's peak conditions occur in both summer afternoons and winter mornings and afternoons, and can be at least several hours in duration, there may be limitations to the capacity value of batteries, particularly batteries charged solely from solar resources. Furthermore, on May 10, 2019, the Commission issued its Order Granting Certificate of Public Convenience and Necessity with Conditions for the DEP Hot Springs Microgrid Project, which is a combination 3 MW (DC) solar and 4 MW lithium-ion based battery energy storage system. The Commission held that although it is not clear that the Hot Springs Microgrid is the most cost-effective way to address reliability and service quality issues at Hot Springs, the overall public convenience and necessity would be served by granting the certificate (CPCN) for the solar generation components of the microgrid because the system benefits of the microgrid are difficult to quantify and DEP will gain valuable experience by operating the Hot Springs Microgrid as a pilot project. The Commission further stated that it supports "cost-effective development of solar and battery storage by DEP . . . and encourages DEP to continue to pursue such projects on behalf of its customers."[41]

Duke noted that it is committed to further studying the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) in the Carolinas at increasing penetration levels. Like the Capacity Value of Solar Study Duke completed in 2018, a similar study is required to study the capacity value of storage. Duke explained that a study of this type is both time and data intensive; however, Duke expects to include the results of a capacity value of storage study as early as the 2020 biennial IRP filings. The Commission expects the 2020 filings to include such results, absent a showing as to why the necessary study could not be completed.

E. Duke's NREL Study

In NCSEA's initial comments, NCSEA noted that Duke has recently retained the National Renewable Energy Laboratory (NREL), to study how Duke's grid can accommodate a renewable energy penetration of 50% of peak demand. NCSEA stated that the fact that Duke is undertaking such a study "undermines the credibility of their own IRPs, and calls into question how Duke has modeled clean energy resources."[42] NCSEA further alleged that its Synapse study shows that Duke has "unfairly marginalized clean energy resources." Id. NCSEA also cited the Virginia State Corporation Commission's

[40] AGO's Comments, p. 4.

[41] Hot Springs Order, at p. 17.

[42] NCSEA Comments, p. 14.

rejection of Dominion's IRP because of failure to adequately model clean energy resources.

In its reply comments, Duke *explained* that it plans to study a number of scenarios. The entire study including Phase II will take as much as two years and possibly longer to complete, which would not be timely for the current IRPs. According to Duke, when Duke's General Manager, Distributed Energy Technologies Renewable Integration & Operations, Ken Jennings, recently spoke at the University of North Carolina at Chapel Hill, he acknowledged that Duke will be examining a number of scenarios but did not state that the system would definitely be able to accommodate that much intermittent solar. He also mentioned that the study would be similar to the TECO Study which states that:

> Must-Take solar becomes infeasible once solar penetration exceeds 14% of annual energy supply due to unavoidable oversupply during low demand periods, necessitating a shift to the Curtailable mode of solar operations. As the penetration continues to grow, the operating reserves needed to accommodate solar uncertainty become a significant cost driver, leading to more conservative thermal plant operations and increasingly large amounts of solar curtailment.

The TECO Study further states:

> The energy value on the TECO system of additional solar energy in Curtailable operating mode decays rapidly above about 14% solar energy penetration. The energy value (or, equivalently, the production cost savings) is calculated as the change in annual production costs as solar penetration increases, excluding the capital cost of additional solar resources. Solar provides very little marginal energy value at penetration levels above 19%. In the extreme – above 23% solar energy production potential – solar has a negative marginal energy value.

According to Duke, at that time, it did not know exactly what the scenarios would be. Currently, Duke projects for Phase I a penetration level as high as 35% solar as a component of energy rather than summer peak demand, which is about 28,000 MW of solar and actually closer to 70% of summer peak demand. Duke argues that, absent results from both the Phase 1 and Phase II versions of the study, it would be imprudent to make assumptions about the utility's ability to manage such levels of intermittent solar, and if the results of the NREL study are similar to the results of the TECO study, such levels of intermittent solar may actually require more thermal generation than is currently called for in the IRPs.

F. DENC Reply Comments – Capacity Value of Solar

In response to the Public Staff's comments, DENC indicated that it is committed to continuing and improving its efforts to analyze solar integration costs, the results of which will be provided in the 2020 IRP. DENC also stated that it intends to further refine its integration costs analysis in future IRPs and updates based on the methodology used in the 2017 and 2018 IRPs. As part of that analysis, the Company committed to consider the costs associated with any identified strategies to mitigate the aggregate effect of distributed solar PV on the Company's system. As previously discussed, DENC also agrees to include in future filings the PJM class average capacity value for solar as a comparison to its proposed capacity value, and provide justification for any difference.[43]

VI. BATTERY STORAGE

In Docket No. E-100, Sub 147, the Commission noted that the evaluations of battery storage technology in the 2016 IRPs have "not been fully developed to a level sufficient to provide guidance as to the role this technology should play going forward."[44] As such, it required utilities to "provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the 'full value' as discussed in the NCSEA comments. If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs."[45]

A. DEC and DEP Integrated Resource Plans – Battery Storage

According to DEC and DEP, they are assessing the integration of battery storage technology into their portfolio of assets. DEC and DEP note that battery storage costs are expected to continue to decline, which may make it a viable option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value.

DEC and DEP further note that energy storage can also provide value to the transmission and distribution (T&D) system by deferring or eliminating traditional upgrades and can be used to improve reliability and power quality to locations on the Company's distribution system. This approach results in stacked benefits which couples value streams from the Transmission, Distribution, and Generation systems. This evaluation process falls outside of the Company's traditional IRP process which focuses primarily on meeting future generation needs reliably and at the lowest possible cost. This new approach to evaluating technologies that have generation, transmission and distribution value is being addressed through the Integrated System and Operations Planning (ISOP) process as discussed later in this Order.

DEC and DEP state that they will begin investing in multiple grid-connected storage systems dispersed throughout their North and South Carolina service territories that will be located on property owned by the Companies or leased from their customers. These deployments will allow for a more complete evaluation of potential benefits to the

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[43] DENC Reply Comments, at 9.

[44] Docket No. E-100, Sub 147, Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans (2016 IRP Order), at 60 (June 27, 2017).

[45] Id. at 60.

distribution, transmission and generation system while also providing actual operations and maintenance cost impacts of batteries deployed at a significant scale.

DEC and DEP included battery storage in its screening analysis for the 2018 IRP: a 5 MW / 5 MWh Li-ion Battery, a 20 MW / 80 MWh Li-ion Battery, and 2 MW Solar PV plus 2 MW / 8 MWh Li-ion Battery. In their IRPs, DEC and DEP have included 150 MW and 140 MW of lithium-based battery storage "placeholders" in their Portfolio 1, respectively. This is reflected in their short-term action plans, in which DEC begins with four MW deployed in 2020, growing to 60 MW by 2023, and DEP begins with 12 MW deployed in 2019, reaching 64 MW by 2023. Both utilities plan to begin investing in grid-connected storage systems dispersed throughout their service territories, with specific investments identified in DEP's discussion of the Western Carolinas Modernization Project (WCMP).[46]

Both DEC and DEP refer to the planned lithium-based battery storage devices as "placeholders" largely due to the way in which energy storage was modeled in the IRP. First, they performed a technical screening of various energy storage technologies. While they identify many types of energy storage, only lithium-ion batteries are actually modeled in System Optimizer and Prosym; the remaining choices are screened out from quantitative analysis for various reasons, including technological feasibility and commercial availability.[47] Traditional generation technologies are made available to the System Optimizer for economic selection, based upon techno-economic characteristics, to meet load and reserve margin requirements over the planning horizon. However, energy storage provides a range of benefits, such as transmission investment deferral and ancillary services,[48] which are difficult, if not nearly impossible, to quantify over the long-term period of the capacity expansion model.

To address the difficulty in modeling energy storage, DEC and DEP specified the battery storage capacity to be included exogenously, effectively "forcing" storage into the capacity expansion plan. The cost impact of energy storage was evaluated in the production cost model Prosym, where battery resources were assumed to have the primary responsibility of providing generation, energy, and ancillary benefits, except in cases where the primary purpose was transmission or distribution benefits.[49] Pumped storage, such as the Bad Creek facility, is analyzed using a two-pass approach: First, Prosym runs without energy storage; then, energy storage inflows and outflows are scheduled to levelized marginal costs subject to physical and technical constraints; finally, Prosym is run a second time with the additional scheduled load or generation from pumped storage. This analysis captures the benefits of bulk energy time shifting, but does

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[46] DEP IRP, at 51.

[47] DEC and DEP screen out the following energy storage technologies from future capacity deployments: pumped storage, compressed air storage, liquid air storage, flow batteries, and high temperature batteries.

[48] See the Storage Applications and Services section of the NC State Energy Storage Team's Energy Storage Options for North Carolina, at 10-13, https://energy.ncsu.edu/storage/.

[49] DEC and DEP's response to PS DR 4-4.

not quantify additional energy storage benefits as defined in the recently published Energy Storage Options for North Carolina study (Storage Study).[50]

DEC and DEP discuss the limitations of the IRP in relation to energy storage in a discussion of the insights gained from an analysis of Portfolio 7, which is based on Portfolio 6, except the next planned CT resource is replaced with battery storage. In DEP, this change actually resulted in a lower PVRR than Portfolio 6 (in no sensitivity scenario was Portfolio 7 more cost effective than Portfolio 1 or 2). These projections depend upon the energy storage device being grid-tied and controlled by the utility in real-time. DEC and DEP both conclude that the difficulty in understanding the value of energy storage makes it "important for the Company to operate utility storage on its system to properly evaluate the abilities and value of battery storage."[51]

B. DENC Integrated Resource Plan – Battery Storage

DENC stated in its IRP that batteries serve a variety of purposes that make them attractive options to meet energy needs in both distributed and utility-scale applications, including providing energy for a power station blackstart, peak load shaving, frequency regulation services, or peak load shifting to off-peak periods. DENC noted that batteries have gained considerable attention due to their ability to integrate intermittent generation sources, such as wind and solar, onto the grid. DENC pointed out that the primary challenge facing battery systems is the cost, and that other factors such as recharge times, variance in temperature, energy efficiency, and capacity degradation are also important considerations for utility-scale battery systems. DENC did not consider batteries for further analysis in the Company's busbar curve. However, under the GTSA, DENC is required to propose a plan to deploy 30 MW of battery storage under a new pilot program. In its revisions to its IRP, the Company modeled 30 MW battery storage pilots as a proxy generation resource.

C. Public Staff Initial Comments – Battery Storage

1. DEC and DEP

The Public Staff recognized that modeling the various uses of energy storage presents challenges such as capturing and quantifying the various value streams. High capital costs of energy storage (even under assumptions of a 50% decline in capital costs by 2028), coupled with the aforementioned challenges, make it nearly impossible for DEC and DEP's existing modeling software to economically select energy storage in its System Optimizer. The Public Staff noted that DEC and DEP have identified the need for improved modeling capabilities in the Integrated System Operations Planning (ISOP) sections of their IRPs, which envision future IRPs that are capable of recognizing the

[50] The full study is available for download at https://energy.ncsu.edu/storage/.

[51] DEP IRP, at 107; DEC IRP, at 105.

benefits energy storage can provide on a sub-hourly and "stacked" basis.[52] In addition, the increasing cost of integrating solar energy identified in the Astrapé Ancillary Service Study[53] indicates the need for a more flexible system, which energy storage is well suited to provide. With improved modeling, energy storage could also be assessed for cost-effectiveness in different renewable energy penetration scenarios.[54] The Public Staff encouraged DEC and DEP to continue to enhance their modeling capabilities as described in the ISOP sections of their IRPs, with the eventual goal of accurately quantifying energy storage benefits and costs so that there would be no need to force storage into the IRP modeling.

2. DENC

The Public Staff noted that DENC discussed battery storage in extremely broad terms, while recognizing that energy storage could provide grid stability as more renewables are integrated into the grid and reduce the intermittency of wind and solar generation. As DENC states did not consider battery storage for further analysis in the Company's busbar curve, the Public Staff concluded that DENC failed to thoroughly assess battery storage technologies or include a separate discussion justifying their absence from the IRP.

The Public Staff stated its belief that DENC did not comply with the Commission's 2016 IRP Order to provide a more complete and thorough analysis of battery storage technologies, as opposed to DEC and DEP's 2018 IRPs where battery storage was included as a technology which their models could select and placeholders were input to the model and production cost runs reflected the effect of bulk energy shifting. The Public Staff noted that the Energy Information Administration (EIA) estimates that there were approximately 700 MW of installed battery storage projects at the end of 2017, with 40% of that capacity in PJM.[55] The Public Staff recommended that DENC be required to submit a supplemental filing to its 2018 IRP with a more detailed analysis showing why battery storage technologies were excluded from the Company's busbar curves, including a quantitative analysis of energy storage costs. The Public Staff also noted that DENC should address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost-effectively integrated if coupled with energy storage technologies in future IRPs and IRP updates.

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[52] Value stacking refers to the ability of energy storage devices to provide benefits over a range of service categories, i.e., one energy storage facility providing frequency regulation, improved reliability, and transmission asset deferral. See Storage Study, p. 137, for a discussion of "value stacking".

[53] Referenced in DEC and DEP's Initial Statement, filed November 1, 2018, Docket No. E-100, Sub 158.

[54] Public Service of New Mexico's 2017-2036 IRP retained Astrapé Consulting to quantify the effect of energy storage on reliability and system flexibility at various levels of solar PV penetration, using similar methodologies to Duke's Ancillary Service Study.

[55] EIA, U.S. Battery Storage Market Trends, May 2018. Accessed at https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

D. SACE, Sierra Club, NRDC Initial Comments – Battery Storage

SACE, et al. noted that DEC and DEP had recognized the declining cost of battery storage and included battery storage in their resource plans, but contended that there should be greater additions of grid-connected battery storage. Additional battery storage would support additional solar and other clean energy resources, as well as provide balancing of grid supply and demand, peak shaving, and other benefits. These parties noted the steady fall of the costs of solar-plus-storage technologies, and contended that contracted and demonstrated prices for battery storage are already least-cost compared with traditional fossil fuels in some applications and are expected to continue to fall. Thus, SACE, et al. recommended that DEC and DEP incorporate higher levels of battery storage into their long-term plans.

E. AGO Comments – Battery Storage

The AGO commented that DEC's and DEP's plans, when modeling resource alternatives, do not adequately address solar-plus-storage resources as options to meet peak hours of demand. The AGO believes that this issue is important to the development of reasonable resource plans because, as was pointed out in NCSEA comments, battery storage technologies provide flexibility that enables a larger part of DEC's and DEP's energy and capacity requirements to be satisfied at lower economic and environmental costs. Given the current broad array of storage technologies with different sizes, configurations, and operating characteristics, modeling should include an array of storage alternatives consistent with industry best practice.

According to the AGO, DEC and DEP considered only one solar-plus-storage technology configuration in the initial screen of the model used to evaluate resource options: a 2-MW battery with 8 MWh of duration paired with a 2-MW solar facility. In contrast, DEC's and DEP's initial modeling screen included nine natural gas-burning technologies, two coal technologies, two nuclear technologies, and two stand-alone storage technologies. Further, the ratio of PV to storage in DEC's and DEP's one option does not necessarily align with recent trends in the industry. Strategen noted that batteries recently procured by utilities in other states (Hawaii, Arizona, Nevada, and Colorado) have been much larger in order to benefit from economies of scale and lower siting and interconnection costs (e.g., installing one 100 MW battery is cheaper than fifty 2 MW batteries).

The AGO asserted that battery storage offers several advantages as described in Strategen's memorandum that are not sufficiently evaluated in Duke's plans:

- Storage is a valuable tool to address peak demand.

- Storage has a modular design and can be added in small increments that fit growth. Whereas larger traditional power plants often add more capacity than is needed, at least until load growth catches up to the installed capacity, storage can be added relatively quickly as needed or avoided altogether if load growth does not materialize.

- Storage enhances the resilience of the grid during catastrophic events like hurricanes. The effectiveness of storage was demonstrated during Hurricane Irma, when two large battery storage projects in the Dominican Republic helped stabilize grid frequency and alleviate fluctuations caused when 40% of the generation fleet had suffered an outage.

- The importance of creating a resilient electric grid that integrates clean energy resources is a factor discussed in Executive Order No. 80, the North Carolina policy addressing climate change.

- Recent studies have shown that inverter-based resources (like batteries) have actually responded faster and more accurately than traditional generators in the face of a disturbance.

The AGO recommended two improvements to DEC's and DEP's analyses of storage. First, multiple storage alternatives should be modeled alongside other resource alternatives. That way, DEC's and DEP's models would select the sizes and ratios of solar plus storage that fit a system need (rather than pre-selecting more limited options). Second, the model should use publicly-available cost estimates wherever possible to make the assumptions underlying the model results more transparent. The model used by intervenor NCSEA relied on publicly-available cost estimates from the National Renewable Energy Laboratory and Lazard that are considered to be industry standards.

F. NC WARN Comments – Battery Storage

NC WARN provided a number of examples of the decline in costs of battery storage and breakthroughs in battery technology. It also highlighted plans of utilities and governmental entities that include substantial amounts of solar coupled with battery storage. NC WARN recommended that DEC and DEP redirect their reliance upon gas turbine generation to reliance upon battery storage, especially solar combined with battery storage.

G. DEC and DEP Reply Comments – Battery Storage

DEC and DEP noted that for the first time, they included battery storage as a resource in the 2018 IRPs; in total, nearly 300 MW (nameplate) of lithium-ion battery storage as capacity resource placeholders were assumed to provide 80% of their nameplate capacity towards meeting the Companies' winter peak capacity needs. The Companies also noted their agreement as indicated in their filed IRPs that battery storage costs are expected to continue to decline, making batteries an option for grid support services, including frequency regulation, solar smoothing during periods with high incidences of intermittency, as well as, the potential to provide overall energy and capacity value. DEC and DEP dispute the AGO's contention that they did not thoroughly evaluate the downward trend of storage technology costs, noting that its IRPs assume that battery storage costs drop by nearly 40% by year 2025 in the IRP Base Case. DEC and DEP also indicated that the Companies' IRPs include an aggressive capital cost sensitivity that would further the decline in battery storage costs to 60% by 2025. Additionally, the Companies include a sensitivity of replacing a future undesignated CT with a grid-tied battery storage option in both the DEC and DEP IRPs. DEC and DEP also argued that pairing storage with solar to allow "the storage component to benefit from federal investment tax credits as suggested by the AGO may not always be in the best interests of ratepayers." They pointed out that because North Carolina's peak conditions occur in both summer afternoon and winter morning and afternoon, and can be at least several hours in duration, there may be limitations to the capacity value of batteries, particularly batteries charged solely from solar resources. DEC and DEP noted the Commission's recent approval of a Certificate of Public Convenience and Necessity for DEP's Hot Springs Microgrid Project, a combination 3 MW (DC) solar and 4 MW lithium-based battery energy storage system. They indicated that they are committed to further studying the capacity value of incremental battery storage (both grid-tied storage and solar plus storage systems) in the Carolinas at increasing penetration levels. They stated that a study of the capacity value of storage is needed, and that the Companies expect to include the results of a capacity value of storage study as early as the Companies' 2020 biennial IRP filings.

H. DENC Reply Comments – Battery Storage

DENC addressed battery storage at Section 5.1.2 of the 2018 IRP and Section 3.c.iv of the Compliance Filing. As referenced in the Compliance Filing and by the Public Staff, in addition, the GTSA requires DENC to submit a proposal to deploy a battery storage pilot of up to 30 MW.

The Public Staff acknowledged DENC's recognition that energy storage could have value to provide grid stability as more renewable energy sources are integrated into the grid and could reduce the intermittency of wind and solar generation. The Public Staff contended, however, that DENC did not comply with the Commission's directive to assess battery storage technology. The Public Staff noted that DENC did not consider battery storage technologies for further analysis in its busbar curve, and asserted that DENC did not appear to thoroughly assess battery storage technologies and did not otherwise justify their absence from the IRP. The Public Staff therefore recommended that DENC be required to submit a supplemental filing to its 2018 IRP with a more detailed analysis of why battery storage technologies were excluded from its busbar curves, including a quantitative analysis of energy storage costs. The Public Staff also encouraged DENC to address how its solar integration cost estimates are affected by battery storage, including a discussion of whether the legislatively mandated 5,000 MW of solar could be more cost effectively integrated if coupled with energy storage techniques. The Public Staff suggested that DENC should also be required to file this information in future IRPs and IRP updates.

In its reply comments, DENC noted that many types of technologies can store energy, including electrical, thermal, mechanical, and electrochemical technologies.

DENC explained that hydroelectric pumped storage, a form of mechanical energy storage, accounts for the greatest share of large-scale energy storage power capacity in the United States. DENC explained further, however, that large-scale energy storage capacity additions since 2003 have been almost exclusively electrochemical (or battery) storage. According to DENC, as of May 2019, there has been limited operating experience in utility scale applications of batteries with 901 MW for the entire United States (298 MW in PJM).

DENC further explained that it is in the early stages of battery research and has relied on publicly available industry guidance regarding battery storage projects to help evaluate the technology's merits as compared to traditional generation sources. DENC acknowledged that battery storage can be a viable future option for peak shifting at a stand-alone storage facility or while co-located at a solar farm and may also improve overall energy production at a solar facility via capturing energy that may be clipped by the inverters.

Because battery storage is still in its early stages of development, DENC stated that the estimates for a battery storage facility in the 2018 IRP were more reflective of a pilot program versus a larger utility scale facility. In addition, DENC explained that CTs can provide backup for periods of lower production from solar facilities, such as prolonged weather patterns or projected variations in capacity factors over the course of a year. DENC stated that CTs in the 2018 IRP short-term action plan were slated for deployment in 2022 and 2023, at approximately 458 MW nominal capacity per facility and an overnight installed cost of $476 per kilowatt (kW). According to DENC, pricing of an equivalent battery storage facility was not cost competitive based on those 2018 estimates. As a result, based on the 2018 economics and technology, DENC stated that it does not expect battery storage facilities to significantly displace CT facilities supplementing the solar generation profile within the next several years.

DENC stated that in the 2018 IRP, it screened out battery storage resources as part of its future resource analysis because of (1) limited utility scale operating experiences, (2) PJM being in the process of revising its tariffs for energy storage resources due to FERC Order 841, and (3) high costs. In the Compliance Filing, a 30 MW battery storage pilot program was available as an option in the "final" PLEXOS IRP modeling based on the directive in the VSCC 2018 IRP Order. DENC stated that the 30 MW battery storage pilot was not chosen by the model as a least-cost option in Plan A. According to DENC, this validates its decision in the 2018 IRP to screen out battery storage resources in its 2018 IRP future resource process because of their then (i.e., 2018) high cost relative to their benefits as a generating resource. Nevertheless, DENC acknowledged that the battery storage pilot was forced into all other Plans (Alternative Plans B through F) as required by the VSCC 2018 IRP Order. Notwithstanding their treatment in the 2018 IRP, DENC stated that it will include battery storage and other energy storage options such as pumped storage facilities in the busbar analysis and provide the results of that revised analysis in its 2019 IRP update.

Finally, DENC stated that it disagrees with the recommendation from Public Staff that the Commission require DENC to submit a supplemental filing to specifically address how its solar integration cost estimates are affected by battery storage. According to DENC, it will not have sufficient information to analyze the effect on solar integration for the 2020 IRP because DENC's experience with battery storage technologies is still in its early stages of development. Nevertheless, DENC stated that it will continue to assess battery storage technologies in future IRPs and IRP updates as required by prior Commission orders, and will report and incorporate the results of any relevant experience with battery storage. As part of that effort, DENC will, as directed by the VSCC Compliance Order, model battery storage using the most updated cost estimates available in its future full IRP filings.

VII. INTEGRATED SYSTEMS AND OPERATIONS PLANNING (ISOP)

Duke stated in its IRPs that it is examining ways of enhancing the traditional methods of utility resource planning in order to keep pace with changes occurring in the industry. As an example, Duke stated that it has not been able to identify the locational value of distributed generation sources, and is now developing models to do so. Duke indicated that it is addressing this and other issues through an Integrated Systems and Operations Planning (ISOP) effort. Further, Duke indicated that the future enhancements in planning are expected to be addressed over the next several years, as soon as the modeling tools, processes, and data development will allow.

The Commission has carefully considered the importance of the evolving nature of integrated resource planning. The Commission recognizes that some of the most promising emerging resource solutions, such as battery storage and leading-edge intelligent grid controls, are still in the early stages and will require enhanced capabilities, such as those promoted through ISOP. As a result, the Commission concluded that it would be helpful for the Commission to receive additional information from Duke about ISOP and ordered that a Technical Conference be held on August 28, 2019 for that reason. (See Commission Order dated July 23, 2019 in Docket No. E-100, Sub 157)

A. Public Staff Initial Comments – ISOP

The Public Staff recognizes the complexity of fully valuing battery storage, and encourages the development of improved modeling capabilities envisioned by ISOP.[56] The Public Staff also recommended that in future IRPs, the Companies continue to evaluate the feasibility and benefits of advanced analytic techniques that incorporate sub-hourly modeling and more granular system performance data, and to the extent these advanced analytics are available at reasonable cost, utilize these resources to provide better information and understanding on optimizing reserve margin needs, as well as overall system operations.

B. EDF Comments – ISOP

EDF commends Duke for using this innovative planning approach, which it maintains can save customers money through deferring or avoiding costly investments.

[56] Initial Comments of the Public Staff, at 76.

However, EDF recognizes that there are not many details in Duke's IRP, and encourages the Commission to open a rulemaking or separate docket to explore the most effective and systematic way to implement ISOP.[57]

C. NCSEA Comments – ISOP

In its initial comments, NCSEA stated that it is encouraged by the statements made regarding Duke's ISOP process, and compares it to Integrated Distribution Planning (IDP), stating that the proposed ISOP description is similar but for its exclusion of a hosting capacity map.[58] NCSEA criticizes Duke for not including more detail or a timeline associated with ISOP, and calls upon the Commission to create a rulemaking proceeding to implement ISOP in order to establish a set of rules by which the ISOP process is governed. NCSEA believes such a rulemaking procedure would guarantee that the process has sufficient oversight and transparency so as to allow ratepayers real opportunities to see if the investment decisions are in their best interests.

D. AGO Comments – ISOP

The AGO supported the recommendation made by intervenor NCSEA that a holistic approach should be adopted for the evaluation of the improvements and investments that will be needed to modernize Duke's distribution and transmission grid to better enable use of energy resources such as storage or demand-side measures. Planning and modeling for the future grid – including the integration of distributed resources into distribution and transmission systems – are important pieces of developing integrated resource plans. Strategen noted that some forecasts indicate that distributed resources will almost double by 2023, and North Carolina has witnessed tremendous growth in solar installations and projects. These forecasts need to be considered when formulating integrated resource plans. Accordingly, the AGO recommended that the Commission review and take a proactive role in the planning of integrated distribution planning, either by opening a rulemaking for that purpose or by other appropriate procedures.

E. DEC and DEP Reply Comments – ISOP

In their comments, EDF and NCSEA asked the Commission to initiate a rulemaking proceeding to adopt procedures related to ISOP and Integrated Distribution Planning (IDP), respectively. Duke commented that it does not oppose a rulemaking, but recommended that the Commission allow interested parties to participate in a pre-rulemaking stakeholder process to facilitate common understanding of ISOP issues, and attempt to reach consensus on as many areas as possible to make the formal rulemaking process more collaborative and efficient. Duke indicated it has discussed this stakeholder proposal informally with the Public Staff, and believes that such a process could be beneficial to the Commission and interested stakeholders.

[57] Initial Comments of EDF, at 5.

[58] Initial Comments of NCSEA, at 19.

VIII. QUANTIFICATION OF THE VALUE OF FUEL DIVERSITY AND RISK ANALYSIS

A. Public Staff Initial Comments – Fuel Diversity and Risk Analysis

The Public Staff noted that the Comprehensive Risk Analysis used by DENC provides valuable information in trying to identify which least cost portfolio is best in an uncertain world. The Public Staff found that the approach taken by DENC to analyze the various scenarios with regard to exposure to fuel price volatility scenarios, consideration of rate impacts to customers, and utilizing a probabilistic risk assessment framework provides insightful information to its customers and the Commission. The Public Staff recommended that DEC and DEP develop similar analytical tools to those utilized by DENC, such as the Comprehensive Risk Analysis, to determine the least cost plan that provides the lowest risk to its customers, while also providing operational and compliance flexibility to each utility.

B. SACE, Sierra Club, and NRDC Initial Comments – Fuel Diversity and Risk Analysis

SACE, et al. commented that Duke's 2018 IRP Plans rely excessively on new gas-fired generating capacity. Gas-fired generation is subject to numerous uncertainties, including fuel cost volatility, and carbon regulation. The groups noted that as more energy efficiency programs, renewable energy resources, and battery storage are added to Duke's resource mix, the need for additional gas-fired capacity is diminished.

NRDC commissioned energy consulting firm ICF to perform a power sector analysis using ICF's Integrated Planning Model (IPM®), a power sector dispatch model. SACE, et al. commented that ICF's IPM analysis shows that greater reliance on cleaner energy sources, rather than fossil fuel generation, delivers cost savings and pollution reductions for North Carolina compared to the "business-as-usual" approach in the Duke IRPs. With respect to gas-fired generation, ICF's "economically optimized" case, which allowed the model to optimize for a least-cost outcome, coal-fired capacity was reduced and replaced primarily with new solar; no new gas capacity was selected by the model based on economics. If North Carolina were to follow this economically optimized path, electric sector carbon emissions would fall to 41% below 2005 levels by 2025. The business-as-usual case would have a total system cost of $5.6 billion more that the economically optimized case—or, 3% higher bills for the average residential customer by 2030 and 5% higher by 2035.

C. NCSEA Initial Comments – Fuel Diversity and Risk Analysis

It is NCSEA's position that, with a heavy reliance on natural gas and other traditional generating resources, the IRP plans fail to account for cost-effective clean energy alternatives to the increasingly uneconomic operations of Duke's existing coal plants. NCSEA argues that the Synapse Study details a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirements as traditional generating resources are retired.

D. AGO Initial Comments – Fuel Diversity and Risk Analysis

The AGO commented that Duke's continued reliance on natural gas plants as the primary way to meet future resource needs is not justified because Duke's plans have not adequately considered the economic and environmental risks of that option.

The AGO stated that one concern about Duke's heavy reliance on natural gas generation for planning purposes is that natural gas production and consumption are associated with significant carbon dioxide and methane emissions, greenhouse gases that contribute to climate change, whereas alternatives that use renewables paired with storage are not. Climate change has real costs affecting ratepayers. The economic costs associated with frequent and intense hurricanes, such as those experienced in North Carolina in the past year, were cited as key factors motivating Executive Order No. 80. That order highlights a State commitment to fight climate change and transition to a clean economy, setting a goal of reducing statewide greenhouse gas emissions to 40% below 2005 levels by 2025. The AGO advocated that the Commission broaden its consideration of environmental factors in light of the policy goals announced in Executive Order 80.

Another concern about Duke's increased reliance on natural gas power production is the economic risk of that option. The AGO and Strategen agreed with the recommendation made by the Public Staff that Duke should be directed to use an analytical tool similar to the Comprehensive Risk Analysis that was employed in the initial IRP report of DENC in order to address the relative riskiness of alternative resources. That tool considers tradeoffs between the costs and riskiness of the resources that make up the portfolio. The risk assessment may take into account not only the potential volatility of prices but also risks associated with climate change impacts and mitigation efforts. If Duke is directed to perform a Comprehensive Risk Analysis, Strategen notes that there should be transparency about the assumptions used in the analysis and recommends that Duke should either supply a working copy of the model so that assumptions may be evaluated by other parties in detail or should run alternative specifications and scenarios for others.

According to the AGO, Duke's increased reliance on natural gas power production also poses a longer-term risk that the investment may become stranded before the end of the useful life of such plants. Conventional gas-fired plants are built to last for decades, and new emission standards or technological change may cause the plants to become uneconomic. This concern was identified by the Indiana Utility Regulatory Commission when it rejected an 850 MW natural gas plant proposal. The Indiana Commission directed Vectren to evaluate alternatives to the large, centralized generation approach, given the potential that the plant could become a stranded asset as the cost of renewable energy declines.

E. NC WARN Initial Comments – Fuel Diversity and Risk Analysis

NC WARN noted in its initial comments that public utility commissions, such as in Arizona and Virginia, have rejected proposed IRPs and required utilities to consider opportunities for renewable energy before considering new natural gas infrastructure. NC WARN recommended that the Commission direct Duke to consider battery storage options as opposed to new natural gas infrastructure. NC WARN filed an updated version of its North Carolina Clean Path 2025 Plan, which provides for replacement of 50% of all coal and gas used for electricity with clean energy by 2025, and 100% by 2030. NC WARN's plan indicates that solar combined with battery storage is now more reliable and cost effective than new natural gas power plants. The Plan indicates that gas turbine manufacturing is declining due to this shift to renewables with storage. The Plan states that Duke's contention that it must build gas turbines to back up solar is "unsubstantiated."

In its reply comments, NC WARN encouraged the Commission to carefully review Duke's plan to meet demand mostly from resources using fracked gas. It contended that the demand for fracked gas would likely decline as renewable energy technologies grew and battery costs fell. NC WARN also recommended that the Commission reject Duke's proposal to add over 9,000 MW of natural gas infrastructure and direct Duke to seek renewable generation instead. NC WARN contends that Duke's proposal to build natural gas plants and pipelines is not the least-cost option and exposes customers to significant risk.

F. DEC and DEP Reply Comments – Fuel Diversity and Risk Analysis

The Public Staff suggests that DEC and DEP adopt a fuel diversity analysis similar to the analysis provided by DENC in its IRP filings. DEC and DEP commented that their high-level understanding of DENC's approach is the deployment of a long-term stochastic modeling approach. Under such an approach, long-term fuel prices are statistically simulated over hundreds or even thousands of scenarios to examine a distribution of potential outcomes dependent on the mean forecast of various fuels such as coal, natural gas and fuel oil. In addition, statistical parameters such as long-term commodity volatility curves and long-term cross commodity correlations would be required in such an approach. While such an approach provides a comprehensive distribution of potential production cost outcomes, it is dependent upon these forward-looking statistical assumptions that are difficult to ascertain and verify. Currently, parties to the IRP docket have varying opinions on the long-term fuel price forecasts used by DEC and DEP. DEC and DEP noted that moving to a long-term statistical approach greatly expands the debate given the dependence on long-term forecasts of fuel volatility, mean reversion parameters and correlation variables. They continue to assert that the use of discrete fuel price sensitivity and scenario analysis provides a more transparent view of fuel diversity benefits. Furthermore, DEC and DEP commented that their discrete sensitivity and scenario approach is consistent with Rule R8-60 that outlines variables such as fuel prices should be varied so portfolio results can be viewed under these varying assumptions.

IX. OTHER ISSUES

A. UTILITY STATEMENT OF NEED

The Public Staff noted the fundamental link between each IOU's IRP and avoided costs, formalized with the passage of HB 589, which provided that a "future capacity need shall only be avoided in a year where the utility's most recent biennial [IRP] filed with the Commission … has identified a projected capacity need to serve system load…" The Public Staff pointed out that a number of assumptions used by the IOUs in the avoided cost proceeding have not been clearly specified by each utility. To remedy this issue and mitigate the potential for paying for more capacity than what is needed, the Public Staff recommended that the utilities, in their IRP Update to be filed in 2019 and all future IRPs and updates, include a new Utility Statement of Need section. The Public Staff explained that the Utility Statement of Need section will specifically address the link between the first year of capacity need and avoided cost proceeding and specifically address:

1. The year in which the utility would fall below its planning reserve margin without commitment(s) to procure additional resources.

2. Whether QF contracts expiring within the avoided cost term are renewed / replaced in kind, or excluded.

3. Whether utility uprates are solely installed for additional capacity and if they could be considered avoidable.

4. Whether new EE measures are included in the determination of capacity need.

5. The quantity of MW needed in the first year, and a discussion of whether avoided capacity payments will be made to QF contracts executed in excess of that capacity.

6. The year in which the utility's first avoidable capacity need becomes unavoidable.

7. Whether it is appropriate to create a separate "Avoided Cost Portfolio" in the IRP's portfolio analysis section, which might present a more objective determination of capacity need that could ensure QFs providing capacity are not treated as captive.

The Public Staff explained that this section would then be directly referenced by each utility in its avoided cost proceeding, establishing a clear and well-understood methodology to establish the first year of capacity need for the calculation of avoided capacity payments. The Public Staff contended that the utilities should continue to conduct the foundational analysis of the IRP, with incorporation of the Public Staff's recommendations.

In its reply comments, Duke agreed with the Public Staff's recommendations and stated that it will include a Statement of Need section to more clearly identify the undesignated capacity needs for each utility in DEC's and DEP's 2019 IRP Updates and in future biennial IRP filings.

B. RETAIL RATE IMPACT OF PORTFOLIOS

In Docket No. E-100, Sub 147, the Public Staff previously recommended that DEC and DEP "file a residential rate analysis of the proposed expansion plans, along with a comprehensive risk analysis that addresses similar key risk factors employed by DNCP" in future IRPs. The Commission did not rule on the issue of including a residential rate analysis of the proposed expansion plans in its June 27, 2017 Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans in Docket No. E-100, Sub 147 (2016 IRP Order).

In the current docket, the Public Staff noted that an analysis of the rate impacts of each portfolio would inform the comments of intervenors, as well as testimony and comments from the using and consuming public, how changes in generation plans and costs would impact a retail customer, particularly residential customers as to an estimate of the short and long-term costs of the various portfolios. The Public Staff indicated that while there is not currently a statutory or regulatory requirement for Duke to include rate impacts in future IRPs as there is in Virginia,[59] such information could also be useful in other forums, such as the North Carolina Climate Change Interagency Council and the stakeholder workshops formed to facilitate the implementation of Executive Order 80. Therefore, the Public Staff recommended that the Commission require DEC and DEP in future IRPs to evaluate the residential rate impacts of each portfolio evaluated against a no CO_2 scenario and present this information in a manner similar to that used by DENC.

The Public Staff noted that DENC presents the incremental cost of compliance of each of the Alternative Plans compared to the least cost plan, but due to the significant changes in investment decisions between the filings of the original IRP and its revisions, these estimates are no longer valid. Thus, the Public Staff recommended that DENC submit as a supplemental filing with a recalculated rate impact analysis of the modified Alternative Plans found in its Compliance Filing. DENC requested instead that it be permitted to provide an updated rate impact analysis of the Alternative Plans in its 2019 IRP Update due to be filed by September 1, 2019.

The AGO supported the recommendations of the Public Staff and other parties that Duke should be required to provide an analysis of the residential annual rate impacts of each of its portfolios similar to that presented in Dominion's 2016 and 2018 IRPs. The AGO recommended that the analysis should show the impacts of the portfolios on ratepayer bills, and the analysis should not be limited to residential ratepayers, but rather, should be applied generally to all customer classes. Further the bill impact analysis should

[59] Va. Code § 56-599 B 9 requires DENC to evaluate "[t]he most cost effective means of complying with current and pending state and federal environmental regulations, including compliance options to minimize effects on customer rates of such regulations." Accordingly, DENC evaluates the residential rate impact of each Alternative Plan against its Plan A: No CO_2 Tax. This analysis may be found in Section 6.6 of DENC's 2018 IRP filed May 1, 2018.

include a breakout of the portion of rates that are fuel-related and thus bear the price risk borne by ratepayers.

C. DENC NUGs

The Public Staff noted that some facilities DENC listed as NUGs in Appendix 3B to its IRP are not included in the NUG capacity in Figure 3.1.1.3, while some utility-scale solar facilities are considered as NUG capacity in Figure 3.1.1.3 and others not. The Public Staff also noted that DENC considers all utility-scale solar facilities to be behind the meter, but these facilities typically separate the metering of electricity sales from electricity purchases. The Public Staff recommended that in future IRPs, DENC clarify its definition of a NUG facility; use that definition consistently through the IRP; re-evaluate which generating facilities sell energy directly to DENC and identify them separately from facilities that do not; separately identify facilities that sell energy/capacity directly to DENC from facilities that sell directly into PJM; and be consist in references to nameplate rating or equivalent firm capacity rating.

In its reply comments, DENC indicated that it had discussed these recommendations with Public Staff and had agreed to make changes to Appendix 3B and Figure 3.1.1.3 in future full IRPs and to provide an updated version of Appendix 3B as part of the 2019 IRP Update filing to the extent the information is available.

D. QF CONTRACT EXPIRATION IN THE IRP

In its Initial Comments, NCSEA takes exception with the method used by Duke in the treatment of QF contract expirations in the IRPs. NCSEA states that, "despite the fact the PPAs with QFs will eventually expire, Duke assumes that the PPAs will 'be either renewed or replaced in kind.' However, there is no guarantee, or requirement, that a QF will continue to provide the utility with capacity past the end of its initial PPA, even if the QF has remaining operational life." [60] This statement was made in reference to a data request response provided by the Companies to the Public Staff in this docket.[61]

Duke commented that this data request response refers only to solar QF contracts, as existing contracts of any other technology are assumed to expire at the end of the purchased power agreement ("PPA") term. Solar capacity, however, will continue to grow in the future, increasing the Companies' planned solar capacity. As such, the capacity of existing solar QFs will either be procured by the renewal of existing contracts or replaced with other solar PPAs. Whether the capacity is from an existing QF or another QF does not matter in the context of the IRP, only that the capacity comes from a solar resource.

NCSEA goes on to allege that "Duke assumes for planning purposes that a QF's PPA will be renewed despite the fact that it has made numerous efforts in other

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[60] NCSEA Comments, p. 25, Paragraph 1.

[61] Duke Energy Carolinas, LLC's Response to Public Staff Data Request No. 6-4 and Duke Energy Progress, LLC's Response to Public Staff Data Request No. 4-12, included in NCSEA's Comments as Attachment 2.

proceedings to make it more difficult for a QF to renew a PPA,"[62] going on to cite Docket No. E-100, Sub 101 and Docket No. E-100, Sub 158, as examples. Duke argued that both dockets cited by NCSEA relate to the upgrade of QF equipment, which is in no way impactful to the 2018 IRPs.

NCSEA continues its argument by stating that "other wholesale PPAs are removed from DEC and DEP's respective generation stacks when they expire and create capacity needs. However, Duke treats PPAs with QFs differently in its planning process."[63] Duke noted that it is true that DEC and DEP have consistently assumed across multiple planning cycles that all wholesale purchase contract capacity, including QFs, is removed in the year after a wholesale contract expires and that QFs are not presumptively assumed to establish a new PPA to deliver capacity and energy to the Companies over a new fixed term in the future. According to Duke, if, however, the QFs have already executed a contract extension or renewal with Duke, the specific contract capacity will be included past the original contract expiration year to the year of expiration of the extended/new contract. Thus, the existing QF contracts may either be renewed or replaced with other new solar facilities so that, in the aggregate solar penetration reaches levels projected in the IRP. The IRP is agnostic as to which choice is made but rather focuses on an expected level of solar penetration. Furthermore, Duke commented that the IRPs present scenarios with both higher and lower levels of solar penetration that are also agnostic to the decision of renewal versus replacement with new solar facilities. Duke noted that this is consistent with the approach for all contracted generation. For example, at the time DEP's 2018 IRP was filed, several natural gas PPAs were expiring. The IRP did not explicitly assume these contracts were renewed but rather put in a generic undesignated PPA that was deemed avoidable by QFs for the purpose of establishing avoided cost rates. Therefore, NCSEA's argument that the Companies are treating existing QF contracts differently and unfairly in the IRPs is untrue.

Duke noted that, based upon the foregoing circumstances, it continues to find its IRP planning approach of assuming a capacity reduction after expiring QF contracts reasonable and consistent with the objectives of their IRPs to determine the long-range generation needs to reliably serve their customers' energy needs in North Carolina. Thus, Duke argues that DEC and DEP are justified in removing from their respective IRPs the third-party wholesale contract capacity (both QF and non-QF) in the year when the contract expires.

According to Duke, DEC and DEP have taken a reasonable and consistent approach to recognizing expiring wholesale purchase contracts, including QF contracts, in their 2018 IRPs. Duke's IRPs actually assume that, upon expiration of any third-party wholesale purchase contract (both QF and non-QF), DEC and DEP recognize a reduction in capacity by the amount of the capacity provided in the expiring wholesale purchase contract in the year following contract expiration. Duke noted that this approach to capacity planning is not new. Since the Duke Energy/Progress Energy merger, Duke's 2012, 2014, 2016, and 2018 biennial IRPs have all consistently assumed the expiration

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[62] NCSEA Comments, p. 25, Paragraph 2.

[63] Id. p. 26, Paragraph 1.

of wholesale purchase PPAs, including QF PPAs, that result in a need for replacement capacity to be procured through each utility's resource planning process to meet the targeted reserve margin during a given year. Thus, the expiration of each PPA has the potential to impact the timing of DEC and DEP's first capacity need, particularly when viewed in aggregate with other contract expirations or retirements. Fundamentally, it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally enforceable commitment guaranteeing delivery exists.

E. CLIMATE CHANGE

Duke responded to intervenor comments on climate change issues as follows.

1. Duke agrees with the AGO that incorporating environmental considerations into resource planning is critical even if specific standards are not yet defined in environmental regulations, which is why Duke models the potential costs of future carbon dioxide (CO_2) legislation as part of their comprehensive scenario analysis described in the IRP.

Duke noted that, as described in Chapter 13 of the DEP IRP and Chapter 12 of the DEC IRP, and in more granular detail in Appendix A of both IRPs, Duke analyzed the potential costs associated with multiple government-imposed limitations on greenhouse gas emissions. These CO_2 sensitivities are placeholders for future legislations, and the IRPs reflect the costs associated with the implementation of those potential regulations. Any benefits to Duke's customers associated with those potential regulations are largely driven by state and federal rules and standards that are also evolving and will influence how technologies are deployed. Duke asserted that, to be clear, the IRP does not set policy, but it responds to regulations and can provide a view of the impacts of potential regulations, as Duke has shown with potential greenhouse gas emission regulations.

2. Duke supports lowering carbon emissions, and the IRPs are consistent with Duke Energy's Sustainability Report. Furthermore, the DEC and DEP systems are projected to exceed Executive Order No. 80 which set a goal of reducing statewide greenhouse gas emissions to 40% below 2005 levels by 2025.

Duke noted that it has been aggressive with its pace of retiring coal plants (having retired more than half of its Carolinas coal plants over the last decade), adding renewables to the resource mix, increasing EE/DSM offerings to its customers, and operating a reliable nuclear fleet that provides half of its customers' energy demand with zero CO_2 emissions. These actions, along with operating efficient natural gas generation with low cost fuel, will allow the DEC and DEP systems to meet and exceed the goals of Executive Order No. 80, signed in the Fall of 2018, as well as the Companies' own sustainability targets, all while meeting the Commission's Rule R8-60 requirement to "provide reliable electric utility service at least cost over the planning period."[64] Duke explained that it is participating in the Executive Order No. 80 stakeholder meetings and, although the State's specific plans to implement the order are currently unknown, with the final report not expected until October 2019, Duke will address any additional requirements in future IRPs once any additional requirements are known.

In the introduction to its reply comments, Duke noted that the IRP is a "snapshot in time" view of DEC's and DEP's proposed mix of diverse resources to reliably meet customers' needs over the fifteen (15) year planning horizon. The IRP process is lengthy and dynamic. Duke commented that a consistent theme reflected in numerous consumer statements of position filed with the Commission is a call for accelerated retirement of the Companies' remaining coal plants, less reliance on natural gas or other fossil fuels, and greater reliance upon renewable resources, energy storage, DSM and EE. These same general themes are expressed in the comments filed by many of the intervenors to this docket. Duke explained that the 2018 Duke IRPs reflect a diverse mix of least-cost generation, storage, DSM and EE resources: in 2019, 46% of DEC's capacity is expected to come from carbon-free resources, and 39% of DEP's capacity is expected to come from carbon-free resources. Using the assumptions embedded in the 2018 IRPs, 60% of the combined DEC and DEP energy would come from carbon-free resources in 2019. Of the proposed resource additions over the 2018 IRP planning horizon, 46% of the DEC additions and 23% of the DEP additions would come from renewables, storage, DSM and EE.

However, change is constant in the energy industry, and Duke noted that successful companies are those that recognize and adapt to the changing landscape. Duke stated that it shares its stakeholders' desire to provide increasingly clean energy for the benefit of its North Carolina and South Carolina customers. A lower carbon future requires a delicate balancing act with no one-size-fits-all solution, as Duke must continue to provide all of its customers with safe, reliable and affordable energy. In its 2017 Climate Report to Shareholders and its 2018 Sustainability Report, Duke Energy Corporation reiterated its voluntary goal to reduce carbon emissions 40% across its six state generation fleets by 2030, and noted that its long-term strategy is to continue to drive carbon out of its system. The specific potential path forward and timing to a low-carbon energy future, however, will depend on a number of challenging and uncertain factors, including market forces, public policy, technology innovation/ commercialization and customer demand. Duke routinely evaluates retirement of its generation assets, but as Duke considers a course specific to the Carolinas, DEC and DEP will evaluate accelerated retirement of their remaining North Carolina coal units, coupled with other necessary supply and demand-side investments to reliably meet customer needs. Because such plans would not only impact Duke's future generation mix, but would also impact customer rates, any such accelerated coal unit retirement plans would also need to be considered in ratemaking dockets. Duke noted its commitment to make appropriate filings with the Commission in future dockets after it has completed its analysis and reached any conclusions.

[64] Commission Rule R8-60 – Integrated Resource Plans and Filings.

F. ALTERNATIVE FILED RESOURCE PLANS

NCSEA, SACE et al., and NC WARN filed what might be styled as alternative resource plans as part of their comments on the 2018 IRPs. Duke responded to these alternative plans as follows.

1. The Synapse Report filed by NCSEA is the product of a special interest group that appears to make assumptions in their model with a predetermined outcome in mind. The Synapse Report would not conform to the regulated utilities' requirement to provide reliable electric utility service at least cost over the planning period and should be dismissed.

Duke noted that the Synapse report filed by NCSEA as Attachment 1 to its comments claims to detail "a realistic clean energy future that provides both the energy and capacity to meet the needs of Duke's customers, while effectively meeting future reliability requirements as traditional generating resources are retired"[65]; however, the report's cost savings are based on multiple assumptions that, if implemented, would cripple the reliability of the DEC and DEP systems.

Duke argues that, first, the Synapse report, which purports to gain an immediate cost savings of 28% through "removal of [coal generation] must-run designations"[66] does not consider "transmission implications that may or may not be associated with must-run designations."[67] The must-run designations that Synapse removes are not required at all energy demand levels on the DEP and DEC systems, and Duke is not seeking "to find a use for the costly must-run coal generation"[68] as Synapse suggests. Duke instead notes that, in fact, in Synapse's attempt to match the DEC and DEP IRP base cases (with must-run designations included), "one-third of the coal generation shown in 2019 is exported to neighboring utility service territories rather than being used to meet Duke's own load requirements."[69] Duke states that it does not model sales to neighboring utilities unless those are firm sales with co-owners that are part of nuclear generation contracts or the new Lee CC, and DEC and DEP generally do not sell energy to external markets unless there are economic incentives for consumers to do so. Generally, must-run requirements increase as system energy demand levels increase or other generating units near the must-run units are not available. This level of detail was not considered relevant to Synapse as they relied on Horizons Energy's National Database for their EnCompass model[70] which greatly oversimplifies must-run requirements on the DEC and DEP systems. Must-run requirements are in place to maintain stability on the transmission

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[65] NCSEA Comments, pp. 5-6

[66] North Carolina's Clean Energy Future: An Alternative to Duke's Integrated Resource Plan, Prepared for the North Carolina Sustainable Energy Association by Synapse Energy Economics, Inc. (Synapse Report), p. 6

[67] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part c.

[68] Synapse Report, p. 6.

[69] Id., p. 5.

[70] NCSEA Response to Duke Data Request No. 1, Item No. 1-3 part b.

system by providing voltage support or other services. According to Duke, without these must-run requirements, the transmission system would be in jeopardy of not being able to serve load, which is a risk that Synapse and NCSEA have ignored.

Another source of cost savings in the Synapse report is the reduction of the required minimum reserve margins in DEC and DEP from 17% to 15% based on the NERC 2018 Long Term Reliability Assessment.[71] As noted in footnote 4 on page 53 of the NERC report, SERC Reliability Corporation (SERC) members perform individual reliability assessments, and SERC does not provide reference margin levels for its sub-regions. Further, page 151 of the NERC report states that NERC applies a 15% margin for predominately thermal systems if a reference margin is not provided by a given assessment area. In short, the SERC and NERC reports cited by NCSEA as a basis for a lower reserve margin do not reflect the level of solar penetration that exists in the Carolinas or the need for a winter reserve margin target as determined by the Companies' resource adequacy studies. The minimum reserve margin requirement in DEC and DEP has been a point of extensive comment since the 17% reserve margin was introduced in the 2016 IRP Reports. The minimum reserve margin requirement is based on comprehensive resource adequacy studies that the Companies conducted with Astrapé Consulting in 2016. Duke explained that, although some of the intervening parties apparently still chose to stubbornly debate the findings of the study, the Commission found the 17% reserve margin requirement reasonable for planning purposes, with the requirement that the Companies and the Public Staff file a joint report summarizing their review after filing the 2017 IRP Update.[72] Synapse took it upon themselves to ignore the 17% requirement that was developed through a study that focused on the issues facing the DEC and DEP systems, and instead used the NERC study that did not consider the level of solar penetration facing the Carolinas, which was a major driver of the increased reserve margin requirement. Duke argued that, again, Synapse and NCSEA are relying on a reduction in system reliability to drive the results of their biased resource report.

Duke commented that the third source of cost savings that is inconsistent with maintaining a reliable energy system in the Carolinas is Synapse's reliance on energy imports into the Carolinas. The Synapse "Clean Energy scenario" relies on 14% energy imports from neighboring utilities to meet demand by 2033.[73] According to Duke, this reliance on neighboring utilities to meet the Carolinas' energy and capacity needs is inconsistent with the reality that there is not enough firm transmission available to reliably import this level of energy, and the Synapse study makes no mention of the costs required to obtain firm transmission into the region. Duke argued that NCSEA and Synapse are either ignorant of the realities of transmission constraints into DEC and DEP, or they have intentionally ignored them.

Duke further pointed out that it is not clear that increasing energy imports from neighboring utilities, as NCSEA proposes to do, would result in fewer CO_2 emissions for

[71] Id., Item No. 1-2 part b.

[72] Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans, Docket No. E-100, Sub 147.

[73] Synapse Report, p. 5.

the Carolinas. In fact, relying on other states' generation, including those states that may still rely mainly on coal generation, would be contrary to the spirit of Executive Order No. 80's goal to reduce CO_2 emissions in the state to 40% of 2005 emission levels by 2025. As stated above, Duke's plan already exceeds Executive Order No. 80's directive by using resources located in the Carolinas.

Duke argued that perhaps the comment that most clearly shows the lack of understanding by NCSEA and Synapse as to what constitutes a reliable system is the following statement:

> The Clean Energy Scenario maintains the required 15 percent reserve margin and EnCompass projects no loss-of-load hours and sees zero hours with unserved energy, proving that the retirement of fossil fuels and build-out of renewables leads to no new system reliability issues.[74]

As Duke explained, one does not simply use Duke's weather-normalized peak demand forecast, along with an hourly load shape from the EnCompass National Database as Synapse did, and claim no reliability concerns when the model converges without unserved energy hours. According to Duke, that is equivalent to someone guaranteeing that because they did not run out of gas when they drove from Chapel Hill to Raleigh at 7:00 a.m. on a Sunday morning with their low fuel light on, then they could successfully complete that drive at any time with little gas in the tank. How would they fare at 5:00 pm on a Friday in rush hour? Duke noted that when asked to explain their understanding of why the Companies carry a reserve margin, NCSEA's consultant, Ric O'Connell responded:

> NCSEA understands the reserve margin used in the IRP is a "planning reserve margin" which is defined by NERC as: Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in [the] planning horizon.

Duke commented that such a definition may be accurate for the NERC study, but the Companies carry a reserve margin to be able to meet unexpected demand due to extreme temperatures, economic load forecast uncertainty, and unexpected outages of its operating units. The reserve margin that Duke requires is there not just to meet expected demand, but to be able to reliably serve customers under extreme and unexpected circumstances.

In summary, Duke noted that any party can claim that their plan is lower cost than the Companies' plans, but to achieve those costs savings in the manner that NCSEA and Synapse did, while still claiming to meet the reliability standards that the NCUC, Duke, and its customers demand, is unrealistic and lacks regulatory rigor. Duke, as the regulated utility in North Carolina, has the sole obligation to meet its customers' energy needs at all times throughout the year, and the Companies are steadfast in their belief that the DEC and DEP IRPs achieve that standard by doing so at the lowest reasonable

[74] NCSEA Comments, p.8.

cost while meeting and exceeding environmental regulations at the state and federal levels. Duke noted that, simply put, other parties to this docket do not have the obligation to serve, nor do they have an obligation to maintain a reliable electric system. Their use of overly simplistic modeling approaches to reach a predetermined ideological outcome would not be compliant with reliability standards and as such should be rejected.

2. SACE et al.'s consultant Applied Economics Clinic's (AEC) Report, "Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans" includes misleading and false accusations regarding the Companies' business practices.

Duke commented that the assertion of the Applied Economics Clinic in Attachment 2 of the SACE et al. comments that "the Companies have hard-wired the useful lives for their existing coal units, preventing a fair comparison of the economics of these units relative to replacement resources"[75] is misleading. The retirement dates for existing coal units are projections for planning purposes in the IRPs, and are based on retirement dates in depreciation studies approved in the most recent general rate cases by the Commission (and PSCSC).

Additionally, Duke argued that AEC's assertion that "…the Companies make major decisions about their resources behind closed doors"[76] is disingenuous.[77] Multiple analyses are performed regarding the retirement options of the Companies' coal units, as confirmed in data requests received and cited by AEC in the SACE et al. Attachment 2. The results of those analyses are utilized and represented in the next filed IRP. Furthermore, Duke's IRPs and depreciation studies are open to scrutiny in the public and transparent dockets this Commission oversees with the intervention and active participation of parties like SACE et al.

Duke commented that while SACE et al. and AEC attempt to discredit Duke and its commitment to meet customers' energy needs at the lowest reasonable costs, the full picture is not considered. Duke is regulated by this Commission and the PSCSC and is under an obligation to provide reliable and affordable service to their customers. Duke pointed out that the special interest group intervenors, on the other hand, may freely utilize whatever data sources and reports that support their intended purpose, while ignoring the realities of the obligation of serving customers. Statements made by the intervenors criticizing Duke's analysis techniques, assumptions, and generally, any decision that does not meet their agenda are presented as fact in their comments, without regard for realistic actualities. In reality, the statements and assertions aimed at discrediting Duke are incorrect. Duke noted that, notwithstanding its criticism of SACE et al.'s tactics, as noted above, Duke will continue to evaluate potential accelerated retirement of their remaining North Carolina coal units and advise the Commission in future dockets.

[75] Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans, p. 18, Part A.

[76] Id.

[77] By this logic, SACE et al.'s comments and AEC's report were also prepared "behind closed doors" as the Companies did not see them until they were filed with the Commission.

3. NRDC's commissioned ICF analysis is unable to be reviewed and should be considered inconsequential.

SACE et al.'s comments state that NRDC commissioned the energy consultant, ICF, to perform analyses to develop its own "optimum" resource plan based upon inputs developed by NRDC. ICF utilized their Integrated Planning Model ("IPM") to develop what they call an "economically optimized" case and an "IRP" case, which is intended to replicate the No Carbon Base Case presented by the Companies in its filed IRP.

In a data request to SACE et al., [78] Duke requested a copy of the report developed by ICF in the study, to which SACE et al. responded that, "ICF did not develop a report. All written materials were developed by NRDC, based on data outputs provided by ICF using their IPM model with all assumptions and policy scenarios provided by NRDC."[79] According to Duke, in the data request response, NRDC provided a file including the inputs developed by them. Duke explained that there is no discussion or detailed information about the calculation and algorithm details of the models. Additionally, how the input data was actually utilized in the model is unclear. In the same response, NRDC provided a single page of outputs for each case developed by the IPM model.[80] While two cases were provided, an "economically optimized" case was not one of them. SACE et al.'s data request response provides outputs for a "reference case" (also titled as "BAU No CCS") and an "IRP case." It is unclear if the "reference case" and the "economically optimized" case are the same case. As such, Duke noted it is impossible for the Companies to adequately review and comment on the outputs at this time.

Duke further commented that, even so, NRDC presents ICF's "economically optimized" case as a least cost option as compared to the "IRP" scenario that was created. There are several issues in question from Duke's point of view. First, in the ICF results presented as Attachment 1 of NRDC's Comments, in the description of the "economically optimized" case, it is stated that, "the model was allowed to endogenously retire and add generating resources to determine a least-cost pathway for the state given existing federal and state regulations."[81] Once again, in the absence of information regarding the calculation methodology and rigor of the ICF study, it is not clear how the model does this, what units are retired or when they are retired.

Duke explained that, additionally, NRDC states in Attachment 1 that "the only additional natural gas capacity added is from units already under construction" in the "economically optimized" case.[82] However, the capital costs and fuel prices utilized by ICF for new natural gas units are based on publicly-available generic data that is proven

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[78] Southern Alliance for Clean Energy, Natural Resources Defense Council and the Sierra Club Responses to Second Data Request of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Docket No. E-100, Sub 157, April 29, 2019.

[79] Id., Response to DEC/DEP Data Request No. 2-1.

[80] Id., Response to DEC/DEP Data Request No. 2-2 including Input and Output Excel Files.

[81] Economically Optimized Independent Power Sector Modeling Shows Multiple Benefits when Compared to Duke's IRP, p. 2, bullet one.

[82] Id., p. 1, bullet three.

to be higher than in-house new-build costs developed for Company-specific locations and that consider economies of scale/scope that make these resources economic options. The costs utilized to make this statement are inordinately high and likely give any natural gas resources an unfair disadvantage.

NRDC claims, also, that "this 'optimized' case only represents a possible future in which decisions are made by an infallible market operator, instead of a reality where regulators may have to base their decisions on imperfect or incomplete information, and utilities are driven by incentives that do not always align with their customers' interests."[83] Duke argues that, first, there is no such thing as an "infallible market operator," which discredits the "optimized" case as being unrealistic. Second, Duke suggests that the inference that utilities make decisions based on "incentives" that do not "align with customers' interests" is outrageous. Duke also notes that the SACE et al. inference that the information utilized by the Companies is incomplete is absolutely false. Duke explains that its resource plans are based on best-available information that takes months to gather, vet, and include properly in modeling and analysis utilized to develop the resource plans.

Finally, NRDC claims that renewable generation (primarily solar) replaces any existing coal or future natural gas resources by stating, "renewable energy generation more than makes up for the generation reductions…"[84] Duke commented that it is impossible for intermittent solar to replace baseload resources required to reliably meet the Companies' customer demand, particularly during peak times when solar is only available to a small degree. The IPM model outputs provided in SACE et al.'s data request response mentioned above do not provide any discernable information about the operational reliability assumptions and load shapes of the solar generation or the impacts of even higher levels of intermittent solar to Duke's generating system. As determined by the Capacity Value of Solar study presented in the Companies' filed IRPs,[85] solar resources provide very little capacity value at the time of winter peak demand and capacity values decrease as the penetration of solar increases. Duke explains that infinitely high amounts of solar cannot be added to a generating system and still maintain the integrity and reliability of the system and meet required NERC reliability standards.

Duke argues that, once again, SACE et al. fail to consider the real world in which the Companies operate. DEC and DEP are regulated utilities that have real obligations to its customers. Duke noted it is DEC and DEP's highest commitment to serve their customers in the most reliable, dependable, environmentally-friendly and economical manner possible. There are real-world consequences to the theoretical exercises SACE et al. continue to present as fact. Duke argues that the misleading and incomplete information presented by the intervenors consistently supports their own agenda but is developed without full consideration of the best interest of all customers.

4. NC WARN Comments – Alternative Filed Resource Plans

[83] Id., p. 5, paragraph two.

[84] Id., p. 1, bullet 4.

[85] DEC 2018 IRP, Chapter 9, and DEP 2018 IRP, Chapter 9.

In its comments and attached report, NC WARN alleged, among other things, that DEC and DEP can achieve 100% fossil-free energy by 2030, getting halfway there by 2025. In response, Duke noted that NC WARN has, yet again, argued that the Commission should adopt an energy plan for North Carolina that is unrealistic and would jeopardize the reliable and affordable energy system that this Commission has consistently required from Duke in fulfilling the Commission's mission under the Public Utilities Act. Duke noted that although NC WARN objected to 8 of the 13 data requests DEC and DEP sent to it seeking analytical and factual support for statements made in its filed IRP comments and report, the information NC WARN did provide in its responses reveals that its comments and report are not supported by competent analysis or facts. For example, in DEC and DEP Data Request 1-4, the Companies asked NC WARN to:

> Please provide all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information supporting your position that sufficient and cost-effective battery storage can be online by 2025 to displace thousands of megawatts of natural gas generation.

In response, NC WARN simply referred the Companies to the reports filed by NC WARN in connection with its 2017 and 2018 IRP comments. Duke notes that, in other words, NC WARN asserted that the underlying analysis supporting its comments was simply its own comments. Likewise, in DEC and DEP Data Request 1-7, the Companies asked NC WARN:

> On page 9 of your initial comments, you state that, "In his report, Mr. Powers establishes that DEC and DEP can achieve one-hundred (100) percent fossil-free energy by 2030, getting halfway there by 2025." Please identify and produce all documents and analyses including inputs, assumptions, calculations, results, models, spreadsheets with working formulas, or other data or information upon which you and/or Mr. Powers rely upon in support of this statement.

In response, NC WARN simply stated, "This statement is explained in detail, with applicable citations, in Mr. Powers' N.C. Clean Path 2025 Report and the Update: N.C. Clean Path 2025." This lack of quantitative analysis and circular reasoning is found throughout NC WARN's data request responses. See DEC/DEP Exhibit 1. Duke explains that although NC WARN's simplistic and hyperbolic conclusions may advance its own interests, its arguments should not, and cannot, be credibly relied upon by the Commission or anyone who truly values a reliable and affordable supply of energy for the State of North Carolina.[86]

X. REQUESTS FOR EXPERT WITNESS HEARING

[86] The Commission notes that NC WARN's assertion that North Carolina can retire all coal and gas-fired power plants by 2030 is directly contradicted by even its own admission in response to DEC and DEP Data Request 1-10, that gas plants would be needed to serve in a backup role in 2030 even under its proposed energy plan.

NC WARN, as well as many of the consumer statements of interest filed with the Commission, have asked for an expert witness hearing on the 2018 IRPs. The Commission concludes that an expert witness hearing with respect to the 2018 biennial plans is not necessary because the Commission has a voluminous record before it, including studies and reports from various technical witnesses, which is adequate to review and rule on the adequacy of the 2018 IRPs. All intervenors have had the opportunity to make legal, factual, and technical arguments to the Commission in their filed comments, and the Commission has received the testimony of public witnesses in a public hearing, as well as numerous statements of consumer position filed with the Commission. Finally, the comments of some consumers appear to reflect an incorrect assumption that Commission acceptance of an IRP constitutes Duke's request for, or Commission approval of, specific generation resources contained therein. As the Commission noted in its June 26, 2015 Order Approving Integrated Resource Plans and REPS Compliance Plans, in Docket No. E-100, Sub 141, at pages 11-12:

> General Statute 62-110.1(c), in pertinent part, requires the Commission to "develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity." In State ex rel. Utils. Comm'n v. North Carolina Electric Membership Corporation, 105 N.C. App 136, 141, 412 S.E.2d 166, 170 (1992), the Court of Appeals discussed the nature and scope of the Commission's IRP proceedings. The Court affirmed the Commission's conclusion that
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> > [t]he Duke and CP&L plans were "reasonable for the purposes of [the] proceeding" before it. That is to say, the plans submitted by Duke and CP&L were reasonable for the purpose of "analy[zing]…the long-range needs for expansion of facilities for the generation of electricity in North Carolina…" See N.C. Gen. Stat. § 62-110.1(c).
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> The Court further explained that the IRP proceeding is akin to a legislative hearing in which the Commission gathers facts and opinions that will assist the Commission and the utilities to make informed decisions on specific projects at a later time. On the other hand, it is not an appropriate proceeding for the Commission to use in issuing "directives which fundamentally alter a given utility's operations." With regard to the Commission's authority to issue specific directives, the Court cited the availability of the Commission's certificate of public convenience and necessity (CPCN) proceedings and complaint proceedings. Id., at 144, 412 S.E.2d at 173.

As such, by statute the Commission's decisions on the need, cost, and timing of a specific generation resource are made only after a CPCN application is filed and considered by the Commission in a public and transparent CPCN proceeding conducted pursuant to N.C.G.S. §§ 62-110.1 and 62-82.

The Commission finds and concludes that for the purposes of N.C.G.S. § 62-110(c) and Rule R8-60 the record in this docket is sufficient, and that NC WARN and the other interested persons requesting an expert witness hearing have not shown good cause for such a hearing. Accordingly, the requests for an expert witness hearing on the 2018 IRPs are denied. As will be noted later in this Order, however, and based on the record compiled in connection with the 2018 filings, the Commission will require certain supplemental filings and proceedings and will direct that certain specific matters be addressed in the utilities' 2020 biennial IRPs.

XI. REPS COMPLIANCE PLANS

North Carolina General Statute § 62-133.8 requires all electric power suppliers in North Carolina to meet specified percentages of their retail sales using renewable energy and energy efficiency. One megawatt-hour (MWh) of renewable energy, or its thermal equivalent, equates to one renewable energy certificate (REC), which is used to demonstrate compliance. An electric power supplier may comply with the REPS by generating renewable energy at its own facilities, by purchasing bundled renewable energy from a renewable energy facility, or by buying RECs. Alternatively, a supplier may comply by reducing energy consumption through implementation of EE measures or electricity demand reduction.[87] The electric public utilities (DEP, DEC, and DENC) may use EE measures to meet up to 25% of their overall requirements in N.C. Gen. Stat. § 62-133.8(b). One MWh of savings from DSM/EE or demand reduction is equivalent to one energy efficiency certificate (EEC), which is a type of REC. All electric power suppliers may obtain RECs from out-of-state sources to satisfy up to 25% of the requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c), with the exception of DENC, which can use out-of-state RECs to meet its entire requirement. The total amount of renewable energy or EECs that must be provided by an electric power supplier for 2018, 2019, and 2020 is equal to 10% of its North Carolina retail sales for the preceding year.

Commission Rule R8-67(b) provides the requirements for REPS Compliance Plans. Electric public utilities must file their plans on or before September 1 of each year, as part of their IRPs, and explain how they will meet the requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), (d), (e), and (f). The plans must cover the current year and the next two calendar years, or in this case 2018, 2019, and 2020 (the planning period). An electric power supplier may have its REPS requirements met by a utility compliance aggregator as defined in R8-67(a)(5).

A. Public Staff Initial Comments – REPS Compliance Plans

The Public Staff commented on DEP, DEC, and DENC's plans to comply with N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d), the general[88] and solar energy requirements. The

[87] "Electricity demand reduction," as used herein, is defined in N.C. Gen. Stat. §62-133.8(a)(3a).

[88] The overall REPS requirement of N.C. Gen. Stat. §62-133.8(b), less the requirements of the three set-asides established by N.C. Gen. Stat. §§ 62-133.8(d)-(f), is frequently referred to as the "general requirement."

Public Staff also provided consolidated comments on the IOUs' plans to comply with N.C. Gen. Stat. §§ 62-133.8(e) and (f), the swine and poultry waste set-asides.

According to the Public Staff, DEP has contracted for and banked sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d). As of December 31, 2017, DEP's compliance services contracts with the Towns of Sharpsburg, Stantonsburg, Black Creek, Lucama, and Winterville terminated, and DEP no longer provides REPS compliance services for any other electric suppliers.

DEP intends to use EE programs to meet 25% of its REPS requirements. A substantial portion of the general requirement will be met by executed purchased power agreements and REC-only purchases from biomass power providers, some of which are combined heat and power (CHP) facilities. Hydroelectric facilities of 10 MW or less, and power generated from landfill gas, will also provide RECs for DEP's retail customers. In addition, DEP plans to continue using solar energy to help it meet the general requirement. It may also use wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina, to satisfy this requirement.

To meet the solar set-aside, DEP will obtain RECs from its own solar facilities, its residential solar V program, and REC-purchase contracts with other solar PV and solar thermal facilities. DEP is the owner of 140.7 MW of solar facilities that are now operational and available for use to meet a portion of its REPS compliance obligations.[89]

DEP plans to evaluate additional projects through the competitive procurement process established in HB 589. HB 589 allows for competitive procurement of 2,660 MW of additional renewable energy capacity in the Carolinas, with proposals issued over a 45-month period. DEP may develop up to 30% of its required competitive procurement capacity using self-owned facilities.

DEP anticipates that its incremental REPS compliance costs will remain below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4), but it expects them to rise by approximately 20% over the planning period, reaching approximately 85% of the cost cap in 2020.

DEP files evaluation, measurement, and verification (EM&V) plans for each EE program in the respective program approval docket.

According to the Public Staff, DEC has contracted for or procured sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b), (c), and (d) for the planning period, both for itself and for the electric power suppliers for which it is providing REPS compliance services. These suppliers are Rutherford EMC, Blue Ridge EMC, the Town of Dallas, the Town of Forest City, the City of Concord, the Town of Highlands, and the City of Kings Mountain (collectively, DEC's Wholesale Customers). DEC's contractual obligation to provide REPS compliance for the City of Concord and the

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[89] See DD Fayetteville Solar, Inc., Docket No. E-2, Subs 1054, 1055, and 1056, Order Transferring Certificate of Public Convenience and Necessity (Dec. 16, 2014); Duke Energy Progress, Inc., Docket No. E-2, Sub 1063, Order Issuing Certificate of Public Convenience and Necessity (Apr. 14, 2015).

City of Kings Mountain ended effective December 31, 2018; therefore, these comments reflect REPS compliance services for the City of Concord and the City of Kings Mountain only through 2018.

DEC intends to use EE programs to meet 25% of its REPS requirements. Hydroelectric facilities with a capacity of 10 MW or less and energy allocations from the Southeastern Power Administration (SEPA) will be used to meet up to 30% of the general requirement of DEC's Wholesale Customers.

Hydroelectric facilities of 10 MW or less, together with incremental capacity from the 2012 modifications to DEC's Bridgewater hydroelectric plant, will provide RECs for DEC's retail as well as its wholesale customers. DEC has entered into a contract to sell five of its hydroelectric facilities. All of these facilities intend to register as new renewable energy facilities, so as to retain the option of selling the RECs produced to DEC for REPS compliance purposes.[90]

A substantial portion of DEC's general requirement will be met by purchased power agreements and REC-only purchases from biomass power providers, some of which are CHP facilities. In addition, DEC will continue to use solar energy and power generated from landfill gas to comply with the general requirement. It may also use wind energy, through either REC-only purchases or energy delivered onto its system.

To meet the solar set-aside, DEC will obtain RECs from its self-owned solar PV facilities and from other solar PV and solar thermal facilities. DEC's solar resources include 75 MW of capacity at the Monroe and Mocksville solar facilities, approximately 20 MW from the small distributed solar facilities approved in Docket No. E-7, Sub 856, and 6 MW of anticipated capacity from the Woodleaf facility, which became fully operational in January 2019.

DEC anticipates that its REPS compliance costs will increase, but will be below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4), for the planning period.

According to the Public Staff, DENC has contracted for and banked sufficient resources to meet the REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c) through 2019 for itself and for the Town of Windsor (Windsor), for which it provides REPS compliance services. DENC has contracted for and banked sufficient resources to meet the REPS requirement of N.C. Gen. Stat. § 62-133.8(d) as well. DENC plans to use EE and purchased RECs to meet the general REPS requirements of N.C. Gen. Stat. §§ 62-133.8(b) and (c) for itself and indicated that it may also use Company generated RECs. For Windsor's general REPS requirement, DENC will use out-of-state wind RECs, in-state biomass and solar RECs, and Windsor's SEPA allocation. For the solar set-aside, DENC plans to purchase in-state and out-of-state solar RECs for itself and Windsor. DENC will rely on out-of-state RECs to meet its compliance requirements, as allowed by

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[90] See Joint Notice of Transfer, Request for Approval of Certificates of Public Convenience and Necessity, Request for Accounting Order and Request for Declaratory Ruling, filed on July 5, 2018, by DEC, Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC, in Docket Nos. E-7, Sub 1181, SP-12478, Sub 0, and SP-12479, Sub 0.

N.C. Gen. Stat § 62-133.8(b)(2)(e), but will obtain in-state RECs to meet Windsor's 75% in-state requirement. Its total costs are the same as its incremental costs because, unlike DEC and DEP, it currently plans to purchase only unbundled RECs, rather than RECs that are bundled with renewable electric energy, to meet its REPS requirements.

DENC anticipates that during the planning period, it will incur annual research costs of $50,000 for the continued development of its Microgrid Project. The Microgrid Project consists of wind, solar and fuel cell energy generation and battery storage at DENC's Kitty Hawk District Office.

DENC expects that the REPS compliance costs for itself and Windsor will be well below the cost caps in N.C. Gen. Stat. §§ 62-133.8(h)(3) and (4) for the planning period.

DENC files EM&V plans for each EE program in the respective program approval docket.

B. REPS Compliance Summary Tables

The following tables are compiled from data submitted in DEP, DEC, and DENC's Plans. Table 1 shows the projected annual MWh sales on which the utilities' REPS obligations are based. It is important to note that the figures shown for each year are the utilities' MWh sales for the preceding year; for instance, the sales for 2018 are MWh sales for calendar year 2017. The totals are presented in this manner because each utility's REPS obligation is determined as a percentage of its MWh sales for the preceding year. The sales amounts include retail sales of wholesale customers for which the utility is providing REPS compliance reporting and services. Table 2 presents a comparison of the projected annual incremental REPS compliance costs with the utilities' annual cost caps.

TABLE 1: MWh Sales for Preceding Year

	Compliance Year		
Electric Power Supplier	**2018**	**2019**	**2020**
DEP	36,829,899	37,521,080	37,685,819
DEC	59,518,351	60,104,379	60,285,246
DENC	4,203,708	4,217,958	4,239,131
TOTAL	100,551,958	101,843,417	102,210,196

TABLE 2: Comparison of Incremental Costs to the Cost Cap

		DEP	DEC	DENC
2018	Incremental Costs	$41,294,711	$27,120,881	$1,052,998
	Cost Cap	$63,874,278	$94,975,829	$5,632,261
	Percent of Cap	65%	29%	19%
2019	Incremental Costs	$47,421,825	$36,738,176	$1,224,857
	Cost Cap	$64,583,052	$93,929,320	$5,288,797
	Percent of Cap	73%	39%	23%
2020	Incremental Costs	$55,445,392	$48,524,154	$1,419,320
	Cost Cap	$65,271,008	$94,623,837	$5,304,517
	Percent of Cap	85%	51%	27%

C. Swine Waste and Poultry Waste Set-Asides

North Carolina General Statute § 62-133.8(a) provides that in 2012 at least 0.02% of the electric power sold to customers should be produced from swine waste, and this percentage increases to 0.14% by 2015 and 0.20% by 2018. Subsection (f) provides that in 2012 at least 170,000 MWh of power sold to retail customers will be generated from poultry waste, and that this requirement will increase to 700,000 MWh in 2013 and 900,000 MWh in 2014.

In every year from 2012 through 2017, the electric suppliers moved that the swine waste requirement be delayed until the following year, and the Commission granted their requests. In 2018, they moved that the requirement be set at 0.02% for the electric public utilities and zero for the EMCs and municipalities, and this request likewise was granted.

With respect to poultry waste, the electric suppliers moved in 2012 and again in 2013 to delay the 170,000-MWh annual requirement for a year, and the Commission granted their motions. The Commission's 2013 order set the requirement at 170,000 MWh for 2014 and 700,000 MWh for 2015. The electric suppliers were able to meet the 170,000-MWh requirement in 2014, but they could not comply with the increase to 700,000 MWh for 2015. In that year, and again in 2016 and 2017, they moved that the poultry waste requirement be kept at 170,000 MWh, and their motions were granted. In their 2018 motion, the electric suppliers proposed that the poultry waste requirement be set at 300,000 MWh, and the Commission approved their proposal.

In its annual orders granting delays or reductions in the swine and poultry waste requirements, the Commission has also required the electric power suppliers to file reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, initially on a tri-annual basis and now semiannually. These reports are filed confidentially in Docket No. E-100, Sub 113A. The Commission has further required the electric power suppliers to provide internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities. Additionally, the Commission has directed the Public Staff to hold periodic stakeholder meetings to facilitate compliance with the swine and poultry waste set-asides. In response, the Public Staff organized a stakeholder meeting held on June 23, 2014, and eight subsequent occasions. The attendees have included farmers, the North Carolina Pork Council, the North Carolina Poultry Federation, waste-to-energy developers, bankers, state environmental regulators, and the electric power suppliers. The meetings allow the stakeholders to network and voice their concerns to the other parties. Due to advancements in compliance, all parties agreed that semiannual meetings were no longer necessary and requested that they only be held yearly. The Commission granted this request in its 2017 order.

Up to now, the State's electric power suppliers have been able to comply only to a limited extent with the poultry waste set-aside requirement, and to an even lesser extent with the swine waste requirement. Nevertheless, the REPS statute has served as a stimulus for several important advances in waste-to-energy technology.

First, several swine farms have installed anaerobic digesters at their swine waste lagoons and have produced biogas that has been used as fuel to operate small electric generators at these farms. Electric power suppliers have purchased the electricity produced by these generators – or, alternatively, have purchased the RECs when the electricity was used on the farm where it was generated – and this represented the initial step toward compliance with the swine waste set-aside.

Second, poultry waste has been transported by truck to existing and new generation facilities, where it has been co-fired with wood or other fuels.

Third, there has been progress in the development of large centralized anaerobic digestion plants in areas where numerous swine farms are located. These plants receive swine waste from numerous sources, produce biogas from the waste by the digestion process, and eliminate impurities from the biogas so that it meets quality standards and is eligible to be injected into the natural gas pipeline system. A specified amount of this biogas, which is referred to as "directed biogas" or "renewable natural gas," is injected into a pipeline, and an equivalent amount of natural gas is delivered by the pipeline operator to a gas-fired electric generating plant. These directed biogas facilities were first built in Midwestern states with extensive swine farming activity, but on December 2, 2016, Carbon Cycle Energy, LLC, began construction of a directed biogas facility in Warsaw, North Carolina.[91]

Four days after the start of construction at the Carbon Cycle facility, Piedmont Natural Gas Company, Inc., petitioned the Commission for approval of a new

[91] See Order Accepting Registration of New Renewable Energy Facilities, Docket No. E-7, Subs 1086 and 1087 (Mar. 11, 2016). In this docket, DEC stated that it had entered into contracts to purchase directed biogas from High Plains Bioenergy, LLC, in Oklahoma, and Roeslein Alternative Energy of Missouri, LLC. On March 18, 2016, DEC supplemented its registration statement to indicate that it also entered into contracts to purchase directed biogas from Carbon Cycle Energy for nomination to its Buck Combined Cycl Station.

Appendix F to its service regulations, authorizing the company to accept "Alternative Gas" (which includes, subject to various restrictions, biogas, biomethane, and landfill gas) onto its system and deliver it to purchasers. In an order issued on June 19, 2018, the Commission approved Piedmont's proposed Appendix F and established a three-year pilot program to implement it. The Commission has authorized six firms – C2E Renewables NC, Optima KV, LLC, Optima TH, LLC, GESS International North Carolina, Inc., Foothills Renewables LLC and Catawba Biogas, LLC – to participate in the pilot program.

In March of 2018, Optima KV completed its interconnection to the Piedmont Natural Gas system and began delivering biogas to DEP's Smith Energy Complex in Hamlet, North Carolina. The Optima KV facility thus became the first operational directed biogas facility in North Carolina.

The Public Staff stated that the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides. However, they have made substantial progress toward complying with these difficult obligations, and as advances in waste processing technology are made, they may be able to achieve full compliance with the statutory requirements in the not too distant future. The supplier best positioned to reach full compliance is DENC, since it can obtain all of its RECs from out-of-state. Indeed, DENC's compliance plan indicates that already "both DENC and the Town of Windsor have sufficient RECs in [NC-RETS] to meet the 2018-2020 requirements" for swine waste. DENC does not express quite as high a degree of certainty about its compliance with the poultry waste set-aside, given the possibility that between now and 2020 some of its suppliers may default on their contracts; however, it does state that its efforts have "yielded multiple poultry waste REC contracts and sufficient delivered volume to comply with both the Company's and Town of Windsor's out-of-state requirements for years 2018, 2019 and 2020."

D. Public Staff Conclusions – REPS Compliance Plans

In summary, the Public Staff concluded that:

1. Overall, the electric public utilities believe they are in a better position to comply with all of the requirements of the REPS, including the set-asides, than in previous years.
2. DEC, DEP, and DENC should be able to meet their REPS obligations during the planning period, with the exception of the swine and poultry waste set-asides, without nearing or exceeding their cost caps; however, DEP may approach the caps in 2020.
3. All three utilities should be able to meet the swine and poultry waste requirements in 2018, after the issuance of the Commission's order of October 8, 2018, reducing the requirements.

a. DEC and DEP indicated in their REPS compliance plans that they could comply with the poultry waste set-aside in 2018, and DEC stated that it could meet the swine waste requirement as well; but both companies indicated that compliance would deplete their supply of swine and poultry RECs so severely that they could not comply in 2019 and 2020. Both subsequently joined in the electric suppliers' motion to reduce the swine and poultry requirements for 2018, and their motion was granted. However, the fact that DEC and DEP were even able to consider the possibility of compliance in 2018 represents progress in comparison with previous years.

b. DENC expects to meet the swine waste requirements for 2018 through 2020, both for itself and the Town of Windsor, and it is confident, although not certain, that it will also meet the poultry waste requirement for all three years of the planning period.

c. DEC and DEP are actively seeking energy and RECs to meet the set-aside requirements for the years in which they expect to fall short of compliance. DENC is also seeking to acquire RECs and thus strengthen its position for compliance with the swine and poultry requirements in future years.

d. The Commission should approve the 2018 REPS Compliance Plans filed by DEC, DEP, and DENC.

Commission Conclusions – REPS Compliance Plans

The Commission concludes that the REPS Compliance Plans filed by the utilities contain the information required by Commission Rule R8-67(b). As such, and based on the recommendation of the Public Staff, the Commission accepts the REPS Compliance Plans filed in this docket.

CONCLUSION

Integrated Resource Planning is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable, and safe electric service. Potential significant regulatory changes, particularly at the federal level, and evolving marketplace conditions create additional challenges for already detailed, technical, and data-driven IRP processes. The Commission finds the IRP processes employed by the utilities to be both compliant with State law and reasonable for planning purposes in the present docket. However, the Commission recognizes that the IRP process continues to evolve.

The Commission carefully considered the full record in this proceeding with respect to the 2018 IRPs and concludes that the record is sufficient to enable the Commission to assess whether the 2018 IRPs comply with the requirements of N.C.G.S. § 62-110.1 and Commission Rule R8-60. The Commission finds and concludes that DENC's 2018 IRP is adequate for planning purposes, and should be accepted, subject to DENC's 2019 IRP Update. The Commission finds and concludes that DEC's and DEP's 2018 IRPs are adequate to be used for planning purposes during the remainder of 2019 and in 2020, subject to DEC's and DEP's 2019 IRP Updates. However, the Commission declines to accept all of the underlying assumptions upon which DEC's and DEP's IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in them beyond 2020.

The parties raised many issues that are worthy of more in-depth examination, along with additional issues that the Commission itself finds pertinent. Some of the issues will require the parties to conduct a considerable amount of research in order to fully address them. In addition, some of the issues may be more effectively addressed by means other than typical IRP hearings. At this point, the Commission's judgment is that the most productive course is to focus the utilities, Public Staff, and other interested parties on the parameters and contents of the IRPs due to be filed in 2020. The Commission will do so by using several different procedures. The first will be the technical conference on ISOP that has been scheduled by the Commission for August 28, 2019. The additional steps are described as part of the following summary of four of the issues that were not fully resolved by the 2018 IRPs.

Load Forecasts and Reserve Margins

On June 27, 2017, in Docket No. E-100, Sub 147, the Commission issued an Order Accepting Integrated Resource Plans and Accepting REPS Compliance Plans (2016 IRP Order). In the 2016 IRP Order, the Commission concluded that the electric utilities' peak load and energy sales forecasts were reasonable for planning purposes. However, the Commission expressed concern about DEC's forecast.

> The Commission further concludes that the DEC load forecast may be high. In reaching this conclusion, the Commission recognizes the Wilson Report.[92] To quote from Mr. Wilson's report, "Overall, the DEC winter peak forecast seems somewhat high compared to the trend in the weather-adjusted peaks . . ." Mr. Wilson notes in his report on page 9 that for DEC, there has been a steady differential between the weather-adjusted summer and winter peaks during recent years, averaging 750 MW over 2009 to 2016, and averaging 683 MW over 2014 to 2016. The report states that DEC's current forecast breaks from this pattern, again suggesting that the winter peak forecast is high (see Figure JFW-6: DEC Summer and Winter Peaks, Historical and Forecast).
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> Continuing to address the DEC winter forecast, Mr. Wilson states in his report on page 7 that changes in end-use technologies may be affecting these brief, extreme winter peak loads under extreme cold conditions. The report points out that DEC stated it has not performed any formal analysis to determine which end uses are contributing to these load spikes on extremely cold winter mornings (response to Data Request SACE 2-11).

2016 IRP Order, at 15.

[92] On behalf of Southern Alliance for Clean Energy, Sierra Club, and Natural Resources Defense Council (hereinafter, SACE), James F. Wilson of Wilson Energy Economics prepared a report entitled "Review and Evaluation of the Peak Load Forecasts for the Duke Energy Carolinas and Duke Energy Progress 2016 Integrated Resource Plans" (Wilson Report).

As a result, the Commission directed DEC to address in its 2017 IRP Update any refinements in its load forecasting methodology. Id.

With respect to reserve margins, in the 2016 IRP Order the Commission concluded that the electric utilities' reserve margins in their IRPs were reasonable for planning purposes. However, the Commission noted concerns identified by the Public Staff and the Wilson Report regarding Duke's proposed 17% winter reserve margin target. Consequently, the Commission directed that

> [D]EC and DEP should work with the Public Staff to address the Public Staff's and Mr. Wilson's reserve margin concerns and to implement changes as necessary to help ensure that the reserve margin target(s) are fully supported in future IRPs. Further, the Commission requests that Duke and the Public Staff file a joint report summarizing their review and conclusions within 150 days of the filing of Duke's 2017 IRP Updates. In addition to addressing the reserve margin concerns identified by the Public Staff and Mr. Wilson, the report should clearly define the support and basis for the targeted reserve margins incorporated into the IRPs. If the parties cannot reach consensus, then the report should outline their differences and recommend a procedure for the Commission to pursue in reaching a conclusion about the reserve margins recommended by DEC and DEP in their IRPs.

Id. at 22-23.

On April 2, 2018, Duke and the Public Staff submitted their joint report on their discussions and conclusions (Joint Report). The Commission accepted the Joint Report in its April 16, 2018 Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, in Docket No. E-100, Sub 147 (2017 IRP Order). The Commission noted that Duke and the Public Staff had engaged in discussions, Duke responded to multiple requests for information and evaluated multiple inputs and scenarios that were suggested by the Public Staff, and Duke and its consultant, Astrapé Consulting, met with the Public Staff to present results of the additional analyses and to work toward a consensus. The Commission stated that the Public Staff and Duke did not reach consensus on all of the issues, one such unresolved issue being how to model economic load forecast uncertainties. In the Joint Report, the Public Staff recommended that DEC and DEP utilize a 16% reserve margin for planning purposes in their 2018 IRPs, and until such time that a new resource adequacy study is conducted. On the other hand, Duke stayed with its position that DEC and DEP utilize a minimum 17% winter reserve margin for planning purposes until such time that a new resource adequacy study is conducted. Both recommended that DEC and DEP update their reserve margins no later than the 2020 biennial IRP filings to reflect updated peak load and forecast data, weather, and other relevant inputs. In the 2017 IRP Order, the Commission directed that Duke further address the reserve margin issue in its 2018 IRPs, including additional review and assessment of the Public Staff's proposed approach versus that employed by Astrapé in its 2016 Resource Adequacy Study. 2017 IRP Order, at 8-9.

In its 2018 IRPs, DEC stated that the use of a 16% reserve margin versus 17% reserve margin would not impact DEC's 2018 IRP. However, DEP acknowledged that DEP's resource plan would be impacted if the lower reserve margin were used for planning. DEP noted that a 16% reserve margin would result in lesser short-term purchase quantities, as well as deferral of some of the undesignated future resources.

Both DEC and DEP discussed the impact of 16% reserves on loss of load expectation (LOLE). DEC stated that allowing the reserve margin to decline to 16% for a given year would increase the LOLE to approximately 0.116 days/year, which equates to one expected firm load shed event approximately every 8.6 years. According to DEP, a comparable increase in LOLE for it is approximately 0.13 days/year, or one expected firm load shed event approximately every 7.7 years.

The Public Staff stated in its comments that it continues to recommend a 16% reserve margin, but will work with Duke "to reach consensus within the constructs of the next resource adequacy study." Comments of the Public Staff, at 46-47.

SACE, et al. included with its comments an updated report by James Wilson. Mr. Wilson again raises concerns about Duke's load forecasts and reserve margins being too high.

To address the above issues surrounding Duke's reserve margin and load forecasts, the Commission will hold an oral argument on Wednesday, January 8, 2020, at 10:00 a.m. The parties who submitted comments on Duke's load forecasts and reserve margins – the Public Staff, SACE et al., and NCSEA – will be given 30 minutes each to present their positions, and Duke will be given 30 minutes to respond. In order to facilitate this hearing, on or before November 4, 2019, Duke and the Public Staff shall file written responses to the questions and information requested in item numbers 1 and 2 of Appendix A, which is attached to this Order. The Commission expects that the hearing will focus on the topics in these two items in Appendix A.

Carbon Dioxide Reductions and Coal Plant Retirements

On October 29, 2018, North Carolina Governor Roy Cooper issued Executive Order No. 80 that, among other things, sets a goal of by 2025 reducing statewide greenhouse gas emissions to 40% below 2005 levels. This goal being well within the IRPs' 15-year planning horizons, the Commission concludes that DEC and DEP should be required to model their IRPs to show the efforts that will be required by each of them to contribute to the attainment of the goal. In particular, the two utilities should model plans that result, on a combined basis, in at least a 40% reduction in CO_2 emissions in 2030 compared to their combined 2005 CO_2 emission levels.

To address the issues surrounding carbon dioxide reductions, on or before November 4, 2019, Duke shall file written responses to the information requested in item number 3 of Appendix A. Based on these responses, the Commission may issue further orders related to the preparation of the utilities' 2020 IRPs.

In their 2018 IRPs DEC and DEP contemplate that their remaining coal-fired generating plants will continue in use until they have been fully depreciated. However, today's capacity factors for these plants are substantially lower than the historical capacity factors of the plants. It does not appear from the information in the IRPs that DEC and DEP have fully considered early retirement of any of these coal plants by replacing their contributions with other alternative generation resources or with energy efficiency (EE) and demand-side management (DSM) resources. As a result, the Commission determines that it should require Duke to provide an analysis showing whether continuing to operate each of its existing coal-fired units is the least cost alternative compared to other supply-side and demand-side resource options, or fulfills some other purpose that cannot be achieved in a different manner.

To address the issue of economic retirement of aging coal plants, in the 2020 IRPs DEC and DEP shall include an analysis that removes any assumption that their coal-fired generating units will remain in the resource portfolio until they are fully depreciated. Instead, the utilities shall model the continued operation of these plants under least cost principles, including by way of competition with alternative new resources. In this exercise the full costs of disposal of coal combustion wastes shall be included in making any comparison with alternative resources. If such analysis concludes that continued operation of the utilities' existing coal-fired units until they are fully depreciated is the least cost resource alternative, then the utilities 2020 IRPs shall separately model an alternative scenario premised on advanced retirement of one or more of such units and shall include in that alternative scenario an analysis of the difference in cost from the base case and preferred case scenarios.

Storage Resources

In the 2016 IRP Order, the Commission noted the potential that battery storage could play in the electric utilities' resource planning. The Commission stated:

> [T]he Commission is of the opinion that evaluations of this technology, as documented in the IRPs, have not been fully developed to a level sufficient to provide guidance as to the role this technology should play going forward. As such, the utilities should provide in future IRPs or IRP updates a more complete and thorough assessment of battery storage technologies including the "full value" as discussed in the NCSEA comments.[93] If the standard technical and economic analyses of generation resources somehow preclude the complete and thorough assessment of battery storage technologies, then a separate discussion of this point should be included in the IRPs.

2016 IRP Order, at 60.

In DEC's and DEP's 2018 IRPs, they provided some discussion of the potential for battery storage, as well as information about its present and planned projects that utilize

[93] NCSEA's Comments, Docket No. E-100, Sub 147 (February 17, 2017), Storage in the Integrated Resource Plans at 5-15.

battery storage. However, DEC and DEP did not model the incorporation of storage facilities as a part of its supply side resources. On the other hand, public witnesses and intervenors have asserted that energy storage is rapidly becoming more cost effective. The Commission concludes that DEC and DEP should be required to provide additional analysis of battery storage in Portfolio 7 of their 2018 IRPs, as described more fully below.

To address the issues surrounding energy storage, on or before November 4, 2019, DEC, DEP, and the Public Staff shall file written responses to the information requested in item number 4 of Appendix A,

<u>Consideration of All Resources</u>

Commission Rule R8-60 (d), (e), (f) and (g) requires the electric utilities to assess the benefits of purchased power solicitations, other alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options. Although Duke's IRPs include some discussion and general information about its consideration of these alternatives, the Commission determines that Duke should be required to explicitly describe all analyses that it has undertaken in developing the IRPs. For example, Duke simply accepts its presently established levels of EE and DSM for planning purposes, and plugs those amounts into its IRP. However, Rule R8-60(f) requires the electric utilities to "assess on an on-going basis programs to promote demand-side management," which under the rule includes EE and conservation programs. The Commission acknowledges that in Portfolio 5 Duke modeled a high EE case, in conjunction with a high renewables scenario. However, the Commission concludes that the IRP information, and the spirit of the rule, will be better served by requiring Duke to separately assess the potential for increased EE and DSM, and model the increase in those resources without combining that modeling with additional renewables, as described more fully below.

To address the requirement that DEC and DEP consider all resource options in developing its IRPs, each utility shall in its 2020 IRPs provide the information and modeling specified in item number 5 of Appendix A.

Finally, after the utilities file their 2019 IRP Updates, the Commission may identify additional issues to be addressed or information to be provided by the utilities and parties.

IT IS, THEREFORE, ORDERED as follows:

1. That the IRP filed herein by Dominion Energy North Carolina is adequate for planning purposes, subject to DENC's 2019 IRP Update, and the Commission hereby accepts DENC's IRP.

2. That the IRPs filed herein by Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, are adequate for planning purposes during the remainder of 2019 and for 2020, subject to DEC's and DEP's 2019 IRP Updates, and the Commission hereby accepts the IRPs, subject to the questions raised in this Order concerning the underlying

assumptions upon which the IRPs are based, the sufficiency or adequacy of the models employed, or the resource needs identified and scheduled in the IRPs beyond 2020.

3. That the 2018 REPS compliance plans filed by the IOUs are hereby accepted.

4. That pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost Integrated Resource Planning and file separate IRPs until otherwise required or allowed to do so by Commission order, or until a combination of the utilities is approved by the Commission.

5. That NC WARN's motion for an expert witness hearing, and the other requests for expert witness and additional public witness hearings on the 2018 IRPs, are denied.

6. That on Wednesday, January 8, 2020, at 10:00 a.m., the Commission will hold an oral argument to address reserve margin and load forecasting issues in DEC's and DEP's IRPs, as specified in the body of this Order. The oral argument will be held in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

7. That on or before November 4, 2019, DEC, DEP, and the Public Staff shall file responses to the information requested in Appendix A, as specified in the body of this Order.

8. That in their 2020 IRPs DEC and DEP shall include the information, analyses, and modeling regarding economic retirement of coal-fired units and consideration of all resource options, as specified in the body of this Order.

ISSUED BY ORDER OF THE COMMISSION.

This the 27th day of August, 2019.

NORTH CAROLINA UTILITIES COMMISSION

Janice H. Fulmore, Deputy Clerk

1. DEC and DEP's basis for using a 17% winter reserve margin target, including:

(a) Additional details for the contention that a holistic view of the Astrapé study's reasonableness is more appropriate than focusing on specific individual factors (such as those raised by the Public Staff) that could potentially result in a lower reserve margin. [See Page 18 of the Joint Report]

(b) An explanation and/or additional support for the following statement: "The 2016 resource adequacy studies also demonstrated the economic benefits of minimizing total reliability costs to customers and showed economic reserve margin ranges of up to about 19% for DEC and 20% for DEP (95th percentile confidence level) to minimize substantial firm load shed and high cost risk. On a probabilistic weighted average basis, the net cost to customers of going from 15% to 17% is small compared to the potential risk of expensive market purchases and customer outage costs that can be avoided in extreme years." [See Page 38 of slide deck attached to the Joint Report] Produce all analyses supporting this cost-benefit claim.

(c) A discussion detailing the "sensitivity analysis items noted in the Wilson report" referred to on Page 34 of the slide deck attached to the Joint Report.

(d) An explanation of "Firm Load Shed Event" and discussion of significance in Astrapé's Resource Adequacy Studies. [See Page 43 of Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study]

(e) An explanation and additional characterization of the potential impact of increasing the loss of load expectation for DEP to approximately 0.13 days/year (one firm load shed event every 7.7 years) and for DEC to approximately 0.116 days/year (one firm load shed event every 8.6 years). [See Page 42 in DEP's IRP and Page 42 in DEC's IRP]

(f) A discussion of the following statement included in Astrapé's 2016 Resource Adequacy Studies: "Across the industry, the traditional 1 day in 10 year standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year, and Expected Unserved Energy (EUE) in MWh." [See Page 30 of both DEP's and DEC's 2016 Resource Adequacy Studies]

Include a discussion and assessment of the following statement: "One event in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. Alternatively, one day in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages. As we show, the difference between these interpretations of the 1-in-10 standard translates to differences in planning reserve margins that may exceed five percentage points, with planning reserve margins of possibly less than 10% based on the 2.4 LOLH standard and more than 15% based on the 0.1 LOLE standard." [Brattle Group and Astrapé Consulting for FERC, Resource Adequacy Requirements: Reliability and Economic Implications, by J. Pfeifenberger and K. Carden (2013), Executive Summary Page iii, www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf]

(g) An analysis and conclusion as to what DEC's and DEP's reserve margins would be using an economically-optimal analysis, as discussed in the Brattle and Astrapé report noted in (f) above. Address the following statement: "Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without evaluating its economic implications." [See reference in (f) above]

(h) A detailed work plan for developing the update to Astrapé's Resource Adequacy Studies proposed for 2020. [See Page 32 of the Joint Report]

(i) A characterization and discussion of the impact and risks of potentially delaying the awarding of contracts associated with DEP's capacity and energy market solicitation until an updated Resource Adequacy Study is completed and effectively vetted. [See Page 81 of DEP IRP]

(j) A listing of the reserve margins included in DEC's and DEP's IRPs from 2003 through 2018;

(k) An explanation of why DEC's and DEP's reserve margins have increased over the last 15 years;

(l) DENC's reserve margin is 11.87% and PJM's reserve margin is 15.9%. DENC's and PJM's resource mix is comparable to Duke's. Explain why DEC's and DEP's reserve margins are higher than DENC's and PJM's.

(m) NERC's 2018 SERC-Southeast reference reserve margin level is 15%. Explain why DEC's and DEP's reserve margins are higher than NERC's.

2. Duke's basis for its load forecasts, including:

   (a) Tables that show DEC's and DEP's summer and winter load forecasts prepared in each of the years 2003 through 2018 and the corresponding actual summer and winter peak loads for each year;

   (b) Analyses performed by Duke to determine which end uses are contributing to load spikes on extremely cold winter mornings.

   (c) As a part of DEP's Blue Horizons Project (BHP), DEP has had success in employing DSM in the Western Region to shave winter peaks. Discuss whether DEP's success in using DSM could be replicated by DEC in its North Carolina service territory. If that success can be replicated, explain why DEC has not done so. If not, explain why not.

3. DEC's and DEP's most current strategic plans to reduce carbon dioxide (CO_2) emissions, including:

   (a) The implementation plan (including CO_2 glide path) that results in the attainment of DEC's and DEP's most current goals for reductions in CO_2 emissions.

   (b) Modelling of the carbon reduction goals in the draft Clean Energy Plan released for public comment on August 16, 2019, by the North Carolina Department of Environmental Quality and Duke's current carbon reduction plan. The modelling should not only show the resource portfolio needed to achieve these goals but should also show any cost differentials (increases or savings) from the base case and the preferred case. In modelling cost differentials, the plans should include anticipated costs attributable to disposal of coal wastes from ongoing and continued operation of coal-fired plants and anticipated cost savings attributable to earlier retirement of such plants.

   (c) A comparison of DEC's and DEP's most current plans for CO2 emission reductions to the Governor's Executive Order No. 80 which states that "The State of North Carolina will strive to accomplish the following by 2025: a. Reduce statewide greenhouse gas emissions to 40% below 2005 levels."

4. With regard to Portfolio 7 in DEC's and DEP's 2018 IRPs (CT Centric with Battery Storage and High Renewables):

(a) A discussion of the differences of executing this portfolio compared to the base case (including the differences in Present Value of Revenue Requirement as well as specific changes to resource plans). [See Page 60 of DEP's IRP and Page 56 of DEC's IRP]

(b) An examination of the cost of battery storage at existing distributed resource sites compared to the expected cost of DEP's capacity and energy market solicitation.

(c) Do the modeling and results in Portfolio 7 provide a statistically representative sample that can be extrapolated into a broader analysis and result by assuming the use of individual battery storage on existing and planned solar facilities, specifically including distribution interconnected QFs and the solar capacity to be brought on line pursuant to HB 589, on Duke's system? If not, explain how the modeling of battery storage added to or included in these solar facilities would differ from that employed in Portfolio 7.

5. 2020 biennial IRPs prepared by DEC and DEP that explicitly include and demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential DSM/EE programs, and a comprehensive set of potential resource options and combinations of resource options, as required by Commission Rule R8-60(d), (e), (f) and (g), including:

(a) A detailed discussion and work plan for how Duke plans to address the 1,200 MW of expiring purchased power contracts at DEP and 124 MW at DEC. [See Page 80 of DEP 2018 IRP and Page 78 of DEC 2018 IRP]

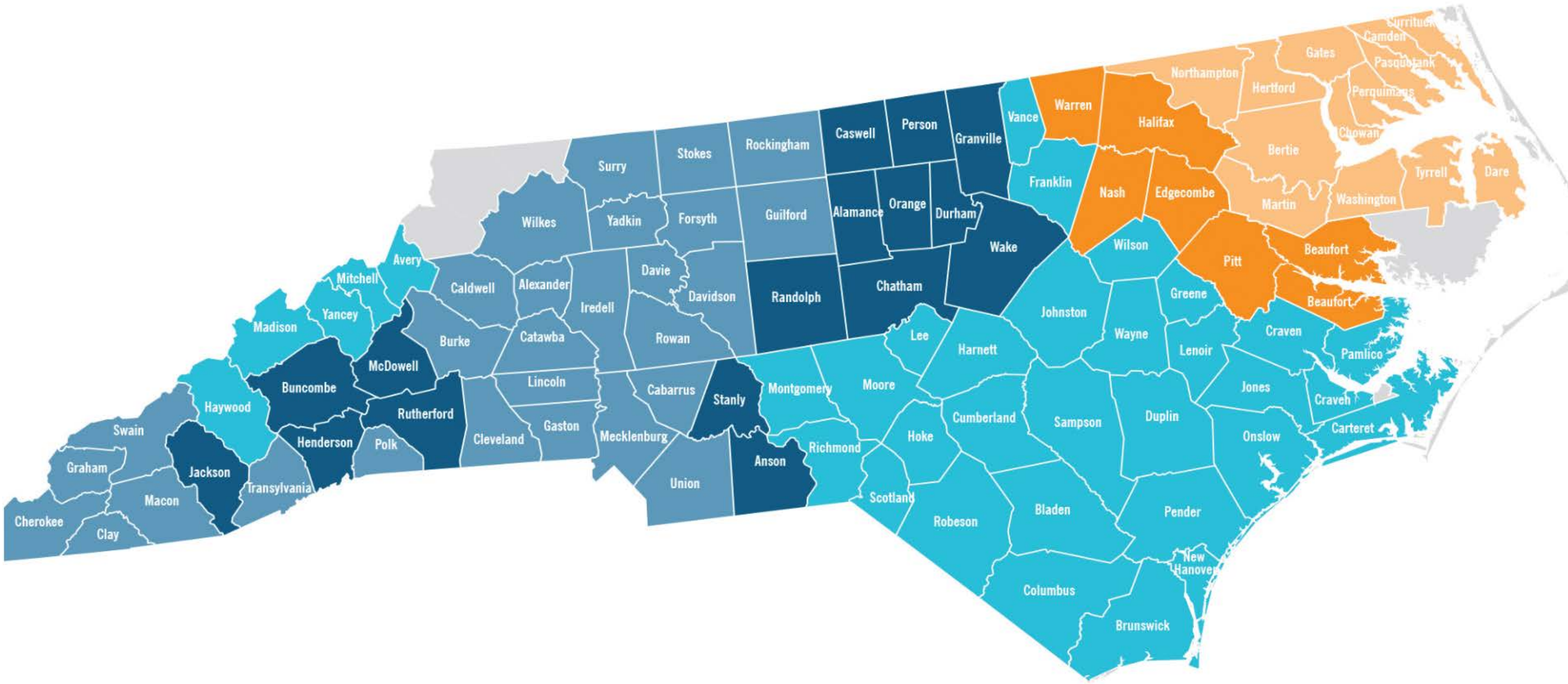
(b) A discussion of the following statement: "The Companies' analysis of their capacity and energy needs focuses on new resource selection while failing to evaluate other possible futures for existing resources. As part of the development of the IRPs, the Companies conducted a quantitative analysis of the resource options available to meet customers' future energy needs. This analysis intended to produce a base case through a least cost analysis where each company's system was optimized independently. However, the modeling exercise fails to consider whether existing resources can

(c) be cost effectively replaced with new resources. Therefore, Duke has not performed a least-cost analysis to design its recommended plans." [See Page 2 of the Report for the Natural resources

Defense Council, the Sierra Club and the Southern Alliance for Clean Energy entitled Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans (March 7, 2019)]

(d) A stand-alone analysis of the cost effectiveness of a substantial increase in EE and DSM, rather than the combined modeling of EE and high renewables included in DEC's and DEP's Portfolio 5 in their 2018 IRPs.

In 2009, in Docket No. E-100, Sub 122, the Commission examined the benefits to be derived if the electric utilities fully utilized the wholesale market to meet their resource needs. Although in the end the Commission did not adopt new IRP requirements, it reiterated the importance of Rule R8-60(d), which requires that the utilities "assess on an ongoing basis the potential benefits of soliciting proposals from wholesale power suppliers and power marketers." Provide a discussion of the advantages and disadvantages of periodically issuing "all resources" RFPs in order to evaluate least-cost resources (both existing and new) needed to serve load



SERVICE TERRITORIES
(counties served)

Duke Energy Carolinas

Duke Energy Progress

Duke Energy Carolinas/
Duke Energy Progress overlapping counties

Dominion Energy North Carolina

Dominion Energy North Carolina/
Duke Energy Progress overlapping counties

$PM_{2.5}$ BACT Cost Analysis

Appendix E
Lambert Compressor Station
PM2.5 BACT Cost Analysis

PM2.5 BASELINE CASE

Assumes the use of Solar Turbines with the following specifications:
9 ppm NOx; 25 ppm CO, 5 ppm VOC (Turbines employ SoloNOx technology)

Turbines Information

Mars 100 Turbine Power Output	hp	16,610
Mars 100 Turbine Power Output	MW	12.39
Hours of Operation	hr	8,760
Mars 100 PM2.5 Emissions - 9 ppm	**PM2.5 - tpy**	**5.95**
Taurus 70 Turbine Power Output	hp	11,146
Taurus 70 Turbine Power Output	MW	8.31
Hours of Operation	hr	8,760
Taurus 70 PM2.5 Emissions - 9 ppm	**PM2.5 - tpy**	**4.06**
Total PM2.5 Emissions	**PM2.5 - tpy**	**10.01**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF(1)	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Item		Cost
Direct and Indirect Capital Costs		
Installed Equipment Cost for Natural Gas-Driven Turbines		
T-70, 9 PPM Unit (2)	11,146 HP	$7,500,000
SCR Exhaust (3)	NA	$0
M-100, 9 PPM Unit(4)	16,610 HP	$10,909,091
SCR Exhaust (5)	NA	$0
Common to Both Units (6)		
Primary Fuel Skid and System Piping Installed:		$250,000
Fuel Heater Installed:		$100,000
C1000 Micro Turbine Installed:		$1,600,000
Micro Turbine Fuel Skid and System Piping Installed:		$150,000
MCC Equipment Inside of Station Installed:		$250,000
Total Capital Cost for Natural Gas-Drive Turbines	*(TCC)*	***$20,759,091***
Annualized Capital Costs	**TCC x CRF**	**$2,137,413**

(2) T-70 equipment cost based on vendor quote
(3) T-70 SCR Exhaust cost based on vendor quote
(4) M-100 equipment cost scaled up based on hp
(5) M-100 SCR Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		Cost
Annual Costs		
Fuel Costs		
Natural Gas Annual Fuel Cost (7)	*$/yr*	*$4,010,863*
Natural Gas Usage	MSCF/yr	$1,682,464
Natural Gas Rate (8)	$/MSCF	*$2.38*
Gas Turbine O&M for M100 and T70		
Turbine Parts Rebuild Exchange		$1,178,182
Inlet Air Filter		$49,091
Gas and Oil Coolers		$71,707
Solar Maintenance Plan		$268,773
Exhaust System Maitenance (SCR)		NA
Total O&M Cost for Gas Turbines		*$1,567,753*
Total Annual Costs	**TAC**	**$5,578,616**

(7) Since natural gas will be avaialable at the site for compression, the natural gas annual fuel cost to run the units is included in the current rate so there is not additional cost to the facility for the natural gas that will be used to run the gas turbines alternative. The gas cost included here is not a cost that the facility will inccur; it is just included to make the estimate as conservative as possible.
(8) The rate of natural gas is based on the average natural gas pipeline import price from January 2016 to March 2020 obtained from the U.S. Energy Information Administration (EIA).

Total Annualized Costs (Capital & Annual)	**$7,716,029**

Appendix E
Lambert Compressor Station
PM2.5 BACT Cost Analysis

PM2.5 CASE 1 - ELECTRIC TURBINES

Assumes the use of electric turbines

Turbines Information

Mars 100 Electric Equivalent	hp	16,000
Mars 100 Electric Equivalent	MW	11.93
Hours of Operation	hr	8,760
Mars 100 Electric Equivalent PM2.5 Emissions	**PM2.5 - tpy**	**0.00**
Taurus 70 Electric Equivalent	hp	11,000
Taurus 70 Electric Equivalent	MW	8.20
Hours of Operation	hr	8,760
Taurus 70 Electric Equivalent PM2.5 Emissions	**PM2.5 - tpy**	**0.00**
Total PM2.5 Emissions	**PM2.5 - tpy**	**0.00**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Item		Cost
Direct and Indirect Capital Costs		
Installed Equipment Cost for Electrical-Driven Turbines		
T-70 Electric Equivalent (2)	11,000 HP	$5,500,000
SCR Exhaust (3)		$0
M-100 Electric Equivalent(4)	16,000 HP	$8,000,000
SCR Exhaust (5)		$0
Common to Both Units (6)		
Primary Fuel Skid and System Piping Installed:		$0
Fuel Heater Installed:		$0
C1000 Micro Turbine Installed:		$0
Micro Turbine Fuel Skid and System Piping Installed:		$0
MCC Equipment Inside of Station Installed:		$500,000
Utility Substation, 28 kVA, 13.8 kV - MVP Purchased		$1,500,000
Total Capital Cost for Natural Gas-Drive Turbines	*(Direct TCC)*	***$15,500,000***
Annualized Equipment Cost	***Direct TCC x CRF***	***$1,595,923***

(2) T-70 electric equivalent equipment cost based on vendor quote
(3) T-70 SCR Exhaust cost based on vendor quote
(4) M-100 electric equivalent equipment cost scaled up based on hp
(5) M-100 SCR Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		Cost
Lambert Substation Electric Cost		
Upgrade project		
Electric substation cost		$2,700,000
T-line construction		$550,000
Adders		$110,000
MEC Upgrades (Mecklenburg Electric Coop)		$5,000,000
SEC Upgrades (Southside Electric Coop)		$2,000,000
ODEC Upgrades (Old Dominion Electric Coop)		$5,000,000
New line project		
New line construction		$8,600,000
Adders		$1,720,000
Ring bus		$6,000,000
Sub-total		$31,680,000
Contingency (10%)		$3,168,000
Total Substation Electric Cost		***$34,848,000***
Annualized Substation Cost	***Substation Cost x CRF***	***$3,588,046***

Total Installed Capital Cost	**TCC**	**$50,348,000**
Annualized Capital Costs	**TCC x CRF**	**$5,183,969**

Appendix E
Lambert Compressor Station
PM2.5 BACT Cost Analysis

PM2.5 CASE 1 - ELECTRIC TURBINES

Annual Costs		
Fuel Costs		
Electric Utility Payments		
Demand	MW	25
Monthly energy	kWh/month	18,000,000
Rate Schedule LGS-U (Mecklenburg Co-op, Chatham VA – Rate sheet provided below)		
Customer charge ($/month)		**$600.00**
	Energy ($/kWh)	**Demand ($/kW)**
Base distribution service rate	$0.00438	$2.90
Electricity supply service rate	$0.0185	$5.65
Subtotal ($/month)	**$411,840**	**$213,750**
Monthly Electric Utility Cost ($/month)	$/month	$626,190
Annual Electric Utility Cost ($/year)		*$7,514,280*
Electric Turbine O&M for 2 Turbines		
Electric Motor Rebuild Exchange		$294,545
Inlet Air Filter		$0
Gas and Oil Coolers		$67,031
Solar Maintenance Plan		$134,386
Exhaust System Maitenance (SCR)		$0
Total O&M Cost for Electric Turbines		*$495,962*
Total Annual Costs	**TAC**	**$8,010,242**

Total Annualized Costs (Capital & Annual)	**$13,194,212**

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PURPOSES ONLY
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MECKLENBURG ELECTRIC COOPERATIVE

SCHEDULE "LGS-U"
LARGE GENERAL SERVICE

AVAILABILITY
Service under this schedule is available to consumers for electric service in all territory served by the Cooperative, where the consumer takes service at one delivery point through one kilowatt-hour meter.

APPLICABILITY
This schedule is applicable to consumers whose annual kW demand averages 500 kW or more per month, or whose highest monthly kW demand exceeds 550 kW. Service under this schedule is subject to the established Terms and Conditions of the Cooperative. This schedule is not available for breakdown, standby, supplemental, self-generation, or resale service.

CHARACTER OF SERVICE
Standard service under this schedule shall be 60-Hertz alternating current, single-phase, or multi-phase where available, at Cooperative's standard secondary voltages. With the Cooperative's prior approval, service may be available at the Cooperative's standard primary distribution voltage.

MONTHLY RATE

III. Distribution Service:		
Consumer Delivery Charge:		
All Consumers:		$ 600.00 per month
Demand Delivery Charge:		
All kW delivered	@	$ 2.90 per kW
Energy Delivery Charges:		
First 219 kWh per kW delivered	@	$0.01771 per kWh
Next 219 kWh per kW delivered	@	$0.01120 per kWh
All kWh over 438 kWh per kW delivered	@	$0.00438 per kWh
IV. Electricity Supply Service:		
Demand Charge:		
All kW sold	@	$ 5.65 per kW
Energy Supply Charges:		
First 219 kWh per kW sold	@	$0.02011 per kWh
Next 219 kWh per kW sold	@	$0.01915 per kWh
All kWh over 438 kWh per kW sold	@	$0.01850 per kWh

All kilowatt-hours used are subject to adjustment for changes in cost of wholesale purchased power and fuel under Schedule K of the Cooperative's Terms and Conditions.

Formaldehyde BACT Cost Analysis

Appendix E
Lambert Compressor Station
Formaldehyde BACT Cost Analysis

Formaldehyde BASELINE CASE

Assumes the use of Solar Turbines with the following specifications:
9 ppm NOx; 25 ppm CO, 5 ppm VOC (Turbines employ SoloNOx technology)

Turbines Information

Mars 100 Turbine Power Output	hp	16,610
Mars 100 Turbine Power Output	MW	12.39
Hours of Operation	hr	8,760
Mars 100 Formaldehyde Emissions - 9 ppm	**Formaldehyde - tpy**	**1.94**
Taurus 70 Turbine Power Output	hp	11,146
Taurus 70 Turbine Power Output	MW	8.31
Hours of Operation	hr	8,760
Taurus 70 Formaldehyde Emissions - 9 ppm	**Formaldehyde - tpy**	**1.40**
Total Formaldehyde Emissions	**Formaldehyde - tpy**	**3.34**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF[1]	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Item		Cost
Direct and Indirect Capital Costs		
Installed Equipment Cost for Natural Gas-Driven Turbines		
T-70, 9 PPM Unit [2]	11,146 HP	$7,500,000
Oxidation Catalyst Exhaust [3]	NA	$0
M-100, 9 PPM Unit[4]	16,610 HP	$10,909,091
Oxidation Catalyst Exhaust [5]	NA	$0
Common to Both Units [6]		
Primary Fuel Skid and System Piping Installed:		$250,000
Fuel Heater Installed:		$100,000
C1000 Micro Turbine Installed:		$1,600,000
Micro Turbine Fuel Skid and System Piping Installed:		$150,000
MCC Equipment Inside of Station Installed:		$250,000
Total Capital Cost for Natural Gas-Drive Turbines	*(TCC)*	***$20,759,091***
Annualized Capital Costs	**TCC x CRF**	**$2,137,413**

(2) T-70 equipment cost based on vendor quote
(3) T-70 Oxidation Catalyst Exhaust cost based on vendor quote
(4) M-100 equipment cost scaled up based on hp
(5) M-100 Oxidation catalyst Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		Cost
Annual Costs		
Fuel Costs		
Natural Gas Annual Fuel Cost [7]	*$/yr*	*$4,010,863*
Natural Gas Usage	MSCF/yr	$1,682,464
Natural Gas Rate [8]	$/MSCF	$2.38
Gas Turbine O&M for M100 and T70		
Turbine Parts Rebuild Exchange		$1,178,182
Inlet Air Filter		$49,091
Gas and Oil Coolers		$71,707
Solar Maintenance Plan		$268,773
Exhaust System Maitenance (Oxidation Catalyst)		$0
Total O&M Cost for Gas Turbines		*$1,567,753*
Total Annual Costs	**TAC**	**$5,578,616**

(7) Since natural gas will be avaialable at the site for compression, the natural gas annual fuel cost to run the units is included in the current rate so there is not additional cost to the facility for the natural gas that will be used to run the gas turbines alternative. The gas cost included here is not a cost that the facility will inccur; it is just included to make the estimate as conservative as possible.
(8) The rate of natural gas is based on the average natural gas pipeline import price from January 2016 to March 2020 obtained from the U.S. Energy Information Administration (EIA).

Total Annualized Costs (Capital & Annual)	**$7,716,029**

Appendix E
Lambert Compressor Station
Formaldehyde BACT Cost Analysis

Formaldehyde CASE 1 - OXIDATION CATALYST

Assumes the use of Solar Turbines with the following specifications and the addition of oxidation catalyst
9 ppm NOx; 25 ppm CO, 5 ppm VOC (Turbines employ SoloNOx technology)

Turbines Information

Mars 100 Turbine Power Output	hp	16,610
Mars 100 Turbine Power Output	MW	12.39
Hours of Operation	hr	8,760
Mars 100 Formaldehyde Emissions - 9ppm & 90% Eff Ox Cat	**Formaldehyde - tpy**	**0.35**
Taurus 70 Turbine Power Output	hp	11,146
Taurus 70 Turbine Power Output	MW	8.31
Hours of Operation	hr	8,760
Taurus 70 Formaldehyde Emissions - 9ppm & 90% Eff Ox Cat	**Formaldehyde - tpy**	**0.32**
Total Formaldehyde Emissions	**Formaldehyde - tpy**	**0.67**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF[1]	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Item		Cost
Direct and Indirect Capital Costs		
Installed Equipment Cost for Natural Gas-Driven Turbines		
T-70, 9 PPM Unit [2]	11,146 HP	$7,500,000
Oxidation Catalyst Exhaust [3]		$175,000
M-100, 9 PPM Unit[4]	16,610 HP	$10,909,091
Oxidation Catalyst Exhaust [5]	1.40 Factor	$245,000
Common to Both Units [6]		
Primary Fuel Skid and System Piping Installed:		$250,000
Fuel Heater Installed:		$100,000
C1000 Micro Turbine Installed:		$1,600,000
Micro Turbine Fuel Skid and System Piping Installed:		$150,000
MCC Equipment Inside of Station Installed:		$250,000
Total Capital Cost for Natural Gas-Drive Turbines	*(TCC)*	***$21,179,091***
Annualized Capital Costs	**TCC x CRF**	**$2,180,658**

(2) T-70 equipment cost based on vendor quote
(3) T-70 Oxidation Catalyst Exhaust cost based on vendor quote
(4) M-100 equipment cost scaled up based on hp
(5) M-100 Oxidation catalyst Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		Cost
Annual Costs		
Fuel Costs		
Natural Gas Annual Fuel Cost [7]	*$/yr*	*$4,010,863*
Natural Gas Usage	MSCF/yr	$1,682,464
Natural Gas Rate [8]	$/MSCF	$2.38
Gas Turbine O&M for M100 and T70		
Turbine Parts Rebuild Exchange		$1,178,182
Inlet Air Filter		$49,091
Gas and Oil Coolers		$71,707
Solar Maintenance Plan		$268,773
Exhaust System Maitenance (Oxidation Catalyst)		$98,182
Total O&M Cost for Gas Turbines		*$1,665,934*
Total Annual Costs	**TAC**	**$5,676,797**

(7) Since natural gas will be avaialable at the site for compression, the natural gas annual fuel cost to run the units is included in the current rate so there is not additional cost to the facility for the natural gas that will be used to run the gas turbines alternative. The gas cost included here is not a cost that the facility will inccur; it is just included to make the estimate as conservative as possible.
(8) The rate of natural gas is based on the average natural gas pipeline import price from January 2016 to March 2020 obtained from the U.S. Energy Information Administration (EIA).

Total Annualized Costs (Capital & Annual)	**$7,857,455**

Appendix E
Lambert Compressor Station
Formaldehyde BACT Cost Analysis

Formaldehyde CASE 2 - ELECTRIC TURBINES

Assumes the use of electric turbines

Turbines Information

Mars 100 Electric Equivalent	hp	16,000
Mars 100 Electric Equivalent	MW	11.93
Hours of Operation	hr	8,760
Mars 100 Electric Equivalent Formaldehyde Emissions	**Formaldehyde - tpy**	**0.00**
Taurus 70 Electric Equivalent	hp	11,000
Taurus 70 Electric Equivalent	MW	8.20
Hours of Operation	hr	8,760
Taurus 70 Electric Equivalent Formaldehyde Emissions	**Formaldehyde - tpy**	**0.00**
Total Formaldehyde Emissions	**Formaldehyde - tpy**	**0.00**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Item		Cost
Direct and Indirect Capital Costs		
Installed Equipment Cost for Electrical-Driven Turbines		
T-70 Electric Equivalent (2)	11,000 HP	$5,500,000
SCR Exhaust (3)		$0
M-100 Electric Equivalent(4)	16,000 HP	$8,000,000
SCR Exhaust (5)		$0
Common to Both Units (6)		
Primary Fuel Skid and System Piping Installed:		$0
Fuel Heater Installed:		$0
C1000 Micro Turbine Installed:		$0
Micro Turbine Fuel Skid and System Piping Installed:		$0
MCC Equipment Inside of Station Installed:		$500,000
Utility Substation, 28 kVA, 13.8 kV - MVP Purchased		$1,500,000
Total Capital Cost for Natural Gas-Drive Turbines	*(Direct TCC)*	***$15,500,000***
Annualized Equipment Cost	***Direct TCC x CRF***	***$1,595,923***

(2) T-70 electric equivalent equipment cost based on vendor quote
(3) T-70 SCR Exhaust cost based on vendor quote
(4) M-100 electric equivalent equipment cost scaled up based on hp
(5) M-100 SCR Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		Cost
Lambert Substation Electric Cost		
Upgrade project		
Electric substation cost		$2,700,000
T-line construction		$550,000
Adders		$110,000
MEC Upgrades (Mecklenburg Electric Coop)		$5,000,000
SEC Upgrades (Southside Electric Coop)		$2,000,000
ODEC Upgrades (Old Dominion Electric Coop)		$5,000,000
New line project		
New line construction		$8,600,000
Adders		$1,720,000
Ring bus		$6,000,000
Sub-total		$31,680,000
Contingency (10%)		$3,168,000
Total Substation Electric Cost		***$34,848,000***
Annualized Substation Cost	***Substation Cost x CRF***	***$3,588,046***

Total Installed Capital Cost	**TCC**	**$50,348,000**
Annualized Capital Costs	**TCC x CRF**	**$5,183,969**

Formaldehyde CASE 2 - ELECTRIC TURBINES

Annual Costs			
Fuel Costs			
Electric Utility Payments			
Demand		MW	25
Monthly energy		kWh/month	18,000,000
Rate Schedule LGS-U (Mecklenburg Co-op, Chatham VA – Rate sheet provided below)			
Customer charge ($/month)			**$600.00**
		Energy ($/kWh)	**Demand ($/kW)**
Base distribution service rate		$0.00438	$2.90
Electricity supply service rate		$0.0185	$5.65
	Subtotal ($/month)	**$411,840**	**$213,750**
Monthly Electric Utility Cost ($/month)		$/month	$626,190
Annual Electric Utility Cost ($/year)			*$7,514,280.00*
Electric Turbine O&M for 2 Turbines			
Electric Motor Rebuild Exchange			$294,545
Inlet Air Filter			$0
Gas and Oil Coolers			$67,031
Solar Maintenance Plan			$134,386
Exhaust System Maitenance (SCR)			$0
Total O&M Cost for Electric Turbines			*$495,962*
Total Annual Costs		**TAC**	**$8,010,242**

Total Annualized Costs (Capital & Annual)	**$13,194,211.69**

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MECKLENBURG ELECTRIC COOPERATIVE

SCHEDULE "LGS-U"
LARGE GENERAL SERVICE

AVAILABILITY
Service under this schedule is available to consumers for electric service in all territory served by the Cooperative, where the consumer takes service at one delivery point through one kilowatt-hour meter.

APPLICABILITY
This schedule is applicable to consumers whose annual kW demand averages 500 kW or more per month, or whose highest monthly kW demand exceeds 550 kW. Service under this schedule is subject to the established Terms and Conditions of the Cooperative. This schedule is not available for breakdown, standby, supplemental, self-generation, or resale service.

CHARACTER OF SERVICE
Standard service under this schedule shall be 60-Hertz alternating current, single-phase, or multi-phase where available, at Cooperative's standard secondary voltages. With the Cooperative's prior approval, service may be available at the Cooperative's standard primary distribution voltage.

MONTHLY RATE
III. Distribution Service:

Consumer Delivery Charge:
All Consumers: $ 600.00 per month

Demand Delivery Charge:
All kW delivered @ $ 2.90 per kW

Energy Delivery Charges:
First 219 kWh per kW delivered @ $0.01771 per kWh
Next 219 kWh per kW delivered @ $0.01120 per kWh
All kWh over 438 kWh per kW delivered @ $0.00438 per kWh

IV. Electricity Supply Service:

Demand Charge:
All kW sold @ $ 5.65 per kW

Energy Supply Charges:
First 219 kWh per kW sold @ $0.02011 per kWh
Next 219 kWh per kW sold @ $0.01915 per kWh
All kWh over 438 kWh per kW sold @ $0.01850 per kWh

All kilowatt-hours used are subject to adjustment for changes in cost of wholesale purchased power and fuel under Schedule K of the Cooperative's Terms and Conditions.

NOx BACT Cost Analysis

Appendix E
Lambert Compressor Station
NOx BACT Cost Analysis

BASELINE CASE

Baseline case assumes the use of Solar Turbines with the following emission specifications:
15 ppm NOx; 25 ppm CO, 5 ppm VOC (Note turbines employ SoloNOx technology)

Turbines Information

Mars 100 Turbine Power Output	hp	17,123
Mars 100 Turbine Power Output	MW	12.77
Hours of Operation	hr	8,760
Mars 100 NOx Emissions - 15 ppm	**NOx - tpy**	**31.66**
Taurus 70 Turbine Power Output	hp	11,792
Taurus 70 Turbine Power Output	MW	8.79
Hours of Operation	hr	8,760
Taurus 70 NOx Emissions - 15 ppm	**NOx - tpy**	**21.81**
Total NOx Emissions	**NOx - tpy**	**53.47**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF[1]	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Cost Analysis

Item		Cost
Direct and Indirect Capital Costs		
Installed Equipment Cost for Natural Gas-Driven Turbines		
T-70, 15 PPM Unit [2]	11,792 HP	$7,250,000
SCR Exhaust [3]	NA	$0
M-100, 15 PPM Unit[4]	17,123 HP	$10,545,455
SCR Exhaust [5]	NA	$0
Common to Both Units [6]		
Primary Fuel Skid and System Piping Installed:		$250,000
Fuel Heater Installed:		$100,000
C1000 Micro Turbine Installed:		$1,600,000
Micro Turbine Fuel Skid and System Piping Installed:		$150,000
MCC Equipment Inside of Station Installed:		$250,000
Total Capital Cost for Natural Gas-Drive Turbines	*(TCC)*	***$20,145,455***
Annualized Capital Costs	**TCC x CRF**	**$2,074,232**

(2) T-70 equipment cost based on vendor quote
(3) T-70 SCR Exhaust cost based on vendor quote
(4) M-100 equipment cost scaled up based on hp
(5) M-100 SCR Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		Cost
Annual Costs		
Fuel Costs		
Natural Gas Annual Fuel Cost [7]	*$/yr*	*$4,015,358*
Natural Gas Usage	MSCF/yr	$1,684,350
Natural Gas Rate [8]	$/MSCF	*$2.38*
Gas Turbine O&M for M100 and T70		
Turbine Parts Rebuild Exchange		$1,178,182
Inlet Air Filter		$49,091
Gas and Oil Coolers		$71,707
Solar Maintenance Plan		$268,773
Exhaust System Maitenance (SCR)		NA
Total O&M Cost for Gas Turbines		*$1,567,753*
Total Annual Costs	**TAC**	**$5,583,111**

(7) Since natural gas will be avaialable at the site for compression, the natural gas annual fuel cost to run the units is included in the current rate so there is not additional cost to the facility for the natural gas that will be used to run the gas turbines alternative. The gas cost included here is not a cost that the facility will inccur; it is just included to make the estimate as conservative as possible.
(8) The rate of natural gas is based on the average natural gas pipeline import price from January 2016 to March 2020 obtained from the U.S. Energy Information Administration (EIA).

Total Annualized Costs (Capital & Annual)	**$7,657,342**

Appendix E
Lambert Compressor Station
NOx BACT Cost Analysis

CASE 1: ULTRA LOW NOx (SOLONOx) CASE

Assumes the use of Solar Turbines with lower NOx emissions specifications:
9 ppm NOx; 25 ppm CO, 5 ppm VOC (Turbines employ SoloNOx technology)

Turbines Information

Mars 100 Turbine Power Output	hp	16,610
Mars 100 Turbine Power Output	MW	12.39
Hours of Operation	hr	8,760
Mars 100 NOx Emissions - 9 ppm	**NOx - tpy**	**19.58**
Taurus 70 Turbine Power Output	hp	11,146
Taurus 70 Turbine Power Output	MW	8.31
Hours of Operation	hr	8,760
Taurus 70 NOx Emissions - 9 ppm	**NOx - tpy**	**13.35**
Total NOx Emissions	**NOx - tpy**	**32.93**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF[(1)]	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Item		Cost
Direct and Indirect Capital Costs		
Installed Equipment Cost for Natural Gas-Driven Turbines		
T-70, 9 PPM Unit [(2)]	11,146 HP	$7,500,000
SCR Exhaust [(3)]	NA	$0
M-100, 9 PPM Unit[(4)]	16,610 HP	$10,909,091
SCR Exhaust [(5)]	NA	$0
Common to Both Units [(6)]		
Primary Fuel Skid and System Piping Installed:		$250,000
Fuel Heater Installed:		$100,000
C1000 Micro Turbine Installed:		$1,600,000
Micro Turbine Fuel Skid and System Piping Installed:		$150,000
MCC Equipment Inside of Station Installed:		$250,000
Total Capital Cost for Natural Gas-Drive Turbines	*(TCC)*	***$20,759,091***
Annualized Capital Costs	**TCC x CRF**	**$2,137,413**

(2) T-70 equipment cost based on vendor quote
(3) T-70 SCR Exhaust cost based on vendor quote
(4) M-100 equipment cost scaled up based on hp
(5) M-100 SCR Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		Cost
Annual Costs		
Fuel Costs		
Natural Gas Annual Fuel Cost [(7)]	*$/yr*	*$4,010,863*
Natural Gas Usage	MSCF/yr	$1,682,464
Natural Gas Rate [(8)]	$/MSCF	*$2.38*
Gas Turbine O&M for M100 and T70		
Turbine Parts Rebuild Exchange		$1,178,182
Inlet Air Filter		$49,091
Gas and Oil Coolers		$71,707
Solar Maintenance Plan		$268,773
Exhaust System Maitenance (SCR)		NA
Total O&M Cost for Gas Turbines		*$1,567,753*
Total Annual Costs	**TAC**	**$5,578,616**

(7) Since natural gas will be avaialable at the site for compression, the natural gas annual fuel cost to run the units is included in the current rate so there is not additional cost to the facility for the natural gas that will be used to run the gas turbines alternative. The gas cost included here is not a cost that the facility will inccur; it is just included to make the estimate as conservative as possible.
(8) The rate of natural gas is based on the average natural gas pipeline import price from January 2016 to March 2020 obtained from the U.S. Energy Information Administration (EIA).

Total Annualized Costs (Capital & Annual)	**$7,716,029**

Appendix E
Lambert Compressor Station
NOx BACT Cost Analysis

CASE 2: SELECTIVE CATALYTIC REDUCTION (SCR)

Assumes the use of Solar Turbines with 15 PPM NOx (Baseline Case) and the addition of a SCR

Turbines Information

Mars 100 Turbine Power Output	hp	16,610
Mars 100 Turbine Power Output	MW	12.39
Hours of Operation	hr	8,760
Mars 100 NOx Emissions - 15 ppm w/82% SCR efficiency	**NOx - tpy**	**5.70**
Taurus 70 Turbine Power Output	hp	11,146
Taurus 70 Turbine Power Output	MW	8.31
Hours of Operation	hr	8,760
Taurus 70 NOx Emissions - 15 ppm w/82% SCR efficiency	**NOx - tpy**	**3.93**
Total NOx Emissions	**NOx - tpy**	**9.62**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF(1)	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Item		**Cost**
Direct and Indirect Capital Costs		
Installed Equipment Cost for Natural Gas-Driven Turbines		
T-70, 15 PPM Unit (2)	11,792 HP	$7,250,000
SCR Exhaust (3)		$2,916,667
M-100, 15 PPM Unit(4)	17,123 HP	$10,545,455
SCR Exhaust (5)	1.40 Factor	$4,083,333
Common to Both Units (6)		
Primary Fuel Skid and System Piping Installed:		$250,000
Fuel Heater Installed:		$100,000
C1000 Micro Turbine Installed:		$1,600,000
Micro Turbine Fuel Skid and System Piping Installed:		$150,000
MCC Equipment Inside of Station Installed:		$250,000
Total Capital Cost for Natural Gas-Drive Turbines	*(TCC)*	***$27,145,455***
Annualized Capital Costs	**TCC x CRF**	**$2,794,971**

(2) T-70 equipment cost based on vendor quote
(3) T-70 SCR Exhaust cost based on vendor quote
(4) M-100 equipment cost scaled up based on hp
(5) M-100 SCR Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		**Cost**
Annual Costs		
Fuel Costs		
Natural Gas Annual Fuel Cost (7)	*$/yr*	*$4,015,358*
Natural Gas Usage	MSCF/yr	$1,684,350
Natural Gas Rate (8)	$/MSCF	*$2.38*
Gas Turbine O&M for M100 and T70		
Turbine Parts Rebuild Exchange		$1,178,182
Inlet Air Filter		$49,091
Gas and Oil Coolers		$71,707
Solar Maintenance Plan		$268,773
Exhaust System Maitenance (SCR)		$386,882
Total O&M Cost for Gas Turbines		*$1,954,635*
Total Annual Costs	**TAC**	**$5,969,993**

(7) Since natural gas will be avaialable at the site for compression, the natural gas annual fuel cost to run the units is included in the current rate so there is not additional cost to the facility for the natural gas that will be used to run the gas turbines alternative. The gas cost included here is not a cost that the facility will inccur; it is just included to make the estimate as conservative as possible.
(8) The rate of natural gas is based on the average natural gas pipeline import price from January 2016 to March 2020 obtained from the U.S. Energy Information Administration (EIA).

Total Annualized Costs (Capital & Annual)	**$8,764,964**

Appendix E
Lambert Compressor Station
NOx BACT Cost Analysis

CASE 3: ULTRA LOW NOx (9 PPM) & SCR

Assumes the use of Solar Turbines with 9 PPM NOx (Baseline Case) and the addition of a SCR

Turbines Information

Mars 100 Turbine Power Output	hp	16,610
Mars 100 Turbine Power Output	MW	12.39
Hours of Operation	hr	8,760
Mars 100 NOx Emissions - 9 ppm w/70% SCR efficiency	**NOx - tpy**	**6.09**
Taurus 70 Turbine Power Output	hp	11,146
Taurus 70 Turbine Power Output	MW	8.31
Hours of Operation	hr	8,760
Taurus 70 NOx Emissions - 9 ppm w/70% SCR efficiency	**NOx - tpy**	**4.16**
Total NOx Emissions	**NOx - tpy**	**10.25**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF(1)	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Item		Cost
Direct and Indirect Capital Costs		
Installed Equipment Cost for Natural Gas-Driven Turbines		
T-70, 15 PPM Unit (2)	11,792 HP	$7,500,000
SCR Exhaust (3)		$2,500,000
M-100, 15 PPM Unit(4)	17,123 HP	$10,909,091
SCR Exhaust (5)	1.40 Factor	$3,500,000
Common to Both Units (6)		
Primary Fuel Skid and System Piping Installed:		$250,000
Fuel Heater Installed:		$100,000
C1000 Micro Turbine Installed:		$1,600,000
Micro Turbine Fuel Skid and System Piping Installed:		$150,000
MCC Equipment Inside of Station Installed:		$250,000
Total Capital Cost for Natural Gas-Drive Turbines	*(TCC)*	***$26,759,091***
Annualized Capital Costs	**TCC x CRF**	**$2,755,190**

(2) T-70 equipment cost based on vendor quote
(3) T-70 SCR Exhaust cost based on vendor quote
(4) M-100 equipment cost scaled up based on hp
(5) M-100 SCR Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		Cost
Annual Costs		
Fuel Costs		
Natural Gas Annual Fuel Cost (7)	*$/yr*	*$4,010,863*
Natural Gas Usage	MSCF/yr	$1,682,464
Natural Gas Rate (8)	$/MSCF	*$2.38*
Gas Turbine O&M for M100 and T70		
Turbine Parts Rebuild Exchange		$1,178,182
Inlet Air Filter		$49,091
Gas and Oil Coolers		$71,707
Solar Maintenance Plan		$268,773
Exhaust System Maitenance (SCR)		$349,017
Total O&M Cost for Gas Turbines		*$1,916,769*
Total Annual Costs	**TAC**	**$5,927,632**

(7) Since natural gas will be avaialable at the site for compression, the natural gas annual fuel cost to run the units is included in the current rate so there is not additional cost to the facility for the natural gas that will be used to run the gas turbines alternative. The gas cost included here is not a cost that the facility will inccur; it is just included to make the estimate as conservative as possible.
(8) The rate of natural gas is based on the average natural gas pipeline import price from January 2016 to March 2020 obtained from the U.S. Energy Information Administration (EIA).

Total Annualized Costs (Capital & Annual)	**$8,682,822**

Appendix E
Lambert Compressor Station
NOx BACT Cost Analysis

CASE 4: ELECTRIC TURBINES

Assumes the use of electric turbines

Turbines Information

Mars 100 Electric Equivalent	hp	16,000
Mars 100 Electric Equivalent	MW	11.93
Hours of Operation	hr	8,760
Mars 100 Electric Equivalent NOx Emissions	**NOx - tpy**	**0.00**
Taurus 70 Electric Equivalent	hp	11,000
Taurus 70 Electric Equivalent	MW	8.20
Hours of Operation	hr	8,760
Taurus 70 Electric Equivalent NOx Emissions	**NOx - tpy**	**0.00**
Total NOx Emissions	**NOx - tpy**	**0.00**

Cost Calculation Assumptions

Annual Interest Rate	%	6%
Equipment Life	yrs	15
Capital Recovery Factor, CRF	CRF	0.103

(1) Appendix B of EPA's New Source Review Workshop Manual (October 1990)

Item		Cost
Direct and Indirect Capital Costs		
Installed Equipment Cost for Electrical-Driven Turbines		
T-70 Electric Equivalent (2)	11,000 HP	$5,500,000
SCR Exhaust (3)		$0
M-100 Electric Equivalent(4)	16,000 HP	$8,000,000
SCR Exhaust (5)		$0
Common to Both Units (6)		
Primary Fuel Skid and System Piping Installed:		$0
Fuel Heater Installed:		$0
C1000 Micro Turbine Installed:		$0
Micro Turbine Fuel Skid and System Piping Installed:		$0
MCC Equipment Inside of Station Installed:		$500,000
Utility Substation, 28 kVA, 13.8 kV - MVP Purchased		$1,500,000
Total Capital Cost for Natural Gas-Drive Turbines	*(Direct TCC)*	***$15,500,000***
Annualized Equipment Cost	***Direct TCC x CRF***	***$1,595,923***

(2) T-70 electric equivalent equipment cost based on vendor quote
(3) T-70 SCR Exhaust cost based on vendor quote
(4) M-100 electric equivalent equipment cost scaled up based on hp
(5) M-100 SCR Exhaust cost scaled up based on similar systems
(6) Equipment common to both units cost was estimated based on experience with similar type of systems

Item		Cost
Lambert Substation Electric Cost		
Upgrade project		
Electric substation cost		$2,700,000
T-line construction		$550,000
Adders		$110,000
MEC Upgrades (Mecklenburg Electric Coop)		$5,000,000
SEC Upgrades (Southside Electric Coop)		$2,000,000
ODEC Upgrades (Old Dominion Electric Coop)		$5,000,000
New line project		
New line construction		$8,600,000
Adders		$1,720,000
Ring bus		$6,000,000
Sub-total		$31,680,000
Contingency (10%)		$3,168,000
Total Substation Electric Cost		***$34,848,000***
Annualized Substation Cost	***Substation Cost x CRF***	***$3,588,046***

Total Capital Cost	**TCC**	**$50,348,000**
Annualized Capital Costs	**TCC x CRF**	**$5,183,969**

Appendix E
Lambert Compressor Station
NOx BACT Cost Analysis

CASE 4: ELECTRIC TURBINES

Annual Costs		
Fuel Costs		
Electric Utility Payments		
Demand	MW	25
Monthly energy	kWh/month	18,000,000
Rate Schedule LGS-U (Mecklenburg Co-op, Chatham VA – Rate sheet provided below)		
Customer charge ($/month)		**$600.00**
	Energy ($/kWh)	**Demand ($/kW)**
Base distribution service rate	$0.00438	$2.90
Electricity supply service rate	$0.0185	$5.65
Subtotal ($/month)	**$411,840**	**$213,750**
Monthly Electric Utility Cost ($/month)	$/month	$626,190
Annual Electric Utility Cost ($/year)		***$7,514,280.00***
Electric Turbine O&M for 2 Turbines		
Electric Motor Rebuild Exchange		$294,545
Inlet Air Filter		$0
Gas and Oil Coolers		$67,031
Solar Maintenance Plan		$134,386
Exhaust System Maitenance (SCR)		$0
Total O&M Cost for Electric Turbines		*$495,962*
Total Annual Costs	**TAC**	**$8,010,242**

Total Annualized Costs (Capital & Annual)	**$13,194,211.69**

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MECKLENBURG ELECTRIC COOPERATIVE

SCHEDULE "LGS-U"
LARGE GENERAL SERVICE

AVAILABILITY
Service under this schedule is available to consumers for electric service in all territory served by the Cooperative, where the consumer takes service at one delivery point through one kilowatt-hour meter.

APPLICABILITY
This schedule is applicable to consumers whose annual kW demand averages 500 kW or more per month, or whose highest monthly kW demand exceeds 550 kW. Service under this schedule is subject to the established Terms and Conditions of the Cooperative. This schedule is not available for breakdown, standby, supplemental, self-generation, or resale service.

CHARACTER OF SERVICE
Standard service under this schedule shall be 60-Hertz alternating current, single-phase, or multi-phase where available, at Cooperative's standard secondary voltages. With the Cooperative's prior approval, service may be available at the Cooperative's standard primary distribution voltage.

MONTHLY RATE
III. Distribution Service:

Consumer Delivery Charge:		
All Consumers:		$ 600.00 per month
Demand Delivery Charge:		
All kW delivered	@	$ 2.90 per kW
Energy Delivery Charges:		
First 219 kWh per kW delivered	@	$0.01771 per kWh
Next 219 kWh per kW delivered	@	$0.01120 per kWh
All kWh over 438 kWh per kW delivered	@	$0.00438 per kWh

IV. Electricity Supply Service:

Demand Charge:		
All kW sold	@	$ 5.65 per kW
Energy Supply Charges:		
First 219 kWh per kW sold	@	$0.02011 per kWh
Next 219 kWh per kW sold	@	$0.01915 per kWh
All kWh over 438 kWh per kW sold	@	$0.01850 per kWh

All kilowatt-hours used are subject to adjustment for changes in cost of wholesale purchased power and fuel under Schedule K of the Cooperative's Terms and Conditions.

Renewable Generation Analysis for the Lambert Compressor Station

Appendix E
Lambert Compressor Station
Renewable Energy Analysis to Power Electric Compression Alternative

Compressor Station required demand (k=MW)	25	MW
Compressor Station Load factor	80%	
Required yearly energy (MWh)	175,200	MWh
Required daily energy (MWh)	480	MWh
Required solar capacity (MWdc)	113	MWdc
DC/AC ratio	1.45	
System size (MWac)	78	MWac
Daily energy produced (December)	480	MW/d
Battery size (MWac)	55	MWac
Energy produced in December (MWh)	14,880	MWh
Energy consumed in December (MWh)	14,880	MWh
Hours of battery storage required	5	hrs
Size of battery (MWh)	275	MWh
Cost of solar ($/W)[(1)]	$1.00	$/W
Cost of Lambert solar array	**$113,000,000**	
Land required per MWdc (Acre)[(2)]	6.0	acres
Acres required for Lambert solar array	678	acres
Cost of battery storage ($/kWh)[(3)]	$330	$/kWh
Cost of Lambert battery storage system	**$90,750,000**	
Batteries that can be placed in 1 acre	20	batteries
Acres required for Lambert battery array	13.75	acres
Lambert Substation Electric Transmission Costs[(4)]	**$34,848,000**	
Total cost of renewable project	**$238,598,000**	
Total land requirements	**692**	**acres**

Notes:
(1) Cost of solar is based on NREL study: https://www.nrel.gov/docs/fy19osti/72133.pdf
(2) Total solar farm footprint estimates are based on NextEra Energy development experience in mid-Atlantic region
(3) Cost of battery storage is based on NREL study: https://www.nrel.gov/docs/fy19osti/73222.pdf
(4) The details on electric transmission costs are provided in Appendix E, under the BACT Cost Analysis

APPENDIX F
EPA'S NAAQS:
Protection of Public Health & Welfare

EPA'S NATIONAL AMBIENT AIR QUALITY STANDARDS:
PROTECTION OF PUBLIC HEALTH & WELFARE

The National Ambient Air Quality Standards (NAAQS) program is central to the health and welfare protection provided by the Clean Air Act (CAA or Act). Section 108 of the Act directs the EPA Administrator to identify air pollutants that are present in ambient air due to emissions from "numerous or diverse mobile or stationary sources," that the Administrator finds "may reasonably be anticipated to endanger public health or welfare," and, for which the Administrator intends to establish air quality criteria. CAA §108(a)(1). These six listed pollutants – particulate matter (PM), photochemical oxidants, sulfur dioxide, oxides of nitrogen, carbon monoxide, and lead – are commonly called criteria pollutants. The Act directs EPA to prepare air quality criteria and set NAAQS for them.

Criteria for Setting NAAQS

1. The air quality criteria, which are now found in a document called an Integrated Science Assessment (ISA), must "accurately reflect the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare that may be expected from the presence of the pollutant in the ambient air, in varying quantities." CAA §108(a)(2). EPA defines ambient air as "that portion of the atmosphere, external to buildings, to which the general public has access." 40 C.F.R. § 50.1(e).

2. The Act does not define public health, but the United States Supreme Court has said that public health means protecting the health of the community or the public. *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 465-66 (2001).[1] Primary NAAQS must protect sensitive populations such as asthmatics and emphysematics. *Am. Lung Ass'n v. EPA*, 134 F.3d 388, 389 (D.C. Cir. 1998); *Lead Indus.*, 647 F.2d at 1152 (citing S. Rpt. No. 91-1196, at 10 (1970), reprinted in 1 S. Comm. on Pub. Works, 93d Cong., A Legislative History of the Clean Air Act Amendments of 1970, at 410 (1974) [hereinafter "S. Rpt."]). They need not, however, protect the most sensitive member of that population. S. Rpt. at 10.

3. Furthermore, primary NAAQS must include a margin of safety "to build a buffer to protect against uncertain and unknown dangers to human health." *Mississippi*, 744 F.3d at 1353. The Administrator has wide discretion with regard to the method he uses to

[1] Public welfare is defined by the Act as including "effects on soils, water, crops, vegetation, manmade materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and well-being, whether caused by transformation, conversion, or combination with other pollutants." CAA § 302(h).

establish that margin of safety. *Am. Trucking Assns v. EPA*, 283 F.3d 355, 368 (D.C. Cir. 2002); *Lead Indus.*, 457 F.2d at 1162.

4. Implementation costs are not a factor in the decision. *Whitman*, 531 U.S. at 471, 486. Nor is attainability. *Murray Energy Co. v. EPA*, 936 F.3d 597, 623-24 (D.C. Cir. 2019); *Am. Petroleum Inst. v. Costle*, 665 F.2d 1176, 1185 (D.C. Cir. 1981).

5. Although a NAAQS must provide the requisite protection of public health or welfare, it need not eliminate all risk, particularly in the case of a pollutant such as PM for which no threshold for adverse effects has been identified. *Whitman*, 531 U.S. at 494 (Breyer, J., concurring); *Mississippi v. EPA*, 744 F.3d 1334, 1351 (D.C. Cir. 2013). Primary NAAQS may protect against effects that are subclinical and not clearly harmful. *Lead Indus. Ass'n v, EPA*, 647 F.2d 1130, 1148, 1159 (D.C. Cir. 1980).[2]

Who sets the NAAQS? What is the process?

1. "[B]ased on" these criteria, the Administrator sets primary NAAQS that "are requisite to protect the public health" with an "adequate margin of safety" and secondary NAAQS that "protect the public welfare from any known or anticipated adverse effects" from the pollutant in ambient air. CAA § 109(b). EPA must review both the air quality criteria and the NAAQS at least every five years and make appropriate revisions to them. CAA § 109(d)(1). NAAQS are set by a rulemaking under the Administrative Procedures Act. 5 U.S.C. §500 et.seq.

2. Whether and how to revise a NAAQS is ultimately a policy judgment for EPA's Administrator. His preliminary judgment and the reasons for it are reflected in a proposed rule. Section 307(d) of the Act specifies procedural requirements for the rulemaking. These requirements include, *inter alia*, the establishment of a public docket that contains factual data, legal interpretations, and policy considerations that underlie the proposal and an opportunity for a public hearing on it. CAA § 307(d)(3), (5).

3. The Act directs the formation of a seven-member committee of scientists to advise the Administrator on the setting and reviewing of NAAQS. This Committee, which is known as the Clean Air Scientific Advisory Committee (CASAC), includes "at least one member of the National Academy of Sciences, one physician, and one person representing State air pollution control agencies." CAA § 109(d)(2)(A). CASAC's recommendations receive special weight under the Act. The preamble to any proposed or

[2] Little guidance is available concerning the type and magnitude of residual risk to public welfare that is acceptable

final NAAQS rule must summarize CASAC's "pertinent findings, recommendations, and findings" and if the rule "differs in any important respect from [CASAC's] recommendations [it] must provide an explanation of the reason's for such differences." CAA § 307(d)(3)(C). To the extent that these differences involve *scientific* judgments, the preamble must provide *scientific* reasons for the differences; if the differences involve *policy* judgment, the preamble may offer *policy* reasons for them. *Mississippi v. EPA*, 744 F.3d 1334, 1358 (D.C. Cir. 2013).

4. In addition to the advice he receives from CASAC when setting NAAQS, the Administrator also receives information and advice from EPA's professional staff. The staff prepares a document called a Policy Assessment (PA). PAs are intended "to help 'bridge the gap' between the Agency's scientific assessments . . . and the judgments required of the Administrator in determining whether it is appropriate to retain or revise the standards." Memorandum from Lisa Jackson, Adm'r, to Elizabeth Craig, Acting Assistant Adm'r for Air and Radiation, and Lek Kadeli, Acting Assistant Adm'r for Research and Dev., Attachment at 2 (May 21, 2009), *available at* https://www.epa.gov/naaqs/historical-information-naaqs-review-process. PAs identify "a range of policy options" for the Administrator to take at the conclusion of a NAAQS review." Health and Envtl. Impacts Div., Office of Air Quality Planning and Standards, EPA, EPA-452/R-16-005, Integrated Review Plan for the National Ambient Air Quality Standards for Particulate Matter 6-1 to 6-2 (2016), *available at* https://www.epa.gov/naaqs/particulate-matter-pm-standards-planning-documents-current-review (IRP).

5. The staff also commonly conducts and reports on quantitative assessments of exposures and health risks posed by the pollutant that is the subject of the review. These assessments estimate exposures and risks to public health and welfare associated with current and alternative NAAQS. IRP at 4-1. They may be reported in the PA or in a separate Exposure and Risk Assessment document. IRP at 4-10. CASAC and the public generally have an opportunity to review and comment on one or more drafts of each of these documents.

Regulation of PM

1. EPA began regulating PM through the NAAQS program in 1971. 36 Fed. Reg. 8186 (Apr. 30, 1971). The regulated form of PM was Total Suspended Particles and the NAAQS included an annual geometric mean primary standard of 75 $\mu g/m^3$, 24-hour primary and secondary NAAQS of 260 $\mu g/m^3$, and an annual secondary mean "guide" of 60 $\mu g/m^3$. 36 Fed Reg. at 8187.

2. Since that time, EPA has revised the PM NAAQS four times, resulting in standards that are both more focused and more stringent. *See* 78 Fed. Reg. 3086 (Jan. 15, 2013); 71 Fed. Reg. 61144(Oct. 17, 2006); 62 Fed. Reg. 38652 (July 18, 1997); 52 Fed. Reg. 24634 (July 1, 1987).

3. The current PM NAAQS include primary and secondary 24-hour average standards of 150 µg/m^3 PM_{10}, primary and secondary 24-hour average standards of 35 µg/m^3 $PM_{2.5}$, a primary annual standard of 12 µg/m^3 $PM_{2.5}$, and a secondary annual standard of 15 µg/m^3 $PM_{2.5}$. 50 C.F.R. §§ 50.6, 50.13 & 50.18.[3]

4. EPA has taken minority and low socioeconomic status into account in revising the PM NAAQS. For example, in 2013, EPA modified the form of the annual primary $PM_{2.5}$ NAAQS to address concerns about potential disproportionate impacts on "at-risk populations, including low-income populations as well as minority groups." 78 Fed Reg at 3127. Specifically, EPA eliminated a provision that allowed averaging of monitored $PM_{2.5}$ levels across an area for purposes of determining compliance with the annual $PM_{2.5}$ NAAQS. EPA took this action to protect people in at-risk population groups residing near monitors recording higher $PM_{2.5}$ levels from unrecognized exposure to $PM_{2.5}$ levels above the NAAQS. *Id*. EPA also considers people with pre-existing respiratory disease to be a sensitive, or "at-risk," population. *See* Health and Envtl. Impacts Div., Office of Air Quality Planning and Standards, EPA, EPA-452/R-20-002, Policy Assessment for the Review of the National Ambient Air Quality Standards for Particulate Matter 3-44 (2020), *available at* https://www.epa.gov/naaqs/particulate-matter-pm-standards-policy-assessments-current-review-0.

5. On April 14, 2020, EPA Administrator Wheeler proposed to retain these standards without revision. https://www.epa.gov/pm-pollution/proposal-retain-national-ambient-air-quality-standards-particulate-matter-pm. EPA will take public comment on this proposal once it is published in the *Federal Register*.

[3] Several earlier, less stringent PM NAAQS using a $PM_{2.5}$ indicator may continue to apply in areas where they have not been attained. 40 C.F.R. §§ 50.7 & 50.13.

APPENDIX G
Air Dispersion Modeling Report

AECOM

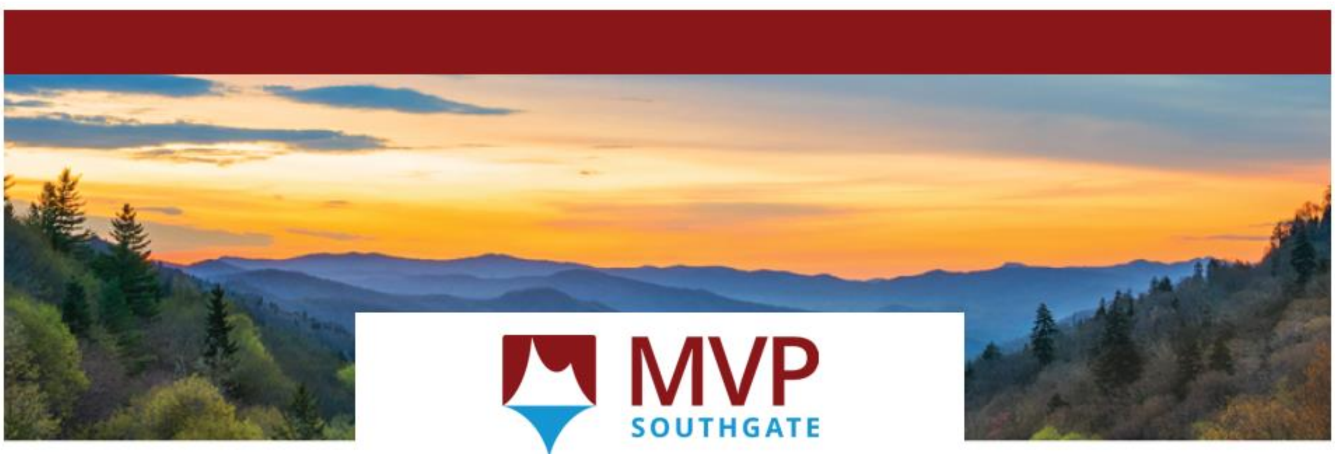
Environment

Prepared for:
Mountain Valley Pipeline, LLC
Lambert Compressor Station

Prepared by:
AECOM
Chelmsford, MA
60522108
June 2020

MVP Southgate Project: Lambert Compressor Station Pittsylvania County, Virginia

Air Quality Dispersion Modeling Report



AECOM Environment

Prepared for:
Mountain Valley Pipeline, LLC
Lambert Compressor Station

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Chelmsford, MA
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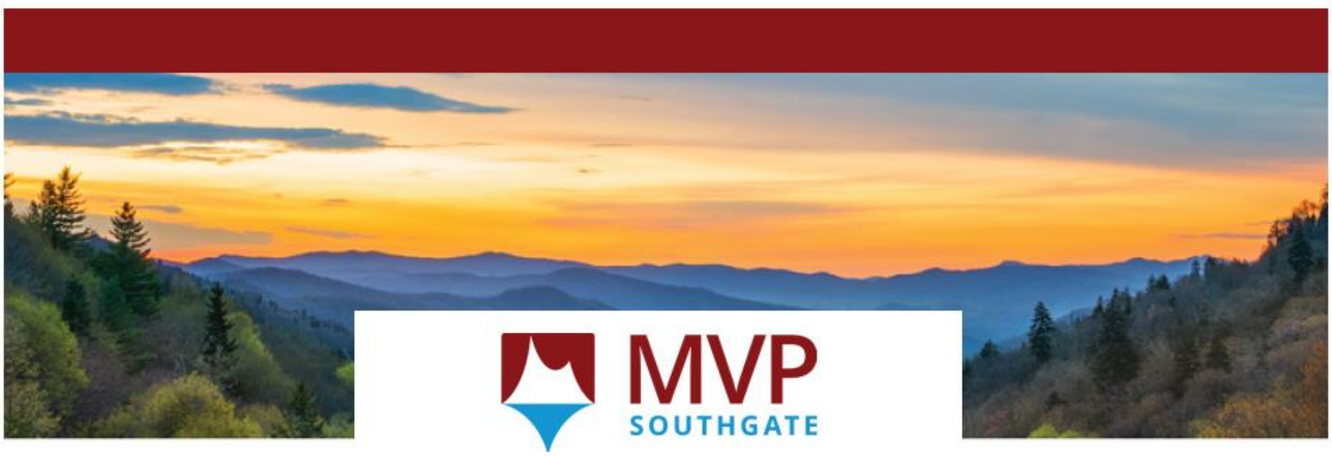
June 2020

MVP Southgate Project: Lambert Compressor Station Pittsylvania County, Virginia

Air Quality Dispersion Modeling Report



Prepared By: Jeffrey Connors

Reviewed By: Christopher Warren

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1.0 Introduction

1.1 Project Overview

Mountain Valley Pipeline, LLC (MVP) is seeking a Certificate of Public Convenience and Necessity (Certificate) from the Federal Energy Regulatory Commission (FERC) to construct approximately a 0.5-mile-long 24-inch-diameter pipeline and 74.6 miles of 24- and 16-inch-diameter natural gas pipeline to provide timely, cost-effective access to new natural gas supplies to meet the growing needs of natural gas users in the southeastern United States (US). The MVP Southgate Project will be located in Pittsylvania County, Virginia and Rockingham and Alamance Counties, North Carolina.

The proposed pipeline will interconnect with and receive gas from the existing Mountain Valley Pipeline near Chatham, Virginia, and receive gas from the East Tennessee Natural Gas, LLC mainline near Eden, North Carolina, and will deliver gas to connections with customers' existing facilities in Eden and Graham, North Carolina. The MVP Southgate Project is a stand-alone project from the Mountain Valley Pipeline and has an expected in-service date of 2nd half of 2021.As part of the MVP Southgate Project and in order to boost pressures on MVP's transmission pipeline system, MVP is proposing to construct and operate a new compressor station, the Lambert Compressor Station (LCS or the "Project"), near the beginning of the pipeline at milepost 0.0. The proposed Project will consist of two gas-driven turbines, one Solar Taurus 70 compressor turbine (11,146 hp) and one Solar Mars 100 compressor turbine (16,610 hp), which combined will provide 27,756 nominal hp of compression LCS will be a new natural gas transmission facility covered by Standard Industrial Classification (SIC) 4922. Ancillary project emission sources include five (5) Capstone microturbines rated at 200 kW each, one (1) 0.77 MMBtu/hr natural gas fired heater, two (2) 10,000 gallon produced fluid tanks, gas filter/separators, gas coolers, inlet air filters, exhaust silencers, and blowdown silencers.

The Lambert Compressor Station (Project or Lambert CS) is a proposed minor stationary source, as defined under Article 6 of the State Air Pollution Control Board's regulations regarding Permits for New and Modified Stationary Sources. As demonstrated in **Section 2** of this report, the proposed project is not subject to major source New Source Review (NSR) or Title V air permitting requirements.

1.2 Project Location

The Project will be located near the town of Chatham, Pittsylvania County, Virginia, which is part of the Central Virginia Interstate Air Quality Control Region (AQCR) in Virginia. Pittsylvania County is considered attainment or unclassifiable for all criteria pollutants. The coordinates of the proposed site are 647,900 meters east and 4,076,900 meters north in NAD83 datum and Universal Transverse Mercator (UTM) Zone 17 (36.827° North Latitude and 79.342° West Longitude). Maps of the site region are shown in **Figures 1-1** and **1-2**. A full scale plot plan showing the area of the proposed project is provided in **Appendix A**. It should be noted that Pittsylvania County, Virginia is in attainment with all National Ambient Air Quality Standards (NAAQS).

1.3 Overview of Methodology

The effects on ambient pollutant concentrations are estimated through the use of a dispersion model applied in conformance to applicable guidelines. The methodology applied for this analysis is based on policies and procedures contained in the US EPA Guideline on Air Quality Models (GAQM, 40 CFR Part 51, Appendix W) and direction from the VA DEQ's modeling staff.

Key elements of the air dispersion modeling analysis are as follows:

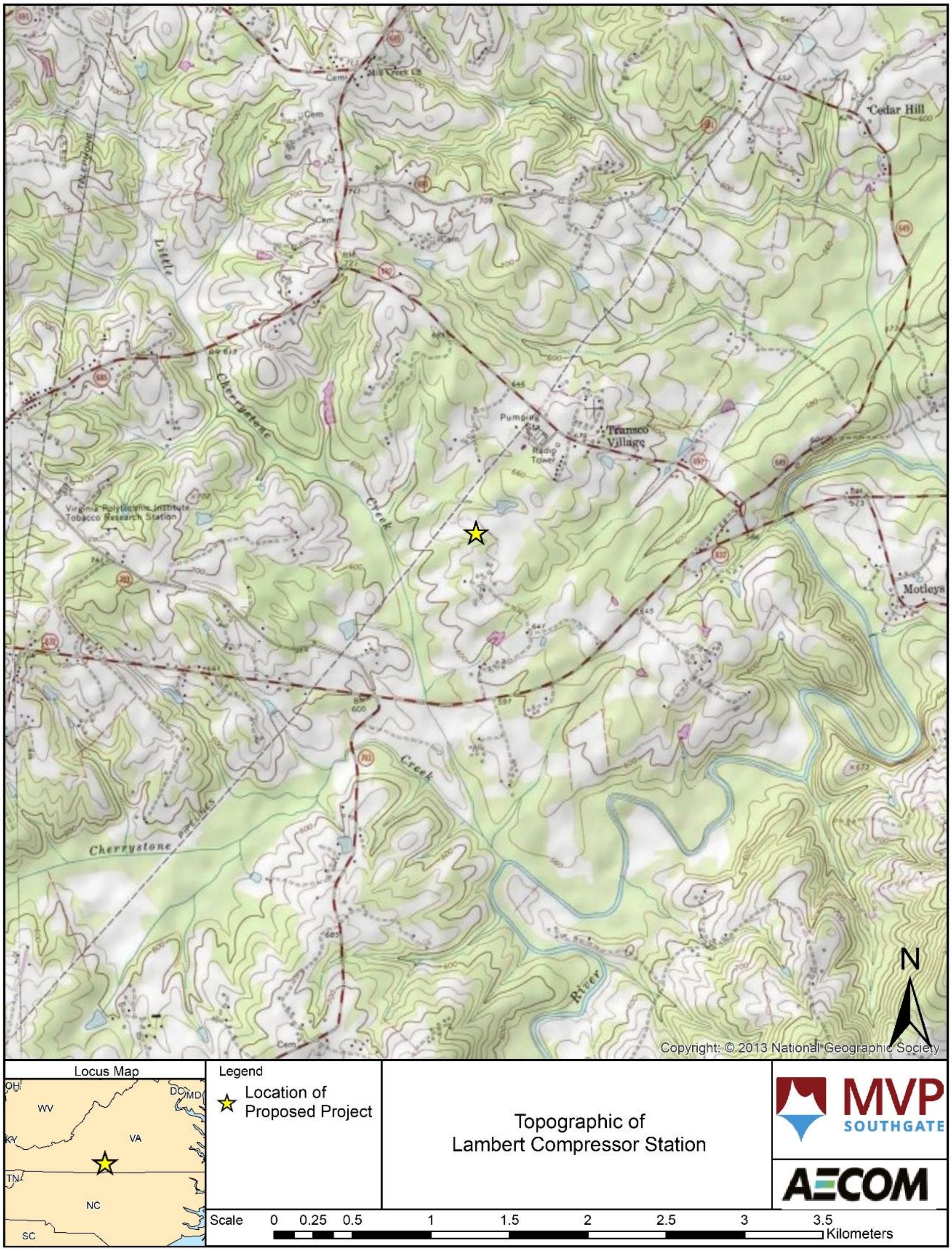
- Air quality modeling analysis for new project sources for NO_2, CO, $PM_{2.5}$, and PM_{10} for comparison to the NAAQS;

- Air quality modeling analyses for formaldehyde and hexane for new project sources for comparison to the VA DEQ Significant Ambient Air Concentrations (SAACs);
- Compile emissions information and stack parameters for the new Project sources;
- Use of the latest version of AERMOD (v19191) with the regulatory default options to estimate air quality impacts;
- Use of five (5) years of meteorological data provided by VA DEQ and processed using the most recent version of AERMET (v19191);
- Develop a comprehensive receptor grid to capture the maximum off-site impacts from maximum operations of the Project consistent with VA DEQ guidelines;
- Demonstrate that allowable emissions from the Project would not cause or contribute to air pollution exceeding any NAAQS for NO_2, CO, $PM_{2.5}$, and PM_{10}.

Section 2 contains a description of project emissions. **Section 3** present a detailed description of the modeling approach used in evaluating air quality impacts of the proposed Project including model selection criteria, good engineering practice stack height determination, refined modeling analyses, and ambient air quality compliance. **Section 4** presents the results of the analysis. **Appendix A** contains the site plan. **Appendix B** provides emission rates and stack parameters used for the modeling. **Appendix C** provides details on the meteorological data processing.

Figure 1-1 Location of Lambert Compressor Station (Aerial)

Figure 1-2 Location of Lambert Compressor Station (Topography)



2.0 Project Emissions

This section describes several aspects of the proposed Project that are relevant for the quality modeling analysis conducted in support of the air permit application including the facility components and modeled emissions.

2.1 Project Emissions and Source Characterization

Air quality modeling was conducted for NO_2, CO, $PM_{2.5}$, and PM_{10} for evaluation against applicable Federal air quality standards. Modeling was also conducted for emissions of formaldehyde and hexane for comparison against the VA DEQ SAACs. **Appendix B** contains stack parameters and modeled emission rates from all Project sources.

The Project included the following proposed sources in the analysis:

- One Solar Taurus 70, 11,146 hp natural gas fired turbine-driven compressor unit
- One Solar Mars 100, 16,610 hp natural gas fired turbine-driven compressor unit
- Five (5) Capstone Microturbines each rated at 200 kW;
- One 0.77 MMBtu/hr heater
- Two (2) 10,000 gallon produced fluids (hexane modeling only)

Sources of project-related emissions of hexane such as fugitive equipment leaks and equipment blowdowns were also included in the analysis. A complete inventory of all project-related sources of hexane is included in **Appendix B**.

2.1.1 Combustion Turbine Operating Scenarios

The project was evaluated for a range of combustion turbine scenarios including startup and shutdown, as well as the following load and ambient temperature scenarios: 50%, 75%, and 100% loads at <0˚F, 0˚F, 20˚F, 40˚F, 60˚F, 80˚F,and 100˚F ambient temperatures. The worst-case emissions and parameters were selected for each turbine for each load case, across the various ambient operating temperature scenarios in order to arrive at a composite worst-case emissions and parameter combination. The highest emission rate combined with the lowest stack exhaust flow and the lowest exit temperature for each load case was selected as the worst case. The resulting composite worst case 50%, 75%, and 100% load scenarios were evaluated against the applicable air quality standards.

The highest emission rate, along with the worst-case stack parameters, was also conservatively used for the annual averaging periods. **Appendix B** includes a summary of the results of the combustion turbine operating scenario analysis.

2.1.2 Combustion Turbine Startup/Shutdown Scenarios

The startup and shutdown scenarios for each turbine will last approximately ten minutes. During the ten minutes of startup or shutdown operation, the exhaust temperature and exit velocity was assumed to be equivalent to the composite worst case 50% load scenario. The emissions during startup or shutdown are based on lb/event data provided by the turbine manufacturer. Startup and shutdown scenarios were modeled for the 1-hour NO_2, 1-hour CO, 8-hour CO, and 24-hour $PM_{2.5}$ and PM_{10}, and 1-hour formaldehyde pollutant and averaging period combinations.

To characterize the startup and shutdown scenarios in the modeling analysis, the emissions and stack parameters for the startup and shutdown scenario needed to be incorporated into the normal operating emissions and stack parameters. The normal operating scenario resulting in the highest modeled concentration was chosen for the incorporation of startup and shutdown emissions and stack parameters. The stack parameters derived for startup and shutdown are presented in **Appendix B**.

2.1.3 Combustion Turbine Controls

Selective catalytic reduction (SCR) and oxidation catalyst will be the controls installed on the proposed turbines. The turbines will operate with the SCR and oxidation catalyst on at all times except during brief (< nominal 10 minute) startup and shutdown events and during cold ambient temperatures (>-20 ° F and < 0 ° F). These controls minimize emissions from the turbines and are expected to be operating at maximum efficiency throughout normal operations. In the unlikely event that the inlet air to the combustion turbine is below 0° F, the turbine manufacturer indicates that emissions can increase as a result of the need to ensure stable combustion. Such operation will not occur in most years. A review of the climatological data in the region of the project indicates that the ambient temperature will not drop below 0° F for more than 5 hours per year (additional discussion in provided in Section 3.9).

2.1.4 Modeling for Hexane

Two scenarios were evaluated in AERMOD related to hexane emissions:

- Facility-wide Emergency Shut Down (ESD) (actual emergency scenario)
- Facility-wide individual unit blowdown

The ESD test scenario includes simultaneous testing of all emergency vents across the facility will not result in any hexane emissions. These planned testing events are capped to limit the amount of gas released into the atmosphere. Even though emergency conditions are not typically required to be modeled, they are provided as a part of this study.

The site-wide individual unit blowdown scenario is a very conservative scenario that includes releases at each compression unit across the facility simultaneously. An individual unit blowdown represents a release that would coincide with a compressor startup or shutdown event. Both events assume simultaneous emissions of hexane from normal operations (e.g., compressor building fugitives) across the facility. Details of the stack characteristics during these events are included in **Appendix B**.

Both scenarios described above also conservatively include hexane emissions from planned pig launching/receiving events. This event involves launching a device known as a ‘pig’ through the pipeline to inspect and/or clean the pipeline. Pigging operations are expected to only occur once every five to seven years as part of normal inspection and equipment maintenance operations. Therefore, including these events in the ESD and unit blowdown scenarios is very conservative due to the very rare occurrence of pig launching and receiving. The emission points of hexane during a pig launch or receiving event consist of small valves on the launcher/receiver piping that are opened following an event in order to depressurize the piping. The stack characteristics that were used to represent both pig launchers and pig launch/receivers in the modeling analysis are included in **Appendix B**.

3.0 Modeling Methodology

3.1 Model Selection

The most recent version of EPA's AERMOD (US EPA 2019a) model (currently v19191) was used for predicting ambient impacts for each modeled compound.

Modeled design value concentrations of criteria pollutants were used to demonstrate that the Project, in addition to existing ambient concentrations of pollutants, will not cause a violation of any NAAQS. The values of the NAAQS are shown in **Table 3-1**. Maximum modeled concentrations of formaldehyde and hexane were compared with the significant ambient air concentrations identified in the Virginia Administrative Code (VAC), shown in **Table 3-2**.

3.2 Ambient Air Quality Standards

Table 3-1 presents a summary of the air quality standards (NAAQS) that were addressed for NO_2, PM_{10}, $PM_{2.5}$, and CO.

Table 3-1 National Ambient Air Quality Standards to be Evaluated

Pollutant	Averaging Period	NAAQS[a] ($\mu g/m^3$)
PM_{10}	24-Hour	150 [b,c]
	Annual	50 (REVOKED) [d, e]
$PM_{2.5}$	24-Hour	35 [f,g]
	Annual	12 [d,h]/15 [d,i]
NO_2	1-Hour	188 [j/k]
	Annual	100 [l]
CO	1-Hour	40,000 [m]
	8-Hour	10,000 [m]

a) Primary (public health) standard unless otherwise noted.
b) Expected number of days per calendar year, on average, with arithmetic time-averaged concentration above standard is equal to or less than one. For modeling analyses, compliance is evaluated by comparing the high, 6th-high modeled concentration over five years (plus an appropriate background concentration) to the NAAQS.
c) For PM_{10} 24-hour average NAAQS analysis, modeled concentration is the highest 6th highest concentration over 5 years of NWS data.
d) Based on 3-year average of the annual mean concentrations.
e) NAAQS REVOKED.
f) The 3-year average of the 98th percentile of 24-hour concentrations must not exceed standard. The NAAQS was revised effective December 18, 2006.
g) For the $PM_{2.5}$ 24-hour SIL analysis, modeled concentration is the highest of the 5-year averages of the maximum modeled 24-hour average $PM_{2.5}$ concentrations predicted each year at each receptor, based on 5 years of National Weather Service (NWS) data. Use of the SIL is subject to evaluation depending on the approach taken to address $PM_{2.5}$ secondary impacts. For the $PM_{2.5}$ 24-hour NAAQS analysis, the modeled concentration is the 98th percentile of the 5-year averages of the maximum modeled 24-hour average $PM_{2.5}$ concentrations (US EPA memorandum, dated March 20, 2014, from S. Page, "Guidance for $PM_{2.5}$ Permit Modeling").
h) The highest average of the modeled annual averages across 5 years of NWS meteorological data is compared to the $PM_{2.5}$ annual average SIL and AAQS. Use of the SIL is subject to evaluation depending on the approach taken to address $PM_{2.5}$ secondary impacts. (US EPA memorandum, dated March 20, 2014, from S. Page, "Guidance for $PM_{2.5}$ Permit Modeling").
i) Secondary standard.
j) The 3-year average of the 98th-percentile of the annual distribution of daily maximum 1-hour concentrations must not exceed standard.
k) For NO_2 1-hour NAAQS analysis, modeled concentration is the 98th percentile (H8H) of the annual distribution of daily maximum 1-hour concentrations averaged across 5 years of NWS data (US EPA memorandum, dated June 28, 2010, from T. Fox, "Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard").
l) No exceedances are allowed for annual averages to determine compliance with the NAAQS and to determine whether impacts are significant compared to the SIL.
m) One exceedance allowed per year.

Table 3-2 presents the SAAC concentrations of formaldehyde and hexane that were used to address air toxics in accordance with 9 VAC 5-60-330 2.

Table 3-2 VAC Significant Ambient Air Concentrations (SAAC)

Toxic Pollutant	Averaging Period	SAAC ($\mu g/m^3$)
Formaldehyde	1-Hour	62.5 [a]
	Annual	2.40 [b]
Hexane	1-Hour	8800 [c]
	Annual	352 [c]

a) The TLV-STEL for formaldehyde is 2.5 mg/m^3.
The significant 1-hour ambient air concentration for an air toxic, as described by 9 VAC 5-60-330 2, is 1/40 of the TLV-STEL.

b) The TLV-TWA® for formaldehyde is 1.2 mg/m^3.
The significant annual ambient air concentration for an air toxic, as described by 9 VAC 5-60-330 2, is 1/500 of the TLV-TWA®.

c) The TLV-TWA® for hexane is 176 mg/m^3.
The significant 1-hour and annual ambient air concentration for an air toxic, as described by 9 VAC 5-60-330 2, is 1/20 and 1/500 of the TLV- TWA® respectively.

3.3 Meteorological Data

Guidance for air quality modeling recommends the use of one year of onsite meteorological data or five years of representative off-site meteorological data. Since onsite data are not available for the Project, meteorological data available from the National Weather Service was used in this analysis. Surface meteorological data collected at the NWS station at the Lynchburg Regional Airport (LYH) and upper air data from the Piedmont Triad International Airport in Greensboro, NC (GSO) for the period 2012-2016; generated using the most recent version of AERMET (v19191) (US EPA 2019b) was acquired from VA DEQ and used in the modeling analyses.

US EPA guidance specifies a completeness requirement of 90% on a quarterly basis. The 90% requirement applies to each of the variables wind direction, wind speed, stability, and temperature and to the joint recovery of wind direction, wind speed, and stability. **Table 3-3** summarizes the quarterly joint data completeness by year which shows that for all quarters the data capture is above 90%. A wind rose of the extracted meteorological data provided by VA DEQ is presented in **Figure 3-1**.

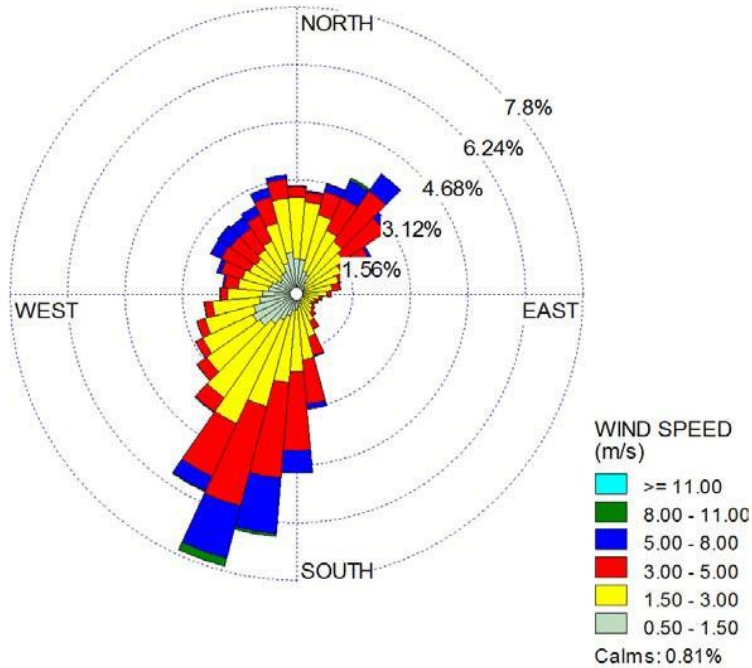
A detailed discussion of how the meteorological data was processed, including the AERSURFACE methodology for this dataset, completeness statistics, and a comparison of surface characteristics between the project site and the LYH meteorological data site, is provided in **Appendix C**.

Table 3-3 Meteorological Data Completeness Percentage by Quarter

Quarter[1]	2012	2013	2014	2015	2016
1	99.5	98.8	100	100	99.7
2	98.9	100	99.4	99.8	99.7
3	100	100	97.2	100	99.9
4	99.5	99.6	100	100	98.6

1. Quarter 1 = Jan, Feb, Mar;
Quarter 2 = April, May, June;
Quarter 3 = July, Aug, Sept; and
Quarter 4 = Oct, Nov, Dec

Figure 3-1 Wind Rose – Lynchburg Regional Airport (2012-2016)



3.4 Geographic Setting

3.4.1 Terrain

The Project is situated at approximately 670 feet elevation above mean sea level. Within about 20 km surrounding the Project, the terrain is characterized by rolling hills, with approximate elevations between 450 to 950 feet above mean sea level. The latest version of US EPA's AERMAP program (version 18081) was used to determine the ground elevation and hill scale heights for each modeled receptor, based on data obtained from the USGS National Elevation Database (NED). The NED data was obtained at a horizontal resolution of 1/3 arc-second (10-m) for use in this analysis. The NED data are distributed by USGS referenced to the North American Datum of 1983 (NAD 83).

3.4.2 Land Use Characteristics

The Project is located in rural Pittsylvania County, VA. The land use classifications within an area defined by a 3 km radius from the approximate center of the project site have been analyzed to determine the land use within this area. This determination was performed by analyzing the United States Geological Survey National Land Cover Database (USGS NLCD) 2011 data, where urban classifications were assumed to be category 23 (developed, medium intensity) and category 24 (developed, high intensity). As shown in **Table 3-4**, less than 1% of the land use within 3 km of the Project is classified as developed (medium or high intensity). Therefore, AERMOD was not used with the urban option.

Table 3-4 NLCD Land Use Classification Within 3-km

Grid Code	Grid Code Description	Acres	% Coverage
11	Open Water	13.15	0.19
21	Developed, Open Space	243.50	3.49

Grid Code	Grid Code Description	Acres	% Coverage
22	Developed, Low Intensity	45.35	0.65
23	Developed, Medium Intensity	1.34	0.02
24	Developed High Intensity	0.22	0.00
31	Barren Land (Rock/Sand/Clay)	0.00	0.00
41	Deciduous Forest	2372.74	34.00
42	Evergreen Forest	659.29	9.45
43	Mixed Forest	108.81	1.56
52	Shrub/Scrub	384.40	5.51
71	Grassland/Herbaceous	788.38	11.30
81	Pasture/Hay	2137.76	30.63
82	Cultivated Crops	171.46	2.46
90	Woody Wetlands	44.05	0.63
95	Emergent Herbaceous Wetlands	9.20	0.13
TOTAL		**6979.65**	**100**

3.5 Receptor Grids

A comprehensive Cartesian receptor grid extending out to approximately 20 kilometers (km) from the Project (centered on the LCS Property) was used in the analysis to assess the maximum ground-level concentration of each air contaminant.

The Cartesian receptor grid consists of the following receptor spacing, per VA DEQ modeling guidance:

- 25-meter spacing along the property boundary;
- 50-meter spacing from the property boundary extending to 1 km from the facility;
- 100-meter spacing from 1 km to 3 km from the facility;
- 250-meter spacing from 3 km to 10 km from the facility; and
- 500-meter spacing from 10 km to 20 km from the facility.

AERMAP was used to define ground elevations and hill scales for each receptor. The property boundary was used as the boundary to determine ambient air. The property boundary will be fenced, and no receptors will be placed within this boundary. If maximum modeled concentrations occur beyond 1 km from the facility, the maximum concentration will be resolved to a resolution of 50-m by adding additional 50-m spaced receptors to that portion of the receptor grid.

3.6 Building Downwash

The US EPA's Building Profile Input Program for PRIME (BPIPPRM), Version 04274, was used to determine the appropriate building dimensions to use to calculate the effects of downwash on the modeled sources in AERMOD. Building, structure, and locations relative to the modeled sources were obtained from engineering drawings of the planned facility and input into BPIPPRM. The stacks for all sources at the facility will not exceed the greater of the Good Engineering Practice (GEP) formula height calculated by BPIPPRM or 65 m (213 feet).

3.7 Background Concentrations

For the cumulative air quality modeling analysis, representative background concentrations were included for NO_2, $PM_{2.5}$, PM_{10}, CO, and O_3. Through consultation with VA DEQ, the Project has identified the most current nearby monitors that are representative (or conservatively representative) of Pittsylvania County. Selection of the background monitors was based on proximity and representativeness of the monitoring sites to the Project site. **Table 3-5** summarizes the air quality data from the monitoring stations that were used for background concentrations.

Table 3-5 Summary of Background Concentrations

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)	Station ID	Station Location	Distance from Project (km)	
NO_2	1-hour	68	37-067-0022	Winston-Salem, NC	111.8	SW
	Annual	13.2				
CO	1-hour	2,300	51-013-0020	Arlington County, VA	300.5	NE
	8-hour	1,380				
$PM_{2.5}$	24-hour	17	51-165-0003	Rockingham County, VA	189	NNE
	Annual	7.2	51-775-0011	Salem, VA	84	NW
PM_{10}	24-hour	31	51-035-0001	Carroll County, VA	139	W
O_3	8-hour	61 ppb	51-161-1004	Roanoke County, VA	69.8	NW

All of the sites listed in **Table 3-5** are located in more developed regions, while the Project site is located in a rural and less populated area. Based on population and population density data from the United States Census Bureau shown in **Table 3-6**, the area surrounding the Project (Pittsylvania County, VA) has both the lowest population and population per square mile of any of the monitoring sites (except for the one in Carroll County, VA) that were considered in the selection process. Although Carroll County, VA has less population than Pittsylvania County, VA (with similar population density), the monitor is located in the relatively populated area of Carroll County while the Project site is located in a rural area of Pittsylvania County. This comparison indicates that any of the monitoring sites chosen from those listed in **Table 3-6** will have conservatively high background concentrations relative to the less populated rural area of the Project site.

Table 3-7 presents emissions by county, obtained from the 2016 National Emissions Inventory (NEI)[1]. The counties in **Table 3-7** are the county where the project is located (Pittsylvania County) and the surrounding counties where air quality monitors are located. Emissions (except for PM_{10} which is described in **Section 3.7.4**) from Pittsylvania County are less than all other counties where air quality monitors are located. This demonstrates that any air quality monitoring data (other than PM_{10}) used from these surrounding counties would be inherently conservative as a representation of background ambient air quality in Pittsylvania County since Pittsylvania has comparatively lower emissions than these other counties. Further discussions on the selection of the monitoring sites are provided in sections **3.7.1** through **3.7.5**.

[1] ftp://newftp.epa.gov/Air/emismod/2016/

Table 3-6 Population Data for Background Monitors

Monitor Station Location	Station ID	County	County Population[1]	Population per Square Mile[2]
Project Site	-	Pittsylvania County, VA	60,949	65.5
Winston-Salem, NC	37-067-0022	Forsyth, NC	379,099	859.2
Arlington County, VA	51-013-0020	Arlington County, VA	237,521	7,993.6
Rockingham County, VA	51-165-0003	Rockingham County, VA	81,244	89.9
Carroll County, VA	51-035-0001	Carroll County, VA	29,636	63.3
Salem, VA Roanoke County, VA	51-775-0011 51-161-1004	Roanoke County, VA	94,073	368.7
Henrico County, VA	51-087-0014	Henrico County, VA	329,26	1,313.4

1 – Data from July 1, 2018
2 – Data from 2010
Source of data: http://www.census.gov/quickfacts

Table 3-7 2016 Emissions from Pittsylvania County and Surrounding Counties with Air Quality Monitors as published in the US EPA National Emissions Inventory

Monitor Station Location	Station ID	County	2016 NEI Emissions for the Entire County (tons)			
			NO_X	CO	$PM_{2.5}$	PM_{10}
(Project Site)	-	Pittsylvania County, VA	1,915	10,213	1,475	7,928
Winston-Salem, NC	37-067-0022	Forsyth, NC	5,517	38,557	1,232	3,230
Arlington County, VA	51-013-0020	Arlington County, VA	4,010	16,088	539	1,940
Rockingham County, VA	51-165-0003	Rockingham County, VA	3,069	46,031	4,573	12,556
Carroll County, VA	51-035-0001	Carroll County, VA	1,456	7,062	752	4,006
Salem, VA Roanoke County, VA	51-775-0011 51-161-1004	Roanoke County, VA	2,043	13,377	732	2,505
Henrico County, VA	51-087-0014	Henrico County, VA	6,234	37,339	1,143	3,156

3.7.1 Background NO_2 Monitor

There are two NO_2 monitors within 120 km distance from the project site. The nearest NO_2 monitor to the project site is located in Roanoke County, VA and located approximately 69.8 km to the northwest of the project site. The next closest monitor is located approximately 111.8 km from the Project near Winston-Salem, Forsyth County, NC. Winston-Salem, Forsyth County, NC has more than double the NO_2 emissions and has much higher population than Roanoke County. Therefore, the NO_2 data from the Winston-Salem site was selected as a conservatively representative and appropriate background monitor to represent background concentrations in Pittsylvania County.

To characterize 1-hour background NO_2 values, data for the most recent three-year average of the 98th percentile 1-hour monitor values by season and hour-of-day was obtained from VA DEQ. The use of variable background 1-hour NO_2 monitor data conforms with US EPA guidance (US EPA 2011). The US EPA guidance suggests that the season and hour-of-day combination be based on the 3rd highest values to represent the 98th percentile. The resultant matrix of ninety-six (96) season and hour-of-day 1-hour NO_2 monitor values were used in AERMOD for the 1-hour NO_2 modeling analyses. The season and hour-of-day NO_2 monitor values are summarized in **Table 3-8**.

Table 3-8 1-hour NO_2 Variable Season and Hour of Day Background Monitor Values (μg/m³)

Winter	**Hour of Day:**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	NO_2 (μg/m³):	52.64	56.9	54.9	52.51	51.14	52.26	55.96	57.4	52.08	46.81	43.55	32.34
	Hour of Day:	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
	NO_2 (μg/m³):	24.5	22.81	25.63	29.2	29.08	41.49	62.67	60.91	57.53	61.41	55.15	54.71
Spring	**Hour of Day:**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	NO_2 (μg/m³):	33.59	37.41	32.65	35.59	41.23	48.88	45.75	47.31	31.9	24.5	17.42	14.16
	Hour of Day:	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
	NO_2 (μg/m³):	12.22	11.15	12.41	13.91	13.91	18.67	24.38	38.92	42.3	36.72	38.1	34.4
Summer	**Hour of Day:**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	NO_2 (μg/m³):	29.01	33.78	29.33	25.69	27.89	29.2	27.95	26.63	27.7	18.3	12.35	9.84
	Hour of Day:	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
	NO_2 (μg/m³):	8.33	7.77	7.9	12.85	12.85	14.1	16.04	23	29.27	32.34	32.77	31.77
Fall	**Hour of Day:**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
	NO_2 (μg/m³):	44.93	44.68	43.05	38.98	39.54	42.24	46.5	44.49	39.54	35.47	23.37	15.1
	Hour of Day:	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
	NO_2 (μg/m³):	16.54	15.92	15.48	21.81	30.77	44.56	62.54	66.93	60.79	55.21	50.82	49.01

3.7.2 Background CO Monitor

Since the monitor in Arlington County, VA has the highest design value for CO in the state of Virginia and Arlington County has both higher CO emissions and population than Pittsylvania County, the monitor in Arlington County was selected as the most conservatively representative and appropriate for CO background concentrations.

3.7.3 Background $PM_{2.5}$ Monitor

The nearest $PM_{2.5}$ monitor to the project site is located in Roanoke County, approximately 84 km to the northwest of the project site. The population of Roanoke County is more than that of Pittsylvania County but the $PM_{2.5}$ emissions of Roanoke County are much smaller than those of Pittsylvania County. The monitor in Rockingham County is 189 km away from the project site but since the $PM_{2.5}$ emissions of Rockingham County are more than those of Pittsylvania County (both counties have significant amount of agriculture PM emissions), the higher value of the monitors in Roanoke County and Rockingham County was chosen. The 24-hour $PM_{2.5}$ background concentration was determined to be 17 μg/m³ from the Rockingham County monitor and the annual $PM_{2.5}$ background concentration was determined to be 7.2 μg/m³ from the Roanoke County monitor.

3.7.4 Background PM_{10} Monitor

Rockingham County has both higher PM_{10} emissions and population density than Pittsylvania County. The monitor in Rockingham County is potentially a good candidate for background PM_{10} concentration for the project site. However, for a more conservative approach, the highest recent PM_{10} High-second-high value (31 μg/m³) across the entire state of Virginia in recent years is proposed. The monitor that reported this highest value is located in Carroll County.

3.7.5 Background O_3 Monitor

There are four close monitors in the nearby counties: Rockingham, Caswell, Person and Roanoke. Rockingham County has the highest design value at 65 ppb while the other three counties have the same reading at 61 ppb. Since Rockingham County has significantly higher NOx emissions than

Pittsylvania County while the NOx emissions from Roanoke County and Pittsylvania County are similar, the Roanoke County monitor was chosen as the more representative O_3 monitor.

3.8 NO_2 Modeling Approach

The modeling was conducted using the USEPA default Ambient Ratio Method 2 (ARM2) to account for the formation of NO_2 from the modeled emissions of NO_X. ARM2 was applied in AERMOD using the default range of NO_2 to NO_X ratios (50% to 90%). When ARM2 is used, AERMOD assigns the appropriate ratio for each hour and receptor based on the total modeled concentration of NO_X. It should be noted that the various load and startup/shutdown scenarios described in **Section 2** were run separately when utilizing ARM2.

3.9 Intermittent Emissions

US EPA has published guidance (US EPA 2011) for air quality modeling analyses for demonstrating compliance with the 1-hour NO_2 NAAQS. The guidance provides clarification of how intermittent emissions scenarios should be treated for a modeling analyses of 1-hour NO_2. Specifically, page 8 of the US EPA 2011 guidance states the following:

> *"…the intermittent nature of the actual emissions associated with emergency generators and startup/shutdown in many cases, when coupled with the probabilistic form of the standard, could result in modeled impacts being significantly higher than actual impacts would realistically be expected to be for these emissions scenarios. The potential overestimation in these cases results from the implicit assumption that worst-case emissions will coincide with worst-case meteorological conditions based on the specific hours on specific days of each of the years associated with the modeled design value based on the form of the hourly standard. In fact, the probabilistic form of the standard is explicitly intended to provide a more stable metric for characterizing ambient air quality levels by mitigating the impact that outliers in the distribution might have on the design value."*

> *"Given the implications of the probabilistic form of the 1-hour NO2 NAAQS discussed above, we are concerned that assuming continuous operations for intermittent emissions would effectively impose an additional level of stringency beyond that intended by the level of the standard itself. As a result, we feel that it would be inappropriate to implement the 1-hour NO2 standard in such a manner and recommend that compliance demonstrations for the 1-hour NO2 NAAQS be based on emissions scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations."*

Based on this guidance, the emissions scenario associated with operations of the combustion turbines at ambient temperatures less than 0° F are intermittent emissions scenarios that are expected to occur in only very rare cases and as such would not contribute significantly to the annual distribution of daily maximum 1-hour concentrations of NO_2. A five-year period between 2012 and 2016 at two nearby Automated Surface Observation System (ASOS) sites, the Lynchburg Regional Airport (KLYH, WBAN 13733) and the Danville Regional Airport (KDAN, WBAN 13728), were analyzed for temperatures below 0° F. The ambient temperature was below 0° F for a total of 5 hours at KLYH, and 0 hours at KDAN. All of the hours below 0° F observed at KLYH occurred during the year 2015. Temperatures below 0° F were not recorded during the remaining four years of meteorological data. Since the 1-hour NO_2 NAAQS is based on the 98^{th} percentile (i.e., the eighth highest annually) of the daily maximum concentrations, the frequency of occurrence of this scenario is not high enough to have a significant effect on the design value of the standard itself. Therefore, the below 0° F case for the turbines was not considered in the 1-hour NO_2 NAAQS modeling analysis.

3.10 Secondary Impacts

In April 2019, US EPA released a guidance memorandum[2] (US EPA 2019c) that described how modeled emission rates of precursors (MERPs) could be calculated as part of a Tier I secondary $PM_{2.5}$ formation analysis to assess a project's emissions of precursor compounds as they would relate to $PM_{2.5}$ "critical air quality thresholds". The Project utilizes the air quality modeling results included in the MERPs guidance to assess the projects impacts on secondary $PM_{2.5}$ formation as described in the paragraphs below.

In order to characterize expected maximum modeled impacts of secondary $PM_{2.5}$ from the proposed Project, model results from the US EPA hypothetical source that is closest to the project location was considered. Specifically, model results from US EPA Source 9 located in Dinwiddie County, VA was considered.

3.10.1 $PM_{2.5}$ Formation

$PM_{2.5}$ is emitted directly from the Project emissions sources and formed in the atmosphere from Project $PM_{2.5}$ precursor emissions (NO_X and SO_2). Therefore, to account for the total air quality impact of $PM_{2.5}$, the modeled concentrations of primary $PM_{2.5}$ should be summed with a conservative concentration representative of $PM_{2.5}$ formed from Project $PM_{2.5}$ precursor emissions. Appropriate secondary $PM_{2.5}$ concentrations were determined based on the project emissions and the air quality modeling results included in the MERPs guidance.

For the 24-hour averaging period, the $PM_{2.5}$ concentrations are based on the highest daily 24-hour average concentration from a hypothetical NO_X source and a hypothetical SO_2 source that were identified from multiple model simulation results contained in the MERPs guidance. For NO_X, the Eastern US (EUS) hypothetical source located at Dinwiddie, Virginia (Source #9) with a surface release (L), annual NO_X emissions of 500 tons per year (tpy), and a maximum concentration of 0.137 $\mu g/m^3$ was used. Therefore, the estimated 24-hour secondary $PM_{2.5}$ concentration from the Project's NO_X emissions was determined as follows:

$$12.00 \text{ tpy } NO_X \text{ from Project PTE} / 500 \text{ tpy } NO_X \times 0.137\ \mu g/m3 = 0.0033\ \mu g/m^3$$

For SO_2, the EUS hypothetical source located at Dinwiddie, Virginia (Source #9) with a surface release (L), annual SO_2 emissions of 500 tpy, and a maximum concentration of 0.601 $\mu g/m^3$ was used. Therefore, the estimated 24-hour secondary $PM_{2.5}$ concentration from the Project's SO_2 emissions was determined as follows:

$$5.39 \text{ tpy } SO_2 \text{ from Project PTE} / 500 \text{ tpy } SO_2 \times 0.601\ \mu g/m3 = 0.0065\ \mu g/m^3$$

As a result, the estimated total concentration of 24-hour secondary $PM_{2.5}$ due to NO_X and SO_2 emissions would be 0.0098 $\mu g/m^3$. This concentration will be combined with the final 24-hour $PM_{2.5}$ modeled concentration from AERMOD to estimate the total $PM_{2.5}$ concentration.

For the annual averaging period, the $PM_{2.5}$ concentrations are based on the highest annual average concentration from a hypothetical NO_X source and a hypothetical SO_2 source that were identified from multiple model simulation results contained in the MERPs guidance. For NO_X, the EUS hypothetical source located at Dinwiddie, Virginia (Source #9) with a surface release (L), annual NO_X emissions of 500 tpy, and a maximum concentration of 0.005153 $\mu g/m^3$ was used. Therefore, the estimated concentration of the annual secondary $PM_{2.5}$ formation from the Project's NO_X emissions was determined as follows:

[2] https://www3.epa.gov/ttn/scram/guidance/guide/EPA454_R_16_006.pdf

12.00 tpy NO_X from Project PTE / 500 tpy NO_X) × 0.005153 µg/m³ = 0.000124 µg/m³

For SO_2, the EUS hypothetical source located at Dinwiddie, Virginia (Source #9) with a surface release (L), annual SO_2 emissions of 500 tpy, and a maximum concentration of 0.01433 µg/m³ was used. Therefore, the estimated concentration of the annual secondary $PM_{2.5}$ formation from the Project's SO_2 emissions was determined as follows:

5.39 tpy SO_2 from Project PTE / 500 tpy SO_2) × 0.0143 µg/m³ = 0.00015 µg/m³

As a result, the estimated total concentration of annual secondary $PM_{2.5}$ due to NO_X and SO_2 emissions would be 0.00027 µg/m³. This concentration was combined with the final annual $PM_{2.5}$ modeled concentration from AERMOD to estimate the total $PM_{2.5}$ concentration.

Please note, secondary $PM_{2.5}$ concentrations from the Transco Station 165/166 source was also included in the cumulative modeling impact assessment. The 24-hour and annual average $PM_{2.5}$ secondary concentrations were based on data obtained from the application submitted to VA DEQ in December 2019. Specifically, the values from Transco Station 165/166 are 0.16705 and 0.00605 µg/m³ respectively for the 24-hour and annual averaging periods. The secondary $PM_{2.5}$ concentrations from other existing background sources would already be included as part of the ambient background concentrations used to determine compliance with the NAAQS.

3.10.2 Ozone Formation

The Project is a source of ozone precursor emissions (NO_X and VOC). An assessment of air quality concentrations for ozone was conducted based on the Project's emission rates of ozone precursors and the air quality modeling results included in the MERPs guidance.

The estimated Project ozone concentrations are based on the highest daily maximum 8-hour ozone concentration from a hypothetical NO_X source and a hypothetical VOC source that were identified from multiple model simulation results contained in the MERPs guidance. For NO_X, the EUS hypothetical source located at Dinwiddie, Virginia (Source #9) with a surface release (L), annual NO_X emissions of 500 tpy, and a maximum concentration of 2.00 ppb was used. Therefore, the estimated ozone concentration from the Project's NO_X emissions was determined as follows:

12.00 tpy NO_X from Project PTE / 500 tpy NO_X MERP) × 2.00 ppb = 0.048 ppb

For VOC, the EUS hypothetical source located at Dinwiddie, Virginia (Source #9) with a surface release (L), annual VOC emissions of 500 tpy, and a maximum concentration of 0.064 ppb was used. Therefore, the estimated ozone concentration from the Project's VOC emissions was determined as follows:

2.48 tpy VOC from Project PTE / 500 tpy VOC MERP) × 0.064 ppb = 0.0003 ppb

The monitored ozone design concentration for the area is approximately 61 ppb. The addition of the Project's estimated NO_X and VOC concentrations to the monitored design concentration equals 61.05 ppb (0.048 ppb + 0.0003 ppb + 61 ppb), which is well below the 8-hour ozone NAAQS of 70 ppb. It is important to note that this approach is highly conservative because it adds a daily maximum 8-hour ozone concentration to a design value. The Project's actual modeled impact on the design value (4th highest ozone concentration averaged over three years) is likely to be less than the result obtained using this approach.

3.11 Offsite Source Inventory

The Project has consulted with VA DEQ to develop an inventory of nearby sources to include in the NAAQS analysis. **Table 3-9** provides a list of facilities included in the cumulative modeling. The complete set of model inputs is provided with the electronic modeling files.

Table 3-9 Facilities Included in the Cumulative Modeling

Site Name	City/County	State	$PM_{2.5}$	PM_{10}	NO_2	CO
Arkema Inc	Pittsylvania County	VA			X	X
Columbia Forest Products	Pittsylvania County	VA	X	X	X	X
Dairy Energy Incorporated	Pittsylvania County	VA			X	X
Dominion - Pittsylvania Power Station	Pittsylvania County	VA	X	X	X	X
Eastern Panel Mfg Inc	Pittsylvania County	VA		X		
Elkay Wood Product Company	Pittsylvania County	VA		X		
IKEA Industry Danville LLC	Pittsylvania County	VA		X		
Intertape Polymer Corporation	Pittsylvania County	VA	X			
Owens-Brockway Glass Container Inc - Ringgold	Pittsylvania County	VA	X	X	X	
Transco Station 165/166	Pittsylvania County	VA	X	X	X	X
Dominion - Altavista Power Station	Campbell County	VA	X	X	X	X
Georgia-Pacific Wood Products LLC	Campbell County	VA	X	X	X	X
Blue Ridge Fiberboard Inc	Danville City	VA	X	X	X	X
Goodyear Tire and Rubber Company Danville	Danville City	VA	X	X	X	
JTI Leaf Services (US) LLC	Danville City	VA	X	X		
Unilin North America LLC	Danville City	VA	X	X		
Wrenn-Yeatts Inc	Danville City	VA	X	X		
Franklin County - Sanitary Landfill	Franklin County	VA		X		
Huber Engineered Woods, LLC	Halifax County	VA	X	X	X	X
NOVEC Energy Production Halifax County Biomass	Halifax County	VA		X	X	X
Piedmont Asphalt LLC - 30029	Halifax County	VA		X	X	
Southern Finishing	Martinsville City	VA	X	X		
Virginia Mirror Company Inc	Martinsville City	VA	X	X		
CertainTeed Roxboro Wallboard Facility	Person County	NC	X	X	X	X
Duke Energy Roxboro Steam Electric Plant	Person County	NC	X	X	X	X
Note: not all Facilities listed were included when modeling each criteria pollutant. "X" in the table indicates the Facility **was** included for that specific pollutant.						

4.0 Modeling Results

Four (4) criteria pollutants, including NO_2, $PM_{2.5}$, PM_{10} and CO, and two (2) air toxic pollutants, formaldehyde and hexane, have been modeled. The background concentrations (described in **Section 3.7**) and nearby offsite sources (described in **Section 3.11**) have been combined with the appropriate model design values, using the sum of these values for comparison to the NAAQS. Maximum modeled concentrations of formaldehyde and hexane have been compared directly to the significant ambient air concentrations. **Appendix B** contains the modeling inputs for the criteria pollutant and toxics modeling.

4.1 Load Analysis Results

The facility was modeled for different worst-case turbine load scenarios (see **Section 2**). The results of the turbine load analysis are provided in **Table 4-1**. The worst-case scenario for each pollutant and averaging period was used for blending in the subsequent startup/shutdown NAAQS analyses. Receptors were included on Transco Station 165/166 property when determining the worst-case load.

Table 4-1 Load Analysis Results

Load Scenario	Maximum Modeled Concentration by Pollutant and Averaging Period (μg/m³)								
	NO_2 (Tier 1)[1]		CO		$PM_{2.5}$		PM_{10}	Formaldehyde	
	1-hr	Annual	1-hr	8-hr	24-hr	Annual	24-hr	1-hr	Annual
All100	**1.286**	**0.201**	**3.208**	**1.645**	**0.2900**	**0.0408**	0.428	0.053	**0.00129**
All75	1.148	0.168	2.860	1.382	0.2768	0.0406	**0.458**	**0.060**	0.00126
All50	1.263	0.193	3.003	1.633	0.2829	0.0402	0.429	0.050	0.00126

[1] The < 0° F scenario was not considered for the 1-hour averaging period because of the intermittent source exemption. The annual averaging period did consider the < 0° F scenario.
[2] Cells highlighted in blue represent the worst-case scenario for a particular pollutant and averaging period.

4.2 NAAQS Analysis Results

A cumulative modeling analysis was conducted for 1-hour and annual NO_2, 1-hour and 8-hour CO, 24-hour and annual $PM_{2.5}$, and 24-hour PM_{10}. Nearby offsite sources have been included in the cumulative modeling analysis, as explained in **Section 3.11**. Background concentrations (**Section 3.7**) and secondary impacts (**Section 3.10.1**) were also combined with the modeled design value concentrations before comparison to the NAAQS.

The results of the NAAQS analysis are provided in **Table 4-2** below. As shown in **Table 4-2**, the NAAQS are not exceeded for any compound for any of the modeled scenarios. This indicates that the proposed project will not cause or contribute to exceedances of the 1-hour or annual NO_2, the 1-hour or 8-hour CO, the 24-hour or annual $PM_{2.5}$, or the 24-hour PM_{10} NAAQS, therefore the proposed project will not adversely impact the public welfare.

In addition, **Table 4-3** shows the modeled design concentrations from just the Project alone. The results presented in **Table 4-3** indicate the Project has a relatively small overall impact relative to the NAAQS and the total modeled concentrations presented in **Table 4-2**. The modeled design concentrations from the Project alone (as shown in **Table 4-3**), are less than 5% of the NAAQS for all pollutants and averaging periods except 1-hour NO_2, which is less than 10% of the NAAQS. **Table 4-3** also shows that $PM_{2.5}$ concentration for the Project Alone is 2.3% and 1.2% of the NAAQS respectively for the 24-hour and annul averaging periods.

The NAAQS modeling was performed using two sets of receptor grids/source combinations: (1) exclusion of receptors within Transco Station 165/166's ambient boundary with all NAAQS sources and (2) exclusion of Transco Station 165/166's sources and receptors included within their ambient boundary. The results presented in **Tables 4-2** and **4-3** are the highest of these receptor/source combination runs, which was always the full set of NAAQS sources (including Transco Station 165/166) without receptors within their ambient boundary.

Table 4-2 NAAQS Analysis Results (All Sources)

Pollutant	Averaging Period	Load Scenario	Background Concentration (µg/m³)	Secondary Impacts[1] (µg/m³)	Model Concentration (µg/m³)	NAAQS (µg/m³)	Cumulative Impact Analysis[2] Concentration (µg/m³)
NO_2	1-hour	50% Load	Variable[3]	-	178.8	188	178.8
		75% Load		-	178.8		178.8
		100% Load		-	178.8		178.8
		Startup (blended with 100% load)		-	178.8		178.8
		Shutdown (blended with 100% load)		-	178.8		178.8
	Annual	50% Load	13.2	-	21.8	100	35.0
		75% Load		-	21.8		35.0
		100% Load		-	21.8		35.0
CO	1-hour	50% Load	2300	-	2151	40,000	4451
		75% Load		-	2151		4451
		100% Load		-	2151		4451
		Startup (blended with 100% load)		-	2151		4451
		Shutdown (blended with 100% load)		-	2151		4451
	8-hour	50% Load	1380	-	1106	10,000	2486
		75% Load		-	1106		2486
		100% Load		-	1106		2486
		Startup (blended with 100% load)		-	1106		2486
		Shutdown (blended with 100% load)		-	1106		2486
$PM_{2.5}$	24-hour	50% Load	17	0.17685	5.8	35	23.0
		75% Load			5.8		23.0
		100% Load			5.8		23.0
		Startup (blended with 75% load)			5.8		23.0
		Shutdown (blended with 75% load)			5.8		23.0
	Annual	50% Load	7.2	0.00632	1.0	12	8.2
		75% Load			1.0		8.2
		100% Load			1.0		8.2
PM_{10}	24-hour	50% Load	31	-	9.1	150	40.1
		75% Load		-	9.1		40.1
		100% Load		-	9.1		40.1
		Startup (blended with 100% load)		-	9.1		40.1
		Shutdown (blended with 100% load)		-	9.1		40.1

[1] $PM_{2.5}$ secondary impact includes sum of Transco Station 165/166 and Lambert Compressor Station, as explained in Section 3.10.1.
[2] The cumulative impact analysis concentration is the sum of the background concentration, the secondary impacts, and the modeled concentration which includes the Lambert Compressor Station, Transco Station 165/166 and other nearby sources (see Section 3.11 for complete listing of modeled facilities).
[3] Background varies by season and hour of day.

Table 4-3 NAAQS Analysis Results (Project Alone)

Pollutant	Averaging Period	Load Scenario	Secondary Impacts[1] (µg/m³)	Model Design Concentrations[2] from LCS Alone (µg/m³)	NAAQS (µg/m³)	% of NAAQS[3]
NO_2	1-hour	50% Load	-	17.48	188	9.3%
		75% Load	-	17.48		
		100% Load	-	17.48		
		Startup (blended with 100% load)	-	17.48		
		Shutdown (blended with 100% load)	-	17.48		
	Annual	50% Load	-	1.35	100	1.4%
		75% Load	-	1.36		
		100% Load	-	1.36		
CO	1-hour	50% Load	-	80.97	40,000	0.4%
		75% Load	-	80.97		
		100% Load	-	80.97		
		Startup (blended with 100% load)	-	156.37		
		Shutdown (blended with 100% load)	-	111.61		
	8-hour	50% Load	-	47.74	10,000	0.5%
		75% Load	-	47.74		
		100% Load	-	47.74		
		Startup (blended with 100% load)	-	47.74		
		Shutdown (blended with 100% load)	-	47.74		
$PM_{2.5}$	24-hour	50% Load	0.0098	0.80	35	2.3%
		75% Load		0.80		
		100% Load		0.80		
		Startup (blended with 75% load)		0.80		
		Shutdown (blended with 75% load)		0.80		
	Annual	50% Load	0.00027	0.14	12	1.2%
		75% Load		0.14		
		100% Load		0.14		
PM_{10}	24-hour	50% Load	-	1.27	150	0.8%
		75% Load	-	1.27		
		100% Load	-	1.27		
		Startup (blended with 100% load)	-	1.27		
		Shutdown (blended with 100% load)	-	1.27		

[1] *$PM_{2.5}$ secondary impact includes Lambert Compressor Station alone.*
[2] *Design concentrations are based on model output in the form of the NAAQS from MVP sources alone.*
[3] *Based on the highest of all the modeled load cases.*

4.3 Air Toxics Model Results

An air toxics modeling analysis was conducted for normal operations for 1-hour and annual formaldehyde emissions, and also for startup and shutdown during the 1-hour averaging period. Additionally, 1-hour and annual hexane emissions were modeled. The highest modeled concentrations were compared with the significant concentrations for these pollutants. The results of the air toxics analyses are provided in **Table 4-4** below.

As shown in **Table 4-4**, the significant concentration values are not exceeded for any compound for any of the modeled scenarios. This indicates that the proposed project will not adversely affect human health.

Table 4-4 Air Toxics Model Results

Pollutant	Averaging Period	Load Scenario	Significant Concentration ($\mu g/m^3$)	Model Result ($\mu g/m^3$)
Formaldehyde	1-hour	50% Load	62.5	2.8
		75% Load		2.8
		100% Load		2.8
		Startup (blended with 50% load)		9.9
		Shutdown (blended with 50% load)		7.0
	Annual	50% Load	2.4	0.050
		75% Load		0.050
		100% Load		0.050
Hexane	1-hour	Unit Blowdown (with Pigging)	8800	1298
		Emergency Shutdown[(1)] (with Pigging)		5435
	Annual	Unit Blowdown (with Pigging)	352	0.276
		Emergency Shutdown[(1)] (with Pigging)		0.228

(1) The ESD scenario reflects an actual emergency scenario.
The ESD testing events are capped to limit the amount of gas released into the atmosphere.

4.4 CONCLUSIONS

The results of the air quality modeling analysis demonstrate that the proposed Project does not cause or contribute to any exceedance of the NAAQS for NO_2, $PM_{2.5}$, PM_{10} and CO, and does not exceed significant air toxics concentrations for formaldehyde and hexane.

All relevant electronic modeling files will be provided to VA DEQ over a secure file transfer as part of this report. The following summarizes the contents of the electronic files:

- AERMOD input and output files for all NAAQS and toxics analyses
- Meteorological data used in the analyses
- BPIP input and output
- Offsite inventory

5.0 References

US EPA 1985. Guideline for the Determination of Good Engineering Practice Stack Height (Technical Support Document for the Stack Height Regulations) - Revised. EPA-450/4-80-023R, US EPA, Research Triangle Park, NC 27711.

US EPA 2013. AERSURFACE User's Guide. EPA-454/B-08-001 (January 2008, revised January 2013). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2011. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS. (March 1, 2011). Office of Air Quality Planning and Standards, Research Triangle Park, NC. Available at: http://www.epa.gov/ttn/scram/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

US EPA 2017. Guideline on Air Quality Models (Revised). Codified in the Appendix W to 40 CFR Part 51. Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2017.

US EPA 2018b. User's Guide for the AERMOD Terrain Preprocessor (AERMAP). EPA-454/B-18-004 (April 2018). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2019a. User's Guide for the AMS/EPA Regulatory Model (AERMOD). EPA-454/B-19-027 (August 2019). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

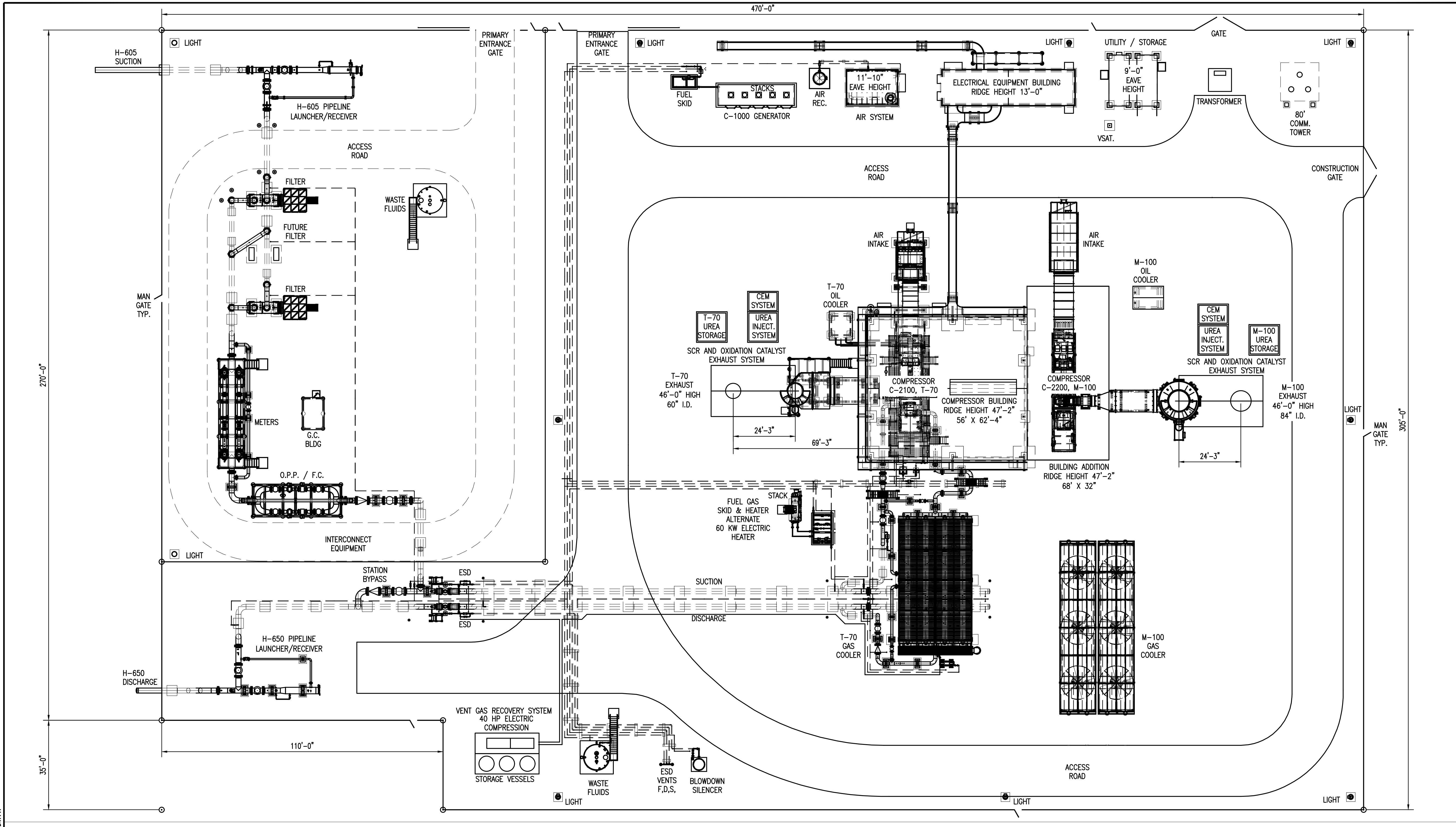
US EPA 2019b. User's Guide for the AERMOD Meteorological Preprocessor (AERMET). EPA-454/B-19-028 (August 2019). Office of Air Quality Planning and Standards, Research Triangle Park, NC.

US EPA 2018a. AERMOD Implementation Guide. EPA-454-B-18-003 (April 2018) US EPA, Research Triangle Park, NC.

US EPA 2019c. US EPA memo entitled "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program", US EPA Office of Air Quality Planning and Standards, Raleigh, NC. April 30, 2019.

Appendix A

Site Plans



NO.	DATE	REVISION	BY	CHK	APPD	NO.	DATE	REVISION	BY	CHK	APPD
B	08/09/2019	FOR PERMITTING	JPO	JAK	JTA						
	3/05/2020	FOR PERMITTING	DKM								
	4/28/2020	FOR PERMITTING	DKM								

TO THE BEST OF MY KNOWLEDGE, ALL COMPONENTS OF THIS DRAWING ARE DESIGNED IN ACCORDANCE WITH APPLICABLE GUIDELINES AND SPECIFICATIONS

DOUGLAS K. MACE — 07/22/19
MECHANICAL DESIGN ENGINEER — DATE

TIMOTHY L. WHITE — 07/22/19
ELECTRICAL DESIGN ENGINEER — DATE

NOTE: ANY CHANGES TO THE DESIGN SHOWN ON THIS DRAWING MUST BE APPROVED BY THE DESIGN ENGINEER.

DESIGN ENGINEERING

MVP SOUTHGATE

SYSTEM NAME: MVP SOUTHGATE
LOCATION: Transco Ln, Chatham, VA 24351
PROJECT ID: C14295
DRAWING SCALE:

DRAWING TITLE: LAMBERT COMPRESSOR STATION

FACILITY	STATE	IDENTIFICATION	SERIES	SHEET	REVISION
C	V	LAM			P

Plotted by: Mace, Doug on: April 28, 2020 - 5:11 PM

File Path: C:\Working\Z__ONE DRIVE PREP PROJECTS\2CURRENT PROJECTS\SOUTHGATE\AIR PERMIT\Lambert Permitting 8-09-2019 REV 4-28-2020.dwg

Appendix B

Modeled Emissions

Table B-1: Ancillary Equipment Emissions and Stack Parameters

Point Source	Model ID	Height (ft)	Diameter (ft)	Velocity (ft/s)	Temperature (F)	Pollutant Emission Rates NO_2 (lb/hr)	NO_2 (tpy)	$PM_{10}/PM_{2.5}$ (lb/hr)	$PM_{10}/PM_{2.5}$ (tpy)	CO (lb/hr)	Formaldehyde (lb/hr)	Formaldehyde (tpy)	Hexane (lb/hr)	Hexane (tpy)
Mars100	CT1_100	50.00	7.000	See Table B-2, B-3, B-4, B-5, B-6, and B-7										
Taurus70	CT2_100	50.00	5.000											
Microturbine	MT01	12.750	1.000	105.60	535.00	0.083	0.363	0.015	0.066	0.219	0.0068	0.0297	--	--
Microturbine	MT02	12.750	1.000	105.60	535.00	0.083	0.363	0.015	0.066	0.219	0.0068	0.0297	--	--
Microturbine	MT03	12.750	1.000	105.60	535.00	0.083	0.363	0.015	0.066	0.219	0.0068	0.0297	--	--
Microturbine	MT04	12.750	1.000	105.60	535.00	0.083	0.363	0.015	0.066	0.219	0.0068	0.0297	--	--
Microturbine	MT05	12.750	1.000	105.60	535.00	0.083	0.363	0.015	0.066	0.219	0.0068	0.0297	--	--
Heater	HT01	14.800	0.670	49.00	460.00	0.070	0.306	0.005	0.023	0.059	0.0001	0.0002	0.0014	0.0060

Fugitive Source	Model ID	Height (ft)	Length (ft)	Pollutant Emission Rates Hexane (lb/hr)	Hexane (tpy)
Condensate Tank	CNDTNK	3.28	3.28	0.00046	0.00200
Building Fugitives	BLDG1	47.17	60.00*	0.01555	0.06810

* Building length is an equivalent building length based on dimensions of 17 x 19 m.

Table B-2: Combustion Turbine Load Analysis

Turbine	Load	Ambient Temperature Case (F)	Height (ft)	Diameter (ft)	Temperature[(a)] (F)	Velocity[(a)] (ft/s)	Pollutant Emission Rates: NO_2[(b)] (lb/hr) Uncontrolled	NO_2[(b)] (lb/hr) Controlled	CO (lb/hr) Uncontrolled	CO (lb/hr) Controlled	$PM_{10}/PM_{2.5}$ (lb/hr)	Formal (lb/ Uncontrolled
Mars 100	50	below 0	50.00	7.00	**651.00**	**60.80**	**11.95**	**3.58**	**17.32**	**1.39**	0.83	0.24
	50	0	50.00	7.00	**651.00**	**60.80**	2.56	0.77	4.33	0.35	0.83	0.24
	50	20	50.00	7.00	893.00	75.87	**3.26**	**0.98**	5.51	0.44	**1.06**	**0.30**
	50	40	50.00	7.00	920.00	73.51	3.11	0.93	5.27	0.42	1.01	0.29
	50	60	50.00	7.00	951.00	71.49	2.96	0.89	5.01	0.40	0.97	0.28
	50	80	50.00	7.00	981.00	68.71	2.78	0.83	4.71	0.38	0.91	0.26
	50	100	50.00	7.00	1010.00	65.97	2.60	0.78	4.40	0.35	0.86	0.25
	75	below 0	50.00	7.00	**871.00**	86.96	**18.95**	**5.68**	**27.48**	**2.20**	**1.28**	**0.37**
	75	0	50.00	7.00	**871.00**	86.96	**4.06**	**1.22**	6.87	0.55	**1.28**	**0.37**
	75	20	50.00	7.00	886.00	84.50	3.93	1.18	6.61	0.53	1.24	0.36
	75	40	50.00	7.00	901.00	81.74	3.74	1.12	6.33	0.51	1.19	0.34
	75	60	50.00	7.00	918.00	78.57	3.55	1.07	6.00	0.48	1.13	0.33
	75	80	50.00	7.00	938.00	75.24	3.33	1.00	5.62	0.45	1.07	0.31
	75	100	50.00	7.00	966.00	**72.17**	3.09	0.93	5.22	0.42	1.00	0.29
	100	below 0	50.00	7.00	**866.00**	89.58	**21.28**	**6.38**	**30.84**	**2.47**	**1.40**	**0.40**
	100	0	50.00	7.00	**866.00**	89.58	**4.56**	**1.37**	7.71	0.62	**1.40**	**0.40**
	100	20	50.00	7.00	879.00	88.30	4.42	1.33	7.47	0.60	1.36	0.39
	100	40	50.00	7.00	893.00	86.59	4.25	1.28	7.19	0.58	1.31	0.38
	100	60	50.00	7.00	910.00	84.35	4.05	1.22	6.85	0.55	1.25	0.36
	100	80	50.00	7.00	926.00	81.55	3.82	1.15	6.46	0.52	1.19	0.34
	100	100	50.00	7.00	947.00	**78.34**	3.56	1.07	6.03	0.48	1.12	0.32
Tarus 70	50	below 0	50.00	5.00	**908.00**	97.96	**10.36**	**3.11**	**15.00**	**1.20**	**0.72**	**0.21**
	50	0	50.00	5.00	**908.00**	97.96	**2.22**	**0.67**	3.75	0.30	**0.72**	**0.21**
	50	20	50.00	5.00	933.00	95.39	2.15	0.65	3.64	0.29	0.70	0.20
	50	40	50.00	5.00	956.00	92.66	2.09	0.63	3.53	0.28	0.68	0.20
	50	60	50.00	5.00	981.00	88.28	1.95	0.59	3.30	0.26	0.64	0.18
	50	80	50.00	5.00	1003.00	84.67	1.81	0.54	3.06	0.24	0.59	0.17
	50	100	50.00	5.00	1031.00	**81.09**	1.67	0.50	2.82	0.23	0.55	0.16
	75	below 0	50.00	5.00	**913.00**	111.44	**12.74**	**3.82**	**18.48**	**1.48**	**0.86**	**0.25**
	75	0	50.00	5.00	**913.00**	111.44	**2.73**	**0.82**	4.62	0.37	**0.86**	**0.25**
	75	20	50.00	5.00	931.00	108.57	2.65	0.80	4.49	0.36	0.84	0.24
	75	40	50.00	5.00	946.00	105.56	2.57	0.77	4.35	0.35	0.81	0.23
	75	60	50.00	5.00	966.00	100.25	2.39	0.72	4.05	0.32	0.76	0.22
	75	80	50.00	5.00	994.00	95.46	2.22	0.67	3.76	0.30	0.71	0.21
	75	100	50.00	5.00	1024.00	**90.09**	2.03	0.61	3.43	0.27	0.66	0.19
	100	below 0	50.00	5.00	**902.00**	116.84	**14.42**	**4.33**	**20.92**	**1.67**	**0.95**	**0.27**
	100	0	50.00	5.00	**902.00**	116.84	**3.09**	**0.93**	5.23	0.42	**0.95**	**0.27**
	100	20	50.00	5.00	909.00	114.24	3.01	0.90	5.09	0.41	0.93	0.27
	100	40	50.00	5.00	920.00	111.89	2.93	0.88	4.95	0.40	0.90	0.26
	100	60	50.00	5.00	943.00	107.97	2.76	0.83	4.66	0.37	0.85	0.25
	100	80	50.00	5.00	967.00	103.49	2.56	0.77	4.33	0.35	0.80	0.23
	100	100	50.00	5.00	1000.00	**98.15**	2.34	0.70	3.96	0.32	0.74	0.21

a - Cells that are highlighted in light grey and bold font are values that were chosen for the worst case scenario to be modeled (the lowest turbine Temperature and exit velocity for that particular load percentage, or the highest emission rate for that particular load percentage).

b - Two sets of worst case emission rates were chosen for NO2: one for the 1-hour averaging period and one for the annual averaging period. The < 0°
F scenario was not considered for the 1-hour averaging period because of the intermittent source exemption, but was considered for the annual

Table B-3: Worst Case Scenarios Determined from Turbine Load Analysis

Source	Load Scenario	Height (ft)	Diameter (ft)	Temperature[(a)] (F)	Exhaust Flow (ACFM)	Velocity[(a)] (ft/s)	Pollutant Emission Rates (lb/hr)				
							NO_X (1hr)[a,b]	NO_X (Annual)[b]	CO (1hr, 8hr)[b]	$PM_{10}/PM_{2.5}$ (24hr, Annual)	Formaldehyde (1hr, Annual)[b]
Mars 100	50	50.00	7.00	651.00	140,400	60.80	0.98	3.58	1.39	1.06	0.03
	75	50.00	7.00	871.00	166,640	72.17	1.22	5.68	2.20	1.28	0.04
	100	50.00	7.00	866.00	180,884	78.34	1.37	6.38	2.47	1.40	0.04
Taurus 70	50	50.00	5.00	908.00	95,533	81.09	0.67	3.11	1.20	0.72	0.02
	75	50.00	5.00	913.00	106,132	90.09	0.82	3.82	1.48	0.86	0.02
	100	50.00	5.00	902.00	115,629	98.15	0.93	4.33	1.67	0.95	0.03

a - The < 0° F scenario was not considered for the 1-hour averaging period because of the intermittent source exemption. The 1-hour averaging period therefore has lower emission rates than the annual averaging period which did consider the < 0° F scenario.

Table B-4: Stack Parameters to Be Blended for Startup and Shutdown Operations

Turbine	Scenario	Exhaust Flow (ACFM)	Temperature (F)	Pollutant Emission Rates (lb/hr)			
				NO_X[b]	CO[b]	$PM_{10}/PM_{2.5}$	Formaldehyde[b]
Mars 100	50% Load (not worst-case for any short-term pollutants/averaging periods)	140,400	651.00	0.98	1.39	1.06	0.03
Taurus 70		95,533	908.00	0.67	1.20	0.72	0.02
Mars 100	75% Load (worst-case for 24hr PM_{10} and 1hr Formadehyde)	166,640	871.00	1.22	2.20	1.28	0.04
Taurus 70		106,132	913.00	0.82	1.48	0.86	0.02
Mars 100	100% Load (worst-case for 1hr NO_2, 1&8hr CO, 24hr $PM_{2.5}$)	180,884	866.00	1.37	2.47	1.40	0.04
Taurus 70		115,629	902.00	0.93	1.67	0.95	0.03
Turbine	**Scenario**	**Exhaust Flow (ACFM)[(a)]**	**Temperature (F)[(a)]**	**Pollutant Emission Rates (lb/event)**			
				NO_X	**CO**	**$PM_{10}/PM_{2.5}$**	**Formaldehyde**
Mars 100	Startup	140,400	651.00	1.00	46.00	0.03	2.40
Taurus 70		95,533	908.00	1.00	88.00	0.15	4.60
Mars 100	Shutdown	140,400	651.00	1.00	82.00	0.06	4.30
Taurus 70		95,533	908.00	1.00	62.00	0.15	3.20

a - Startup and shutdown exhaust flow and temperature are assumed to be the same as the worst case 50% scenario.

Table B-5: Modeled Startup / Shutdown Operations

Source	Scenario[(a),(b)]	Height (ft)	Diameter (ft)	Exhaust Flow (ACFM)	Velocity (ft/s)[(d)]	Temperature (F)[(d)]	Pollutant Emission Rates (lb/hr)[(c)]							
							Startup NO_X	Shutdown NO_X	Startup CO	Shutdown CO	Startup $PM_{10}/PM_{2.5}$	Shutdown $PM_{10}/PM_{2.5}$	Startup Formaldehyde	Shutdown Formaldehyde
Mars 100	1-hour (NOX and CO)	50.00	7.00	174,137	75.41	830.17	2.14	2.14	48.06	84.06	--	--	--	--
Taurus 70		50.00	5.00	112,280	95.31	903.00	1.77	1.77	89.39	63.39	--	--	--	--
Mars 100	1-hour (Formaldehyde)	50.00	7.00	162,267	70.27	834.33	--	--	--	--	--	--	2.43	4.33
Taurus 70		50.00	5.00	104,366	88.59	912.17	--	--	--	--	--	--	4.62	3.22
Mars 100	8-hour (CO)	50.00	7.00	180,041	77.97	861.52	--	--	8.17	12.67	--	--	--	--
Taurus 70		50.00	5.00	115,210	97.79	902.13	--	--	12.64	9.39	--	--	--	--
Mars 100	24-hour ($PM_{2.5}$)	50.00	7.00	180,603	78.21	864.51	--	--	--	--	1.39	1.40	--	--
Taurus 70		50.00	5.00	115,489	98.03	902.04	--	--	--	--	0.95	0.95	--	--
Mars 100	24-hour (PM_{10})	50.00	7.00	166,458	72.09	869.47	--	--	--	--	1.28	1.28	--	--
Taurus 70		50.00	5.00	106,058	90.03	912.97	--	--	--	--	0.86	0.86	--	--

a - Startup and shutdown are expected to last for 10 minutes each.
b - Startup and shutdown emissions and stack parameters were blended with worst case normal operation emissions and stack parameters for the relevant averaging periods. The properties that were blended together can be found in Table B-4.
c - Emission rates reflect the addition of lb/event (for startup or shutdown) with the normal operation emissions in lb/hr for the duration of the averaging period. For example, the amount of NO_X emitted during 1 hour of startup for the Mars100 is equal to 1.0 lbs + (4.56 lb/hr for 50 minutes, or 3.80 lbs) = 4.80 lb/hr.
- Another example: the amount of CO emitted during 8 hours with a shutdown of the Mars100 is equal to (7 hours * 30.84 lb/hr) + 46.00 lbs + (30.84 lb/hr for 50 minutes, or 25.7 lbs) = 287.58 lbs over the 8 hour period, or 35.95 lb/hr.
d - Stack exhaust temperature and exhaust exit velocity are calculated by weighting the duration of the startup/shutdown scenario and the normal operation scenario by the percentage of the averaging periods that each respectively represents. For example, 24 hours with one startup is 10/1440 minutes and 1430/1440 normal operations. Therefore, the stack exhaust temperature for the Mars100, (startup for PM_{10}) would be (10/1440 * 651° F) + (1430/1440 * 866° F) = 864.51° F

Table B-6: Sitewide Individual Unit Blowdown Scenario - Stack Parameters and Hexane Emissions [a]

Source	Model ID	Stack Type	Stack Description	Stack Height (ft)	Exit Diameter (ft)	Exhaust Gas Velocity[(c)] (ft/s)	Exit Gas Temperature (F)	Blowdown Volume (scf)[b]	Hexane (lb/event)	Events / Year	Hexane (lb/hr)	Hexane (TPY)
Mars 100 Unit Blowdown	CT1_BD	Point	Vertical	22.00	4.00	0.07	115.0	3,365	0.12	12	0.12	7.35E-04
Taurus 70 Unit Blowdown	CT2_BD	Point	Vertical	22.00	4.00	0.05	115.0	2,055	0.07	12	0.07	4.49E-04
Pig Receiver Blowdown	PIGRBD	Point	Vertical	7.50	0.17	92.31	60.0	7,250	0.26	2	0.26	2.64E-04
Pig Launcher Blowdown	PIGLBD	Point	Vertical	7.50	0.17	134.90	60.0	10,595	0.39	2	0.39	3.86E-04
1) Interconnect / Turbine Suction Gas Filter #1	ITCNTGF1	Point	Vertical	12.00	0.17	176.23	60.0	13,841	0.50	12	0.50	3.02E-03
2) Interconnect / Turbine Suction Gas Filter #2	ITCNTGF2	Point	Vertical	12.00	0.17	176.23	60.0	13,841	0.50	12	0.50	3.02E-03
3) Interconnect / Turbine Suction Gas Filter #3	ITCNTGF3	Point	Vertical	12.00	0.17	176.23	60.0	13,841	0.50	12	0.50	3.02E-03
3) Station Fuel Gas Fiilter	SFGF	Point	Vertical	9.50	0.08	10.81	60.0	212	0.01	12	0.01	4.64E-05
4) C-1000 Fuel Gas Filter	C1000FGF	Point	Vertical	7.50	0.08	0.95	70.0	19	0.00	12	0.00	4.08E-06
5) Taurus 70 Fuel Gas Filter	T70FGF	Point	Vertical	9.50	0.08	4.59	70.0	90	0.00	12	0.00	1.97E-05
6) Mars 100 Fuel Gas Filter	M100FGF	Point	Vertical	9.50	0.08	4.59	70.0	90	0.00	12	0.00	1.97E-05
7) Taurus 70 Seal Gas Filter	T70SGF	Point	Vertical	7.50	0.08	6.33	70.0	124	0.00	12	0.00	2.71E-05
8) Mars 100 Seal Gas Filter	M100SGF	Point	Vertical	7.50	0.08	6.33	70.0	124	0.00	12	0.00	2.71E-05

a - All ancillary equipment listed in Table B-1 was also included in the sitewide individual unit blowdown scenario. Pigging was also conservatively included in this scenario.

b - All blowdown volumes take into account the gas volume that is purged after equipment or piping is blown down. This purge volume was conservatively assume to be 10% of the event total blowdown volume.

c - Exhaust gas velocity calculated from Gas Blowdown Volume assumed to occur over the course of 1 hour.

Table B-7: Sitewide Emergency Shutdown Scenario - Stack Parameters and Hexane Emissions [a]

Source	Model ID	Stack Type	Stack Description	Stack Height (ft)	Exit Diameter (ft)	Exhaust Gas Velocity[c] (ft/s)	Exit Gas Temperature (F)	Gas Release Volume (scf)	Hexane (lb/event)	Events / Year	Hexane (lb/hr)	Hexane (tpy)
Unit Blow Down Silencer[(b)]	UBDS	Point	Vertical	22.00	4.00	1.60	115.00	72,198	2.63	1	2.63	1.31E-03
Unit Blow Down Silencer Bypass[(b)]	UBDSBYP	Point	Vertical	7.50	0.33	229.81	115.00	72,198	2.63	1	2.63	1.31E-03
Suction Header Blow Down Vent	SHBDV	Point	Vertical	7.50	0.33	167.41	60.00	52,594	1.91	1	1.91	9.57E-04
Discharge Header Blow Down Vent	DHBDV	Point	Vertical	7.50	0.33	260.70	100.00	81,901	2.98	1	2.98	1.49E-03
Fuel Gas Header Blow Down Vent	FGHBDV	Point	Vertical	7.50	0.17	14.77	100.00	1,160	0.04	1	0.04	2.11E-05

a - All ancillary equipment listed in Table B-1 was also included in the sitewide emergency shutdown scenario. Pigging was also conservatively included in this scenario.

b - Unit blowdowns include Mars 100 and Taurus 70 unit blowdowns. These occur through the silencer and silencer bypass. It is assumed that each location blowdowns half the total flow.

c - Exhaust gas velocity calculated from Gas Blowdown Volume assumed to occur over the course of 1 hour.

Appendix C

AERMET Methodology and Dataset Analysis for Lynchburg, VA (KLYH)

Introduction

This appendix documents the meteorological data processing for a 5-year AERMET meteorological dataset (2012-2016) as processed by the Virginia Department of Environmental Quality (VA DEQ). The meteorological data processed by VA DEQ were from surface observations from the Lynchburg Regional Airport, VA (airport code LYH) and upper air soundings from the Piedmont Triad International Airport, located in Greensboro, NC (airport code GSO).

Meteorological data required for AERMOD (US EPA 2019a) include hourly values of wind speed, wind direction, and ambient temperature. Since the AERMOD dispersion algorithms are based on atmospheric boundary layer dispersion theory, additional boundary layer variables are derived by parameterization formulas, which are computed by the AERMOD meteorological preprocessor, AERMET (US EPA 2019b). These parameters include sensible heat flux, surface friction velocity, convective velocity scale, vertical potential temperature gradient, convective and mechanical mixing heights, Monin-Obukhov length, surface roughness length, Bowen ratio, and albedo.

Available Meteorological Data

The hourly meteorological data was processed with the latest version of AERMET (Version 19191) (US EPA 2019b), the meteorological preprocessor for AERMOD. Specifically, AERMET was run utilizing five concurrent years (2012-2016) of hourly surface observations from LYH along with concurrent upper air data from the National Weather Service (NWS) Station at GSO. Figure 1 shows the location of meteorological stations.

The AERMET inputs were based on surface meteorological data from the National Climatic Data Center's (NCDC) Integrated Surface Hourly (ISH) database along with 1- and 5-minute Automated Surface Observing System (ASOS) data. The upper air data input to AERMET was downloaded from the NOAA/ESRL/GSD - RAOB database[3].

Table 1 gives the site location and information on these data sets. The surface wind data are measured 10.0 meters above ground level. The temperature and relative humidity are measured 2.0 meters above ground level.

US EPA guidance provided in Meteorological Monitoring Guidance for Regulatory Modeling Applications (US EPA 2000), Section 5.3, specifies a completeness requirement of 90% on a quarterly basis. The 90 percent requirement applies to each of the variables wind direction, wind speed, stability, and temperature and to the joint recovery of wind direction, wind speed, and stability. Table 2 summarizes the quarterly joint data completeness by year. As shown in Table 2, all quarters show the data capture is above 90 percent.

[3] http://esrl.noaa.gov/raobs/

Figure 1 Location of Meteorological Stations

Table 1 Meteorological Data Used in Running AERMET

Met Site	Latitude	Longitude	Base Elevation (m)	Data Source	Data Format
Lynchburg Regional Airport (LYH)	37.321N	79.207W	286	NCDC	ISHD and 1- min ASOS
Upper Air Station at Greensboro, NC (GSO)	36.08N	79.95W	277	FSL	FSL

Table 2 Meteorological Data Completeness Percentage per Quarter

Quarter[1]	2012	2013	2014	2015	2016
1	99.5	98.8	100	100	99.7
2	98.9	100	99.4	99.8	99.7
3	100	100	97.2	100	99.9
4	99.5	99.6	100	100	98.6

1. Quarter 1 = Jan, Feb, Mar;
   Quarter 2 = April, May, June;
   Quarter 3 = July, Aug, Sept; and
   Quarter 4 = Oct, Nov, Dec

AERSURFACE Analysis –Land Use Characteristics

AERMET requires specification of site characteristics including surface roughness, albedo, and Bowen ratio. These parameters were developed according to the guidance provided by US EPA in the recently revised AERMOD Implementation Guide (AIG) (US EPA2019c) and input provided by VA DEQ.

The revised AIG provides the following recommendations for determining the site characteristics:

1. The determination of the surface roughness length should be based on an inverse distance weighted geometric mean for a default upwind distance of 1 kilometer relative to the measurement site. Surface roughness length may be varied by sector to account for variations in land cover near the measurement site; however, the sector widths should be no smaller than 30 degrees.
2. The determination of the Bowen ratio should be based on a simple un-weighted geometric mean (i.e., no direction or distance dependency) for a representative domain, with a default domain defined by a 10-km by 10-km region centered on the measurement site.
3. The determination of the albedo should be based on a simple un-weighted arithmetic mean (i.e., no direction or distance dependency) for the same representative domain as defined for Bowen ratio, with a default domain defined by a 10-km by 10-km region centered on the measurement site.

The AIG recommends that the surface characteristics be determined based on digitized land cover data. US EPA has developed a tool called AERSURFACE (US EPA 2008) that can be used to determine the site characteristics based on digitized land cover data in accordance with the recommendations from the AIG discussed above. AERSURFACE incorporates look-up tables of representative surface characteristic values by land cover category and seasonal category.

US EPA has two versions of AERSURFACE currently available, Version 13016 and a draft Version 19039_DRFT (US EPA 2019d). The primary difference between the two versions of AERSURFACE is that the draft 2019 version can use newer National Land Cover Database (NLCD) datasets from 2001, 2006, and 2011 compared to previous versions that only allowed the use of NLCD data from 1992. There are other AERSURFACE model formulation changes that were required in order to use the newer NLCD dataset and these are described in more detail in the AERSURFACE User's Guide for the draft Version 19039[4]. Use of the newer years of NLCD data also allows for the inclusion of supplemental databases to help characterize surface roughness including percent impervious and percent tree canopy data, when available.

For LYH, NLCD data are available for both 1992 and 2011. The 2011 NLCD data also includes the supplemental percent impervious and percent tree canopy data. A comparison of the 1992 and 2011 NLCD data is shown in Figure 2 and Figure 3. The more recent 2011 NLCD data were selected for processing, and as such, the latest version of AERSURACE that is able to utilize the 2011 data (Version 19039_DRFT) was utilized when processing the meteorological data.

[4] https://www3.epa.gov/ttn/scram/models/aermod/draft_aersurface/aersurface_ug_19039_DRFT.pdf

Figure 2 1992 NLCD Data

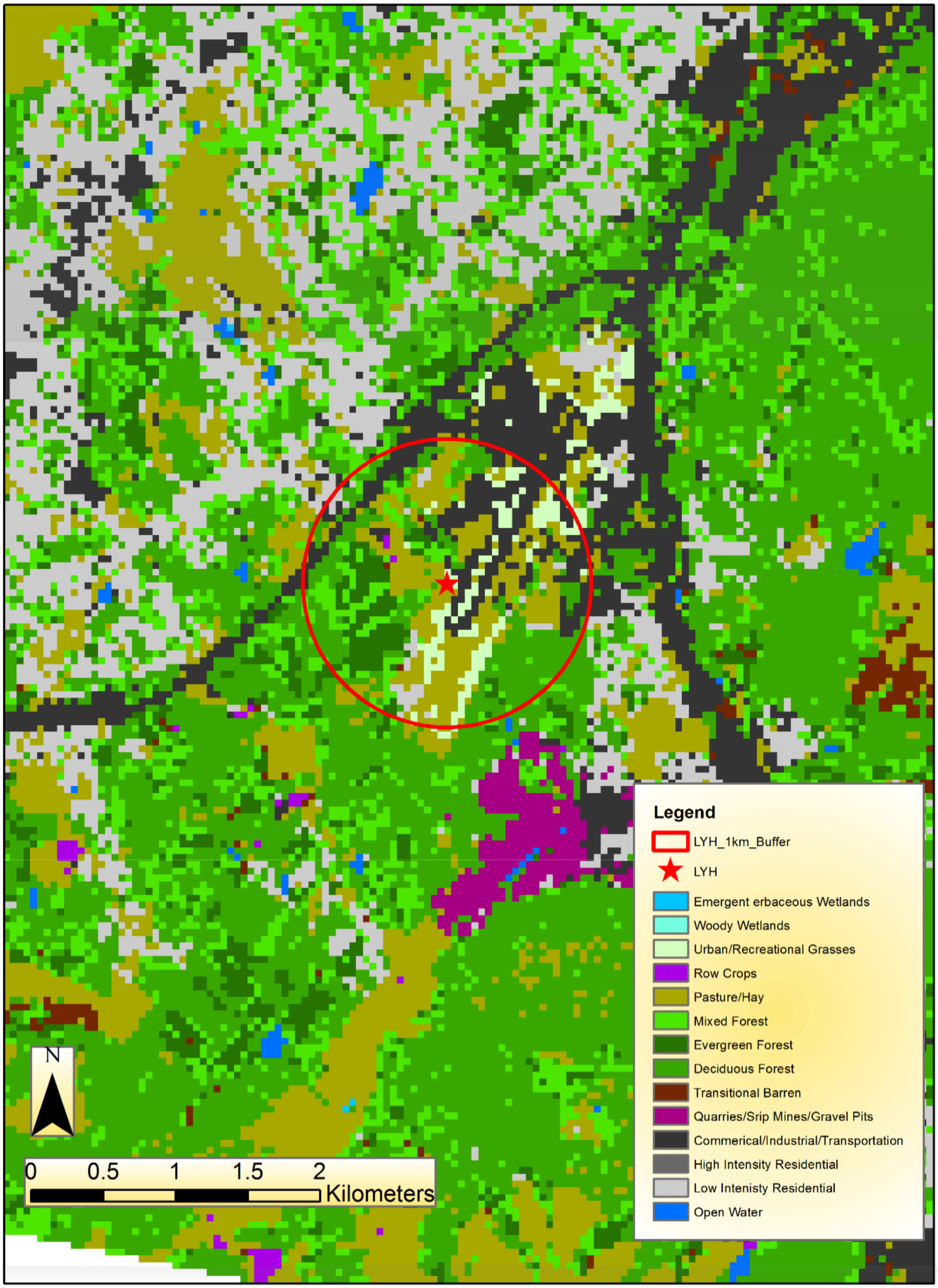
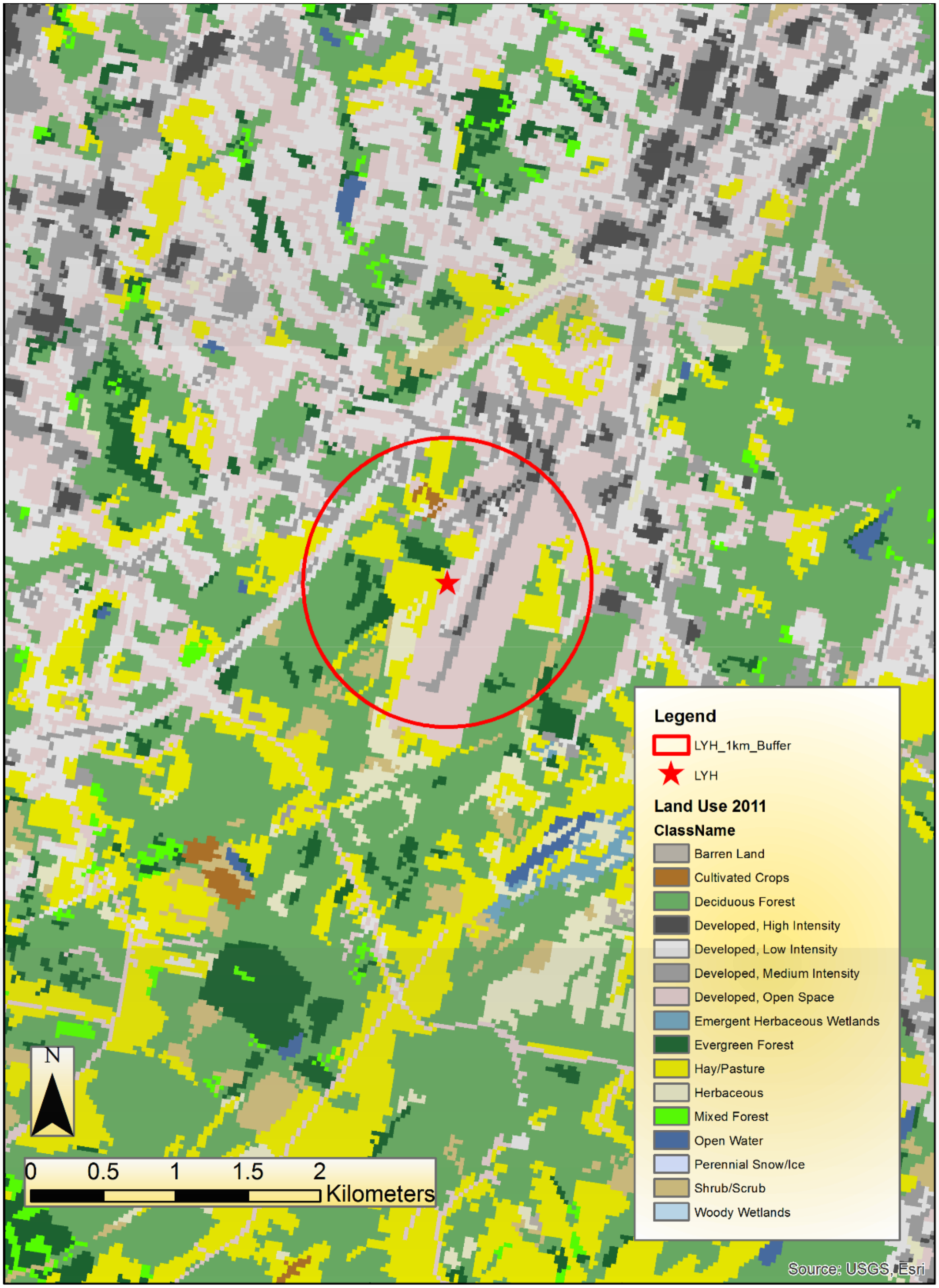


Figure 3 2011 NLCD Data



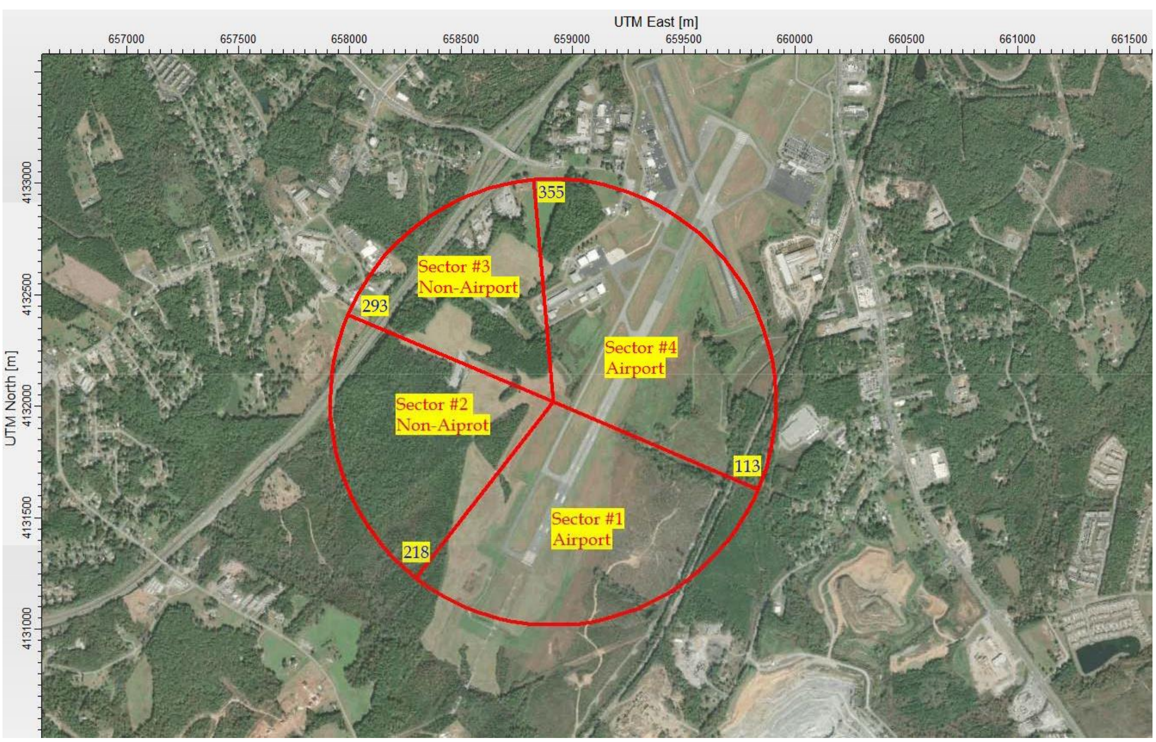
As recommended in the 2019 AERSURFACE User's Guide, the surface roughness processing was performed using the default ZORAD method[5]. This method for determining surface roughness length is the same as previous versions of AERSURFACE and is based on an inverse distance-weighted geometric mean. The mean is calculated from the roughness values associated with the land cover category that defines each land cover grid cell within the area or individual sectors out to a fixed radial distance from the meteorological tower. The recommended and default radial distance of 1 km was used[6].

The AIG recommends that the 1-km radius circular area centered at the meteorological station site can be divided into sectors as needed for the analysis; each chosen sector has a mix of land uses that is different from that of other selected sectors. Sectors used to define the meteorological surface characteristics for the airport site are listed below in Table 3 and shown in Figure 4. For each sector, it is also indicated as "airport" or "non-airport" as required by the AERSURFACE Version 19039_DRFT[7].

Table 3 AERSURFACE Land Use Sectors

Sector	Start (degrees)	End (degrees)	Airport vs NonAirport
1	113	218	Airport
2	218	293	NonAirport
3	293	255	NonAirport
4	355	113	Airport

Figure 4 Sectors Used for Surface Characteristics at Lynchburg Regional Airport



[5] Section 1.3 of the 2019 AERSURFACE User's Guide (second paragraph in page 1-4).

[6] Section 2.4.1 of the 2019 AERSURFACE User's Guide (second paragraph in page 2-10).

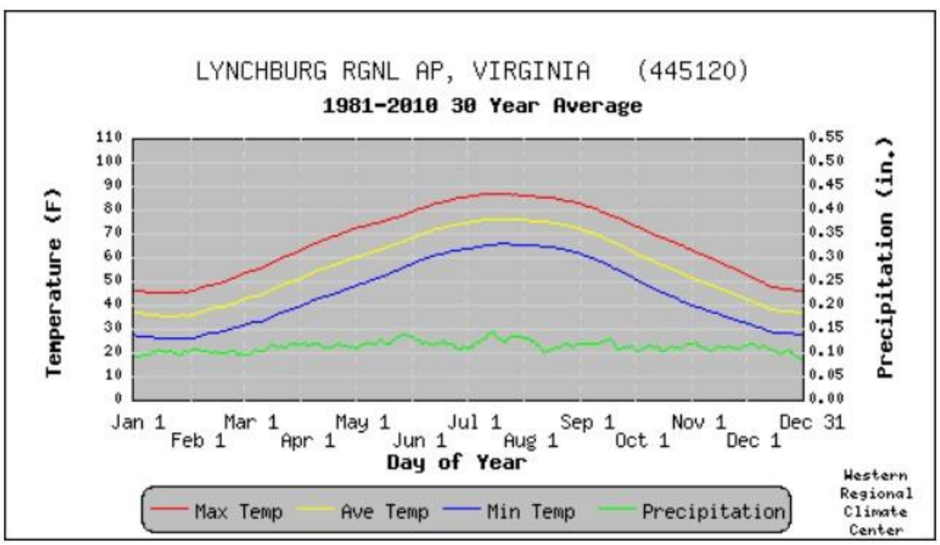
[7] Section 2.3.2 of the 2019 AERSURFACE User's Guide (second paragraph in page 2-8).

In AERSURFACE, the various land cover categories are linked to a set of seasonal surface characteristics. As such, AERSURFACE requires specification of the seasonal category for each month of the year. Based on the climatology of high and low daily temperatures shown in Figure 5 for a 30-year period of record at LYH[8], the following five seasonal categories were mapped to the following months in AERSURFACE[9]:

- Midsummer with lush vegetation (May-September);
- Autumn with un-harvested cropland (October-November);
- Late autumn after frost and harvest, or winter with no snow (December-February);
- Winter with continuous snow on ground (none); and
- Transitional spring with partial green coverage or short annuals (March-April).

For Bowen ratio, the land use values are linked to three categories of surface moisture corresponding to average, wet and dry conditions. The surface moisture condition for the site may vary depending on the meteorological data period for which the surface characteristics will be applied. AERSURFACE applies the surface moisture condition for the entire data period. Therefore, if the surface moisture condition varies significantly across the data period, then AERSURFACE can be applied multiple times to account for those variations. As recommended in the AERSURFACE User's Guide, the surface moisture condition for each month will be determined by comparing precipitation for the period of data to be processed to the 30-year climatological record, selecting "wet" conditions if precipitation is in the upper 30th-percentile, "dry" conditions if precipitation is in the lower 30th-percentile, and "average" conditions if precipitation is in the middle 40th-percentile[10]. The 30-year precipitation data set used to process the meteorological data was taken at LYH. The 30-year period of record used to establish the 30-year average monthly precipitation totals include 1987 through 2016. The monthly designations of surface moisture input to AERSURFACE are summarized in Table 4.

Figure 5 Regional Temperature Climatology



8 Based on Western Regional Climate Center (WRCC) https://wrcc.dri.edu/cgi-bin/cliMAIN.pl?va5120

9 For the winter-to-spring designation, a month needed approximately more than 50% of the low temperatures > freezing; conversely the transition from autumn-to-winter occurred when the low temperatures dipping below freezing exceeded approximately 50% of the time.

10 Section 2.3.3 of the 2019 AERSURFACE User's Guide (second paragraph in page 2-9).

Table 4 AERSURFACE Bowen Ratio Condition Designations

Month	2012	2013	2014	2015	2016
January	Dry	Wet	Average	Dry	Average
February	Average	Dry	Wet	Average	Wet
March	Wet	Average	Dry	Average	Average
April	Average	Average	Wet	Wet	Dry
May	Average	Wet	Wet	Dry	Wet
June	Dry	Wet	Average	Wet	Wet
July	Dry	Average	Wet	Average	Wet
August	Average	Average	Wet	Average	Dry
September	Average	Dry	Dry	Wet	Average
October	Dry	Average	Wet	Wet	Dry
November	Dry	Average	Average	Wet	Dry
December	Average	Wet	Average	Wet	Average

A comparison of the land use characteristics between the LYH ASOS station and the project site was made to assess the similarity between the two sites. AERSURFACE Version 19039_DRFT was used to summarize various meteorological variables associated with LYH and the project site, including the Bowen ratio, albedo, and surface roughness, based on U.S. Geological Survey (USGS) National Land Cover Data (NLCD) from 2011. A general comparison of these values is provided in Table 5. For the purposes of this comparison, the four sectors and the twelve months used for LYH were applied to the project site with values of “Non-Airport” and the average moisture condition with no snow coverage was selected. Although some minor differences in the surface roughness (Zo) in the “Airport” sectors (#1 and #4) between the two sites are observed, a weighted average calculation by sector areas shows that the overall difference of Zo between the project site (0.128 m) and the airport (0.246 m) is small.

Therefore, there appears to be reasonable similarity in these micrometeorological variables between the project site and airport.

Table 5 Micrometeorological Variables Comparison between the Project Site and LYH

Month	Sector	Project Site			LYH		
		Alb	Bo	Zo	Alb	Bo	Zo
1	1	0.170	0.850	0.089	0.170	0.910	0.033
1	2	0.170	0.850	0.118	0.170	0.910	0.098
1	3	0.170	0.850	0.097	0.170	0.910	0.142
1	4	0.170	0.850	0.103	0.170	0.910	0.030
2	1	0.170	0.850	0.089	0.170	0.910	0.033
2	2	0.170	0.850	0.118	0.170	0.910	0.098
2	3	0.170	0.850	0.097	0.170	0.910	0.142
2	4	0.170	0.850	0.103	0.170	0.910	0.030
3	1	0.150	0.500	0.149	0.160	0.570	0.049
3	2	0.150	0.500	0.254	0.160	0.570	0.155
3	3	0.150	0.500	0.186	0.160	0.570	0.194
3	4	0.150	0.500	0.150	0.160	0.570	0.040
4	1	0.150	0.500	0.149	0.160	0.570	0.049

Month	Sector	Project Site			LYH		
		Alb	Bo	Zo	Alb	Bo	Zo
4	2	0.150	0.500	0.254	0.160	0.570	0.155
4	3	0.150	0.500	0.186	0.160	0.570	0.194
4	4	0.150	0.500	0.150	0.160	0.570	0.040
5	1	0.170	0.420	0.320	0.160	0.460	0.063
5	2	0.170	0.420	0.408	0.160	0.460	0.332
5	3	0.170	0.420	0.297	0.160	0.460	0.366
5	4	0.170	0.420	0.304	0.160	0.460	0.050
6	1	0.170	0.420	0.320	0.160	0.460	0.063
6	2	0.170	0.420	0.408	0.160	0.460	0.332
6	3	0.170	0.420	0.297	0.160	0.460	0.366
6	4	0.170	0.420	0.304	0.160	0.460	0.050
7	1	0.170	0.420	0.320	0.160	0.460	0.063
7	2	0.170	0.420	0.408	0.160	0.460	0.332
7	3	0.170	0.420	0.297	0.160	0.460	0.366
7	4	0.170	0.420	0.304	0.160	0.460	0.050
8	1	0.170	0.420	0.320	0.160	0.460	0.063
8	2	0.170	0.420	0.408	0.160	0.460	0.332
8	3	0.170	0.420	0.297	0.160	0.460	0.366
8	4	0.170	0.420	0.304	0.160	0.460	0.050
9	1	0.170	0.420	0.320	0.160	0.460	0.063
9	2	0.170	0.420	0.408	0.160	0.460	0.332
9	3	0.170	0.420	0.297	0.160	0.460	0.366
9	4	0.170	0.420	0.304	0.160	0.460	0.050
10	1	0.170	0.850	0.320	0.160	0.910	0.054
10	2	0.170	0.850	0.408	0.160	0.910	0.325
10	3	0.170	0.850	0.289	0.160	0.910	0.353
10	4	0.170	0.850	0.295	0.160	0.910	0.044
11	1	0.170	0.850	0.320	0.160	0.910	0.054
11	2	0.170	0.850	0.408	0.160	0.910	0.325
11	3	0.170	0.850	0.289	0.160	0.910	0.353
11	4	0.170	0.850	0.295	0.160	0.910	0.044
12	1	0.170	0.850	0.089	0.170	0.910	0.033
12	2	0.170	0.850	0.118	0.170	0.910	0.098
12	3	0.170	0.850	0.097	0.170	0.910	0.142
12	4	0.170	0.850	0.103	0.170	0.910	0.030
Weighted Average		**0.167**	**0.613**	**0.246**	**0.163**	**0.666**	**0.128**

AERMET Data Processing

AERMET (Version 19191) and AERMINUTE (Version 15272) were used to process data required for input to AERMOD. Boundary layer parameters used by AERMOD, which also are required as input to the AERMET processor, include albedo, Bowen ratio, and surface roughness. The land classifications and associated boundary layer parameters were determined following procedures outlined above. In running AERMET, the observed airport hourly wind directions were randomized and the default ADJ_U* option was utilized.

AERMET was applied to create two meteorological data files required for input to AERMOD:

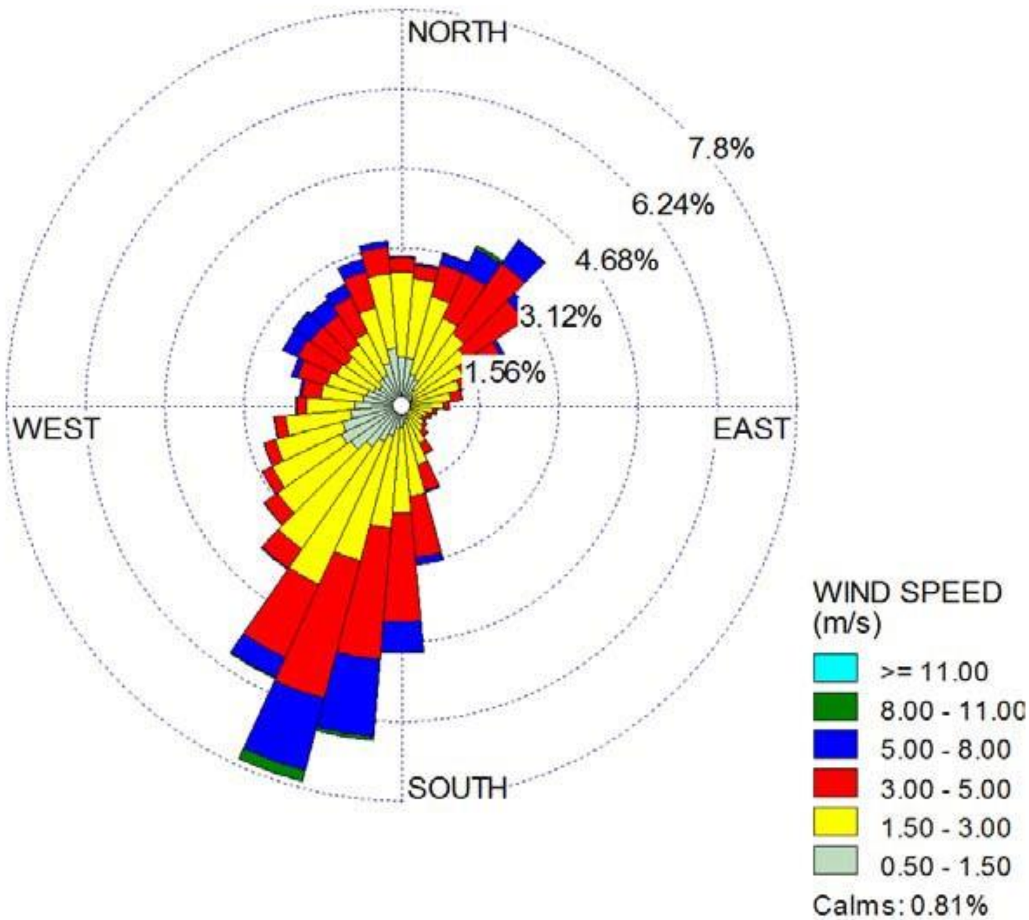
> **Surface**: A file with boundary layer parameters such as sensible heat flux, surface friction velocity, convective velocity scale, vertical potential temperature gradient in the 500-meter layer above the planetary boundary layer, and convective and mechanical mixing heights.

Also provided are values of Monin-Obukhov length, surface roughness, albedo, Bowen ratio, wind speed, wind direction, temperature, and heights at which measurements were taken.

Profile: A file containing multi-level meteorological data with wind speed, wind direction, temperature, sigma-theta ($\sigma\theta$) and sigma-w (σw) when such data are available. For this application, the profile file will contain a single level of wind data (10 meters) and the temperature data only.

A wind rose for LYH from the 10-meter level is provided Figure 6. The wind-rose was generated using the AERMET surface file (which include the 1-minute ASOS data). As shown in the wind rose, the predominant wind direction for the site is from the south- southwest, although winds out of the northeast are also common.

Figure 6 Wind Rose for Lynchburg Regional Airport (2012-2016)



APPENDIX H
Specific Safety Measures

Lambert Compressor Station Specific Safety Measures

All the measures provided in this list are not part of regulatory requirements.

1) The compressor station foot print includes an (8) foot tall perimeter fence with (3) strands of barbed wire, keyed man gates with panic bar exit latches and a motor operated security access gate to deter the general public from entering the facility
2) All aboveground, gas-containing equipment is located a minimum of 15 ft inside of the perimeter fence, 15 ft is the class 1, division 2 hazardous area bubble which prevents the general public from introducing an ignition source, such as a cigarette in a potentially hazardous environment.
3) The station fenced area includes a 360-degree access roadway around the compression equipment that provides uninterrupted motor vehicle access for employees and first responders
4) The perimeter includes directional lighting activated by photo cell to illuminate the station area during dusk to dawn and provides safe access for employees and first responders between dusk and dawn
5) All buildings include emergency lighting on the interior and exterior with battery backup which provides safe egress during power outage
6) Power for the facility is generated on site by natural gas micro turbine generators with commercial power back up that is activated by automated transfer switch gear for uninterrupted power delivery and maintains all primary and safety systems during power outages.
7) Control systems have additional battery backup redundancy, which provides a third level of safety that will allow control systems to continue to operate during both a generator and commercial power failure.
8) Safety critical valves are spring and or pneumatically operated with low voltage controls. Valves continue to operate as intended during the interruption of primary power.
9) Facility includes an Emergency Shutdown (ESD) System that will automatically block gas from entering the compression facility, confirm the block valves are shut, then automatically vent gas from the facility.
10) The ESD system can be triggered by the automated detection of a gas leak, the automated detection of a flame or by an employee initiated manual push button command.
11) Gas and flame detection is located around the compression equipment and manual ESD buttons are located throughout the facility and at man gates along the station fence.

12) All valves associated with the ESD system are pneumatically operated with spring return and are fail safe.

13) The loss of primary power or control system power will fail the valve to the safe position.

14) The control systems for these valves include battery backup power.

15) The purpose of a Compression facility is to increase pipeline system pressure. The compression control system has redundant relay logic controls with redundant sensors to detect and shut down the compression if the system pressure exceeds set values.

16) The relay controls are separate and completely redundant from the primary PLC control systems which also have battery backup power to prevents system over pressure.

17) All tanks are double walled with interstitial space leak detection to minimize the potential of a fluid leakage.

18) Automatically filled tanks are double walled and include level transmitters with automatic shut off valves that will close to prevent the tank from overfilling.

19) Normal operational and maintenance areas that are not at ground level are equipped with Osha approved service platforms.

20) Station operations are remotely monitored by gas control system personnel 24 hours a day, 365 days per year. These personnel can initiate critical safety systems and dispatch local operations personnel or local emergency crews if required.

APPENDIX I
2018 Air Emissions Inventory for Pittsylvania County

2018 Air Emissions Inventory for Pittsylvania County

Reg No	Site Name	Federal Classification	SIC Primary Code	NAICS Primary Code	NOX Emissions in Tons	CO Emissions in Tons	VOC Emissions in Tons	PM 10 Emissions in Tons	PM 2.5 Emissions in Tons	SO2 Emissions in Tons
30864	Transco Gas Pipe Line Corp Station 165	Major/Potential Major	4922	486210	956.2458	232.9234	59.9859	14.8574	14.8576	2.3776
30718	Owens-Brockway Glass Container Inc - Ringgold	Major/Potential Major	3221	327213	165.5888	0.6254	6.3153	28.9776	28.9776	119.9169
30871	Dominion - Pittsylvania Power Station	Major/Potential Major	4911	221117	59.6614	262.9086	6.8558	13.8119	13.7338	2.893
30120	Columbia Forest Products	Synthetic Minor	2435	321211	13.477	16.5024	23.1571	6.254	6.1852	0.1289
21514	Dairy Energy Incorporated	True Minor	0241	112120	12.3613	13.5981	6.1838	0	0	12.885
30823	Intertape Polymer Corporation	Major/Potential Major	3081	326113	3.8672	3.2484	57.2246	5.7784	5.7784	0.0232
30954	Arkema Inc	Synthetic Minor	2821	325211	3.7082	5.8612	7.5338	0.5075	0	0.0402
30585	Polynt Composites USA Inc	Synthetic Minor	2821	325211	2.05	1.722	1.7973	0.1558	0.1558	0.0123
32065	IKEA Industry Danville LLC	Synthetic Minor	2511	337122	1.195	1.0038	2.65	8.9288	0	0
30242	DanChem Technologies Inc	Synthetic Minor	2821	325211	0.6776	0.5204	58.1918	2.0046	2.0011	0.004
32027	Norris Funeral Service and Crematory	True Minor	7261	812220	0.0154	0.0512	0.0154	0.0241	0.0241	0.0128
30866	A C Furniture Co	Synthetic Minor	2599	337127	0	0	49.12	1.0315	0	0
30593	Times Fiber Communications Inc	Synthetic Minor	3357	331491	0	0	29.5827	0	0	0
30268	Capps Shoe Co	Synthetic Minor	3149	316210	0	0	11.42	0.912	0	0
30892	Amthor International	Synthetic Minor	3713	336211	0	0	0.792	0.1064	0	0
30870	Central Va Hardwood Products Inc	True Minor	2511	337122	0	0	0.376	0	0	0
31019	Eastern Panel Mfg Inc	Synthetic Minor	2435	321211	0	0	0	0.8214	0	0
21606	Southside Concrete Supply LLC	Synthetic Minor	3273	327320	0	0	0	0.1143	0.1143	0
				Total Emissions	**1218.8**	**539.0**	**321.2**	**84.3**	**71.8**	**138.3**

APPENDIX J
Real Estate Appraiser Letters

March 24, 2020

Mr. Wade W. Massie
Penn, Stuart & Eskridge
208 East Main Street
Abingdon, Virginia 24210-2904

RE: Mountain Valley Pipeline, Inc.
Compressor Station
987 Transco Road
Chatham, Virginia
Pittsylvania County, Virginia

Dear Mr. Massie:

At your request, I have considered the 154+/- acres of land identified as Tax Parcel No. 2436-60-3630. Additionally, I have considered the potential impacts of the proposed compressor station to be constructed on the 154+/- acres on the surrounding areas. I made a personal inspection of the subject property, the surrounding area and the neighborhood in general on March 9, 2020.

The focus of this analysis consists of a proposed compressor station to service the Mountain Valley Pipeline, Inc. The compressor station will be located to the south of the existing Transco facility located on the south side of Secondary Route 692 (Transco Road) to the east of Chatham in Pittsylvania County, Virginia. The Mountain Valley Pipeline, Inc. (MVP) compressor station is proposed to be constructed on the northern portion of Tax Parcel No.2436-60-3630. This property was acquired by MVP on March 15, 2018 for $175,000.

The purpose of this analysis is to assist MVP to analyze the impact, if any, to the properties surrounding the 154+/- acres, as a result of the proposed compressor station.

Based on my measurements using the Pittsylvania County GIS the closest inhabited dwellings from the proposed compressor station, to the immediate south and west of the property range from about 3,250 feet in distance to approximately 3,600 feet in distance. It is noted that the nearest inhabited structure measures about 2,900 feet in distance from the proposed compressor station. It is interesting to note that the nearest dwelling, located at 709 Transco Road, was recently constructed in 2018. What is interesting about this dwelling is the fact that it is located immediately adjacent to the existing Transco compressor station which was constructed in 1960's. For example, the dwelling at 709 Transco Road is located approximately 1,000 feet, at the nearest point, to the existing Transco compressor station.

In referring back to the distances from the nearest dwellings to the proposed MVP compressor station, excluding the aforementioned 709 Transco Road property, those other structures located to the northwest and the immediate west of the proposed facility are between 3,000 to 4,300 feet away from the existing Transco compressor station.

To recap, the purpose of my analysis was to consider the potential impacts of the proposed MVP compressor station on the surrounding areas. I have researched a wide variety of properties and have specifically considered the subject's neighborhood. I have not found any instances or data to support that the proposed MVP compressor station would have any negative impact on the surrounding properties. MVP owns the subject 154+/- acres which is located to the immediate south of the circa-1960s Transco facility. If any impact was done to the neighborhood, it certainly came when Transco constructed the original facility in the early 1960s and/or constructed their newer facility to the immediate south. Further emphasis is placed on the fact that in 2018 a new dwelling was constructed at 709 Transco Road, which is located to the immediate east of the Transco facility. Again, this dwelling located about 1,000 feet away from the existing Transco facility and is within immediate visual distance of the Transco facility.

Therefore, I have no data to support, or conclude, that the proposed Mountain Valley Pipeline compressor station would have any additional negative impact on the immediate neighborhood.

Attached is a Uniform Standards of Professional Appraisal Practice (USPAP) compliance form, which is required when an opinion of value is being provided. My signed Certification is also attached.

Respectfully,

Wesley Woods, MAI
Certified General Real Estate Appraiser
VA License No. 4001 003642
Expires 05/31/2020

UNIFORM STANDARDS OF PROFESSIONAL APPRAISAL PRACTICE COMPLIANCE

Under the Uniform Standards of Professional Appraisal Practice (USPAP) (2020-2021 Edition), certain reporting requirements are necessary when reporting an opinion of value. These compliance pages are intended to satisfy the USPAP requirements.

CLIENT: Mountain Valley Pipeline, Inc. c/o Penn, Stuart & Eskridge

It is noted that this Appraisal Report and additional information is available in our work file that will provide a better understanding of, and our arrival at the value opinion and conclusions of this assignment.

INTENDED USE: The intended use of this report is to consider the impacts of the proposed Mountain Valley Pipeline compressor station off of Transco Road in Pittsylvania County, Virginia.

IDENTIFICATION OF THE SUBJECT PROPERTY: The real property being appraised is 154+/- acres in Pittsylvania County, Virginia. The Pittsylvania County Commissioner of the Revenue identifies the property as Tax Parcel No. 2436-60-3630.

PROPERTY INTEREST APPRAISED: Fee Simple

TYPE OF VALUE: Market Value (See USPAP Page U-3)

EFFECTIVE DATES: The effective date of this opinion of value is March 9, 2020. The date of this report is March 24, 2020.

SCOPE OF WORK: To estimate the impact, if any, on the neighborhood surrounding the proposed Mountain Valley Pipeline compressor station located at 987 Transco Road, Chatham, Virginia.

APPRAISAL METHODS USED: I have considered the surrounding land areas and potential impacts to those parcels as a result of the proposed compressor station.

PROPERTY USE: The subject property is proposed to be used as a high transmission gas line compressor station.

EXTRAORDINARY ASSUMPTIONS: It is an extraordinary assumption that no known adverse environmental conditions exist on the site.

HYPOTHETICAL CONDITIONS: The properties have been considered under the hypothetical condition that the proposed Mountain Valley Pipeline compressor station has been constructed.

CERTIFICATION

SUBJECT PROPERTY: **154+/- ACRES IN PITTSYLVANIA COUNTY, VIRGINIA**
TAX PARCEL NO. 2436-60-3630

DATE OF VALUATION: **MARCH 9, 2020**

I certify that, to the best of my knowledge and belief:

- The statements of fact contained in this report are true and correct;
- The reported analyses, opinions, and conclusions are limited only by the reported assumptions and limiting conditions, and are my personal, impartial, and unbiased professional analyses, opinions, and conclusions;
- I have no present or prospective interest in the property that is the subject of this report, and I have no personal interest with respect to the parties involved;
- I have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment;
- I have not performed a previous appraisal, or any other valuation service, of the subject property within the three (3) years prior to this assignment;
- My engagement in this assignment was not contingent upon developing or reporting predetermined results;
- My compensation for completing this assignment is not contingent upon the development or reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value opinion, the attainment of a stipulated result, or the occurrence of a subsequent event directly related to the intended use of this appraisal;
- This report is intended to comply with the Code of Ethics and Standards of Professional Appraisal Practice of the Appraisal Institute. It is further intended to comply with the Uniform Standards of Professional Appraisal Practice (USPAP);
- The reported analyses, opinions, and conclusions were developed, and this report has been prepared, in conformity with the requirements of the Code of Professional Ethics & Standards of Professional Appraisal Practice of the Appraisal Institute;
- Wesley D. Woods has made a personal inspection of the appraised property that is the subject of this report.
- The use of this report is subject to the requirements of the Appraisal Institute relating to review by its duly authorized representatives.
- As of the date of this report, I have completed the Standards and Ethics Education Requirement of the Appraisal Institute.
- I currently hold an appropriate state certification allowing the performance of real estate appraisals in connection with federally related transactions in the state in which the subject property is located.
- This appraisal assignment was not based upon a requested minimum valuation, specific valuation, or the approval of a loan.

- My current or future employment has not been conditioned upon the appraisal producing a specific value or value within a given range.

WESLEY D. WOODS, MAI
CERTIFIED GENERAL REAL ESTATE APPRAISER
VA LIC. NO. 4001 003642
EXP. 5/31/2020

Source Deed

PG0073 MAR 15 18-01222

Prepared by:
M. Shaun Lundy, Esq.
VA Bar No. 82360
Penn, Stuart & Eskridge
P. O. Box 2009
Bristol, VA 24203

Map and Parcel No. 2436-60-1838
Account No. 227527

Assessed Value: $247,000
Sales Price: $175,000

DEED

THIS DEED made this 14th day of March, 2018, by and between **Robert C. Lilley**, **Eve M. Thorson** and **Susan Hellebush Moses**, parties of the first part and also referred to herein collectively as "Grantor," and **Mountain Valley Pipeline, LLC**, with a mailing address of 625 Liberty Avenue, Suite 1700, Pittsburgh, PA 15222, party of the second part and also herein referred to as "Grantee."

WITNESSETH:

That for and in consideration of the sum of One Hundred Seventy-five Thousand Dollars ($175,000) cash in hand paid, and other valuable consideration, receipt of which is hereby acknowledged, the Grantor does hereby **GRANT** and **CONVEY** unto the Grantee, with General Warranty and English Covenants of Title, that certain tract or parcel of land, being Tax ID # 2436-60-1838, and being more particularly described as follows:

A tract of land situate on the waters of Little Cherrystone Creek in Chatham Magisterial District, Pittsylvania County, Virginia, and being more particularly described as follows:

Beginning at a 5/8" rebar found, a corner to Kessler Revocable Trust's 189.595 acres and Transcontinental Gas Pipe Line Company, LLC's 29.292 acres (surveyed concurrently with this survey), thence leaving said 29.292 acres and with said 189.595 acres for five (5) lines

S 26°29'03" W 450.42' to a 5/8" x 30" epoxy coated rebar with a pink plastic cap (5/8" rebar, hereafter) set, from which a 1/2" rebar found with no cap bears S 46°53'35" E at 27.94', thence

S 31°15'27" W 417.89' to a 5/8" rebar set, from which a 1/2" rebar found with no cap bears S 12°18'05" E at 51.34', thence

S 55°58'51" E 519.14' to a 1/2" rebar found with no cap, from which another 1/2" rebar found with no cap, a corner to a Cemetery Lot (surveyed concurrently with this survey), bears S 89°18'12" W at 88.84', thence

S 44°31'49" W at 591.40' passing a 1/2" rebar found with no cap and 1179.79' passing another 1/2" rebar found with no cap, **in all 1527.54'** to another 1/2" rebar found with no cap, thence

S 67°12'45" W 1029.33' to a 5/8" rebar set, a corner to Lisa B. Shorter's 70.005 acres, from which a 1/2" rebar found with no cap, a corner to said 189.595 acres and said 70.005 acres bears S 15°52'35" E at 940.20', thence leaving said 189.595 acres and with said 70.005 acres for two (2) lines

N 15°48'19" W 791.35' to a 1/2" rebar found with a cap labeled "H.J.A. PT", thence

N 11°02'21" W 1154.26' to a 5/8" rebar set, a corner to said 70.005 acres and Samuel J. & Christie O. Adkins' 100.580 acres, from which a 1" iron pipe found bears S 09°46'57" E at 6.92' and from which a 1/2" rebar found with no cap, a corner to said 100.580 acres, bears S 38°49'25" W at 2341.87', thence leaving said 70.005 acres and with said 100.580 acres for a line

N 61°53'53" W 527.52' to a point in the center of Little Cherrystone Creek, a corner to William S. Jones, et al.'s 51.475 acres, from which a 5/8" rebar found with no cap, a corner to said 100.580 acres, bears S 70°19'03" W at 1210.29', thence leaving said 100.580 acres and with said 51.475 acres for fifty-three (53) lines

N 70°21'36" E at 33.94' passing a 5/8" rebar set on top of the creek bank, **in all 199.97'** to a 5/8" rebar found with no cap, thence

N 28°40'30" W at 534.70' passing a 5/8" rebar found with no cap, **in all 562.93'** to a point in the center of an unnamed tributary of Little Cherrystone Creek, thence with the centerline of said unnamed tributary as it meanders for fifty-one (51) lines

N 27°23'40" E 19.54' to a point, thence

N 06°54'05" E 52.25' to a point, thence

N 25°32'40" E 11.00' to a point, thence

S 72°31'43" E 6.73' to a point, thence

N 38°19'36" E 58.00' to a point, thence

N 25°18'08" E 65.02' to a point, thence

N 36°02'02" E 47.21' to a point, thence

N 54°00'57" W 18.08' to a point, thence

N 32°17'34" E 13.34' to a point, thence

N 48°57'19" E 36.26' to a point, thence

N 18°51'49" W 15.76' to a point, thence

N 29°23'16" W 24.48' to a point, thence

N 49°45'32" E 16.02' to a point, thence

N 33°59'06" W 17.83' to a point, thence

N 37°39'38" E 77.76' to a point, thence

N 20°27'51" E 90.04' to a point, thence

N 36°30'13" E 40.42' to a point, thence

N 05°32'31" E 40.91' to a point, thence

N 15°35'58" E 54.48' to a point, thence

N 69°02'59" E 18.14' to a point, thence

N 23°33'48" E 50.87' to a point, thence

N 26°50'01" W 10.59' to a point, thence

N 42°11'25" E 24.05' to a point, thence

S 83°37'47" E 18.49' to a point, thence

N 10°37'53" E 32.33' to a point, thence

N 31°33'13" E 52.87' to a point, thence

S 67°12'04" E 26.27' to a point, thence

N 60°27'33" E 15.68' to a point, thence

N 25°50'48" W 31.89' to a point, thence

N 62°15'25" E 26.95' to a point, thence

N 07°39'13" W 11.05' to a point, thence

N 77°19'11" E 16.30' to a point, thence

S 39°03'26" E 9.81' to a point, thence

N 66°15'20" E 57.20' to a point, thence

N 54°16'07" E 54.94' to a point, thence

N 65°01'08" E 35.09' to a point, thence

N 45°05'52" E 37.28' to a point, thence

N 27°12'16" W 22.68' to a point, thence

N 11°03'36" W 19.65' to a point, thence

N 12°33'31" E 13.97' to a point, thence

N 50°58'35" E 38.60' to a point, thence

S 76°07'57" E 27.76' to a point, thence

N 32°26'03" E 28.34' to a point, thence

S 89°22'26" E 33.68' to a point, thence

N 16°59'27" W 27.94' to a point, thence

S 72°40'24" W 17.69' to a point, thence

N 57°56'45" W 11.30' to a point, thence

N 07°10'40" E 22.49' to a point, thence

N 40°54'42" E 32.61' to a point, thence

N 22°08'04" E 54.04' to a point, thence

N 10°50'46" E 37.79' to a point, thence leaving said centerline of creek and with said 51.475 acres for part of a line and with Mountain Valley Pipeline, LLC's 77.444 acres for its remainder

S 60°40'19" E at 61.72' passing a 5/8" rebar found on a previous survey performed by Allegheny Surveys, Inc. for Mountain Valley Pipeline, LLC's, a corner to said 51.475 acres and said 77.444 acres, at 194.31' passing a 5/8" rebar found with no cap, at 362.26' passing another 5/8" rebar found with no cap and at 539.41' passing a 5/8" rebar found with no cap, **in all 928.58'** to a 5/8" rebar found with no cap, a corner to said 77.444 acres and Transcontinental Gas Pipe Line Company, LLC's 34.453 acres, thence leaving said 77.444 acres and with said 34.453 acres for a line

S 61°45'29" E 694.12' to a 1/2" rebar found with cap (not legible), a corner to said 34.453 acres and Transcontinental Gas Pipe Line Company, LLC's 29.292 acres (surveyed concurrently with this survey), thence leaving said 34.453 acres and with said 29.292 acres for a line

S 59°03'16" E at 949.77' passing the center of a 9' wide dirt road, **in all 1037.35'** to the **Point of Beginning** containing **154.396 acres** as surveyed on the grid north meridian by Allegheny Surveys, Inc. of Birch River, West Virginia on February 13-20, 2018 and shown on a plat titled "Plat of Survey for Mountain Valley Pipeline, LLC VA-PI-112.01" attached hereto, and by reference, made a part of this description.

Being a portion of the property conveyed to Eve M. Thorson, Pattie M. Lilley and P. Donald Moses by P. Donald Moses (Administrator of the Estate for Preston Brooks Moses) by deed dated February 26, 1998 and of record in the Clerk's Office of the Circuit Court of Pittsylvania County, Virginia, in Deed Book 1141 at page 702, and as shown on the plat of survey for "Boundary Survey for Eve M. Thorson, Pattie M. Lilley and P. Donald Moses" recorded in Map Book 44 at Page 206E.

Sellers hereby reserve unto themselves, their heirs and assigns, an undivided one-half interest in all uranium ore underlying the property described herein. If any uranium ore is to be mined or removed, said mining and removal shall require unanimous consent of all co-tenants in the uranium ore estate, which unanimous consent shall not be unreasonably withheld.

This conveyance is made subject to all restrictions, reservations, rightsofway and exceptions, as set forth in prior deeds in the chain of title hereto.

This conveyance is made subject to rights of others in and to the cemetery located on the above described property, including access thereto.

This conveyance is made subject to the foregoing and to the lien for the 2018 real property taxes, which shall be prorated between the parties hereto as of the date of this deed, the said party of the first part hereby covenants to and with the said party of the second part that they will **WARRANT GENERALLY** the title to the property herein conveyed and that the same is free and clear of all liens and encumbrances.

Witness the following signatures:

Robert C. Lilley
Robert C. Lilley

STATE OF NC,
COUNTY OF Wake, **towit:**

I, Diane S Krajewski, a Notary Public in and for the county and state aforesaid, do hereby certify that **Robert C. Lilley**, who signed the foregoing writing, has this day acknowledged the same before me in my said county.

Given under my hand and official seal this 14 day of March, 2018.

My commission expires August 27, 2022.

Diane S Krajewski
Notary Public

[SEAL] Diane S. Krajewski NOTARY PUBLIC Wake County NC

Bristol: 754941-1

PG0079 MAR 15 18

Eve M. Thorson

Eve M. Thorson

STATE OF Maine,
COUNTY OF Cumberland, **to-wit:**

I, Melanie Goldstein, a Notary Public in and for the county and state aforesaid, do hereby certify that **Eve M. Thorson**, who signed the foregoing writing, has this day acknowledged the same before me in my said county.

Given under my hand and official seal this 14 day of March, 2018.

My commission expires 5 Dec 2024.

Melanie Goldstein

Notary Public

[SEAL]

MELANIE A. GOLDSTEIN
Notary Public, Maine
My Commission Expires December 5, 2024

Susan Hellebush Moses

Susan Hellebush Moses

STATE OF California,
COUNTY OF Marin, to-wit:

I, Lisa A. Walsmith, a Notary Public in and for the county and state aforesaid, do hereby certify that **Susan Hellebush Moses**, who signed the foregoing writing, has this day acknowledged the same before me in my said county.

Given under my hand and official seal this 14th day of March, 2018.

My commission expires 10-28-2019

Lisa A. Walsmith

Notary Public

[SEAL] LISA A. WALSMITH
Commission # 2131253
Notary Public - California
Marin County
My Comm. Expires Oct 28, 2019

INSTRUMENT 180001222
RECORDED IN THE CLERK'S OFFICE OF
PITTSYLVANIA COUNTY CIRCUIT ON
March 15, 2018 AT 01:29 PM
$247.00 GRANTOR TAX WAS PAID AS
REQUIRED BY SEC 58.1-802 OF THE VA. CODE
STATE: $123.50 LOCAL: $123.50
MARK W. SCARCE , CLERK
RECORDED BY: TBC

Tax Card

PITTSYLVANIA
COUNTY, VIRGINIA

Parcel ID: 2436-60-3630
Account Number: N/A
Property Address 987 TRANSCO RD

General Information

Owner Name:	MOUNTAIN VALLEY PIPELINE LLC
Owner Address:	EQUITRANS MIDSTREAM CORPORATION CANONSBURG, PA 15317
Property Description:	HALIFAX RD/57
Use Description:	N/A
Total Acreage:	154.4
Square Footage:	N/A
Zoning Description:	A-1 AGRICULTURAL DISTRICT

Township Description:	05 CHATHAM MAGISTERIAL DISTRICT
Neighborhood Description:	100 0%
Map Sheet:	18/02750
Current Owner Deed Book/Page:	LR18/01222
Deed Date:	3/15/2018
General Remarks:	N/A
Previous Sold Price:	$

Building Details

Year Built:	N/A
Effective Year Built:	N/A
Number of Stoies :	N/A
Building Area:	N/A
Building Class:	N/A
Building Description:	N/A
Building Remarks:	N/A
Building Grade Factor:	N/A
Building Grade Amount:	N/A

Interior

Basement Area:	N/A
Basement Finished Percentage:	N/A
Main Attic - Finished Area SqFt:	N/A
Main Attic - Unfinished Area SqFt:	N/A
Attic Area:	N/A
Attic Finished Percentage:	N/A
Number of Rooms:	N/A
Number of Bedrooms:	N/A
Full Baths:	N/A
Half Bath:	N/A
Fireplace:	N/A
Chimneys:	N/A
Floor Description:	N/A
Interior Description:	N/A

Exterior

Condition Description:	N/A
Road Description:	03 DIRT
Found Description:	N/A
Structure Description:	N/A
Style Description:	N/A
Exterior Wall Description:	N/A
Roof Description:	N/A

Utilities

Fuel Description:	N/A
Heat Description:	N/A
Air Description:	N/A
Fire Description:	N/A
Main Heating Area SqFt:	N/A
Main Air Conditioned Area SqFt:	N/A
Main Fire Place Area SqFt:	N/A

Assessments Information

Last Appraiser:	N/A
Last Appraised Date:	N/A
Building Undepreciated Value:	N/A
Building Physical:	N/A
Active Building Value:	N/A
Building Subtotal:	N/A
Total Land Value:	$298,200
Total Building Value:	$

Total Market Value:	$298,200
Total Use Deferment:	0
Total Net Value:	$298,200
Previous Land Value:	$298,200
Previous Building Value:	$
Previous Use Deferment:	$
Previous Net Value:	$298,200
Total Improvement:	$

PITTSYLVANIA
COUNTY, VIRGINIA

Legend

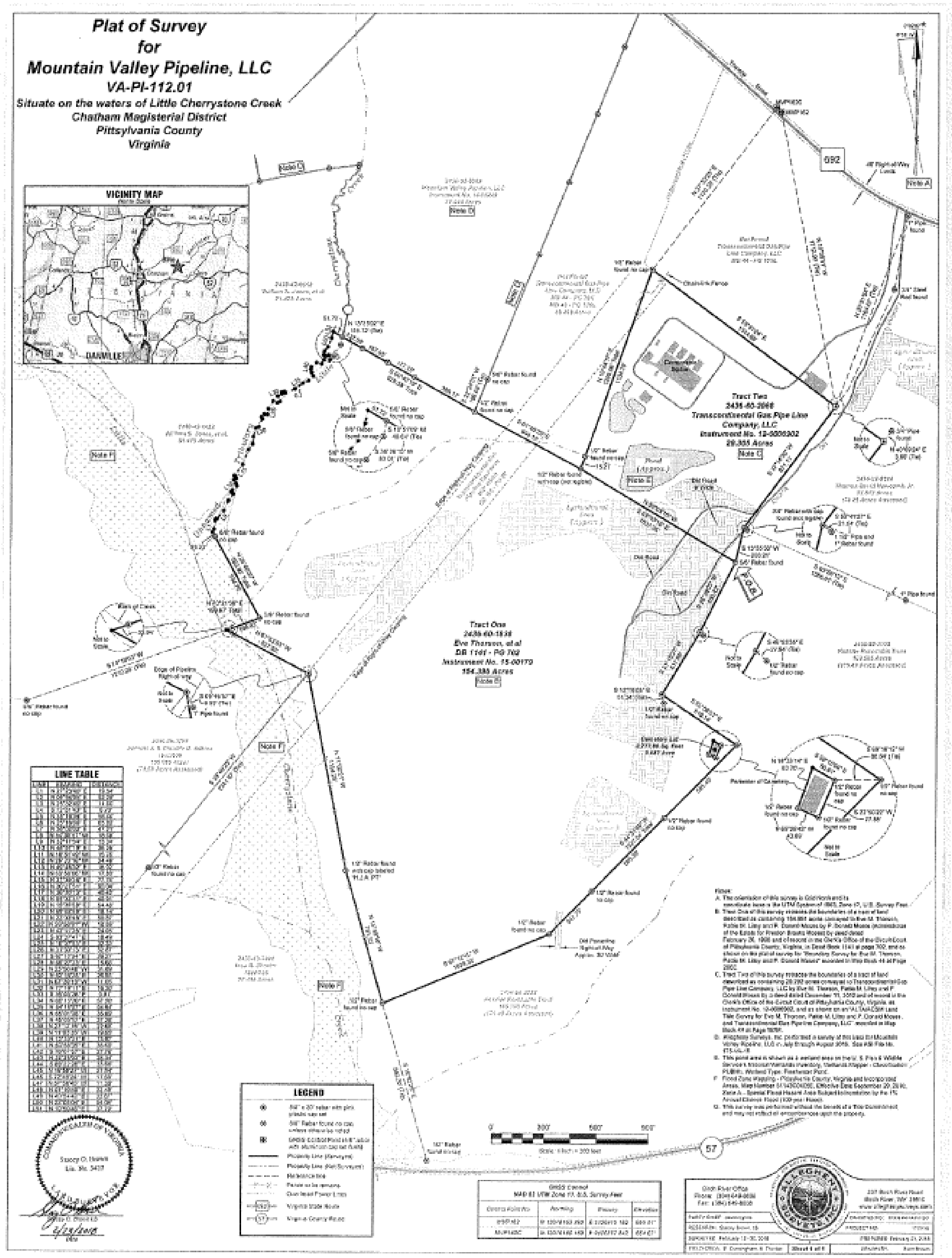
- Assessed Parcels
- Parcels
- County Boundary

Feet
0 500 1000 1500 2000

Title: Assessed Parcels **Date: 3/24/2020**

DISCLAIMER: This drawing is neither a legally recorded map nor a survey and is not intended to be used as such. The information displayed is a compilation of records, information, and data obtained from various sources, and Pittsylvania County is not responsible for its accuracy or how current it may be.

SURVEY


Plat of Survey
for
Mountain Valley Pipeline, LLC
VA-PI-112.01
Situate on the waters of Little Cherrystone Creek
Chatham Magisterial District
Pittsylvania County
Virginia
VICINITY MAP
DANVILLE
Tract One
Tract Two
LINE TABLE
LEGEND
Notes:
Note A
Note B
Note C
Note D
Note F
692
57

Aerial Map


1213
1981
945
766
896
600
629
397
575
192
288
709
987
421
397
105
461
605
520
345
740
1004
960
892
792
406
614
640
929
893
865
709
700
713
989
709
687
272
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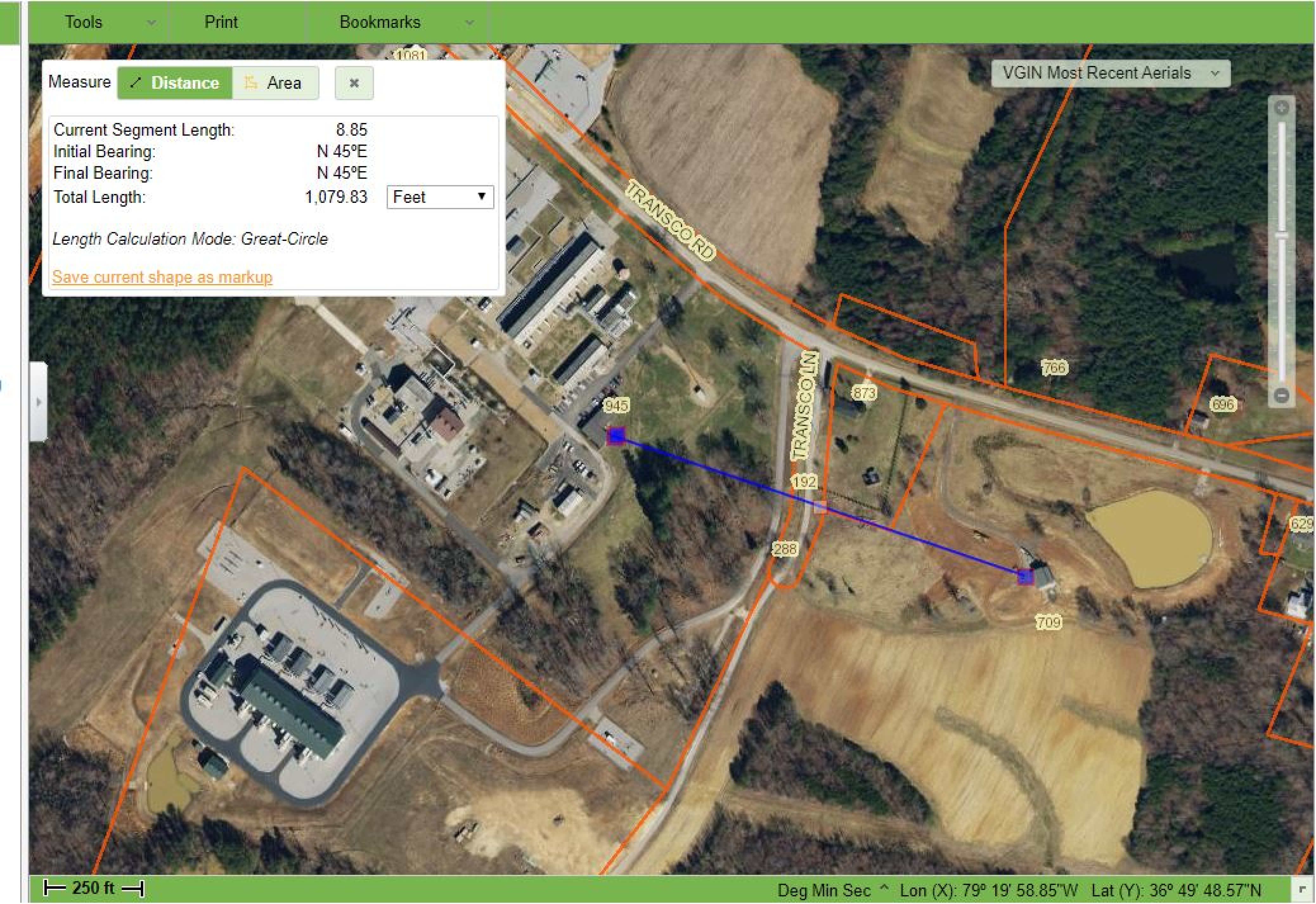
4117
3240
3821
DOB LN


Tools
Print
Bookmarks
Measure
Distance
Area
Current Segment Length: 8.85
Initial Bearing: N 45ºE
Final Bearing: N 45ºE
Total Length: 1,079.83
Feet
Length Calculation Mode: Great-Circle
Save current shape as markup
VGIN Most Recent Aerials
1081
TRANSCO RD
TRANSCO LN
766
873
696
945
192
288
629
709
250 ft
Deg Min Sec
Lon (X): 79º 19' 58.85"W
Lat (Y): 36º 49' 48.57"N

**INFERRED ANALYSIS OF THE
REAL ESTATE TRENDS NEAR THE
MOUNTAIN VALLEY PIPELINE COMPRESSOR STATION
LOCATED SOUTHWEST OF TRANSCO ROAD (STATE ROUTE 692),
ADJACENT TO TRANSCO VILLAGE
PITTSYLVANIA COUNTY, VIRGINIA 24531
MLA FILE MVP-VA-PI-001**

MILLER, LONG & ASSOCIATES, INC.
REAL ESTATE APPRAISAL COMPANY
2618 Colonial Avenue, SW
Roanoke, Virginia 24015-3834

SAMUEL B. LONG, MAI, CRE, SRA
JARED L. SCHWEITZER, MAI
THOMAS D. BARLOW, MAI, SRA
M. KIRBY SMELTZER, JR.
PATRICIA C. BOONE, MAI
GREGORY W. MACKEY
M. HANES FELDMANN
JOHN H. MILLER, MAI (1920 – 2013)

BUSINESS TELEPHONE
(540) 345-3233

FAX NUMBER
(540) 344-3966

WEB ADDRESS
www.millerlongandassociates.com

June 3, 2020

Wade W. Massie, Esq.
Seth M. Land, Esq.
Penn Stuart & Eskridge, PLC
P.O Box 2088
Abingdon, Virginia 24212

RE: Inferred analysis of the
Real estate trends near the
Mountain Valley Pipeline Compressor Station
Located southwest of Transco Road (State Route 692), adjacent to Transco Village
Pittsylvania County, Virginia 24531
MLA File MVP-VA-PI-001

Dear Mr. Massie and Mr. Land:

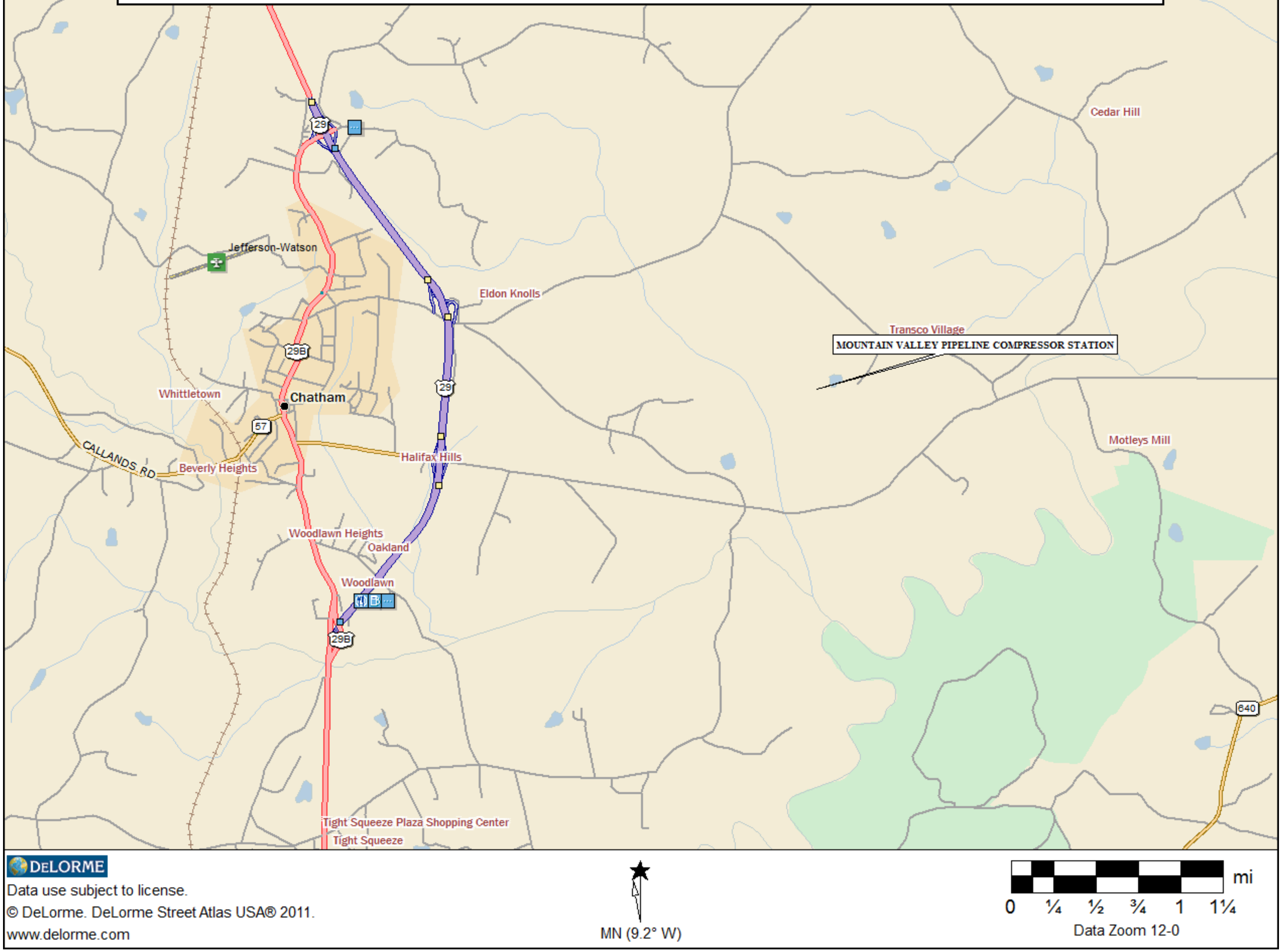
At your request, I have examined real estate trends near the Mountain Valley Pipeline compressor station property located south of Transco Road (State Route 692), within Pittsylvania County, Virginia. Additionally, this property is located in central Pittsylvania County, ±2.5 miles east of U.S. Route 29 and ±2.8 miles east of the Town of Chatham (Pittsylvania County seat). The property contains ±154.396 acres (per legal description) and is identified by Pittsylvania County as Parcel ID 2436-60-3630. Additionally, this parcel is identified by Mountain Valley Pipeline as VA-PI-002.000.

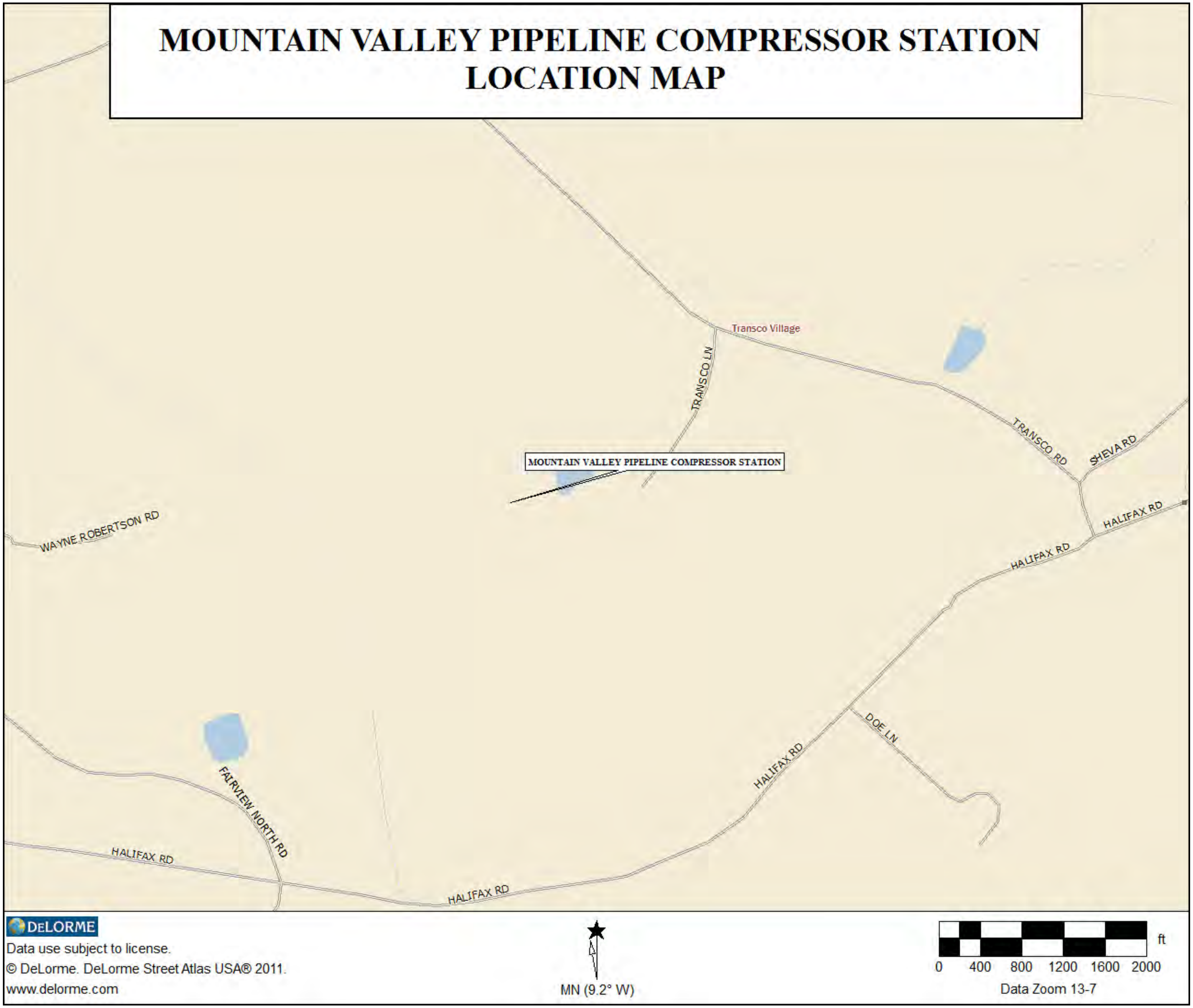
By definition, inferred analysis is "A prediction of future market conditions based on inferences drawn from general market information, published data, and historical trends in rents and absorption rates and occupancy for similar property types." (Source: The Appraisal Institute, *The Dictionary of Real Estate Appraisal, 6th Edition,* Page 117, 2015).

On May 20, 2020, I met with a representative of Mountain Valley Pipeline, LLC, and observed the parcel owned by Mountain Valley Pipeline, LLC. The total property owned in the area contains ±234.84 acres. The property representative showed me the interior of VA-PI-002.000, and showed me where the planned location for the Southgate Extension pipeline would commence at the compressor station. Additionally, the Mountain Valley Pipeline, LLC representative showed me the interior of the adjoining parcels owned by Mountain Valley Pipeline, LLC, identified by Pittsylvania County as Parcel IDs 2436-53-9983 and 2436-64-3488. These parcels are identified by Mountain Valley Pipeline as VA-PI-001.000 and VA-PI-002.015.CY01. After my observation, I drove through and observed the immediate market area and noted the property uses of surrounding properties and lands.

The following pages include maps (location maps and aerial maps) that can garner a better understanding of the immediate area, as well as the compressor station property.

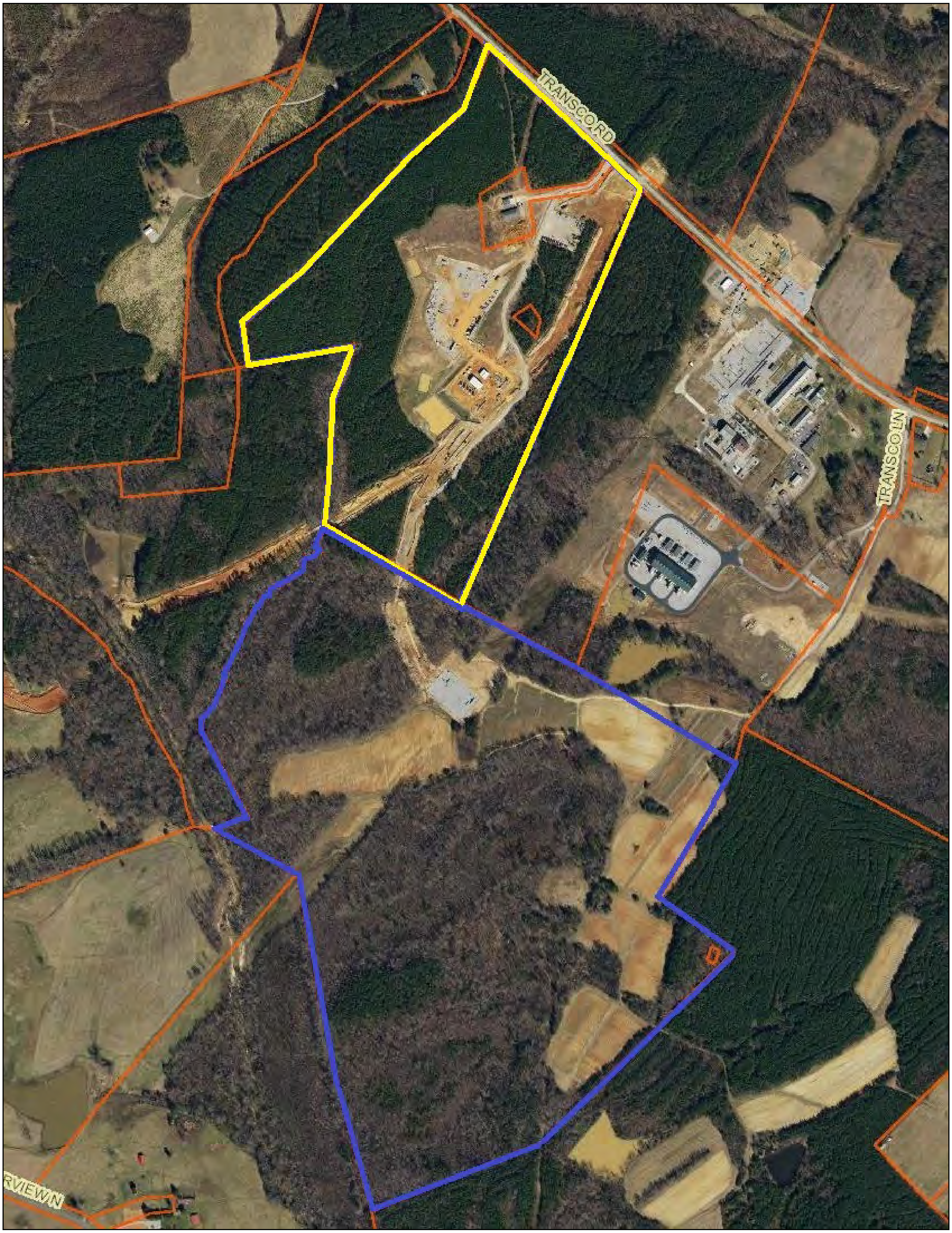
MOUNTAIN VALLEY PIPELINE COMPRESSOR STATION LOCATION MAP



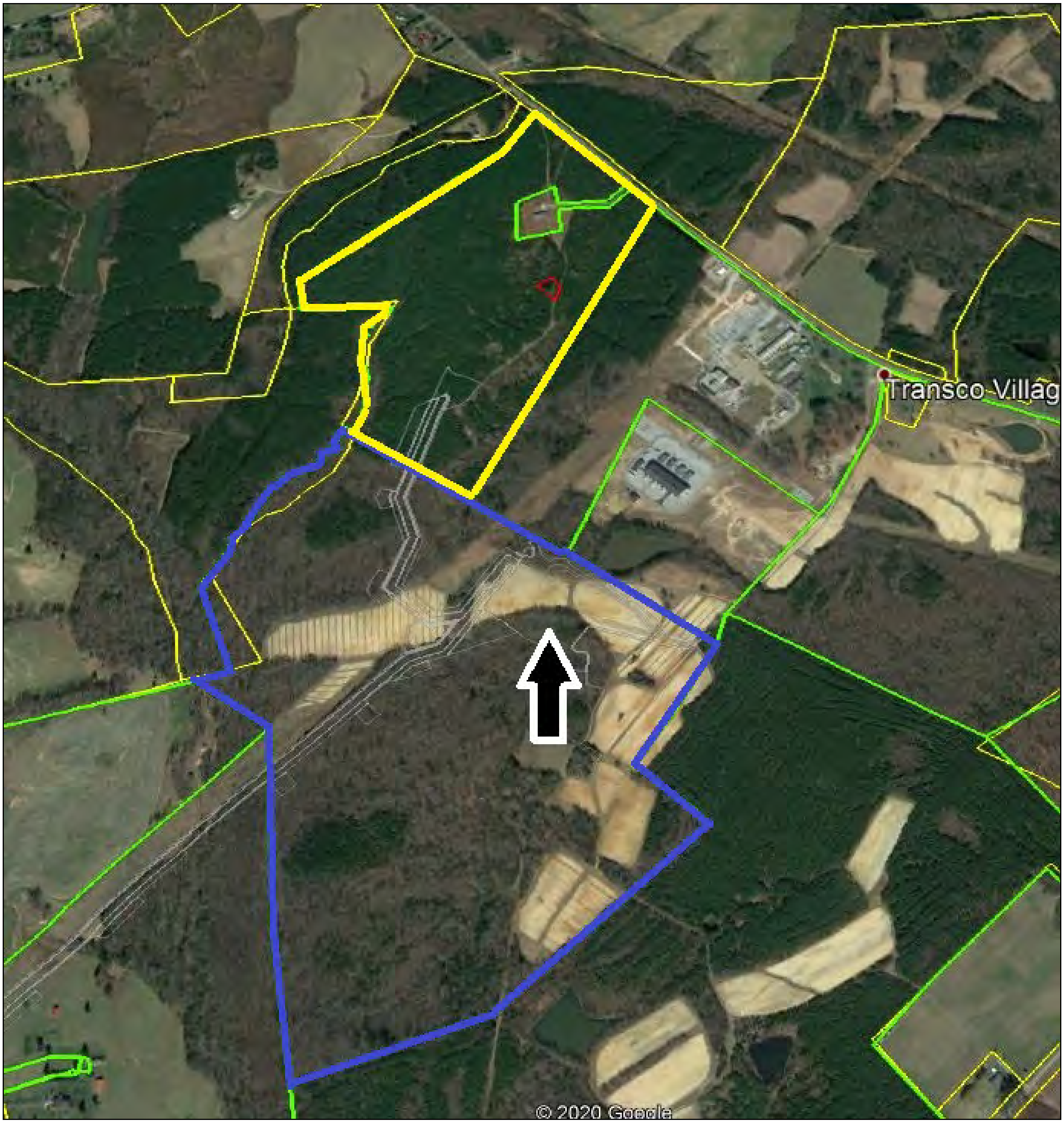


MOUNTAIN VALLEY PIPELINE COMPRESSOR STATION
LOCATION MAP
Transco Village
TRANSCO LN
TRANSCO RD
SHEVA RD
MOUNTAIN VALLEY PIPELINE COMPRESSOR STATION
HALIFAX RD
HALIFAX RD
WAYNE ROBERTSON RD
DOE LN
HALIFAX RD
FAIRVIEW NORTH RD
HALIFAX RD
HALIFAX RD
DELORME
Data use subject to license.
© DeLorme. DeLorme Street Atlas USA® 2011.
www.delorme.com
MN (9.2° W)
ft
0 400 800 1200 1600 2000
Data Zoom 13-7

AERIAL MAP OBTAINED FROM PITTSYLVANIA COUNTY GIS SHOWING COMPRESSOR STATION PROPERTY OWNED BY MOUNTAIN VALLEY PIPELINE, LLC (OUTLINED IN BLUE) AND OTHER PARCELS OWNED BY MOUNTAIN VALLEY PIPELINE, LLC (OUTLINED IN YELLOW)



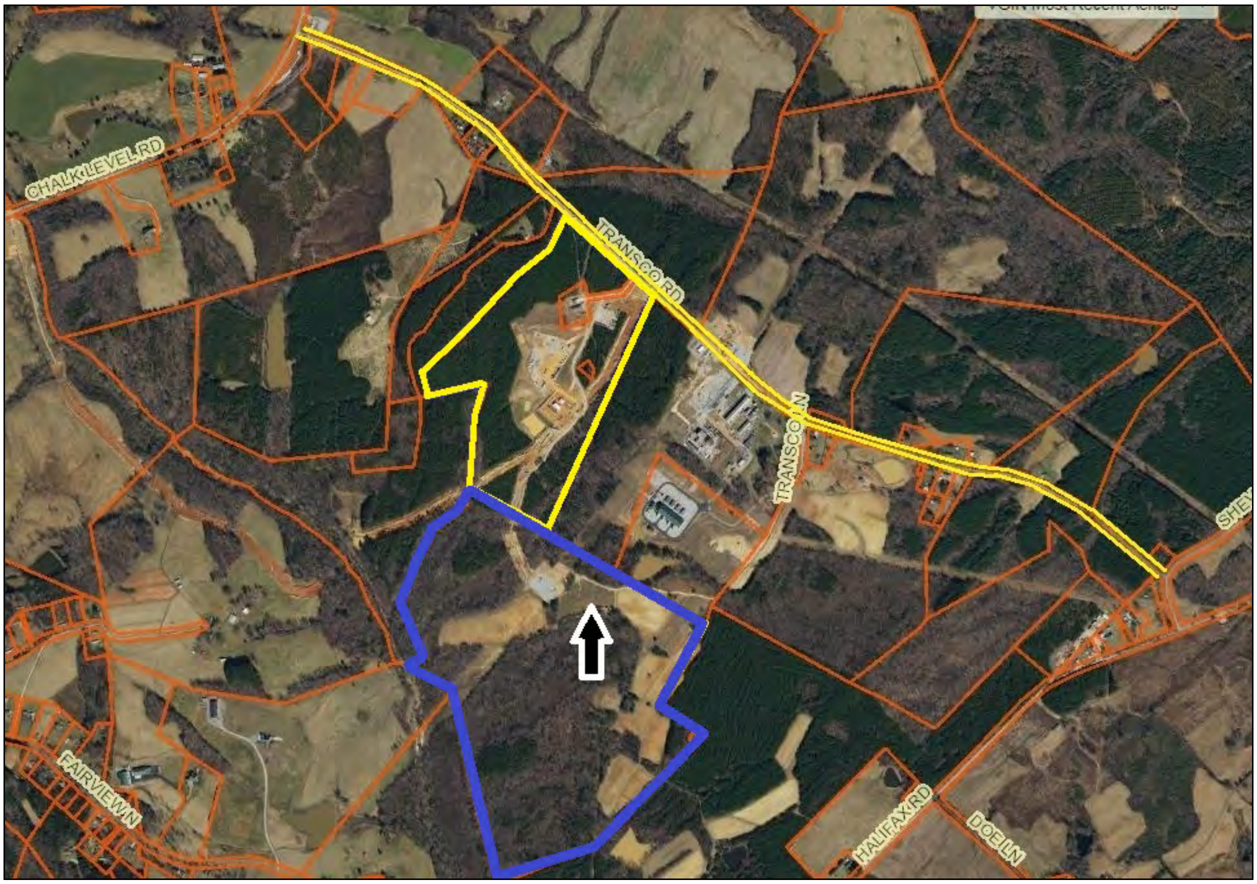
AERIAL MAP OBTAINED FROM GOOGLE EARTH AND PROVIDED BY THE CLIENT SHOWING APPROXIMATE LOCATION OF COMPRESSOR STATION ON THE PROPERTY



The market area analyzed on May 20, 2020 includes and considers surrounding property in all directions, specifically along Transco Road, between Chalk Level Road and Sheva Road. The following information provides greater detail and illustration of the uses along Transco Road.

TRANSCO ROAD (STATE ROUTE 692):

Transco Road (State Route 692) is a two-lane, asphalt paved and state-maintained roadway. This roadway is ±1.9 miles in length, and connects with Chalk Level Road (State Route 685) to the northwest and Sheva Road (State Route 649) to the southeast. The aerial map below highlights the Mountain Valley Pipeline compressor station property in blue, the adjoining parcels also owned by Mountain Valley Pipeline in yellow and Transco Road in yellow.



Property uses along this roadway are predominately agricultural and recreational (including timber growth), with some single-family residential uses noted as well. Also, noted are the existing Williams Co. (Transcontinental Pipeline) tracts (Parcel IDs 2436-73-3459 and 2436-72-5208). These parcels are located contiguous to the Mountain Valley Pipeline properties to the immediate southeast. Zoning of the properties along Transco Road (State Route 692) are predominately A-1, Agricultural District, with nine other (9) parcels zoned R-1, Residential Suburban Subdivision District, two other (2) parcels zoned M-2, Industrial District, Heavy Industry, one other (1) parcel zoned B-2, Business District, General and three other (3) parcels that do not have a zoning district classification, according to the Pittsylvania County GIS zoning overlay map.

Based on my research, there are twelve (12) single-family residential dwellings along Transco Road (State Route 692), eight (8) of which are more modest dwellings ranging in size from ±1,025 S.F. to ±1,823 S.F. and original construction dates ranging between 1957 and 1972. The remaining four (4) single-family dwellings are more recently built dwellings (2007, 2011, 2013 and 2018, respectively), ranging in size from ±1,892 S.F. to ±2,708 S.F. The four (4) more recently built single-family dwellings along Transco Road (State Route 692) appear to be of good quality construction.

No parcels along Transco Road will have a direct view of the proposed natural gas location compressor station. The compressor station will be located in close proximity to the northeast boundary line of Parcel ID 2436-60-3630, just southwest of the Williams Co. parcels where the Transco Village compressor station has been located for many years. In fact, the improvements and the compressor station situated on the Williams Co. parcels to the immediate north inhibits essentially all visibility from Transco Road (State Route 692) of the situs of the Mountain Valley Pipeline compressor station. Additionally, the wooded coverage of Parcel ID 2436-60-3630 (MVP Parcel No. VA-PI-002.000), as well as the contours of the land, limits most, if not all of the visibility of the compressor station from Fairview North Road and Halifax Road to the southwest and southeast, respectively. There is no data to support that the use of properties along the roadways in the immediate area (Transco Road, Fairview North Road, Halifax Road, Transco Lane) will change, or that the values of these properties will be affected negatively by the Mountain Valley Pipeline, LLC compressor station.

As stated, Williams Co. has had the Transco Village compressor station in this immediate location for many years. The first pipeline was built c.1949 and there have been several added since that time. Residents in the immediate area have made the decision to build along Transco Road despite the location of the existing compressor station.

In addition to the above, the proposed compressor station will be adjacent to a similar site that functions in a similar capacity. The Transco compressor station is situated on two (2) adjoining parcels of land (Parcel IDs 2436-72-5208 and 2436-73-3459) that contain an approximate total area of 100.32 acres (measured utilizing Pittsylvania County GIS).

In conclusion, after a thorough observation of the Mountain Valley Pipeline, LLC compressor station property, and the immediate market area, there is no evidence to suggest that the use and value of the surrounding properties will be negatively impacted by the Mountain Valley Pipeline compressor station. As stated previously, Williams Co. and Transco have operated a natural gas compressor station in the immediate area for many years. The first natural gas pipeline operated by Transco was installed c.1949.

Thank you for the opportunity to be of service. Please let me know if you need clarification or additional information.

Sincerely,

Jared L. Schweitzer, MAI
VIRGINIA CERTIFIED GENERAL APPRAISER #4001009036

JLS/GWM/jmm

P:/APPRAISALS/MOUNTAIN VALLEY PIPELINE/SOUTHGATE EXTENSION/MVP, LLC COMPRESSOR STATION TRACT.DOC

133 Kirk Avenue SW
Roanoke, VA 24011
Phone: 540.491.9988
Info@Thompsonvc.com

June 2, 2020

Mountain Valley Pipeline, LLC
C/O
Seth Land
Penn Stuart
208 E. Main Street
Abingdon, VA 24210

Re: Consulting Assignment related to:
Proposed Compressor Station
Transco Road
Chatham, VA 24351
TVC File No.: 20-5

Dear Mr. Land:

As requested, I have conducted an investigation of the effect on property values resulting from the presence of a compressor station within the subject neighborhood. The attached consulting report has been prepared in conformance with my understanding of the appraisal standards and requirements of the Appraisal Institute.

The purpose of the following consulting assignment is to form an opinion of the effects on the neighborhood's property values as a result of a natural gas compressor station. The intended use of this report is to provide information to the client, Mountain Valley Pipeline, LLC and counsel.

The subject neighborhood and other neighborhoods surrounding compressor stations in the region have been reviewed. After this investigation, I have concluded that **the subject neighborhood will not realize adverse effects on property value resulting from Mountain Valley Pipeline's proposed natural gas compressor station.**

Respectfully Submitted,

Joseph E. Thompson, MAI, CCIM
VA Certification No. 4001-010982

EXECUTIVE SUMMARY

Client: Mountain Valley Pipeline, LLC

Intended Use/User: The intended use of this consulting assignment is to provide information to the client, Mountain Valley Pipeline, LLC and counsel.

Purpose: The purpose of this consulting assignment is to form an opinion of the effects on the neighborhood's property values as a result of a natural gas compressor station.

Effective Date of Opinions: June 2, 2020

Scope of Work in Review:

- Observe proposed location of compressor station and review proposed layout
- Observe surrounding properties
- Research transactional and land use history within immediate market area
- Conduct similar investigations for existing compressor stations in the region
- Develop an opinion of the effects of compressor stations on property value and land use patterns in the neighborhood

After a review of land use patterns and transactional data in the immediate market area and other market areas with compressor station presence, it is my opinion that **the subject neighborhood will not realize adverse effects on property value resulting from Mountain Valley Pipeline's proposed natural gas compressor station.**

SUMMARY OF INVESTIGATION

SUBJECT AREA & EXISTING TRANSCO COMPRESSOR STATION

Subject Area

The subject's immediate area has been investigated for land use and transactional data given the presence of an existing natural gas compressor station operated by Williams Companies (Transco). With signage at both access points to Transco Road designating a natural gas facility and the prominence of the structures visible from the roadway, the presence of the compressor station is known.

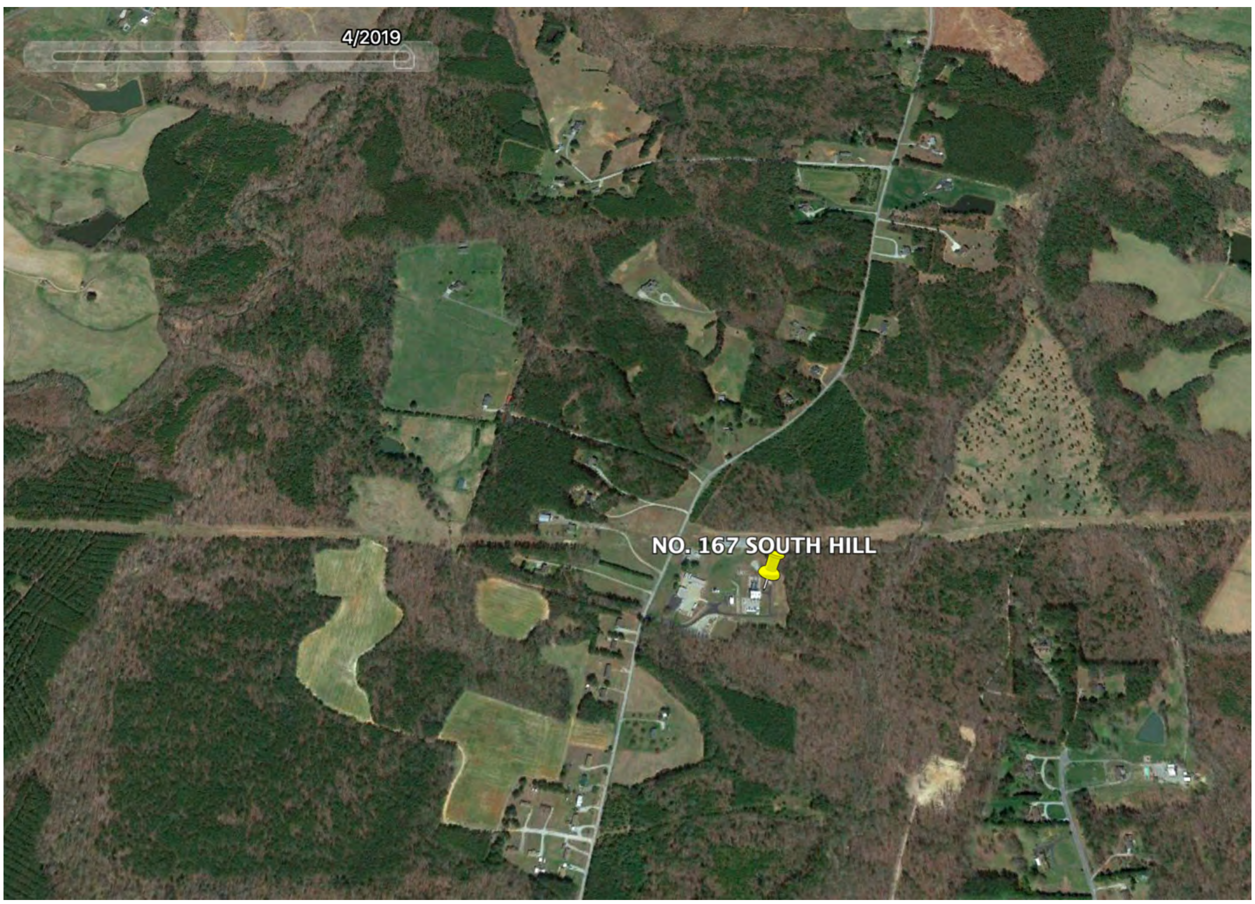
Illustrations have been inserted in the addenda section of this report. As shown, the market is generally rural in nature. The following items summarize the findings of the investigation:

- A dwelling was recently constructed in proximity to the subject property. Adjacent to the holdings of Williams Companies (Transco) and Mountain Valley, this is the most recent construction along Transco Road. The improvements are above average in size and quality for the neighborhood. This investment suggests that no stigma is created by the presence of the existing natural gas compressor station.

- Previous Sale of 626 Transco Road at $92,000 shows no diminution in value when compared with sales outside of the immediate area that are not in proximity to a compressor station. This suggests that market values are not negatively affected in the immediate area of the neighborhood.

- Adjacent to the south of the existing compressor station is the neighborhood's most prominent residential development along Fairview Road. This community enjoys some of the highest assessments in the market and most stately residences. This suggests that land use patterns are in the neighborhood are not negatively affected by the existing compressor station.

SOUTH HILL COMPRESSOR STATION



South Hill

This station is located in a rural area of Southside Virginia outside of the town of South Hill. The following items summarize the findings of the investigation related to the South Hill neighborhood.

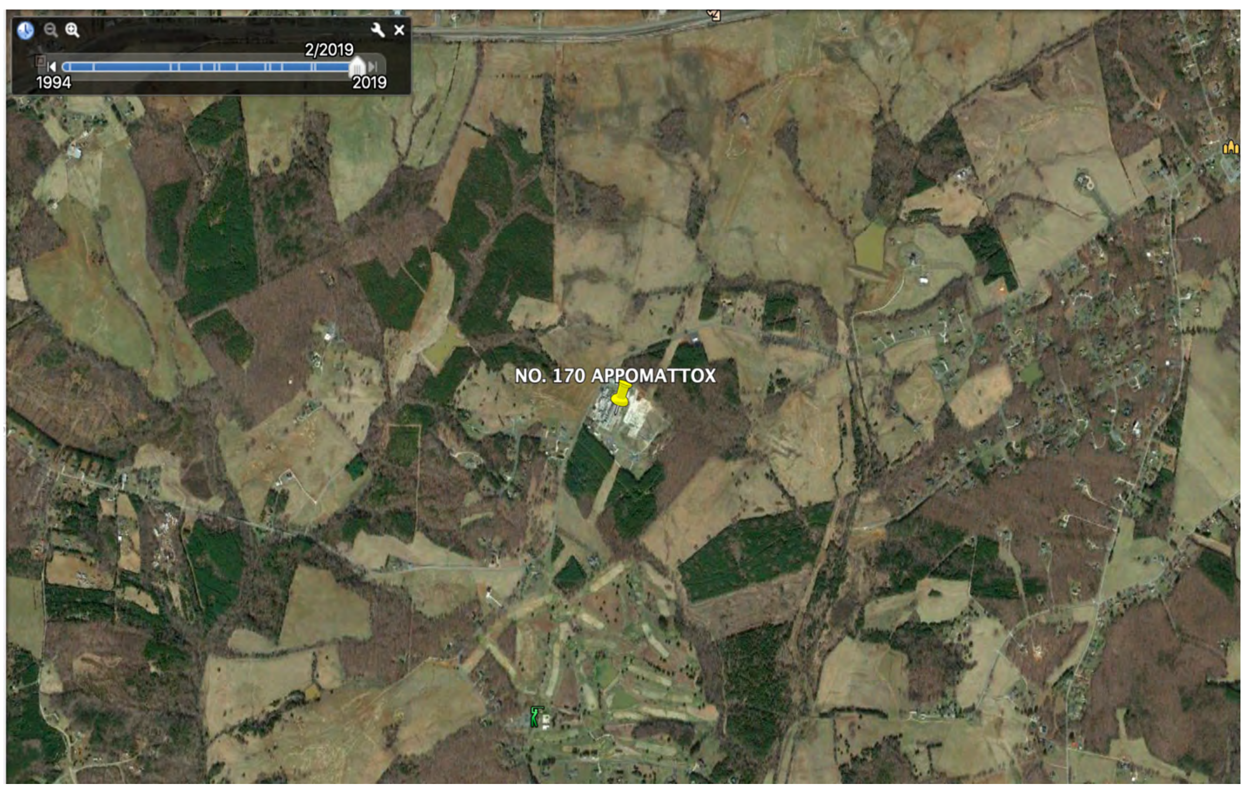
- Recently the subdivision and bulk sale of lots to a builder has taken place adjacent to the site to the north.

- Nearby sales in 2019 reflect some of the highest price sales in the market. This indicates that no adverse effects were realized on market value in the immediate area of the neighborhood.

- Multiple single-family homes were constructed across Choptico Road since the mid-1990s. These residences reflect the upper end of housing in the neighborhood.

- Land use patterns in the immediate area were not affected by the presence of the compressor station. This is evidenced by the noted activity and anticipated future activity resulting from the adjacent development. Overall, the character of the immediate area is similar to that of the perimeter communities of South Hill.

APPOMATTOX COMPRESSOR STATION



Appomattox

This station is located in a rural area of Central Virginia outside of the town of Appomattox. The following items summarize the findings of the investigation related to the neighborhood.

- Located just north of the Falling River Country Club.
- One of the neighborhood's highest quality residences was constructed approximately 1,500 feet or two parcels away from the compressor station in 2004. This investment indicates that a stigma does not exist in the neighborhood resulting from the presence of the compressor station.
- Land use patterns in the immediate area were not affected by the presence of the compressor station. This is evidenced by surrounding subdivisions. Overall, the character of the immediate area is similar to that of the perimeter communities of Appomattox.

GALA COMPRESSOR STATION

Gala

This station is located in a rural area of Botetourt County north of the Roanoke Valley along the neighborhood's primary corridor, Route 220. The following items summarize the findings of the investigation related to the neighborhood.

- This area is restricted by topography and flooding, forcing most development in the village of Gala to be confined to the immediate area of the compressor station.
- The village's only commercial use, Kelly's Market, is located adjacent to the compressor station. This property sold in recent years and the seller reports that the proximity to the compressor station was not a factor in pricing.
- Accessed from a right of way through the compressor station parcel, the adjacent recreational kayaking area has recently been upgraded by Botetourt County. Botetourt County has invested in the form of a 2018 purchase, grading, site improvements, and signage. This recreational use and subsequent investment show the area's acceptance of the use.

REIDSVILLE COMPRESSOR STATION

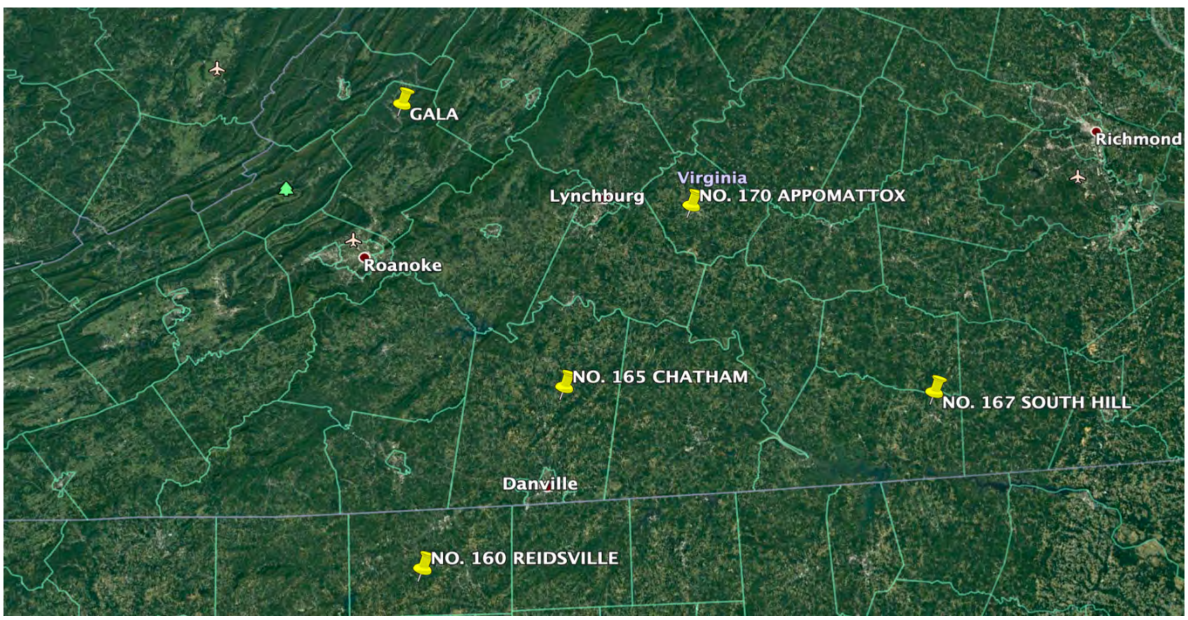
Reidsville Compressor

This is station is located in a generally rural area of North Carolina. At 7 miles outside of Reidsville, the rural development pattern appears uniform and unaffected by the presence of a compressor station.

As for property immediately adjacent to compressor stations, the previously provided summaries indicate that with appropriate setbacks and unobstructed viewshed no negative effects on adjacent property is realized.

COMPRESSOR STATIONS IN THE REGION

As shown in the below illustration, each of the compressor stations in the region have been investigated for evidence of negative effects on property value and land use. Each of these stations are located within similar rural markets and do not exhibit any evidence of negative effects on market values within their respective neighborhoods.



SUMMARY & CONCLUSION

The existing Transco compressor station and its lack of effect on the subject neighborhood are an excellent indication that the neighborhood will not realize a decrease in property value or negative effects on land use as a result of the proposed project.

After this investigation, I have concluded that **the subject neighborhood will not realize adverse effects on property value resulting from Mountain Valley Pipeline's proposed natural gas compressor station.**

APPRAISER CERTIFICATION

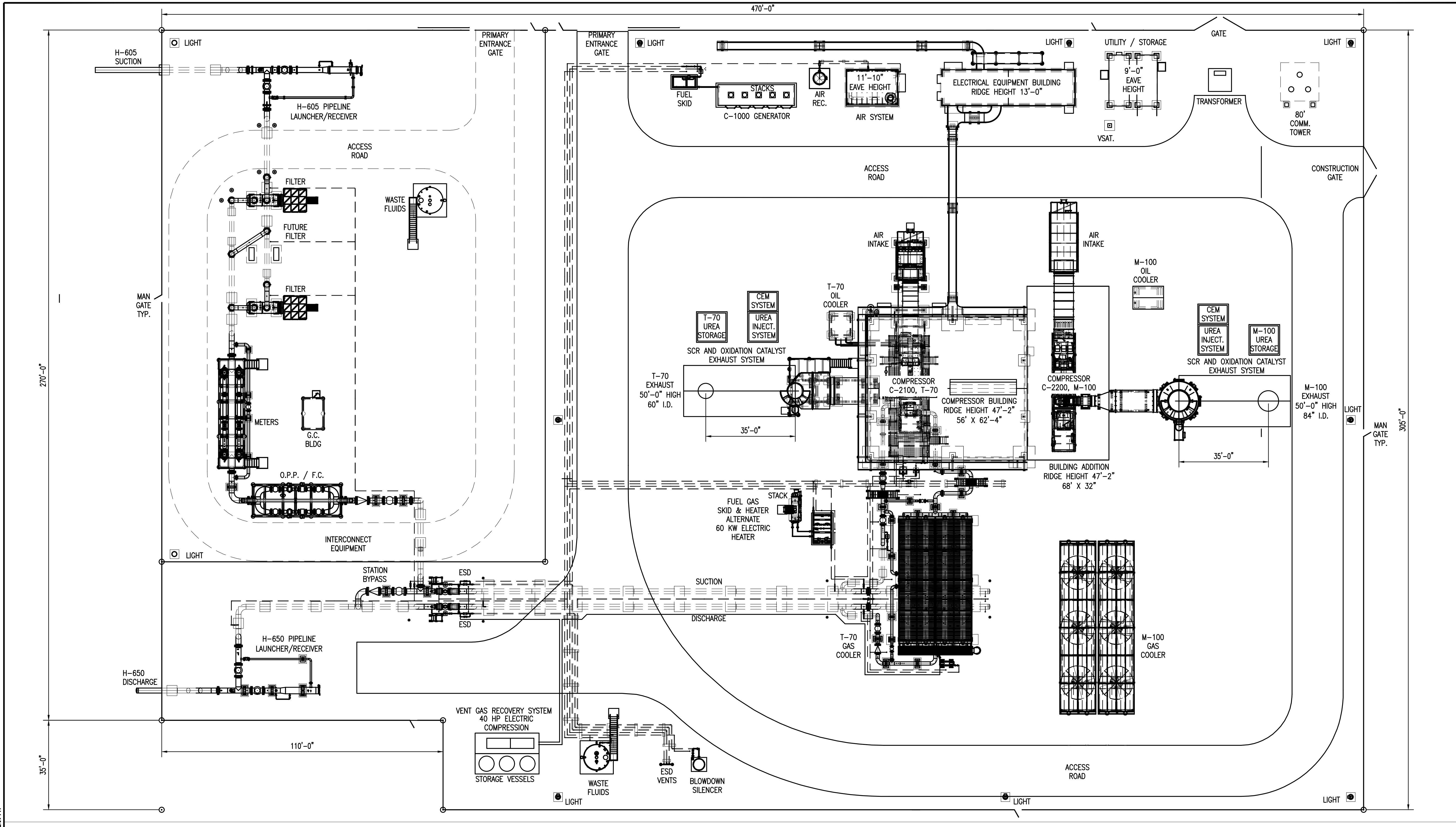
I certify that, to the best of my knowledge and belief:

- The statements of fact contained in this report are true and correct.
- The reported analyses, opinions, and conclusions are limited only by the reported assumptions and limiting conditions and are my personal, impartial, and unbiased professional analyses, opinions, and conclusions.
- I have no present or prospective interest in the property that is the subject of the work under review and no personal interest with respect to the parties involved.
- I have performed no services, as an appraiser or in any other capacity, regarding the property that is the subject of the work under review within the three-year period immediately preceding the acceptance of this assignment.
- I have no bias with respect to the property that is the subject of the work under review or to the parties involved with this assignment.
- My engagement in this assignment was not contingent on an action or event resulting from the analyses, opinions, or conclusions in the review or from its use.
- My compensation is not contingent on an action or event resulting from the analyses, opinions, or conclusions in this review or from its use.
- My compensation for completing this assignment is not contingent upon the development or reporting of a predetermined value or direction in value that favors the cause of the client, the amount of the value opinion, the attainment of a stipulated result, or the occurrence of a subsequent event directly related to the intended use of this appraisal review.
- My analyses, opinions, and conclusions were developed and this consulting report was prepared in conformity with the Uniform Standards of Professional Appraisal Practice.
- The use of this report is subject to the requirements of the Appraisal Institute relating to review by its duly authorized representatives.
- I have not made a personal inspection of the property that is the subject of the work under review.
- No one provided significant real property appraisal assistance to the person signing this certification.
- As of the date of this report, I have completed the continuing education program of the Appraisal Institute.

Joseph E. Thompson, MAI, CCIM

SUBJECT IMMEDIATE AREA

SUBJECT NEIGHBORHOOD



NO.	DATE	REVISION	BY	CHK	APPD	NO.	DATE	REVISION	BY	CHK	APPD
B	08/09/2019	FOR PERMITTING	JPO	JAK	JTA						
	3/05/2020	FOR PERMITTING	DKM								

TO THE BEST OF MY KNOWLEDGE, ALL COMPONENTS OF THIS DRAWING ARE DESIGNED IN ACCORDANCE WITH APPLICABLE GUIDELINES AND SPECIFICATIONS

DOUGLAS K. MACE — 07/22/19
MECHANICAL DESIGN ENGINEER — DATE

TIMOTHY L. WHITE — 07/22/19
ELECTRICAL DESIGN ENGINEER — DATE

NOTE: ANY CHANGES TO THE DESIGN SHOWN ON THIS DRAWING MUST BE APPROVED BY THE DESIGN ENGINEER.

DESIGN ENGINEERING

MVP SOUTHGATE

SYSTEM NAME: MVP SOUTHGATE
LOCATION: Transco Ln, Chatham, VA 24351
PROJECT ID: C14295
DRAWING SCALE:

DRAWING TITLE: LAMBERT COMPRESSOR STATION

FACILITY	STATE	IDENTIFICATION	SERIES	SHEET	REVISION
C	V	LAM			P

Plotted by: Mace, Doug on: April 17, 2020 - 2:09 PM

File Path: C:\Working\Z__ONE DRIVE PREP PROJECTS\2CURRENT PROJECTS\SOUTHGATE\AIR PERMIT\Lambert Permitting 8-09-2019 REV 4-17-2020.dwg

APPENDIX K
MVP Southgate Project Support Letters

August 22, 2018

Ms. Kimberly Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, D.C. 20426

Subject: Docket No. PF18-4, the MVP Southgate project

Dear Ms. Bose:

With more than 26,000 member companies, the Virginia Chamber of Commerce is the leading advocate for business and economic growth in the Commonwealth. The Chamber is dedicated to working at the state and federal levels to champion long-term economic growth in Virginia, and it is with this mission in mind that the Chamber submits this letter in support of the proposed MVP Southgate project.

As the Federal Energy Regulatory Commission evaluates potential impacts of the proposed pipeline's construction, the Chamber fully supports efforts to ensure that this important infrastructure project is constructed and operated in a way that is environmentally sound and respectful of landowners' rights. Stringent review and regulation of project plans at the state and federal levels will help ensure that this is the case. It also is our understanding that the project team's currently proposed route through Virginia is largely collocated along an existing pipeline right-of-way in order to minimize impacts on the surrounding environment and communities.

The proposed MVP Southgate project is anticipated to generate significant economic activity by creating hundreds of jobs in Virginia during construction and substantial tax revenues for local and state governments. Manufacturing companies, like many major employers, depend on access to natural gas to fuel their business operations because it is reliable and cleaner than coal, and it's also abundant in the U.S. and very affordable. These features can allow businesses to increase efficiency, boost output and pass along savings to consumers while strengthening U.S. energy independence.

Certain regions in Virginia, including Pittsylvania County in Southern Virginia, have lacked the access to natural gas needed to draw new businesses and retain existing businesses. Unemployment rates in Southern Virginia remain higher than the state average and underscore the need for policies and projects that provide additional economic opportunity. As an open-access natural gas transmission line, the MVP Southgate proposal is one such project that could help position the region for long-term growth.

Another is the Berry Hill Industrial Park, through which the proposed MVP Southgate project would pass. The Berry Hill site is a 3,700-acre mega-park and the largest such park in Virginia. It represents a joint effort by the City of Danville and Pittsylvania County to create conditions and an environment capable of attracting economic activity, and it carries tremendous potential for recruiting major employers and spurring development and growth throughout the region. Federally-certified Opportunity Zones in the region also help to position it for growth through tax incentives that are designed to promote investment there.

The prospect of increasing access to natural gas in a responsible and safe manner through MVP Southgate is welcome and promising. The Virginia Chamber of Commerce fully supports the proposed MVP Southgate project.

Sincerely,

Barry E. DuVal
President and CEO

VOGA
Virginia Oil & Gas Association
408 West Main Street, Abingdon, VA 24210

September 6, 2018

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

Subject: MVP Southgate – Docket No. PF18-4-000

Dear Ms. Bose:

On behalf of the Virginia Oil and Gas Association ("VOGA"), I am writing in support of the proposed MVP Southgate project. As you know, federal regulations and changing markets have decreased demand for coal while increasing public demand for natural gas. As the cleanest burning fossil fuel, and as an energy source that is abundant in the U.S., natural gas provides homes and businesses with an affordable, reliable and cleaner domestic fuel that also promotes American energy independence.

The proposed MVP Southgate project is approximately 72 miles long. Of that length, approximately 26 miles would be in Virginia. The route is largely collocated along existing rights of way in Virginia, illustrating the effort that the project team has taken to minimize impacts to the environment and landowners. Furthermore, the project would pass through the Berry Hill Industrial Park, one of the nation's largest tracts designated for business development.

As an open-access interstate natural gas transmission pipeline, the MVP Southgate project offers opportunity for local distribution companies and major employers to tap the line in order to meet demand in the future. Access to natural gas is an important factor taken into consideration by manufacturers and other major employers as they look for new potential sites.

Every American benefits from the increasing role that natural gas plays in this nation. Natural gas is a key component in a vast majority of manufactured goods, including life-saving medicines, surgical equipment, electronics, computers, phones, CDs, paint and clothing. More affordable energy allows consumers to save more of their money, which they can then choose to spend on other goods and services. This has had a significant impact on the U.S. economy, making American companies more competitive, creating jobs and putting money back in the pockets of working Americans. It also is increasing energy independence and strengthening national security.

The natural gas industry is not new; in fact, it is a proven and safe industry with a long history. Demand for natural gas is projected to increase by 40 percent in the next decade to meet the needs of manufacturing and power generation. U.S. supply is expected to increase by 48 percent in the next decade to meet new demand.

All of this speaks to the importance of building new infrastructure, such as the proposed MVP Southgate project. This pipeline is needed to meet demand and deliver an abundant supply of affordable natural gas to customers in the southern Virginia and northern North Carolina regions who demand it. The project also would generate hundreds of construction jobs in Virginia and millions of dollars in positive economic impact for the region.

VOGA is proud to support the construction and operation of the MVP Southgate project.

Sincerely,

Ian Landon

Ian Landon
President

VIRGINIA CHAMBER

THE VOICE of BUSINESS

September 16, 2019

Ms. Kimberly Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: Docket No. CP19-14-000

Dear Ms. Bose:

The Virginia Chamber of Commerce supports construction of the Mountain Valley Pipeline Southgate Project (the Project) and agrees with the conclusions found in the draft environmental impact statement (EIS) prepared by the Federal Energy Regulatory Commission (FERC).

As the largest business advocacy organization in the Commonwealth, the Virginia Chamber understands the importance of expanding our natural gas infrastructure to reduce energy costs and spearhead economic development, especially in rural areas of Virginia. *Blueprint Virginia 2025*, the Virginia Chamber's comprehensive business plan developed in coordination with 6,000 businesses, supports the development of infrastructure projects that increase access to affordable, reliable natural gas for manufacturing, power generation, and home heating.

The Project has the potential to provide tremendous benefits to the residents and business community of southern Virginia by creating additional pipeline capacity in the region. Not only is natural gas a cleaner burning fuel than other traditional energy sources but it also is an affordable, reliable heating and power source. Increasing natural gas supplies via the Project will likely result in cleaner, more efficient power generation and will help ensure that Virginia lowers its already competitive electric rates, a factor considered by businesses looking to re-locate to Virginia. Further, this transformative project could encourage the development of additional energy infrastructure, which could advance business development and long-term economic growth in the region.

In addition to the pipeline's potential impact on southern Virginia's energy infrastructure, the Project will provide a financial boon to residents, as well as state and local governments. During the construction phase, Mountain Valley anticipates spending $38.7 million on payroll in Virginia and hiring 55 percent of the required workforce from the local area, which would amount to 576 workers in Virginia and North Carolina. The project would likely generate $0.9 million in income tax revenues from the Virginia construction workforce and $1.2 million in annual property taxes over the life of the Project, thus creating a significant revenue source for Pittsylvania County. Specific to surrounding landowners, the draft EIS concluded that the Project would neither have a significant adverse impact on property values nor interfere with homeowners' ability to purchase market-priced insurance.

Specific to the draft EIS, the Virginal Chamber is encouraged by the environmental findings from the FERC staff, most notably that "… route alternatives/variations do not offer a significant environmental advantage when compared to the proposed route." The Project minimizes the potential impacts to drinking water sources, as evidenced by the fact that the proposed route does not come within 150 feet of public water supply wells or springs and does not cross sole source or principal source aquifers. Further, the draft EIS determined that groundwater contamination during operation of the pipeline is unlikely, in part due to regular monitoring of the pipeline for leaks. The draft EIS also found that the pipeline would not have a significant impact on local or regional air quality during construction and operation.

The Virginia Chamber appreciates the recommendations prepared by the FERC staff and is hopeful they will not impose unreasonable delays during the planning and construction phases. Specifically, in order to prevent delays prior to construction, the Fish and Wildlife Service—and other federal and state agencies when applicable—should provide comments to FERC staff in a timely manner and engage in consultations with Mountain Valley that follow a mutually agreeable timeline. Delays stemming from a lack of attention or prioritization from any government entity could result in significant financial costs to Mountain Valley and prolonged work stoppages for local tradesmen.

Above all, the Virginia Chamber applauds Mountain Valley for its commitment to engage with affected landowners along the proposed pipeline route and its efforts to minimize residual effects during the planning and construction phase of the Project. According to the draft EIS, less than 10 acres of residential land would be affected by pipeline construction and 39 miles (or 53 percent) of the pipeline route would be constructed adjacent to existing rights-of-way. Perhaps more importantly, Mountain Valley incorporated more than 100 route variations during the environmental scoping phase after meeting with landowners and interested parties, which speaks highly to their level of public engagement.

Thank you for your consideration of this request. The Virginia Chamber endorses the draft EIS conclusion "… that the proposed Project is the preferred alternative that can meet the Project purpose" and is confident that Mountain Valley will receive all applicable authorizations under federal law to construct the Project. Please do not hesitate to contact me or my staff with any questions.

Kind regards,

Barry E. DuVal
President and CEO

VIRGINIA
CHAMBER

THE VOICE of BUSINESS

December 18, 2018

Ms. Kimberly Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: Docket No. CP19-14

Dear Ms. Bose,

As the largest business advocacy organization in the Commonwealth, the Virginia Chamber of Commerce supports approval of the Mountain Valley Pipeline (MVP) Southgate project. This proposed infrastructure project has the potential to significantly increase economic development in Southern Virginia by providing a stable supply of natural gas to businesses, manufacturers, power generators, and residents.

In December 2017, the Virginia Chamber released *Blueprint Virginia 2025*, a comprehensive business plan outlining the priorities and recommendations necessary for improving Virginia's business climate. During the stakeholder engagement process, the Chamber heard from industry leaders about accessing affordable and reliable energy sources and how this factor is critical to expanding businesses development in Virginia. While being mindful of environmental conservation and respecting landowners' rights, the MVP Southgate project achieves this notable requirement by expanding energy infrastructure in the state and increasing access to natural gas supplies for manufacturing, power generation, and residential heating.

By supplying abundant natural gas to Southern Virginia, the proposed MVP Southgate project is anticipated to provide businesses with access to an affordable and reliable energy source. The MVP Southgate project and other pipelines will lead to cleaner, more efficient power generation facilities and will help ensure that Virginia lowers its already competitive electric rates, which are fundamental to maintaining and attracting new businesses. Manufacturing companies, especially those in heavy industries, also require access to natural gas due to its affordability, allowing them to invest capital toward improving efficiencies, increasing production, and hiring additional workers.

Many areas across Virginia, including Pittsylvania County in the southern part of the Commonwealth, lack the natural gas infrastructure necessary to support existing businesses and attract new ones. Construction of the MVP Southgate pipeline could not only create well-paying construction jobs and generate tax revenue for local governments but also encourage significant business investment in Southern Virginia. Further, the pipeline could encourage the development

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of additional energy infrastructure, which could further the expansion of business development and long-term economic growth in underserved areas.

One project that stands to benefit from the MVP Southgate pipeline is the Berry Hill Industrial Park, a 3,700-acre mega-park in Pittsylvania County and the largest business park in Virginia. The Berry Hill site is a joint effort by the City of Danville and Pittsylvania County to incentivize and attract economic activity, and coupled with federally-certified Opportunity Zones, the industrial park has the potential to recruit major employers to the region. The MVP Southgate project, which as proposed will pass through a portion of the Berry Hill site, could help advance the site's effectiveness and could lead to additional access to natural gas for new users in the region and incentivize additional energy infrastructure projects.

Thank you for your consideration of this request. The Virginia Chamber believes that the MVP Southgate project has the potential to provide long-term economic benefits to Southern Virginia while striking an appropriate balance between environmental conservation, rural development, and energy production. Please do not hesitate to contact me with any questions.

Best regards,

Barry E. DuVal
President and CEO

energy API | **Virginia** Petroleum Council
A Division of the American Petroleum Institute

Miles Morin, Executive Director
Virginia Petroleum Council
1011 E Main St, Suite 202
Richmond, VA 23219

August 21, 2019

Ms. Kimberly Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, D.C. 20426

Subject: MVP Southgate (Docket No. CP19-14)

Dear Ms. Bose:

I am writing on behalf of the Virginia Petroleum Council and in support of the proposed MVP Southgate project.

Natural gas is the cleanest burning fossil fuel, producing about half the carbon emissions of coal, and it is very reliable and affordable. On a national level, carbon emissions from electricity generation remain at modern historic lows, and overall energy-related carbon emissions dropped nearly 12 percent below 2008 levels in 2017, according to the U.S. EIA. The EIA also credits this progress as primarily due to "increased use of natural gas for electricity generation."

The U.S. has an abundant supply of natural gas, and the proposed MVP Southgate project is needed to meet existing and projected demand in the southern Virginia and north-central North Carolina region. Businesses, especially manufacturing companies, look for access to natural gas when deciding where to locate, and southern Virginia – home to a large industrial park at Berry Hill, through which the proposed MVP Southgate line would pass – could benefit significantly from construction and operation of the project.

The MVP Southgate project team has worked diligently to establish a route that both minimizes the project's impact on the environment and accommodates property owners' requests. The recent Draft Environmental Impact Statement shows that the project can be built and operated safely, and it acknowledges the many efforts made by the project team to avoid impacts to natural resources.

Natural gas is going to be an important part of the nation's energy portfolio for generations. We need to build infrastructure to get cleaner, cheaper fuel to market in order to help spur the economy and help consumers save money on fuel costs. The proposed MVP Southgate line would achieve these goals in a responsible manner.

The Virginia Petroleum Council supports continued expansion of natural gas infrastructure to connect growing supply and demand, and therefore supports this project, and is hopeful that it will receive the necessary authorizations for construction to commence and the project to enter service.

Sincerely,

Miles Morin
Executive Director
Virginia Petroleum Council
1011 E Main St, Suite 202
Richmond, VA 23219

Virginia FREE

ORIGINAL

August 22, 2019

Ms. Kimberly Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, D.C. 20426

Subject: Docket No. CP19-14 – MVP Southgate Draft Environmental Impact Statement

Dear Ms. Bose:

As executive director of Virginia FREE, the premiere source of non-partisan political information for Virginia's business community, I am writing today in support of the proposed MVP Southgate project.

The MVP Southgate project offers short- and long-term economic opportunities for southern Virginia and the commonwealth. The construction of the proposed 74-mile underground natural gas pipeline and associated facilities would create hundreds of jobs and stimulate business activity across Pittsylvania County. Once the project is operational, the pipeline will bring a new source of domestic natural gas through southern Virginia, providing greater opportunities for new residential and commercial access to an affordable, reliable and cleaner fuel source.

As you may know, southern Virginia has a long history of being home to manufacturing operations. The city of Danville and Pittsylvania County are working together to develop the Southern Virginia Mega Site at Berry Hill. This 3,500-acre mega-site is Virginia's largest, and it is primed for development after earning the state's Tier 4 certification last year, which signals its readiness for new employers. The proposed MVP Southgate project route passes through this proposed park, providing tremendous opportunity for potential future employers that may want to establish facilities in the region and draw natural gas from the pipeline to fuel operations.

It is critically important for infrastructure routes to be developed in ways that strive to minimize environmental impacts and respect private property. To that end, the MVP Southgate project is proposed to run adjacent to an existing right-of-way through most of its planned 26-mile route in Virginia. This maximizes the potential benefits of the project to serve public need while minimizing potential adverse impacts associated with its construction and operation, as described in the Draft Environmental Impact Statement.

The MVP Southgate project is important to the region and to the commonwealth. The efforts undertaken by the project team reflect a commitment to build the proposed pipeline in a safe and respectful manner, and Virginia FREE supports it.

Sincerely,

Chris Saxman

Chris Saxman
Executive director
Virginia FREE

Document Content(s)

VOGA
Virginia Oil & Gas Association
408 West Main Street, Abingdon, VA 24210

August 30, 2019

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426

Subject: MVP Southgate – Docket No. CP19-14

Dear Ms. Bose:

On behalf of the Virginia Oil and Gas Association ("VOGA"), I am writing in support of the proposed MVP Southgate project. As you know, federal regulations and changing markets have decreased demand for coal while increasing public demand for natural gas. As the cleanest burning fossil fuel, and as an energy source that is abundant in the U.S., natural gas provides homes and businesses with an affordable, reliable and cleaner domestic fuel that also promotes American energy independence.

The proposed MVP Southgate project is approximately 74 miles long. Of that length, approximately 26 miles would be in Virginia. The route is largely co-located along existing rights of way in Virginia, illustrating the effort that the project team has taken to minimize impacts to the environment and landowners. Furthermore, the project would pass through the Southern Virginia Mega Site at Berry Hill, one of the nation's largest tracts designated for business development.

As an open-access interstate natural gas transmission pipeline, the MVP Southgate project offers opportunity for local distribution companies and major employers to tap the line in order to meet demand in the future. Access to natural gas is an important factor taken into consideration by manufacturers and other major employers as they look for new potential sites.

Every American benefits from the increasing role that natural gas plays in this nation. Natural gas is a key component in a vast majority of manufactured goods, including life-saving medicines, surgical equipment, electronics, computers, phones, CDs, paint and clothing. More affordable energy allows consumers to save more of their money, which they can then choose to spend on other goods and services. This has had a significant impact on the U.S. economy, making American companies more competitive, creating jobs and putting money back in the pockets of working Americans. It also is increasing energy independence and strengthening national security.

The natural gas industry is not new; in fact, it is a proven and safe industry with a long history. Demand for natural gas is projected to increase by 40 percent in the next decade to meet the needs of manufacturing and power generation. U.S. supply is expected to increase by 48 percent in the next decade to meet demand.

All of this speaks to the importance of building new infrastructure, such as the proposed MVP Southgate project. This pipeline is needed to meet demand and deliver an abundant supply of affordable natural gas to customers in the southern Virginia and northern North Carolina regions who demand it. The project also would generate hundreds of construction jobs in Virginia and millions of dollars in positive economic impact for the region. And, as the Draft Environmental Impact Statement reported, the construction and operation of the project can be done in a manner that would minimize impacts to the environment.

VOGA is proud to support the construction and operation of the MVP Southgate project.

Sincerely,

Ian Landon

Ian Landon
President
Virginia Oil & Gas Association

Document Content(s)

ORIGINAL

September 4, 2019

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

Dear Secretary Bose:

Please find written comments submitted by the "Teamsters National Pipeline Labor Management Cooperation Trust" on the MVP Southgate Project Draft EIS Statement. **(Docket No. CP19-14-000)**

If you have any questions I can be reached at (703) 508-8690.

Sincerely,

Richard Stern, Administrator
Teamsters National Pipeline Labor
Management Cooperation Trust

Enclosures

Please find our comments on the "Draft EIS Statement" in support of the construction of the MVP Southgate Project **(Docket No. CP19-14-000)** submitted to FERC on behalf of the Teamsters National Pipeline Labor Management Cooperation Trust representing over 125 contributing Union Pipeline Contractors affiliated with the Pipeline Contractors Association and the International Brotherhood of Teamsters with over 1.4 million members who support the building of the Project.

The Teamsters and their signatory contractors are committed to building this Project with well-trained and qualified local workers who can perform their work at a high level to help mitigate any potential environmental concerns.

These workers have a vested interest in building the project in an environmentally safe manner since their own families could be affected by this project.

Teamsters North Carolina and Virginia Local Unions having jurisdiction for all pipeline work for the Project have a large cadre of experienced and trained Teamster pipeline membership.

By utilizing union contractors to build this "Project" it guarantees that at least 50% of the workers will be local hires from these Teamsters Local Unions.

The collective bargaining agreement between the Teamsters and Pipeline Contractors Association states:

"The words "regular employee" shall mean those who are regularly and customarily employed by the Individual Employer and because of their special knowledge and experience in pipeline construction work, are considered key men. It is anticipated that the number of regular employees shall not be more than a majority of the total number required but there shall be no limitation on the classification of such regular employees, with the understanding that these classifications will be distributed as evenly as possible." (See Exhibit A)

Therefore, when a pipeline such as this "Project" is built using Teamster members at least half of the Teamster pipeline construction workers will be from the local community and thus have a greater sensitivity for the environment.

However, due to the large Teamsters Pipeline workforce in North Carolina and Virginia the number of local hires most of the times are greater than 50.00%.

Also, many of these North Carolina and Virginia Teamster Pipeliners hunt and fish so their concern for the environment when constructing this pipeline is more heightened.

These workers have an incentive in building the "Project" environmentally safe because again they live here too.

Thus, any negative environmental impact will be lessened.

You get this guarantee with a union pipeline contractor.

Furthermore, by utilizing Teamster Pipeline Contractors and local Teamster Pipeline members to do the work it will result in high wages, paid health insurance and paid pension. (See Exhibit B)

Directional Drilling (HDD) type of work.

HDD is used for the installation of pipelines beneath rivers, highways, and other environmentally sensitive areas requiring technology and equipment that can install pipelines without any disturbance to natural habitats.

Some of our specialized signatory contractors and a more detailed explanation of the work they perform in areas of great environmental concern are included in this submission. (See Exhibit C)

Prior to the construction of the "Project" we will provide Classroom training programs based on the U.S. Department Transportation's Regulations on "Compliance, Safety and Accountability" (CSA) and also Defensive Driving.

The Teamsters CSA/Defensive Driving Instructor has been cited as a Trend Setter by the "National Safety Council" an Award he has received from them in the past. (See Exhibit D)

Under pages 6 and 7 in the collective bargaining agreement workers must have certain qualifications prior to working on this project. (See Exhibit E)

Under pages 17 and 18 of the Pipeline Agreement is the language on "Drug and Alcohol Testing" to ensure a drug free work environment and "Training/DOT Rules" to maintain high quality work standards and qualifications. (See Exhibit F)

This means greater federal, state and local taxes for each government entity.

We have pipeline contractors who specialize in Horizontal

I have supplied information on our support of Teamster Military Veterans many who belong to our North Carolina and Virginia Teamsters Local Unions and who hopefully will be working on this project if awarded to one of our signatory contractors. (See Exhibit G)

Also, there is a brochure on our training program funded through hourly contributions from our union contractors for your review. (See Exhibit H)

In closing, we believe that if this "Project" is constructed with our trained and highly skilled local union workers most who reside in North Carolina and Virginia and specialized union contractors the "Project" will be built in a safe manner and in compliance with all federal, state and local environmental regulations.

EXHIBIT A

additional pre-job conference will be required if hours of work or work conditions are changed.

No representative of any individual Employer and no representative of the Union or any of its local unions shall demand at the pre-job conference or at any other time during the continuance of the job any term or condition not covered by this Agreement. A copy of the report made of each pre-job conference shall be furnished to the Pipe Line Contractors Association and to the International Brotherhood of Teamsters, and no agreement made at any pre-job conference which adds to or modifies in any way the terms and conditions of this Agreement shall be binding on any individual Employer or the Union, or any of its local unions, unless approved and ratified by the PLCA and the International Brotherhood of Teamsters.

In the event that the Union and the Employer are unable to mutually agree upon layoff procedure at the pre-job conference, the matter will be referred to the Director, Construction Division, International Brotherhood of Teamsters, and the Managing Director, PLCA, for decision along previously established guidelines.

(E) If any individual Employer pays any wages in excess of the wages negotiated in this Agreement in the form of extra money, extra hours, extra travel or stand-by-time, or in the form of a bonus by any subterfuge, and if the PLCA and the International Brotherhood of Teamsters shall jointly determine that such bonus is for the purpose of pirating men from other individual Employers, or results in conditions injurious to the pipeline industry, then such individual Employer shall be required to pay the same extra compensation to all employees classified as Group 1 or Group 2 in this Agreement, and a proportionate additional compensation to all employees classified as Group 3 in this Agreement, and such requirement shall continue until that particular job is completed. It is understood and agreed, however, that any profit-sharing, retirement, or pension plan which an individual Employer may have in effect which has not been set up for that particular job shall not be considered a bonus.

(F) Upon request of the local union having jurisdiction of the job, and upon presentation of proper authorization forms executed by the individual employees, the individual Employer agrees to deduct from the wages of such individual employees Union initiation fees and dues and shall pay over to such local unions the amount so deducted.

(G) The Union agrees to send a copy of this Agreement to each and every one of its locals having jurisdiction over any area in which Employer becomes obligated to construct a pipe line, and agrees that the terms of this Agreement shall be recognized by such local, so that industrial peace will not be disturbed and so that the Employees may perform Employer's work efficiently and continuously. The Employer agrees as well to furnish its supervisory personnel copies of this Agreement so that they may be familiar with the terms.

(H) Employer shall have the right to hire the first driver, the second employee hired shall be the steward. Employer shall have the right to employ, direct and bring into the job men who are regular employees in Employer's work and shall have the right to keep such men in his employ on all work throughout the territory covered by this Agreement.

(I) The words "regular employee" shall mean those who are regularly and customarily employed by the individual Employer and because of their special knowledge and experience in pipeline construction work, are considered key men. It is anticipated that the number of regular employees shall not be more than a majority of the total number required but there shall be no limitation on the classification of such regular employees, with the understanding that these classifications will be distributed as evenly as possible.

(J) It is understood and agreed that the above limitations shall not apply to the pipeline stringing operations.

(K) The hiring of men in addition to the Employer's regular employees, either at the start of the job or later, shall be conducted in the following manner:

1. In the event a valid non-discriminatory exclusive referral procedure has been established by collective bargaining between a local of the Union and an association of highway and heavy contractors in the area in which the job is to be done, Union shall notify the Association from time to time as to the existence of such exclusive referral procedures and Employer agrees to utilize such referral procedures upon the following conditions:

a. Nothing in this Agreement shall affect the Employer's inherent right to determine the competence and qualifications of applicants for employment or of his employees and his right to reject or discharge accordingly.

b. The selection of applicants for referral to jobs shall be based on a non-discriminatory basis and shall not be based on or in any way affected by union membership, by-laws, regulations, constitutional provisions, or any other aspect or obligation of union membership, policy or requirement.

c. Workmen referred under Article II to the contractor's job who are not able to perform the job to which they are referred because of their own lack of qualifications, or for some other reason which is the workman's own responsibility, shall not be paid show-up time.

d. Qualified applicants required by Employer at the start of the job must be referred by a local referral office within 48 hours of the receipt of Employer's request; those required by Employer after a job has started must be referred by a local referral office within 24 hours of the receipt of Employer's request. If the local referral office fails to comply with this condition, Employer may secure qualified applicants from any other source. Qualified applicants under this section must have the following:

(i) Proper federal and state licenses;

(ii) Proper OQ credentials where necessary;

(iii) Pipeline or general construction work experience relevant to pipeline work or completion of a certified pipeline training course operated or approved by the Teamsters Pipeline Training Fund. The Teamsters and PLCA also agree they will jointly review the training program on a 6-month basis.

(iv) Compliance with company Employee and safety policy standards. These

EXHIBIT B

NATIONAL PIPELINE AGREEMENT 2014-2017

SOUTHERN RATES (Hourly)

Covers: Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee and Texas

	5/30/16-6/4/17	6/5/17-6/4/18	6/4/18-6/3/19	6/4/19-5/31/20
GROUP 1*	$29.18	$30.09	$31.09	$32.06
GROUP 2	$26.09	$26.91	$27.81	$28.68
GROUP 3	$24.78	$25.56	$26.42	$27.25
H&W	$6.90	$7.17	$7.40	$7.70
PENSION	$3.00	$3.25	$3.50	$3.75
TRAINING	$ .20	$.20	$ .20	$ .20
LMCT	$ .20	$.20	$ .20	$ .20

PREMIUMS (National)

Steward	+ $2.25
Stringing Truck	+ $2.25
Mechanic	+ $3.00
Lowboy	+ $2.25
Fuel Truck	+ $2.25
Haz-Mat	+ $1.00

***Log/Grapple Truck Rate:**

Updated 9/12/18

PIPELINE RATES (HOURLY)

VIRGINIA – ZONE 2 (Locals 22, 29, 171, 519, 592, 822)

	5/30/16-6/4/17	6/5/17-6/4/18	6/4/18-6/3/19	6/4/19-5/31/20
GROUP 1*	$29.38	$30.30	$31.30	$32.28
GROUP 2	$26.40	$27.23	$28.14	$29.02
GROUP 3	$25.19	$25.98	$26.85	$27.69
H&W	$6.90	$7.17	$7.40	$7.70
PENSION	$3.00	$3.25	$3.50	$3.75
TRAINING	$ .20	$ .20	$ .20	$ .20
LMCT	$ .20	$ .20	$ .20	$ .20

PREMIUMS (National)

Steward	+$2.25
Stringing Truck	+$2.25
Haz-Mat	+$1.00
Mechanic	+$3.00
Lowboy	+$2.25
Fuel Truck	+$2.25

*Log/Grapple Truck Rate: $43.49, effective date 6/4/18

ZONE 2 – COUNTIES (Locals) Accomack (822), Albemarle (29), Allegheny (171), Amelia (592), Amherst (29), Appomattox (171), Augusta (29), Bath (29), Bedford (171), Bland (171), Botetourt (171), Brunswick (592), Buchanan (519), Buckingham (592), Campbell (171), Caroline (592), Carroll (22), Charles City (592), Charlotte (22), Chesapeake (822), Chesterfield (592), Clarke (29), Craig (171), Culpepper (29), Cumberland (592), Danville-City (22), Dickenson (519), Dinwiddie (592), Essex (592), Fauquier (29), Floyd (22), Fluvanna (592), Franklin (22), Frederick (29), Giles (171), Gloucester (822), Goochland (592), Grayson (22), Greene (29), Greensville (822), Halifax (22), Hanover (592), Henrico (592), Henry (22), Highland (29), Isle of Wight (822), James City (822), King & Queen (592), King William (592), Lancaster (822), Lee (519), Loudon (29), Louisa (592), Lunenburg (592), Madison (29), Mathews (822), Mecklenburg (592), Middlesex (822), Montgomery (171), Nelson (29), New Kent (592), Newport News City (822), Northampton (822), Northumberland (592), Nottoway (592), Orange (29), Page (29), Patrick (22), Pittsylvania (22), Powhatan (592), Prince Edward (592), Prince George (592), Pulaski (171), Rappahannock (29), Richmond (592), Roanoke (171), Rockbridge (29), Rockingham (29), Russell (519), Scott (519), Shenandoah (29), Smyth (519), Southampton (822) Spotsylvania (592), Suffolk (29), Surry (822), Sussex (822), Tazewell (519), Warren (29), Washington (519), Westmoreland (592), Wise (519), Wythe (171) and York (822)

Updated 9/17/18

EXHIBIT C

ABOUT

THE STORY OF OZ

OZ DIRECTIONAL DRILLING, FORMED IN 2008, IS ONE OF MANY PIPELINE COMPANIES OWNED BY THE OSADCHUK FAMILY OVER THE PAST 50 YEARS. THE MANAGEMENT TEAM AT OZ HAS BEEN IN THE PIPELINE INDUSTRY SINCE 1950 AND THE HORIZONTAL DIRECTIONAL DRILLING INDUSTRY SINCE 1991. KNOWN FOR THEIR EXCELLENCE IN PERFORMANCE, OZ HAS COMPLETED SEVERAL HUNDRED DIRECTIONAL BORES IN NORTH AMERICA, INCLUDING WORLD RECORD BORES OF 6,380 FEET IN LENGTH AND THE DEEPEST BORE OF 860 FEET. OZ IS A MEMBER OF THE PLCA (PIPE LINE CONTRACTORS ASSOCIATION), THE DCA (DISTRIBUTION CONTRACTORS ASSOCIATION), AND THE IPLOCA (INTERNATIONAL PIPE LINE & OFFSHORE CONTRACTORS ASSOCIATION).

WE HAVE THE CAPABILITY OF PERFORMING DIRECTIONAL DRILLS UNDER MANY DIFFERENT CIRCUMSTANCES SUCH AS, HIGHLY SENSITIVE AREAS, ENVIRONMENTAL AREAS, CITY STREETS, CROSS COUNTRY PIPELINES, MAJOR RIVER CROSSINGS, RAILROADS, ROADWAYS, AND MANY MORE. WE ALSO HAVE EXPERIENCE IN DRILLING ALL TYPES OF SOILS, INCLUDING GRANITE, SOLID ROCK, GLACIER TILL FORMATIONS, FROZEN TUNDRA, RUNNING SAND, AND GRAVEL. WE HAVE WORKED FROM THE EAST COAST TO THE WEST COAST AND AS FAR AS THE NORTHERN SLOPE OF ALASKA DOWN TO THE SOUTHERN TIP OF MEXICO. WE ARE COMMITTED TO MAINTAINING AN ON TIME SCHEDULE, WHILE MAINTAING A SAFE WORK ENVIRONMENT, SATISFYING ENVIRONMENTAL MONITORS, PUBLIC AGENCIES, AND LAND OWNERS.

HORIZONTAL DIRECTIONAL DRILLING (HDD) IS A SOPHISTICATED BUSINESS. DWAYNE OSADCHUK HAS SPENT MANY YEARS IN THE FIELD SUPERVISING THE TRAINING OF HIS DRILL CREWS AND PERFECTING THE COMPANY'S DRILLING EXPERTISE. A KEY INGREDIENT TO THE SUCCESS

EXHIBIT D

June 8, 2016

Michael Borjas
IL Teamsters/Employers Apprenticeship & Trng Fund Afftl/Joint Councils 25
990 NE Frontage Rd
Ste 4
Joliet, IL 60431

Customer Number: 699382

Dear Michael Borjas,

We are extremely pleased to announce that your organization has been chosen as a DDC Award recipient for your outstanding training efforts in 2015. The award(s) being presented to your organization are:

Award	Curriculum
Trend Setter	NSC PTD

National Safety Council would like to recognize your training center at the 2016 NSC Congress and Exposition in Anaheim, CA. We invite you to be our guest at the Annual DDC Training Center & Instructor of the Year Awards Celebration to be held on Saturday evening, October 15th, 2016.

To help us prepare for the awards ceremony, please pre-register your organization for the event online at www.nsc.org/2016DDCawards. We will need your organization's customer number as well as the proper spelling of your organization's name and how it should appear on the award (s). If you are unable to attend, please be sure to go online to pre-register, indicating you cannot attend, and providing shipping information for the award(s). **We appreciate your prompt response no later than end of day, June 24, 2016.**

In the meantime, if you have any questions, please give our office a call at 800-621-7619 ext. 52041. A formal invitation will be sent in July with final registration instructions.

To help your organization broadcast its success to your community; we have enclosed a press release and an awards definition page. Also enclosed is a FAQ sheet that will help to answer any remaining questions you may have regarding the awards celebration. We congratulate you and look forward to seeing you in Anaheim!

Sincerely,

James A. Solomon

Subject Matter Expert for NSC Defensive Driving Courses
Enclosure

National Safety Council announces local Defensive Driving Course Training Center IL Teamsters/Employers **Apprenticeship & Trng Fund Afftl/Joint Council 25** is an award winner of the following:

Trend Setter NSC PTD

On October 15, 2016 during the National Safety Council's Congress and Exposition in Anaheim, California IL Teamsters/Employers Apprenticeship & Trng Fund Afftl/Joint Councils 25&65 of Joliet, IL will receive honors for their 2015 Defensive Driving Course training.

The National Safety Council's Defensive Driving Course, the first name in life saving driver safety courses, began in 1964. With over 8,000 instructors worldwide, the Defensive Driving Courses have graduated over 70,000,000 drivers.

James A. Solomon, Subject Matter Expert for NSC Defensive Driving Courses, will personally congratulate representatives from IL Teamsters/Employers Apprenticeship & Trng Fund Afftl/Joint Councils 25&65 at the Council's Annual DDC Training Center & Instructor of the Year Awards Celebration for their hard work in making the highways safer.

Press Release

EXHIBIT E

pipeline construction work, are considered key men. It is anticipated that the number of regular employees shall not be more than a majority of the total number required but there shall be no limitation on the classification of such regular employees, with the understanding that these classifications will be distributed as evenly as possible.

(J) It is understood and agreed that the above limitations shall not apply to the pipeline stringing operations.

(K) The hiring of men in addition to the Employer's regular employees, either at the start of the job or later, shall be conducted in the following manner:

1. In the event a valid non-discriminatory exclusive referral procedure has been established by collective bargaining between a local of the Union and an association of highway and heavy contractors in the area in which the job is to be done, Union shall notify the Association from time to time as to the existence of such exclusive referral procedures and Employer agrees to utilize such referral procedures upon the following conditions:

a. Nothing in this Agreement shall affect the Employer's inherent right to determine the competence and qualifications of applicants for employment or of his employees and his right to reject or discharge accordingly.

b. The selection of applicants for referral to jobs shall be based on a non-discriminatory basis and shall not be based on or in any way affected by union membership, by-laws, regulations, constitutional provisions, or any other aspect or obligation of union membership, policy or requirement.

c. Workmen referred under Article II to the contractor's job who are not able to perform the job to which they are referred because of their own lack of qualifications, or for some other reason which is the workman's own responsibility, shall not be paid show-up time.

d. Qualified applicants required by Employer at the start of the job must be referred by a local referral office within 48 hours of the receipt of Employer's request; those required by Employer after a job has started must be referred by a local referral office within 24 hours of the receipt of Employer's request. If the local referral office fails to comply with this condition, Employer may secure qualified applicants from any other source. Qualified applicants under this section must have the following:

(i) Proper federal and state licenses;

(ii) Proper OQ credentials where necessary;

(iii) Pipeline or general construction work experience relevant to pipeline work or completion of a certified pipeline training course operated or approved by the Teamsters Pipeline Training Fund. The Teamsters and PLCA also agree they will jointly review the training program on a 6-month basis.

(iv) Compliance with company Employee and safety policy standards. These policy standards will be provided by each Employer at the pre-job conference.

2. In the event there is no valid exclusive referral procedure established in the area where the particular job is to be done or the proper conditions set out hereinabove have not been met by the referral procedure which has been established, Employer will at the pre-job conference notify Union, as one of the sources from which men are to be recruited, as to the number of men who will be needed in addition to his Regular Employees. Employer shall give preference in employment to men in the area who have had previous pipeline construction experience. It is understood that Employer may also recruit men from other sources, will hire all employees at the job site in a non-discriminatory manner, and shall have the absolute right to determine the competence and qualifications of applicants and employees and to reject and discharge accordingly.

3. Once the original crew has been employed, Employer shall have the right to keep such crew on all the work throughout the territory covered by the particular job for which the pre-job conference was held, regardless of local union jurisdiction.

(L) The Union shall post in places where notices to employees and applicants for employment are customarily posted all provisions relating to the functioning of this hiring arrangement, including the provisions set forth. The Employer shall similarly post in places where notices to employees and applicants for employment are customarily posted all provisions relating to the functioning and operation of the hiring arrangements, including these provisions.

(M) The business representative of the Union shall have access to any job at any time, subject to the owner safety and security rules and Federal and State regulations, and shall notify the field office of his presence on the job prior to entering the job site. The representatives of the Union shall not schedule meetings which could in any way hinder ongoing production.

III.
STEWARDS

As soon as any work starts, including unloading, racking, or stringing of pipe or clearing of right-of-way, the Union may select any Employee of the Employer who shall act as Steward for the Union. It is understood that the Employer will not be required to employ a Steward for any subcontract work prior to the start of operations by the Employer. The Steward shall be paid for the number of hours he actually works each day or for the number of hours for which the job is set up on a daily basis, whichever is greater, except that on those days when no work is performed, then the Reporting Time Pay provisions of Article VIII will apply. The steward shall perform his work for Employer the same as any other worker, and shall be entitled to receive the rate of pay in Article V(C) for the area in which the job is located. Stewards shall not be discharged without forty-eight hours' previous notice to Union. Although it is agreed that there will be no non-working stewards, it is also recognized by the parties that the steward has an important function in maintaining harmony and cooperation on the job, and therefore his assignment should not be such to prevent his normal function as a steward. Therefore, the parties agree that his job assignment will be a subject to be decided at the pre-job conference. The Employer shall provide the steward a weekly record of all Teamster employees listing date of

EXHIBIT F

procedure set out above, the Association will immediately contact the Federal Mediation and Conciliation Service to obtain a list of three (3) individuals with as much experience and knowledge as possible in the pipeline construction industry. A copy of this list will be furnished to the Union, and thereafter, the PLCA and Union shall attempt to mutually agree upon one (1) of the individuals listed. If no agreement can be reached, the Union and the PLCA will each strike one (1) name from the list and the remaining individual will be the Arbitrator.

3. A statement of the facts shall be presented to the Arbitrator within forty-eight (48) hours after his selection either:

a. Jointly, if the Union and PLCA mutually agree; or

b. Separately, if no mutual agreement, and the Association will submit a written statement setting out the Employer's position and the Union will submit a written statement setting out the Union's position.

4. All information submitted to the Arbitrator will be in writing. No personal appearances or oral testimony will be allowed. The Arbitrator will then issue, within five (5) days, a decision based upon the evidence submitted.

(G) The Union and the Employer involved shall bear the expense of their appointed Arbitrators. In the event an Arbitrator from the Federal Mediation and Conciliation Service is selected, then the Union and the Employer shall be jointly responsible for that person's expenses.

(H) In the event Employer fails or refuses to comply with the grievance procedure set out hereinabove, the provisions of Article IX shall not be binding upon Union. If Union fails or refuses to comply with the grievance procedure set out hereinabove, the Employer shall have the right to declare this entire Agreement null and void.

XII.
SPECIAL CONDITIONS

In order to be more competitive in certain areas of the country, the PLCA and the Union may mutually agree to put into effect special wages and conditions for specific areas or projects. These special wages and conditions will apply to the areas or projects involved for the period of time to be established by the principal parties.

XIII.
DRUG AND ALCOHOL TESTING

(A) A Substance Abuse Policy has been negotiated by the PLCA and the International Brotherhood of Teamsters and is attached hereto and made a part of this Agreement as Schedule "C".

(B) If an Employee fails a pre-employment drug or alcohol test and is so notified by 9:00 a.m. on the fifth business day following the day of taking the test, then the Employee's wage rate shall not be the hourly wage rate set forth in this Agreement. Instead, the Employee shall be paid wages at a flat rate of $90 per day worked (but in no event less than the applicable minimum wage) for all days worked prior to receiving such notification (not to exceed five (5) days) and for which no wages have yet been paid as required by this Agreement. If subsequent testing reveals a false positive, the Employee will be entitled to full compensation for the period he worked and reinstatement. The results of all tests will be kept confidential between the Employee, the Employer and the Union.

XIV.
TRAINING/DOT RULES

(A) Training – The Trustees of the Teamsters National Pipeline Training Fund will develop a National Pipeline Training Program for Teamsters to train in operating pipeline equipment in areas of high pipeline construction.

(B) DOT Rules – The Trustees of the Teamsters National Pipeline Training Fund will develop a DOT training program to teach Teamsters the necessary skills to comply with DOT driver requirements. Part of this program will be to develop a general pre-dispatch drug and alcohol testing program to be applied to all drivers seeking work under the National Pipe Line Agreement.

(C) Contributions shall be made to the Teamsters National Pipe Line Training Fund and Labor-Management Cooperation Trust in accordance with Schedule "A" and the provisions above. The National Pipe Line Training Fund will establish proficiency training standards to be used in a National Pipeline Training Course, which will include specific Operator Qualification training. Regional training courses also will be set up throughout the country as necessary and will be subject to the proficiency training standards developed by the Fund. A list of Teamsters who have successfully completed the course will be made available to signatory contractors on request. Funds contributed to local training funds for pipeline work covered under the National Pipe Line Agreement should be used by the local funds to provide pipeline and OQ training. Local pipeline training will be monitored by the Teamsters National Pipe Line Training Fund.

XV.
HISTORICAL PRECEDENT

Since the inception of the National Pipe Line Agreements, which cover all main line, cross-country pipeline construction, only four (4) Unions have been recognized, and all work relating to such pipeline construction has been performed by these four (4) Unions. They are: The International Brotherhood of Teamsters, The United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada, The International Union of Operating Engineers, and the Laborers' International Union of North America. The recognition of only these four (4) Unions on such work is hereby reaffirmed.

XVI.
INDIAN PREFERENCE IN EMPLOYMENT

The hiring procedures contained in this Agreement shall not apply in the "territorial jurisdiction" of any Indian Nation which has adopted an Indian Preference in Employment law, provided that those persons covered by the law and seeking covered employment under this

EXHIBIT G

TEAMSTERS ASSISTANCE PROGRAM MILITARY

International Brotherhood of Teamsters Veteran Registration

Name: ______________________________ Phone: ____________________

Address: ______________________________ Cell: ____________________

______________________________ E-mail: ____________________

City State Zip

Are you a veteran? Yes / No What dates did you serve? ____________________

In which branch of the military did you serve? (Circle one)

Army Marines Navy Coast Guard Air Force

How long have you been a Teamster? ____________________

What Joint Council are you affiliated with? __________ What is your local? __________

Who is your current employer? ____________________

Are you currently receiving benefits for service-related disabilities? Yes / No

Do you require assistance to pursue or file a disability claim? Yes / No

Do you want to receive updates on disability benefits or presumptive disease issues? Yes / No

Claims and disability filings will be done through certified claims representatives. All information regarding your filing(s) is confidential between you and a certified claims representative.

Thank you for your service to our country. We hope the resources available are beneficial to you and your family.

Please return your completed form via mail or fax to: *Teamsters Building and Construction Trades Division, 25 Louisiana Avenue, NW, Washington, D.C. 20001, or fax (202) 624-8107.*

EXHIBIT H

About Pipeline Training

The Teamsters National Pipeline Agreement (TNPA) is a labor agreement covering all pipeline construction work in the United States. Pay rates under this agreement are based on "local rates" or composite rates if the work encompasses several Teamster jurisdictions. The typical work day is 10 hours a day six days a week.

When a project is in a local area, the local union with jurisdiction who can staff the project will refer local members to the contractor. In this case local hires are paid local wages and fringe benefits go to the appropriate local fringe benefit fund.

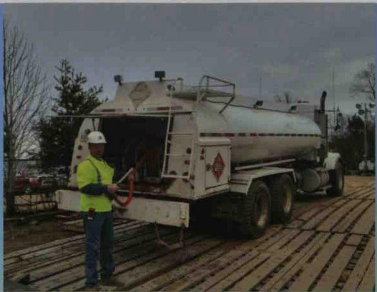
PLACE
STAMP
HERE

Teamsters National Pipeline

GCC/IBT

Teamsters National Pipeline

A Common Effort between the International Brotherhood of Teamsters and The Pipeline Contractors Association



About Us

Since 1903, the Teamsters labor union has helped millions of workers achieve the American dream. Their success is a testament to those who came before, who united to form a labor movement. These workers fought for the rights and privileges that many Americans take for granted today. For instance, without the solidarity of unions, there would be no weekends, no pensions, and no health insurance.

The pipeline construction industry must confront many competitive and technical challenges including the need to increase the work opportunities for union construction, the need to increase the efficiency of the pipeline construction industry, the need to foster more harmonious relationships between IBT and its affiliates and the PLCA and its members, the increasingly hazardous nature of the work, the need for specially-trained IBT members, the extent of government regulation, and the necessity to protect public health and safety.

Training Courses

Stringer Truck Driver

The Stringer Truck Driver course is designed to train Class A Commercial Drivers to safely transport pipe using steering trailers in both on road and off road situations. Training will include General Safety, Pre-trip Inspections, Stretching and Shorting the Trailer and Adjusting Steering Cables. The course is taught in both classroom and field formats. Course length is 24 hours.

Crew Bus

The Crew Bus Driver course will teach drivers to safely operate a crew bus and to prepare them to take the Passenger Endorsement in their home state. The course is taught in both classroom and field formats. Course length 8 hours.

Fork Lift

The Fork Lift course addresses lift truck operation safety in pipeline operations and in accordance with OSHA requirements. The course is taught in both classroom and field formats. Training can include both warehouse, lay down yard and rough terrain situations. Course length 8 hours.

Fueler

The Fueler course focuses on HAZ-MAT training and various fuels and compressed gases used in pipeline construction. Course length 8 hours.

Additional Equipment

There is a host of "trucks" used on a pipeline construction job. This can include Lowboy, Flatbed or Float, Drop-deck, Dump Truck, Morooka and a host of other different combination vehicles. The driver must have a Class "A" or Class "B" CDL depending on the type of truck used.

Contact Us

To Contact Teamsters National Pipeline Please use the Contact Form on our website.

Visit us on the web at:
www.teamsterspipeline.com

Document Content(s)

APPENDIX L
Economic Benefits of the MVP Southgate Project in Virginia and North Carolina

JANUARY 2019

ECONOMIC BENEFITS OF THE MVP SOUTHGATE PROJECT IN VIRGINIA AND NORTH CAROLINA

EXPERTS WITH IMPACT™

DISCLAIMER

The analysis and findings expressed herein are those of the author(s) and not necessarily the views of FTI Consulting, Inc., its management, its subsidiaries, its affiliates, or its other professionals.

Principal Authors:

Ken Ditzel

Scott Nystrom

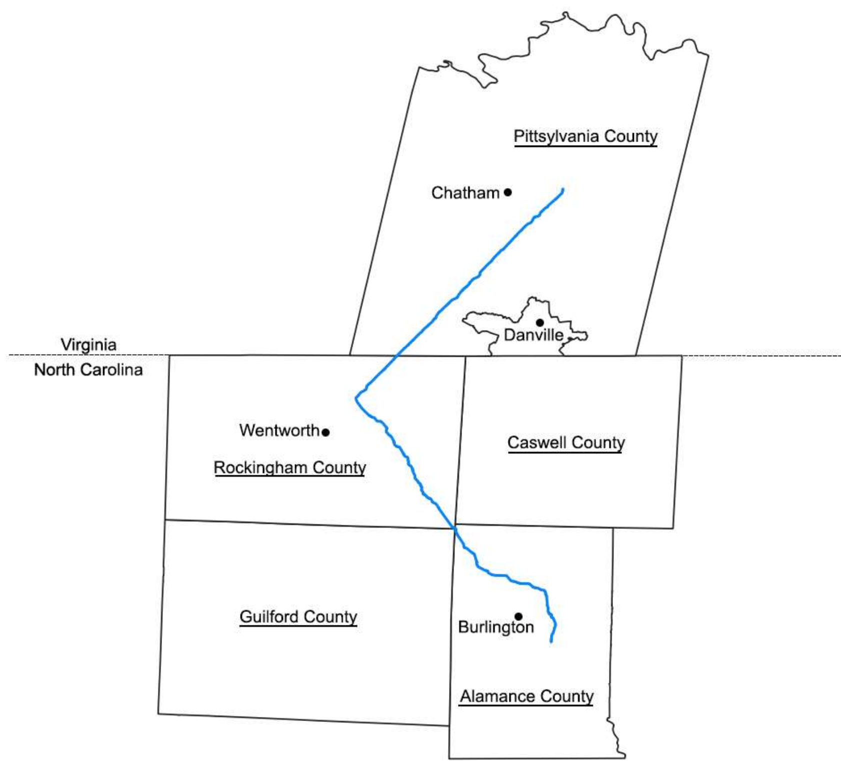
Katie O'Hare

Table of Contents

Executive Summary

Mountain Valley Pipeline, LLC ("Mountain Valley") retained FTI Consulting ("FTI") to examine the potential economic benefits of the MVP Southgate project to the states of Virginia and North Carolina through which the project would traverse. The MVP Southgate project is a natural gas pipeline system that would span approximately 73 miles from southern Virginia into central North Carolina through the counties of Pittsylvania, Rockingham, and Alamance, as shown below in Figure 1.

Figure 1 - Proposed MVP Southgate Pipeline Route



Specifically, the MVP Southgate pipeline would interconnect with the Mountain Valley Pipeline in Pittsylvania County, Virginia, pass through the county and by the City of Danville to Rockingham County, North Carolina, where it would interconnect with the PSNC Energy and East Tennessee pipelines, and terminate in Alamance County, North Carolina at an additional interconnect with PSNC Energy. The project would also include a new compressor station in Pittsylvania County, Virginia.

Three types of economic benefits would occur from the construction and operation of the MVP Southgate project. These benefits include:

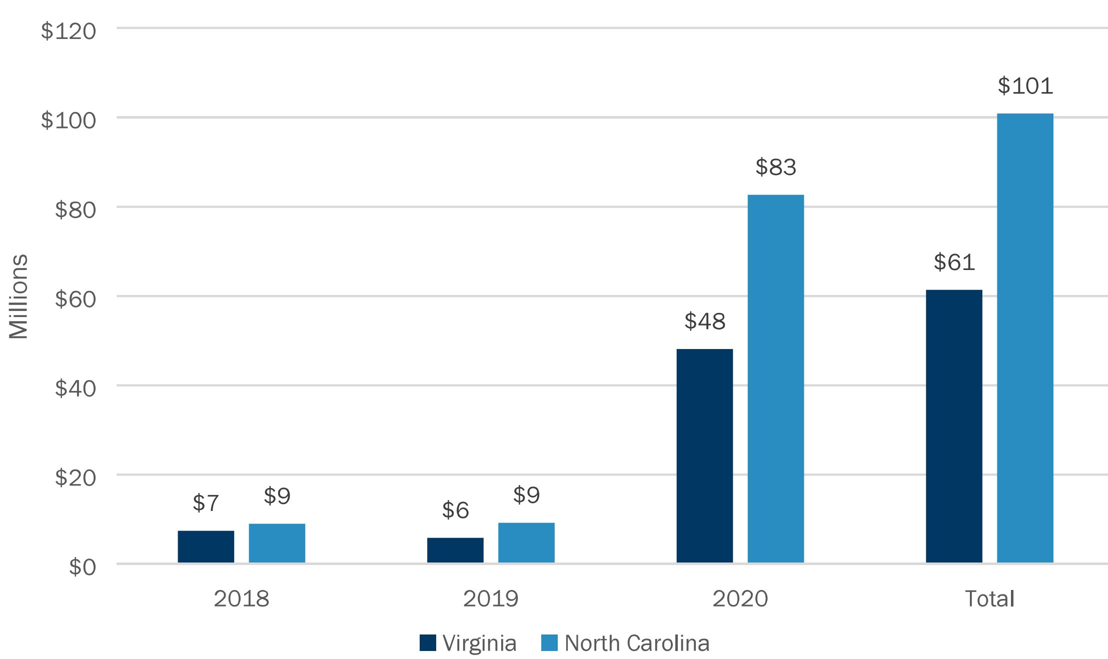
- **Construction Spending Benefits:** Expenditures on goods and services in each state would translate into job creation along with economic benefits to Virginia and North Carolina suppliers, their employees, and the overall economy.

- **Operational Benefits:** Once in service, the project would generate annual property tax revenues for the counties, providing an additional stream of funds.
- **Direct-Use Benefits:** Each state would benefit from the potential direct use of gas from the MVP Southgate project. The project would enhance gas service already available, help enable new gas service, and expand opportunities for commercial and manufacturing activities.

Construction Spending Benefits

From 2018 to 2020, the MVP Southgate project owners plan to spend a total of almost $468 million[1] on construction of the pipeline, spending $68 million and $113 million of this total directly on resources (equipment, materials, labor, and services) in Virginia and North Carolina, respectively. This direct spending would translate into approximately $60 million and $97 million in cumulative gross regional product ("GRP") over the three-year period in Virginia and North Carolina, respectively, as shown in Figure 2 below.

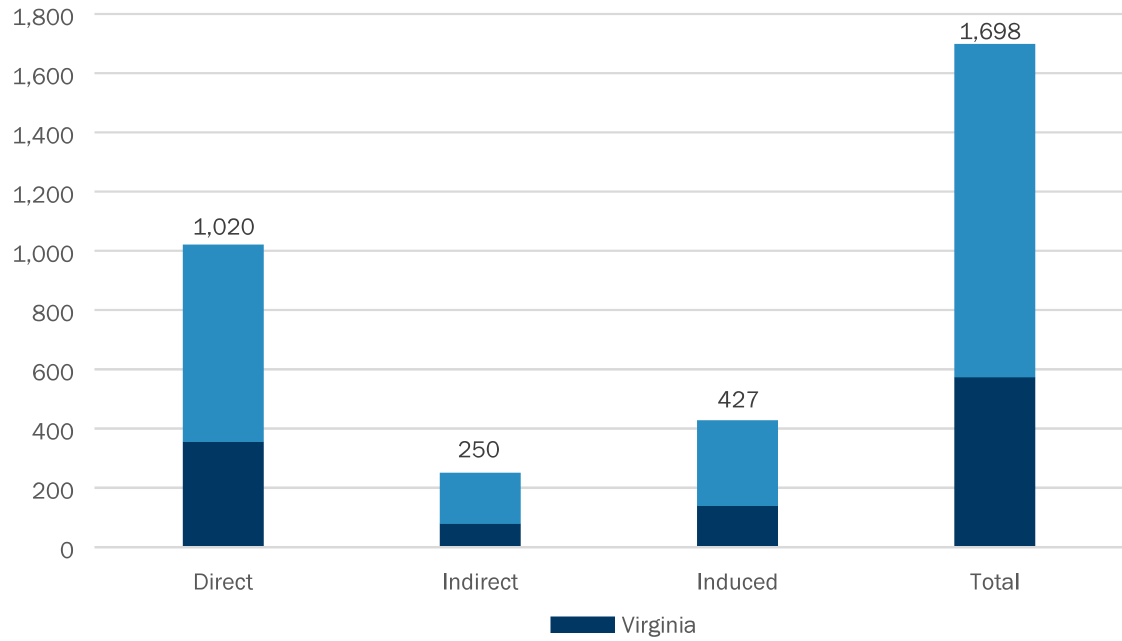
Figure 2 - Value Added (GRP) by State from Construction Spending, 2018-2020 (Millions)



The MVP Southgate project would create approximately 1,700 jobs at the peak of construction in 2020. Approximately 1,020 of these jobs would be directly associated with the project (labeled "direct" in Figure 3); 250 jobs would be created along the supply-chain ("indirect"); and 430 jobs would be created in the general economy ("induced").

[1] This figure includes approximately $4.6 million in ad valorem tax revenue during the first year of operations.

Figure 3 - Employment from Construction in 2020 by Category



Cumulatively, the MVP Southgate project would create approximately 2,020 job-years over the course of construction.[2]

Another benefit of the MVP project is the increased state and local tax revenues that result from the economic ripple effect of construction expenditures. As shown in Figure 4, the project would generate approximately $4.1 million in aggregate tax revenues from 2018 to 2020 during construction in Virginia. In addition, as shown in Figure 5, the project would generate approximately $6.3 million in aggregate tax revenues over this same three-year period during construction in North Carolina.

[2] The MVP Southgate employment contributions are directly tied to the capital spending in each year and are best expressed in 'job-years.' A job-year is the equivalent of one full-time job lasting a single year.

Figure 4 - Virginia State and Local Tax Revenues Generated during Construction, 2018-2020

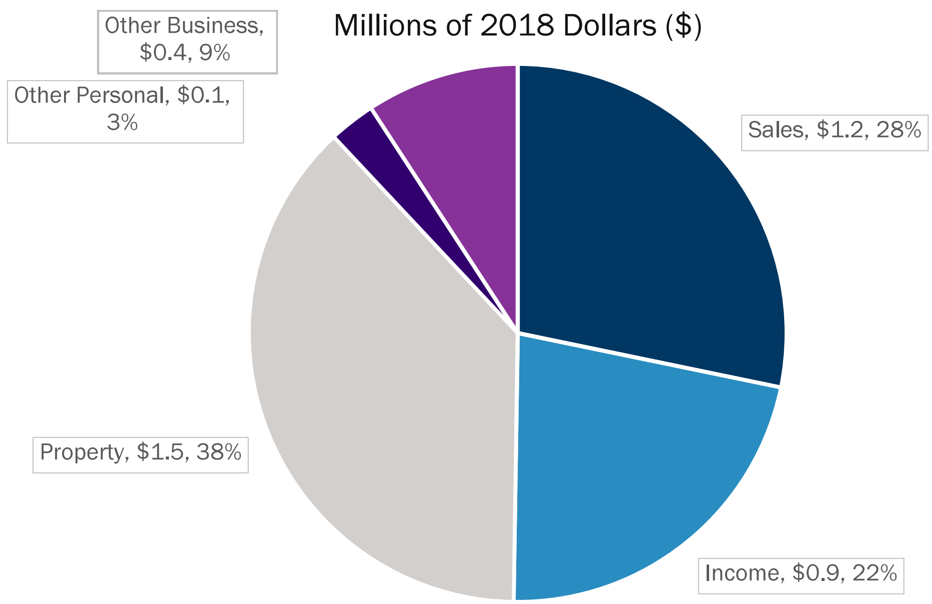
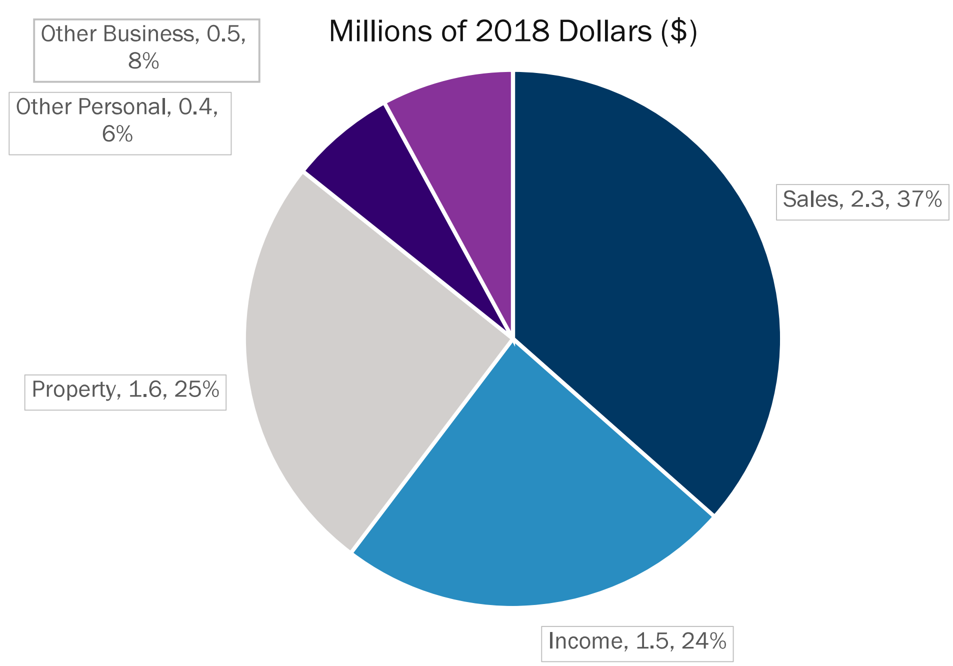


Figure 5 - North Carolina State and Local Tax Revenues Generated during Construction, 2018-2020



Operational Benefits

Once in service, the MVP Southgate project would continue to benefit Virginia and North Carolina's economies along three main areas. The first is in operational employment and spending. Ongoing operation and maintenance of the MVP Southgate pipeline would support 12 jobs across both state economies, with four of these jobs directly supporting the pipeline's operations (two in North Carolina and two in Virginia) and eight additional jobs across both states' economies (four in North Carlina and four in Virginia). These jobs would provide average annual wages and benefits of approximately $79,000 and $71,000 in Virginia and North Carolina, respectively. Notably, the Mountain Valley Pipeline and MVP Southgate pipelines together would support 40 jobs in Virginia.

The second area of economic impact during operations is tax revenue. Based on estimated pipeline investments and county property tax rates, the MVP Southgate project owners estimate that they would pay approximately $1.2 and $3.4 million in ad valorem taxes annually in counties in Virginia and North Carolina, respectively. Of the total for North Carolina, Alamance County would receive $681,000 million in ad valorem tax revenues, Rockingham County would receive over $1 million, and municipalities in the state of North Carolina would receive the remaining $1.7 million. In addition, the MVP Southgate project would generate approximately $269,000 and $226,000 annually in other federal, state, and local taxes, in Virginia and North Carolina, respectively, during operations.

Finally, in addition to employment, labor income, and tax revenue benefits, the MVP Southgate project would generate almost $1.6 million annually in GRP, with approximately $732,000 and $684,000 in Virginia and North Carolina, respectively.

Direct-use benefits of the pipeline's natural gas represent the third area where each state potentially could benefit from the project and are discussed in further detail below.

Direct-Use Benefits

In terms of direct gas-use benefits, the MVP Southgate project could provide substantial savings from fuel switching (i.e., switching from propane, fuel oil, diesel, or electricity to natural gas) across Pittsylvania, Danville, Alamance, and Rockingham. For this analysis, we consider the impact of converting county vehicles, such as school buses and solid waste trucks, to natural gas, as well as converting residential households using electricity as their primary heating fuel to natural gas. Table 1 below summarizes our results, which show that fuel savings for switching to natural gas would total approximately $1.8 million for municipal vehicles and $8.4 million for household electricity consumption.

Table 1 - Direct-Use Benefits from Fuel Switching

County/City	Annual Savings from Fleet Vehicle Fuel Switching	Annual Savings from Home Fuel Switching	Total Savings
Pittsylvania	$289,000	$172,000	$461,000
Danville	$222,000	$2,236,000	$2,458,000
Alamance	$802,000	$2,185,000	$2,987,000
Rockingham	$478,000	$3,833,000	$4,311,000
Total	**$1,791,000**	**$8,426,000**	**$10,217,000**

FTI's interviews with county leaders indicated that natural gas access can play a major role in business decisions to expand operations, particularly energy-intensive and advanced technology manufacturing. These manufacturers can provide significant economic benefits to communities from an employment, wage, and tax revenue perspective. For example, the average annual manufacturing wage in the City of Danville, where manufacturing employs 16 percent of workers, is approximately $56,680, or 56 percent higher than the average annual wage of $36,300 for all jobs in the city in 2017.

Altogether, the proposed MVP Southgate project would provide a number of economic and employment benefits to Virginia and North Carolina along the proposed route. During construction, these benefits would result from capital spent directly within Virginia and North Carolina, and the jobs created. Once in service, MVP Southgate would employ people within the state to help operate and maintain the pipeline. Also, counties would collect property taxes from the project. Finally, MVP Southgate would provide sizable opportunities for direct gas use, including additional supply reliability, fuel-switching savings, and new energy-intensive and advanced technology businesses started in both states.

1. Introduction

1.1. Project Background

The MVP Southgate project is a 24-inch and 16-inch diameter underground natural gas pipeline that would span approximately 73 miles from Pittsylvania County, Virginia, to Alamance County, North Carolina.[3] The pipeline would be regulated by the Federal Energy Regulatory Commission ("FERC").

The line would interconnect with the Mountain Valley Pipeline in Pittsylvania County, and traverse past the City of Danville into North Carolina. It would then continue through Rockingham County, North Carolina, interconnecting with PSNC Energy and East Tennessee pipelines, and terminate at an interconnect with PSNC Energy in Alamance County, North Carolina. The MVP Southgate project would also include a new compressor station in Pittsylvania County. The project's developers expect the Mountain Valley Pipeline to provide at least two billion cubic feet per day, or approximately three percent of current U.S. gas demand to markets in the Mid and South Atlantic regions.[4] In addition, PSNC Energy has already committed to 300 million cubic feet per day of firm transportation service on the MVP Southgate pipeline.[5]

Mountain Valley has retained FTI to examine the MVP Southgate project's potential economic benefits along three areas: (1) economic growth and employment resulting from construction expenditures, (2) operational benefits in terms of jobs created and ad valorem taxes paid by the MVP Southgate project owners, and (3) direct gas-use opportunities that would result within each state.

1.2. Approach

1.2.1. Construction Economic Impacts and Job Creation Benefits

FTI applied the IMPLAN model to estimate the economic impact and jobs created from construction activities in Virginia and North Carolina. The IMPLAN model is a general input-output modeling software and data system that tracks the movement of money through an economy, looking at linkages between industries along the supply chain, to measure the cumulative effect of spending in terms of job creation, income, production, and taxes. The IMPLAN data sets represent all industries within the regional economy – rather than extrapolating from national averages – and are derived primarily from data collected by federal agencies.[6]

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[3] The MVP Southgate project would be constructed and owned by Mountain Valley Pipeline, LLC, a joint venture in which the primary partners are EQM Midstream Partners and NextEra US Gas Assets, LLC.
[4] https://www.mountainvalleypipeline.info/overview
[5] Draft Resource Report No. 1, Summary of Alternatives, and MOU of Mountain Valley Pipeline, LLC, Docket No. PF18-4-000, June 18, 2018.
[6] The 2012 IMPLAN Dataset includes data from the U.S. Bureau of Labor Statistics ("BLS") Covered Employment and Wages program; U.S. Bureau of Economic Analysis ("BEA") Regional Economic Information System program; U.S. BEA Benchmark I/O Accounts of the U.S.; BEA Output estimates; BLS Consumer Expenditure Survey; U.S. Census Bureau

The economic impacts that IMPLAN calculates can be broken into direct impacts, indirect impacts, and induced impacts, defined as follows:

- **Direct impacts:** the economic activity resulting from the MVP Southgate project's capital costs spent on industries residing in Virginia and North Carolina. These are the industries that provide the "direct" materials, construction labor, construction management, and technical services (e.g., engineering and design, surveying, and permitting) for the project. This is the first order impact of the MVP Southgate project expenditures within the two states.
- **Indirect impacts:** the economic activity resulting from the "direct" industries spending a portion of their revenues on goods and services provided by their supply chain in Virginia and North Carolina. These supply chain industries represent the second order or 'indirect' impacts of the original MVP Southgate project expenditures in Virginia and North Carolina.
- **Induced impacts:** the economic activity resulting from the spending of the income earned by employees within the "directly" and "indirectly" affected industries. The benefactors of induced impact are primarily consumer-related businesses such as retail stores, restaurants, and personal service industries. These 'induced' impacts represent the third order impact.

Through the direct, indirect, and induced impact calculations, IMPLAN provides the economic ripple effect, or multiplier, that tracks how each dollar of input, or direct spending, cycles through the economy to suppliers and ultimately to households.

The first step of the IMPLAN process was to collect the estimate for state-only spending for each of the major project cost categories. These categories included the following:

- Pipeline Materials
- Compressor materials
- Meters and regulator devices
- Technical services such as engineering design, survey, and permitting
- Construction and commissioning services
- Land and right of way acquisitions

The MVP Southgate project owners anticipate spending $68 million and $113 million in Virginia and North Carolina, respectively, of the project's total $468 million estimated cost.[7]

FTI then assigned these cost categories to one of more than 500 IMPLAN economic sectors as inputs to the model. The model was then run from 2018 to 2020 to provide the following direct, indirect, and induced economic impacts:

County Business Patterns Program; U.S. Census Bureau Decennial Census and Population Surveys; U.S. Census Bureau Censuses and Surveys; and U.S. Department of Agriculture Census.

[7] This figure includes approximately $4.6 million in ad valorem tax revenue during the first year of operations.

- **GRP:** an industry's value of production over the cost of its purchasing the goods and services required to make its products. GRP includes wages and benefits paid to wage and salary employees and profits earned by self-employed individuals (labor income), monies collected by industry that are not paid into operations (profits, capital consumption allowance, payments for rent, royalties and interest income), and all payments to government (excise taxes, sales taxes, customs duties) with the exception of payroll and income taxes.

- **Employment Contributions:** direct, indirect, and induced annual average jobs for full-time, part-time, and seasonal employees and self-employed workers.

- **State, Local, and Federal Taxes:** payments to government that represent employer collected and paid social security taxes on wages, excise taxes, sales taxes, customs duties, property taxes, severance taxes, personal income taxes, corporate profits taxes, and other taxes.

- **Labor Income:** the wages and benefits paid to wage and salary employees and profits earned by self-employed individuals. Labor income demonstrates a complete picture of the income paid to the entire labor force within the model.

Section 2 provides the results of the IMPLAN construction and employment benefits analysis.

1.2.2. Operational Job Creation and Ad Valorem Tax Benefits

The MVP Southgate project would create jobs within the state to operate and maintain the pipeline and would generate ad valorem tax (property tax) revenues for the counties along the proposed route. To estimate the job benefits of ongoing operations, FTI collected data from the project owners on the annual direct employment (i.e., the number of full-time employees) and the amount of money they anticipate spending annually to support the pipeline's operations in Virginia and North Carolina. We then applied the data within the IMPLAN framework described above to determine the total statewide direct, indirect, and induced employment numbers and average wages.

In addition, Mountain Valley provided FTI with estimates for ad valorem taxes that were based upon the number of miles the MVP Southgate project would traverse in each county, the various county tax rates, and the monetary value of the project. FTI then reviewed the ad valorem tax estimates to verify that it is consistent with the methodology applied in the October 2, 2015 report on the Mountain Valley Pipeline ("2015 Mountain Valley Pipeline Report").[8]

1.2.3. Direct-Use Benefits

For this report, we supplemented the direct-use benefit data from the 2015 Mountain Valley Pipeline Report by calculating the amount of natural gas that could be used in municipal vehicles and residential households.

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[8] 2015 Mountain Valley Pipeline Report: https://www.mountainvalleypipeline.info/en/Location/VA.aspx

For municipal vehicles, we estimated the number of county vehicles, other school vehicles, and solid waste trucks based on the estimates obtained in the 2015 Mountain Valley Pipeline Report. We were also able to obtain the number of school buses for each county from state data. We then used the same methodology as in the 2015 Mountain Valley Pipeline to estimate the amount of gasoline and diesel consumption these vehicles consume and converted our results to MMSCF to demonstrate how much natural gas these vehicles would consume if converted.

To infer the effect of fuel-switching for households, we used data from the U.S. Census Bureau on the number of households that used various types of fuel for heating in 2016. We also obtained the average annual household site end-use consumption by fuel from the Energy Information Administration ("EIA") for the South Atlantic census region. Next, we calculated the fuel consumption of households using electricity, propane, and fuel oil/kerosene for space and water heating and then calculated the approximate cost of using these fuels based on EIA prices. We then calculated the equivalent amount of natural gas and associated costs using EIA prices,

2. Economic Benefits of the MVP Southgate

1.1. Construction Benefits

The MVP Southgate project owners plan to spend a total of $468 million on goods and services on constructing the pipeline, spending $68 million and $113 million of this total in Virginia and North Carolina, respectively. The project owners plan to spend the remaining $283 million outside Virginia and North Carolina. The combined $181 million in spending in Virginia and North Carolina would translate into job creation and economic growth for both states, as shown below in Figure 6.

Figure 6 - Economic Benefits of Construction in Virginia and North Carolina, 2018 - 2020

Economic Indicator	Virginia	North Carolina	Total
Aggregate GRP	$60 million	$97 million	$157 million
Peak Employment (2020)	570	1,130	1,700
Aggregate Labor Income	$38.7 million	$65.6 million	$104.3 million
Average Labor Income	$55,800	$49,300	$51,600
Aggregate State and Local Tax Revenues	$4.1 million	$6.3 million	$10.4 million

As shown above in Figure 6, the construction of MVP Southgate would generate over $157 million in additional GRP during the three-year construction period. Figure 7 and Figure 8 below show the composition of MVP Southgate capital expenditures by category for Virginia and North Carolina.

Figure 7 - MVP Southgate Capital Expenditures in Virginia by Major Spending Category

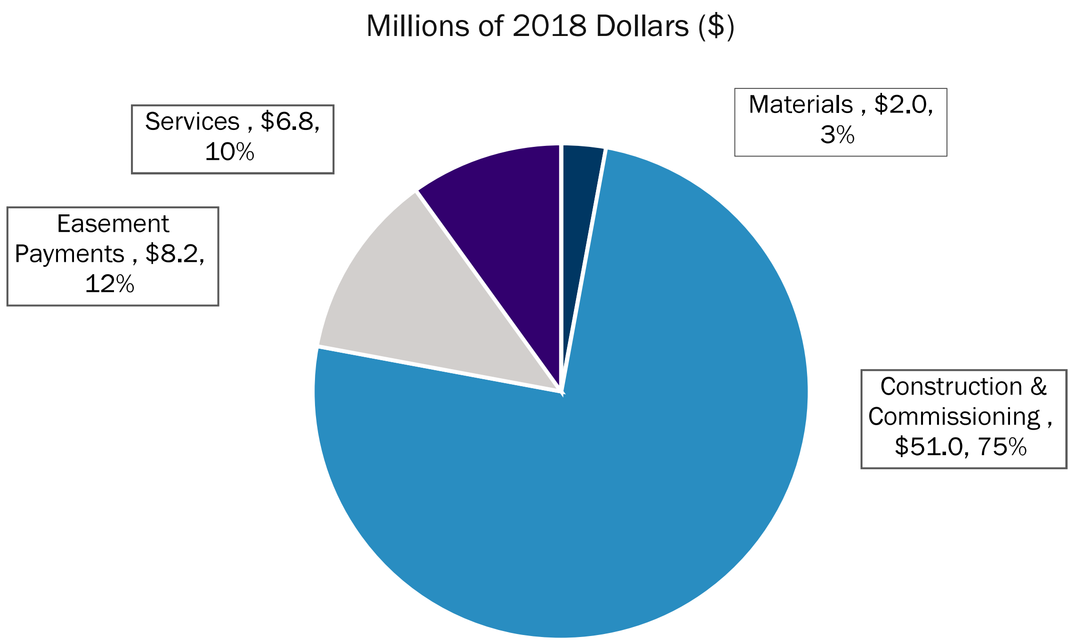
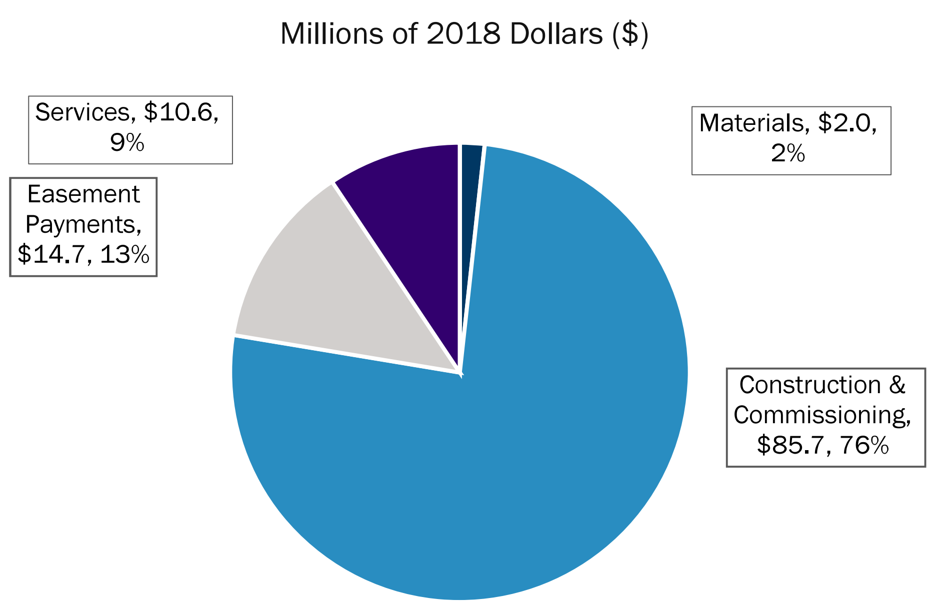


Figure 8 - MVP Southgate Capital Expenditures in North Carolina by Major Spending Category



This spending would also increase GRP by almost $47 million in Virginia in the peak construction year (i.e., 2020). Over the course of the project construction, the project would generate over $60 million in cumulative GRP in Virginia, as shown below in Figure 9.

Figure 9 - Impact of Construction Spending on Virginia GRP, 2018 - 2020

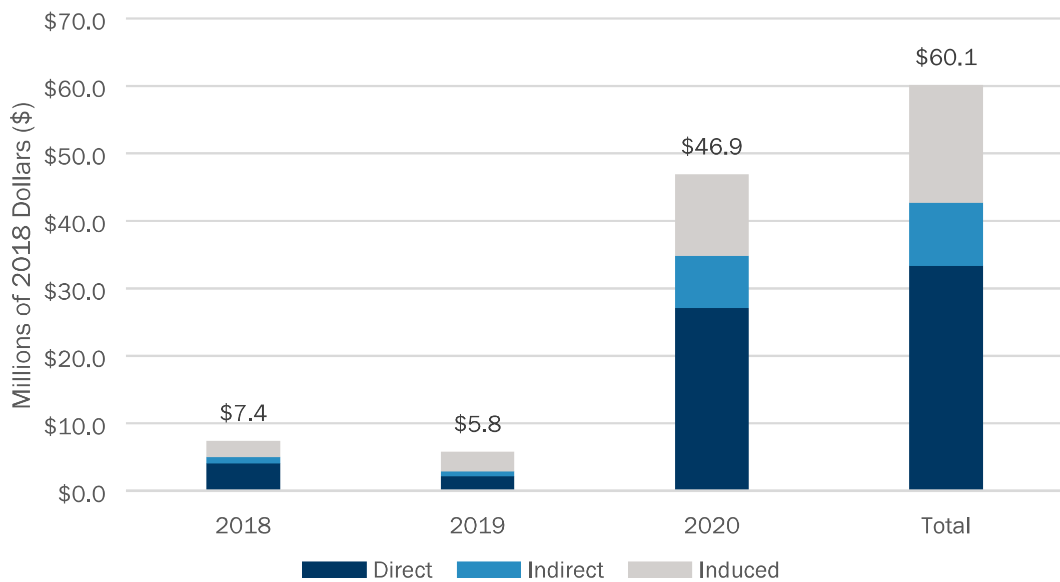
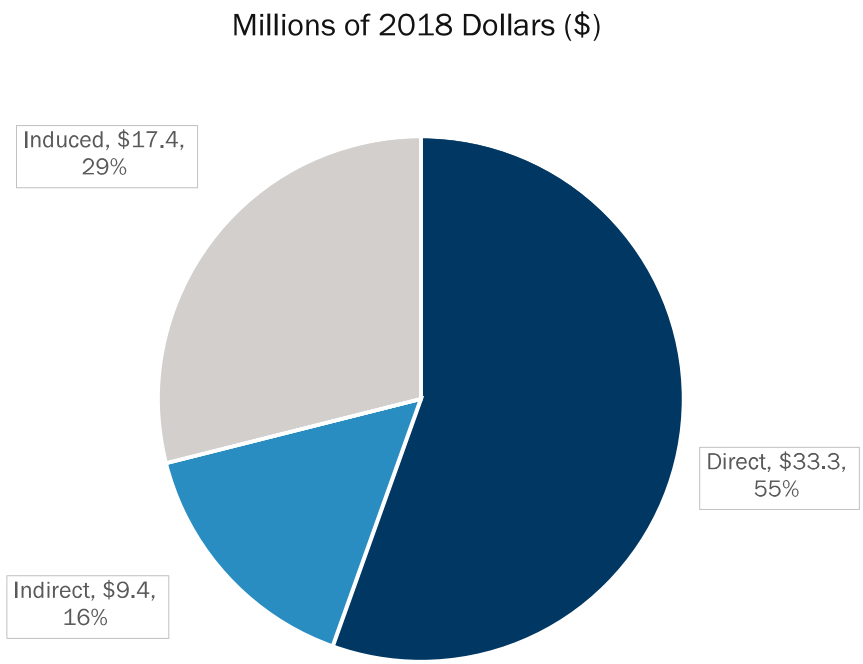


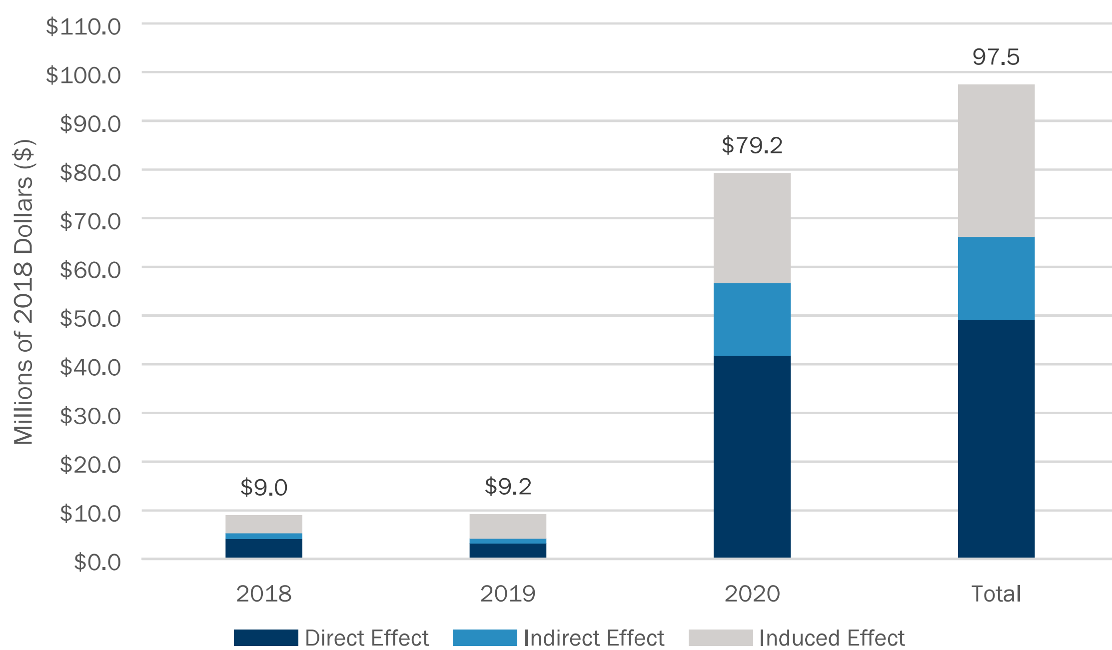
Figure 10 below shows the Virginia GRP added by MVP Southgate segmented into direct, indirect, and induced GRP. As discussed above, “direct” refers to the GRP occurring from the capital expenditures within the industry sectors immediately impacted. “Indirect” represents the GRP impacts from suppliers to the directly impacted industries. “Induced” GRP reflects the local spending of employee’s wages and salaries of directly and indirectly affected industries. Notably, construction of the MVP Southgate project would have the largest direct impact on Virginia’s GRP.

Figure 10 - Impact of MVP Southgate Construction Spending on Virginia GRP by Category, 2018 – 2020



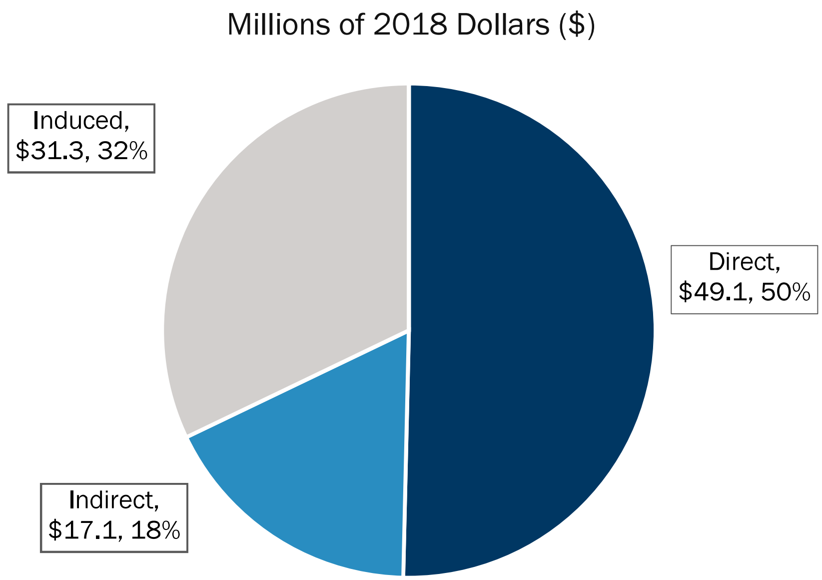
Construction spending for the MVP Southgate project would also generate over $79 million in GRP for North Carolina in 2020 at construction's peak and over $97 million over the three-year construction period, shown in Figure 11 below.

Figure 11 - Impact of Construction Spending on North Carolina GRP, 2018 - 2020



In addition, Figure 12 below shows MVP Southgate's contributions to GRP by spending category both annually and in aggregate. Similar to spending in Virginia, construction of the MVP Southgate project would have the largest direct impact on North Carolina's GRP.

Figure 12 - Impact of MVP Southgate Construction Spending on North Carolina's GRP by Category, 2018 – 2020



GRP is defined as the summation of employee compensation, proprietors' income, other property income, and federal, state, and local taxes on production and imports. Figure 13 and Figure 14 show employee compensation would have the largest impact on GRP in both states.

Figure 13 - Composition of MVP Southgate's Cumulative GRP Contributions in Virginia

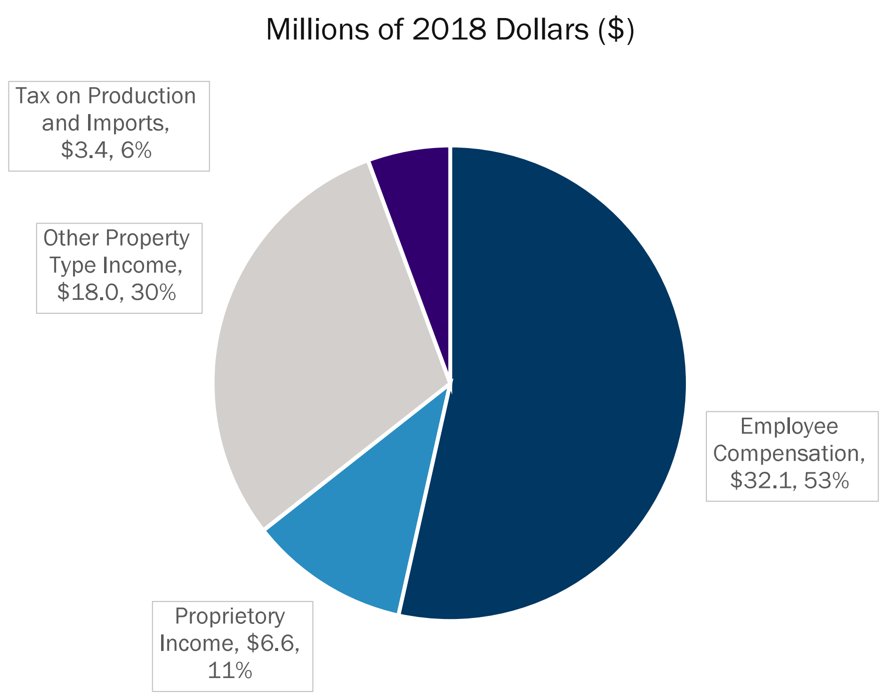
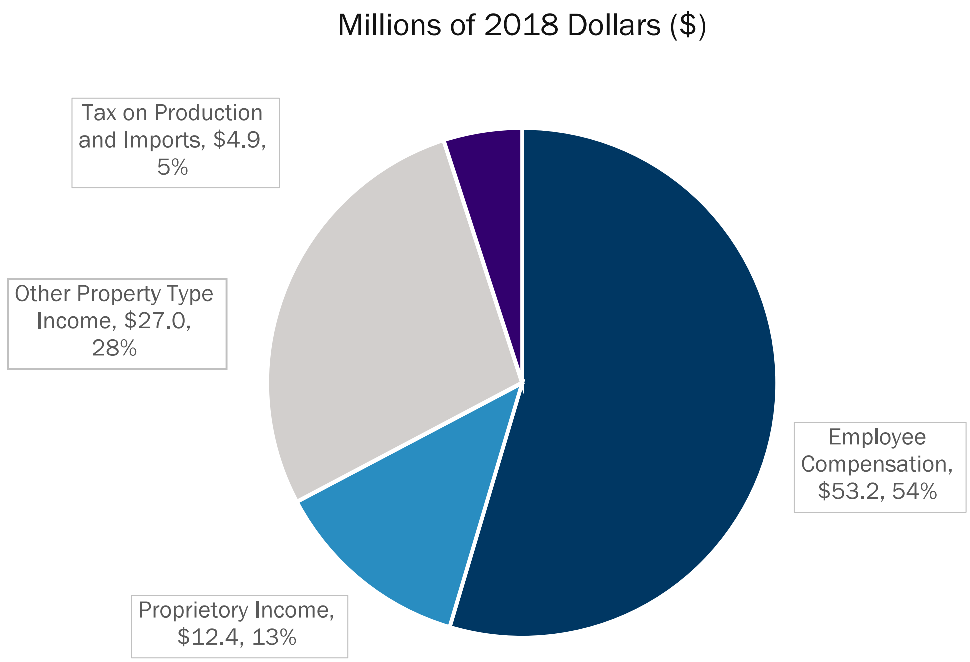
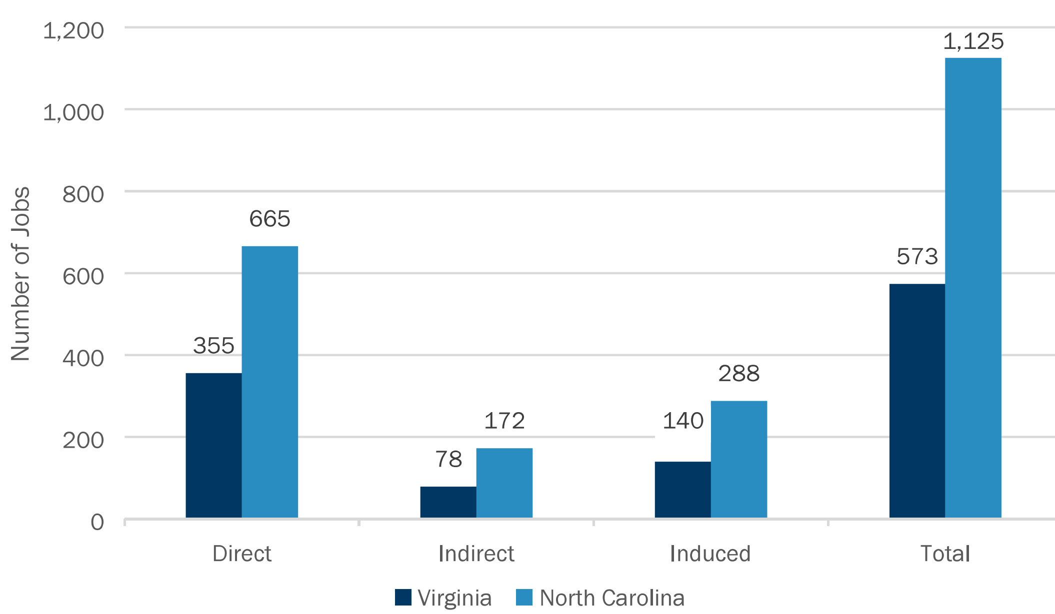


Figure 14 - Composition of MVP Southgate's Cumulative GRP Contributions in North Carolina



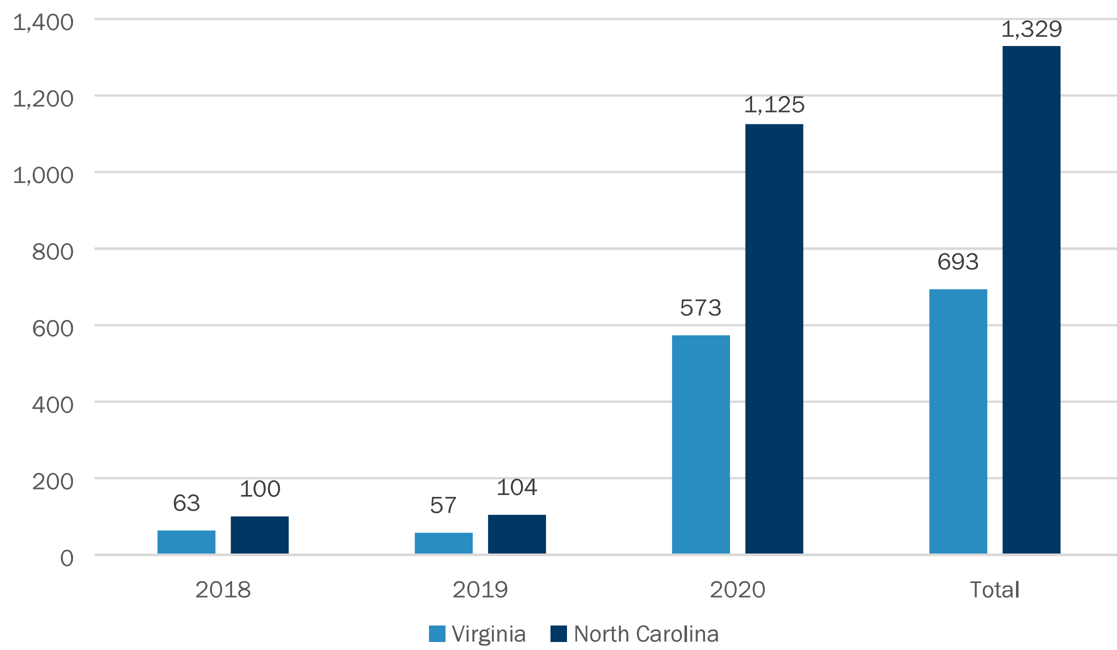
In addition to the GRP benefits, the project would generate approximately 570 and 1,130 jobs in Virginia and North Carolina, respectively, in 2020 at peak construction activity. These jobs include construction jobs, indirect jobs (i.e., jobs created in the state by suppliers to the direct industries impacted), and induced jobs (i.e., jobs created in the state via the spending of construction workers and employees of businesses hired to construct the pipeline). Figure 15 shows the impact of construction on employment in both states in 2020.

Figure 15 - Impact of MVP Southgate Construction Spending on Employment in 2020 by Category



Construction of the MVP Southgate project would create about 690 and 1,330 job-years in Virginia and North Carolina, respectively, over the three-year construction period as shown in Figure 16.[9]

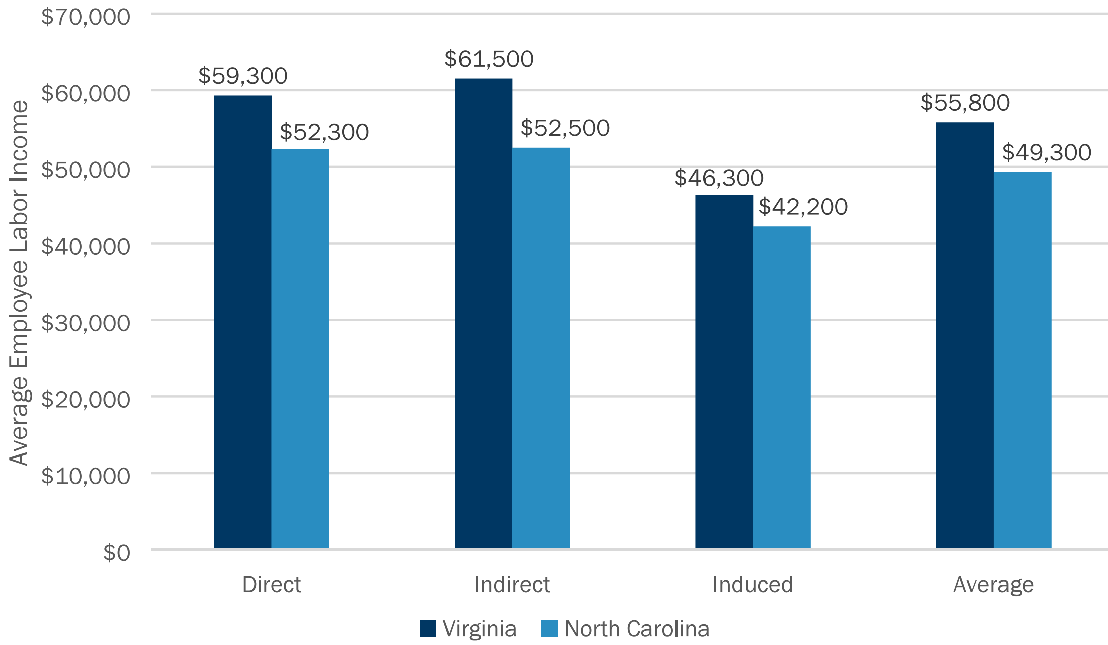
Figure 16 - Impact of MVP Southgate Construction Spending on Employment, 2018 - 2020



The MVP Southgate employment contribution also would have a positive impact on employee compensation relative to the median income in the state. Figure 17 shows the average employee compensation for direct, indirect, and induced jobs from the MVP Southgate project. Notably, the BLS reports that the average wage for construction occupations was $44,610 and $39,940 per year in Virginia and North Carolina, respectively, in 2017.[10]

[9] The MVP Southgate employment contributions are directly tied to capital spending in each year and are best expressed in "job-years." A job-year is the equivalent of one full-time job lasting a single year.
[10] https://www.bls.gov/oes/current/oessrcst.htm

Figure 17 - Average Employee Labor Income by Category



As shown above, workers would earn an average of approximately $55,800 and $49,300 in Virginia and North Carolina, respectively, both of which are higher than the average annual wage for residents in counties along the pipeline route.

1.2. Operational Benefits

The MVP Southgate project would continue to contribute to employment and generate county property or ad valorem taxes after construction once it becomes operational, employing 12 people across both state economies. Specifically, ongoing operation and maintenance of the pipeline in Virginia would employ six people (two of whom would be employed directly by the pipeline) with average annual wages and benefits of approximately $79,000. In combination with the Mountain Valley Pipeline, both pipelines would employ a total of 40 people in Virginia. In North Carolina, ongoing operation and maintenance of the MVP Southgate pipeline would also employ six people (two of whom would be employed directly by the pipeline), with average annual wages and benefits of almost $71,000.

The MVP Southgate project would also continue to contribute to GRP, sales output, and tax revenue for each state while it is operational. Table 2 below summarizes the annual operational benefits of the project in each state.

Table 2 - Annual Operational Benefits in Virginia and North Carolina

Category	Virginia	North Carolina	Total
GRP	$732,000	$684,000	$1.4 million
Ad Valorem Taxes	$1.2 million	$3.4 million[11]	$4.6 million
Other State, Local, and Federal Taxes	$269,000	$226,000	$495,000

1.3. Direct-Use Benefits

The following section reviews and discusses existing opportunities and savings in each county that could occur as a result of switching to natural gas from gasoline, propane, and diesel for transportation fuels and from electricity, fuel oil, or propane for household heating fuels. These opportunities exist in each of the city/county's end-use energy consumption sectors – residential & commercial, municipal buildings, manufacturing, and transportation (fleet vehicles). The shale gas revolution has enabled these switching opportunities as it has increased the supply of natural gas, lowered its cost, and stabilized prices.

1.3.1. Fleet Vehicles

For transportation, we used the same methodology as in the 2015 Mountain Valley Pipeline Report to estimate the number of fleet vehicles located in each county or town as well as their consumption of transportation fuels. Fleet vehicles include municipal solid waste trucks, school buses, other school vehicles, and county vehicles. Table 3 below shows estimates for the number of vehicles, current fuel consumption, and equivalent natural gas consumption.

[11] Rockingham and Alamance counties will directly receive $1.7 million of this total whereas municipalities in the state of North Carolina will receive the remaining $1.7 million.

Table 3 - Estimated Municipal Fleet Vehicle Annual Energy Consumption

County/City	Number of Fleet Vehicles	Annual Gasoline/ Diesel Consumption (Gallons)	Equivalent Natural Gas Consumption (MMSCF)	Annual Savings
Pittsylvania	450	684,000	90	$289,000
Danville	290	441,000	60	$222,000
Alamance	1,150	1,748,000	230	$802,000
Rockingham	640	973,000	1,130	$478,000
Total	**2,530**	**3,846,000**	**1,510**	**$1,791,000**

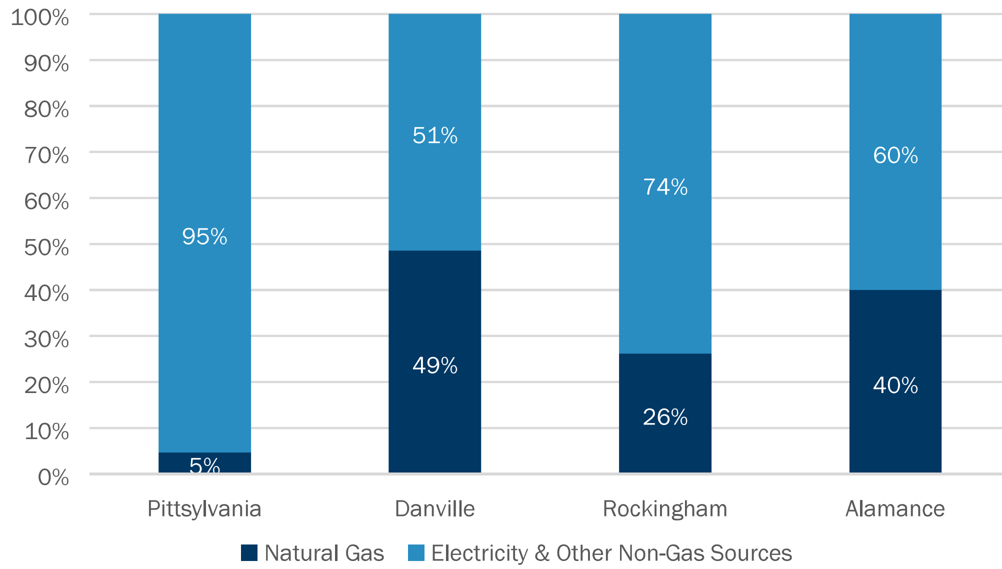
We estimate the natural gas switching potential in Pittsylvania, Alamance, and Rockingham counties and the city of Danville to be 1,510 MMSCF per year if all 2,530 fleet vehicles were switched to natural gas. The annual savings of switching to natural gas vehicles, inclusive fuel costs, compressed natural gas station costs, and vehicle conversion, would equate to approximately $1.8 million.

1.3.2. Residential Space Heating, Water Heating, and Cooking

All four areas considered in this report have varying degrees of natural gas access; however, most households use electricity, propane, and fuel oil for space heating, water heating, and cooking. Figure 18 below highlights the percentage of households in Pittsylvania, Danville, Rockingham, and Alamance that use natural gas versus other fuels for space heating.[12]

[12] https://www.census.gov/acs/www/data/data-tables-and-tools/data-profiles/2016/

Figure 18 – Household Heating Fuel by County, 2016



To compute the economic switching potential to natural gas for the four areas, FTI applied the following sets of data:

- Values in Figure 18
- 2018 delivered energy price data from the EIA
- Residential consumption by fuel type from EIA's Residential Energy Consumption Survey
- Urban populations percentages

Table 4 below shows the economic switching potential by area. We assume that only urban populations would have access to natural gas and thus natural gas distribution upgrades would be nominal. The values in Table 4 also do not include the costs for equipment and ventilation upgrades. For propane and fuel oil, these upgrades, relative to fuel cost savings, would be nominal at the point when existing furnaces reach the end of their useful lives.

Table 4 – Residential Natural Gas Switching Annual Fuel Cost Savings by Area

County/City	Natural Gas Switching Annual Fuel Cost Savings
Pittsylvania	$172,000
Danville	$2,236,000
Rockingham	$2,185,000
Alamance	$3,833,000
Total	**$8,426,000**

Note: Cost savings exclude distribution, equipment, and ventilation upgrades

Table 4 shows that Pittsylvania County has the lowest economic switching potential. The reason is that Pittsylvania County's urban residences account for only six percent of the county's population and that five percent of the county's households (conservatively assumed to be urban) already use natural gas for space heating, water heating, and cooking. As a result, there is limited technical potential for residential natural gas switching in Pittsylvania. However, Danville, Rockingham, and Alamance households have sizable urban populations that could switch to natural gas and save $2 million to $4 million annually.

1.3.3. Manufacturing

The manufacturing sector accounts for almost 17 percent of the jobs in Pittsylvania, Danville, Rockingham, and Alamance, and is a sector that could benefit significantly from having more reliable natural gas service. Natural gas is an influencing factor in retaining existing manufacturers and attracting new ones to the county. With annual wages that are, on average, 37 percent higher than the average wages across all sectors in each city/county, the manufacturing sector is crucial to the local economy and would benefit from the MVP Southgate project. Notably, access to natural gas is a major factor when businesses decide to invest in facilities, expand and modernize operations, and locate or relocate plants. Thus, access to natural gas can draw new businesses to areas and ensure current businesses remain committed to the long-term success of their operations within the community.

3. Summary

The proposed MVP Southgate project would provide several benefits to the areas in Virginia and North Carolina through which the pipeline would run. The pipeline would benefit existing natural gas customers by helping to ensure future access to a reliable supply of natural gas. These customers include manufacturing firms, which pay higher wages and make up a substantial portion of these counties' economies.

The shale gas revolution has helped lower natural gas prices, making natural gas an economically attractive alternative to existing fuel sources. FTI estimated the potential demand for switching to natural gas for both municipal vehicles and households using electricity as their primary heat source.

The MVP Southgate pipeline could also help retain or attract manufacturers. Interviews with country representatives, regional partnership leaders, and manufacturers identified that businesses value abundant and reliable gas service. All four areas already maintain a significant manufacturing presence, with the sector employing 17 percent of workers on average, and have plans to continue expanding with the development of additional industrial parks.

These types of investments can provide large economic benefits to communities from an employment, wage, and tax revenue perspective. Input-output modeling software such as IMPLAN can help to estimate the magnitude of these impacts. In addition to the initial economic impact of the investment, businesses along the supply chain benefit through ripple, or multiplier, effects, as do households in the form of higher wages and disposable income.

Appendix I: County Economic and Energy Profiles

Pittsylvania County, Virginia

Economic Profile

Pittsylvania County, Virginia, is a 978-square mile county located in the Piedmont region of Virginia with a 2017 population of 63,506.[13] In 2016, Pittsylvania's GDP was $3.24 billion[14] and its median household income was median household income of $43,087.[15] The largest towns in Pittsylvania are Chatham, Gretna, and Hurt. Pittsylvania County's 2017 unemployment rate was 4.5 percent, higher than the unemployment rates of both Virginia and the United States of 3.8 percent and 4.3 percent, respectively.[16]

12,357 people work in Pittsylvania County, approximately 24 percent of which work for the federal, state, or local government. The next largest sectors are manufacturing, health care and social assistance, and construction, which employ approximately 15 percent, 11 percent, and nine percent, respectively, of Pittsylvania workers.[17] In addition, the average annual wage in Pittsylvania County is $35,776, almost 39 percent less than the average annual state wage of $58,292 in Virginia.[18] Table 5 below shows employment and average wage by industry for Pittsylvania County.[19]

[13] U.S. Census QuickFacts: Pittsylvania County, Virginia, https://www.census.gov/quickfacts/fact/table/danvillecityvirginia,pittsylvaniacountyvirginia/PST045217
[14] National Association of Counties. http://explorer.naco.org/
[15] U.S. Census QuickFacts: Pittsylvania County, Virginia, https://www.census.gov/quickfacts/fact/table/danvillecityvirginia,pittsylvaniacountyvirginia/PST045217
[16] http://virginialmi.com/report_center/community_profiles/5104000143.pdf; https://data.bls.gov/timeseries/LNS14000000
[17] http://virginialmi.com/report_center/community_profiles/5104000143.pdf
[18] http://virginialmi.com/report_center/community_profiles/5101000000.pdf
[19] http://virginialmi.com/report_center/community_profiles/5104000143.pdf

Table 5 - Employment and Wages in Pittsylvania County by Industry

Industry	Employment	Percent of Total Employment	Average Annual County Wage	Percent Higher/Lower than County Wage
Government (Total)	2,919	23.6%	$38,948	8.9%
Government (Local)	2,359	19.1%	$30,992	-13.4%
Manufacturing	1,815	14.7%	$52,988	48.1%
Health Care and Social Assistance	1,358	11.0%	$24,752	-30.8%
Construction	1,102	8.9%	$43,940	22.8%
All Industries	11,824		$35,776	

As shown above in Table 5, manufacturing is one of the highest paying industries in Pittsylvania County, paying approximately 48 percent more than the average county wage. Manufacturing is also one of the largest employers in the county; DTI, Intertape Polymer Group, Swedwood Danville, Times Fiber Communications, and Unique Industries, described below, are Pittsylvania's largest manufacturing employers.[20]

- **Intertape Polymer Group ("IPG"):** IPG develops and manufactures paper and film-based sensitive and water-active tapes, polyethylene and specialized polyolefin films, and complementary packaging systems for diverse industrial and retail uses. IPG also produces woven coated fabrics. IPG currently employs 280 people in Pittsylvania and is the fifth largest employer in the county.[21] IPG recently announced that it is expanding its manufacturing operations by investing $7 million in the county and hiring an additional 15 employees.[22]

- **Owens-Illinois Inc.("O-I"):** O-I is a global producer of glass containers, primarily for beverages, and maintains a manufacturing center in Ringgold. O-I is the eleventh largest employer in Pittsylvania County with up to 300 employees.[23]

- **Swedwood Danville:** Swedwood Danville is a subsidiary of the Swedish furniture company, IKEA. Also located in Ringgold, Swedwood Danville employs approximately 400 people at its

[20] http://virginialmi.com/report_center/community_profiles/5104000143.pdf
[21] http://www.dpchamber.org/employment
[22] https://www.gosouthernvirginia.com/about-svra/news/intertape-polymer-group-bringing-15-new-jobs-to-pittsylvania-county
[23] https://www.gosouthernvirginia.com/workforce/major-employers

930,000-square foot facility at the Cane Creek Centre and is the third largest employer in the county.[24]

- **Times Fiber Communication:** Times Fiber Communication is a global manufacturer of high quality cables, fiber optic management equipment, and interconnect products for cable television, satellite, data, and powering applications for broadband communications networks. With operations located in Chatham employing up to 300 people, Times Fiber Communication is the twelfth largest employer in Pittsylvania.[25]

- **Unique Industries:** A wholesale manufacturer and supplier of party goods with manufacturing operations located in Blairs, Unique Industries employs 325 people and is Pittsylvania's second largest employer behind the county school board.[26]

Pittsylvania County has shown its commitment to new manufacturing by breaking ground on the new, 3,700-acre Berry Hill Industrial Park, located in Pittsylvania County near the Virginia-North Carolina border. The park, which will cost $29.8 million to construct, is the largest industrial park in Virginia and the fifth largest on the East Coast.[27] While still under development, the park, shown in Figure 19 below,[28] will be located close to both the Norfolk Southern Railroad and interstate highways 58 and 40.[29]

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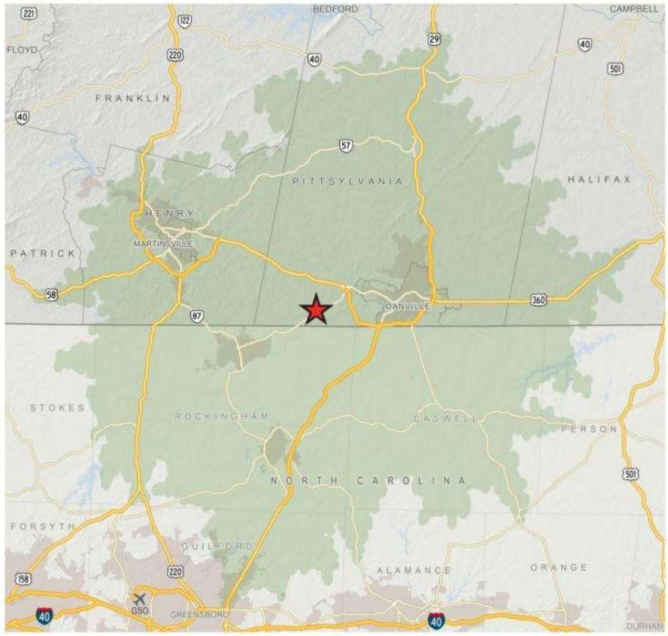
[24] http://www.dpchamber.org/employment
[25] https://www.gosouthernvirginia.com/workforce/major-employers
[26] http://www.dpchamber.org/employment
[27] https://www.greensboro.com/rockingham_now/business/berry-hill-industrial-park-breaks-ground/article_24faef7c-126f-11e7-8aad-37409504e5ee.html
[28] https://maps.vedp.org/LaborMaps/242790.pdf
[29] http://www.gosouthernvirginia.com/sites-buildings/sites-buildings

Figure 19 – Map of Berry Hill Industrial Park



The park's developers anticipate it to maintain water and sewer capacities of 12 million gallons/day and four million gallons/day, respectively.[30] Appalachian Power, owned by American Electric Power, provides electrical service to the Berry Hill Industrial Park.[31] In addition, the Transco pipeline, which serves the City of Danville, passes directly past the park and will run parallel to the MVP Southgate project, offering another source of natural gas supply for industrial and residential customers.

Pittsylvania County maintains several industrial parks, including the 900-acre Cane Creek Centre,[32] and has plans to develop additional facilities. These plans include a new 800-acre industrial park in Hurt that will be a joint development project between Pittsylvania County, the Town of Hurt, the Town of Altavista, the City of Danville, and Southern Virginia Multimodal Park, LLC.[33]

Energy Profile

As mentioned above, the Transco pipeline passes directly through Pittsylvania; however, as shown in Figure 20 below, only five percent of households use natural gas provided by local utilities Columbia Gas and Southwestern Virginia Gas as their primary fuel for household heating.[34] Both Dominion Power and Appalachian Power provide electric service to Pittsylvania.[35]

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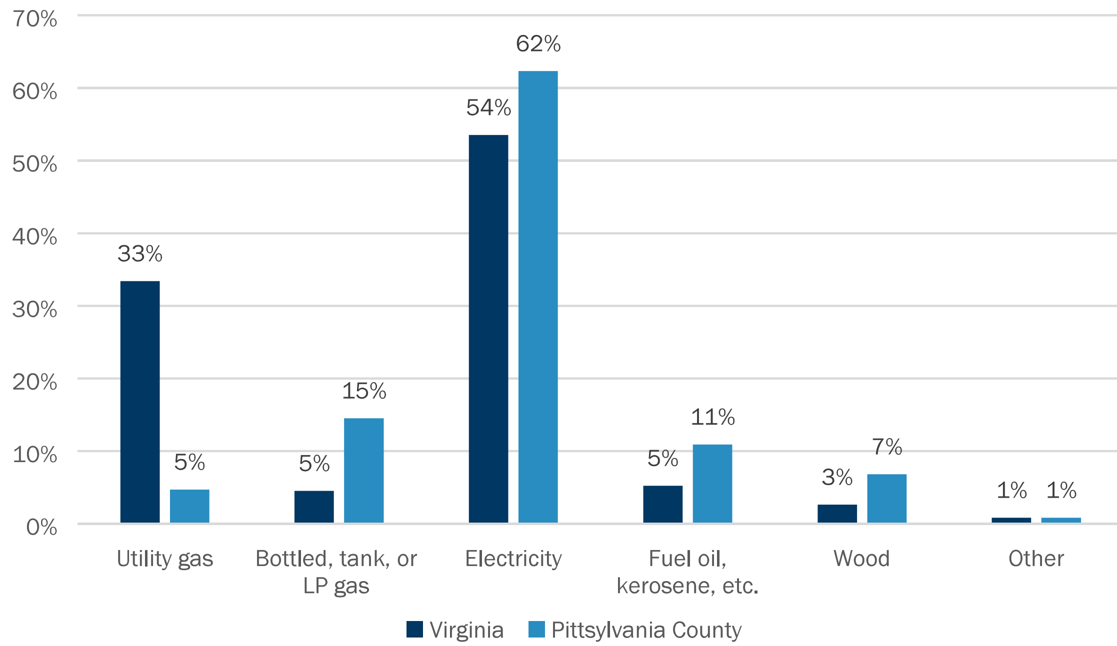
[30] https://bloximages.newyork1.vip.townnews.com/godanriver.com/content/tncms/assets/v3/editorial/3/d2/3d25cccc-1024-11e7-9800-6b457e241a5f/58d46084d9e16.image.jpg
[31] https://virginiascan.yesvirginia.org/GetBinary?id=184992
[32] http://www.discoverdanville.com/index.aspx?NID=252
[33] https://townofhurtva.gov/economic-development/; https://d2oc0ihd6a5bt.cloudfront.net/wp-content/uploads/sites/1667/2016/06/SVMP2.pdf
[34] American FactFinder, U.S. Census, https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=bkmk

Figure 20 – Primary Household Heating Fuel in Virginia and Pittsylvania County, 2016



In contrast to the state of Virginia and the other areas described further below, many more households in Pittsylvania use fuel sources other than electricity and natural gas, such as propane, petroleum, and wood. In addition, some counties near Pittsylvania, such as Franklin, Floyd, and Patrick counties, do not have natural gas access, and could also benefit from enhanced natural gas capacity provided by MVP Southgate.[36]

Natural gas is also important to retaining existing manufacturers and attracting new manufacturers to the county. Our interviews and analysis identified that manufacturers value abundant and reliable gas service and that access to natural gas is a primary criterion for determining where to locate new manufacturing facilities. Thus, enhanced natural gas access via the MVP Southgate project could provide an additional incentive for companies considering opening or relocating manufacturing operations to the city.

Danville, Virginia

Economic Profile

Danville, Virginia, is an approximately 45-square mile independent city located next to Pittsylvania County in the Piedmont region of Virginia. Danville maintained a population of 41,130 in 2017 and a 2016 median household income of $33,721.[37] Danville's 2017 unemployment rate was six percent,

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[35] https://www.scc.virginia.gov/pur/elec/el_map.pdf
[36] https://www.scc.virginia.gov/pur/gas/gas_map.pdf
[37] https://www.census.gov/quickfacts/fact/table/danvillecityvirginia,pittsylvaniacountyvirginia/PST045217

higher than the unemployment rates of both Virginia and the United States of 3.8 percent and 4.3 percent, respectively.[38]

27,062 people work in the city of Danville, approximately 19 percent of which work in the health care and social assistance industry. The next largest sectors are manufacturing, retail, and government, which employ approximately 16 percent, 16 percent, and 14 percent, respectively, of Danville workers.[39] In addition, the average annual wage in Danville is $36,296, almost 38 percent less than the average annual state wage of $58,292 in Virginia.[40] Table 6 below shows employment and average wage by industry for Danville.[41]

Table 6 - Employment and Average Wages in Danville by Industry, 2016

Industry	Employment	Percent of Total Employment	Average Annual County Wage	Percent Higher/Lower than County Wage
Health Care and Social Assistance	5,061	18.7%	$40,924	12.8%
Manufacturing	4,355	16.1%	$56,680	56.2%
Retail	4,264	15.8%	$25,272	-30.4%
Government (total)	3,673	13.6%	$45,084	24.2%
All Industries	27,062		$36,296	

As shown above in Table 6, manufacturing is one of the highest paying industries in Danville, paying approximately 56 percent more than the average county wage. Manufacturing is also one of the largest employers in the county; EBI, Essel Propack, Goodyear Tire & Rubber, Nestle, and Unlin, described below, are among Danville's largest manufacturing employers.

- **EBI**: EBI is a Polish company that manufactures and distributes upholstered furniture and mattresses for Com.40, Ltd. IKEA is one of EBI's main buyers.[42] The eighth largest employer in Danville, EBI's manufacturing center in the city employs approximately 270 people.[43]

- **Essel Propack**: Essel Propack is a global specialty packaging manufacturer of laminated plastic tubes primarily used for fast-moving consumer goods and pharmaceuticals. Essel

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38 http://virginialmi.com/report_center/community_profiles/5104000590.pdf; https://data.bls.gov/timeseries/LNS14000000
39 http://virginialmi.com/report_center/community_profiles/5104000143.pdf
40 http://virginialmi.com/report_center/community_profiles/5101000000.pdf
41 http://virginialmi.com/report_center/community_profiles/5104000143.pdf
42 https://www.tradeandindustrydev.com/industry/manufacturing/com40-ltd-danville-virginia-2370
43 http://www.dpchamber.org/employment

Propack is one of the top 20 largest employers in Danville and employs over 230 people at its Airside Industrial Park location, which it expanded in 2011 by adding 105,000 square feet.[44]

- **Goodyear Tire & Rubber**: Goodyear is one of the largest tire manufacturers in the world and has expanded its business to include commercial truck service, tire retreading centers, and auto service outlets. Goodyear is also the largest employer in Danville with over 2,300 employees.[45]

- **Nestle**: Nestle is a Swiss company and one of the largest food companies in the world, producing food and beverages, including pet foods, under various brands in more than 47 states. Nestle's manufacturing center, located in Danville's Airside Industrial Park, which produces Toll House cookie dough and Buitoni pasta products, employs approximately 6450 people.[46]

- **Unlin**: This Belgian company, known mostly for its Quick-Step floors, also manufactures flooring, panels, and insulation. In 2005, Unlin acquired Mohawk Industries, which owns a manufacturing center in Danville, and is now the thirteenth largest employer in the city.

The City of Danville has shown its commitment to new manufacturing by breaking ground on the new, 3,700-acre Berry Hill Industrial Park, located in Pittsylvania County near the Virginia-North Carolina border. The park, which will cost $29.8 million to construct, is the largest industrial park in Virginia and the fifth largest on the East Coast.[47] While still under development, the park, shown in Figure 21 below,[48] will be located close to both the Norfolk Southern Railroad and interstate highways 58 and 40.[49]

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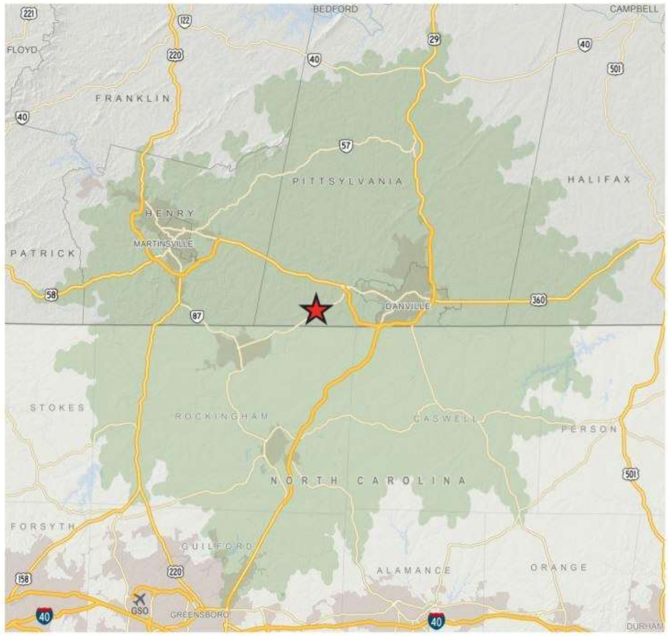
[44] http://www.dpchamber.org/employment
[45] http://www.dpchamber.org/employment
[46] http://www.dpchamber.org/employment
[47] https://www.greensboro.com/rockingham_now/business/berry-hill-industrial-park-breaks-ground/article_24faef7c-126f-11e7-8aad-37409504e5ee.html
[48] https://maps.vedp.org/LaborMaps/242790.pdf
[49] http://www.gosouthernvirginia.com/sites-buildings/sites-buildings

Figure 21 – Map of Berry Hilly Industrial Park Site



The park's developers anticipate it to maintain water and sewer capacities of 12 million gallons/day and four million gallons/day, respectively.[50] Appalachian Power, owned by American Electric Power, provides electrical service to the Berry Hill Industrial Park.[51] In addition, the Transco pipeline, which serves the City of Danville, passes directly past the park and will run parallel to the MVP Southgate project, offering another source of natural gas supply for industrial and residential customers.

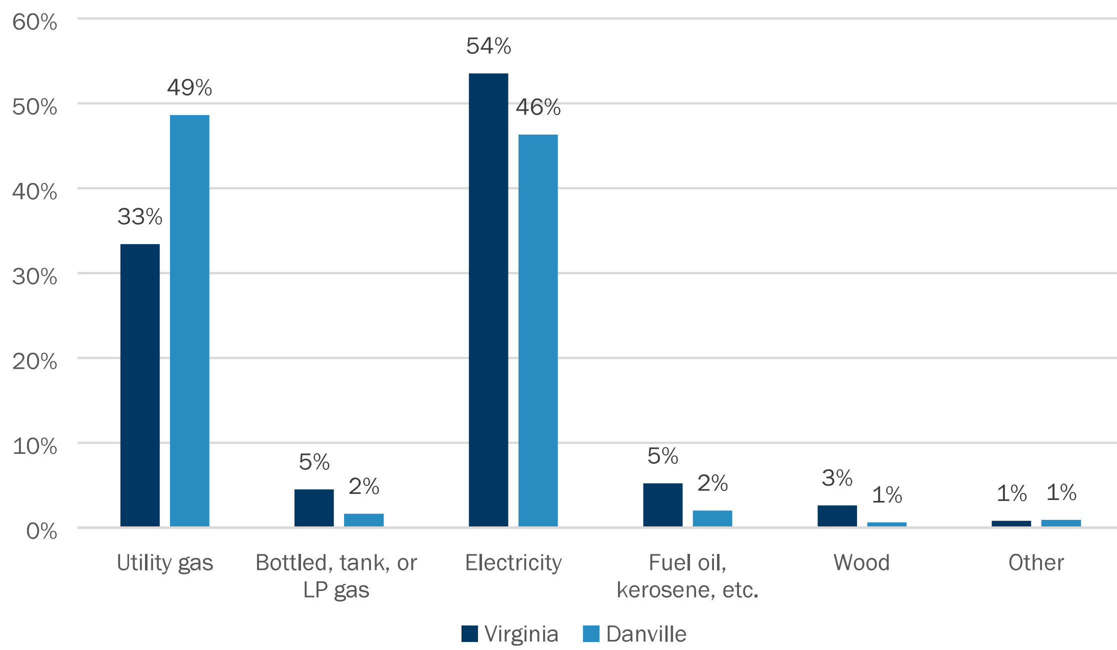
There are three other major industrial parks in the city – the Airside Industrial Park, Riverview Industrial Park, and Cyber Park – all of which have lots currently available.[52]

Energy Profile

As mentioned above, the Transco pipeline provides natural gas service to the City of Danville through Danville Utilities, which also offers electricity service. As shown in Figure 22 below, almost half of Danville households use natural gas as their primacy fuel for household heating while slightly fewer use electricity.

[50] https://bloximages.newyork1.vip.townnews.com/godanriver.com/content/tncms/assets/v3/editorial/3/d2/3d25cccc-1024-11e7-9800-6b457e241a5f/58d46084d9e16.image.jpg
[51] https://virginiascan.yesvirginia.org/GetBinary?id=184992
[52] http://www.discoverdanville.com/index.aspx?NID=229

Figure 22 - Primary Household Heating Fuel in Virginia and the City of Danville, 2016



Natural gas is also important to retaining existing manufacturers and attracting new manufacturers to the county. Our interviews and analysis identified that manufacturers value abundant and reliable gas service and that access to natural gas is a primary criterion for determining where to locate new manufacturing facilities. Thus, enhanced natural gas access via the MVP Southgate project could provide an additional incentive for companies considering opening or relocating manufacturing operations to the city.

Alamance County, North Carolina

Economic Profile

Alamance County, North Carolina, is a 424-square mile county located in the Piedmont region of North Carolina with a 2017 population of 162,391.[53] In 2016, Alamance's GDP was $6.15 billion[54] and its 2017 median household income was $43,209.[55] Large cities and areas in Alamance County include Burlington, Graham, and Mebane.[56] Alamance County's unemployment rate is 4.3 percent, lower than the unemployment rate of 3.8 percent in North Carolina and the same as the unemployment rate of 4.3 percent in the United States.[57]

61,317 people work in Alamance County, approximately 16 percent of which work for in the healthcare and social assistance industry. The next largest sectors are manufacturing, retail, and accommodation and food service, which employ approximately 15 percent, 15 percent, and 12 percent, respectively, of Alamance workers. In addition, the average annual wage in Alamance County is $40,092,[58] about 13 percent less than the average annual state wage of $46,080 in North Carolina.[59] Table 7 below shows employment and average wage by industry for Alamance County.

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[53] U.S. Census QuickFacts: Alamance County, North Carolina, https://www.census.gov/quickfacts/fact/table/alamancecountynorthcarolina,rockinghamcountynorthcarolina/PST045217

[54] National Association of Counties. http://explorer.naco.org/

[55] U.S. Census QuickFacts: Alamance County, North Carolina, https://www.census.gov/quickfacts/fact/table/alamancecountynorthcarolina,rockinghamcountynorthcarolina/PST045217

[56] https://www.alamance-nc.com/about-alamance-county/communities/

[57] Access NC: North Carolina, https://accessnc.nccommerce.com/DemoGraphicsReports/pdfs/stateComparison/NC_NC.pdf; https://data.bls.gov/timeseries/LNS14000000

[58] Access NC: Alamance County, https://accessnc.nccommerce.com/DemoGraphicsReports/pdfs/countyProfile/NC/37001.pdf

[59] https://www.bls.gov/oes/current/oes_nc.htm

Table 7 - Employment and Average Wages in Alamance County by Industry

Industry	Employment	Percent of Total Employment	Average Annual County Wage	Percent Higher/Lower than County Wage
Health Care and Social Assistance	9,853	16.07%	$54,080	34.89%
Manufacturing	9,240	15.07%	$47,476	18.42%
Retail	9,082	14.81%	$25,272	-36.96%
Accommodation and Food Service	7,190	11.73%	$32,240	-19.58%
Government (total)	6,851	11.17%	$47,476	18.42%
All Industries	61,317		$40,092	

As shown above in Table 7, manufacturing is one of the highest paying industries in Alamance County, paying approximately 18 percent more than the average county wage. Manufacturing is also one of the largest employers in the county; GKN Driveline, Glen Raven, Honda, Jabil Packaging Solutions, and Kayser-Roth Corp, described below, are Alamance's largest manufacturing employers. [60]

- **GKN Driveline**: GKN Driveline is a multinational automotive components manufacturer that specializes in various driveline technologies. GKN Driveline's Mebane facility employs approximately 800 people.

- **Glen Raven, Inc. ("Glen Raven")**: Glen Raven is a fabrics manufacturer for the awning, marine, furniture, protective, military, and geosynthetics markets. Glen Raven operates multiple locations, including both corporate functions and manufacturing, in the town of Glen Raven, located in Alamance County, and employs approximately 500 people.

- **Honda Power Equipment Mfg., Inc. ("Honda")**: Honda operates a manufacturing facility in Haw River that produces engines for lawn mowers, generators, and water pumps. Honda also operates a second location in Burlington at its Honda Aero headquarters and manufacturing building that designs gas turbine engines for the Honda Jet. At these locations, Honda employs approximately 750 people.

- **Jabil**: Jabil is a product solutions company that engineers and manufactures products in a variety of spaces, including electrical, optical, software, and mechanical. Jabil's Mebane

[60] Alamance Chamber: Industries, http://b49826eovvwg61335b3co132.wpengine.netdna-cdn.com/wp-content/uploads/2018/03/AC_EconDev_ProfileSheet3_Industries_v5.pdf

location specializes in the design and manufacture of rigid food containers, closures, and devices and employs approximately 400 people.

- **Kayser-Roth**: Kayser-Roth, owned by the Italian company Golden Lady, manufactures intimate apparel and hosiery. Kayser-Roth's Graham manufacturing facility employs approximately 460 people.

The county has three main industrials parks: Alamance County has three industrial parks: North Carolina Commerce Park and North Carolina Industrial Park, both located in Mebane, and Buckhorn Economic Development Zone, which is located in both Alamance and Orange counties. Notably, Lotus Bakeries, based in Belgium, plans to open its first U.S. manufacturing plant in Mebane in 2020. According to the company, the new manufacturing center, located at the North Carolina Industrial Center, will cost $48 million and employ 60 people.[61]

Energy Profile

Both Piedmont Natural Gas and PSNC Energy provide natural gas service to Alamance, while Duke Energy provides electric service.[62] As shown in Figure 23 below, most Alamance County households use electricity as their primary fuel for household heating; however, more Alamance households use natural gas than North Carolina residents.[63]

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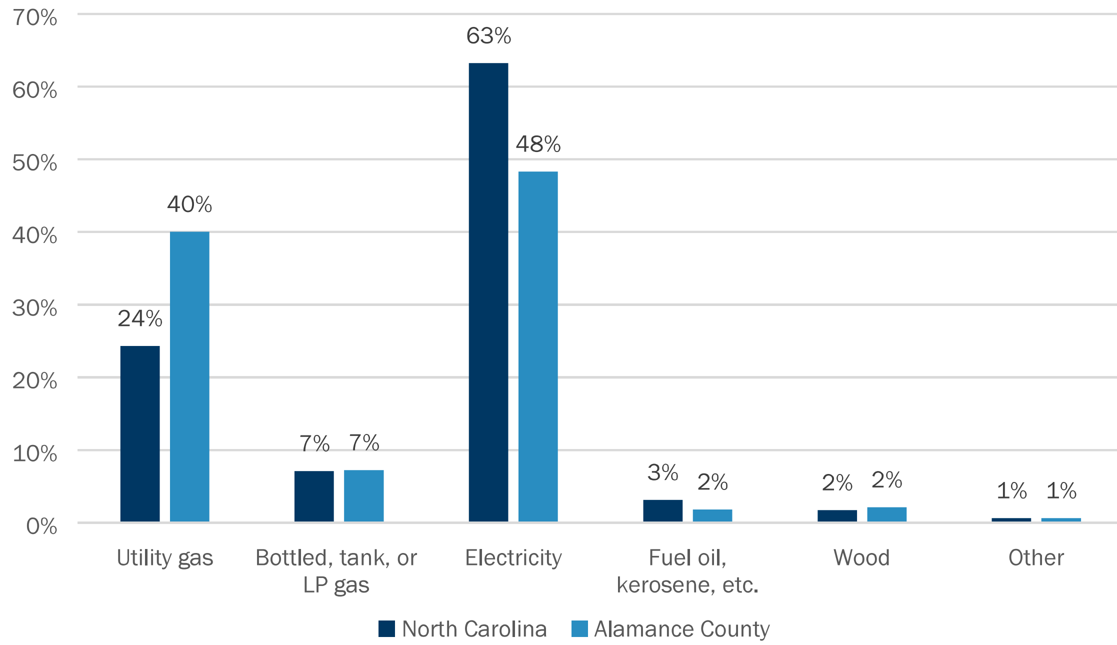
[61] http://www.areadevelopment.com/newsItems/11-7-2016/lotus-bakeries-manufacturing-operation-mebane-north-carolina.shtml
[62] http://pubstaff.s3.amazonaws.com/s3fs-public/documents/files/natural-gas-service-areas.pdf; http://www.ncuc.commerce.state.nc.us/overview/overview.pdf
[63] U.S. Census, American FactFinder, Alamance County and North Carolina, https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_16_5YR_DP04&prodType=table

Figure 23 – Primary Household Heating Fuel in Alamance County, 2016



Natural gas is also important to retaining existing manufacturers and attracting new manufacturers to the county. Our interviews and analysis identified that manufacturers value abundant and reliable gas service and that access to natural gas is a primary criterion for determining where to locate new manufacturing facilities. Thus, enhanced natural gas access via the MVP Southgate project could provide an additional incentive for companies considering opening or relocating manufacturing operations to the city.

Rockingham, North Carolina

Economic Profile

Rockingham County, North Carolina, is a 573-square mile county located in the Piedmont region of North Carolina with a 2017 population of 90,949. Rockingham is made up of six municipalities, the largest of which are Madison and Reidsville.[64] In 2016, Rockingham's GDP was $2.57 billion[65] and its 2017 median household income was $40,003.[66] Rockingham County's unemployment rate is 5.2 percent,[67] higher than the unemployment rates of both North Carolina and the United States of 3.8 percent and 4.3 percent, respectively.[68]

25,507 people work in Rockingham County, approximately 22 percent of which work in the manufacturing industry. The next largest sectors are retail, government, and accommodation and food service, which employ approximately 15 percent, 15 percent, and 12 percent, respectively, of Rockingham workers. In addition, the average annual wage in Alamance County is $34,996,[69] about 24 percent less than the average annual state wage of $46,080 in North Carolina.[70] Table 8 below shows employment and average wage by industry for Rockingham County.

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64 http://www.co.rockingham.nc.us/pview.aspx?id=14872&catid=0
65 National Association of Counties. http://explorer.naco.org/
66 U.S. Census QuickFacts: Rockingham County, North Carolina, https://www.census.gov/quickfacts/fact/table/alamancecountynorthcarolina,rockinghamcountynorthcarolina/PST045217
67 Access NC: Rockingham County, https://accessnc.nccommerce.com/DemoGraphicsReports/pdfs/countyProfile/NC/37157.pdf
68 Access NC: North Carolina, https://accessnc.nccommerce.com/DemoGraphicsReports/pdfs/stateComparison/NC_NC.pdf; https://data.bls.gov/timeseries/LNS14000000
69 Access NC: Alamance County, https://accessnc.nccommerce.com/DemoGraphicsReports/pdfs/countyProfile/NC/37001.pdf
70 https://www.bls.gov/oes/current/oes_nc.htm

Table 8 - Employment and Average Wages in Rockingham County by Industry

Industry	Employment	Percent of Total Employment	Average Annual County Wage	Percent Higher/Lower than County Wage
Manufacturing	5,635	22.1	$44,096	26.0%
Retail	3,849	15.1%	$24,596	-29.7%
Government (total)	3,845	15.1%	$37,492	7.1%
Health Care and Social Assistance	3,085	12.1%	$36,192	3.4%
Accommodation and Food Service	2,222	8.7%	$14,040	-59.9%
All Industries	25,507		$34,996	

As shown above in Table 8, manufacturing is one of the highest paying industries in Rockingham County, paying approximately 26 percent more than the average county wage. Manufacturing is also one of the largest employers in the county; Frontier Spinning Mills; Gildan; Keystone Foods; Sturm, Ruger & Co.; and Unifi, described below, are Rockingham's largest manufacturing employers.

- **Frontier Spinning Mills:** Frontier Spinning Mills produces spun yarns for the knitting and weaving industries. With two manufacturing plants in Mayodan, Frontier Spinning Mills employs 515 people.

- **Gildan:** Gildan is manufacturer of branded basic family apparel sold under a variety of company-owned brands. Gildan also produces other clothing items, primarily socks, for other private labels as well as unbranded activewear. Gildan operates a large distribution center in Mebane, which employs over 515 people.

- **Keystone Foods:** Keystone Foods, owned by Marfrig Global Foods, is a global food services company that supplies frozen animal protein products. Keystone Foods operates a manufacturing center in Reidsville that employs over 420 people.

- **Sturm, Ruger & Co ("Ruger"):** Ruger is one of the country's largest firearm manufacturers for the commercial sporting market. Located in Mayodan, Ruger employs over 365 people.

- **Unifi:** Unifi is a global textile company known for its production of repreve, a recycled performance fiber. With a manufacturing center located in Reidsville, Unifi employs almost 800 people.

Rockingham County also has five industrial parks: Eden Industrial Center, Madison Business Park, Osborne Industrial Park, Reidsville Industrial Park, and Stone Industrial Site. Duke Energy owns a 620-megawatt combined cycle natural gas plant in Rockingham, and Piedmont Natural Gas provides natural gas service to the industrial parks.[71]

Natural gas is important to retaining existing manufacturers and attracting new manufacturers to the county. Our interviews and analysis identified that manufacturers value abundant and reliable gas service and that access to natural gas is a primary criterion for determining where to locate new manufacturing facilities. In fact, NTE Energy is currently developing a 500-megawatt combined cycle natural gas plant in Rockingham and expects to begin construction this year with operations beginning in 2021.[72] The Transco pipeline also passes through Rockingham County but, instead of traversing east into Alamance County, the pipeline travels west through Guilford and Forsyth counties.

Regarding transportation, Rockingham recently undertook a new I-73 connector project to improve secondary roads. Norfolk Southern Railway also runs 48 miles of track through the county, with 21 miles cleared for double-stack container movement.[73] Our interviews, however, revealed that projects have turned down sites in Rockingham because of lacking infrastructure, including high costs of getting needed materials to project sites and inadequate highway access.

Energy Profile

Piedmont Natural Gas provides natural gas service to Rockingham, while Duke Energy provides electric service.[74] As shown in Figure 24 below, the distribution of household fuel sources in Rockingham County closely mirrors that of North Carolina as a whole, with most households using electricity as their primary household heating source.[75]

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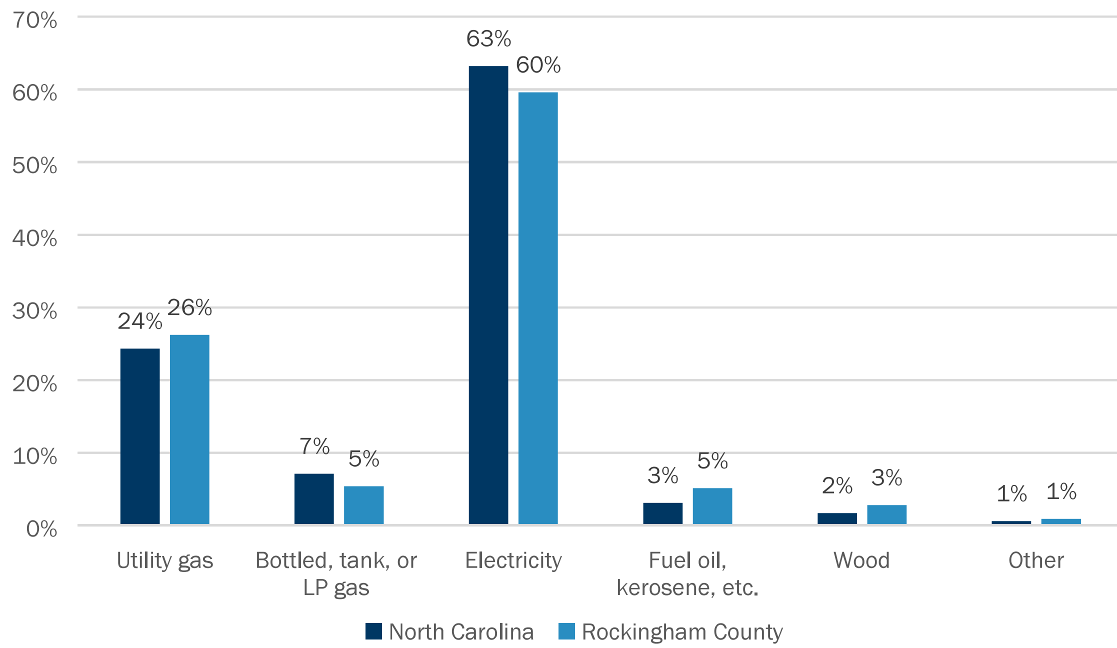
[71] http://www.gorockinghamcountync.com/site-selection-2/infrastructure/
[72] http://reidsvilleenergy.com/#project-overview
[73] http://www.gorockinghamcountync.com/site-selection-2/infrastructure/
[74] http://pubstaff.s3.amazonaws.com/s3fs-public/documents/files/natural-gas-service-areas.pdf; http://www.ncuc.commerce.state.nc.us/overview/overview.pdf
[75] U.S. Census, American FactFinder, Rockingham County and North Carolina, https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?pid=ACS_16_5YR_DP04&prodType=table

Figure 24 - Primary Household Heating Fuel in Rockingham County, 2016



Natural gas is also important to retaining existing manufacturers and attracting new manufacturers to the county. Our interviews and analysis identified that manufacturers value abundant and reliable gas service and that access to natural gas is a primary criterion for determining where to locate new manufacturing facilities. Thus, enhanced natural gas access via the MVP Southgate project could provide an additional incentive for companies considering opening or relocating manufacturing operations to the city.

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APPENDIX M
FERC Resource Report 10 – Summary of Alternatives

MVP Southgate Project

Docket No. CP19-XX-000

Resource Report 10 – Alternatives

November 2018

MVP Southgate Project
Resource Report 10 – Alternatives

Resource Report 10 – Filing Requirements	
Information	**Location in Resource Report**
Minimum Filing Requirements	
1. Address the “no action” alternative (Sec. 380.12(l)(1)).	Section 10.2
2. For large projects, address the effect of energy conservation or energy alternatives to the project (Sec. 380.12(l)(1)).	Section 10.3
3. Identify system alternatives considered during the identification of the project and provide the rationale for rejecting each alternative (Sec. 380.12(l)(1)).	Section 10.4
4. Identify major and minor route alternatives considered to avoid impact on sensitive environmental areas (e.g., wetlands, parks, or residences) and provide sufficient comparative data to justify the selection of the proposed route (Sec. 380.12(l)(2)(ii)).	Section 10.5 and 10.6
5. Identify alternative sites considered for the location of major new aboveground facilities and provide sufficient comparative data to justify the selection of the proposed site (Sec. 380.12(l)(2)(ii)).	Section 10.7
Additional Information Often Missing and Resulting in Data Requests	
6. Ensure that project objectives that serve as the basis for evaluating alternatives are consistent with the purpose and need discussion in Resource Report 1.	Section 10.1.2
7. Identify and evaluate alternatives identified by stakeholders.	Section 10.5.3
8. Clearly identify and compare the corresponding segments of route alternatives and route variations to the segments of the proposed route that they would replace if adopted.	Section 10.5

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SUMMARY OF ALTERNATIVES
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RESOURCE REPORT 10
SUMMARY OF ALTERNATIVES

LIST OF ACRONYMS AND ABBREVIATIONS

ACP	Atlantic Coast Pipeline
Bcf/d	billion cubic feet per day
Certificate	Certificate of Public Convenience and Necessity
East Tennessee	East Tennessee Natural Gas, LLC
EIA	U.S. Energy Information Administration
FERC or Commission	Federal Energy Regulatory Commission
LNG	liquefied natural gas
MMcf/d	million cubic feet per day
MMDth/d	million dekatherms per day
Mountain Valley	Mountain Valley Pipeline, LLC
MW	megawatt
NWI	National Wetland Inventory
Piedmont	Piedmont Natural Gas Company
PSNC Energy	PSNC Energy, a wholly owned subsidiary of SCANA Corporation
Project or Southgate Project	MVP Southgate Project
Transco	Transcontinental Gas Pipe Line Company, LLC
U.S.	United States

RESOURCE REPORT 10
SUMMARY OF ALTERNATIVES

10.1 INTRODUCTION

Mountain Valley Pipeline, LLC ("Mountain Valley") is seeking a Certificate of Public Convenience and Necessity from the Federal Energy Regulatory Commission ("FERC" or "Commission") pursuant to Section 7(c) of the Natural Gas Act to construct and operate the MVP Southgate Project ("Southgate Project" or "Project"). The Southgate Project facilities will be located in Pittsylvania County, Virginia and Rockingham and Alamance counties, North Carolina. See Resource Report 1 (General Project Description) for additional Project information.

10.1.1 Environmental Resource Report Organization

Resource Report 10 is prepared and organized according to the FERC Guidance Manual for Environmental Report Preparation (February 2017). This report describes the no action alternative (Section 10.2), other energy alternatives (Section 10.3), system alternatives (Section 10.4), route alternatives (Section 10.5), route variations (Section 10.6), aboveground facility alternatives (Section 10.7), and presents references (Section 10.8). Appendix 1-N of Resource Report 1 provides a response matrix for FERC Comments on Draft Resource Report 10.

10.1.2 Purpose and Need

See Resource Report 1 (General Project Description) for additional information on the Project purpose and need.

10.2 NO ACTION ALTERNATIVE

The No Action Alternative for the Project would avoid the temporary and permanent environmental impacts associated with construction and operation of the Project. However, the No Action Alternative would not achieve the Project's purpose and need as stated in Resource Report 1 (General Project Description). Under the No Action Alternative, North Carolina and southern Virginia will not receive the significant benefits associated with the Project. In addition, the Project's anchor shipper, PSNC Energy, a wholly owned subsidiary of SCANA Corporation ("PSNC Energy") would experience a capacity shortfall as projected in its annual filing with the North Carolina Public Utilities Commission.

The Project would not be able to meet the specific transportation needs for natural gas as contracted by PSNC Energy if the Project is not constructed. On a broader scale, implementing the No Action Alternative would not support the goal of increasing consumer access to stable and reliable natural gas supplies in the southeastern U.S.

In recent years, the North American natural gas market has seen enormous growth in production and demand. The U.S. Energy Information Administration ("EIA") estimates that total natural gas consumption in the U.S will increase from 27.6 trillion cubic feet in 2017 to 35.6 trillion cubic feet in 2050, with a large portion of this increased demand occurring in the electric generation sector (EIA, 2018a). A sizable portion of growth in natural gas production is occurring in the Appalachian Basin, with Marcellus Shale production alone increasing from 10 billion cubic feet per day ("Bcf/d") in 2013 to approximately 20 Bcf/d in October 2017 (EIA, 2018b). The increased demand for natural gas is expected to be especially high in the southeastern U.S., and in particular, North Carolina, as its population continues to grow. The Project will benefit North Carolina and southern Virginia by connecting the additional supply to the increased market demand. In doing so, the Project will bring clean-burning, domestically-produced natural gas supplies to support the growing demand for natural gas, provide increased supply diversity, and improve supply reliability.

If the purpose and need of the Project are to be met without construction of the Project facilities, other projects and activities would be needed resulting in their own environmental impacts. This would result in the transfer of environmental impacts from one project to another, but would not necessarily eliminate or reduce impacts. The No Action Alternative is not considered a viable option because it does not meet the objectives of the Project or its anchor shipper.

10.3 ENERGY ALTERNATIVES

Use of certain alternative fuels to supply the needs of the market served by the Project are not alternatives to the Project. As described below, renewable energy, energy conservation, alternative fossil fuels, nuclear, and fuel cells do not meet the Southgate Project purpose.

10.3.1 Renewable Energy Sources

Renewable energy sources, such as wind, solar, geothermal, and biomass are increasing in capacity and benefit the energy market by diversifying the fuels used to generate electricity. However, these sources are not interchangeable with natural gas. Renewable energy sources cannot meet the objectives of the Project or its anchor shipper to provide natural gas for typical local distribution uses (e.g., home heating, cooking and industrial uses). In addition, renewable energy does not meet the purpose of the Project to provide new natural gas transmission pipeline capacity that will increase competition and enhance the reliability and resiliency of the existing pipeline infrastructure in North Carolina and southern Virginia.

10.3.2 Energy Conservation

Energy conservation measures have an increasing role in reducing future energy demand in the U.S. The Energy Policy Act of 2005 provides guidelines to: (1) diversify America's energy supply and reduce dependence on foreign sources of energy; (2) increase residential and business' energy efficiency and conservation (e.g., Energy Star Program); (3) improve vehicular energy efficiency; and (4) modernize the domestic energy infrastructure.

Energy conservation reduces the demand or growth in demand for natural gas and other energy sources. It is possible that the development and implementation of additional cost-effective conservation measures could have some effect on the demand for natural gas. However, substantial new advances in technology would be needed before the magnitude of such energy conservation measures necessary to equal the amount of energy transported by the Project could be implemented. PSNC Energy already participates in energy conservation programs for its customers, as approved by the North Carolina Utilities Commission. Programs include discount rates and rebates on energy efficient equipment. Because PSNC Energy already participates in these programs, and the Southgate Project is designed to meet PSNC Energy's additional projected need, energy efficiency programs are not an alternative to the Project.

10.3.3 Alternative Fossil Fuels, Nuclear, and Fuel Cells

While other fossil fuels (e.g., coal and oil), nuclear power, and fuel cells can be viable alternatives to natural gas in generating electricity, these sources are not interchangeable with natural gas. These alternative energy sources cannot meet the objectives of the Project or its anchor shipper to provide natural gas for typical local distribution uses (e.g., home heating, cooking and industrial uses). In addition, these alternative energy sources do not meet the purpose of the Project to provide new natural gas transmission pipeline capacity that will increase competition and enhance the reliability and resiliency of the existing pipeline infrastructure in North Carolina and southern Virginia.

10.4 SYSTEM ALTERNATIVES

System alternatives are alternatives to the proposed action that would make use of other existing, modified, or proposed pipeline systems to meet the purpose and need of the Project. If available as a viable alternative, a system alternative could make it unnecessary to construct all or part of the Project, although some modifications or additions to the alternative systems would be required to increase their capacity or provide receipt and delivery capability consistent with that of the Project. These modifications or additions would result in environmental impacts that may be less than, comparable to, or greater than those associated with construction of the Project. System alternatives that would result in significantly less environmental impact might be preferable to the Project. However, a viable system alternative must also be technically and economically feasible and practicable, and must satisfy necessary contractual commitments (including timing) made with shippers supporting the development of the Project. The systems evaluated as potential alternatives to the Project are discussed below.

10.4.1 Surface Transportation System Alternatives

A surface transportation system alternative would involve the liquefaction of natural gas at the receipt points along the pipeline and transportation of the liquefied natural gas ("LNG") volumes to the delivery points where regasification facilities would be installed. To liquefy and transport natural gas, the temperature and pressure design points are -260 degrees Fahrenheit and 4 pounds per square inch gauge. Converting the 300 million cubic feet per day ("MMcf/d") of natural gas volumes that the Project will deliver to PSNC in North Carolina to LNG would require a production and transportation of approximately 3.7 million gallons per day. Transportation of the LNG would involve trucking on local and interstate highways to a centralized delivery point and transporting to regasification facilities at the delivery points along the pipeline. Given a truck tanker capacity of 10,850 gallons, it would take approximately 345 trucks per day to transport this volume with a truck limiting load rate of approximately 300 gallons per minute. To transport the LNG volumes, a 24-hour per day, simultaneous loading operations of approximately nine trucks would be required. Any additional natural gas volume increase would result in an incremental increase in the number of trucks per day.

Truck transportation options are not as safe and reliable as pipelines, as discussed and demonstrated statistically in Resource Report 11 (Reliability and Safety). Installation of processing facilities to liquefy and subsequently re-gasify natural gas would require extensive permitting; require large tracts of land for a regasification facility, and result in associated air emissions from the liquefaction/regasification process and the truck or rail traffic. In addition, the development or improvement of the transportation network would be necessary to transport LNG gas would be required. Transporting LNG by rail is also not a viable option. Currently, there are no approved LNG rail tankers, and shipment of LNG in International Organization for Standardization containers by rail is very limited due to regulatory constraints. Therefore, new regulatory processes and approvals would be required before LNG rail shipments would be possible. Since the LNG by rail alternative would not be available to meet the timeframe required for energy demands by the market, use of this alternative is not a viable alternative to the Project. Therefore, transporting the Project's natural gas volumes as LNG by trucks and rail/or is not considered a viable alternative to the Project pipeline facilities and was eliminated from further consideration.

10.4.2 Transco Pipeline System and Cardinal Pipeline

Transco Pipeline System

The Transcontinental Gas Pipe Line Company, LLC ("Transco") system encompasses approximately 10,200 miles from South Texas to New York City with a system peak design capacity of approximately 15 million dekatherms per day ("MMDth/d"). The Project's pipeline would be located adjacent to or in close proximity to Transco's system for approximately 23.0 miles, between approximate MP 0.4 and MP 32.9, in Virginia and North Carolina.

On April 11, 2018 Transco's filed an application with FERC for its proposed Southeastern Trail Expansion Project (Docket No. CP18-186). According to Transco, its Southeastern Trail Expansion Project would provide 296.4 MMcf/ of natural gas per day of additional firm transportation to serve markets in the Mid-Atlantic and Southeastern states by November 2020. Transco states that the project would provide additional reliable service to utility and local distribution companies in the southeast including Virginia and North Carolina. Customers served by the Southeastern Trail Expansion Project include: PSNC Energy (60 MMcf/d), South Carolina Electric and Gas (215 MMcf/d), Virginia Natural Gas (14.6 MMcf/d), and the Cities of Buford (3.8 MMcf/d) and LaGrange (3 MMcf/d) in Georgia. The project would involve construction and operation of approximately 7.7 miles of new natural gas pipeline (Manassas Loop) located along the existing Transco Mainline in Fauquier and Prince William Counties, Virginia; expansion of three existing compressor stations in Virginia (Stations 185, 175, and 165), and modification of 21 existing facilities in South Carolina, Georgia, and Louisiana. The project also includes the retirement and abandonment of 10 compressor units and related buildings and ancillary equipment at Transco's existing Compressor Station 165 in Pittsylvania County, Virginia. Transco's Compressor Station 165 is located approximately 3.0 miles west of the Project's proposed Lambert Compressor Station. No facilities associated with the Southeastern Trail Expansion Project are proposed in North Carolina.

Currently, Transco's pipeline system does not have the long-term firm capacity to serve the Project's anchor shipper (PSNC Energy) contracted amount. In addition, use of a Transco system alternative would require additional gas delivery infrastructure. To meet the needs of PSNC Energy, approximately 40 miles of new pipeline from the existing Transco system to the PSNC's Haw River Interconnect, as well as any necessary compressor station facilities and mainline pipeline upgrades, would need to be constructed. The Project provides a primary receipt and delivery forward haul transportation path that offers improved reliability as compared to the secondary-firm backhaul deliveries PSNC Energy currently receives from Transco. In addition, PSNC Energy considered other existing and proposed interstate pipeline providers, including Transco, to meet its needs. Finally, PSNC Energy committed to the firm transportation service of the

Project to diversify its gas transportation supply. Therefore, the Project does not consider Transco's system to be a reasonable alternative to the Project.

Cardinal Pipeline System

The Cardinal Pipeline Company is a 105-mile, 24-inch intrastate pipeline that extends from Rockingham County, North Carolina to a point southeast of Raleigh, North Carolina, with a design capacity of 279,000 dekatherms per day. The Cardinal Pipeline System receives all its gas from Transco in North Carolina and redelivers this gas to Piedmont and PSNC Energy.

At its closest point, the Cardinal Pipeline System is approximately 2.0 miles west of MP 71.0 of the pipeline near Graham, North Carolina. To meet the objectives of the Southgate Project, this pipeline system would require additional gas delivery infrastructure in North Carolina and Virginia that would result in environmental impacts similar to those that would occur as proposed by the Project. In addition, PSNC Energy considered other existing and proposed interstate pipeline providers, including the Cardinal Pipeline System; however, PSNC Energy committed to firm transportation service associated with the Project and entered into binding long-term agreements that made PSNC Energy an anchor shipper for the Project. Therefore, the Southgate Project does not consider the Cardinal Pipeline System to be a reasonable alternative to the Project.

10.4.3 Atlantic Coast Pipeline Project

The Atlantic Coast Pipeline Project, which is currently under construction, is expected to be in service in late 2019. The project consists of approximately 600 miles of pipeline that originates in West Virginia, crosses Virginia, and then continues south into eastern North Carolina, ending in Robeson County. It also includes three new compressor stations. The Atlantic Coast Pipeline Project is designed to provide up to 1.5 MMDth/d of natural gas transportation service to consumers in Virginia and North Carolina including Dominion Energy, Duke Energy, Piedmont, Virginia Natural Gas, and PSNC Energy. This pipeline system is located approximately 100 miles east of the Southgate Project. To meet the objectives of the Southgate Project, this pipeline system would require over 100 miles of new pipeline infrastructure in North Carolina and/or Virginia that would result in environmental impacts greater than those that would occur as a result of the Project. In addition, PSNC Energy considered other existing and proposed interstate pipeline providers, including Atlantic Coast Pipeline to meet its gas transportation demand. PSNC Energy committed to firm transportation service associated with the Project and entered into binding long-term agreements that made PSNC Energy an anchor shipper for the Project. Therefore, the Project does not consider the Atlantic Coast Pipeline to be a reasonable alternative to the Project.

10.4.4 East Tennessee Natural Gas System

The East Tennessee Natural Gas, LLC ("East Tennessee") pipeline system consists of approximately 1,536 miles of pipeline in the Southeast and Mid-Atlantic. The system begins in Tennessee and extends to an area just south of Roanoke, Virginia. A segment of the system extends into southwest Virginia and northern North Carolina through a 95-mile natural gas pipeline that interconnects with the Transco system near Eden, North Carolina. East Tennessee interconnects with Texas Eastern Transmission, Tennessee Gas Pipeline, Columbia Gulf, Southern Natural Gas and Midwestern Gas Transmission. The East Tennessee system currently provides direct access to natural gas producers in the Appalachian region through multiple pipeline interconnections on its mainline.

While East Tennessee interconnects with the Southgate Project at the LN 3600 Interconnect (approximately 1.1 miles west of MP 27.4) it cannot be considered a viable system alternative as it would need to build similar facilities as proposed by the Project to meet the Project objectives. Significant modifications to the East Tennessee system (and the existing pipelines interconnected to East Tennessee), including the construction of new pipeline facilities, would be needed to provide the necessary design pressure and capacity to serve the Project's anchor shipper (PSNC Energy). Therefore, the Project does not consider this pipeline system to be a reasonable alternative to the Project.

10.4.5 Piedmont Natural Gas

Piedmont Natural Gas is a local distribution company operating in North Carolina. The anchor shipper for the Project (PSNC Energy) is also a local distribution company operating in North Carolina. Transporting gas volumes from one local distribution company to another does not meet the purpose and need for the Project. Local distribution systems are designed to meet the needs of their customers, not the needs of other distribution systems. It would also not provide the incremental volumes that PSNC Energy needs to meet growing system demand, as discussed in the purpose and need section in Resource Report 1. Further, Piedmont's system could not satisfy any of the other reasons cited by PSNC Energy for becoming a Project shipper, including transportation cost, supply cost, supply diversity, reliability/resiliency, and operational efficiencies. Therefore, Piedmont's system is not a viable alternative for the Project.

10.4.6 PSNC Distribution System

The anchor shipper for the Project (PSNC Energy) is a local distribution company operating in three non-contiguous regions in North Carolina. As discussed in the purpose and need section in Resource Report 1, PSNC Energy solicited interest from existing and proposed interstate pipelines, and ultimately signed a long-term agreement with Mountain Valley for the Project, because it needs incremental volumes to meet growing system demand. PSNC Energy's existing pipelines are not a viable system alterative because they would not provide the incremental volumes PSNC Energy needs for its customers. In addition, as it is currently designed, during high demand times (i.e., peak winter demand scenarios) PSNC Energy's distribution system does not have the ability to serve all of its current customers through the Dan River Interconnect only. Due to current pipeline size and existing horsepower limitations, PSNC Energy requires supply of natural gas from both the Dan River Interconnect as well as the Haw River Interconnect to reliably serve its customers. Further, PSNC Energy's existing system could not satisfy any of the other reasons for becoming a Project shipper, including transportation cost, supply cost, supply diversity, reliability/resiliency, and operational efficiencies. Therefore, PSNC Energy's own distribution system is not a viable alternative for the Project.

10.5 ROUTE ALTERNATIVES

10.5.1 Pipeline Routing

During the route development of the Southgate Project an extensive desktop and field review of potential pipeline routes to identify viable pipeline corridors was conducted; and then further refined the review to determine the most feasible route within the most favorable corridor. One of the Project's primary objectives with respect to pipeline routing was to avoid or minimize, to the extent possible, crossings of major population centers and significant environmental resources. The Project also attempted to route its pipeline adjacent to existing rights-of-way, where feasible. The Project used field reconnaissance, aerial photography, topographic maps from the U.S. Geological Survey, and National Wetland Inventory maps during the route identification and evaluation processes.

The Southgate Project includes the installation of approximately 73 miles of natural gas pipeline and appurtenant facilities (e.g., compressor station, meter stations, valve settings and launcher/ receiver equipment) within a new permanent right-of-way. As discussed further below, the Project has evaluated major and minor route alternatives to maximize constructability, minimize impacts to sensitive resources and avoid encroachments. Mountain Valley is committed to further refinement of the pipeline alignment, as necessary, to ensure minimization of Project-related impacts on affected landowners and the environment.

10.5.2 Major Pipeline Route Alternatives

Mountain Valley evaluated major pipeline route alternatives as part of the planning and design process for the Project, and based the evaluation on environmental and land use impacts, as well as permanent easement acquisitions and overall Project costs. The primary objective in performing this analysis is to develop the most direct route that could connect customers to the available supply system while avoiding or minimizing potential adverse environmental impacts and engineering constraints to the greatest extent practicable. The Project evaluated pipeline routing options based on potential adverse environmental impacts, existing land usage, constructability, safety, and feasibility considerations.

The selection of the major route alternatives involves several steps.

- Development of routing criteria;
- Identification of potential routing alternatives;
- Collection of data relative to each alternative;
- Evaluation of potential environmental and land use impacts;
- Evaluation of routing alternatives against routing criteria; and
- Determination of the most cost-effective technical solution

This section describes and evaluates the major route alternatives identified during the initial planning stage of the Project. The major route alternatives are shown on Figure 10.5-1 and summarized in Tables 10.5-1 through 10.5-3 below.

Figure 10.5-1: Major Route Alternatives

10.5.2.1 Route Alternative 1

The Project evaluated Route Alternative 1 between MP 23.7 and MP 53.6 (see Figure 10.5-1). This alternative begins in Pittsylvania County, Virginia at MP 23.7 and extends in a southeasterly direction for approximately 1.9 miles to the North Carolina border. Within this segment, this alternative crosses Berry Hill Road/U.S. Highway 311, a railroad track, the Dan River, South River Road, and mixed forested and agricultural/open land. At the North Carolina border in Rockingham County, Route Alternative 1 continues in a south-southeasterly direction for approximately 21.7 miles. It crosses mixed forested and agricultural/open land; Berry Hill Ridge, Gravel Hill, and Dix roads; State Highway 700; Guerrant Springs Road; Worsham Mill Road; Quaqua Hill and Estes roads; U.S. Highway 29-BR, a railroad track, Benton Road, and U.S. Highway 29; and three existing utility easements. From this point, Route Alternative 1 continues in a south-southeasterly direction crossing U.S. Highway 58, Grooms Road, Tate Road, Rockingham Lake Road, and the Colonel Heritage Byway/State Route 150. Within this section, this alternative would be approximately 0.05 mile east of Williamsburg Wildlife Lake. From Colonel Heritage Byway/State Route 150, Route Alternative 1 continues to cross mixed forested and agricultural/open land; and County Line Creek; Trails End Road; State Route 87; Zeb, Kernodle, and Parkdale roads. Route Alternative 1 then extends south into Guilford County for approximately 0.6 mile and southeast into Alamance County for approximately 0.5 mile to rejoin the preferred route at MP 53.6. Route Alternative 1 includes an approximate 5.4-mile long lateral from the alternative route south of Guerrant Springs Road to an interconnect with PSNC Energy, east of Eden, North Carolina.

As shown in Table 10.5-1, the primary advantages of Route Alternative 1 are:

- crosses fewer miles of environmental justice communities;
- crosses fewer waterbodies and wetlands; and
- crosses slightly fewer areas with potential for shallow depth to bedrock.

The primary disadvantages of Route Alternative 1 are:

- greater length and associated land disturbance;
- collocates with existing rights-of-way for approximately 10.1 fewer miles;
- crosses more parcels and affects more residences within 50 feet of workspace; and
- affects significantly more forest land.

The presence of existing infrastructure must be considered when evaluating route alternatives and comparing relevant impacts, including environmental justice. When collocated with existing infrastructure or utility corridors, the incremental impacts of an additional pipeline are significantly less compared to routing through a greenfield area. Collocation minimizes potential impacts on the general population and environmental justice communities alike. Mountain Valley developed the Southgate Project preferred route to collocate to the maximum extent practicable and avoid unnecessary greenfield impacts. Overall, the preferred route is collocated for 6.9 miles of the 21.6 miles within environmental justice communities, resulting in significantly fewer greenfield impacts, including greenfield impacts on environmental justice communities. Considering all relevant impacts, the Southgate Project preferred route would not cause significant impacts or disproportionate impacts on environmental justice communities and is advantageous to the alternative route. Because the primary disadvantages outweigh the primary advantages, the Project eliminated this alternative from further consideration as its preferred pipeline route.

Table 10.5-1

Comparison of the Preferred Route and Route Alternative 1

Feature	Preferred Route	Route Alternative 1	Difference
General			
Total length (miles) a/	29.8	30.1	+0.3
Length adjacent to existing ROW (miles)	14.7	4.6	-10.1
Land affected during construction (acres) a/	361.7	364.7	+3.0
Land affected during operation (acres) a/	180.9	182.4	+1.5
Land Use			
Populated areas w ithin ½ mile (number)	0	0	0
National Forest System lands crossed (miles)	0	0	0
National Forest Wilderness crossed (miles)	0	0	0
State lands crossed (forests, parks, wildlife management areas) (miles)	0	0	0
Scenic Trail crossings (number)	0	0	0
Designated Natural and Scenic Rivers, Nationw ide Rivers Inventory, significant fisheries, ponds/lakes (number)	1	0	-1
NRHP designated or eligible historic districts crossed (miles)	0	0	0
Landow ner parcels crossed (number)	148	154	+6
Residences w ithin 50 feet of construction work space (number)	5	11	+6
Environmental Justice Areas (miles)	21.6	10.1	-11.5
Resources			
Agricultural land crossed (miles) c/	8.2	9.2	+1.0
Open land crossed (miles)	14.8	13.2	-1.6
Developed land crossed (miles)	0.3	0.2	-0.1
Forested land crossed (miles)	14.5	16.3	+1.8
Forested land affected during construction (acres)	175	198.6	+23.6
Forested land affected during operation (acres)	87.8	99.2	+11.4
Total Wetlands (NWI) crossed (feet)	1240	726	-514
PEM NWI w etlands affected by construction (acres) b/	0.2	0	-0.2
PEM NWI w etlands affected by operation (acres) a/	0.1	0	-0.1
PSS NWI w etlands affected by construction (acres) b/	0.7	0.6	-0.1
PSS NWI w etlands affected by operation (acres) a/	0.5	0.4	-0.1
PFO NWI w etlands crossed (feet)	755	391	-364
PFO NWI w etlands affected by construction (acres) b/	1.3	0.8	-0.5
PFO NWI w etlands affected by operation (acres) a/	0.9	0.5	-0.4
Perennial w aterbody crossings (number)	16	14	-2
Crossings of major w aterbodies (>100 feet) (number)	0	0	0

Table 10.5-1

Comparison of the Preferred Route and Route Alternative 1

Feature	Preferred Route	Route Alternative 1	Difference
Presence of critical habitat or federally endangered or threatened species (Yes/No). Number of species.	No/0	No/0	0
Shallow bedrock crossed (miles)	4.0	3.8	-0.2
Karst area crossed (miles)	0	0	0

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW. Includes a 5.4-mile long lateral from Alternative 1 to an interconnect with PSNC Energy, east of Eden, North Carolina.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
Populated Areas = census designated places, consolidated cites, and incorporated places.
ROW = right-of-way. NWI = National Wetland Inventory. NRHP = National Register of Historic Places.
PEM = Palustrine Emergent Wetland; PSS = Palustrine Scrub-Shrub Wetland; PFO = Palustrine Forested Wetland.
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
VA Parcel Boundaries and Standard Fields - https://www.arcgis.com/home/item.html?id=f1dccaf1f42e40cbba791feae2e23690
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
USDA - https://data.fs.usda.gov/geodata/edw/datasets.php
NRHP - National Register of Historic Places - https://www.nps.gov/nr/research/data_downloads.htm
ESRI - GIS Mapping - http://www.esri.com/

10.5.2.2 Route Alternative 2

The Project evaluated Route Alternative 2 between MP 23.7 and MP 66.1 (see Figure 10.5-1). This alternative begins in Pittsylvania County, Virginia at MP 23.7 and extends in a southeasterly direction for approximately 2.0 miles to the North Carolina border. Within this segment, this alternative crosses Berry Hill Road/U.S. Highway 311, a railroad track, the Dan River, South River Road, and mixed forested and agricultural/open land. At the North Carolina border, Route Alternative 2 continues in a south-southeasterly direction for approximately 7.0 miles within Rockingham County. It crosses mixed forested and agricultural/open land; Gravel Hill Road, Goose Pond Road, State Highway 700, an unnamed road, Service Road, U.S. Highway 29, a railroad track, and Old Highway 29. It then traverses Caswell County for approximately 17.3 miles and crosses mixed forested and agricultural/open land. It crosses several roadways including Anderson and Chapman roads, Hogans Creek, Park Springs Road, Allison Grove Road, and U.S. Highway 158. From this point, it continues in a south-southeasterly direction and crosses Bethesda Church Road twice, Holster Branch, Colonel Heritage Byway/State Route 150, Cherry Grove Road, Stadler Road, Milesville Road, Kerrs Chapel Road, and Old Stoney Mountain Road. Route Alternative 2 then continues in Alamance County for approximately 8.7 miles and rejoins the at MP 66.1. Within this section, this alternative crosses Toms Creek, Union Ridge Road, Jefferies Cross Road, State Route 63, and mixed forested and agricultural/open land. It continues in a southerly direction and crosses McCray Road, Deep Creek Church Road, North Fonville Road, Sandy Cross Road, and rejoins the preferred route at MP 66.1. Route Alternative 2 includes an approximate 8.8-mile long lateral from the alternative route north of U.S. Route 29 to an interconnect with PSNC Energy, east of Eden, North Carolina.

As shown in Table 10.5-2, the primary advantages of Route Alternative 2 are:

- crosses fewer miles of environmental justice communities;
- crosses fewer parcels;
- affects less open and developed land;
- affects fewer designated waterbodies; and
- crosses one less major waterbody.

The primary disadvantages of Route Alternative 2 are:

- greater length and land disturbance;
- collocates with existing rights-of-way for approximately 5.4 fewer miles;
- affects more residences within 50 feet of workspace;
- affects significantly more forested land;
- crosses significantly more wetlands including 3.5 acres of forested wetlands; and
- crosses more shallow bedrock areas.

As described in Section 10.5.2.1 above, the presence of existing infrastructure must be considered when evaluating route alternatives and comparing relevant impacts, including environmental justice. Overall, the preferred route is collocated for 6.9 miles of the 21.6 miles within environmental justice communities, resulting in significantly fewer greenfield impacts, including greenfield impacts on environmental justice communities. Considering all relevant impacts, the Southgate Project preferred route would not cause significant impacts or disproportionate impacts on environmental justice communities and is advantageous to the alternative route. Because the primary disadvantages outweigh the primary advantages, the Project eliminated this alternative from further consideration as its preferred pipeline route.

Table 10.5-2

Comparison of the Preferred Route and Route Alternative 2

Feature	Preferred Route	Route Alternative 2	Difference
General			
Total length (miles) a/	42.3	43.4	+1.2
Length adjacent to existing ROW (miles)	20.0	14.6	-5.4
Land affected during construction (acres) a/	513.3	525.5	+12.2
Land affected during operation (acres) a/	256.6	262.7	+6.1
Land Use			
Populated areas within ½ mile (number)	0	0	0
National Forest System lands crossed (miles)	0	0	0
National Forest Wilderness crossed (miles)	0	0	0
State lands crossed (forests, parks, wildlife management areas) (miles)	0	0	0
Scenic Trail crossings (number)	0	0	0
Designated Natural and Scenic Rivers, Nationwide Rivers Inventory, significant fisheries, ponds/lakes (number)	2	0	-2
NRHP designated or eligible historic districts crossed (miles)	0	0	0

Table 10.5-2

Comparison of the Preferred Route and Route Alternative 2

Feature	Preferred Route	Route Alternative 2	Difference
Landowner parcels crossed (number)	220	191	-29
Residences within 50 feet of construction workspace (number)	7	11	+4
Environmental Justice Areas (miles)	21.6	3.7	-17.9
Resources			
Agricultural land crossed (miles) c/	14.2	13.3	-0.9
Open land crossed (miles)	21.7	21.5	-0.2
Developed land crossed (miles)	0.6	0.4	-0.2
Forested land crossed (miles)	19.6	21.1	+1.5
Forested land affected during construction (acres)	237.4	256.1	+18.7
Forested land affected during operation (acres)	118.9	128	+9.1
Total Wetlands (NWI) crossed (feet)	1,972	3,047	+1,075
PEM NWI wetlands affected by construction (acres) b/	0.8	0	-0.8
PEM NWI wetlands affected by operation (acres) a/	0.6	0	-0.6
PSS NWI wetlands affected by construction (acres) b/	0.7	0.5	-0.2
PSS NWI wetlands affected by operation (acres) a/	0.5	0.4	-0.1
PFO NWI wetlands crossed (feet)	790	2,763	+1,973
PFO NWI wetlands affected by construction (acres) b/	1.4	4.9	+3.5
PFO NWI wetlands affected by operation (acres) a/	0.9	3.3	+2.4
Perennial waterbody crossings (number)	18	19	+1
Crossings of major waterbodies (>100 feet) (number)	1	0	-1
Presence of critical habitat or federally endangered or threatened species (Yes/No). Number of species.	No / 0	No / 0	0
Shallow bedrock crossed (miles)	4.0	4.3	+0.3
Karst area crossed (miles)	0	0	0

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW. Includes an 8.8-mile long lateral from Alternative 2 to an interconnect with PSNC Energy, east of Eden, North Carolina.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
Populated Areas = census designated places, consolidated cites, and incorporated places.
ROW = right-of-way. NWI = National Wetland Inventory. NRHP = National Register of Historic Places.
PEM = Palustrine Emergent Wetland; PSS = Palustrine Scrub-Shrub Wetland; PFO = Palustrine Forested Wetland.
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
VA Parcel Boundaries and Standard Fields - https://www.arcgis.com/home/item.html?id=f1dccaf1f42e40cbba791feae2e23690
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
USDA - https://data.fs.usda.gov/geodata/edw/datasets.php
NRHP - National Register of Historic Places - https://www.nps.gov/nr/research/data_downloads.htm
ESRI - GIS Mapping - http://www.esri.com/

10.5.2.3 Route Alternative 3

The Project evaluated Route Alternative 3 between MP 6.1 and MP 66.1 (see Figure 10.5-1). This alternative begins in Pittsylvania County, Virginia at MP 6.1 and extends in a southerly direction for approximately 16.7 miles to the North Carolina border where it crosses mixed forested and agricultural/open land. Within this segment, this alternative primarily parallels an existing Duke Energy electric transmission easement and crosses White Oak Creek, Dry Fork Road, Hither Land and Court, R and L Smith Road, and Mountain View Road. Near Mountain View Road, this alternative deviates from the electric transmission easement to the west to minimize loss of vegetative buffer between the easement and nearby residences. Approximately 0.2 mile south of this location, this alternative deviates to the west to avoid utility congestion in the neighborhoods along Springlake Place, Springdale Drive, and Deerwood Drive. From this point, Route Alternative 3 continues in a southerly direction and crosses County Road 946, East Witt Road, Railroad Lane, and U.S. Highway 29-BR. Between Railroad Lane and U.S. Highway 29-BR, this alternative makes another deviation from the electric transmission easement to the west to avoid multiple utility easements on a residential property. From this point, this alternative crosses Landrum Road, U.S. Highway 29, Twin Arch Drive, and Old Richmond Road/State Route 30.

Route Alternative 3 then crosses the Danville City limits including residential, commercial, and industrial areas; several roadways, and mixed forested and agricultural/open land. Once south of Danville, this alternative enters Caswell County, North Carolina for approximately 21.9 miles where it crosses mixed forested and agricultural/open land. It crosses Walter's Mill Road twice, Hogan's Creek, an unnamed road, Moon Creek Lane, and Old State Highway 86-North. It continues in a south-southwesterly direction and crosses State Route 86, Foster Road, East Prong Moon Creek, Hodges Dairy Road, and Colonel Heritage Byway/State Route 150. Route Alternative 3 would be approximately 0.2 mile west of the Caswell Airpark. It crosses County Road, County Line Creek, Cherry Gove Road, Senior Alfred Road, Byrd's Sawmill Road, Kerr's Chapel Road, and two Duke Energy electric transmission easements. Route Alternative 3 then continues in Alamance County for approximately 8.7 miles and rejoins the at MP 66.1. Within this section, this alternative crosses Roscoe Road, Toms Creek, Union Ridge Road, Jefferies Cross Road, State Route 63, and mixed forested and agricultural/open land. It continues in a southerly direction and crosses McCray Road, Deep Creek Church Road, North Fonville Road, Sandy Cross Road, and rejoins the preferred route at MP 66.1. Route Alternative 3 includes an approximate 16.6-mile long lateral from the alternative route, approximately 2.3 miles south of Foster Road, to an interconnect with PSNC Energy, east of Eden, North Carolina.

As shown in Table 10.5-3, the primary advantage of Route Alternative 3 is:

- crosses fewer miles of environmental justice communities;
- affects fewer designated waterbodies;
- crosses fewer mile of agricultural land and one less major waterbody; and
- crosses fewer miles of potential karst.

The primary disadvantages of Route Alternative 3 are:

- greater length and land disturbance;
- collocates with existing rights-of-way for approximately 1.5 fewer miles;
- crosses more parcels and affects more residences within 50 feet of workspace;
- affects significantly more forested land;

- crosses more wetlands including forested wetlands; and waterbodies;
- crosses one more major waterbody; and
- crosses more shallow bedrock areas.

As described in Section 10.5.2.1 above, the presence of existing infrastructure must be considered when evaluating route alternatives and comparing relevant impacts, including environmental justice. Overall, the preferred route is collocated for 6.9 miles of the 21.6 miles within environmental justice communities while Route Alternative 3 is collocated for 7.8 miles of the 19.1 miles within environmental justice communities, resulting in fewer greenfield impacts, including greenfield impacts on environmental justice communities. Considering all relevant impacts, the Southgate Project preferred route would not cause significant impacts or disproportionate impacts on environmental justice communities and is advantageous to the alternative route. Because the primary disadvantages outweigh the primary advantages, the Project eliminated this alternative from further consideration as its preferred pipeline route.

Table 10.5-3

Comparison of the Preferred Route and Route Alternative 3

Feature	Preferred Route	Route Alternative 3	Difference
General			
Total length (miles) a/	60.0	63.4	+3.4
Length adjacent to existing ROW (miles)	26.9	25.4	-1.5
Land affected during construction (acres) a/	726.7	769.0	+42.3
Land affected during operation (acres) a/	363.4	384.5	+21.1
Land Use			
Populated areas within ½ mile (number)	0	1	+1
National Forest System lands crossed (miles)	0	0	0
National Forest Wilderness crossed (miles)	0	0	0
State lands crossed (forests, parks, wildlife management areas) (miles)	0	0	0
Scenic Trail crossings (number)	0	0	0
Designated Natural and Scenic Rivers, Nationwide Rivers Inventory, significant fisheries, ponds/lakes (number)	2	0	-2
NRHP designated or eligible historic districts crossed (miles)	0	0	0
Landowner parcels crossed (number)	309	369	+60
Residences within 50 feet of construction workspace (number)	13	23	+10
Environmental Justice Areas (miles)	21.6	19.1	-2.5
Resources			
Agricultural land crossed (miles) c/	0.5	0.4	-0.1
Open land crossed (miles)	31.9	27.3	-4.6
Developed land crossed (miles)	0.6	1	+0.4
Forested land crossed (miles)	26.9	34.7	+7.8
Forested land affected during construction (acres)	324.6	422.1	+97.5
Forested land affected during operation (acres)	162.8	210.6	+47.8
Total Wetlands (NWI) crossed (feet)	2,196	3,159	+963

Table 10.5-3

Comparison of the Preferred Route and Route Alternative 3

Feature	Preferred Route	Route Alternative 3	Difference
PEM NWI wetlands affected by construction (acres) b/	1.1	0.6	-0.5
PEM NWI wetlands affected by operation (acres) a/	0.8	0.4	-0.4
PSS NWI wetlands affected by construction (acres) b/	0.7	2.1	+1.4
Total PSS NWI wetlands affected by operation (acres) a/	0.5	1.2	+0.7
PFO NWI wetlands crossed (feet)	790	1,614	+824
PFO NWI wetlands affected by construction (acres) b/	1.4	2.8	+1.4
PFO NWI wetlands affected by operation (acres) a/	0.9	1.9	+1.0
Perennial waterbody crossings (number)	28	31	+3
Crossings of major waterbodies (>100 feet) (number)	1	0	-1
Presence of critical habitat or federally endangered or threatened species (Yes/No). Number of species.	No / 0	No / 0	0
Shallow bedrock crossed (miles)	4.8	10.4	+5.6
Karst area crossed (miles)	2.0	0.6	-1.4

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW. Includes a 16.6-mile long lateral from Alternative 3 to an interconnect with PSNC Energy, east of Eden, North Carolina.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
Populated Areas = census designated places, consolidated cites, and incorporated places.
ROW = right-of-way. NWI = National Wetland Inventory. NRHP = National Register of Historic Places
PEM = Palustrine Emergent Wetland; PSS = Palustrine Scrub-Shrub Wetland; PFO = Palustrine Forested Wetland.
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
VA Parcel Boundaries and Standard Fields - https://www.arcgis.com/home/item.html?id=f1dccaf1f42e40cbba791feae2e23690
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
USDA - https://data.fs.usda.gov/geodata/edw/datasets.php
NRHP - National Register of Historic Places - https://www.nps.gov/nr/research/data_downloads.htm
ESRI - GIS Mapping - http://www.esri.com/

10.5.3 FERC Requested Route Alternatives

The FERC requested that Mountain Valley evaluate six route alternatives to avoid or reduce impacts along its preferred pipeline route. The desktop analysis included: length of pipeline; acreage of permanent and temporary rights-of-way; number of parcels crossed; number of residences within 25 and 50 feet of the edge of the construction right-of-way; number of waterbodies and wetlands crossed, and the length of each crossing; acres of agricultural and forested land affected; and the miles of right-of-way that would be parallel or adjacent to existing rights-of-way. The desktop analyses of these alternatives are presented below.

FERC Alternative 1 (MP 63.9 to MP 72.9)

The Project evaluated FERC Alternative 1 between MP 63.9 and MP 72.9 (see Figure 10.5-2, Appendix 10-A). At MP 63.9, FERC Alternative 1 extends in a southerly direction for approximately 4.69 miles to MP 68.6 of the preferred route. Within this section, the alternative crosses agricultural and forested land, Deep Creek Church Road, Sandy Cross Road, and Meeting Ground Road. It then collocates with the existing Cardinal Pipeline Company, LLC ("Cardinal Pipeline") on the east side of the Haw River for approximately 2.2 miles. At MP 68.6 of the preferred route, FERC Alternative 1 extends southwest for approximately 0.1 mile and crosses agricultural land and the Haw River. At this point, the alternative remains on the west side of the Haw River and turns in a more southerly direction continuing to be collocated with the existing Cardinal Pipeline for approximately 3.4 miles. Within this segment, the alternative crosses mixed forested and agricultural land, West Main Street, parallels the eastern boundary of the Challenge Golf Club for approximately 1.3 miles, and crosses Interstate 40/85. FERC Alternative 1 turns west, southwest, south, and southeast and crosses forested and agricultural land, State Highway 54/E. Harden Street, Cooper Road, and the Haw River to rejoin the preferred route at MP 72.9.

As shown in Table 10.5-4, the primary advantages of FERC Alternative 1 are:

- less length and land disturbance;
- crosses fewer parcels and affects fewer residences within 50 feet of workspace;
- collocates with existing rights-of-way for approximately 5.7 more miles; and
- affects fewer acres of forested agricultural land.

The primary disadvantages of FERC Alternative 1 are:

- crosses more waterbodies and eight more wetlands; and
- affects significantly more acres of wetlands.

Constructability concerns of FERC Alternative 1 are:

- two crossings of the Haw River;
- limited area for workspace layout at the Haw River crossings and along the alternative route due to an existing golf course, existing utility infrastructure and residential areas;
- new temporary access road to the alternative route.

Because the primary disadvantages, coupled with the constructability concerns, outweigh the primary advantages, the Project eliminated this alternative from further consideration as its preferred pipeline route.

Table 10.5-4

Comparison of the Preferred Route and FERC Alternative 1

Feature	Preferred Route	FERC Alternative 1	Difference
Total length (miles)	9.1	8.7	-0.4
Construction right-of-way (acres) a/	110.1	105.6	-4.5
Permanent right-of-way (acres) a/	55.0	52.8	-2.2
Total number of parcels crossed	103	58	-45

Table 10.5-4

Comparison of the Preferred Route and FERC Alternative 1

Feature	Preferred Route	FERC Alternative 1	Difference
Number of residences within 25 and 50 feet of the edge of the construction ROW (and associated additional temporary workspace)	1 / 3	1 / 1	0 / -2
Number of waterbodies crossed	18	23	+5
Number of NWI wetlands crossed	1	9	+8
Total NWI wetland crossing length (feet)	25	3,990	+3,965
NWI wetlands within construction ROW (acres) b/	0.2	6.8	+6.6
Agricultural land within construction ROW (acres) c/	29.2	20.5	-8.7
Forested land within construction ROW (acres)	57.7	55.1	-2.6
Length parallel or adjacent to existing ROW (miles)	0.25	5.95	+5.7

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
ROW = right-of-way. NWI = National Wetland Inventory
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
ESRI - GIS Mapping - http://www.esri.com/

FERC Alternative 2 (MP 69.1 to MP 73.0)

The Project evaluated FERC Alternative 2 between MP 69.1 and MP 73.0 (see Figure 10.5-3, Appendix 10-A). This portion of FERC Alternative 2 is the same as FERC Alternative 1 from MP 69.1 and MP 72.5 described above. At MP 68.6, FERC Alternative 2 turns southwest for approximately 0.1 mile and crosses agricultural land and the Haw River. It then turns in a more southerly direction and is collocated with the existing Cardinal Pipeline for approximately 3.4 miles and crosses mixed forested and agricultural land, West Main Street, parallels the eastern boundary of the Challenge Golf Club for approximately 1.3 miles, and crosses Interstate 40/85. FERC Alternative 2 then turns west, southwest, south, and southeast and crosses forested and agricultural land, State Highway 54/E. Harden Street, Cooper Road, and the Haw River to rejoin the preferred route at MP 73.0.

As shown in Table 10.5-5, the primary advantages of FERC Alternative 2 are:

- crosses 17 fewer parcels,
- affects fewer residences within 25 and 50 feet of workspace;
- collocates with existing rights-of-way for approximately 3.4 more miles; and
- affects 1.5 fewer acres of forested land.

The primary disadvantages of FERC Alternative 2 are:

- greater length and land disturbance;

- crosses four more waterbodies and nine more wetlands; and
- affects significantly more acres of wetlands and 0.9 more acre of agricultural land.

Constructability concerns of FERC Alternative 2 are:

- two crossings of the Haw River; and
- limited area for workspace layout at the Haw River crossings and along the alternative route due to an existing golf course, existing utility infrastructure and residential areas.

Because the primary disadvantages, along with the potential constructability concerns, outweigh the primary advantages, the Project eliminated this alternative from further consideration as its preferred pipeline route.

Table 10.5-5

Comparison of the Preferred Route and FERC Alternative 2

Feature	Preferred Route	FERC Alternative 2	Difference
Total length (miles)	3.8	4.0	+0.2
Construction right-of-way (acres) a/	46.5	48.8	+2.3
Permanent right-of-way (acres) a/	23.2	24.4	+1.2
Total number of parcels crossed	51	34	-17
Number of residences within 25 and 50 feet of the edge of the construction ROW (and associated additional temporary workspace)	1 / 3	0 / 0	-1 / -3
Number of waterbodies crossed	8	12	+4
Number of NWI wetlands crossed	0	9	+9
Total NWI wetland crossing length (feet)	0	4,163	+4,163
NWI wetlands within construction ROW (acres) b/	0.1	6.9	+6.8
Agricultural land within construction ROW (acres) c/	6.6	7.5	+0.9
Forested land within construction ROW (acres)	23.4	21.9	-1.5
Length parallel or adjacent to existing ROW (miles)	0.2	3.6	+3.4

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
ROW = right-of-way. NWI = National Wetland Inventory
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
ESRI - GIS Mapping - http://www.esri.com/

FERC Alternative 3 (MP 65.8 to MP 67.5)

The Project evaluated FERC Alternative 3 between MP 65.8 and MP 67.5 (see Figure 10.5-4, Appendix 10-A). The FERC Alternative 3 deviates from the original route at MP 65.45 and extends east-southeast for approximately 0.4 mile. At MP 65.8 of the preferred route, the FERC Alternative 3 extends southeast and east for approximately 0.3 mile and crosses agricultural and forested land and North Fonville Road. It then turns in a more southerly direction for approximately 1.3 miles and crosses agricultural and forested land, Sandy Cross Road, and an existing electric transmission easement. It rejoins the Preferred Route at MP 67.5.

As shown in Table 10.5-6, the primary advantages of FERC Alternative 3 are:

- crosses less fewer parcels; and
- affects 0.4 fewer acre of forested land.

The primary disadvantages of FERC Alternative 3 are:

- greater length and land disturbance; and
- affects 2.9 more acres of agricultural land.

Constructability concerns of FERC Alternative 3 are:

- none identified based on initial review.

The Project further evaluated FERC Alternative 3 and incorporated approximately 1.7 miles of the alternative route into the Mystic Valley Reroute described in Section 10.5.4 below.

Table 10.5-6

Comparison of the Preferred Route and FERC Alternative 3

Feature	Preferred Route	FERC Alternative 3	Difference
Total length (miles)	1.5	2.0	+0.5
Construction right-of-way (acres) a/	18.9	24.7	+5.8
Permanent right-of-way (acres) a/	9.4	12.3	+2.9
Total number of parcels crossed	16	14	-2
Number of residences within 25 and 50 feet of the edge of the construction ROW (and associated additional temporary workspace)	0 / 0	0 / 0	0 / 0
Number of waterbodies crossed	3	3	0
Number of NWI wetlands crossed	0	0	0
Total NWI wetland crossing length (feet)	0	0	0
NWI wetlands within construction ROW (acres) b/	0	0	0
Agricultural land within construction ROW (acres) c/	9.5	12.4	2.9
Forested land within construction ROW (acres)	10.9	10.5	-0.4
Length parallel or adjacent to existing ROW (miles)	0	0	0

Table 10.5-6 Comparison of the Preferred Route and FERC Alternative 3			
Feature	Preferred Route	FERC Alternative 3	Difference
a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW. b/ Assuming 75-foot-wide construction ROW. c/ Includes pasture/hay and cultivated crops. ROW = right-of-way. NWI = National Wetland Inventory Information Sources: GIS – Analysis based on Geodatabase layers and shapefiles. NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/ USGS – U.S. Geological Survey - http://www.usgs.gov/ NHD – National Hydrography Dataset - http://nhd.usgs.gov/ ESRI - GIS Mapping - http://www.esri.com/			

FERC Alternative 4 (MP 65.8 to MP 70.8)

The Project evaluated FERC Alternative 4 between MP 65.8 and MP 70.8 (see Figure 10.5-5, Appendix 10-A). At MP 65.6, FERC Alternative 4 extends in an easterly direction for approximately 3.8 miles and crosses agricultural and forested land. Within this segment, the alternative route crosses North Fonville Road, State Highway 49, and Johnson Road. It then turns in a south-southwest direction for approximately 5.8 miles and crosses agricultural and forested land, and several road / railroads including Mebane Rodgers Road/State Route 1921, Dewitt Drive, Bason Road/State Route 1927, U.S. Highway 70/E. Main Street, a railroad track, Stone Street Extension/State Route 1936, and Tollingwood Road. It rejoins the preferred route at MP 70.8.

As shown in Table 10.5-7, the primary advantages of FERC Alternative 4 are:

- affects fewer residences within 25 and 50 feet of workspace;
- collocates with existing rights-of-way for an additional 1.8 miles.

The primary disadvantages of FERC Alternative 4 are:

- greater length and land disturbance;
- affects three more parcels;
- crosses two more waterbodies and four more wetlands; and
- affects 0.5 more acre of wetlands 24 more acres of agricultural land, and 18.4 more acres of forested land.

Potential constructability concerns of FERC Alternative 4 are:

- none identified based on initial review.

Because the primary disadvantages outweigh the primary advantages, the Project eliminated this alternative from further consideration as its preferred pipeline route.

Table 10.5-7

Comparison of the Preferred Route and FERC Alternative 4

Feature	Preferred Route	FERC Alternative 4	Difference
Total length (miles)	5.0	9.4	+4.4
Construction right-of-way (acres) a/	61.3	114	+52.7
Permanent right-of-way (acres) a/	30.6	57.0	+26.4
Total number of parcels crossed	63	60	-3
Number of residences within 25 and 50 feet of the edge of the construction ROW (and associated additional temporary workspace)	1 / 2	0 / 0	-1 / -2
Number of waterbodies crossed	12	14	+2
Number of NWI wetlands crossed	1	5	+4
Total NWI wetland crossing length (feet)	25	321	+296
NWI wetlands within construction ROW (acres) b/	0.2	0.7	+0.5
Agricultural land within construction ROW (acres) c/	12.4	36.3	+23.9
Forested land within construction ROW (acres)	35	53.4	+18.4
Length parallel or adjacent to existing ROW (miles)	0.2	2.0	+1.8

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
ROW = right-of-way. NWI = National Wetland Inventory
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
ESRI - GIS Mapping - http://www.esri.com/

FERC Alternative 5 (MP 71.8 to MP 73.1)

The Project evaluated FERC Alternative 5 between MP 71.8 and MP 73.1 (see Figure 10.5-6, Appendix 10-A). At MP 71.8, FERC Alternative 5 extends in an east/southeast direction for approximately 0.6 mile and crosses agricultural and forested land and Jimmie Kerr Road. It then turns in a south-southwest direction for approximately 1.7 miles and crosses agricultural and forested land, Cherry Lane, Jimmie Kerr Road, and State Highway 54/E. Harden Street before rejoining the preferred route at MP 73.1.

As shown in Table 10.5-8, the primary advantage of FERC Alternative 5 is:

- affects fewer residences within 50 feet of workspace.

The primary disadvantages of FERC Alternative 5 are:

- greater length and land disturbance; and

- affects three more parcels and 8.7 additional acres of agricultural land.

Potential constructability concerns of FERC Alternative 5 are:

- none identified based on initial review.

Because the primary disadvantages outweigh the primary advantages, the Project eliminated this alternative from further consideration as its preferred pipeline route.

Table 10.5-8

Comparison of the Preferred Route and FERC Alternative 5

Feature	Preferred Route	FERC Alternative 5	Difference
Total length (miles)	1.3	2.2	+0.9
Construction right-of-way (acres) a/	16.2	26.3	+10.1
Permanent right-of-way (acres) a/	8.1	13.1	+5.0
Total number of parcels crossed	17	20	+3
Number of residences within 25 and 50 feet of the edge of the construction ROW (and associated additional temporary workspace)	1 / 1	0 / 0	-1/ -1
Number of waterbodies crossed	3	3	0
Number of NWI wetlands crossed	0	0	0
Total NWI wetland crossing length (feet)	0	0	0
NWI wetlands within construction ROW (acres) b/	0	0	0
Agricultural land within construction ROW (acres) c/	3	11.7	+8.7
Forested land within construction ROW (acres)	9.5	9.5	0
Length parallel or adjacent to existing ROW (miles)	0.1	0	-0.1

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
ROW = right-of-way. NWI = National Wetland Inventory
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
ESRI - GIS Mapping - http://www.esri.com/

FERC Alternative 6 (MP 58.2 to MP 62.0)

The Project evaluated FERC Alternative 6 between MP 58.2 and MP 62.0 (see Figure 10.5-7, Appendix 10-A). At MP 58.2, FERC Alternative 6 extends south and is collocated with a Duke Energy electric transmission easement for approximately 2.9 miles. It crosses agricultural and forested land, Burch Bridge Road and Iseley School Road. The alternative is collocated with an existing utility easement between Iseley School Road and Huffinese Drive (approximately 0.9 mile). It continues in an easterly direction and crosses agricultural and forested land before it rejoins the preferred route at MP 62.0.

As shown in Table 10.5-9, the primary advantages of FERC Alternative 6 are:

- affects 4.0 fewer acres of agricultural land; and
- collocates with existing rights-of-way for an additional 1.6 miles.

The primary disadvantages of FERC Alternative 6 are:

- greater length and land disturbance;
- affects seven more parcels;
- affects more residences within 25 and 50 feet of workspace;
- crosses five more waterbodies and one more wetland; and
- affects 0.2 more acre of wetlands and 3.6 additional acres of forested land.

Potential constructability concerns of FERC Alternative 6 are:

- none identified based on initial review.

Because the primary disadvantages outweigh the primary advantages, the Project eliminated this alternative from further consideration as its preferred pipeline route.

Table 10.5-9

Comparison of the Preferred Route and FERC Alternative 6

Feature	Preferred Route	FERC Alternative 6	Difference
Total length (miles)	3.7	4.4	+0.7
Construction right-of-way (acres) a/	45.6	53.3	+7.7
Permanent right-of-way (acres) a/	22.7	26.6	+3.9
Total number of parcels crossed	21	28	+7
Number of residences within 25 and 50 feet of the edge of the construction ROW (and associated additional temporary workspace)	0 / 0	1 / 1	+1 / +1
Number of waterbodies crossed	5	10	+5
Number of NWI wetlands crossed	1	2	+1
Total NWI wetland crossing length (feet)	35	131	+96
NWI wetlands within construction ROW (acres) b/	0.1	0.3	+0.2
Agricultural land within construction ROW (acres) c/	21.8	17.8	-4
Forested land within construction ROW (acres)	21.3	24.9	+3.6
Length parallel or adjacent to existing ROW (miles)	0.9	2.5	+1.6

Table 10.5-9 Comparison of the Preferred Route and FERC Alternative 6			
Feature	Preferred Route	FERC Alternative 6	Difference

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
ROW = right-of-way. NWI = National Wetland Inventory
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
ESRI - GIS Mapping - http://www.esri.com/

10.5.4 Mystic Valley Reroute (Preferred Route)

Between MP 64.0 and MP 67.5 in Alamance County, North Carolina, the Project evaluated the Mystic Valley Reroute (preferred route) to avoid a U.S. Army Corps of Engineers Cripple Creek Mitigation Bank and address landowner concerns along its original route (filed under PF18-4-000 on August 20, 2018). The Mystic Valley Reroute deviates from the Project's original route at MP 64.0 and extends generally east, southeast, and south. From MP 64.0 to MP 65.8, it crosses open, agricultural, forest land; and Hidden Valley Trail/Road, Faucette Lane, and Deep Creek Church Road. At MP 65.8, the Mystic Valley Reroute intersects with the FERC Alternative 3 route described above and extends generally southeast. It crosses agricultural and forested land and North Fonville Road. It then turns in a more southerly direction and crosses agricultural and forested land, Sandy Cross Road, and an existing electric transmission easement before it rejoins the original route at MP 67.5 (see Figure 10.5-4).

As shown in Table 10.5-10, the primary advantages of the Mystic Valley Reroute (preferred route) are:

- crosses less agricultural land;
- addresses landowner concerns; and
- affects less forest land.

The primary disadvantages of the Mystic Valley Reroute (preferred route) are:

- greater length and land disturbance.

Potential constructability concerns of the Mystic Valley Reroute (preferred route) are:

- none identified based on initial review.

While the Mystic Valley Reroute (preferred route) results in similar environmental impacts as the original route, it avoids a U.S. Army Corps of Engineers Cripple Creek Mitigation Bank and addresses landowner concerns along its original route. Therefore, it was incorporated into the Project's preferred pipeline route.

Table 10.5-10

Comparison of the Original Route and Mystic Valley Reroute (Preferred Route)

Feature	Original Route	Mystic Valley Reroute (Preferred Route)	Difference
General			
Total length (miles) a/	2.99	3.49	+0.5
Length adjacent to existing ROW (miles)	0	0	0
Land affected during construction (acres) a/	36.4	42.5	+6.1
Land affected during operation (acres) a/	18.1	21.2	+3.1
Land Use			
Populated areas within ½ mile (number)	0	0	0
National Forest System lands crossed (miles)	0	0	0
National Forest Wilderness crossed (miles)	0	0	0
State lands crossed (forests, parks, wildlife management areas) (miles)	0	0	0
Scenic Trail crossings (number)	0	0	0
Designated Natural and Scenic Rivers, Nationwide Rivers Inventory, significant fisheries, ponds/lakes (number)	0	0	0
NRHP designated or eligible historic districts crossed (miles)	0	0	0
Landowner parcels crossed (number)	27	27	0
Residences within 50 feet of construction workspace (number)	0	0	0
Environmental Justice Areas (miles)	1.1	1.1	0
Resources			
Agricultural land crossed (miles) c/	19.1	19.2	-0.1
Open land crossed (miles)	1.9	1.7	+0.2
Developed land crossed (miles)	0	0	0
Forested land crossed (miles)	1.1	1.7	-0.6
Forested land affected during construction (acres)	14	20.1	-6.1
Forested land affected during operation (acres)	6.8	10	-3.2
Total Wetlands (NWI) crossed (feet)	0	0	0
PEM NWI wetlands affected by construction (acres) b/	0	0	0
PEM NWI wetlands affected by operation (acres) a/	0	0	0
PSS NWI wetlands affected by construction (acres) b/	0	0	0
PSS NWI wetlands affected by operation (acres) a/	0	0	0
PFO NWI wetlands crossed (feet)	0	0	0
PFO NWI wetlands affected by construction (acres) b/	0	0	0

Table 10.5-10

Comparison of the Original Route and Mystic Valley Reroute (Preferred Route)

Feature	Original Route	Mystic Valley Reroute (Preferred Route)	Difference
PFO NWI wetlands affected by operation (acres) a/	0	0	0
Perennial waterbody crossings (number)	0	0	0
Crossings of major waterbodies (>100 feet) (number)	0	0	0
Presence of critical habitat or federally endangered or threatened species (Yes/No). Number of species.	No / 0	No / 0	0
Shallow bedrock crossed (miles)	0	0	0
Karst area crossed (miles)	0	0	0

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
Populated Areas = census designated places, consolidated cites, and incorporated places.
ROW = right-of-way. NWI = National Wetland Inventory. NRHP = National Register of Historic Places.
PEM = Palustrine Emergent Wetland; PSS = Palustrine Scrub-Shrub Wetland; PFO = Palustrine Forested Wetland.
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
VA Parcel Boundaries and Standard Fields - https://www.arcgis.com/home/item.html?id=f1dccaf1f42e40cbba791feae2e23690
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
USDA - https://data.fs.usda.gov/geodata/edw/datasets.php
NRHP - National Register of Historic Places - https://www.nps.gov/nr/research/data_downloads.htm
ESRI - GIS Mapping - http://www.esri.com/

10.6 ROUTE VARIATIONS

Route variations differ from route alternatives as they consist of alignment adjustments that enhance constructability, reduce impacts on localized features, sensitive resources, terrain, and/or provide appropriate space to allow for the safe operation and maintenance of the pipeline. They are typically shorter than route alternatives and may not always display a clear environmental advantage other than avoiding or reducing the impact to site-specific features or resources. After selection of the preferred route, the Project evaluated potential route variations using both desktop and field survey data to address construction constraints and to reduce impacts to landowners and sensitive environmental resources.

The FERC requested that the Project evaluate two route variations to minimize effects on the Robert Pollok-Hill View Farms at approximately MP 15.0 in Pittsylvania County, Virginia and residences between MP 40.2 and MP 41.0 in Rockingham County, North Carolina. These variations are described below.

10.6.1 Robert Pollock-Hill View Farms Variation

The Project evaluated the Robert Pollok-Hill View Farms Variation between MP 14.7 and MP 15.7 to reduce impact on the farm (see Figure 10.6-1). At MP 14.7, this variation extends west of the preferred route and continues in a southwest direction for approximately 1.0 mile. It parallels an existing utility easement, crosses mostly agricultural and open land, Whitmell School Road/County Road 750, and rejoins the preferred route at MP 15.7.

As shown in Table 10.6-1, the primary advantages of the Robert Pollok-Hill View Farms Variation are:

- collocates with existing rights-of-way for an additional 1.0 mile; and
- affects less agricultural land.

The primary disadvantages of the Robert Pollok-Hill View Farms Variation are:

- none identified based on initial review.

Potential constructability concerns of the Robert Pollok-Hill View Farms Variation are:

- none identified based on initial review.

While the Project did not fully incorporate the Robert Pollok-Hill View Farms Variation as a result of the alternative analysis, approximately 1,300 feet of access road and approximately 0.3 acre of additional temporary workspace were removed between MP 14.7 and MP 15.7.

Table 10.6-1

Comparison of the Preferred Route and Robert Pollok-Hill View Farms Variation

Feature	Preferred Route	Robert Pollok-Hill View Farms Variation	Difference
Total length (miles)	1.0	1.0	0
Construction right-of-way (acres) a/	12.3	12.3	0
Permanent right-of-way (acres) a/	6.1	6.1	0
Total number of parcels crossed	6	6	0
Number of residences within 25 and 50 feet of the edge of the construction ROW (and associated additional temporary workspace)	0/0	0/0	0/0
Number of waterbodies crossed	0	0	0
Number of NWI wetlands crossed	0	0	0
Total NWI wetland crossing length (feet)	0	0	0
NWI wetlands within construction ROW (acres) b/	0	0	0
Agricultural land within construction ROW (acres) c/	9.4	8.6	-0.8
Forested land within construction ROW (acres)	2.0	2.0	0
Length parallel or adjacent to existing ROW (miles)	0	1	+1

Table 10.6-1

Comparison of the Preferred Route and Robert Pollok-Hill View Farms Variation

Feature	Preferred Route	Robert Pollok-Hill View Farms Variation	Difference

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
ROW = right-of-way. NWI = National Wetland Inventory
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
ESRI - GIS Mapping - http://www.esri.com/

Figure 10.6-1: Robert Pollock-Hill Farms Variation

Figure 10.6-1a: Robert Pollock-Hill Farms Variation – Aerial

10.6.2 MP 40.0 to MP 41.4 Variation

The Project evaluated a route variation between MP 40.0 and MP 41.4 to reduce the number of residences potentially affected by the Project (see Figure 10.6-2). At MP 40.0, this variation extends south-southwest for approximately 0.5 mile and crosses forested and open land and Narrow Gauge Road. It then turns east-southeast for approximately 1.1 miles and crosses mostly forested land before it rejoins the preferred route at MP 41.4.

As shown in Table 10.6-2, the primary advantages of the MP 40.0 and MP 41. 4 Variation are:

- affects two fewer parcels;
- affects fewer residences within 25 and 50 feet of workspace; and
- affects less forested land.

The primary disadvantages of the MP 40.0 and MP 41. 4 Variation are:

- greater length and associated land disturbance; and
- affects more wetlands and agricultural land.

Potential constructability concerns of the MP 40.0 and MP 41. 4 Variation are:

- none identified based on initial review.

Because the primary disadvantages outweigh the primary advantages, the Project eliminated this variation from further consideration as its preferred pipeline route.

Table 10.6-2

Comparison of the Preferred Route and MP 40.0 to MP 41.4 Variation

Feature	Preferred Route	MP 40.0 to MP 41.4 Variation	Difference
Total length (miles)	1.4	1.6	+0.2
Construction right-of-way (acres) a/	17.4	19.8	+2.4
Permanent right-of-way (acres) a/	8.7	9.9	+1.2
Total number of parcels crossed	10	8	-2
Number of residences within 25 and 50 feet of the edge of the construction ROW (and associated additional temporary workspace)	1/1	0/0	-1/-1
Number of waterbodies crossed	3	3	0
Number of NWI wetlands crossed	1	1	0
Total NWI wetland crossing length (feet)	243	303	+60
NWI wetlands within construction ROW (acres) b/	0.4	0.5	+0.1
Agricultural land within construction ROW (acres) c/	1.0	2.2	+1.2
Forested land within construction ROW (acres)	13.1	11.8	-1.3
Length parallel or adjacent to existing ROW (miles)	0.5	0.2	-0.3

Table 10.6-2 Comparison of the Preferred Route and MP 40.0 to MP 41.4 Variation			
Feature	**Preferred Route**	**MP 40.0 to MP 41.4 Variation**	**Difference**

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
ROW = right-of-way. NWI = National Wetland Inventory
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
ESRI - GIS Mapping - http://www.esri.com/

Figure 10.6-2: MP 40.0 to MP 41.4 Variation

10.6.3 MP 69.5 to MP 69.7 Variation (Preferred Route)

The Project evaluated a route variation between MP 69.5 and MP 69.7 (preferred route) to avoid a significant part of the Town of Haw River's vision for revitalizing the downtown / Main Street core area that the original route crossed. The MP 69.5 to MP 69.7 Variation from the Project's original route at MP 69.5 and extends generally southeast and south. It crosses open, forest, and developed land and East Main Street, a railroad track, and driveway and rejoins the original route at MP 69.7 (see Figure 10.6-3).

As shown in Table 10.6-3, the primary advantages of the MP 69.5 to MP 69.7 Variation are:

- avoids the Town of Haw River town revitalization area;
- affects one less residence within 25 feet of workspace; and
- affects a town fire hall and small business.

The primary disadvantages of the MP 69.5 to MP 69.7 Variation are:

- greater length and associated land disturbance; and
- limited construction work area due to exposed sewage and water line.

Potential constructability concerns of the MP 69.5 to MP 69.7 Variation are:

- foreign utility line crossing, limited work area at town fire hall and small business, and residence located east of North Main Street.

While the MP 69.5 to MP 69.7 Variation (preferred route) results in similar environmental impacts as the original route, it avoids the Town of Haw River's vision for revitalizing the downtown/Main Street core area and addresses town concerns along its original route. Therefore, it was incorporated into the Project's preferred pipeline route.

Table 10.6-3

Comparison of the Original Route and MP 69.5 to MP 69.7 Variation (Preferred Route)

Feature	Original Route	MP 69.5 to MP 69.69 Variation (Preferred Route)	Difference
Total length (miles)	0.5	0.4	+0.1
Construction right-of-way (acres) a/	6.5	5.4	+1.1
Permanent right-of-way (acres) a/	3.2	2.6	+0.6
Total number of parcels crossed	12	14	-2
Number of residences within 25 and 50 feet of the edge of the construction ROW (and associated additional temporary workspace)	2/3	3/3	-1/0
Number of waterbodies crossed	1	1	0
Number of NWI wetlands crossed	0	0	0
Total NWI wetland crossing length (feet)	0	0	0
NWI wetlands within construction ROW (acres) b/	0	0	0
Agricultural land within construction ROW (acres) c/	0	0	0
Forested land within construction ROW (acres)	1.8	1.8	0

Table 10.6-3

Comparison of the Original Route and MP 69.5 to MP 69.7 Variation (Preferred Route)

Feature	Original Route	MP 69.5 to MP 69.69 Variation (Preferred Route)	Difference
Length parallel or adjacent to existing ROW (miles)	0	0	0

a/ Assuming 100-foot-wide construction ROW and 50-foot-wide permanent ROW.
b/ Assuming 75-foot-wide construction ROW.
c/ Includes pasture/hay and cultivated crops.
ROW = right-of-way. NWI = National Wetland Inventory
Information Sources:
GIS – Analysis based on Geodatabase layers and shapefiles.
NC Parcel Boundaries and Standard Fields - http://data.nconemap.gov/geoportal/catalog/search/resource/details.page
NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html
NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/
USGS – U.S. Geological Survey - http://www.usgs.gov/
NHD – National Hydrography Dataset - http://nhd.usgs.gov/
ESRI - GIS Mapping - http://www.esri.com/

Figure 10.6-3: MP 69.5 to MP 69.7 Variation (Preferred Route)

10.6.4 Route Variations Incorporated into the Project Pipeline

The Southgate Project has currently identified route variations during preliminary routing, stakeholder outreach efforts, and landowner and/or and agency requested route deviations. The Project has incorporated 191 of these route variations into the current preferred route to address landowner concerns, environmental resources, potential culturally sensitive areas, and constructability issues. These are shown in Table 10.6-4 in Appendix 10-B.

The Project continues to evaluate these variations and will continue to refine the route as necessary through the remainder of the field survey process. In addition, the Project will continue to coordinate with stakeholders with respect to developing route variations for site-specific concerns and will provide the FERC with a summary of alignment revisions in supplemental filings, as applicable.

10.7 ABOVEGROUND FACILITY ALTERNATIVES

10.7.1 Compressor Station Alternatives

The Project conducted a hydraulic analysis to determine the optimum horsepower and compression to provide the increased volumes of natural gas necessary to meet the purpose and need of the Project. As a result, the Project determined that two new compressor stations were necessary to meet the compression requirements for the increased delivery volume and delivery locations. The compressor station site selection-process used multiple factors including: engineering design and construction, pipeline design limitations, land/workspace requirements, site elevation, road access, interconnecting pipe, land availability, and environmental effects.

The Project evaluated alternative site for its proposed Lambert Compressor Station site, as described below.

10.7.1.1 Lambert Compressor Station Alternative

The Project considered one alternative site for the location of the Lambert Compressor Station in Pittsylvania County, Virginia. The proposed Lambert Compressor Station site is located at MP 0.0 of the pipeline route (see Figure 10.7-1). Land use at the proposed compressor station site consists of forested and agricultural land. Table 10.7-1 provides an analysis of the proposed Lambert Compressor Station site and the alternative site.

<u>Lambert Compressor Station Alternative 1</u>

The Lambert Compressor Station Alternative 1 site is located near MP 0.0 of the pipeline approximately 0.4 mile northwest of the proposed compressor station site (see Figure 10.7-1). The alternative site consists of forested land, is surrounded by forested land, and would require a new permanent access road from Transco Road/County Road 692 located approximately 0.4 mile to the northeast. An existing electric powerline is located approximately 0.6 mile to the northwest of the alternative site. Two residences are located approximately 0.3 and 0.4 mile northeast and northwest of the alternative site, respectively, and a third residence is located approximately 0.5 mile to the southwest. Transco's compressor facilities (Stations 165 and 166) are located approximately 0.2 mile to the east of the Lambert Compressor Station Alternative 1 site.

Figure 10.7-1: Lambert Compressor Station Alternative

As shown in Table 10.7-1, the primary advantages of the Lambert Compressor Station Alternative 1 are:

- smaller site size and associated land disturbance;
- shorter pipeline length to reach the site; and
- shorter access road length to reach the site.

The primary disadvantages of the Lambert Compressor Station Alternative 1 are:

- unknown availability of land;
- more noise sensitive areas within 1.0 mile of the site.

Potential constructability concerns of the Lambert Compressor Station Alternative 1 are:

- future natural gas infrastructure associated with the Mountain Valley Pipeline to be placed within the site.

In addition, approximately 90 percent of the Lambert Compressor Station Alternative 1 site is vegetated with trees and shrubs while the proposed site consists of open land and is approximately 30 percent vegetated with trees and shrubs. The vegetation at both sites would provide a visual buffer. The nearest residence/noise sensitive areas are located approximately 1,300 and 3,300 feet from the alternative and proposed site, respectively. Activities at the alternative site could affect waterbodies and would require the removal of approximately 25,000 cubic yards of material (soil and rock) from the site. The proposed site will not affect waterbodies and would require the removal of approximately 16,500 cubic yards of material from the site. Because the Lambert Compressor Station Alternative 1 would be within 1.0 mile of more noise sensitive areas, be located in an area of future natural gas infrastructure, and does not offer an environmental or constructability advantage, the Project eliminated this alternative site from further consideration as its preferred compressor station site.

Table 10.7-1

Comparison of the Proposed Lambert Compressor Station Site and Alternative 1

Feature	Proposed Lambert Compressor Station	Alternative 1
Land availability (Yes/No)	Yes	Unknown
Total land to be acquired (estimated acres)	127.5	Unknown
Construction workspace (acres)	14.7	14.5
Operation workspace (acres)	3.8	3.8
Length of pipeline required to reach the site (miles)	0.4	<0.1
Length of access road required to reach the site (miles)	0.6	0.4
Existing land use (type)	Forested/Agriculture	Forested
Construction/operation impact on prime farmland soils (acres)	12.8 / 3.7	14.5 / Unknown
Construction/operation impact on NWI wetlands (acres)	0 / 0	0 / 0
Presence of critical habitat or federally endangered or threatened species (Yes/No)	No	No
Presence of NRHP-eligible sites (Yes/No)	No	No

Table 10.7-1 Comparison of the Proposed Lambert Compressor Station Site and Alternative 1		
Feature	**Proposed Lambert Compressor Station**	**Alternative 1**
Number of NSAs within 1 mile of the site	45	55
Zoning	Unknown	Unknown
NWI = National Wetland Inventory; NRHP = National Register of Historic Places; NSAs = Noise Sensitive Areas; Information Sources: GIS – Analysis based on Geodatabase layers and shapefiles. NLCD – 2006 National Land Cover Data - http://www.epa.gov/mrlc/nlcd-2006.html NWI – National Wetlands Inventory - http://www.fws.gov/wetlands/ USGS – U.S. Geological Survey - http://www.usgs.gov/ NHD – National Hydrography Dataset - http://nhd.usgs.gov/ ESRI - GIS Mapping - http://www.esri.com/		

10.7.2 Electric Driven Compressor Units

The proposed Project compressor stations will include centrifugal turbines powered by natural gas with the natural gas obtained directly from the pipeline. While electric motor-driven compressors can power compressor stations in some instances, this is not feasible for the Project due to the lack of sufficient electricity required for each compressor station site.

To use electric driven compressor units, electric power at high voltage would need to be supplied by overhead transmission lines to a substation that would be located at each compressor station site. The compressor stations are not located near existing high voltage electric transmission lines. The substation would step down the voltage for electric driven compressor motors and other miscellaneous loads. Additionally, electric driven motors located at each compressor station could require a liquid cooled variable frequency drive, primarily to start the motor and then for speed control of the compressor. For these reasons, the use of electric driven compressor units is not a reasonable alternative for the proposed Project compressor stations.

10.7.3 Meter Station Alternatives

The proposed Lambert Interconnect, LN 3600 Interconnect, T-15 Dan River Interconnect, and T-21 Haw River Interconnect locations reflect customer and system requirements. There are no alternatives that would satisfy all of these requirements; therefore, no alternatives were considered.

10.8 REFERENCES

U.S. Energy Information Agency (EIA). 2017a. State Profile and Energy Estimates – Virginia. Available online at: https://www.eia.gov/state/analysis.php?sid=VA Accessed June 3, 2018.

U.S. Energy Information Agency (EIA). 2017b. State Profile and Energy Estimates – North Carolina. Available online at: https://www.eia.gov/state/analysis.php?sid=NC Accessed June 3, 2018.

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Appendix 10-A

FERC Requested Route Alternative Figures

MVP Southgate Project

Docket No. CP19-XX-000

Resource Report 10

Appendix 10-B

Route Variations Incorporated into the MVP Southgate Project Pipeline

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
VA-PI-001.000 VA-PI-002.000	MVP-RA-228-1624	0	0	0.00	H-605 Lambert Compressor Station Suction Line	H-605 Lambert Compressor Station Suction Line
VA-PI-002.000	MVP-RA-228-1627	0	0	0.00	Lambert Compressor Station Discharge Line	Lambert Compressor Station Discharge Line
VA-PI-008.000 VA-PI-009.000	MVP-RA-143-1526	1	1.25	0.25	Adjusted centerline (“CL”) to be next to existing right-of-way (“ROW”)	Adjusted CL to be next to existing ROW
VA-PI-012.000	MVP-RR-257-1422	2.25	2.25	0.00	Adjusted the access road TA-PI-005 to end at a additional temporary workspace (“ATWS”) that is outside of a wetland	Adjusted the access road TA-PI-005 to end at a ATWS that is outside of a wetland
VA-PI-014.000	MVP-RA-143-1527	2.35	2.7	0.35	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-022.000 VA-PI-023.000	MVP-RR-257-1425	3.4	3.4	0.00	Extended access road TA-PI-006 to a public road	Extended access road TA-PI-006 to a public road
VA-PI-022.000 VA-PI-023.000	MVP-RR-228-1312	3.55	3.55	0.00	Contoured this work box to fit stream/wetland angles	Adjusted the ATWS to contour to stream/wetland
VA-PI-029.000 VA-PI-030.000 VA-PI-031.000 VA-PI-032.000	MVP-RA-143-1528	4.25	4.4	0.15	Removed Point of Intersections (“PI’s”)	The removal of the PI's makes it better for a horizontal directional drill (“HDD”) or a conventional bore
VA-PI-032.000	MVP-RA-143-1529	4.6	4.9	0.30	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-034.000	MVP-RA-143-1530	5	5.1	0.10	Minimized creek crossing and adjust PI away from creek crossing	Minimized creek crossing and adjust PI away from creek crossing
VA-PI-034.000 VA-PI-034.000.RR VA-PI-035.000	MVP-RA-183-0855	5	5.3	0.30	Adjusted CL to avoid being in stream for approximately 600 feet.	Adjusted CL to avoid being in stream for approximately 600 feet.
VA-PI-034.000	MVP-RA-221-1831	5	5	0.00	Trimmed ATWS to 30' x 100' to avoid sensitive resource area	Trimmed ATWS to 30' x 100' to avoid sensitive resource area as much as possible
VA-PI-034.000	MVP-RA-221-1835	5	5	0.00	Removed. Reduce / avoid impact on sensitive resource area	Access road not needed
VA-PI-034.000 VA-PI-034.100.AR	MVP-RA-253-1423	5.1	5.1	0.00	Modified access road layout	Adjusted access road to follow the existing road

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
VA-PI-035.000	MVP-RA-218-1715	5.3	5.3	0.00	Access road removed	Access road not needed
VA-PI-035.000 VA-PI-036.000	MVP-RA-253-1606	5.5	5.5	0.00	Removed TA-PI-044	Access road not needed
VA-PI-035.100.AR VA-PI-036.000 VA-PI-037.000	MVP-RR-270-1240	5.9	5.9	0.00	Extend access road to a public road	Extend access road to a public road
VA-PI-037.000	MVP-RA-153-1208	6.3	6.5	0.20	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-041.000	MVP-RA-153-1215	7.2	7.3	0.10	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-041.000 VA-PI-042.000 VA-PI-044.000	MVP-RA-228-1315	7.2	7.5	0.30	Straighten out and follow existing pipelines	Adjusted CL to be next to existing ROW
VA-PI-043.000	MVP-RA-218-1732	7.6	7.6	0.00	Removed TA-PI-020	Access road not needed
VA-PI-053.000	MVP-RR-183-0902	9.6	9.6	0.00	Adjusted access road to avoid cemetery	Adjust access road to avoid cemetery
VA-PI-053.000	MVP-RA-254-1528	9.6	9.6	0.00	Modified access road layout	Adjusted access road to follow the existing road
VA-PI-053.000	MVP-RR-183-0859	9.65	10	0.35	Adjusted centerline to avoid large cemetery	Adjusted CL to avoid large cemetery
VA-PI-075.000 VA-PI-075.001.ASC VA-PI-076.000	MVP-RR-221-1024	11	11.5	0.50	Alternate route to avoid sensitive resource area	Adjusted the route to avoid potential sensitive resource area
VA-PI-077.000	MVP-RR-255-1641	11.65	11.9	0.25	Adjusted centerline to avoid cemetery	Adjusted CL to avoid cemetery
VA-PI-079.000	MVP-RA-218-2017	12.2	12.2	0.00	Removed access road	Access road not needed
VA-PI-082.000	MVP-RA-219-1725	12.4	12.4	0.00	Reduced ATWS to property lines to avoid cemetery	Reduced ATWS to property lines to avoid cemetery
VA-PI-082.000	MVP-RA-219-1839	12.6	12.6	0.00	Removed access road	Access road not needed
VA-PI-082.000	MVP-RA-219-1846	12.65	12.65	0.00	Removed access road	Access road not needed

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
VA-PI-084.000	MVP-RA-153-1249	12.8	13.1	0.30	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-092.200.AR	MVP-RR-219-0800	14.15	14.15	0.00	The landowner requested that the access road not to go past their house and barn but from the gates at the road along the property line	Adjusted the access road at the land owners request
VA-PI-092.200.AR	MVP-RA-254-1542	14.15	14.15	0.00	Removed section of access road	Adjusted access road to not go near land owners house
VA-PI-094.000	MVP-RA-153-1254	14.2	14.4	0.20	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-094.000 VA-PI-095.000 VA-PI-096.000	MVP-RA-153-1257	14.7	14.85	0.15	Adjusted CL to reduce the number of PIs.	Adjusted CL to reduce the number of PIs.
VA-PI-096.000, VA-PI-099.000	MVP-RA-218-2043	14.8	15.2	0.40	Adjusted to route to the west based on the property evidence gathered and run the line north to a point of intersection with original route. Avoid VA-PI-097.000.ABU.	Adjusted to route to the west, run the line north to a point of intersection with original route. Avoid VA-PI-097.000.ABU.
VA-PI-100.000 VA-PI-099.000 VA-PI-101.000	MVP-RA-153-1303	15.2	15.45	0.25	Adjusted CL to reduce the number of PIs in this location.	Adjusted CL to reduce the number of PIs in this location.
VA-PI-099.000	MVP-RR-218-2047	15.2	15.2	0.00	Landowner does not want the access road going by his house.	Adjusted access road to not go near land owners house
VA-PI-099.000 VA-PI-099.100.AR	MVP-RA-253-1127	15.4	15.4	0.00	Remove section of TA-PI-037	Adjusted the route of the access road to not go past the land owners house
VA-PI-102.000.ABU VA-PI-103.000	MVP-RA-179-1227	15.7	15.85	0.15	Adjusted CL to be next to existing pipeline ROW. According to the LDAR info the slope is ~14.9% (8.2 deg)	Adjusted CL to be next to existing ROW
VA-PI-103.000 VA-PI-104.000.ABU VA-PI-106.000	MVP-RA-199-1127	15.9	16.05	0.15	Avoided sensitive resource area.	Adjusted route to avoid sensitive resource area
VA-PI-106.000	MVP-RA-253-1124	16.1	16.1	0.00	Removed TA-PI-040	Access road not needed

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
VA-PI-115.000 VA-PI-118.000	MVP-RA-219-1808	16.8	17.2	0.40	At 16.9, propose to cross the creek at a more perpendicular angle.	Adjusted the route to reduce the amount of environmental impact
VA-PI-118.000	MVP-RA-253-1035	17.4	17.4	0.00	Removed TA-PI-044	Access road not needed
VA-PI-120.000 VA-PI-121.000 VA-PI-122.000.ABU VA-PI-123.000 VA-PI-124.000	MVP-RA-163-1213	18	18.4	0.40	Adjusted CL to be next to the existing pipeline ROW. There is an old farm house and barn next to the existing pipeline ROW, potential karst area.	Adjusted CL to be next to the existing pipeline ROW. There is an old farm house and barn next to the existing pipeline ROW, potential karst area.
VA-PI-121.000	MVP-RA-197-1303	18	18	0.00	Adjusted CL of access road TA-PI-046 to avoid sensitive resource area	Adjusted CL of access road TA-PI-046 to avoid sensitive resource area
VA-PI-121.000 VA-PI-122.000.ABU VA-PI-123.000 VA-PI-124.000	MVP-RA-239-1745	18.2	18.35	0.15	Adjusted CL to avoid A frame electric poles	Adjusted CL to avoid A frame electric poles
VA-PI-124.000	MVP-RA-239-1750	18.3	18.3	0.00	MLV3	MLV3
VA-PI-150.000	MVP-RA-228-1319	19.8	19.9	0.10	Crossed the existing lines square	Crossed the existing lines square
VA-PI-150.000 VA-PI-151.000 VA-PI-152.000 VA-PI-155.000 VA-PI-156.000	MVP-RA-153-1458	19.9	20.3	0.40	This will reduce the number of Pi's needed and this route will miss the structure.	This will reduce the number of Pi's needed and this route will miss the structure.

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
VA-PI-150.000 VA-PI-151.000 VA-PI-152.000 VA-PI-153.000.ABU VA-PI-154.000.ABU VA-PI-160.000	MVP-RR-218-2110	19.9	20.4	0.50	Preferred by the landowner. He had no issues with us co-locating but stressed that he did not want us to go through the center of his pasture. There is ~75' between the Williams line and the garage on tract VA-PI-153.000.ABU	Adjusted the route at the land owners request
VA-PI-160.000	MVP-RR-257-1433	20.45	20.45	0.00	Adjusted access road TA-PI-052 to avoid sensitive resource area	Adjusted access road to avoid sensitive resource area
VA-PI-160.000 VA-PI-161.000 VA-PI-162.000 VA-PI-163.000	MVP-RA-155-1441	20.5	21.2	0.70	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-164.100.AR VA-PI-164.000.ABU	MVP-RA-218-1737	21.2	21.2	0.00	Removed TA-PI-054	Access road not needed
VA-PI-163.000 VA-PI-165.000	MVP-RA-155-1446	21.35	21.65	0.30	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-171.000 VA-PI-172.000 VA-PI-173.000	MVP-RA-155-1449	22.15	22.75	0.60	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-173.000	MVP-RA-249-1429	22.35	22.35	0.00	Removed ATWS 1172	ATWS not needed
VA-PI-173.000	MVP-RA-249-1444	22.35	22.35	0.00	Removed TA-PI-056	Access road not needed
VA-PI-173.000	MVP-RA-249-1437	22.45	22.45	0.00	ATWS 1174 Removed	ATWS not needed
VA-PI-173.000	MVP-RA-249-1447	22.45	22.45	0.00	TA-PI-057 Removed	Access road not needed
VA-PI-166.100.AR VA-PI-166.200.AR	MVP-RA-249-1450	22.6	22.6	0.00	TA-PI-058 Removed	Access road not needed

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
VA-PI-173.000 VA-PI-173.100.AR						
VA-PI-173.000	MVP-RA-249-1454	22.7	22.7	0.00	TA-PI-060 Removed	Access road not needed
VA-PI-174.000 VA-PI-175.000	MVP-RA-177-1447	23.1	23.7	0.60	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
VA-PI-178.000	MVP-RA-177-1449	24.4	24.7	0.30	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
NC-RO-002.000	MVP-RA-157-1313	26.25	26.45	0.20	Adjusted CL to be next to existing ROW	Adjusted CL to be next to existing ROW
NC-RO-005.000 NC-RO-006.000	MVP-RR-269-1541	27	28.3	1.30	Adjusted CL to avoid sensitive resource area and for LN3600	Adjusted CL to avoid sensitive resource area and for LN3600
NC-RO-005.000 NC-RO-006.000	MVP-RR-270-1244	27.4	27.4	0.00	Added access road	Added access road
NC-RO-006.000 NC-RO-006.001.CS2	MVP-RR-257-1435	28.1	28.1	0.00	Extended access road PA-RO-000 to public road	Extended access road PA-RO-000 to public road
NC-RO-006.000	MVP-RA-153-1309	28.3	28.3	0.00	Moved the ATWS to stay out of large wetland	The previous location of this ATWS was in a large wetland. This location had no wetlands
NC-RO-007.000	MVP-RA-159-1655	29.3	29.65	0.35	There is side hill construction in this area, adjust CL to be on top of the hill	There is side hill construction in this area, adjust CL to be on top of the hill
NC-RO-011.000 NC-RO-012.000.WBC NC-RO-013.000 NC-RO-014.000 NC-RO-015.000 NC-RO-016.000 NC-RO-018.000.ABU NC-RO-019.000	MVP-RR-269-1549	29.9	30.55	0.65	Adjusted CL for HDD profile and T15 location	Adjusted CL for HDD profile and T15 location

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-RO-011.000	MVP-RR-270-1247	29.9	29.9	0.00	Added ATWS for equipment and mats	Added ATWS for equipment and mats
NC-RO-011.000	MVP-RR-270-1248	29.9	29.9	0.00	Added ATWS for HDD area	Added ATWS for HDD area
NC-RO-011.000	MVP-RR-270-1250	29.9	29.9	0.00	Added ATWS for truck turning	Added ATWS for truck turning
NC-RO-011.000	MVP-RR-270-1251	29.9	29.9	0.00	Adjusted where the access road route	Adjusted where the access road route to HDD location
NC-RO-014.000	MVP-RR-228-1322	30.3	30.3	0.00	ATWS for Hydro test	ATWS for Hydro test
NC-RO-022.000 NC-RO-025.000	MVP-RR-257-1438	30.75	31.15	0.40	Adjusted route to avoid red tract and 2 large stream crossings	Adjusted route to avoid red tract and 2 large stream crossings
NC-RO-025.000 NC-RO-027.000 NC-RO-029.000	MVP-RA-159-1700	31.2	31.4	0.20	Adjusted CL to reduce the amount of stream impact and to avoid side hill construction	Adjusted CL to reduce the amount of stream impact and to avoid side hill construction
NC-RO-025.900.AR NC-RO-025.850.ABU NC-RO-025.800.ABU NC-RO-025.700.AR NC-RO-025.650.ABU NC-RO-025.600.AR NC-RO-025.500.AR NC-RO-025.400.AR NC-RO-025.300.AR NC-RO-025.200.AR NC-RO-025.100.AR NC-RO-026.000.ABU NC-RO-025.000	MVP-RA-219-1902	31.2	31.2	0.00	Removed access road TA-RO-083	Access road not needed
NC-RO-029.000 NC-RO-030.000	MVP-RA-179-1146	31.4	31.6	0.20	Adjusted CL to stay away from sensitive resource area and bring the PI closer to the top of the hill	Adjusedt CL to stay away from sensitive resource area and bring the PI closer to the top of the hill

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-RO-033.000 NC-RO-034.000	MVP-RA-159-1706	31.6	31.9	0.30	Adjusted CL to avoid side hill and multiple ravines	Adjusted CL to avoid side hill and multiple ravines
NC-RO-035.000 NC-RO-037.000	MVP-RA-159-1717	32	32.15	0.15	Adjusted CL to avoid side hill construction	Adjusted CL to avoid side hill construction
NC-RO-038.000	MVP-RR-257-1441	32.35	32.55	0.20	Adjusted route to co-locate with existing pipeline	Adjusted route to co-locate with existing pipeline
NC-RO-047.000 NC-RO-048.000 NC-RO-049.000 NC-RO-050.000 NC-RO-051.000 NC-RO-052.000 NC-RO-053.000 NC-RO-054.000 NC-RO-055.000 NC-RO-056.000 NC-RO-057.000	MVP-RA-162-1521	34.2	35.35	1.15	Adjusted CL to avoid side hill construction, baptism area around MP 34.6 and sensitive resource area around MP 34.9	Adjusted CL to avoid side hill construction, baptism area around MP 34.6 and sensitive resource area around MP 34.9
NC-RO-054.000 NC-RO-056.000 NC-RO-057.000	MVP-RR-193-1030	34.95	35.35	0.40	Adjusted CL to avoid multiple stream crossings and side hill construction	Adjusted CL to avoid multiple stream crossings and side hill construction
NC-RO-058.000 NC-RO-060.000 NC-RO-061.000	MVP-RA-162-1535	35.9	36.35	0.45	Adjusted CL to avoid side hill construction and to stay off "NO" tract	Adjusted CL to avoid side hill construction and to stay off "NO" tract
NC-RO-060.000 NC-RO-061.000	MVP-RA-228-1520	36	36	0.00	Removed ATWS 1304 because it is in a ravine.	ATWS not usable
NC-RO-060.000	MVP-RA-242-1543	36	36	0.00	Trimmed the workspace out of the corner to stay off red tract	Trimmed the workspace out of the corner to stay off red tract
NC-RO-077.000 NC-RO-081.000 NC-RO-080.000	MVP-RR-242-1509	37.6	37.85	0.25	Adjusted route to avoid red tract	Adjusted route to avoid red tract

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-RO-084.000 NC-RO-085.000 NC-RO-086.000 NC-RO-087.000 NC-RO-088.000 NC-RO-089.000 NC-RO-090.000	MVP-RA-143-1533	38	38.8	0.80	Avoided Side Hill Construction	Avoided Side Hill Construction
NC-RO-085.000	MVP-RA-230-1251	38.1	38.1	0.00	Changed ATWS 1328 to 240' x 90' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-091.000	MVP-RA-230-1254	38.85	38.85	0.00	Change ATWS 1337 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-091.000 NC-RO-092.000 NC-RO-094.000	MVP-RA-162-1541	39	39.35	0.35	Adjusted CL to avoid side hill construction	Adjusted CL to avoid side hill construction
NC-RO-092.000 NC-RO-094.000 NC-RO-095.000	MVP-RR-193-1501	39.2	39.6	0.40	Adjusted CL to bring the CL up the hill a little bit more and to get the WS out of the wetland/pond area	Adjusted CL to bring the CL up the hill a little bit more and to get the WS out of the wetland/pond area
NC-RO-100.000 NC-RO-101.000	MVP-RA-163-1116	40	40.2	0.20	Adjusted CL to stay away from washout ditch	Adjusted CL to stay away from washout ditch
NC-RO-101.000	MVP-RA-230-1302	40.15	40.15	0.00	Change ATWS 1350 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-101.000	MVP-RA-230-1305	40.2	40.2	0.00	Changed ATWS 1352 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-106.000	MVP-RA-230-1308	40.5	40.5	0.00	Changed ATWS 1355 to 90' Wide to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-108.000	MVP-RA-230-1311	40.6	40.6	0.00	Changed ATWS 1357 to 90' Wide to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-109.000	MVP-RA-153-1317	40.7	40.9	0.20	Adjusted CL to avoid side hill construction	Adjusted CL to avoid side hill construction

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-RO-111.000	MVP-RR-270-1253	41.4	41.4	0.00	Extended access road to public road	Extended access road to public road
NC-RO-111.000 NC-RO-111.000.RC NC-RO-112.000	MVP-RA-193-1511	41.45	41.8	0.35	Adjusted CL to straighten out the route and reduce the number of PIs needed	Adjusted CL to straighten out the route and reduce the number of PIs needed
NC-RO-111.000 NC-RO-112.000	MVP-RR-249-1522	41.55	41.75	0.20	Adjusted CL to be able to bore Hwy 29	Adjusted CL to be able to bore Hwy 29
NC-RO-112.000	MVP-RA-153-1320	41.6	41.8	0.20	Straighten out this road crossing to follow the power lines.	Straighten out this road crossing to follow the power lines.
NC-RO-111.000 NC-RO-112.000	MVP-RR-249-1517	41.65	41.65	0.00	ATWS for bore	ATWS for bore
NC-RO-112.000	MVP-RA-157-1325	41.9	42.2	0.30	Adjusted CL to stay away from small cemetery.	Adjusted CL to stay away from small cemetery.
NC-RO-112.200 NC-RO-112.300 NC-RO-112.400 NC-RO-117.000	MVP-RR-162-1547	42.3	43	0.70	Adjusted CL to avoid AT&T tower	Adjusted CL to avoid AT&T tower
NC-RO-117.000 NC-RO-118.000.ABU NC-RO-122.000	MVP-RR-177-1515	42.5	43.4	0.90	Adjusted CL to stay away from large cemetery	Adjusted CL to stay away from large cemetery
NC-RO-122.000	MVP-RA-230-1313	43.4	43.4	0.00	Changed ATWS 1391 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-122.100	MVP-RA-230-1315	43.45	43.45	0.00	Changed ATWS 1392 to 75' x 260' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-133.200	MVP-RA-230-1317	43.8	43.8	0.00	Changed ATWS 1396 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-133.000	MVP-RA-230-1320	44.1	44.1	0.00	Changed ATWS 1403 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-RO-138.000	MVP-RA-230-1322	44.8	44.8	0.00	Changed ATWS 1408 to 60' x 220' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-140.000 NC-RO-142.000	MVP-RA-153-1324	45.45	45.75	0.30	CL adjustment to route around pasture.	CL adjustment to route around pasture.
NC-RO-148.505.AR NC-RO-148.510.AR	MVP-RR-254-1405	46.75	46.75	0.00	Adjusted TA-RO-129 CL to MDS CL points of existing road and change the start of the access road off Frank Rd to follow existing gravel path	Adjusted access road to follow the existing road
NC-RO-149.000	MVP-RA-230-1324	47.05	47.05	0.00	Changed ATWS 1429 to 90' x 230' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-153.000	MVP-RA-153-1329	47.3	47.5	0.20	Straighten out to reduce the number of PIs	Straighten out to reduce the number of PIs
NC-RO-154.000	MVP-RR-257-1443	47.3	47.3	0.00	Extended access road TA-RO-130 to public road	Extended access road TA-RO-130 to public road
NC-RO-154.000	MVP-RA-153-1333	47.6	47.7	0.10	Straighten out to reduce the number of PIs	Straighten out to reduce the number of PIs
NC-RO-154.000	MVP-RA-230-1327	47.6	47.6	0.00	Changed ATWS 1437 to 90' Wide to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-156.000	MVP-RA-153-1338	48	48.1	0.10	Straighten out to reduce the number of PIs	Straighten out to reduce the number of PIs
NC-RO-156.000	MVP-RA-193-1529	48	48.1	0.10	Adjusted CL to keep CL on top of hill	Adjusted CL to keep CL on top of hill
NC-RO-162.000	MVP-RA-230-1329	48.7	48.7	0.00	Changed ATWS 1449 to 90' Wide to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-165.000	MVP-RA-253-1620	49.2	49.2	0.00	Adjusted TA-RO-135 CL to MDS CL points of existing road and round turns	Adjusted access road to follow the existing road

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-RO-171.000 NC-RO-171.100.AR	MVP-RA-242-1439	49.8	49.8	0.00	Removed access road TA-RO-138, runs through land owner's car port and past house. The access road is approx. 855' and the nearest road crossing is approx. 1330'.	Access road not needed
NC-RO-170.000 NC-RO-171.100.AR	MVP-RR-257-1446	49.8	49.8	0.00	Adjusted access road TA-RO-138 to avoid going under car port	Adjusted access road TA-RO-138 to avoid going under car port
NC-RO-181.000	MVP-RA-253-1624	51.4	51.4	0.00	Adjusted TA-RO-140 CL to MDS CL points of existing road and round turns	Adjusted access road to follow the existing road
NC-RO-181.000	MVP-RA-253-1626	51.6	51.6	0.00	Adjusted TA-RO-141 CL to MDS CL points of existing road and round turns	Adjusted access road to follow the existing road
NC-RO-183.000	MVP-RA-253-1628	51.7	51.7	0.00	Adjusted TA-RO-142 CL to MDS CL points of existing road and round turns	Adjusted access road to follow the existing road
NC-RO-186.000	MVP-RA-230-1331	52.55	52.55	0.00	Changed ATWS 1477 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-186.000	MVP-RA-230-1333	52.6	52.6	0.00	Changed ATWS 1478 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-000.005	MVP-RA-230-1335	52.6	52.6	0.00	Change ATWS 1479 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-RO-186.000	MVP-RR-257-1448	52.6	52.6	0.00	Changed access road TA-TO-146 to go from public road to TWS	Changed access road TA-TO-146 to go from public road to TWS
NC-AL-000.065	MVP-RA-250-1321	53.5	53.5	0.00	Trimmed this section of TA-AL-152	Trimmed this section of TA-AL-152
NC-AL-008.000 NC-AL-009.000	MVP-RR-165-1051	54.85	55.1	0.25	Adjusted CL to avoid pond / swamp area	Adjusted CL to avoid pond / swamp area
NC-AL-015.000 NC-AL-016.000	MVP-RA-206-1431	55.3	55.3	0.00	Removed - There is enough ATWS at the PI (ATWS 1509) that this ATWS is not needed.	ATWS not needed

TABLE 10.6-4						
Route Variations Incorporated into the MVP Southgate Project Pipeline						
Tract ID	**Reroute No.**	**Approx. Begin MP**	**Approx. End MP**	**Length (miles)**	**Variation Description**	**Justification**
NC-AL-017.000.ABU NC-AL-018.000						
NC-AL-010.000 NC-AL-018.000	MVP-RA-230-1340	55.3	55.3	0.00	Changed ATWS 1509 to 75' x 230' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-018.000 NC-AL-019.000 NC-AL-021.000 NC-AL-022.000 NC-AL-023.000 NC-AL-024.000 NC-AL-025.000 NC-AL-025.100.AR NC-AL-027.000	MVP-RA-153-1347	55.5	56.35	0.85	Adjusted CL to reduce the number of PIs and to reduce the amount of tree clearing needed	Adjusted CL to reduce the number of PIs and to reduce the amount of tree clearing needed
NC-AL-018.000	MVP-RR-270-1255	55.6	55.6	0.00	Adjusted access road to be on existing path	Adjusted access road to be on existing path
NC-AL-028.000	MVP-RA-153-1356	56.4	56.4	0.00	Moved ATWS to the road crossing because the ATWS at MP 56.7 is on top of a pond	Moved ATWS to the road crossing because the ATWS at MP 56.7 is on top of a pond
NC-AL-028.000 NC-AL-033.000	MVP-RR-257-1513	56.8	56.8	0.00	Added access road	Added access road
NC-AL-035.000.ABU NC-AL-036.000	MVP-RA-242-1409	56.9	56.9	0.00	Removed access road TA-AL-160 runs on top of land owner's septic and in between their crop fields. The access road is approx. 2000' and the nearest road crossing is approx. 2740'.	Access road not needed
NC-AL-033.000	MVP-RR-257-1515	56.9	56.9	0.00	Added access road	Added access road
NC-AL-042.000 NC-AL-043.000	MVP-RA-186-1423	57.35	57.75	0.40	LiDAR suggests that the PI is in the pond. This adjustment is to avoid the pond	LiDAR suggests that the PI is in the pond. This adjustment is to avoid the pond
NC-AL-043.000	MVP-RR-257-1517	57.75	57.75	0.00	Extended access road TA-AL-161 to public road	Extended access road TA-AL-161 to public road

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-AL-051.000	MVP-RA-231-0828	58.6	58.6	0.00	Changed ATWS 1543 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-054.000 NC-AL-058.000	MVP-RA-228-1324	59.1	59.2	0.10	Extended PIs out of the road ROW	Extended PIs out of the road ROW
NC-AL-075.000	MVP-RA-231-0832	60.7	60.7	0.00	Change ATWS 1559 to 90' x 110' to fit inside survey corridor	Adjust ATWS to fit inside of survey corridor
NC-AL-076.100.AR NC-AL-076.200.AR NC-AL-076.400.AR NC-AL-076.500.AR NC-AL-076.000 NC-AL-074.450.AR NC-AL-076.000 NC-AL-074.100.AR NC-AL-074.000	MVP-RA-172-0945	60.8	60.8	0.00	The landowner walked with the civil crew to show them where he wants the access road to be.	The landowner walked with the civil crew to show them where he wants the access road to be.
NC-AL-076.100.AR NC-AL-076.000 NC-AL-074.450.AR NC-AL-074.000	MVP-RA-153-1402	60.9	60.9	0.00	This property owner has an existing access road to the backfield that has been logged and cleared.	The existing access could be squared up to Boone Road for better turning and the current route has a few tight turns in it that could be straightened out to reduce the number of turns for large trucks.
NC-AL-103.000 NC-AL-104.000 NC-AL-106.000 NC-AL-128.000 NC-AL-134.000 NC-AL-135.000 MVF-NC-AL-001.000 MVF-NC-AL-002.000 MVF-NC-AL-003.000 MVF-NC-AL-004.000 MVF-NC-AL-005.000 MVF-NC-AL-006.000 MVF-NC-AL-007.000 MVF-NC-AL-010.000 NC-AL-110.000.RC MVF-NC-AL-011.000	MVP-RR-240-1812	61	67.5	6.50	Mystic Valley Farm re-route	Mystic Valley Farm re-route

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
MVF-NC-AL-012.000.ABU MVF-NC-AL-013.000 MVF-NC-AL-016.000 MVF-NC-AL-017.000 NC-AL-120.000 NC-AL-119.000 FA34-AL-001.000 FA3-AL-002.000 FA3-AL-003.000 FA3-AL-005.000 FA3-AL-006.000 FA3-AL-007.000 FA3-AL-008.000 FA3-AL-009.000 FA3-AL-010.000						
NC-AL-085.000 NC-AL-086.000	MVP-RR-165-0832	62.25	62.5	0.25	The land owner mentioned that in the field of tract NC-AL-085.000 they would like to put a sub-division in the future	The land owner mentioned that in the field of tract NC-AL-085.000 they would like to put a sub-division in the future
NC-AL-086.000	MVP-RA-231-0841	62.65	62.65	0.00	Changed ATWS 1573 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-089.000 NC-AL-088.000.ABU	MVP-RA-231-0844	62.8	62.8	0.00	Changed ATWS 1575 to 90' x 330 to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-093.000	MVP-RA-231-0846	63	63	0.00	Changed ATWS 1577 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-096.000 NC-AL-097.000 NC-AL-098.000	MVP-RA-143-1534	63.1	63.5	0.40	Extended PI out of creek	Extended PI out of creek
NC-AL-101.000.ABU NC-AL-102.000.ABU	MVP-RA-231-0848	63.45	63.45	0.00	Changed ATWS 1582 to 90' x 230' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-102.000.ABU	MVP-RA-231-0852	63.5	63.5	0.00	Changed ATWS 1583 to 90' x 330' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-AL-103.000	MVP-RR-206-1421	63.7	63.7	0.00	This is an alternate access to TA-AL-172 and TA-AL-173 access roads.	The land owner requested that the access road be on the west side of the property instead of going around their house
NC-AL-103.000 NC-AL-103.100.AR	MVP-RA-250-1017	63.7	63.7	0.00	Trimmed TA-AL-172 to remove the section behind the house	Trimmed TA-AL-172 to remove the section behind the house
NC-AL-103.000	MVP-RA-250-1019	64	64	0.00	Removed TA-AL-173	Access road not needed
NC-AL-119.000 NC-AL-120.000	MVP-RA-247-1539	65.6	65.6	0.00	Mystic Valley Farm Access road 1	Mystic Valley Farm Access road 1
NC-AL-120.000	MVP-RA-231-0855	65.8	65.8	0.00	Changed ATWS 1605 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-121.000.ABU NC-AL-122.000	MVP-RA-231-0858	65.9	65.9	0.00	Change ATWS 1607 to 90' Wide to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-128.000	MVP-RA-247-1557	66.75	66.75	0.00	Mystic Valley Farm Access road 4	Mystic Valley Farm Access road 4
NC-AL-132.100.AR NC-AL-133.000 NC-AL-128.000 NC-AL-133.000	MVP-RA-247-1551	67.25	67.25	0.00	Mystic Valley Farm Access road 2	Mystic Valley Farm Access road 2
NC-AL-138.000 NC-AL-139.000 NC-AL-140.000 NC-AL-141.000 NC-AL-142.000	MVP-RR-186-1407	67.9	68.2	0.30	The LiDAR information suggests that the end of the pond is in the perm. ROW. This adjustment is to stay away from the pond	Adjust route to avoid pond
NC-AL-143.000	MVP-RA-231-0901	68.3	68.3	0.00	Changed ATWS 1629 to 90' Wide to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-143.000	MVP-RR-270-1257	68.3	68.3	0.00	Added perm. access road because Indian Village Trail is a private road	Added perm. access road because Indian Village Trail is a private road

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-AL-143.000	MVP-RA-231-0903	68.35	68.35	0.00	Changed ATWS 1631 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-143.000	MVP-RA-231-0907	68.4	68.4	0.00	Changed ATWS 1632 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-143.000	MVP-RA-231-0928	68.45	68.45	0.00	Changed ATWS 1634 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-148.000	MVP-RA-231-0930	68.7	68.7	0.00	Changed ATWS 1639 to 90' x 165' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-148.000	MVP-RA-231-0933	68.8	68.8	0.00	Changed ATWS 1641 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-148.000	MVP-RA-231-0937	68.85	68.85	0.00	Changed ATWS 1643 to 90' x 140' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-148.000 NC-AL-149.000	MVP-RA-231-0939	68.95	68.95	0.00	Changed ATWS 1646 to 85' x 220' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-149.000 NC-AL-150.000 NC-AL-151.000	MVP-RA-228-1327	69	69.1	0.10	Straighten out and move PI out of road ROW	Straighten out and move PI out of road ROW
NC-AL-169.000.ABU NC-AL-170.000.ABU NC-AL-176.000.ABU NC-AL-179.000.ABU NC-AL-180.000.ABU NC-AL-181.000.ABU NC-AL-183.000 NC-AL-184.000	MVP-RR-221-0832	69.5	69.9	0.40	Less impact for this route. Shorter distance, less fittings, less pipe, lessen foreign utility impact, less overhead utility relocation.	Less impact for this route. Shorter distance, less fittings, less pipe, lessen foreign utility impact, less overhead utility relocation.
NC-AL-182.000 NC-AL-182.100.ABU NC-AL-184.000	MVP-RA-156-1740	69.8	69.95	0.15	Adjusted CL to avoid abandoned building and to stay away from steep hill side	Adjusted CL to avoid abandoned building and to stay away from steep hill side
NC-AL-184.000	MVP-RA-231-0941	69.9	69.9	0.00	Changed ATWS 1659 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor

TABLE 10.6-4

Route Variations Incorporated into the MVP Southgate Project Pipeline

Tract ID	Reroute No.	Approx. Begin MP	Approx. End MP	Length (miles)	Variation Description	Justification
NC-AL-186.000 NC-AL-188.000	MVP-RA-219-1820	70.35	70.7	0.35	Proposed a couple minor shifts of centerline to account for side-hill terrain	Adjusted the line due to slight side hill
NC-AL-191.000	MVP-RA-231-0943	70.9	70.9	0.00	Changed ATWS 1670 to 90' wide to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-191.000	MVP-RA-231-0945	71	71	0.00	Changed ATWS 1672 to 90' Wide to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-191.000	MVP-RA-231-0947	71.05	71.05	0.00	Changed ATWS 1675 to 90' x 110' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-191.000	MVP-RA-231-0948	71.3	71.3	0.00	Changed ATWS 1676 to 80' x 280' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-192.000	MVP-RR-270-1300	71.55	71.55	0.00	Extended access road to a public road	Extended access road to a public road
NC-AL-192.000 NC-AL-193.000	MVP-RA-231-0950	71.8	71.8	0.00	Changed ATWS 1680 to 90' x 230' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-193.000 NC-AL-194.000	MVP-RA-231-0952	71.9	71.9	0.00	Changed ATWS 1681 to 90' x 260' to fit inside survey corridor	Adjusted ATWS to fit inside of survey corridor
NC-AL-199.000 NC-AL-200.000 NC-AL-201.000	MVP-RA-198-1549	72.4	72.7	0.30	According to the LiDAR info, there is side hill construction in this area (~32.5%, ~18 deg.) Adjust the CL to avoid the side hill construction	According to the LiDAR info, there is side hill construction in this area (~32.5%, ~18 deg.) Adjust the CL to avoid the side hill construction
NC-AL-210.000	MVP-RR-270-1302	73.1	73.1	0.00	Add ed perm. access road for T21	Added perm. access road for T21
NC-AL-210.000	MVP-RR-270-1303	73.1	73.1	0.00	Changed location of T21 Site	Changed location of T21 Site

APPENDIX N
Environmental Justice Report

APPENDIX O
Environmental Justice Information Submitted to FERC

Responses to Environmental Information Request Dated February 13, 2019

Resource Report 1 –General Project Description Cumulative Impacts..

Request:

RR1 does not currently include a resource-specific discussion regarding cumulative impacts on environmental justice communities. Identify all projects within shared or adjacent census tracts to Southgate Project facilities and discuss potential cumulative impacts on environmental justice communities as a result of the Southgate Project when considered with other projects in the area.

MVP Response:

The Project evaluated other projects within potential environmental justice communities shared by the Southgate Project and other projects that occur in potential environmental justice communities not shared by the Project (see Attachment 19-1). Other projects that are within potential environmental justice communities shared by the Southgate Project are in North Carolina and include the existing Transco Pipeline in Rockingham County and LGI Homes Bedford Hills and Clayton Homes in Alamance County. The Southgate Project and the other shared projects are not expected to result in disproportionate impacts on the health, social conditions, or economic conditions of minority or low-income communities. The primary adverse impacts associated with the construction of these projects include temporary noise, dust, and traffic impacts. None of these impacts are considered significant given the temporary nature of the impacts and measures that each project would implement to minimize such impacts. In addition,construction of the Southgate Project would begin after construction of the other shared projects is complete. Construction related impacts associated with the Southgate Project will occur in areas with a variety of socioeconomic backgrounds. Positive cumulative economic benefits will be generated from the Southgate Project and other shared projects, including an increase in annual tax revenue from project operations and an increase in permanent employment with the cumulative benefit of potentially lowering local unemployment rates. The construction and operation of the Southgate Project and the other shared projects would not cause a disproportionate share of adverse environmental or socioeconomic impacts on any racial, ethnic, or socioeconomic groups that meet the environmental justice criteria; therefore, it is not anticipated cumulative impacts on environmental justice communities will result from the construction of the Southgate Project when considered with the other shared projects in the area.

Resource Report 5–Socioeconomics

Request:

Clarify if Mountain Valley has accounted for socioeconomic and environmental justice impacts from all laydown/contractor yard/additional workspace areas, including those identified in RR1, table 1.3-4.

Response:

The Project considered environmental justice impacts for all laydown/contractor yard/additional workspace areas.The Project will provide updated information within the Supplemental Information Package to be submitted in March 2019 that will account for socioeconomic and environmental justice impacts from all laydown/contractor yard/additional workspace areas, including those identified in Resource Report 1, Table 1.3-4

Resource Report 5–Socioeconomics

Request:

Provide an updated environmental justice analysis, including an impacts discussion, using the following criteria (recommended by the NCDEQ and U.S. Environmental Protection Agency's Environmental Justice Interagency Working Group Promising Practices for Environmental Justice Methodologies in NEPA Reviews)to identify environmental justice communities: a. census block groups that have a minority population of more than 50 percent; b. census block groups that have a household poverty rate of more than 20 percent; and c. census block groups that have a household poverty rate or minority population that is 10 percent higher than their respective county.

MVP Response:

The Project will provide an updated environmental justice analysis within the Supplemental Information Package to be submitted in March 2019 to identify environmental justice communities.

<u>Responses to Environmental Information Request Dated June 11, 2019</u>

Resource Report 10 – Alternatives

Request:

The following requests pertain to the comparison tables for route alternatives and route variations in Resource Report 10.

a. If applicable, provide revised comparison tables of the proposed route and alternatives based on project modifications filed by Mountain Valley on May 22, 2019.

b. Provide total number of residences within 25 feet and total number of residences within 50 feet in each of the comparison tables for the proposed route and each route alternative and route variation (if applicable).

c. Provide data source and methodology for determining Environmental Justice Areas reported in comparison tables provided in Mountain Valley's May 22, 2019 supplemental filing.

d. Some of the comparison tables for alternative routes and route variations present the length of the route adjacent to existing rights-of-way, while other comparison tables present the length of the route parallel or adjacent to existing rights-of-way.

Clarify Mountain Valley's use of the terms "parallel" and "adjacent" providing typical offsets from existing rights-of-way.

MVP Response:

a. Revised comparison tables are included in Attachment 28-1. The tables compare the current pipeline route (May 2019) with alternatives and variations. The Project has changed "Preferred Route" to Current Route (May 2019) in the titles of the comparison tables.

b. Total number of residences within 25 feet and total number of residences within 50 feet in each of the comparison tables were included in all comparison tables except tables 10.5-1, 10.5-2, 10.5-3, and 10.5-10. Those tables have been updated to include this information (see Attachment 28-1).

c. To determine potential impacts on minority and low-income populations, the Southgate Project used the following demographic index criteria to identify environmental justice communities: census block groups that have a minority population of more than 50 percent; census block groups that have a household poverty rate of more than 20 percent; and census block groups that have a household poverty rate or minority population that is 10 percent higher than their respective county. This criteria used was the Environmental Protection Agency's ("EPA") Environmental Justice Interagency Working Group Promising Practices for Environmental Justice Methodologies in NEPA Reviews)[1] as recommended by the North Carolina's Department of Environmental Quality (NCDEQ). Please note, the minority population of more than 50 percent remain the same as the same criteria was used. However, the low-income populations has changed significantly since the recommended criteria uses populations whose household income is below once the federally defined poverty threshold (Table B17017) whereas, prior results were reported using population whose household income was below twice the federally defined poverty threshold (e.g., EJSCREEN).

d. The Revised comparison tables have been changed to use the term "adjacent to" to existing right-of-way.

APPENDIX P
Tribal Outreach

Organization	Name	Title	Date	Type	Comments
Absentee-Shawnee Tribe of Oklahoma	Edwina Butler-Wolfe	Governor	5/31/2018	Phone Call	Phone call to schedule project introduction meeting
			6/1/2018	Email	Follow up email regarding introduction
			11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Absentee-Shawnee Tribe	Devon Frazier	Tribal Historic Preservation Officer	11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Catawba Indian Nation	Wenonah G. Haire	Tribal Historic Preservation Officer	5/31/2018	Phone Call	Phone call to schedule project introduction meeting
			6/1/2018	Email	Follow up email regarding introduction
			6/28/2018	Meeting	MVP Southgate Introductory Meeting with invitation to coordinate
			7/11/18	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			9/5/18	Letter	Hard and digital copies of the prefiling draft of MVP Southgate Project Resource Report 4.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			12/21/18	Phone Call	Contacted Alex Miller to request project address.
			2/6/19	Email	MVP invitation to attend a site visit location along the MVP Southgate pipeline route on March 14, 2019.
			2/27/19	Email	MVP emailed the tribes with the 2nd transmittal of Southgate Cultural Resource Report(s).
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			8/7/19	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			9/5/19	Letter	The Catawba Indian Nation disclosed a letter to MVP Southgate stating they have no immediate concerns with regard to traditional cultural properties, sacred sites, or Native American archaeological sites. However, they would like to be notified if Native American artifacts or remains are found during ground disturbance.
			11/5/2019	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Catawba Indian Nation	Caitlin (Haire) Rogers	Tribal Historic Preservation Office	5/31/2018	Phone Call	Phone call to schedule project introduction meeting
			6/1/2018	Email	Follow up email regarding introduction
			7/11/18	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			2/27/19	Email	MVP emailed the tribes with the 2nd transmittal of Southgate Cultural Resource Report(s).
Catawba Indian Nation	Darin Steen	Environmental Services Director	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Catawba Indian Nation	Evie Stewart	Tribal Administrator	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Catawba Indian Nation	William Harris	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Cayuga Nation	Clint Halftown	Nation Representative	11/2/22018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Cherokee Nation of Oklahoma	Elizabeth Toombs	Tribal Historic Preservation Office	5/31/2018	Phone Call	Phone call to schedule project introduction meeting
			6/1/2018	Email	Follow up email regarding introduction
			11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			11/30/18	Email	Email discussion regarding MVP Southgate's FERC filing.
			12/5/18	Email	Email discussion between MVP Southgate and Ms. Toombs regarding the FERC filing docket number.
			5/31/2018	Phone Call	Phone call to schedule project introduction meeting
			6/1/2018	Email	Follow up email regarding introduction
			11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Cherokee Nation of Oklahoma	Bill John Baker	Principle Chief	11/6/2018	Email	Email discussion regarding MVP Southgate's FERC filing.
Cheroenhaka (Nottoway) Tribe	Walt Brown	Chief	5/31/2018	Phone Call	Phone call to schedule project introduction meeting
			6/1/2018	Email	Follow up email regarding introduction
			8/3/18	Email	Additional information is provided
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			3/6/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Cheyenne River Sioux Tribe	Steve Vance	Tribal Historic Preservation Officer	5/31/2018	Phone Call	Phone call to schedule project introduction meeting
			6/1/2018	Email	Follow up email regarding introduction
			7/11/18	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			11/2/18	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Chickahominy Tribe	Ruth Hennamen		5/31/2018	Phone Call	Phone call to schedule project introduction meeting
			6/1/2018	Email	Follow up email regarding introduction
			8/15/18	Phone Call	Schedule joint tribal meeting in Richmond
			9/6/18	Meeting	Joint tribal meeting
			11/2/18	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			5/1/19	Meeting	Plan (UDP). No comments from the tribe were mentioned, however there will be continued coordination between MVP and the
Chickahominy Tribe	Stephen Adkins	Chief	5/31/2018	Phone Call	Phone introduction and to schedule meeting
			6/1/2018	Email	Follow up email regarding introduction
			6/25/18	Meeting	MVP Southgate Introductory Meeting with invitation to coordinate
			8/15/18	Phone Call	Schedule joint tribal meeting in Richmond
			7/11/18	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			9/6/18	Meeting	Joint tribal meeting
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			2/6/19	Email	MVP invitation to attend a site visit at a location along the MVP Southgate pipeline route on March 14th, 2019.
			2/27/19	Email	MVP emailed the tribes with the 2nd transmittal of Southgate Cultural Resource Report(s).
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			4/16/19	Email	MVP communication about the Southgate Tribal/Archaeological site visit.
			4/16/19	Email	MVP Southgate reached out to provide a photo/video session as an alternative to the tribal site visit occurring on 4/25/2019.
			5/1/19	Meeting	MVP met with Chief Adkins and Ms. Hennamen to discuss Cultural Resource Investigations and the Unanticipated Discoveries Plan (UDP). No comments from the tribe were mentioned, however there will be continued coordination between MVP and the tribe.
			8/7/19	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			11/5/19	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/6/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Chickahominy Tribe Eastern Division	Gene Pathfollower Adkins	Chief	5/31/2018	Phone Call	Phone introduction and to schedule meeting
			6/1/2018	Email	Follow up email regarding introduction
			8/15/18	Phone Call	Schedule joint tribal meeting in Richmond
			9/6/18	Meeting	Joint tribal meeting
			11/2/18	Email	Formal introduction to MVP Southgate, notice of application with FERC, and invitation for coordination (NC State Recognized Tribe)
			11/5/19	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Chickahominy Tribe Eastern Division	Gerald Stewart	Chief	5/31/2018	Phone Call	Phone introduction and to schedule meeting
			11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			4/16/19	Email	MVP Southgate reached out to provide a photo/video session as an alternative to the tribal site visit occurring on 4/25/2019.
			8/7/19	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			3/6/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Chickasaw Nation	Bill Anoatubby	Governor	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Choctaw Nation of Oklahoma	Gary Batton	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Choctaw Nation of Oklahoma	Ian Thompson	Tribal Historic Preservation Officer	11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Coharie Tribe	Gene Jacobs	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Coharie Tribe	Freddie Carter	Chair	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Coharie Tribe	Greg Jacobs	Executive Director	5/31/2018	Phone Call	Phone introduction and to schedule meeting
			8/3/18	Email	Additional information provided

Organization	Name	Title	Date	Type	Comments
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Cultural Heritage Partners (CHP)	Marion Werkheiser	Representative	10/9/2018	Meeting	MVP Southgate Met With CHP (Marion Werkheiser And Ellen Chapman) In Richmond, VA To Discuss MVP Southgate.
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			3/29/2019	Email	MVP Southgate Informed CHP That The Site Visit Has Been Postponed To April 25th, 2019.
			4/10/2019	Email	MVP Soutgate Sent Email With The Final Logistics For The Site Visit On April 25, 2019.
			8/7/19	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			11/5/19	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			1/24/2020	Email	Email regarding unanticipated discoveries plan
			2/6/2020	Email	Discussion On Deep Testing And Future Meeting Arrangements.
			3/6/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/18/2020	Meeting	Meeting With CHP Partners (Marion Wekheiser, Greg Werkheiser, Will Cook), Monacan Indian Nation (Rufus Elliott), Sappony Tribe (Dante Desiderio) And MVP Southgate (Alex Miller, William Lavarco, Rich Estabrook, Carolyn Stewart, Agnes Ramsey).
			3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Cultural Heritage Partners (CHP)	Ellen Chapman	Representative	10/9/2018	Meeting	MVP Southgate Met With CHP (Marion Werkheiser And Ellen Chapman) In Richmond, VA To Discuss MVP Southgate.
			2/13/19	Email	Discussion between MVP and Ms. Chapman about the MVP Southgate Cultural Resource Reports.
			2/21/19	Email	Email from Ms. Chapman to MVP discussing the Southgate FTP website.
			2/27/19	Email	MVP emailed the tribes with the 2nd transmittal of Southgate Cultural Resource Report(s).
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			3/25/19	Email	Ms. Chapman emailed MVP Southgate in regards to the Southgate Resource Report 4.
			4/18/19	Phone Call	Phone Call with Ellen Chapman of Cultural Heritage Partners who represent the Monacan Nation (VA federally recognized tribe).Requested site number for the archaeological tribal site visit. Does not know at this time if CHP will attend the site visit. Monacan Nation may be sending their own representative, Vicky Ferguson. Identified site of interest for CHP and the Monacan – 31RK235
Cultural Heritage Partners (CHP)	Kelli Peterson	Attorney at Law	2/6/19	Email	MVP invitation to attend a site visit at a location along hte MVP Southgate pipeline route on March 14th, 2019.
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
Delaware Nation	Darren Hill	Director of Cultural Preservation Program	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Delaware Nation	Deborah Dotson	President	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Delaware Nation	Kim Penrod	Director of Cultural Resources	5/31/2018	Phone Call	Phone introduction and to schedule meeting
			6/1/2018	Email	Follow up email regarding introduction
			7/11/2018	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Delaware Tribe of Indians	Chester Brooks	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Delaware Tribe	Susan Bachor	Tribal Historic Preservation Officer	11/2/2018	Email	occur on November 6, 2018.
Eastern Band of Cherokee Indians	Russell Townsend	Tribal Historic Preservation Officer	5/31/18	Phone Call	Phone call to schedule project introduction meeting
			6/1/18	Email	Follow up email regarding introduction
			6/29/18	Meeting	MVP Southgate Introductory Meeting with invitation to coordinate
			10/15/18	Email	Cherokee tribe confirmed that the Southgate project is outside of their designated terroritory.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			2/6/19	Email	MVP invitation to attend a site visit at a location along the MVP Southgate pipeline route on March 14th, 2019.
			2/27/19	Email	MVP emailed the tribes with the 2nd transmittal of Southgate Cultural Resource Report(s).
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
Eastern Band of Cherokee Indians	Richard Sneed	Principal Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Eastern Shawnee Tribe of Oklahoma	Glenna Wallace	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Eastern Shawnee Tribe of Oklahoma	Brett Barnes	Tribal Historic Preservation Officer	5/31/2018	Phone Call	Phone introduction and to schedule meeting
			7/11/2018	Email	Archaeological Survey, testing, and deep testing investigations for your review and comment.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Haliwa-Saponi Tribe	Archie Lynch	Tribal Administrator	5/31/18	Phone Call	Phone call to schedule project introduction meeting
			8/3/18	Email	Additional information is provided
			11/2/18	Email	Formal introduction to MVP Southgate, notice of application with FERC, and invitation for coordination (NC State Recognized Tribe)
			11/6/2018	Letter	MVP Southgate Natural Gas Pipeline in Pittsylvania County, VA and Alamance County, NC
Haliwa-Saponi Indian Tribe	Ogletree Richardson	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Haliwa-Saponi Indian Tribe	Michael Richardson	Chair	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Jena Band of Choctaw Indians	Cheryl Smith	Principal Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would
Jena Band of Choctaw Indians	Alina Shively	Tribal Historic Preservation Officer	11/2/18	Email	Formal introduction to MVP Southgate, notice of application with FERC, and invitation for coordination (NC State Recognized Tribe)
Lumbee Tribe of North Carolina	Harvey Godwin	Chair	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
The Lumbee Tribe	Freda Porter	Administrator	5/31/18	Phone Call	Phone call to schedule project introduction meeting
			8/3/18	Email	Additional information is provided
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Mattaponi Tribe	Mark Custalow	Chief	5/31/18	Phone Call	Phone call to schedule project introduction meeting
			8/3/18	Email	Additional information is provided
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Meherrin Indian Tribe	Jonathan Caudill	Chair	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would
Meherrin Indian Tribe	Wayne Brown	Chief/Tribal Administrator	5/31/18	Phone Call	Phone call to schedule project introduction meeting
			8/3/2018	Email	Additional information is provided
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Mississippi Band of Choctaw Indians	Phyliss Anderson	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Monacan Indian Nation	Dean Branham	Chief	5/31/18	Phone Call	Phone introduction and to schedule meeting
			6/1/18	Email	Follow up email regarding introduction
			6/27/18	Phone Call	Pre-Scheduled meeting for project introduction, arrived in Lynchburg to meet, Chief Branham asked to delay and then postponed.
			7/11/18	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			8/15/18	Phone Call	Schedule joint tribal meeting in Richmond (Left Message)
			9/6/18	Meeting	Joint tribal meeting (Chief Branham invited, did not attend)
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			2/6/19	Email	MVP invited the stakeholder to attend a Tribal Site visit.
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			4/16/19	Email	MVP Southgate reached out to provide a photo/video session as an alternative to the tribal site visit occurring on 4/25/2019.
			8/7/19	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			11/5/19	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/6/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Monacan Indian Nation	Kenneth Branham	Museum Guide (Chief as of July, 2019)	4/26/2019	Visit	Monacan Museum visit, tour guided by Kenneth Branham. Two hours spent touring museum and learning about Monacan history and current interests. Obtained 2 copies of *The Monacan Indians: Our Story*, by Diane Shields and Karenne Wood
			3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Muscogee Creek Nation	Corain Lowe-Zepeda	Tribal Historic Preservation Officer	5/31/18	Phone Call	Phone introduction and to schedule meeting
			7/11/2018	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Muscogee Creek Nation	James Floyd	Principal Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Muscogee Creek Nation	Raelynn Butler	Manager, Historic and Cultural Preservations	5/31/18	Phone Call	Phone introduction and to schedule meeting
			7/11/2018	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.

Organization	Name	Title	Date	Type	Comments
Nansemond Tribe	Sam Bass	Chief	5/31/18	Phone Call	Phone introduction and to schedule meeting
			7/11/2018	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			2/6/19	Email	MVP Southgate sent the stakeholder an invitation to a Tribal site visit.
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			4/16/19	Email	MVP Southgate reached out to provide a photo/video session as an alternative to the tribal site visit occurring on 4/25/2019.
			4/29/19	Meeting	Meeting with Sam Bass with MVP Southgate.
			5/1/19	Meeting	Mr. Bass Received A CD With The Latest Reports For Review From MVP And Stated There Are No Concerns At This Point. He Appreciates The Continued Coordination From MVP Moving Forward.
			8/7/19	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			11/5/2019	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Nansemond Tribe	Lee Lockamy	Chief	5/31/2018	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			7/11/2018	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
North Carolina Comission of Indian Affairs	Gregory Richardson	Executive Director	2/28/2019	Email	MVP Notified The Stakeholder That An Upcoming Site Visit Will Be Rescheduled In April Due To Inclement Weather.
			4/15/2019	Email	MVP Southgate Emailed MR. Richardson To Provide Details For A Tribal Site Visit.
			4/23/2019	Email	Mr. Richardson Confirmed He Will Attend The Tribal Site Visit On 4/25/2019.
			4/25/2019	Meeting	Meeting – Archaeological Site Visit: Jean Gibby, US Army Corps Of Engineers; John Mintz, NC State Archaeologist; Rosie Blewitt-Golsch, Assistant State Archaeologist; Greg Richardson, Executive Director Of NC Commission Of Indian Affairs
			4/26/2019	Email	Follow Up Email Regarding The Southgate Tribal Visit On 4/25/2019.
			8/7/2019	Letter	MVP Southgate Sent A Project Update About The FERC Draft Environmental Impact Statement Issuance.
			8/23/2019	Phone Call	Phone Call Discussion In Regards To Attending The NC Commission Of Indian Affairs Annual Meeting.
			9/4/2019	Phone Call	Phone Call Discussion In Regards To Attending The NC Commission Of Indian Affairs Annual Meeting (Confirm Date, Time, Etc.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			11/5/2019	Mail	MVP Southgate Sent A Flash Drive With The Latest Cultural Reports.
			3/30/2020	Mail	MVP Southgate Sent A Flash Drive With The Latest Cultural Reports.
Nottoway Indian Tribe of VA	Leroy Hardy	Councilperson	5/31/2018	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			11/6/2018	Letter	MVP Southgate Natural Gas Pipeline in Pittsylvania County, VA and Alamance County, NC
			4/23/19	Email	Email communication between MVP and Nottoway Tribe for an attempt to initiate coordination regarding the project.
Nottoway Tribe	Lynette Allston	Chief	5/31/2018	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			8/3/18	Email	Additional project information provided.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Nottoway Indian Tribe of VA	Beth Roach	Councilperson	5/31/2018	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			5/7/19	Phone Call	Ms. Roach, a Tribal Council Member, returned a call to MVP Southgate to inform that the Tribe would be signing the Confidentiality Agreement, thus allowing MVP to supply archaeological reports for their review,
			5/10/19	Phone Call	Follow up conversation on taking next steps after the NDA is signed. MVP expects to begin coordinating with her by meeting face to face soon to share project progress, cultural information and schedule going forward.
Occaneechi Band of the Saponi Nation	W.A. (Tony) Hayes	Tribal Chair	5/31/2018	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			8/3/18	Email	Additional project information provided.
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			2/6/19	Email	MVP invitation to attend a site visit at a location along the MVP Southgate pipeline route on March 14th, 2019.
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			4/15/19	Email	MVP Southgate reached out to the Occaneechi Band of Saponi to invite them on a tribal site visit.
			4/15/19	Email	The Occaneechi Band of Saponi responded "Yes" to MVP Southgate's tribal site visit invitation.2019.
			5/15/19	Phone Call	MVP Southgate coordinating with Mr. Hayes for the delivery of Southgate reports.
			5/17/19	Email	Mr. Hayes, Please find enclosed 3 CDs containing all of the Cultural Resource Reports available to date for MVP Southgate. Please do not hesitate to contact me if you have any questions, comments, or issues. Thank you, Agnes S. Ramsey Project Manager - Tribal Relations Phone (561) 691-2820 Cell (561) 385-9018
			8/7/19	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			10/4/19	Email	PRIV- Discussion regarding Southgate DEIS comment.
			11/5/19	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/6/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Occaneechi Band of Saponi Indians	Vickie Jeffries	Tribal Administrator	5/31/2018	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			2/25/19	Email	MVP invited the stakeholder to a Tribal Site Visit.
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			8/7/19	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			3/6/2020	Mail	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
Oneida Nation of Wisconsin	Corina Williams	Tribal Historic Preservation Officer	11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Oneida Nation of Wisconsin	Tehassi Hill	Chair	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Oneida Indian Nation	Raymond Halbritter	Nation Representative	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Oneida Indian Nation	Jesse Bergevin	Historian	11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Onondaga Nation	Sidney Hill	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Onondaga Nation	Tony Gonyea	Faithkeeper of the Onondaga Nation	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Ottawa Tribe of Oklahoma	Ethel Cook	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Ottawa Tribe of Oklahoma	Rhonda Hayworth	Tribal Historic Preservation Officer	11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Pamunkey Tribe	Robert Gray	Representative	5/31/2018	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			11/2/2018	Email	occur on November 6, 2018.
			2/6/19	Email	MVP invitation to attend a site visit at a location along the MVP Southgate pipeline route on March 14th, 2019.
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			4/16/19	Email	MVP Southgate reached out to provide a photo/video session as an alternative to the tribal site visit occurring on 4/25/2019.
Patawomeck Tribe	John R. Lightner	Chief	5/31/2018	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			8/3/18	Email	Additional information provided
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Poarch Band of Creeks	Stephanie Bryan	Chair	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Poarch Band of Creek Indians	Carolyn White	Tribal Historic Preservation Officer	11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Rappahannock Tribe	Anne Richardson	Chief	5/31/18	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			7/11/18	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			8/15/18	Phone Call	Schedule joint tribal meeting in Richmond
			9/6/18	Meeting	Joint tribal meeting
			11/2/18	Email	Formal introduction to MVP Southgate, notice of application with FERC, and invitation for coordination (NC State Recognized Tribe)
			2/6/19	Email	MVP invitation to attend a site visit at a location along the MVP Southgate pipeline route on March 14th, 2019.
			2/27/19	Email	MVP emailed the tribes with the 2nd transmittal of Southgate Cultural Resource Report(s).
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			4/16/19	Email	MVP Southgate reached out to provide a photo/video session as an alternative to the tribal site visit occurring on 4/25/2019.
			5/10/19	Phone Call	MVP spoke with Anne Richards, Chief of the Rappahannock. She stated MVP Southgate is outside of their Area of Interest. However, if Human Remains are identified to let them know.
Sappony	Otis Martin	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.

Organization	Name	Title	Date	Type	Comments
Sappony	Dorothy Crowe	Tribal Chair	5/31/18	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			11/2/2018	Letter	Formal introduction to MVP Southgate, notice of application with FERC, and invitation for coordination (NC State Recognized Tribe)
			2/6/19	Email	MVP invited the stakeholder to a Tribal Site Visit.
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			11/5/19	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Sappony	Dante Desiderio	Executive Director	5/31/18	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			8/3/18	Email	Additional information provided
			6/1/2018	Email	Follow up email regarding introduction
			11/2/18	Email	Formal introduction to MVP Southgate, notice of application with FERC, and invitation for coordination (NC State Recognized Tribe)
			1/25/19	Meeting	MVP Southgate Discussion @ Sappony Tribal Center
			8/7/2019	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			3/6/2020	Letter	MVP Southgate sent a flash drive with the latest cultural reports.
			3/18/2020	Meeting	Meeting With CHP Partners (Marion Wekheiser, Greg Werkheiser, Will Cook), Monacan Indian Nation (Rufus Elliott), Sappony Tribe (Dante Desiderio) And MVP Southgate (Alex Miller, William Lavarco, Rich Estabrook, Carolyn Stewart, Agnes Ramsey).
			3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Seneca Nation	Jay Toth	Tribal Historic Preservation Officer	11/2/18	Email	Formal introduction to MVP Southgate, notice of application with FERC, and invitation for coordination (NC State Recognized Tribe)
Seneca Nation of Indians	Todd Gates	President	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Seneca-Cayuga Nation	William Fisher	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Seneca-Cayuga Tribe	William Tarrant	Tribal Historic Preservation Officer	11/2/18	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Shawnee Tribe (Pipelines)	Tonya Tipton	Preservation Office	11/6/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Shawnee Tribe of Oklahoma	Ron Sparkman	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Stockbridge-Munsee Mohican Community	Bonney Hartley	Tribal Historic Preservation Officer	11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Stockbridge-Munsee Community of Wisconsin	Shannon Holsey	President	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
St. Regis Mohawk Tribe	Beverly Cook	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
St. Regis Mohawk Tribe	Arnold Printup	Tribal Historic Preservation Officer	11/2/18	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Tonawanda Band of Seneca	Roger Hill	Chief /NAGPRA Contact	11/2/18	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Tonawanda Band of Seneca Indians of New York	Roger Hill	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Tuscarora Nation	Neil Patterson	Director of the Chiefs Council Tuscarora Environmental Program	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Tuscarora Nation	Leo Henry	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Tuscarora Nation	Bryan Printup	Representative	5/31/18	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			7/11/2018	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			11/6/2018	Letter	MVP Southgate Natural Gas Pipeline in Pittsylvania County, VA and Alamance County, NC
Upper Mattaponi Tribe	Frank Adams	Chief	5/31/18	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/24/18	Meeting	MVP Southgate Introductory Meeting with invitation to coordinate
			7/11/18	Email	Follow up email to the introductory information that was sent in June. Attached are the detailed work plans for Project Archaeological Survey, testing, and deep testing investigations for your review and comment.
			11/2/18	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
			11/6/2018	Letter	MVP Southgate Natural Gas Pipeline in Pittsylvania County, VA and Alamance County, NC
			2/6/19	Email	MVP invitation to attend a site visit at a location along the MVP Southgate pipeline route on March 14th, 2019.
			2/27/19	Email	MVP emailed the tribes with the 2nd transmittal of Southgate Cultural Resource Report(s).
			2/28/19	Email	MVP notified the stakeholder that an upcoming site visit will be rescheduled in April due to inclement weather.
			4/16/19	Email	MVP Southgate reached out to provide a photo/video session as an alternative to the tribal site visit occurring on 4/25/2019.
			5/1/19	Phone Call	Chief Adams of the Upper Mattaponi Tribe received a CD with the latest reports for review from MVP and stated they have no concerns at this point. He appreciates the continued coordination from MVP moving forward.
			8/7/19	Letter	MVP Southgate sent a project update about the FERC Draft Environmental Impact Statement issuance.
			11/5/19	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
			3/6/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
United Keetoowah Band of Cherokee Indians	Karen Prichett	Tribal Historic Preservation Office	11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
United Keetoowah Band of Cherokee Indians in Oklahoma	Joe Bunch	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Upper Mattaponi Tribe	Kenneth Adams	Chief	3/30/2020	Mail	MVP Southgate sent a flash drive with the latest cultural reports.
Waccamaw Sioux Tribe	Brenda Moore	Housing Coordinator	5/31/18	Phone Call	Introduction and Coordination Call to introduce MVP Southgate project and invite participation
			6/1/2018	Email	Follow up email regarding introduction
			8/3/18	Email	Additional information provided
			11/2/2018	Email	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Waccamaw Tribe	Lacy Freeman	Chief	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.
Waccamaw Tribe	Matthew Blanks	Council Chair	11/2/2018	Letter	Notification that MVP Southgate's filing with FERC of an application for an approximately 73-mile natural gas pipeline would occur on November 6, 2018.