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May 25, 2018

BY: OVERNIGHT MAIL

Mr. Patrick Corbett
Central Office
Virginia Department of Environmental Quality
P.O. Box 1105
Richmond, VA 23218

Subject: Atlantic Coast Pipeline, L.L.C.
Buckingham Compressor Station
Minor New Source Permit Application Update

Dear Mr. Corbett:

Atlantic Coast Pipeline, L.L.C. (ACP) filed the original application for the new Buckingham Compressor Station on September 16, 2015 and submitted application updates on May 25, 2016 and August 7, 2017 to address changes to the compressor station. ACP previously responded to information requests dated: September 5, 2017 information request on October 10, 2017; November 1, 2017 information request on January 8, 2018; March 5, 2018 information request on March 13, 2018; and March 29, 2018 information request on March 22, 2018. Based on information previously submitted as well as meetings with the Virginia Department of Environmental Quality (DEQ), ACP has developed the enclosed update to the proposed Buckingham Compressor Station air permit application.

The purpose of this update is to more accurately reflect the station design, including the associated reductions in potential to emit for the station. The prior versions of the application contained conservative estimates that are being revised based on the availability of additional design details and confirmation of planned station operating practices, particularly with respect to events that could result in venting of equipment at the station. Additionally, this update is consistent with recent responses to questions from DEQ (see November 2017, January 2018, and March 2018 responses from Dominion).

Specific updates to this application include:

- Updated emissions data for the four (4) Solar combustion turbines (CT-01 through CT-04) and their respective controls to incorporate the following design revisions that impact the site Potential to Emit (PTE):
    - Apply the oxidation catalyst efficiency to shutdown events;
    - Apply Pilot Active Control Logic to low temperature operations;
    - Decrease the expected low temperature operations from 50 hours per year to 5 hours per year; and
    - Provide updated control efficiencies for the Selective Catalytic Reduction (SCR) (58% NO_x) and Oxidation Catalyst (92% CO, 50% VOC) control devices used to control emissions from the combustion turbines.

- Provide a revised basis for emissions from turbine and station blowdowns (FUG-02), including:
  - Decrease in the number of start-up and shutdown events (per turbine) requiring blowdown from 100 per year to 10 per year;
  - Reflect a revised estimate of the volume of gas emitted during start-up and shutdown blowdown events consistent with the station design;
  - Reflect the use of annual capped blowdown tests of the emergency shutdown (ESD) system (versus a full depressurization event once every five years); and
  - Incorporate emissions from pigging operations.
- Increase the operating schedule of the emergency generator (EG-01) from 100 hours per year to 500 hours per year;
- Correct TK-1 and TK-2 descriptions consistent with the final design. The Accumlator Tank (TK-1) has a 2,500 gallon capacity and Pipeline Fluids (Hydrocarbon Waste) Tank (TK-2) is 1,000 gallons;
- Update Ammonia Tank (TK-3) capacity from 13,000 to 13,400 (no emissions impact), and
- Provide an updated Best Available Control Technology (BACT) analysis consistent with impacts of the above changes on emissions.

Included with this letter is the updated Permit Application Package which consists of the permit application narrative along with the following list of appendices:

- Appendix A – Virginia DEQ Form 7 Application Forms;
- Appendix B – Facility Plot Plan;
- Appendix C – Potential to Emit Calculations;
- Appendix D – Vendor Specifications;
- Appendix E – RBLC Database Search Results;
- Appendix F – Comparison of Flaring Emissions and VGR Emissions;
- Appendix G – SCR Cost Effectiveness Evaluation; and
- Appendix H – VGR System Design and Operation Details.

If you have questions about this submittal, please do not hesitate to contact Mr. T.R. Andrake at (804) 273-2882 or at Thomas.R.Andrake@dominionenergy.com.

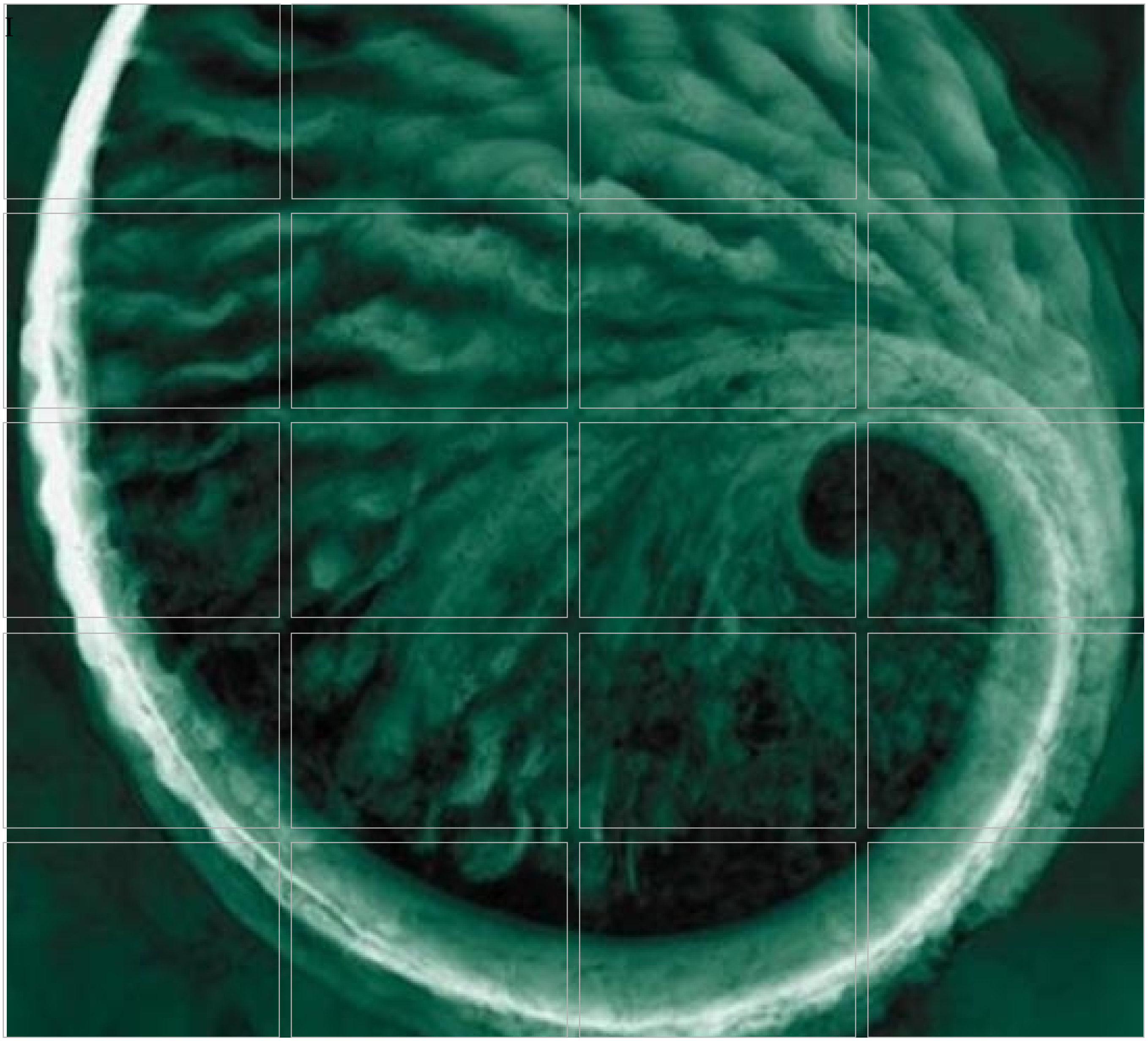
Sincerely,

Richard Gangle
Director Environmental Services

RG/tra

Attachments:

CC: Ms. Cheryl Mayo, Virginia Department of Environmental Quality



Prepared For:

Atlantic Coast Pipeline, LLC.

Atlantic Coast Pipeline Project
Permit Application
Buckingham Compressor Station
Buckingham County, VA

May 2018

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1.0 INTRODUCTION

1.1 BACKGROUND

Atlantic Coast Pipeline, LLC (ACP, LLC) proposes to construct and operate the Atlantic Coast Pipeline (ACP), an approximately 600-mile-long interstate natural gas transmission pipeline system designed to meet growing energy needs in Virginia and North Carolina. The proposed project has the capacity to deliver 1.5 billion standard cubic feet of natural gas per day (bscf/d) from Pennsylvania and West Virginia to power generation facilities and other end-users.

In support of the ACP, Dominion Energy Transmission Inc. (DETI), a subsidiary of Dominion Energy, Inc., will contract with ACP, LLC to construct and operate the Buckingham Compressor Station (ACP-2) in Buckingham County, Virginia to provide compression to support the transmission of natural gas. An adjacent metering and regulating (M&R) station (Woods Corner) will also be operated by DETI and will therefore be considered part of the Buckingham Compressor Station.

ACP, LLC is submitting this update to the proposed Buckingham Compressor Station air permit application, dated September 16, 2015. The air permit application was previously updated in May 2016 to replace a Solar Taurus 60 turbine to with a Solar Titan 130 turbine. The air permit application was updated again in August 2017 to reflect the following ancillary equipment changes:

- Remove ten (10) Capstone C200 microturbines (MT-01 through MT-10), rated at 200 kW each;
- Add one (1) Caterpillar G3516C emergency generator (EG-01), rated at 1,500 kW (engine rated at 2,175 hp);
- Provide updated information for one (1) Hurst S45 boiler (WH-01), rated at 6.4 MMBtu/hr;
- Provide updated information for four (4) ETI line heaters (LH-01 through LH-04), rated at 21.22 MMBtu/hr each (two (2) separate burners per line heater, rated at 10.61 MMBtu/hr each); and
- Increase the capacity of the ammonia tank (TK-3) from 8,000 gallons to 13,000 gallons.

The purpose of this update is to more accurately reflect the station design and the true potential to emit for the station. The prior versions of the application contained conservative estimates made very early in the design process that can now be revised based on the availability of additional design details and confirmation of planned station operating practices, particularly with respect to events that could result in depressurizing of equipment at the station. Additionally, this update is consistent with recent responses to questions from

Virginia Department of Environmental Quality (DEQ) (see November 2017, January 2018, and March 2018 responses from Dominion).

Specific updates to this application include:

- Reflect updated emissions data for the four (4) Solar combustion turbines (CT-01 through CT-04) and their respective controls and incorporate the following design updates that impact the site Potential to Emit (PTE):
    - Apply oxidation catalyst efficiency to shutdown events;
    - Apply Pilot Active Control Logic to low temperature operations;
    - Decrease the expected low temperature operations from 50 hours per year to 5 hours per year[i]; and
    - Provide updated control efficiencies for the Selective Catalytic Reduction (SCR) (58% NO_x) and Oxidation Catalyst (92% CO, 50% VOC) control devices used to control emissions from the combustion turbines.
- Provide a revised basis for emissions from turbine and station blowdowns (FUG-02), including:
    - Decrease in the number of start-up and shutdown events (per turbine) requiring blowdown from 100 per year to 10 per year;
    - Reflect a revised estimate of the volume of gas emitted during start-up and shutdown blowdown events consistent with the station design;
    - Reflect the use of annual capped[ii] blowdown tests of the emergency shutdown (ESD) system (versus a full depressurization event once every five years); and
    - Incorporate emissions from pigging operations[iii].
- Increase the operating schedule of the emergency generator (EG-01) from 100 hours per year to 500 hours per year;
- Correct TK-1 and TK-2 descriptions consistent with the final design. The Accumulator Tank (TK-1) has a 2,500 gallon capacity and the Pipeline Fluids (Hydrocarbon Waste) Tank (TK-2) has a 1,000 gallon capacity;

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[i] Five (5) hours per year used to estimate overall potential emissions form the station based on review of historical weather data. However, since there is no ability for DETI to control this variable, no permit limit on hours of operation below 0 °F is being sought.

[ii] Capped Emergency Shutdown Testing – The station will do annual safety test using Yale (or other) enclosures to prevent gas loss. The enclosures function similar to a cap at the end of the pipe and prevent gas loss.

[iii] Pigging operations occur rarely, but are a periodic required maintenance activity for the reliable and safe operations of pipelines. An expected maximum number of four pigging events with blowdown emissions were assumed for estimating potential emissions from the station. The emissions associated with pigging events will be very small (<< 1 ton/year). DETI will track pigging events that result in blowdown emissions and will incorporate these emissions into annual emission determination for the station. DETI is not seeking permit limit on the number of de minimis venting events associated with pigging operations.

- Update Ammonia Tank (TK-3) capacity from 13,000 to 13,400 (no emissions impact); and
- Provide an updated Best Available Control Technology (BACT) analysis consistent with impacts of the above changes on emissions.

For convenience and ease of reference, the entire application text is provided again to reflect the above updates. The changes in annual emissions as a result of the updates to the permit application are summarized in Table 1.1 below. The updates result in a decrease in NO_X, CO, VOC, PM, and CO_2e emissions and an increase in SO_2 emissions when compared to the previous update. The increase in SO_2 does not reflect a design or capacity change, but rather ensuring consistency of the emission rate associated with the low level of sulfur content in combusted natural gas.

TABLE 1.1 SUMMARY OF TOTAL POTENTIAL EMISSIONS

Project Emissions	Annual Emissions (tpy)					
	NO_X	CO	VOC	PM	SO_2	CO_2e
Application Update (2017)	46.1	86.4	32.1	43.3	7.26	317,637
Proposed Update (2018)	34.3	51.6	7.69	43.2	8.30	295,686

1.2 APPLICATION OVERVIEW

ACP, LLC submits this Article 6 permit application to the Virginia Department of Environmental Quality, Piedmont Regional Office for the authority to construct the Buckingham Compressor Station in Buckingham County, Virginia. This permit application narrative is provided to add clarification and/or further detail to the information in the permit application forms provided by the DEQ.

Concurrent with the submittal of this air quality permit application, other required environmental permits and approvals are being pursued with the appropriate regulatory agencies.

This section (Section 1) contains introductory information. Section 2 presents a description of the Buckingham Compressor Station and its associated equipment. The estimated emissions of regulated pollutants from the equipment and operating scenarios are presented in Section 3. Section 4 addresses federal regulatory requirements applicable to project sources and Section 5 provides a review of State regulatory requirements. Section 6 is the State Best Available Control Technology (BACT) analysis for the combustion turbines. Section 7 provides ACP, LLC’s proposed compliance demonstration methods.

This application contains the following appendices:

- Appendix A – Virginia DEQ Form 7 Application Forms;
- Appendix B – Facility Plot Plan;
- Appendix C – Potential to Emit Calculations;
- Appendix D – Vendor Specifications;
- Appendix E – RBLC Database Search Results;
- Appendix F – Comparison of Flaring Emissions and VGR Emissions;
- Appendix G – SCR Cost Effectiveness Evaluation; and
- Appendix H – VGR System Design and Operation Details.

2.0 FACILITY AND PROJECT DESCRIPTION

2.1 BUCKINGHAM COMPRESSOR STATION

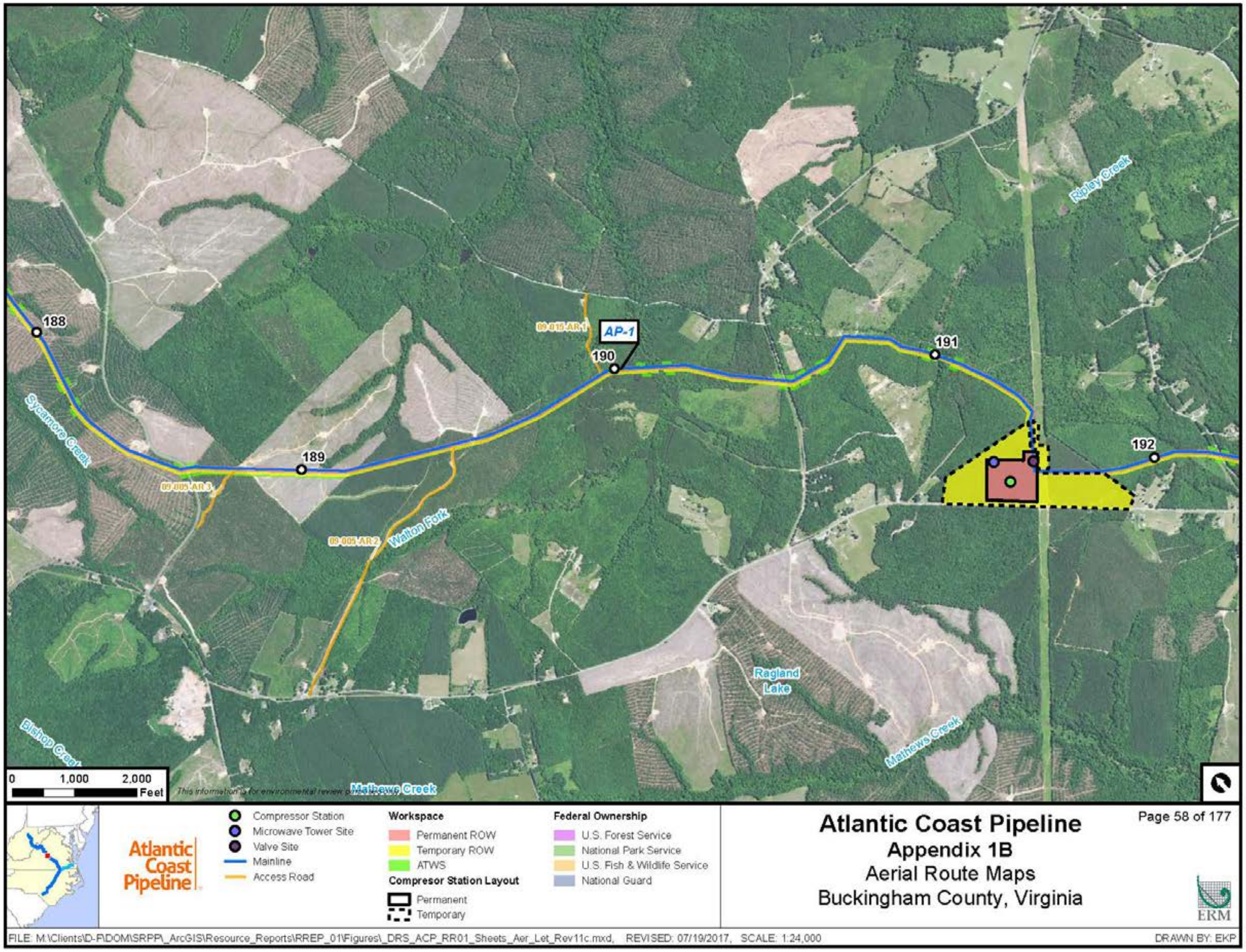
The Buckingham Compressor Station will operate in Buckingham County, Virginia to provide compression to support the transport of natural gas. The proposed project will require the construction of a new facility subject to the requirements of 9 VAC 5-80 Part II Article 6 – "Permits for New and Modified Stationary Sources" and 9 VAC 5-85 – *"Permits for Stationary Sources of Pollutants Subject to Regulation"*. In addition to the Buckingham Compressor Station, the facility will also include a nearby metering and regulating (M&R) station (Woods Corner) in Buckingham County, also operated by DETI.

ACP, LLC seeks authorization for the construction and operation of:

- One (1) Solar Mars 100 Combustion Turbine (CT-01);
- One (1) Solar Taurus 70 Combustion Turbine (CT-02);
- One (1) Solar Titan 130 Combustion Turbine (CT-03);
- One (1) Solar Centaur 50L Combustion Turbine (CT-04);
- One (1) Hurst S45 Boiler (WH-01) rated at 6.384 Million British Thermal Units per hour (MMBtu/hr);
- Four (4) ETI WB Line Heaters (LH-01, LH-02, LH-03, and LH-04) each rated at 21.22 Million British Thermal Units per hour (MMBtu/hr) [two (2) burners per line heater each rated at 10.61 MMBtu/hr] (located at Woods Corner);
- One (1) Caterpillar G3516C Emergency Generator (EG-01) rated at 1,500 kW [2,175 hp];
- One (1) Accumulator Tank (TK-1) with a capacity of 2,500 gallons;
- One (1) Pipeline Fluids (Hydrocarbon Waste) Tank (TK-2) with a capacity of 1,000 gallons;
- One (1) Aqueous Ammonia Storage Tank (TK-3) with a capacity of 13,400 gallons; and
- Various operational natural gas releases associated with station components (FUG-01) and piping fugitive emissions (FUG-02) related to the equipment proposed at the Buckingham Compressor Station.

A map displaying the location of the Buckingham Compressor Station is provided in Figure 2.1 of this application.

FIGURE 2.1 BUCKINGHAM COMPRESSOR STATION LOCATION MAP



2.2 *AGGREGATION DETERMINATION*

The Buckingham Compressor Station will be operated by DETI. Stationary sources of air pollutants may require aggregation of total emission levels if these sources share the same industrial grouping, are operating under common control, and are classified as contiguous or adjacent properties. DETI will operate the Buckingham Compressor Station with the same industrial grouping as the adjacent Woods Corner M&R station. This application includes emission sources associated with both the compressor station and the M&R station. Other than the interstate pipeline, which is specifically exempt from the requirement to aggregate as stated in the preamble to the 1980 PSD regulations, there are no other facilities that would be considered adjacent to the Buckingham Compressor Station and thus no other sources must be aggregated with the Buckingham Compressor Station.

3.0 PROJECT EMISSIONS INFORMATION

As discussed in Section 2.1 of this application, ACP, LLC seeks the authority to construct and operate new emission sources. This section provides a description of the basis for the estimation of emissions from these sources.

3.1 COMBUSTION TURBINES

The proposed natural gas-fired turbines to be installed at the Buckingham Compressor Station will be equipped with Solar's SoLoNOx dry low NO_x combustor technology as well as add-on emission controls including selective catalytic reduction (SCR) for NO_x and oxidation catalyst for CO and VOC.

Emissions for the Solar Turbines assume that the units will operate up to 8,760 hours per year and up to 100% rated output. Pre-control (SCR and oxidation catalyst) emissions of nitrogen oxides (NO_x), carbon monoxide (CO) and volatile organic compounds (VOC) are based on emission rates provided by Solar. VOC emissions are estimated as 10% of uncombusted hydrocarbon (UHC). Solar also provided emission estimates for carbon dioxide (CO_2), formaldehyde and total hazardous air pollutants.

The pre-control 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):

- 9 ppmvd NO_x;
- 25 ppmvd CO;
- 25 ppmvd unburned hydrocarbons (UHC); and
- 2.5 ppmvd VOC.

The proposed SCR will further reduce the normal operation NO_x emission rate for each of the proposed turbines by approximately 58% to 3.75 ppmvd at 15% O_2.

Per vendor estimates, the oxidation catalyst will provide 92% control for CO, to achieve 2 ppmvd CO @ 15% O_2 during normal operation. The catalyst will also control organic compound emissions and will provide an estimated 50% control for VOC (1.25 ppmvd @ 15% O_2) and formaldehyde emissions.

Vendor estimates for SCR and oxidation catalyst performance are provided in Appendix D.

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 NO_x, CO and VOC to increase (emission rates of other pollutants are unchanged). Low-load operation (non-normal SoLoNOx operation) of the turbines is expected to occur only during periods of start-up and shutdown. Solar has provided emissions estimates during start-up and shutdown (see Solar Product Information Letter (PIL) 170[iv], included as part of the vendor attachments to this application for more detail).

Similarly, Solar has provided emissions estimates for low temperature operation (inlet combustion air temperature less than 0° F and greater than -20° F). The turbines will be equipped with Pilot Active Control Logic to reduce the emission increases of NO_x, CO, and VOC that could otherwise occur during low temperature operations. Table 3.1 provides estimated pre-control emissions from the turbines at low temperature conditions.

TABLE 3.1 PRE-CONTROL TURBINE LOW TEMPERATURE EMISSION RATES (< 0^0 F AND > -20^0 F)[1]

Applicable Load	NOx, ppm	CO, ppm	UHC, ppm
50-100% load	42	100	50

1. Emissions Estimates from Table 1 of Solar Product Information Letter 167[v].

ACP, LLC reviewed historic meteorological data from the previous five years for the region to estimate a worst case number of hours per year under sub-zero (less than 0° F but greater than -20° F) conditions. The annual hours of operation during sub-zero conditions were conservatively assumed to be not more than five (5) hours per year.

A summary of the controlled potential emissions of NO_X, CO, and VOC during normal operations and low temperature scenarios is provided in Table 3.2.

[iv] PIL 170 Revision 5, dated 13 June 2012.

[v] PIL 167 Revision 4, dated 6 June 2012.

TABLE 3.2 TURBINE CONTROLLED SHORT-TERM EMISSION RATES

Pollutant	Operating Scenario	CT-01 Solar Mars 100 Turbine lb/hr	CT-02 Solar Taurus 70 Turbine lb/hr	CT-03 Solar Titan 130 Turbine lb/hr	CT-04 Solar Centaur 50L Turbine lb/hr
NO_x	Normal	1.95	1.29	2.36	0.828
	Low Temp.	9.09	6.01	11.0	3.86
CO	Normal	0.633	0.418	0.766	0.268
	Low Temp.	2.53	1.67	3.07	1.07
VOC	Normal	0.227	0.150	0.275	0.096
	Low Temp.	0.453	0.299	0.549	0.192

The emission rates presented in Table 3.2 are estimates based on the emissions factors provided by Solar multiplied by the control efficiency expected from the installation of the SCR (approximately 58% NO_x control) and oxidation catalyst (approximately 50% VOC control and 92% CO control).

Potential turbine emissions also include emissions from start-up and shutdown events calculated using emission estimations provided by Solar. ACP, LLC expects that control will be achieved by the oxidation catalysts during the shutdown events. Ton per year potential emission estimates are based on an assumed count of 100 start-up and 100 shutdown events per year for the turbines (Note: Not every start and shutdown of the turbine will result in a blowdown event as the units are generally maintained in pressurized holds – See Sections 3.4 and 6.0 for discussions of blowdowns). The duration of each start-up and shutdown is expected to be approximately 10 minutes per event. Thus, it is assumed that there will be approximately 33.3 hours of start-up and shutdown event time when the unit may not be operating in SoLoNOx mode. Table 3 of Solar PIL 170[vi] was used as the basis for NO_x, CO, VOC, CO_2, and CH_4 emissions during these events. Emission estimations provided by Solar were used as the basis for SO_2, PM, N_2O, and HAP emissions during these events. A 10 ppm ammonia slip was used as the basis for NH_3 emissions during these events.

A summary of the potential emissions during start-up and shutdown events is presented in Tables 3.3 and 3.4.

[vi] PIL 170 Revision 5, dated 13 June 2012.

TABLE 3.3 TURBINE POTENTIAL EMISSIONS DURING START-UP EVENTS

Pollutant	CT-01 Solar Mars 100 Turbine		CT-02 Solar Taurus 70 Turbine		CT-03 Solar Titan 130 Turbine		CT-04 Solar Centaur 50L Turbine	
	lb/event	tpy	lb/event	tpy	lb/event	tpy	lb/event	tpy
NO_x	1.4	0.070	0.8	0.040	1.9	0.095	0.8	0.040
CO	123.5	6.18	73.1	3.66	176.9	8.85	69.1	3.46
VOC	0.710	0.036	0.420	0.021	1.01	0.051	0.400	0.020
SO_2	0.01	5.00E-04	0.01	5.00E-04	0.02	0.001	0.01	5.00E-04
PM_{-Filt}	0.017	8.64E-04	0.017	8.64E-04	0.032	0.002	0.009	4.32E-04
$PM_{10-Filt}$	0.017	8.64E-04	0.017	8.64E-04	0.032	0.002	0.009	4.32E-04
$PM_{2.5-Filt}$	0.017	8.64E-04	0.017	8.64E-04	0.032	0.002	0.009	4.32E-04
PM_{Cond}	0.043	0.002	0.043	0.002	0.078	0.004	0.021	0.001
CO_2	829	41.5	519	26.0	1,161	58.1	469	23.5
CH_4	6.39	0.320	3.78	0.189	9.09	0.455	3.60	0.180
N_2O	0.07	0.004	0.13	0.007	0.08	0.004	0.03	0.002
CO_2e	1,010	50.5	652	32.6	1,412	70.6	568	28.4
NH_3	0.309	0.015	0.220	0.011	0.388	0.019	0.136	0.007
Total HAP	2.6	0.130	4.9	0.245	3.0	0.150	1.2	0.060
Formaldehyde	2.4	0.120	4.6	0.230	2.9	0.145	1.1	0.055

TABLE 3.4 TURBINE POTENTIAL EMISSIONS DURING SHUTDOWN EVENTS

Pollutant	CT-01 Solar Mars 100 Turbine		CT-02 Solar Taurus 70 Turbine		CT-03 Solar Titan 130 Turbine		CT-04 Solar Centaur 50L Turbine	
	lb/event	tpy	lb/event	tpy	lb/event	tpy	lb/event	tpy
NO_x	1.7	0.085	1.1	0.055	2.4	0.120	0.4	0.020
CO	11.9	0.597	7.47	0.374	16.6	0.830	2.83	0.142
VOC	0.425	0.021	0.265	0.013	0.595	0.030	0.100	0.005
SO_2	0.02	0.001	0.01	5.00E-04	0.03	0.002	0.01	5.00E-04
PM_{-Filt}	0.029	0.001	0.020	0.001	0.043	0.002	0.014	7.20E-04
$PM_{10-Filt}$	0.029	0.001	0.020	0.001	0.043	0.002	0.014	7.20E-04
$PM_{2.5-Filt}$	0.029	0.001	0.020	0.001	0.043	0.002	0.014	7.20E-04
PM_{Cond}	0.071	0.004	0.050	0.002	0.107	0.005	0.036	0.002
CO_2	920	46.0	575	28.8	1,272	63.6	217	10.9
CH_4	7.65	0.383	4.77	0.239	10.7	0.536	1.80	0.090
N_2O	0.13	0.007	0.09	0.005	0.14	0.007	0.06	0.003
CO_2e	1,150	57.5	721	36.1	1,581	79.1	280	14.0
NH_3	0.309	0.015	0.220	0.011	0.388	0.019	0.136	0.007
Total HAP	2.30	0.115	1.70	0.085	2.55	0.128	1.00	0.050
Formaldehyde	2.15	0.108	1.60	0.080	2.40	0.120	0.950	0.045

Table 3.5 includes the facility's potential emissions for the combustion turbines, including: Normal continuous operation controlled by SoLoNOx mode, SCR, and oxidation catalyst; low temperature operation controlled by Pilot Active Control Logic, SCR, and oxidation catalyst; uncontrolled emissions associated with start-up events; and shutdown events controlled by oxidation catalyst.

TABLE 3.5 TURBINE POTENTIAL EMISSIONS

Pollutant	CT-01 Solar Mars 100 Turbine tpy	CT-02 Solar Taurus 70 Turbine tpy	CT-03 Solar Titan 130 Turbine tpy	CT-04 Solar Centaur 50L Turbine tpy
NO_x	8.67	5.72	10.5	3.68
CO	9.54	5.85	13.0	4.77
VOC	1.05	0.687	1.28	0.444
SO_2	2.12	1.40	2.57	0.898
PM_{-Filt}	3.58	2.37	4.35	1.52
$PM_{10-Filt}$	3.58	2.37	4.35	1.52
$PM_{2.5-Filt}$	3.58	2.37	4.35	1.52
PM_{-Cond}	8.87	5.86	10.8	3.76
CO_2	74,103	48,911	89,784	31,455
CH_4	6.05	3.96	7.48	2.54
N_2O	1.88	1.24	2.27	0.796
CO_2e	74,813	49,381	90,649	31,755
NH_3	8.12	5.77	10.2	3.58
Total HAP	1.11	0.900	1.32	0.476
Formaldehyde	1.04	0.848	1.25	0.448

3.2 BOILER AND HEATERS

The proposed natural gas boiler will be used to provide building heat (space heating) only, and will have a maximum heat input capacity of 6.384 MMBtu/hr. The boiler will use Low NO_x Burners (LNB). Emissions for the proposed natural gas-fired Boiler are calculated using EPA's AP-42 emission factors for Natural Gas Combustion (Section 1.4) conservatively assuming 8,760 hours per year. SO_2 emissions are calculated using a sulfur content equivalent to 11,108 grains per million cubic feet - the default value from AP-42 for stationary gas turbines. This value is used, as it is more conservative than the default value from AP-42 for natural gas-fired boilers (2,000 grains per million cubic feet).

Emissions for the four (4) proposed 21.22 MMBtu/hr ETI Line Heaters at the Woods Corner M&R station conservatively assume 8,760 hours of operation per year and are calculated using vendor provided emissions factors for NO_x, CO, and PM. All other pollutants were calculated using EPA's AP-42 emission factors for Natural Gas Combustion (Section 1.4). SO_2 emissions are also calculated using a sulfur content equivalent to 11,108 grains per million cubic feet.

Under 9 VAC 5-80-1105, external combustion units using gaseous fuel with a maximum heat input of less than 50 MMBtu/hr are exempt from permitting requirements. For completeness of the project, the potential emissions from the boiler and line heaters are provided in Table 3.6. The line heater emissions are presented on a per unit basis.

TABLE 3.6 BOILER AND HEATER POTENTIAL

Pollutant	WH-01 Boiler tpy	LH-01 thru LH-04 Line Heater tpy
NO_x	1.37	0.929
CO	2.30	3.44
VOC	0.151	0.501
SO_2	0.091	0.304
PM_{-Filt}	0.052	0.112
$PM_{10-Filt}$	0.052	0.112
$PM_{2.5-Filt}$	0.052	0.112
PM_{-Cond}	0.156	0.335
CO_2	3,290	10,935
CH_4	0.063	0.210
N_2O	0.060	0.200
CO_2e	3,309	11,000
Total HAP	0.052	0.172
Formaldehyde	0.002	0.007
Hexane	0.049	0.164

3.3 EMERGENCY GENERATOR

Emission estimates for the Caterpillar Emergency Generator assume 500 hours per year at 100% rated output. The emergency generator will provide emergency electrical power to operate the compressor station and M&R station. The emergency generator, which will fire natural gas, has a rated electrical output of 1,500 kW and a rated engine output of 2,175 hp. Emissions of NO_x, CO, VOC, CO_2, CH_4, and formaldehyde are based on emission rates from manufacturer's data. These vendor specifications are included in Appendix D. All other pollutant emissions are based on Section 3.2 of EPA's AP-42 emission factors for natural gas-fired reciprocating engines. SO_2 emissions are calculated using a sulfur content of 11,108 grains per million cubic feet. The potential emissions for the new Caterpillar Emergency Generator are provided in Table 3.7.

TABLE 3.7 EMERGENCY GENERATOR POTENTIAL EMISSIONS

Pollutant	EG-01 Caterpillar G3516C Emergency Generator tpy
NO_x	0.599
CO	2.40
VOC	0.599
SO_2	0.012
PM_{-Filt}	0.144
$PM_{10-Filt}$	0.144
$PM_{2.5-Filt}$	0.144
PM_{-Cond}	0.037
CO_2	531
CH_4	4.80
N_2O	0
CO_2e	651
Total HAP	0.657
Formaldehyde	0.623
Hexane	0.001

3.4 FUGITIVE EMISSIONS

The proposed project will include fugitive components including valves, flanges, pumps, etc. Emission factors for fugitive components were based on EPA's report on equipment leaks for oil and gas production facilities[vii]. This facility will comply with New Source Performance Standard Subpart OOOOa (subject to subsequent modification) which incorporates fugitive emissions monitoring program. In accordance with EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry, dated October 2016, implementing a fugitive emissions monitoring and repair program equivalent to that required by OOOOa, ACP, LLC can expect to achieve at least an 80% reduction of fugitive emissions. However, no credit for any reduced emissions has been taken in the numbers below.

[vii] USEPA, 1995. "Emission factors from Protocol for Equipment Leak Emission Estimates," EPA-453/R-95-017 Table 2.4, Oil and Gas Production Operations Average Emission Factors.

Additionally, ACP, LLC has estimated emissions from blowdown events at the station. ACP, LLC will minimize these events whenever possible, but blowdown of the machines and piping will sometimes occur for safety reasons and to ensure protection of equipment. The potential to emit from blowdowns is based on ten (10) start-up/shutdown events per turbine requiring blowdown, once annual capped blowdown event for testing of the station's emergency shut down (ESD) system, and pigging operations.

The total fugitive emissions are summarized in Table 3.8.

TABLE 3.8 POTENTIAL EMISSIONS ASSOCIATED WITH FUGITIVE COMPONENTS

Pollutant	FUG-01 Fugitive Leaks – Blowdowns (SU/SD and pigging) Tpy	FUG-02 Fugitive Leaks - Piping tpy
VOC	0.421	0.910
CO_2	0.433	0.936
CH_4	14.3	30.9
CO_2e	357	772
Total HAP (Hexane)	0.026	0.056

3.5 STORAGE TANKS

The Buckingham Compressor Station will operate three (3) aboveground storage tanks (ASTs).

TK-1 (Accumulator Storage Tank) will have a capacity of 2,500 gallons and will receive liquids from the compressor building and auxiliary building floor drains. The emissions associated with the operation of this accumulator storage tank were calculated using EPA's TANKS program. The emissions associated with unloading of the accumulator storage tank are estimated using Section 5.2 of EPA's AP-42 emission factors for Transportation and Marketing of Petroleum Liquids. ACP, LLC has estimated that this storage tank will complete five (5) turnovers per year.

TK-2 (Pipeline Fluids (Hydrocarbon Waste Tank)) will have a capacity of 1,000 gallons and will receive and store pipeline liquids captured by the station's separators and filter-separators. The emissions associated with the operation of this hydrocarbon waste tank are estimated using E&P Tanks to ensure capture of any flash emissions (which the EPA TANKS program cannot estimate). The emissions associated with unloading of the hydrocarbon waste tank are estimated using Section 5.2 of EPA's AP-42 emission factors for Transportation and Marketing of Petroleum Liquids. ACP, LLC has estimated that this storage tank will complete five (5) turnovers per year.

The potential VOC emissions associated with the proposed new storage tanks, TK-1 and TK-2, are 0.146 tpy with a maximum hourly VOC emission rate of 0.754 lb/hr (during unloading operations). The potential emissions from the proposed storage tanks also include trace amounts of greenhouse gas emissions (0.439 tpy CO_2e) and HAP emissions (0.010 tpy). Detailed emission calculations are provided in Appendix C of this document.

TK-3 (Aqueous Ammonia Storage Tank) will have a capacity of 13,400 gallons and will be used to supply aqueous ammonia to SCRs. There are no potential emissions expected from the ammonia storage tank, as the vessel is a pressurized, closed-system.

3.6 PROJECT EMISSIONS

The potential emissions associated with the proposed new equipment at the Buckingham Compressor Station are summarized in Table 3.9 in tons per year. Detailed emission calculations are provided in Appendix C of this document.

TABLE 3.9 FACILITY-WIDE POTENTIAL EMISSIONS (TPY)

Unit ID	Criteria Pollutants NO_x	CO	VOC	SO_2	PM_{Filt}	$PM_{10\text{-}Filt}$	$PM_{2.5\text{-}Filt}$	PM_{Cond}	Greenhouse Gases CO_2	CH_4	N_2O	CO_2e	NH_3	Total HAPs
CT-01	8.67	9.54	1.05	2.12	3.58	3.58	3.58	8.87	74,103	6.05	1.88	74,813	8.12	1.11
CT-02	5.72	5.85	0.687	1.40	2.37	2.37	2.37	5.86	48,911	3.96	1.24	49,381	5.77	0.900
CT-03	10.5	13.0	1.28	2.57	4.35	4.35	4.35	10.8	89,784	7.48	2.27	90,649	10.2	1.32
CT-04	3.68	4.77	0.444	0.898	1.52	1.52	1.52	3.76	31,455	2.54	0.796	31,755	3.58	0.476
WH-01	1.37	2.30	0.151	0.091	0.052	0.052	0.052	0.156	3,290	0.063	0.060	3,309	0	0.052
LH-01	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
LH-02	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
LH-03	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
LH-04	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
EG-01	0.599	2.40	0.599	0.012	0.144	0.144	0.144	0.037	531	4.80	0	651	0	0.657
FUG-01	-	-	0.421	-	-	-	-	-	0.433	14.3	-	357	-	0.026
FUG-02	-	-	0.910	-	-	-	-	-	0.936	30.9	-	772	-	0.056
TK-1	-	-	2.52E-05	-	-	-	-	-	-	-	-	-	-	2.52E-05
TK-2	-	-	0.146	-	-	-	-	-	0.009	0.017	-	0.439	-	0.010
Total	34.3	51.6	7.69	8.30	12.5	12.5	12.5	30.8	291,812	70.9	7.05	295,686	27.7	5.30

4.0 FEDERAL REGULATORY REQUIREMENTS

Note: There have been no significant updates to Section 4 since the August 2017 submittal. The only updates include revising the NOx emission rate listed in Section 4.1.3 (from 5 ppmvd to 3.75 ppmvd), correcting a typo in Section 4.2.5 (compliance with NSPS Subpart JJJJ, not Subpart IIII, demonstrates compliance with NESHAP Subpart ZZZZ), and updating the status of NSPS Subpart OOOOa.

4.1 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

NSPS have been established by the EPA to limit air pollutant emissions from certain categories of new and modified stationary sources. The NSPS regulations are contained in 40 CFR Part 60 and cover many different source categories, and applicable categories are described below.

4.1.1 40 CFR 60 Subpart Dc – Standards of Performance for 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 equipment subject to this regulation includes the four line heaters proposed to be installed. To demonstrate compliance with this rule, these sites will maintain and report fuel records certifying the fuel complies with the NSPS Dc standards for SO_2.

4.1.2 40 CFR 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels

This regulation applies to volatile organic liquid storage vessels with storage capacities greater than or equal to 75 cubic meters (19,812 gallons) for which construction, reconstruction, or modification commenced after July 23, 1984. There are no petroleum storage vessels with capacities greater than 19,812 gallons planned at the Buckingham Compressor Station, and this regulation is therefore not applicable to the facility.

4.1.3 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

NSPS 40 CFR Part 60 Subpart KKKK regulates stationary combustion turbines with a heat input rating of 10 MMBtu/hr or greater that commence construction, modification, or reconstruction after February 18, 2005. Subpart KKKK limits emissions of NO_x as well as the sulfur content of fuel that is combusted from subject units.

The proposed Solar combustion turbines will be subject to the requirements of this subpart. Subpart KKKK specifies several subcategories of turbines, each with different NO_x emissions limitations. The proposed turbines fall within the "medium sized" (> 50MMBtu/hr, < 850 MMBtu/hr) category for natural gas turbines. "Medium sized" turbines must meet a NO_x limitation of 25 parts per million by volume (ppmv) at 15 percent oxygen (O_2), and "small sized, mechanical drive" turbines must meet a NO_x limitation of 100 ppmv at 15 percent O_2 under the requirements of Subpart KKKK and units must minimize emissions consistent with good air pollution control practices during start-up, shutdown and malfunction.

Solar provides an emissions guarantee of 9 parts per million volume dry (ppmvd) NO_x at 15 percent O_2 for the proposed SoLoNO$_x$ equipped units. These guarantees apply at all times except during periods of start-up and shutdown and periods with ambient temperatures below 0°F. In addition, SCR will be installed to lower emissions for all turbines to further reduce NO_x emissions to 3.75 ppmvd at 15 % O_2, except during periods of start-up and shutdown and periods with ambient temperatures below 0°F.

ACP, LLC plans to conduct stack tests for NO_x emissions to demonstrate compliance with the Subpart KKKK emissions limits.

The NSPS Subpart KKKK emission standard for SO_2 is the same for all turbines, regardless of size and fuel type. All new turbines are required to meet an emission limit of 110 nanogram per joule (ng/J) (0.90 pounds [lbs]/megawatt-hr) or a sulfur limit for the fuel combusted of 0.06 lbs/MMBtu. The utilization of natural gas as fuel will ensure compliance with the SO_2 standard. Dominion will demonstrate compliance with the SO2 standard in accordance with the requirements specified in Subpart KKKK.

4.1.4 40 CFR 60 Subparts OOOO and OOOOa – Standards of Performance for 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. Subpart OOOO establishes emissions standards and compliance schedules for the control of VOCs and SO_2 emissions for affected facilities producing, transmitting, or distributing natural gas. Compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment are subject to this Subpart. Custody transfer is defined as the transfer of natural gas after processing and/or treatment in the producing operations. All compressor stations will be located after the point of custody transfer, and therefore centrifugal compressors driven by the proposed turbines are not currently subject to this regulation. Storage vessels located in the natural gas transmission and storage segment that have the potential for VOC emissions equal to or greater than 6 tpy are also subject to this Subpart. All storage vessels to be located at compressor stations will emit less than this threshold, and thus will not be subject to this regulation.

On June 3, 2016 EPA published amendments to 40 CFR 60, Subpart OOOO and proposed an entirely new Subpart OOOOa. The revisions proposed for Subpart OOOO apply to oil and natural gas production, transmission, and distribution affected facilities that were constructed, reconstructed, and modified between August 23, 2011 and September 18, 2015. Subpart OOOOa applies to oil and natural gas production, transmission, and distribution affected facilities that are constructed, reconstructed, and modified after September 18, 2015. NSPS Subpart OOOOa establishes standards for both VOC and methane.

Since this station is a new facility, this site is required to comply with the requirements of NSPS Subpart OOOOa.

The Subpart OOOOa provisions for storage vessels located in the natural gas transmission and storage segment that have the potential for VOC emissions equal to or greater than 6 tpy are subject to Subpart OOOOa. All storage vessels will emit less than this threshold, and thus will not be subject to this regulation.

Subpart OOOOa also includes provisions to reduce emissions from centrifugal compressors and the collection of fugitive emission components from transmission and storage facilities. For centrifugal compressors, Subpart OOOOa requires the use of dry seals or the control of emissions if wet seals are used. Dry seals are already planned for use in all proposed compressors; therefore, the compressors are not subject to Subpart OOOOa. For the collection of fugitive emission components, Subpart OOOOa requires implementation of fugitive emissions monitoring and repair program, which includes conducting periodic surveys using optical gas imaging (OGI) technology and subsequent repair of any identified leaks. The project will comply with all applicable leak detection provisions specified in Subpart OOOOa.

No other provisions of Subpart OOOOa are applicable. Specifically, no high continuous bleed natural gas pneumatic controllers (i.e. natural gas bleed rate greater than 6 standard cubic feet per hour [scfh]) are planned and no reciprocating compressors will be present and thus those provisions do not apply. Further, the station is considered a compressor station with no wells present on site. Therefore, the station is not subject to any of the Subpart OOOOa provisions regarding well affected facilities. Finally, the site is a considered a compressor station under the rule and is not considered a natural gas processing plant. The facility will not contain process units or sweetening units as defined in Subpart OOOOa.

4.1.5 40 CFR 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

NSPS Subpart JJJJ was promulgated on Jan 8, 2008 and is applicable to new stationary spark ignition internal combustion engines depending upon model year and size category. The new emergency generator is subject to the NO_x, CO and VOC emission limit requirements of this subpart and will comply with the emission standards, testing requirements, maintenance requirements, and monitoring, recordkeeping, and reporting requirements under this subpart.

4.2 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP)

NESHAP regulations established in 40 CFR Part 61 and Part 63 regulate emission of air toxics. NESHAP standards primarily apply to major sources of Hazardous Air Pollutants (HAPs), though some Subparts of Part 63 have been revised to include area (non-major) sources. The NESHAP regulations under 40 CFR Part 61 establish emission standards on the pollutant basis whereas 40 CFR Part 63 establishes the standards on a source category basis. The Buckingham Compressor Station will not emit any single HAP in excess of 10 tpy and will not emit combined HAPS in excess of 25 tpy, and will therefore be designated as an area source of HAPs.

4.2.1 40 CFR 63 Subpart HHH – National Emissions Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities

This regulation applies to certain affected facilities at major HAP sources. The Buckingham Compressor Station will be an area HAP source. Therefore, this regulation is not applicable.

4.2.2 40 CFR 63 Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers And Process Heaters

Industrial, commercial, or institutional boilers or process heaters located at a major source of HAPs are subject to this Subpart. The Buckingham Compressor Station will not be a major source of HAPs, and therefore will not be subject to this Subpart.

4.2.3 40 CFR 63 Subpart JJJJJJ – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

This Subpart applies to area sources of HAPs. The Buckingham Compressor Station will be an area source of HAPs; however, gas-fired boilers as defined by this Subpart are not subject to any requirements under this rule. Furthermore, natural gas-fired process heaters are not subject to the 40 CFR 63 Subpart JJJJJJ. As such, this subpart does not apply.

4.2.4 *40 CFR 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*

Stationary combustion turbines located at major sources of HAP emissions are subject to this Subpart. The Buckingham Compressor Station will be an area HAP source. Therefore, this regulation is not applicable.

4.2.5 *40 CFR 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

The emergency generator is subject to the NESHAP requirements under 40 CFR Part 63 Subpart ZZZZ (and applies to both major and area sources of HAPs). However, for new affected units located at an area source of HAPs the NESHAP refers to the NSPS Subparts JJJJ and IIII for all applicable requirements. Therefore, compliance with the NSPS Subpart JJJJ requirements ensures compliance with the NESHAP requirements.

4.3 *PREVENTION OF SIGNIFICANT DETERIORATION (PSD) AND NON-ATTAINMENT NEW SOURCE REVIEW*

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. The Virginia State Regulations address federal regulations where Virginia has been delegated authority of enforcement, including Prevention of Significant Deterioration permitting.

The Buckingham Compressor Station will be located in Buckingham County. The air quality of Buckingham County is designated by the U.S. EPA as either "better than normal standards" or "unclassified/attainment" for all criteria pollutants (40 CFR 81.347). As such, new construction or modifications that result in emission increases are potentially subject to the PSD permitting regulations.

PSD applicability depends on the existing status of a facility (i.e. major or minor source) and the net emissions increase associated with the project. The major source threshold for PSD applicability for a new facility is 250 tons per year (tpy) unless the source is included on a list of 28 specifically defined industrial source categories for which the PSD "major" source threshold is 100 tpy. Since the Buckingham Compressor Station is not one of the 28 listed sources, the PSD major source threshold is 250 tpy of any pollutant regulated by the Clean Air Act (CAA). Potential emissions of each criteria pollutant from the proposed facility will not exceed 250 tpy, as shown in Section 3. Therefore, the facility and project are not subject to PSD review.

4.4 *TITLE V OPERATING PERMIT*

See Section 5.0 for Title V applicability information.

4.5 *MAINTENANCE EMISSIONS AND FEDERAL ROUTINE MAINTENANCE, REPAIR AND REPLACEMENT PROVISIONS (RMRR)*

As part of normal operations of the Buckingham Compressor Station, ACP, LLC will routinely conduct activities associated with maintenance and repair of the facility equipment. These maintenance and repair activities will include, but will not be limited to, compressor engine start-up/shutdowns, calibrating equipment, changing orifice plates, deadweight testing, changing equipment filters (e.g., oil filters, separator filters), compressor engine and auxiliary equipment inspection and testing, and use of portable gas/diesel engines for air compressors and lube guns.

Furthermore, in order to ensure the reliability of natural gas deliveries to their customers, ACP, LLC may conduct equipment and component replacement activities that conform to the currently applicable federal laws and regulations.

4.6 *CHEMICAL ACCIDENT PREVENTION AND RISK MANAGEMENT PROGRAMS (RMP)*

The Buckingham Compressor Station will not be subject to the Chemical Accident Prevention Provisions (40 CFR 68.1), as no chemicals subject to regulation under this Subpart will be present onsite. The aqueous ammonia stored will have a concentration of less than 20%.

4.7 *ACID RAIN REGULATIONS*

The Buckingham Compressor Station will not sell electricity and is a non-utility facility. Therefore, the facility will not be subject to the federal acid rain regulations found at 40 CFR Parts 72 through 77.

4.8 *STRATOSPHERIC OZONE PROTECTION REGULATIONS*

Subpart F, Recycling and Emissions Reductions, of 40 CFR Part 82, Protection of Stratospheric Ozone, generally requires that all repairs, service, and disposal of appliances containing Class I or Class II ozone depleting substances be conducted by properly certified technicians. The facility will comply with this regulation as applicable.

4.9 GREENHOUSE GAS REPORTING

On November 8, 2010, the USEPA finalized GHG reporting requirements under 40 CFR Part 98. Subpart W of 40 CFR Part 98 requires petroleum and natural gas facilities with actual annual GHG emissions equal to or greater than 25,000 metric tons CO_2e to report GHG from various processes within the facility. Following this project, Buckingham is expected to be subject to GHG emissions reporting. If the emissions threshold is met or exceeded, ACP, LLC will comply with the applicable GHG reporting requirements.

5.0 *STATE REGULATORY APPLICABILITY*

Note: The only update to Section 5 since the August 2017 submittal is adding Hazardous Air Pollutant Sources (9 VAC 5-60) to Table 5.1.

This section outlines the State air quality regulations that could be reasonably expected to apply to the Buckingham Compressor Station and makes an applicability determination for each regulation based on activities planned at the Station and the emissions of regulated air pollutants associated with this project. This review is presented to supplement and/or add clarification to the information provided in the Virginia DEQ Article 6 permit application forms (Form 7).

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. The Virginia State Regulations address federal regulations where Virginia has been delegated authority of enforcement, including Prevention of Significant Deterioration permitting, Title V permitting, New Source Performance Standards (NSPS), and National Emission Standards for Hazardous Air Pollutants (NESHAP). These regulatory requirements in reference to the Buckingham Compressor Station are described in Table 5.1 below.

TABLE 5.1 STATE REGULATORY APPLICABILITY

Regulatory Citation	Applicable Requirement	Compliance Approach
General Provisions on Air Pollution Control (9 VAC 5-20)	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.
Ambient Air Quality Standards (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.	The project will comply with the National Ambient Air Quality Standards.
Federal Operating Permits (9 VAC-5-80-50)	A federal operating permit is 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 Buckingham Compressor Station is not subject to this rule.

Regulatory Citation	Applicable Requirement	Compliance Approach
BACT (9 VAC 5-50-260 B)	Virginia's regulations establish that a BACT review must be completed for certain sources that are not otherwise exempt and whose total emissions exceed Uncontrolled Emission Rate (UER) thresholds	Subject emissions have been reviewed and have been demonstrated to meet BACT levels. See Section 6 for a full discussion.
State Operating Permits (9 VAC 5-80-800)	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 Buckingham Compressor Station will not seek a synthetic minor and is not subject to this regulation.
Construction Permits (9 VAC 5-80-1100)	Article 6 permitting must be completed before construction of a new source.	The required Form 7 application forms and attachments are included with this text report to satisfy this requirement for the construction of sources at the Buckingham Compressor Station.
Permits for Stationary Sources of Pollutants (9 VAC 5-85)	This chapter contains definitions and general provisions which are essentially identical to those discussed in 9 VAC-5-20.	See 9 VAC 5-20.
Emergency Generator Requirements (9 VAC 5-540)	Affected units are required to install a non-resettable hour metering device to monitor the operating hours for each unit, calculated monthly as the sum of each consecutive 12-month period. The non-resettable hour metering shall be observed by the owner or operator within a frequency no less than once per month. The owner or operator shall keep a log of the following; monthly observations of meters, start-up dates, equipment malfunctions, corrective actions, and shutdown dates. Records must be kept onsite for 5 years.	The proposed emergency generator will include a non-resettable hour meter. Hours from this meter will be recorded each month and tracked on a rolling 12-month basis. The operating data will be maintained in an operating log (with hours of operation, 12-month rolling total hours of operation, and start-up and shutdown dates) Equipment malfunctions and corrective actions will be maintained as a separate record from the operating log. All records will be maintained for at least five years.

Regulatory Citation	Applicable Requirement	Compliance Approach
Hazardous Air Pollutant Sources (9 VAC 5-60)	Article 5 of 9 VAC 5-60 contains the Emission Standards for Toxic Pollutants from New and Modified Sources (Rule 6-5). Emissions of toxic pollutants discharged into the atmosphere from any affected facility may not cause, or contribute to, any significant ambient air concentration that may cause, or contribute to, the endangerment of human health. Facilities that have a potential to emit toxic pollutants in quantities that endanger human health shall employ best available control technologies for the control of toxic pollutants.	The project emissions of toxic pollutants have been compared to the exemption thresholds as defined in Rule 6-5. Formaldehyde is the only toxic pollutant for which project emissions are above the exemption thresholds. A separate modeling protocol has been submitted and approved. Modeling results will be submitted separately, demonstrating that project emissions of formaldehyde will not cause, or contribute to, any significant ambient air concentration that may cause, or contribute to, the endangerment of human health.

6.0 BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

Consistent with Virginia's June 12, 2015 memo (APG-354; Permitting and BACT Applicability under Chapter 80 Article 6), ACP, LLC has reviewed the proposed sources to determine applicability of BACT review.

Per 9 VAC 5-80-1005C, new stationary sources with uncontrolled emission rates less than all of the emission rates specified (see Table 6.1 below) shall be exempt from the provisions of Article 6. The uncontrolled emission rate of a new stationary source is the sum of the uncontrolled emission rates of the individual affected emission units. Facilities exempted by subsection B of 9 VAC 5-80-1005 shall not be included in the summation of uncontrolled emissions for purposes of exempting new stationary sources.

Step 1 – Emission Units

ACP, LLC seeks the authority to construct and operate several new emission sources, as discussed in Section 2.1 of this application.

Step 2 – Individually Exempt Equipment

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

- One (1) Hurst S45 Boiler (WH-01) rated at 6.384 Million British Thermal Units per hour (MMBtu/hr) – exempt as an external combustion source < 50 MMBtu/hr;
- Four (4) ETI WB Line Heaters (LH-01, LH-02, LH-03, and LH-04) each rated at 21.22 Million British Thermal Units per hour (MMBtu/hr) (located at Woods Corner) – exempt as an external combustion source < 50 MMBtu/hr; and
- Three (3) aboveground storage tanks (TK-1, TK-2, and TK-3) with capacities of 2,500 gallons, 1,000 gallons, and 13,400 gallons, respectively – exempt as a storage tanks < 40,000 gallons.

Step 3 – Annual UER Increase

The Uncontrolled Emission Rate (UER) for each new stationary source is summarized in Table 6.1 below. It is noted that the UER for VOCs from blowdowns is higher than previously represented. There are two reasons for this: (1) With the progression of detailed design activities, more accurate estimates of the volumes of gas in piping and equipment that would be vented during a blowdown are now available, and (2) no credit for the use of the planned vent gas reduction system to reduce system pressure prior to venting is considered in determining the UER (that is, UER now reflects blowdown from maximum station operating pressure (1400 PSIG) vs. 30 PSIG.

TABLE 6.1 STATE EXEMPTION RATES OF REGULATED POLLUTANTS FOR NEW STATIONARY SOURCES (9 VAC 5-80-1105C.1) VS. UER

Pollutant	Exemption Levels	UER	Solar Mars 100 Turbine (tpy)	Solar Taurus 70 Turbine (tpy)	Solar Titan 130 Turbine (tpy)	Solar Centaur 50L Turbine (tpy)	Caterpillar G3516C Emergency Generator (tpy)	Fugitive Leaks – Blowdowns (tpy)	Fugitive Leaks – Piping (tpy)
CO	100 tpy	163	48.2	31.1	61.1	19.9	2.40	-	-
NO_x	40 tpy	68.5	20.6	13.6	25.0	8.74	0.599	-	-
SO_x	40 tpy	6.99	2.12	1.40	2.57	0.898	0.012	-	-
PM_F	25 tpy	12.0	3.58	2.37	4.35	1.52	0.144	-	-
PM_{10}	15 tpy	41.2	12.5	8.23	15.1	5.28	0.181	-	-
$PM_{2.5}$	10 tpy	41.2	12.5	8.23	15.1	5.28	0.181	-	-
VOC	25 tpy	72.4	2.06	1.35	2.51	0.868	0.599	64.1	0.910
Pb	0.6 tpy	-	-	-	-	-	-	-	-
Fluorides	3 tpy	-	-	-	-	-	-	-	-
Sulfuric Acid Mist	6 tpy	-	-	-	-	-	-	-	-
Hydrogen Sulfide (H_2S)	9 tpy	-	-	-	-	-	-	-	-
Total Reduced Sulfur (including H_2S)	9 tpy	-	-	-	-	-	-	-	-

Step 4 –UER Increases vs. Exempt Emission Rates

The total UER for PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC exceed the threshold values in Table 6.1 and thus, are subject to BACT review. ACP, LLC submitted a BACT review for PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC with the September 2015 and August 2017 air permit application submittals.

BACT for Caterpillar Emergency Generator

In accordance with 9 VAC 5-80-1105B.2., "engines and turbines that are used for emergency purposes only and that do not individually exceed 500 hours of operation per year at a single stationary source" are exempt from BACT review. However, 9 VAC 5-80-1105B.2. also states that "all engines and turbines in a single application must also meet the following criteria to be exempt." Those additional criteria are as follows:

- "Gasoline engines with an aggregate rated brake (output) horsepower of less than 910 hp and gasoline engines powering electrical generators having an aggregate rated electrical power output of less than 611 kilowatts."
- "Diesel engines with an aggregate rated brake (output) horsepower of less than 1,675 hp and diesel engines powering electrical generators having an aggregate rated electrical power output of less than 1125 kilowatts."
- "Combustion gas turbines with an aggregate of less than 10,000,000 Btu per hour heat input (low heating value)."

The proposed Caterpillar emergency generator that will be installed at the Buckingham Compressor Station will not exceed 500 hours of operation per year. However, natural gas-fired generators are not one of the additional criteria categories listed under 9 VAC 5-80-1105B.2. The Caterpillar emergency generator is rated at 1,500 kW and the corresponding engine is rated at 2,175 hp. Although natural gas generators are not specifically exempt, natural gas is a cleaner burning fuel than diesel. A comparison of the 2,175 hp Caterpillar emergency generator PTE and the PTE of a diesel-fired emergency generator rated at 1,675 hp (a source that would be exempt from BACT review) is shown in Table 6.2.

TABLE 6.2 CATERPILLAR EMERGENCY GENERATOR PTE VS. DIESEL-FIRED EMERGENCY GENERATOR PTE

Pollutant	EG-01 Caterpillar G3516C Emergency Generator tpy	1,675 hp Diesel-Fired Emergency Generator* tpy
CO	2.40	2.80
NO_x	0.599	13.0
PM_{10}	0.181	0.921
$PM_{2.5}$	0.181	0.921
VOC	0.599	1.05

*Assumptions:
-PTE calculated using a maximum operating schedule of 500 hours/year, the same operating schedule used for EG-01.
-Emission factors from Table 3.3-1 of AP-42, Section 3.3, "Gasoline and Diesel Industrial Engines".

As shown in Table 6.2, the PTE of the Caterpillar emergency generator is less than the PTE of a theoretical diesel-fired emergency generator rated at 1,675 hp (which would be exempt from a BACT review) for all pollutants for which the total UER exceeds the threshold value.

Add-on control technologies may be technically feasible for the Caterpillar emergency generator. However, due to the low PTE (less than 2.5 tpy CO and less than 0.6 tpy NO_x, PM_{10}, $PM_{2.5}$, and VOC) for all pollutants which the total UER exceeds the threshold value, the cost of an add-on control technology would greatly outweigh any minimal emission reduction benefits. Further, emergency generators generally do not run continuously, adding operational and technical challenges to the operation of any potential controls. Therefore, a full BACT review is unwarranted for the Caterpillar emergency generator and no further analysis is required.

The requirements of BACT will be met for the Caterpillar emergency generator by employing good combustion practices.

Note: The only material updates to Sections 6.1 through 6.4 since the August 2017 submittal is updating the control efficiencies of the SCR (from 5 ppmvd to 3.75 ppmvd) and Oxidation Catalyst (from 80% control and 5 ppmvd to 92% control and 2 ppmvd).

6.1 BACT FOR PARTICULATE MATTER (PM_{10} AND $PM_{2.5}$)

Particulate matter emissions result from the proposed combustion turbines.

The following summarizes the BACT evaluation conducted for the Solar combustion turbines, the only significant equipment type for the Buckingham Compressor Station with respect to PM_{10} and $PM_{2.5}$ emissions.

The emissions of particulate matter emissions from gaseous fuel combustion have been estimated to be less than 1 micron in equivalent aerodynamic diameter, have filterable and condensable fractions, and usually consist of hydrocarbons of larger molecular weight that are not fully combusted[viii]. Because the particulate matter typically is less than 2.5 microns in diameter, this BACT discussion assumes the control technologies for PM_{10} and $PM_{2.5}$ are the same.

As part of the step 1 analysis, searches of the RACT/BACT/LAER Clearinghouse (RBLC) database for similar units were conducted. For any instances where the emission rate is lower than what is proposed by ACP, LLC, comments have been provided detailing why the listed rate was not considered to be BACT.

Step 1 – Identify Potential Control Technologies

Pre-Combustion Control Technologies

The major sources of PM_{10} and $PM_{2.5}$ 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.

The use of clean-burning, low-sulfur gaseous fuels will result in minimal formation of PM_{10} and $PM_{2.5}$ 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 emissions.

Post-Combustion Control Technologies

There are several post-combustion PM control systems potentially feasible to reduce PM_{10} and $PM_{2.5}$ 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

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[viii] *USEPA, 2006 http://www.epa.gov/ttnchie1/conference/ei15/training/pm_training.pdf*

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.

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.

Step 2 - Eliminate Technically Infeasible Options

Pre-Combustion Control Technologies

The pre-combustion control technologies identified above (i.e., clean-burning, low-sulfur fuels and good combustion practices) are available and technically feasible for reducing PM emissions from the combustion turbine exhaust streams.

Post-Combustion Control Technologies

Each of the post-combustion control technologies described above (i.e., cyclones, baghouses, ESPs, scrubbers) are generally available. However, none of these technologies is considered practical or technically feasible for installation on gaseous fuel-fired combustion turbines since $PM_{2.5}$, which, as stated above, generally makes up all of the PM emissions.

The particles emitted from gaseous fuel-fired are typically less than 1 micron in diameter. Cyclones are not effective on particles with diameters of 10 microns or less. Therefore, a cyclone/centrifugal collection device is not a technically feasible alternative.

Baghouses, ESPs, and scrubbers have never 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 is 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. Review of the RBLC, as well as USEPA and State permit databases, indicates that post-combustion controls have not been required as BACT for gaseous fuel-fired fired combined-cycle combustion turbines. Therefore, the use of baghouses, ESPs, and scrubbers is not considered technically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The use of clean-burning fuels and good combustion practices are technically feasible technologies to control PM_{10} and $PM_{2.5}$ emissions.

Step 4 - Evaluate Most Effective Controls and Document Results

Based on the information presented in this BACT analysis, using the proposed good combustion practices to control PM_{10} and $PM_{2.5}$ emissions is considered BACT. This is consistent with BACT at other similar sources. Therefore, an assessment of the economic and environmental impacts is not necessary.

Step 5 – Select BACT

ACP, LLC proposes BACT for PM_{10} and $PM_{2.5}$ emissions from the combustion turbines is the use of clean-burning fuels and good combustion practices to control PM_{10} and $PM_{2.5}$.

Emissions will be limited to 0.02 lb/MMBtu PM from each turbine.

6.2 BACT FOR NITROGEN OXIDES (NO_X)

NO_x emissions result from the proposed combustion turbines.

The following summarizes the BACT evaluation conducted for the Solar combustion turbines, the only significant equipment type for the Buckingham Compressor Station with respect to NO_x emissions.

Step 1 – Identify Potential Control Technologies

The potentially applicable controls to reduce NO_x emissions from turbines include:

- Dry Low NOx (DLN) Combustor Technology;
- Wet Controls - Water and Steam Injection;
- Selective Catalytic Reduction (SCR); and
- Selective Non-Catalytic Reduction (SNCR).

Additional control candidates available to control NO_x emissions from simple-cycle turbines, not listed in the EPA's Technology Transfer Network, include the following:

- Rich/Quench/Lean (RQL) Combustion;
- Catalytic Combustion – Xonon™;
- Catalytic Absorption (formally SCONOx™); and
- Alternate Lower FBN (fuel-bound nitrogen) Fuels.

Dry Low NOx (DLN) Combustors

DLN combustion control techniques reduce NO_x emissions without the use of water or steam injection. 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 NO_x 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 to maintain the fuel-lean conditions.

Wet Controls - Water and Steam Injection

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.

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 NO_x to form molecular nitrogen 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 of can vary. The reaction of NH_3 and NOx is favored by the presence of excess oxygen. 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).

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.

Rich/Quench/Lean (RQL) Combustion

RQL combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone, reduce both thermal and fuel NO_x. 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 oxygen for NO_x formation and also act as reducing agents for any NO_x 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 NO_x formation.

Catalytic Combustion – Xonon™

Xonon™ is a catalytic combustion technology in development that reduces the production of NO_x. The technology has only been tested on small turbines (less than 10 MW) and it is still not commercially available for the proposed simple-cycle turbines. 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 2,000^{0}F, which is the temperature at which significant amounts of thermal NO_x begin to form.

Catalytic Absorption (formally SCONOx™)

SCONOx™, a post-combustion technology, proposes to remove NO_x from the exhaust gas stream following NO_x formation in combined cycle combustion turbine applications. While SCONOx™ has been marketed for more than ten years in the US, it has been installed and tested on only a handful of installations. 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 NO_x where it 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 the ejection of nitrogen gas and water.

Alternate Lower FBN (Fuel-Bound Nitrogen) Fuels

The utilization of a lower FBN fuel such as coal-derived gas or methanol is not deemed practical based on the nature of the proposed operations at the Buckingham Compressor Station. Thus, this control alternative is not addressed further in this BACT determination.

Step 2 - Eliminate Technically Infeasible Options

Dry Low NOx (DLN) Combustors

The proposed simple-cycle turbines at the Buckingham Compressor Station are Solar turbines equipped with SoLoNOx dry low NOx combustors. SoLoNOx 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. Accordingly, DLN combustion technology is considered technically feasible and considered further in this analysis.

Wet Controls - Water and Steam Injection

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 NO_x reductions, but may also cause potential flameouts, increasing maintenance requirements and reducing turbine efficiency. During startup and shutdown events for the simple-cycle turbines, introduction of water or steam injection into the proposed SoLoNOx dry low NO_x 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.

Selective Catalytic Reduction (SCR)

Base metal catalysts deteriorate quickly when continuously subjected to temperatures above this range or under thermal cycling, which commonly occurs in turbines in gas compression service. In effect, if these catalyst systems are operated beyond their specified temperature ranges, oxidation of the ammonia to either additional nitrogen oxides or ammonium nitrate may result. Moreover, the variable load demands on turbines in gas compression services create significant operational complexities for use of SCRs.

Based on a review of EPA's RBLC database, SCR systems have been installed on some simple cycle combustion turbines and are therefore considered technically feasible, and SCR is considered further in the BACT analysis.

Selective Non-Catalytic Reduction (SNCR)

The exhaust temperatures in gas turbines typically do not exceed 1,250°F. Therefore, the operative temperature window of this control alternative is not technically feasible for this application. Exhaust temperatures for the proposed gas turbines are approximately 900 °F, which is well below the range for SNCR applications. In addition, this technology has a residence time requirement of 100 milliseconds, which is relatively slow for gas turbine operating flow velocities. Thus, adequate residence time for the NOx destruction chemical reaction will not be available.

Further, a review of the RBLC database for recent BACT/LAER determinations for this particular source category and discussions with control system vendors 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 for the Buckingham Compressor Station turbines.

Rich/Quench/Lean (RQL) Combustion

Theoretically, this control alternative is applicable to natural gas-fired turbines; however, based on information presented in the EPA ACT (Alternative Control Techniques) document, RQL combustors are not commercially available for most turbine designs and there is no known application for only natural gas-fired simple-cycle combustion turbines. Because it is not commercially demonstrated on combustion turbines, RQL combustion will be removed from further consideration in this BACT determination for the turbines.

Catalytic Combustion – Xonon™

Catalytic converters are not commercially available for this application. Until such time that the technology is commercially available, catalytic combustors are not considered technically feasible. In addition, discussions with Solar indicated that this technology is not commercially available for any Solar product. In view of the above limitations in utilizing catalytic combustor control, this control alternative is precluded from further consideration in the Buckingham Compressor Station BACT determination.

Catalytic Absorption (formally SCONOx™)

The advantage of SCONOx™ relative to SCR is that SCONOx™ does not require ammonia injection to achieve NOx emissions control. 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; secondly, the technology is not readily adaptable to high-temperature applications outside the 300°-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. In addition, based on review of EPA's RBLC database and other permits issued in different states, this technology has not been applied on simple cycle combustion turbines used for natural gas compression. Therefore, this technology is not considered further in the BACT analysis.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The control technologies, which have been demonstrated in commercial practice on turbines are:

- Dry Low NOx Combustor Technology, SoLoNOx Technology; and
- Selective Catalytic Reduction.

Step 4 - Evaluate Most Effective Controls and Document Results

ACP, LLC is proposing installation of SCR for the turbines at the Buckingham Compressor Station. For the types and designs of turbines proposed for this project at the Buckingham Compressor Station, SCR is commonly disqualified from BACT through cost effectiveness calculations. ACP, LLC previously provided an evaluation of cost effectiveness for SCR at Buckingham (See January 8, 2018 letter to DEQ). The analyses provided in January for the four turbines have been updated to reflect the 3.75 ppm control level and are provided in Appendix G. As can be seen, the cost effectiveness ranges from $50,000 to $103,000 per ton. At these cost to control levels, the technology is not cost effective and should not be considered BACT.

Based on the information presented in this BACT analysis, the use of low NO_x combustion technology (SoLoNOx) and good combustion practices are the most common control option proposed for turbines similar to the proposed turbines in this project.

Step 5 – Select BACT

The proposed Buckingham Compressor Station turbines will be equipped with SoLoNOx dry low NO_x combustors with a vendor performance specification for NO_x emission rate of 9 ppmvd @ 15% O_2. Therefore, the use of SoLoNOx dry low NO_x combustors and good combustion practices is considered BACT for reducing NO_x emissions from the proposed Buckingham Compressor Station turbines.

However, in addition to the BACT controls proposed, ACP, LLC plans to install SCR on the proposed Buckingham Compressor Station turbines to further reduce emissions to 3.75 ppmvd NO_x @ 15% O_2 during normal operations.

6.3 BACT FOR CARBON MONOXIDE (CO)

CO emissions result from the proposed combustion turbines.

The following summarizes the BACT evaluation conducted for the Solar combustion turbines, the only significant equipment type for the Buckingham Compressor Station with respect to CO emissions.

Step 1 – Identify Potential Control Technologies

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

- Combustion Control;
- Catalytic Oxidation/Absorption (formally SCONOx™); and
- CO Oxidation Catalysts.

Combustion Control

Because CO is essentially a by-product of incomplete or inefficient combustion, it is important that combustion control constitutes the primary mode of reduction of CO emissions. As discussed above, 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 NO_x 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 NO_x 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 CO emissions.

Catalytic Absorption (formally SCONOx™)

SCONOx is a post combustion technology that, along with NO_x reductions, results in almost 100% removal of CO. As discussed in the NO_x BACT, SCONOx is deemed technically infeasible and will not be considered further.

CO Oxidation Catalyst

Oxidation catalyst systems serve to remove CO (and VOC) 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.

Step 2 - Eliminate Technically Infeasible Options

Combustion Control

Combustion control is considered technically feasible.

Catalytic Absorption (formally SCONOx™)

As discussed in the NO_x BACT, SCONOx is deemed technically infeasible and will not be considered further.

CO Oxidation Catalyst

CO oxidation catalyst is considered technically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The control technologies, which have been demonstrated in commercial practice on the types of turbines proposed for this project, are summarized below:

- Dry Low NOx Combustor Technology, SoLoNOx Technology – 25 ppmvd CO @ 15% O_2; and
- CO Oxidation Catalyst (~80-92% control).

Step 4 - Evaluate Most Effective Controls and Document Results

Recently issued DEQ permits for other compressor stations have reflected the determination that combustion technology (SoLoNOx) and good combustion practices meet BACT.

Step 5 – Select BACT

ACP, LLC plans to install turbines which will be equipped with SoLoNOx dry low NO_x combustors which will achieve a guaranteed CO emission rate of 25 ppmvd @ 15% O_2. In addition, ACP, LLC plans to install oxidation catalysts on the proposed Buckingham Compressor Station turbines. The estimated efficiency of the oxidation catalyst will be approximately 92% control for CO, to further reduce emissions to 2 ppmvd CO @ 15% O_2 during normal operation.

6.4 BACT FOR VOLATLE ORGANIC COMPOUNDS (VOC)

The following summarizes the BACT evaluation conducted for each significant piece of equipment with respect to VOC emissions. For the Buckingham Compressor Station, this includes combustion turbines and fugitive emissions sources.

6.4.1 Combustion Turbines

The available emission control options for minimizing VOC emissions from the turbines include:

- Good combustion practices; and
- Oxidation catalyst.

For the types and designs of turbines proposed for the Buckingham Compressor Station, oxidation catalysts are commonly disqualified from BACT through cost effectiveness calculations. However, for this project, oxidation catalyst will be installed on each turbine (to minimize CO emissions). VOC emissions will be reduced as part of the oxidation process. The oxidation catalyst is expected to achieve approximately 50% control efficiency for VOC. Good combustion practices alone are considered BACT for VOC emissions.

VOC emissions will be limited to 1.3 ppmvd @ 15% O_2 from the turbines.

6.4.2 Blowdowns

DEQ requested ACP, LLC to evaluate the use of a flare to control VOC emissions from blowdown events. In both of the previous BACT submittals, ACP, LLC stated that BACT for blowdown fugitive VOC emissions is operation according to ACP, LLC and the manufacturer's best practices.

The majority of emissions from blowdowns can result from depressurization events associated with turbine startups and shutdowns. A worst-case estimation of 100 startup and shutdown events per year requiring blowdown of each turbine has been used to calculate the uncontrolled potential to emit (PTE). Unplanned startups and shutdowns can occur to satisfy changes in pressure demand. Pressure demand depends on the demand from downstream of the compressor station. A turbine might need to be started up if pressure demand increases and shutdown if pressure demand decreases. Startups and shutdowns also occur for performing maintenance activities.

Facility-wide blowdown events may occur for unplanned reasons (e.g. when an unsafe operating condition is detected). To prepare for such events, ACP, LLC must perform ESD testing to ensure proper operation of the ESD system. One (1) facility-wide blowdown event each year, a planned ESD test, was previously included as part of the station PTE in the prior application and the 2017 update. Following commissioning, a full station blowdown would only occur during upset conditions (e.g. an actual ESD). Emergency events are expected to be very infrequent and cannot be predicted. Accordingly, emergency blowdown events are not considered in the PTE.

Certain maintenance operations, such as pipeline inspections and cleanings, require the use of a device known as a "pig". The pig is inserted into the pipeline through a pig launcher and is removed from the pipeline through a pig receiver. These "pigging" operations also contribute to total emissions from blowdowns.

The following summarizes the BACT evaluation conducted for blowdowns with respect to VOC emissions.

Step 1 – Identify Potential Control Technologies

The potentially available approaches to reduce VOC emissions from blowdown events include:

- Flaring, and
- Operational Controls [Vent Gas Reduction (VGR) System and Capped ESD Testing].

Flaring

VADEQ requested that ACP, LLC evaluate flaring as an available control to reduce fugitive VOC emissions from blowdown events.

It is noted that ACP, LLC has not been able to identify any transmission compression stations in the country that utilize a flare for the control of turbine or station wide blowdown events.

Enclosed combustors are sometimes used to control emissions from glycol dehydrators and storage tanks at gathering compressor stations and other facilities and, in fact, are identified in federal regulations (New Source Performance Standards - Subpart OOOO, OOOOa - and National Emission Standards for Hazardous Air Pollutants (NESHAP) – Subpart HH, HHH) as well as state general permitting programs. These federal and state requirements are focused on limiting VOC emissions from sources with lower flow, but much higher potential VOC concentrations than will be found in blowdown gas.

Operational Control - VGR System

A vent gas reduction (VGR) system involves process equipment and operating practices to manage the pressure in the compressor piping, which can be used to decrease the number of blowdowns associated with startup / shutdown events as well as reduce the amount of natural gas emitted during blowdown events. The following is a summary of benefits associated with use of a VGR system at the Buckingham Compressor Station. Appendix H contains additional details describing the design and operation of the VGR system.

Decrease in start-up and shutdown blowdown events – As stated in Section 3.1, consistent with the original application, potential turbine combustion emissions included 100 start-up and 100 shutdown events per year based on the assumption that blowdowns would be required whenever a turbine engine is turned off in response to demand. However, the VGR system uses an electrocompressor to equalize pressure across seals allowing the use of pressurized holds, so that the compressors can be maintained in a pressurized hold state, thus avoiding the need to blowdown the unit during normal operations. As a result, the VGR system reduces the worst-case estimation of start-up and shutdown events (per turbine) requiring blowdown from 100 per year to 10 per year.

Decrease in shutdown blowdown gas volume – The uncontrolled blowdown volumes for shutdown events will vary based on the system pressure prior to venting. Conservatively assuming a maximum expected operating pressure of 1400 psig, the volumes associated with uncontrolled unit blowdowns range from approximately 80,000 SCF/event to 430,000 SCF/event. As mentioned before, blowdowns from planned shutdowns are expected during maintenance events to allow for access. When a blowdown is required during shutdown, the VGR system includes a series of piping and an electric compressor that is used to remove gas from the equipment, which lowers the pressure and thus limits the volume of gas that would be blown down. The VGR system lowers the pressure to 30 psig before a shutdown turbine is depressurized. With the VGR system implemented, the blowdown volumes for shutdown events are significantly reduced (proportional to the reduction in system pressure from up to 1400 psig to 30 psig)..

Operational Control - Capped ESD Testing

The facility-wide blowdown event provided in the original application and 2017 update represents necessary safety testing of the ESD valves and systems at the station. An uncontrolled blowdown volume of approximately 4,100,000 scf/event reflects a once-every-five year full station blowdown for the test. In lieu of a full blowdown once every five years, ACP, LLC plans to conduct annual “capped” emission testing. The use of annual “capped” ESD testing versus once every five year full ESD testing can significantly decrease the volume of gas associated with planned testing of the ESD system. Additional discussion of this technique can be found in the Natural Gas Star literature[ix].

The blowdown volume during capped testing is significantly reduced to approximately 280 scf/event. Following commissioning, a full station blowdown would only occur during upset conditions (an actual ESD, not a test). Emergency events are expected to be very infrequent and cannot be predicted. Accordingly, emergency blowdown events are not considered in the PTE.

Step 2 - Eliminate Technically Infeasible Options

Flaring

ACP, LLC was not able to identify another transmission station where flaring of turbine or station wide blowdown events is being demonstrated in practice. The table provided in Appendix E shows the results of a search of EPA’s RBLC database. None of the sites identified as using flares are compressor stations. Rather, they are generally processing plants – facilities that handle gas streams with lower volumetric flow and much higher VOC and hazardous air pollutant content. For example, VOC content in the gases at processing plants can easily exceed 10% by weight. The natural gas processed at the Buckingham Compressor Station is expected to be less than 3% VOC by weight. Generally, per EPA guidance, “Innovative controls that have not been demonstrated on any source type *similar to the proposed source* need not be considered in the BACT analysis.” [Cite 1990 NSR Guidance, B21 (emphasis added).] However, as requested by VADEQ, ACP, LLC will carry the use of a flare forward in this analysis. While blowdown gas is generally pipeline quality natural gas that is combustible, there are a number of challenges and other impacts associated with combustion of station-wide blowdown (i.e., lower VOC content, significantly higher volume and flowrate) of natural gas in an open flare that make this technology infeasible as applied to the proposed source. See Step 4 of this review for further discussion.

[ix] https://www.epa.gov/sites/production/files/2016-06/documents/redesignblowdownsystems.pdf

Operational Control - VGR System

The implementation of the VGR System is technically feasible.

Operational Control - Capped ESD Testing

The implementation of "capped" ESD testing is technically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The control technologies that are technically feasible to reduce VOC emissions from blowdown events are:

- Operational Controls followed by Flaring – 99.9% + reduction
- Operational Controls – 99.5%+ reduction:
  - VGR system – 99.5% reduction in VOC emissions from blowdowns during SU/SD events; and
  - Capped ESD Testing – 99.99% reduction in VOC emissions from blowdowns during station wide emergency test.
- Flaring - 98% reduction in VOC emissions[x] from blowdowns during SU/SD and emissions from blowdowns during station wide emergency test.

Step 4 - Evaluate Most Effective Controls and Document Results

The combination of operational controls followed by flaring of the small amount of residual vented material would be the most effective control option as noted in Step 3. However, following application of operational controls, the remaining emissions are only 0.42 tons per year of VOC emissions. The application of a flare to such low levels of emissions would not be cost effective. This is supported by engineering estimates of greater than $100,000 in engineering design and piping costs that would be required to tie in multiple blowdown stacks to a flaring system alone. Preliminary flare cost estimates range from $250,000 to over $500,000 as the flare must be large in size due to relatively high flow albeit short duration events. Additionally, as discussed further below, the use of a flare would result in other environmental and energy impacts that would make its usage to control such a small amount of emissions unattractive from an overall environmental benefit.

[x] Note – use of the flare would result in generation of additional VOC emissions not considered in 98% value. Specifically, a flare would require the combustion of pilot and purge gas that would generate VOC emissions as well as other emissions (NOx, CO, PM, etc.).

The use of operational controls is the next highest ranked option and is the proposed approach to minimize emissions. While further analysis is not required under BACT for lower ranked options, DETI is providing more detail on flaring per DEQ's request.

When determining the most effective control option(s), the extent of control of the primary pollutant is important, but consistent with EPA guidance on making BACT determination, other considerations must be made as well. Specifically, these considerations include the energy and environmental impacts.

The use of a flare for control of blowdowns would require a large, open flare. Final engineering estimates are not yet available, but initial engineering estimates are that the flare would require a 16-24 inch diameter flare with a height of 100 feet or more to safely handle the heat load during blowdown events. Impacts associated with the usage of such a large flare include:

Pilot and Purge Gas Usage – Pilot gas is needed to keep flare lit at all times and purge gas is needed to ensure no explosive mixtures of air and natural gas build up and no backflow of pilot flame occurs within the blowdown piping. Final engineering estimates are not yet available, but initial engineering estimates are that the flare would burn 195 scf/hr of pilot gas and 435 scf/hr of purge gas. This results in emissions, light (from pilot), and the combustion of natural gas that would not occur in the proposed venting scenario for the blowdowns.

Significant Expansion of the Station Footprint – The flare(s) needed to handle the heat load during a blowdown event will be large and must be safely located away from other operating equipment and site personnel. Accordingly, the addition of a flare(s) would lead to a significantly large land use impact than the currently planned facility – initial estimates are that the siting of the flare(s) could lead to a 20 to 50% increase in the land impacted by the station's construction and operation.

Increased Noise Impacts – Currently, the noise associated with blowdowns is mitigated by silencers on the blowdown stacks. Further, the planned blowdown operations have been considered as part of the noise impact assessment completed during the FERC application process and shown to meet acceptable noise impact levels. By contrast, there are no comparable noise mitigation technologies for a flare. As such, the sound associated with a flare is expected to be significantly higher than that from venting of the blowdown gases through stacks with silencers as currently planned.

Light Impacts – As stated earlier, initial estimates are that a flare with a height of 100 feet or more would be required. A pilot light would be required at all times, causing constant light pollution to the public. Further, the flare could have a 30 to 60 foot flame when blowing down, causing more significant light pollution during blowdown events.

Increased Emissions of Non-VOC Emissions – Flaring of blowdown gases would reduce VOC emissions. However, the flaring would generate secondary emissions of combustion pollutants. For every ton of VOC reduced, there will be approximately 0.25 tons of CO, 0.08 tons of PM, and 0.06 tons of NOx generated. Please see Appendix F for detailed emission calculations. These emissions arguably offset the reduction of VOC, particularly when one considers that the impact of NOx is two to three orders of magnitude larger (10 to 100+ times) with respect to the formation of ozone than VOC. See discussion in VADEQ document "Ozone Advance Action Plan Hampton Roads Area".

As stated in Step 3, application of operational controls (VGR system and implementation of "capped" ESD testing) has a higher VOC control efficiency (greater than 99%) than flaring (98%). The PTE for blowdown fugitive VOC emissions after implementation of a VGR system and capped ESD testing is 0.42 tpy, more than three times less than the VOC PTE of 1.3 tpy after implementation of a flare.

Furthermore, the use of the VGR system and "capped" ESD testing are a more effective emission reduction method for CO_2e and total HAP when one considers impacts from the natural gas combustion. The PTE for blowdown fugitive emissions after implementation of the VGR system and capped ESD testing is 357 tpy CO_2e and 0.026 tpy HAP, less than the PTE of 7,006 tpy CO_2e and 0.110 tpy HAP after implementation of a flare.

Overall, implementation of a VGR system and "capped" ESD testing provides equivalent or better emission reduction than installation of a flare. Further, installation of a flare would create adverse environmental and community impacts, as described above, which are not created through the implementation of the proposed operational controls.

<u>Step 5 – Select BACT</u>

ACP, LLC proposes to implement operational controls - VGR system and "capped" ESD testing – to minimize the number of blowdown events and reduce the quantity of gas emitted during the required blowdown events. ACP, LLC believes that the implementation of the proposed VGR system and utilization of "capped" emission testing clearly go above and beyond BACT with respect to reducing potential emissions and avoiding undesirable environmental and community impacts associated with the application of a flare.

7.0 PROPOSED COMPLIANCE DEMONSTRATIONS

The following methods are proposed for demonstrating ongoing compliance for the sources described in this application:

<u>Compressor Turbines (CT-01 through CT-04)</u>

NO_x:

Annual stack testing (or biennial testing as allowed) will be completed to demonstrate compliance with the NSPS Subpart KKKK emissions limits (NO_2 emissions).

Compliance with the combustion turbines potential to emit will be demonstrated on a 12-month rolling total basis by the sum of the following emissions:

- Normal Operation: The average emission rate from the most recent stack test (lb/hour) times the number of hours operating in SoLoNOx mode (mode indication provided and recorded by control logic on turbine).
- Low Temperature (< 0^{o} F) Operation: The proposed controlled emission rates (lb/hr, see Table 3.2) determined using the Solar provided emissions factor multiplied by the control efficiency of the SCR times the number of hours when inlet combustion air for turbine was measured to be below 0 degrees F.
- Startup and Shutdown Emissions (< 50% load): The Solar-provided emission rates (see Tables 3.3 and 3.4) divided by Solar-assumed duration for startups and shutdowns (1/6 of an hour each) times the number of hours operating in non-SoLoNOx mode (mode indication provided and recorded by control logic on the turbine).

CO, VOC, $PM_{10}/PM_{2.5}$:

Initial stack testing will be completed to determine $PM_{10}/PM_{2.5}$ emission rates (lb/MMBtu). Fuel firing will be tracked and used to calculate annual (rolling 12-month total) ton per year emissions.

Initial stack testing will be competed to determine VOC and CO emission rates. Compliance with the combustion turbines potential to emit will be demonstrated on a 12-month rolling total basis by the sum of the following emissions:

- Normal Operation: The average emission rate from the most recent stack test (lb/hour) times the number of hours operating in SoLoNOx mode (mode indication provided and recorded by control logic on turbine).
- Low Temperature (< 0^{o} F) Operation: The proposed controlled emission rates (lb/hr, see Table 3.2) determined using the Solar provided emissions factor multiplied by the control efficiency of the oxidation catalyst times the number of hours when inlet combustion air for turbine was measured to be below 0 degrees F.
- Startup and Shutdown Emissions (< 50% load): The Solar-provided emission rates (see Tables 3.3 and 3.4) divided by Solar-assumed duration for startups and shutdowns (1/6 of an hour each) times the number of hours operating in non-SoLoNOx mode (mode indication provided and recorded by control logic on the turbine).

GHG:

Total annual fuel volume will be tracked to determine total MMBtu of firing. This value times the EPA Mandatory Reporting Rule natural gas emission factor (40 CFR Part 98 Subpart C) times the Global Warming Potential (40 CFR Part 98 Subpart A) will be used to calculate ton per year CO_2e emissions.

<u>Line Heaters (LH-01 through LH-04)</u>

The units will maintain compliance with NSPS Subpart Dc (maintain records of the amount of each fuel combusted during each calendar month and sulfur content of gas).

<u>Emergency Generator</u>

Records of the monthly emergency and non-emergency hours will be maintained to confirm compliance with the annual limit for non-emergency operation.

<u>Other Combustion Sources</u>

If not otherwise specified above, the amount of fuel fired in units and/or hours of operation will be tracked and multiplied by the appropriate emission factor to calculate emissions on an annual basis.

<u>Emissions from Blowdowns</u>

Emissions resulting from blowdown of the compressor units occur during the shutdown events and purging of the unit during startup. Records of the gas pressure prior to venting for unit blowdown events will be maintained to ensure proper operation of the VGR system. Planned equipment blowdowns will occur after equipment pressure has been reduced to approximately 30 PSIG or lower. Any blowdowns from higher pressure will be documented and reason provided (e.g. actual ESD event, equipment malfunction, etc.). The number of unit blowdown events will be tracked to ensure that VGR system is properly implemented and maintained. In addition, if the compressor unit is required to be purged prior to startup, gas volumes vented during purging will be documented.

As previously discussed and detailed in Appendix H, the VGR system can maintain the unit in a pressurized hold state when compressor shuts down to avoid unit blowdowns and purging to significantly reduce the amount natural gas vented from the unit. Pressurized hold will be monitored and maintained by the unit's programmable logic controller (PLC). The PLC will display a pressurized hold status and the case pressure will be monitored while the unit is not operating. The case pressure will be maintained above 30 psi during a pressurized hold and if the pressure falls below 30 psi or the pressurized hold status changes, the units PLC will alarm to notify personnel of the change. Pressurized hold status and case pressure monitoring will be tracked in a data management system.

Within 180 days of commissioning, DETI will perform an inspection of the VGR system to ensure the system is operating as designed, free of leaks and effective at holding turbine(s) in a pressurized hold mode. To verify that the system is free of leaks, the inspection will utilize an optical gas imaging device (e.g. FLIR camera). The VGR system will be inspected annually thereafter and any leaks identified during the inspection will be repaired as soon as practicable. A first attempt to repair will be conducted no later than 5 calendar days after the leak is detected and the repair will be completed no later than 30 calendar days after lead is detected. Leaks may be place on delay of repair in the event that the leak or defect has been detected and is technically infeasible to repair without a shutdown, or if it is determined that emissions resulting from the immediate repair would be greater than the fugitive emissions likely to result from delay of repair.

APPENDICES

APPENDIX A

VIRGINIA DEQ FORM 7 APPLICATION FORMS

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

Virginia Department of Environmental Quality

What pages do I fill out for my facility?

- All new sources and major modifications: 3
- All new and modified sources (except for true minors): 4
- All new and modified sources and State Operating Permits: 7, 8, 9
- All new and modified major sources: 25, 26, 27, 28, 29

In addition, complete the following pages:

- For boilers, external combustion units, turbines: 10, (19, 20 if applicable), 21, 22, 23, 24, 30
- For stationary combustion engines: 11, (19, 20 if applicable), 21, 22, 30
- For incinerators: 12, 19, 20, 21, 22, 23, 24, 30
- For surface coating operations: 13, 14, (19, 20 if applicable), 21, 22, 23, 24, 30
- For quarry operations: 13, 19, 20, 21, 22
- For VOC/Petroleum storage tanks: 15, 16, 21, 22, 23, 24, 30
- For loading racks and oil water separators: 17, 21, 22, 23, 24, 30
- For fumigation operations: 18
- For all other sources: 13, (19, 20, 23, 24 if applicable), 21, 22, 30

****NOTE:** ***The facility only has to fill out the applicable pages that apply.*** If any pages are unused, the facility does not need to submit the unused pages with the application.

Source-Specific Form 7 Applications

There are some source-specific Form 7 Applications available for these sources:
(check out the DEQ website at http://www.deq.virginia.gov/Programs/Air/Forms.aspx)

- Asphalt plants (Form 7A)
- Crematories (Form 7B)
- Concrete Batch Plant (Form 7C)

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY - AIR PERMITS

LOCAL GOVERNING BODY CERTIFICATION FORM

Facility Name: Buckingham Compressor Station	Registration Number: NA
Applicant's Name: Atlantic Coast Pipeline, LLC	Name of Contact Person at the site: Thomas R Andrake
Applicant's Mailing address: 707 E Main St Richmond, VA 23219	Contact Person Telephone Number: (804) 273-2882

Facility location (also attach map): Buckingham County, VA

Facility type, and list of activities to be conducted:
Natural gas compression and transmission station; Atlantic Coast Pipeline, LLC proposes to construct and operate via Dominion Energy Transmission, Inc. (DETI) an approximately 600-mile long interstate natural gas transmission pipeline system. The Station will provide compression to support the transmission of natural gas. The adjacent metering and regulation (M&R) station (Woods Corner) will also be operated by DETI and will be considered part of the Station.

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: 5/25/18

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: Please see attached approval dated 02/08/2017	Date:
Type or print name:	Title:
County, city or town:	

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

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY - AIR PERMITS

LOCAL GOVERNING BODY CERTIFICATION FORM

Facility Name: Buckingham Compressor Station	Registration Number: NA
Applicant's Name: Atlantic Coast Pipeline, LLC	Name of Contact Person at the site: Laurence Labrie
Applicant's Mailing address: 707 East Main Street Richmond, Virginia 23219	Contact Person Telephone Number: 804-273-3075

Facility location (also attach map): Buckingham County, VA

Facility type, and list of activities to be conducted:
Natural gas compression and transmission station; Atlantic Coast Pipeline, LLC proposes to construct and operate via Dominion Transmission, Inc. (DTI) an approximately 600-mile long interstate natural gas transmission pipeline system. The Station will provide compression to support the transmission of natural gas. The adjacent metering and regulation (M&R) station (Woods Corner) will also be operated by DTI and will be considered part of the Station.

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: 2/2/17

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: Rebecca S Carter	Date: 02/08/2017
Type or print name: REBECCA S CARTER	Title: County Administrator
County, city or town: COUNTY OF BUCKINGHAM	

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

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY – 2018 AIR PERMIT APPLICATION FEES

Air permit applications are subject to a fee. The fee does not apply to administrative amendments or true minor sources. Applications will be considered incomplete if the proper fee is not paid and will not be processed until full payment is received. Air permit application fees are not refundable.

Fees are adjusted January 1 of each calendar year. THIS FORM IS VALID JANUARY 1, 2018 TO DECEMBER 31, 2018.

Send this form and a check (or money order) payable to "Treasurer of Virginia" to:
Department of Environmental Quality
Receipts Control
P.O. Box 1104
Richmond, VA 23218

Send a copy of this form with the permit application to:
The DEQ Regional Office

Please retain a copy for your records. Any questions should be directed to the DEQ regional office to which the application will be submitted. **Unsure of your fee? Contact the Regional Air Permit Manager.**

COMPANY NAME:	**Atlantic Coast Pipeline, LLC**	**FIN:**	
COMPANY REPRESENTATIVE:	**Richard B Gangle**	**REG. NO.**	**NA**
MAILING ADDRESS:	**5000 Dominion Blvd, 2NE Glen Allen, VA 23060**		
BUSINESS PHONE:	**(804) 273-2814**	**FAX:**	
FACILITY NAME:	**Buckingham Compressor Station**		
PHYSICAL LOCATION:	**Buckingham County, VA**		

PERMIT ACTIVITY	APPLICATION FEE AMOUNT	CHECK ONE
Sources subject to Title V permitting requirements:		
• Major NSR permit (Articles 7, 8, 9)	$63,000	
• Major NSR permit amendment (Articles 7, 8, 9)*	$10,000	
• State major permit (Article 6)	$25,000	
• Title V permit (Articles 1, 3)	$35,000	
• Title V permit renewal (Articles 1, 3)	$15,000	
• Title V permit modification (Articles 1, 3)	$4,000	
• Minor NSR permit (Article 6)	$5,000	X
• Minor NSR amendment (Article 6)*	$2,500	
• State operating permit (Article 5)	$10,000	
• State operating permit amendment (Article 5)*	$4,000	
Sources subject to Synthetic Minor permitting requirements:		
• Minor NSR permit (Article 6)	$3,000	
• Minor NSR amendment (Article 6)*	$1,000	
• State operating permit (Article 5)	$5,000	
• State operating permit amendment (Article 5)*	$2,500	
***FEES DO NOT APPLY TO ADMINISTRATIVE AMENDMENTS AIR PERMIT APPLICATION FEES ARE NOT REFUNDABLE**		

DEQ OFFICE TO WHICH PERMIT APPLICATION WILL BE SUBMITTED (check one)

☐ **SWRO/Abingdon**	☐ **NRO/Woodbridge**	☒ **PRO/Richmond**	**FOR DEQ USE ONLY** **Date:** ________________ **DC #:** ________________
☐ **VRO/Harrisonburg**	☐ **BRRO/Roanoke**	☐ **TRO/Virginia Beach**	**Reg. No.:** ________________

APPLICATION FEE FORM DEFINITIONS:

Administrative amendment – An administrative change to a permit issued pursuant to Article 1 (9 VAC 5-80-50 et seq.), Article 3 (9 VAC 5-80-360 et seq.), Article 5 (9 VAC 5-80-800 et seq.), Article 6 (9 VAC 5-80-1100 et seq.), Article 7 (9 VAC 5-80-1400 et seq.), Article 8 (9 VAC 5-80-1605 et seq.), or Article 9 (9 VAC 5-80-2000 et seq.) of 9 VAC 5 Chapter 80. Administrative amendments include, but are not limited to, the following:

- Corrections of typographical or any other error, defect or irregularity which does not substantially affect the permit,
- Identification of a change in the name, address, or phone number of any person identified in the permit, or of a similar minor administrative change at the source,
- Change in ownership or operational control of a source where the board determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the board.

Major new source review permit (Major NSR permit) – A permit issued pursuant to Article 7 (9 VAC 5-80-1400 et seq.), Article 8 (9 VAC 5-80-1605 et seq.), or Article 9 (9 VAC 5-80-2000 et seq.) of 9 VAC 5 Chapter 80. For purposes of fees, the Major NSR permit also includes applications for projects that are major modifications.

- An Article 7 permit is a preconstruction review permit (case-by-case Maximum Achievable Control Technology (MACT) determination) for the construction or reconstruction of any stationary source or emission unit that has the potential to emit, considering controls, 10 tons per year or more of any individual hazardous air pollutant (HAP) or 25 tons per year or more of any combination of HAPs and EPA has not promulgated a MACT standard or delisted the source category.
- An Article 8 permit is for a source (1) with the potential to emit over 250 tons per year of a single criteria pollutant OR (2) is in one of the listed source categories under 9 VAC 5-80-1615 and has the potential to emit over 100 tons per year of any criteria pollutant OR (3) with the potential to emit over 100,000 tons per year of CO_2 equivalent (CO_2e) (9 VAC 5-85 Part III). PSD permits are issued in areas that are in attainment of the National Ambient Air Quality Standards.
- An Article 9 permit is a preconstruction review permit for areas that are in nonattainment with a National Ambient Air Quality Standard (NAAQS). Nonattainment permits are required by any major new source that is being constructed in a nonattainment area and is major for the pollutant for which the area is in nonattainment. Nonattainment permitting requirements may also be triggered if an existing minor source makes a modification that results in the facility being major for the pollutant for which the area is in nonattainment. A major source is any source with potential to emit over 250 tons per year of a single criteria pollutant or is in one of the listed source categories under 9 VAC 5-80-2010 and the potential to emit over 100 tons per year of any criteria pollutant. However, if any area is in nonattainment for a specific pollutant, the major source threshold may be lower for that pollutant. For example, sources locating in the Northern Virginia Ozone Nonattainment Area which are part of the Ozone Transport Region would be a major source if they have the potential to emit more than 100 tons per year of NO_X and/or 50 tons per year of VOC regardless of source category. Nonattainment permits do not require an air quality analysis but require a source to control to the Lowest Achievable Emission Rate (LAER) and to obtain offsets.

Major NSR permit amendment – A change to a permit issued pursuant to Article 7 (9 VAC 5-80-1400 et seq.), Article 8 (9 VAC 5-80-1605 et seq.), or Article 9 (9 VAC 5-80-2000 et seq.) of 9 VAC 5 Chapter 80. Only minor amendments and significant amendments are included in this category.

Minor new source review permit (Minor NSR permit) – A permit to construct and operate issued under Article 6 (9 VAC 5-80-1100 et seq.) of 9 VAC 5 Chapter 80. Minor NSR permits are 1) categorically required; or 2) issued to sources whose uncontrolled emission rate for a regulated criteria pollutant is above exemption thresholds and permitting allowables are below Title V thresholds, and/or 3) issued to sources whose potential to emit for a toxic pollutant is above state toxic exemption thresholds and permitting allowables are below Title V thresholds. The minor NSR permit can be used to establish synthetic minor limits for avoidance of state major, PSD and/or Title V permits. For purposes of fees, the Minor NSR permit also includes exemption applications and applications for projects at existing sources.

Minor NSR amendment - A change to a permit issued pursuant to Article 6 (9 VAC 5-80-1100 et seq.) of 9 VAC 5 Chapter 80. Only minor amendments and significant amendments are included in this category.

Sources subject to Synthetic Minor permitting requirements - Stationary sources whose potential to emit exceeds the Title V threshold (100 tons per year of a criteria pollutant, 10/25 tpy of HAPs, and/or 100,000 tpy CO_2e) but have taken federally enforceable limits, either through a state operating permit or a minor NSR permit, to avoid Title V permit applicability.

Sources subject to Title V permitting requirements – Stationary sources that have a potential to emit above the Title V thresholds or are otherwise applicable to the Title V permitting program.

State major permit – A permit to construct and operate issued under Article 6 (9 VAC 5-80-1100 et seq.) of 9 VAC 5 Chapter 80. State major permits are for facilities that have an allowable emission rate of more than 100 tons per year, but less than 250 tons per year, of any criteria pollutant and are not listed in the 28 categories under "major stationary source" as defined in 9 VAC 5-80-1615.

State operating permit (SOP) – A permit issued under Article 5 (9 VAC 5-80-800 et seq.) of 9 VAC 5 Chapter 80. SOPs are most often used by stationary sources to establish federally enforceable limits on potential to emit to avoid major New Source Review permitting (PSD and Nonattainment permits), Title V permitting, and/or major source MACT applicability. SOPs can also be used to combine multiple permits from a stationary source into one permit or to implement emissions trading requirements. The State Air Pollution Control Board, at its discretion, may also issue SOPs to cap the emissions of a stationary source or emissions unit causing or contributing to a violation of any air quality standard or to establish a source-specific emission standard or other requirement necessary to implement the federal Clean Air Act or the Virginia Air Pollution Control Law.

SOP permit amendment - A change to a permit issued pursuant to Article 5 (9 VAC 5-80-800 et seq.) of 9 VAC 5 Chapter 80. Only minor amendments and significant amendments are included in this category.

Title V permit – A federal operating permit issued pursuant to Article 1 (9 VAC 5-80-50 et seq.) or Article 3 (9 VAC 5-80-360 et seq.) of 9 VAC 5 Chapter 80. Facilities which (1) have the potential to emit of air pollutants above the major source thresholds, listed in 9 VAC 5-80-60 OR (2) are area sources of hazardous air pollutants, not explicitly exempted by EPA OR (3) have the potential to emit over 100,000 tons per year of CO_2 equivalent (CO_2e) (9 VAC 5-85 Part III), are required to obtain a Title V permit. For purposes of fees, the Title V permit also includes Acid Rain (Article 3) permit applications.

Title V permit modification - A change to a permit issued pursuant to Article 1 (9 VAC 5-80-50 et seq.) or Article 3 (9 VAC 5-80-360 et seq.) of 9 VAC 5 Chapter 80. Only minor modifications and significant modifications are included in this category.

Title V permit renewal – A renewal of a Title V permit pursuant to Article 1 (9 VAC 5-80-50 et seq.) of 9 VAC 5 Chapter 80. Title V permits are renewed every 5 years and a renewal application must be submitted to the regional office no sooner than 18 months and no later than 6 months prior to expiration of the Title V permit. For purposes of fees, the Title V permit renewal also includes Acid Rain (Article 3) permit renewal applications.

True minor source – A source that does not have the physical or operational capacity to emit major amounts (even if the source owner and regulatory agency disregard any enforceable limits). For further information, click here.

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

1	Local Government Certification Form, Page 3
1	Application Fee Form, Pages 4-6
1	Document Certification Form, Page 7
1	General Information, Pages 8-9
1	Fuel Burning Equipment, Page 10
1	Stationary Internal Combustion Engines, Page 11
	Incinerators, Page 12
	Processing, Page 13
	Inks, Coatings, Stains, and Adhesives, Page 14
1	VOC/Petroleum Storage Tanks, Pages 15-16
	Loading Rack and Oil-Water Separators, Page 17
	Fumigation Operations, Page 18
1	Air Pollution Control and Monitoring Equipment, Page 19
1	Air Pollution Control/Supplemental Information, Page 20
1	Stack Parameters and Fuel Data, Page 21
1	Proposed Permit Limits for Criteria Pollutants, Page 22
1	Proposed Permit Limits for Toxic Pollutants/HAPs, Page 23
	Proposed Permit Limits for Other Reg. Pollutants, Page 24
	Proposed Permit Limits for GHGs on Mass Basis, Page 25
	Proposed Permit Limits for GHGs on CO_2e Basis, Page 26
	BAE for Criteria Pollutants, Page 27
	BAE for GHGs on Mass Basis, Page 28
	BAE for GHGs on CO_2e Basis, Page 29
1	Operating Periods, Page 30
7	ATTACHED DOCUMENTS:
	Map of Site Location
1	Facility Site Plan
	Process Flow Diagram/Schematic
	MSDS or CPDS Sheets
1	Estimated Emission Calculations
	Stack Tests
	Air Modeling Data
	Confidential Information (see Instructions)
1	BACT Analysis
1	Vendor Specifications
1	Permit Application Narrative
4	BACT Analysis Appendices

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: [signature] DATE: 5/25/18

NAME: Leslie Hartz REGISTRATION NO: ______

TITLE: VP Pipeline Construction COMPANY: Atlantic Coast Pipeline, LLC

PHONE: (804) 771-4468 ADDRESS: 707 E. Main Street

EMAIL: Leslie.hartz@domionenergy.com Richmond, VA 23219

References: Virginia Regulations for the Control and Abatement of Air Pollution (Regulations), 9 VAC 5-20-230B and 9 VAC 5-80-1140E.

GENERAL INFORMATION

Person Completing Form: Alan Mikowychok	Date: 05/25/2018	Registration Number: NA
Company and Division Name: Environmental Resources Management (ERM)		FIN:
Mailing Address: 180 Admiral Cochrane Dr, Suite 400 Annapolis, MD 21401		
Exact Source Location – Include Name of City (County) and Full Street Address or Directions: Buckingham County, Virginia		
Telephone Number: (410) 266-0006	No. of Employees:	Property Area at Site:
Person to Contact on Air Pollution Matters – Name and Title: Richard B Gangle Mgr Environmental	Phone Number: (804) 273-2814 Fax: Email: richard.b.gangle@domionenergy.com	
Latitude and Longitude Coordinates **OR** UTM Coordinates of Facility: Latitude: 37º 35' 23.29" Longitude: 78º 39' 31.48"		

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):

Atlantic Coast Pipeline, LLC (ACP, LLC) proposes to construct and operate the Buckingham Compressor Station in Buckingham County, Virginia to provide compression to support the transmission of natural gas. An adjacent metering and regulating (M&R) station (Woods Corner) has been included as part of this application for the Buckingham Compressor Station.

APC, LLC submits this Article 6 permit application to the Virginia Department of Environmental Quality (DEQ), Piedmont Regional Office for the authority to construct the Buckingham Compressor Station in Buckingham County, Virginia. Please see the attached permit application narrative for clarification and/or further detail to the information in these permit application forms provided by the DEQ.

GENERAL INFORMATION (CONTINUED)

For Portable Plants:

Is this facility designed to be portable? ☐ Yes ☒ No

- If yes, is this facility already permitted as a portable plant? ☐ Yes ☐ No Permit Date: ______

If not permitted, is this an application to be permitted as a portable plant? ☐ Yes ☒ No

If permitted as a portable facility, is this a notification of relocation? ☐ Yes ☐ No

- Describe the new location or address (include a site map): ______
- Will the portable facility be co-located with another source? ☐ Yes ☐ No Reg. No. ______
- Will the portable facility be modified or reconstructed as a result of the relocation? ☐ Yes ☐ No
- Will there be any new emissions other than those associated with the relocation? ☐ Yes ☐ No
- Is the facility suitable for the area to which it will be located? (attach documentation) ☐ Yes ☐ No

Describe the products manufactured and/or services performed at this facility:

The facility serves as a natural gas compression and transmission station along the Atlantic Coast Pipeline (ACP), helping to deliver natural gas from Pennsylvania and West Virginia to Virginia and North Carolina.

List the Standard Industrial Classification (SIC) Code(s) for the facility:

4 9 2 2

List the North American Industry Classification System (NAICS) Code(s) for the facility:

4 8 6 2 1 0

List all the facilities in Virginia under common ownership or control by the owner of this facility:

Milestones: This section is to be completed if the permit application includes a new emissions unit or modification to existing operations.

Milestones*:	Starting Date:	Estimated Completion Date:
New Equipment Installation	Q3 2018	Q4 2019
Modification of Existing Process or Equipment		
Start-up Dates		

*For new or modified installations to be constructed in phased schedule, give construction/installation starting and completion date for each phase.

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

Company Name: Atlantic Coast Pipeline, LLC	**Date:** 05/25/2018	**Registration Number:** NA

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
WH-01	Hurst, Boiler, S45-G-152-60W		Q3 2018	6.384	Natural Gas	12	3	8,760 hrs/yr	40 CFR Part 98
LH-01	ETI, Line Heater, WB HTR		Q3 2018	21.22	Natural Gas	12	4	8,760 hrs/yr	40 CFR Part 98 40 CFR 60 Subpart Dc
LH-02	ETI, Line Heater, WB HTR		Q3 2018	21.22	Natural Gas	12	4	8,760 hrs/yr	40 CFR Part 98 40 CFR 60 Subpart Dc
LH-03	ETI, Line Heater, WB HTR		Q3 2018	21.22	Natural Gas	12	4	8,760 hrs/yr	40 CFR Part 98 40 CFR 60 Subpart Dc
LH-04	ETI, Line Heater, WB HTR		Q3 2018	21.22	Natural Gas	12	4	8,760 hrs/yr	40 CFR Part 98 40 CFR 60 Subpart Dc

[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) ___________________________

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) ___________________________

***Pick only one option for a requested throughput.**

NOTE: Dryers, kilns, and furnaces also have to fill out Page 13.

STATIONARY INTERNAL COMBUSTION ENGINES:

Company Name: Atlantic Coast Pipeline, LLC	**Date:** 05/25/2018	**Registration Number:** NA

Unit Ref. No.	Equipment Manufacturer, Type, and Model Number	Date of Manuf.	Date of Const.	Output Brake Horsepower (bhp)	Output Electrical Power (kW)	Type of Fuel	Usage* (use Code C)	Requested Throughput** (hrs/yr OR fuel/yr)	Federal Regulations that Apply
CT-01	Solar, Mars Turbine, 100-16000S		Q3 2018	17,574	13,105	Natural Gas	3	8,760 hrs/yr	40 CFR Part 98 NSPS Subpart KKKK
CT-02	Solar, Taurus Turbine, 70-10802S		Q3 2018	12,102	9,024	Natural Gas	3	8,760 hrs/yr	40 CFR Part 98 NSPS Subpart KKKK
CT-03	Solar, Titan Turbine, 130-20502S		Q3 2018	21,732	16,206	Natural Gas	3	8,760 hrs/yr	40 CFR Part 98 NSPS Subpart KKKK
CT-04	Solar, Centaur Turbine, 50-6200LS		Q3 2018	6,754	5,036	Natural Gas	3	8,760 hrs/yr	40 CFR Part 98 NSPS Subpart KKKK
EG-01	Caterpillar, Emergency Generator, G3516C		Q3 2018	2,175	1,500	Natural Gas	1	500 hrs/yr	NSPS Subpart JJJJ NESHAP Subpart ZZZZ

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

Code C – Usage

1. Emergency Generator
2. Participates in Emergency Load Response Program
3. Non-Emergency Generator
4. Participates in Demand Response Program(s)
5. Other (specify) ___________________________

***Can pick more than one option**
(i.e. 1 and 2 **OR** 3 and 4)

****Pick only one option for a requested throughput.**

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

Company Name: Atlantic Coast Pipeline, LLC	**Date:** 05/25/2018	**Registration Number:** NA

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. (ºF)	Tank Diameter (feet)	Tank Capacity (gal)	Requested Throughput (gal/yr)	Federal Regulations that Apply
TK-1	1b	5		Q3 2018	Hydrocarbons (Lube Oil, Waste Oil)	7.7	7.51 (@ 20ºC)	80	5.33	2,500	12,500	
TK-2	1b	5		Q3 2018	Hydrocarbons (Produced Fluids, Pipeline Liquids)	0.0001	6.67 (@ 100ºF)	80	4.00	1,000	5,000	
TK-3	1b	3		Q3 2018	Ammonia 7664-41-7			80	9.00	13,400	160,800	

[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.**

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

Company Name: Atlantic Coast Pipeline, LLC	**Date:** 05/25/2018	**Registration Number:** NA

Unit Ref. No.	Tank Color		Fixed Roof Only					Floating Roof Only				
	Shell	Roof	Internal Tank Height or Length (feet)	Max. Hourly Filling (gallons)	External Fixed Roof			Seal Type (use Code J)	Max. Hourly Withdrawal (gallons)	Internal Floating Roof		
					Type of Roof (cone or dome)	Cone height (ft) and slope (ft/ft)	Dome height (ft) and radius (ft)			Self Supporting?	If no,	
											No. of Columns	Column Diameter (ft)
TK-1	Gray/ Light	Gray/ Light	15.0									
TK-2	Gray/ Light	Gray/ Light	9.83									
TK-3	Gray/ Light	Gray/ Light	32.9									

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

AIR POLLUTION CONTROL AND MONITORING EQUIPMENT:

Company Name: Atlantic Coast Pipeline, LLC	**Date:** 05/25/2018	**Registration Number:** NA

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	SCR-01	NOx	Peerless Mfg. Co.	16	58.3	Combustion controls. Stack test for compliance demonstration.
CT-01	CT-01	OC-01	CO VOC, HAP	Peerless Mfg. Co.	21	92 50	Combustion controls. Stack test for compliance demonstration.
CT-02	CT-02	SCR-02	NOx	Peerless Mfg. Co.	16	58.3	Combustion controls. Stack test for compliance demonstration.
CT-02	CT-02	OC-02	CO VOC, HAP	Peerless Mfg. Co.	21	92 50	Combustion controls. Stack test for compliance demonstration.
CT-03	CT-03	SCR-03	NOx	Peerless Mfg. Co.	16	58.3	Combustion controls. Stack test for compliance demonstration.
CT-03	CT-03	OC-03	CO VOC, HAP	Peerless Mfg. Co.	21	92 50	Combustion controls. Stack test for compliance demonstration.
CT-04	CT-04	SCR-04	NOx	Peerless Mfg. Co.	16	58.3	Combustion controls. Stack test for compliance demonstration.
CT-04	CT-04	OC-04	CO VOC, HAP	Peerless Mfg. Co.	21	92 50	Combustion controls. Stack test for compliance demonstration.

[X] 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 (OxCat)

AIR POLLUTION CONTROL EQUIPMENT - SUPPLEMENTAL INFORMATION:

Company Name: Atlantic Coast Pipeline, LLC	**Date:** 05/25/2018	**Registration Number:** NA

Device Ref. No.	Type (use Code N)	Liquid Flow Rate (gpm) (4, 5, 6, 7, 17 ,19)	Liquid Medium (4, 5, 6, 7, 17, 19)	Cleaning Method (9, 10, 17, 18)	Number of Fields (10)	Number of Sections (9, 10)	Air to Cloth Ratio (fpm) (9)	Filter Material (9)	Inlet Temp. (°F)	Regeneration Method & Cycle Time (sec) (18)	Chamber Temp. (°F) (11, 12, 14, 15)	Retention Time (sec) (11, 12, 14, 15)	Pressure Drop (inch H_2O) (3, 4, 5, 6, 7, 9, 17)
SCR-01	16								750				
OC-01	21								750				
SCR-02	16								750				
OC-02	21								750				
SCR-03	16								750				
OC-03	21								750				
SCR-04	16								700				
OC-04	21								700				

NOTE: Numbers listed in parenthesis in the columns above represent the Control Equipment in Code N below.

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 (OxCat)

STACK PARAMETERS AND FUEL DATA:

Company Name: Atlantic Coast Pipeline, LLC	Date: 05/25/2018	Registration Number: NA

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/scf)	Max. Rated Burned/hr (Mscf/hr)	Max. Sulfur %	Max. Ash %
CT-01	**CT-01**	5	60.0	7.33	84.6	214,295	750	Natural Gas	1020	127.10	0.00362	0
CT-02	**CT-02**	5	60.0	6.00	80.8	137,027	750	Natural Gas	1020	83.94	0.00362	0
CT-03	**CT-03**	5	60.0	9.00	70.1	267,458	750	Natural Gas	1020	154.12	0.00362	0
CT-04	**CT-04**	5	60.0	6.00	58.1	98,489	700	Natural Gas	1020	53.90	0.00362	0
WH-01	**WH-01**	5	26.1	1.00	48.2	2,270	838	Natural Gas	1020	6.26	0.00362	0
LH-01	**LH-01A**	6	15.0	3.00	9.9	4,191	982	Natural Gas	1020	10.40	0.00362	0
	LH-0AB	6	15.0	3.00	9.9	4,191	982	Natural Gas	1020	10.40	0.00362	0
LH-02	**LH-02A**	6	15.0	3.00	9.9	4,191	982	Natural Gas	1020	10.40	0.00362	0
	LH-02B	6	15.0	3.00	9.9	4,191	982	Natural Gas	1020	10.40	0.00362	0
LH-03	**LH-03A**	6	15.0	3.00	9.9	4,191	982	Natural Gas	1020	10.40	0.00362	0
	LH-03B	6	15.0	3.00	9.9	4,191	982	Natural Gas	1020	10.40	0.00362	0
LH-04	**LH-04A**	6	15.0	3.00	9.9	4,191	982	Natural Gas	1020	10.40	0.00362	0
	LH-04B	6	15.0	3.00	9.9	4,191	982	Natural Gas	1020	10.40	0.00362	0
EG-01	**EG-01**	5	45.0	1.33	147.2	12,271	867	Natural Gas	1020	15.30	0.00362	0
TK-1	**TK-1**	5	8.6	0.33	0.003	0.015	Ambient	---	---	---	---	---
TK-2	**TK-2**	5	7.3	0.33	0.003	0.015	Ambient	---	---	---	---	---

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.**

NOTE: All data based on normal operation.

PROPOSED PERMIT LIMITS FOR CRITERIA POLLUTANTS:

Company Name: Atlantic Coast Pipeline, LLC	**Date:** 05/25/2018	**Registration Number:** NA

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	2.85	12.5	2.85	12.5	2.85	12.5	0.485	2.12	9.27	8.67	126	9.54	1.09	1.05	---	---
CT-02	1.88	8.23	1.88	8.23	1.88	8.23	0.320	1.40	6.11	5.72	74.5	5.85	0.669	0.687	---	---
CT-03	3.46	15.1	3.46	15.1	3.46	15.1	0.588	2.57	11.6	10.5	179	13.0	1.47	1.28	---	---
CT-04	1.21	5.28	1.21	5.28	1.21	5.28	0.206	0.898	4.02	3.68	70.0	4.77	0.560	0.444	---	---
WH-01	0.048	0.208	0.048	0.208	0.048	0.208	0.021	0.091	0.313	1.37	0.526	2.30	0.034	0.151	---	---
LH-01	0.102	0.446	0.102	0.446	0.102	0.446	0.069	0.304	0.212	0.929	0.785	3.44	0.114	0.501	---	---
LH-02	0.102	0.446	0.102	0.446	0.102	0.446	0.069	0.304	0.212	0.929	0.785	3.44	0.114	0.501	---	---
LH-03	0.102	0.446	0.102	0.446	0.102	0.446	0.069	0.304	0.212	0.929	0.785	3.44	0.114	0.501	---	---
LH-04	0.102	0.446	0.102	0.446	0.102	0.446	0.069	0.304	0.212	0.929	0.785	3.44	0.114	0.501	---	---
EG-01	0.725	0.181	0.725	0.181	0.725	0.181	0.049	0.012	2.40	0.599	9.59	2.40	2.40	0.599	---	---
FUG-01	---	---	---	---	---	---	---	---	---	---	---	---	82.8	0.421	---	---
FUG-02	---	---	---	---	---	---	---	---	---	---	---	---	0.208	0.910	---	---
TK-1	---	---	---	---	---	---	---	---	---	---	---	---	0.001	2.52E-5	---	---
TK-2	---	---	---	---	---	---	---	---	---	---	---	---	0.753	0.146	---	---
TOTAL:	**10.6**	**43.2**	**10.6**	**43.2**	**10.6**	**43.2**	**1.95**	**8.30**	**34.5**	**34.3**	**463**	**51.6**	**90.5**	**7.69**	**---**	**---**

[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.

NOTE: Unit hourly emission rates represent the worst-case hour of operation for that unit. Total hourly emission rates are the sum of all unit hourly emission rates. This is an over-estimation because the worst-case hour of operation would not occur simultaneously for each unit.

PROPOSED PERMIT LIMITS FOR TOXIC POLLUTANTS/HAPS:

Company Name: Atlantic Coast Pipeline, LLC	Date: 05/25/2018	Registration Number: NA

Unit Ref. No.	Proposed Permit Limits for Toxic/HAP Pollutants*													
	HAP Name: Formaldehyde **CAS #:** 50-00-0		**HAP Name:** Hexane **CAS #:** 110-54-3		**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**
CT-01	2.56	1.04	---	---										
CT-02	4.70	0.858	---	---										
CT-03	3.09	1.25	---	---										
CT-04	1.17	0.448	---	---										
WH-01	4.69E-4	0.002	0.011	0.049										
LH-01	0.002	0.007	0.037	0.164										
LH-02	0.002	0.007	0.037	0.164										
LH-03	0.002	0.007	0.037	0.164										
LH-04	0.002	0.007	0.037	0.164										
EG-01	2.49	0.623	0.002	0.001										
FUG-01	---	---	7.61	0.026										
FUG-02	---	---	0.013	0.056										
TK-1	---	---	0.001	2.52E-5										
TK-2	---	---	0.052	0.010										
TOTAL:	**14.0**	**4.24**	**7.84**	**0.798**										

[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.

****Note: Hexane emissions are only included as a reference. Hexane emissions are below Virginia DEQ's Air Toxic Exemption Thresholds. For more details, please see the Estimated Emission Calculations and Air Toxics Assessment in Appendix C.**

OPERATING PERIODS:

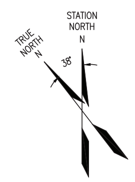
Company Name: Atlantic Coast Pipeline, LLC	Date: 05/25/2018	Registration Number: NA

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
CT-03	25	25	25	25	24	7	52	24	7	52
CT-04	25	25	25	25	24	7	52	24	7	52
WH-01	25	25	25	25	24	7	52	24	7	52
LH-01	25	25	25	25	24	7	52	24	7	52
LH-02	25	25	25	25	24	7	52	24	7	52
LH-03	25	25	25	25	24	7	52	24	7	52
LH-04	25	25	25	25	24	7	52	24	7	52
EG-01	25	25	25	25	1	1	52	24	7	52
TK-1	25	25	25	25	24	7	52	24	7	52
TK-2	25	25	25	25	24	7	52	24	7	52
TK-3	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**

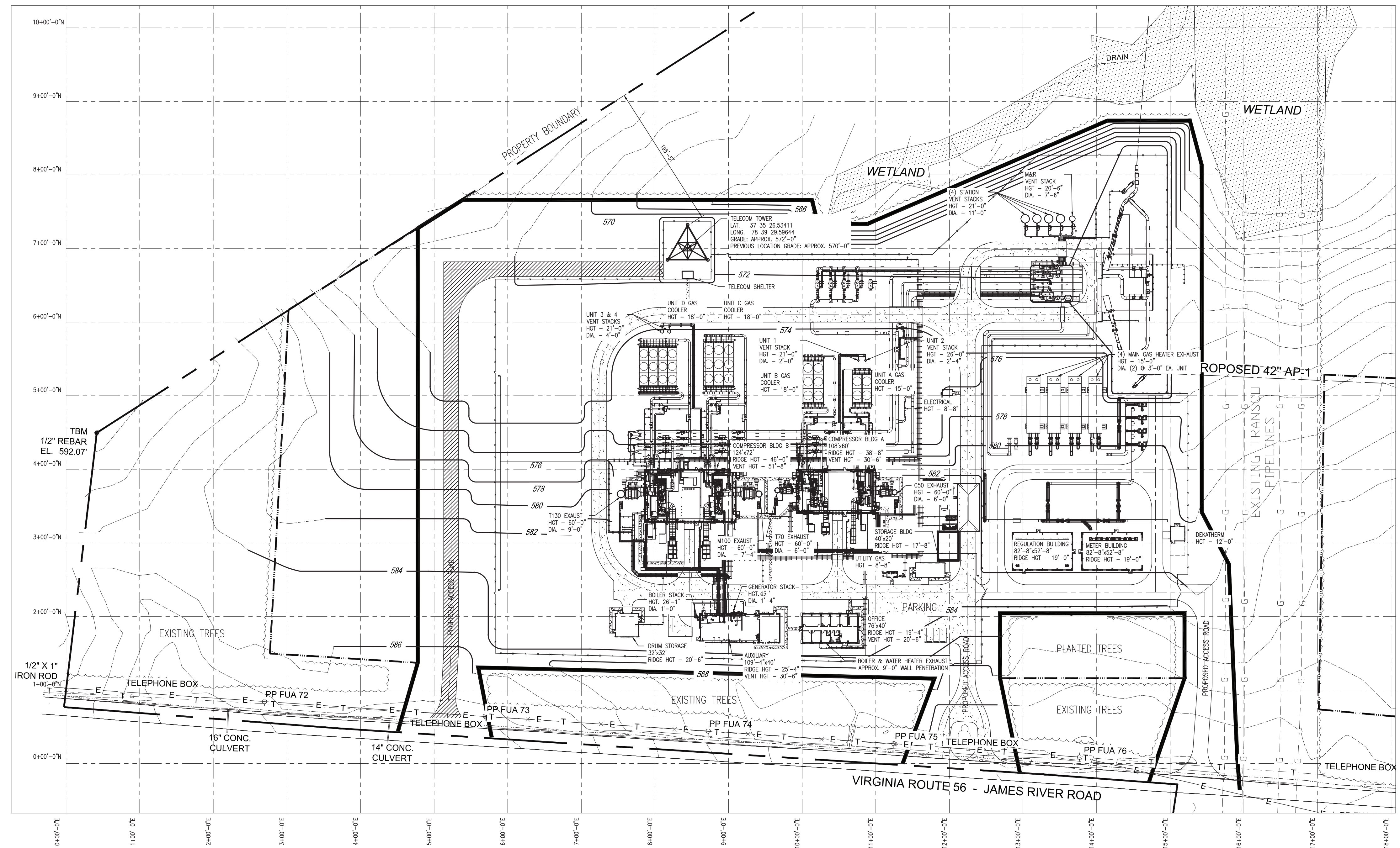
APPENDIX B

FACILITY PLOT PLAN



LEGEND

580	CONTOUR
	ACP CENTER LINE
	EDGE OF ROAD
	FENCE
	DITCH
	RIGHT-OF-WAY
E	OVERHEAD UTILITY
G	BURIED PIPELINE
PP FUA 74	POWER POLE WITH IDENTIFICATION
TBM	TEMPORARY BENCHMARK



REISSUED FOR
12/1/2017
INFORMATION

BASIC SYSTEMS
BASIC SYSTEMS, INC.
9255 CADIZ ROAD
CAMBRIDGE, OHIO 43725
(740) 432-3001

GENERAL NOTES AND COMMENTS:

V.T.D = VENDOR TO DETERMINE

SYM.	DATE	BY	REVISION INFORMATION	PROJECT/TASK	APP.
g	12/1/17	JLB	MOVED FENCE AT STATION BLOWDOWN AREA	64649.CS.CS2.1	
f	11/9/17	JLB	ADDED VENT SILENCER INFORMATION	64649.CS.CS2.1	
e	9/20/17	JLB	REVISED FENCE AT RECEIVER/LAUNCHER AREA	64649.CS.CS2.1	
d	8/30/17	JLB	REVISED APU STACK LOCATION	64649.CS.CS2.1	
c	8/17/2017	JLB	ISSUED FOR AIR PERMIT	64649.CS.CS2.1	
b	6/29/2017	JLB	ISSUED FOR 100% DESIGN REVIEW	64649.CS.CS2.1	
a	12/08/16	JLB	ISSUED FOR 75% DESIGN REVIEW	64649.CS.CS2.1	

SEAL

ORIGINAL CONSTRUCTION INFORMATION		
PROJECT/TASK:	64649.CS.CS2.1	
DRAWN:	mls	4/5/2016
CHECKED:		
APP. FOR BID:		
APP. FOR CONST.:		
SCALE:	1" = 60'-0"	

Atlantic Coast Pipeline, LLC.
925 White Oaks Blvd., Bridgeport, West Virginia 26330

FOR: BUCKINGHAM COMPRESSOR STATION

TITLE: SITE LAYOUT PLAN

TOWN: WOODS CORNER	COUNTY: BUCKINGHAM, VA	GROUP	DWG. NO.	REV.
DIR/FILE: I:\1800s\1866\Drawings		PD	E9925A	g

APPENDIX C

POTENTIAL TO EMIT CALCULATIONS

Table C-1 Permit to Construct Application Project Equipment List

ACP Buckingham Compressor Station - Buckingham County, Virginia

Emission Point ID	Source	Manufacturer	Model/Type	Rated Capacity
CT-01	Compressor Turbine	Solar Turbines	Mars 100-16000S	15,900 hp
CT-02	Compressor Turbine	Solar Turbines	Taurus 70-10802S	11,107 hp
CT-03	Compressor Turbine	Solar Turbines	Titan 130-20502S	20,500 hp
CT-04	Compressor Turbine	Solar Turbines	Centaur 50-6200LS	6,276 hp
WH-01	Boiler	Hurst	S45-G-152-60W	6.384 MMBtu/hr
LH-01	Line Heater	ETI	WB HTR	21.22 MMBtu/hr
LH-02	Line Heater	ETI	WB HTR	21.22 MMBtu/hr
LH-03	Line Heater	ETI	WB HTR	21.22 MMBtu/hr
LH-04	Line Heater	ETI	WB HTR	21.22 MMBtu/hr
EG-01	Emergency Generator	Caterpillar	G3516C	2,175 hp
FUG-01	Fugitive Leaks - Blowdowns	-	-	-
FUG-02	Fugitive Leaks - Piping	-	-	-
TK-1	Accumulator Tank	-	-	2,500 gal
TK-2	Hydrocarbon (Waste Oil) Tank	--	--	1,000 gal
TK-3	Ammonia Tank	--	--	13,400 gal

Notes:
1. The rated capacity for the compressor turbines represents the ISO rated capacity.

Table C-2 Potential Emissions From Combustion Sources

ACP Buckingham Compressor Station - Buckingham County, Virginia

Turbine Operational Parameters:

Normal Hours of Operation:	8,722
Hours at Low Load (<50%)	0
Hours of Low Temp. (< 0 deg. F)	5
Hours of Start-up/Shut-down	33.3
Total Hours of Operation (hr/yr):	8,760

Emergency Generator Operational Hours:

Normal Hours of Operation:	500

Boiler/Heater Operational Parameters:

Normal Hours of Operation:	8,760

Pre-Control Potential to Emit

Combustion Sources	Power Rating	Units	Fuel	Criteria Pollutants (tpy)								GHG Emissions (tpy)				Ammonia (tpy)	HAP (tpy)
				NOx	CO	VOC	SO2	PMF	PMF-10	PMF-2.5	PMC	CO2	CH4	N2O	CO2e	NH3	Total HAP
Solar Mars 100 Turbine	15,900	hp	Natural Gas	20.4	34.6	1.98	2.12	3.58	3.58	3.58	8.86	74,015	5.35	1.87	74,705	8.09	1.73
Solar Taurus 70 Turbine	11,107	hp	Natural Gas	13.5	22.8	1.31	1.40	2.37	2.37	2.37	5.85	48,856	3.53	1.23	49,312	5.75	1.14
Solar Titan 130 Turbine	20,500	hp	Natural Gas	24.8	41.9	2.40	2.57	4.34	4.34	4.34	10.7	89,662	6.49	2.26	90,499	10.2	2.09
Solar Centaur 50L Turbine	6,276	hp	Natural Gas	8.68	14.6	0.838	0.897	1.52	1.52	1.52	3.76	31,420	2.27	0.792	31,713	3.57	0.732
Hurst S45 Boiler	6.384	MMBtu/hr	Natural Gas	1.37	2.30	0.151	0.091	0.052	0.052	0.052	0.156	3,290	0.063	0.060	3,309	0	0.052
ETI Line Heater 1 (Woods Corner)	21.22	MMBtu/hr	Natural Gas	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
ETI Line Heater 2 (Woods Corner)	21.22	MMBtu/hr	Natural Gas	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
ETI Line Heater 3 (Woods Corner)	21.22	MMBtu/hr	Natural Gas	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
ETI Line Heater 4 (Woods Corner)	21.22	MMBtu/hr	Natural Gas	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
Caterpillar G3516C EGen (Woods Corner)	2,175	hp	Natural Gas	0.599	2.40	0.599	0.012	0.144	0.144	0.144	0.037	531	4.80	0	651	0	0.657
Total (tons/yr)				**73.1**	**132**	**9.27**	**8.29**	**12.5**	**12.5**	**12.5**	**30.8**	**291,513**	**23.3**	**7.02**	**294,187**	**27.6**	**7.09**

Turbine Control Efficiencies

Control Technology	NOx	CO	VOC
Selective Catalytic Reduction	58%	-	-
Oxidation Catalyst	-	92%	50%

Post-Control Potential to Emit

Combustion Sources	Power Rating	Units	Fuel	Criteria Pollutants (tpy)								GHG Emissions (tpy)				Ammonia (tpy)	HAP (tpy)
				NOx	CO	VOC	SO2	PMF	PMF-10	PMF-2.5	PMC	CO2	CH4	N2O	CO2e	NH3	Total HAP
Solar Mars 100 Turbine	15,900	hp	Natural Gas	8.52	2.77	0.989	2.12	3.58	3.58	3.58	8.86	74,015	5.35	1.87	74,705	8.09	0.863
Solar Taurus 70 Turbine	11,107	hp	Natural Gas	5.63	1.83	0.653	1.40	2.37	2.37	2.37	5.85	48,856	3.53	1.23	49,312	5.75	0.570
Solar Titan 130 Turbine	20,500	hp	Natural Gas	10.3	3.35	1.20	2.57	4.34	4.34	4.34	10.7	89,662	6.49	2.26	90,499	10.2	1.05
Solar Centaur 50L Turbine	6,276	hp	Natural Gas	3.62	1.17	0.419	0.897	1.52	1.52	1.52	3.76	31,420	2.27	0.792	31,713	3.57	0.366
Hurst S45 Boiler	6.384	MMBtu/hr	Natural Gas	1.37	2.30	0.151	0.091	0.052	0.052	0.052	0.156	3,290	0.063	0.060	3,309	0	0.052
ETI Line Heater 1 (Woods Corner)	21.22	MMBtu/hr	Natural Gas	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
ETI Line Heater 2 (Woods Corner)	21.22	MMBtu/hr	Natural Gas	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
ETI Line Heater 3 (Woods Corner)	21.22	MMBtu/hr	Natural Gas	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
ETI Line Heater 4 (Woods Corner)	21.22	MMBtu/hr	Natural Gas	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
Caterpillar G3516C EGen (Woods Corner)	2,175	hp	Natural Gas	0.599	2.40	0.599	0.012	0.144	0.144	0.144	0.037	531	4.80	0	651	0	0.657
Total (tons/yr)				**33.8**	**27.6**	**6.01**	**8.29**	**12.5**	**12.5**	**12.5**	**30.8**	**291,513**	**23.3**	**7.02**	**294,187**	**27.6**	**4.24**

Notes:

(1) Turbine emissions are calculated by the following formula: ER * Run Hours / 2000 * (1 - Control Efficiency)
ER = Emission Rate for particular equipment and pollutant (lbs/hr)
2000 = The amount of lbs in a ton
(2) Caterpillar G3516C EGen emissions are calculated by the following formula: Power Rating * Run Hours * EF / 2000
Power Rating = Engine rating (hp)
EF = Emission Factor from either manufacturer's data or AP-42 (lb/hp-hr)
2000 = The amount of lbs in a ton
(3) Hurst S45 Boiler and ETI Line Heater emissions calculated by the following formula: EF * Power Rating * Run Hours / HHV / 2000
EF = Emission Factor from either manufacturer's data or AP-42 (lb/MMscf)
Power Rating = Boiler/Heater heat capacity (MMBtu/hr)
HHV = Natural Gas High Heating Value (1020 MMBtu/MMscf)
2000 = The amount of lbs in a ton
(4) Turbines are equipped with Selective Catalytic Reduction (SCR) and oxidation catalyst for control of NOx (58%), CO (92%), and VOC (50%)
(5) Caterpillar G3516C EGen hp taken from manufacturer data
(6) Hurst S45 Boiler assumed to have low-NOx burners
(7) See the "HAP Emissions" worksheet for a more detailed breakdown of HAP emissions
(8) See Emissions Factors table for Emissions Factors for each operating scenario
(9) Each start-up/shut-down event assumed to last 10 minutes

Table C-3A Event Based Potential Emissions From Combustion Sources

ACP Buckingham Compressor Station - Buckingham County, Virginia

Startup Emissions

Combustion Sources	Power Rating	Units	Fuel	Startup Events	Criteria Pollutants (tpy)								GHG Emissions (tpy)				Ammonia	HAP
					NOx	CO	VOC	SO2	PMF	PMF-10	PMF-2.5	PMC	CO2	CH4	N2O	CO2e	NH3	Total HAP
Solar Mars 100 Turbine	15,900	hp	Natural Gas	100	0.070	6.18	0.036	5.00E-04	8.64E-04	8.64E-04	8.64E-04	0.002	41.5	0.320	0.004	50.5	0.015	0.130
Solar Taurus 70 Turbine	11,107	hp	Natural Gas	100	0.040	3.66	0.021	5.00E-04	8.64E-04	8.64E-04	8.64E-04	0.002	26.0	0.189	0.007	32.6	0.011	0.245
Solar Titan 130 Turbine	20,500	hp	Natural Gas	100	0.095	8.85	0.051	0.001	0.002	0.002	0.002	0.004	58.1	0.455	0.004	70.6	0.019	0.150
Solar Centaur 50L Turbine	6,276	hp	Natural Gas	100	0.040	3.46	0.020	5.00E-04	4.32E-04	4.32E-04	4.32E-04	0.001	23.5	0.180	0.002	28.4	0.007	0.060
Total (tons/yr)					**0.245**	**22.1**	**0.127**	**0.003**	**0.004**	**0.004**	**0.004**	**0.009**	**149**	**1.14**	**0.016**	**182**	**0.053**	**0.585**

Shutdown Emissions

Combustion Sources	Power Rating	Units	Fuel	Shutdown Events	Criteria Pollutants (tpy)								GHG Emissions (tpy)				Ammonia	HAP
					NOx	CO	VOC	SO2	PMF	PMF-10	PMF-2.5	PMC	CO2	CH4	N2O	CO2e	NH3	Total HAP
Solar Mars 100 Turbine	15,900	hp	Natural Gas	100	0.085	0.597	0.021	0.001	0.001	0.001	0.001	0.004	46.0	0.383	0.007	57.5	0.015	0.115
Solar Taurus 70 Turbine	11,107	hp	Natural Gas	100	0.055	0.374	0.013	5.00E-04	0.001	0.001	0.001	0.002	28.8	0.239	0.005	36.1	0.011	0.085
Solar Titan 130 Turbine	20,500	hp	Natural Gas	100	0.120	0.830	0.030	0.002	0.002	0.002	0.002	0.005	63.6	0.536	0.007	79.1	0.019	0.128
Solar Centaur 50L Turbine	6,276	hp	Natural Gas	100	0.020	0.142	0.005	5.00E-04	7.20E-04	7.20E-04	7.20E-04	0.002	10.9	0.090	0.003	14.0	0.007	0.050
Total (tons/yr)					**0.280**	**1.94**	**0.069**	**0.004**	**0.005**	**0.005**	**0.005**	**0.013**	**149**	**1.25**	**0.021**	**187**	**0.053**	**0.378**
Total SUSD Emissions (tons/yr)					**0.525**	**24.1**	**0.196**	**0.006**	**0.009**	**0.009**	**0.009**	**0.022**	**298**	**2.39**	**0.037**	**369**	**0.105**	**0.963**

Compressor Blowdown Emissions - Controlled

Source Designation:	FUG-01

Blowdown Startup Events (April 2018 Update: Values updated to reflect compressor purge volumes)

		CT-01	CT-02	CT-03	CT-04
Blowdown from Startup	scf/event	3,768	1,884	4,083	1,095
Volumetric flow rate	scf-lbmol	385	385	385	385
Gas Molecular Weight	lb-lbmol	17.17	17.17	17.17	17.17
Startup Blowdown	lb/event	168	84.0	182	48.8

Blowdown Shutdown Events (December 2017 Update: Values updated to reflect VGR system limiting blowdown volume, based on blowing down from 30 PSIG)

		CT-01	CT-02	CT-03	CT-04
Blowdown from Shutdown	scf/event	12,087	5,142	13,443	2,600
Volumetric flow rate	scf-lbmol	385	385	385	385
Methane Molecular Weight	lb-lbmol	17.17	17.17	17.17	17.17
Shutdown Blowdown	lb/event	539	229	600	116

Gas Composition

Pollutant	Molecular Weight (lb/lb-mol)	Molar (Volume) Fraction (mol%)	Wt. Fraction[1] (wt. %)
Total Stream Molecular Weight	17.17		
Non-VOC			
Carbon Dioxide	44.01	1.041%	**2.67%**
Nitrogen	28.01	0.994%	**1.62%**
Methane	16.04	94.206%	**88.00%**
Ethane	30.07	2.923%	**5.12%**
VOC			
Propane	44.10	0.546%	**1.40%**
n-Butane	58.12	0.084%	**0.28%**
IsoButane	58.12	0.079%	**0.27%**
n-Pentane	72.15	0.022%	**0.09%**
IsoPentane	72.15	0.024%	**0.10%**
n-Hexane	86.18	0.032%	**0.16%**
n-Heptane	100.21	0.049%	**0.29%**
Total VOC Fraction	53.28	**0.836%**	**2.59%**
Total HAP Fraction	86.18	0.032%	**0.16%**

Blowdown from Startup Events

Combustion Sources	Startup Events	VOC	GHG Emissions (tpy)			HAPs
			CO2	CH4	CO2e	
Solar Mars 100 Turbine	10	0.022	0.022	0.739	18.5	0.001
Solar Taurus 70 Turbine	10	0.011	0.011	0.370	9.25	6.75E-04
Solar Titan 130 Turbine	10	0.024	0.024	0.801	20.1	0.001
Solar Centaur 50L Turbine	10	0.006	0.007	0.215	5.38	3.92E-04
Total (tons/yr)		**0.063**	**0.064**	**2.13**	**53.2**	**0.004**

Blowdown from Shutdown Events

Combustion Sources	Shutdown Events	VOC	GHG Emissions (tpy)			HAPs
			CO2	CH4	CO2e	
Solar Mars 100 Turbine	10	0.070	0.072	2.37	59.4	0.004
Solar Taurus 70 Turbine	10	0.030	0.031	1.01	25.3	0.002
Solar Titan 130 Turbine	10	0.078	0.080	2.64	66.0	0.005
Solar Centaur 50L Turbine	10	0.015	0.015	0.510	12.8	9.31E-04
Total (tons/yr)		**0.192**	**0.198**	**6.53**	**163**	**0.012**

Site-Wide Blowdown Events (April 2018 Update: The gas vented from the site wide blowndown event reflects the amount vented during a capped event for testing of the ESD system.)

Site-Wide Blowdown	280	scf/event
Volumetric flow rate	385	scf-lbmol
Site-Wide Blowdown	12.5	lb/event

Blowdown from Site-Wide Events

Sources	Site-Wide Events	VOC	GHG Emissions (tpy)			HAPs
			CO2	CH4	CO2e	
ACP-2	1	1.62E-04	1.67E-04	0.005	0.138	1.00E-05
Total (tons/yr)		**1.62E-04**	**1.67E-04**	**0.005**	**0.138**	**1.00E-05**

Blowdown from Pigging Events

Gas Vented Per Launcher Event	1,563	lb/event
Gas Vented Per Receiver Event	1,630	lb/event

Sources	Pigging Events	VOC	GHG Emissions (tpy)			HAPs
			CO2	CH4	CO2e	
Pig Launcher	4	0.081	0.083	2.75	68.9	0.005
Pig Receiver	4	0.085	0.087	2.87	71.8	0.005
Total (tons/yr)		**0.166**	**0.170**	**5.62**	**141**	**0.010**
Total Blowdown Emissions (ton/yr)		**0.421**	**0.433**	**14.3**	**357**	**0.026**
Total Uncontrolled Blowdown Emissions (ton/yr)		**5.09**	**5.23**	**173**	**4,321**	**0.315**
Total Blowdown Emission Control Efficiency		**91.7%**	**91.7%**	**91.7%**	**91.7%**	**91.7%**

Table C-3B Potential Uncontrolled Emissions From Blowdowns

ACP Buckingham Compressor Station - Buckingham County, Virginia

Compressor Blowdown Emissions - Uncontrolled

Source Designation:	FUG-01

Blowdown Startup Events (April 2018 Update: Values updated to reflect compressor purge volumes)

		CT-01	CT-02	CT-03	CT-04
Blowdown from Startup	scf/event	3,768	1,884	4,083	1,095
Volumetric flow rate	scf-lbmol	385	385	385	385
Gas Molecular Weight	lb-lbmol	17.17	17.17	17.17	17.17
Startup Blowdown	lb/event	168	84.0	182	48.8

Blowdown Shutdown Events (May 2018 Update: Values updated to reflect blowdown volume, based on blowing down from 1400 PSIG)

		CT-01	CT-02	CT-03	CT-04
Blowdown from Shutdown	scf/event	12,087	5,142	13,443	2,600
Volumetric flow rate	scf-lbmol	385	385	385	385
Methane Molecular Weight	lb-lbmol	17.17	17.17	17.17	17.17
Shutdown Blowdown	lb/event	539	229	600	116

Gas Composition

Pollutant	Molecular Weight (lb/lb-mol)	Molar (Volume) Fraction (mol%)	Wt. Fraction[1] (wt. %)
Total Stream Molecular Weight	17.17		
Non-VOC			
Carbon Dioxide	44.01	1.041%	**2.67%**
Nitrogen	28.01	0.994%	**1.62%**
Methane	16.04	94.206%	**88.00%**
Ethane	30.07	2.923%	**5.12%**
VOC			
Propane	44.10	0.546%	**1.40%**
n-Butane	58.12	0.084%	**0.28%**
IsoButane	58.12	0.079%	**0.27%**
n-Pentane	72.15	0.022%	**0.09%**
IsoPentane	72.15	0.024%	**0.10%**
n-Hexane	86.18	0.032%	**0.16%**
n-Heptane	100.21	0.049%	**0.29%**
Total VOC Fraction	53.28	**0.836%**	**2.59%**
Total HAP Fraction	86.18	0.032%	**0.16%**

Blowdown from Startup Events

			GHG Emissions (tpy)			
Combustion Sources	**Startup Events**	**VOC**	**CO2**	**CH4**	**CO2e**	**HAPs**
Solar Mars 100 Turbine	100	0.218	0.224	7.39	185	0.013
Solar Taurus 70 Turbine	100	0.109	0.112	3.70	92.5	0.007
Solar Titan 130 Turbine	100	0.236	0.243	8.01	201	0.015
Solar Centaur 50L Turbine	100	0.063	0.065	2.15	53.8	0.004
Total (tons/yr)		**0.626**	**0.644**	**21.3**	**532**	**0.039**

Blowdown from Shutdown Events

			GHG Emissions (tpy)			
Combustion Sources	**Shutdown Events**	**VOC**	**CO2**	**CH4**	**CO2e**	**HAPs**
Solar Mars 100 Turbine	100	0.699	0.719	23.7	594	0.043
Solar Taurus 70 Turbine	100	0.297	0.306	10.1	253	0.018
Solar Titan 130 Turbine	100	0.778	0.800	26.4	660	0.048
Solar Centaur 50L Turbine	100	0.150	0.155	5.10	128	0.009
Total (tons/yr)		**1.92**	**1.98**	**65.3**	**1,634**	**0.119**

Site-Wide Blowdown Events (December 2017 Update: Total potential site-wide blowdown event volume updated based detailed design and reflects all equipment and piping at the station pressurized to maximum extent prior to the event. This site wide event occurs once every 5 years.

Site-Wide Blowdown	4,100,000	scf/event
Volumetric flow rate	385	scf-lbmol
Site-Wide Blowdown	182,866	lb/event

Blowdown from Site-Wide Events

			GHG Emissions (tpy)			
Sources	**Site-Wide Events**	**VOC**	**CO2**	**CH4**	**CO2e**	**HAPs**
ACP-2	1	2.37	2.44	80.5	2,014	0.147
Total (tons/yr)		**2.37**	**2.44**	**80.5**	**2,014**	**0.147**

Blowdown from Pigging Events

Gas Vented Per Launcher Event	1,563	lb/event
Gas Vented Per Receiver Event	1,630	lb/event

			GHG Emissions (tpy)			
Sources	**Pigging Events**	**VOC**	**CO2**	**CH4**	**CO2e**	**HAPs**
Pig Launcher	4	0.081	0.083	2.75	68.9	0.005
Pig Receiver	4	0.085	0.087	2.87	71.8	0.005
Total (tons/yr)		**0.166**	**0.170**	**5.62**	**141**	**0.010**

Total Blowdown Emissions (tons/yr)		**5.09**	**5.23**	**173**	**4,321**	**0.315**

Table C-4 Combustion Source Criteria Pollutant Emission Factors

ACP Buckingham Compressor Station - Buckingham County, Virginia

Solar Turbine Normal Operation Emission Factors (lb/hr)																
Equipment Name	**Fuel**	**Units**	**NOx**	**CO**	**VOC**	**SO2**	**PMF**	**PMF-10**	**PMF-2.5**	**PMC**	**CO2**	**CH4**	**N2O**	**CO2e**	**NH3**	**Total HAP**
Solar Centaur 50L Turbine	Natural Gas	lb/hr	1.99	3.35	0.192	0.206	0.348	0.348	0.348	0.861	7,201	0.520	0.181	7,268	0.818	0.168
Solar Taurus 70 Turbine	Natural Gas	lb/hr	3.09	5.22	0.299	0.320	0.542	0.542	0.542	1.34	11,197	0.810	0.283	11,301	1.32	0.261
Solar Mars 100 Turbine	Natural Gas	lb/hr	4.67	7.91	0.453	0.485	0.821	0.821	0.821	2.03	16,963	1.23	0.428	17,121	1.85	0.395
Solar Titan 130 Turbine	Natural Gas	lb/hr	5.67	9.58	0.549	0.588	0.996	0.996	0.996	2.46	20,549	1.49	0.519	20,741	2.33	0.479

Notes
(1) Pre-Control Emission Rates for NOx, CO, VOC, PMF, PMC, and CO2 taken from Solar Turbine Data at 100% load and 0 degrees F
(2) Emission Factors for SO2, CH4, N2O, and HAP taken from AP-42 in (lbs/MMBtu) and multiplied by turbine fuel throughput by Solar Turbine at 100% load and 0 degree F to get Emission Rates
(3) Assume PMF=PMF-10=PMF-2.5; Filterable and Condensable based on Solar Turbine Emission Factor and ratio of AP-42 Table 3.1 factors
(4) NH3 emission rates based on a 10 ppm ammonia slip from the SCR based on manufacturer information
(5) CO2e emission rate calculated by multiplying each GHG (CO2, CH4, N2O) by its Global Warming Potential (GWP) and adding them together
(6) CO2 GWP = 1; CH4 GWP = 25; N2O GWP = 298 [40 CFR Part 98]

Controlled Solar Turbine Normal Operation Emission Factors (lb/hr)						
Equipment Name	**Fuel**	**Units**	**NOx**	**CO**	**VOC**	**Total HAP**
Solar Centaur 50L Turbine	Natural Gas	lb/hr	0.828	0.268	0.096	0.084
Solar Taurus 70 Turbine	Natural Gas	lb/hr	1.29	0.418	0.150	0.131
Solar Mars 100 Turbine	Natural Gas	lb/hr	1.95	0.633	0.227	0.198
Solar Titan 130 Turbine	Natural Gas	lb/hr	2.36	0.766	0.275	0.240

Notes
1. Control efficiency of SCR and Oxidation Catalyst applied during normal operations.

Solar Turbine Alternate Operation Emission Factors (lb/hr)								
			< 0 degrees F			**Solar Turbine Low Load F**		
Equipment Name	**Fuel**	**Units**	**NOx**	**CO**	**VOC**	**NOx**	**CO**	**VOC**
Solar Centaur 50L Turbine	Natural Gas	lb/hr	9.27	13.4	0.384	15.4	1,340	7.68
Solar Taurus 70 Turbine	Natural Gas	lb/hr	14.4	20.9	0.598	24.0	2,088	12.0
Solar Mars 100 Turbine	Natural Gas	lb/hr	21.8	31.6	0.906	36.4	3,164	18.1
Solar Titan 130 Turbine	Natural Gas	lb/hr	26.5	38.3	1.10	44.1	3,832	22.0

Notes
(1) Pre-Control low temperature Emission Rates for NOx, CO, VOC. Conservatively assume 42 ppm NOx, 100 ppm CO, and 5 ppm VOC (10% of UHC) per Table 1 of Solar PIL 167 Revision 4 (dated 6 June 2012)
(2) Pre-Control low load Emission Rates for NOx, CO, VOC. Conservatively assume 70 ppm NOx, 10,000 ppm CO, and 100 ppm VOC (10% of UHC) per Table 4 of Solar PIL 167 Revision 4 (dated 6 June 2012)
(3) Alternate Operation Emission Factor = Normal Operation Emission Factor * (ppm alternate operation) / (ppm normal operation)
Example calculation - Centaur 50L NOx (lb/hr) @ < 0 deg. F = 1.99 lb/hr * (42 ppm / 9 ppm) = 9.27 lb/hr

Controlled Solar Turbine Alternate Operation Emission Factors (lb/hr)								
			< 0 degrees F			**Solar Turbine Low Load F Operation**		
Equipment Name	**Fuel**	**Units**	**NOx**	**CO**	**VOC**	**NOx**	**CO**	**VOC**
Solar Centaur 50L Turbine	Natural Gas	lb/hr	3.86	1.07	0.192	6.44	107	3.84
Solar Taurus 70 Turbine	Natural Gas	lb/hr	6.01	1.67	0.299	10.0	167	5.98
Solar Mars 100 Turbine	Natural Gas	lb/hr	9.09	2.53	0.453	15.1	253	9.06
Solar Titan 130 Turbine	Natural Gas	lb/hr	11.0	3.07	0.549	18.4	307	11.0

Notes
1. Control efficiency of SCR and Oxidation Catalyst applied during low temperature (< 0 deg. F) and low load operations.

Solar Turbine Start-up Emission Factors (lb/event)																
Equipment Name	**Fuel**	**Units**	**NOx**	**CO**	**VOC**	**SO2**	**PMF**	**PMF-10**	**PMF-2.5**	**PMC**	**CO2**	**CH4**	**N2O**	**CO2e**	**NH3**	**Total HAP**
Solar Centaur 50L Turbine	Natural Gas	lb/event	0.8	69.1	0.400	0.01	0.009	0.009	0.009	0.021	469	3.60	0.03	568	0.136	1.2
Solar Taurus 70 Turbine	Natural Gas	lb/event	0.8	73.1	0.420	0.01	0.017	0.017	0.017	0.043	519	3.78	0.13	652	0.220	4.9
Solar Mars 100 Turbine	Natural Gas	lb/event	1.4	123.5	0.710	0.01	0.017	0.017	0.017	0.043	829	6.39	0.07	1,010	0.309	2.6
Solar Titan 130 Turbine	Natural Gas	lb/event	1.9	176.9	1.01	0.02	0.032	0.032	0.032	0.078	1,161	9.09	0.08	1,412	0.388	3.0

Notes
(1) Start-up Emissions of NOx, CO, VOC, CO2, and CH4 based on Solar Turbines Incorporated Product Information Letter 170: Emission Estimates at Start-up, Shutdown, and Commissioning for SoLoNOx Combustion Products (13 June 2012).
(2) Start-up Emissions of SO2, PM, N2O, and HAP based on Solar estimations.
(3) NH3 emission rates based on a 10 ppm ammonia slip from the SCR based on manufacturer information and a start-up duration of 10 minutes.
(4) VOCs assumed to be 10% of UHC and CH4 assumed to be 90% of UHC.
(5) CO2e emission rate calculated by multiplying each GHG (CO2, CH4, N2O) by its Global Warming Potential (GWP) and adding them together.
(6) CO2 GWP = 1; CH4 GWP = 25; N2O GWP = 298 [40 CFR Part 98].

Controlled Solar Turbine Start-up Emission Factors						
Equipment Name	**Fuel**	**Units**	**NOx**	**CO**	**VOC**	**Total HAP**
Solar Centaur 50L Turbine	Natural Gas	lb/event	0.8	69.1	0.400	1.2
Solar Taurus 70 Turbine	Natural Gas	lb/event	0.8	73.1	0.420	4.9
Solar Mars 100 Turbine	Natural Gas	lb/event	1.4	123.5	0.710	2.6
Solar Titan 130 Turbine	Natural Gas	lb/event	1.9	176.9	1.01	3.0
Solar Centaur 50L Turbine	Natural Gas	lb/hr	1.49	70.0	0.560	1.27
Solar Taurus 70 Turbine	Natural Gas	lb/hr	1.87	74.5	0.669	5.01
Solar Mars 100 Turbine	Natural Gas	lb/hr	3.02	125.6	1.09	2.76
Solar Titan 130 Turbine	Natural Gas	lb/hr	3.87	179.5	1.47	3.20

Notes
1. Control efficiency of SCR and Oxidation Catalyst not applied during start-up operations.
2. Lb/hr rates based on one start-up event (10 minutes) and 50 minutes of normal (NOx, HAP) or low temperature operation (CO, VOC)

Solar Turbine Shutdown Emission Factors (lb/event)																
Equipment Name	**Fuel**	**Units**	**NOx**	**CO**	**VOC**	**SO2**	**PMF**	**PMF-10**	**PMF-2.5**	**PMC**	**CO2**	**CH4**	**N2O**	**CO2e**	**NH3**	**Total HAP**
Solar Centaur 50L Turbine	Natural Gas	lb/event	0.4	35.4	0.200	0.01	0.014	0.014	0.014	0.036	217	1.80	0.06	280	0.136	2.0
Solar Taurus 70 Turbine	Natural Gas	lb/event	1.1	93.4	0.530	0.01	0.020	0.020	0.020	0.050	575	4.77	0.09	721	0.220	3.4
Solar Mars 100 Turbine	Natural Gas	lb/event	1.7	149.2	0.850	0.02	0.029	0.029	0.029	0.071	920	7.65	0.13	1,150	0.309	4.6
Solar Titan 130 Turbine	Natural Gas	lb/event	2.4	207.6	1.19	0.03	0.043	0.043	0.043	0.107	1,272	10.7	0.14	1,581	0.388	5.1

Notes
(1) Shut-down Emissions of NOx, CO, VOC, CO2, and CH4 based on Solar Turbines Incorporated Product Information Letter 170: Emission Estimates at Start-up, Shutdown, and Commissioning for SoLoNOx Combustion Products (13 June 2012).
(2) Shut-down Emissions of SO2, PM, N2O, and HAP based on Solar estimations.
(3) NH3 emission rates based on a 10 ppm ammonia slip from the SCR based on manufacturer information and a shut-down duration of 10 minutes.
(4) VOCs assumed to be 10% of UHC and CH4 assumed to be 90% of UHC.
(5) CO2e emission rate calculated by multiplying each GHG (CO2, CH4, N2O) by its Global Warming Potential (GWP) and adding them together.
(6) CO2 GWP = 1; CH4 GWP = 25; N2O GWP = 298 [40 CFR Part 98].

Controlled Solar Turbine Shutdown Emission Factors						
Equipment Name	**Fuel**	**Units**	**NOx**	**CO**	**VOC**	**Total HAP**
Solar Centaur 50L Turbine	Natural Gas	lb/event	0.4	2.83	0.100	1.00
Solar Taurus 70 Turbine	Natural Gas	lb/event	1.1	7.47	0.265	1.70
Solar Mars 100 Turbine	Natural Gas	lb/event	1.7	11.9	0.425	2.30
Solar Titan 130 Turbine	Natural Gas	lb/event	2.4	16.6	0.595	2.55
Solar Centaur 50L Turbine	Natural Gas	lb/hr	1.09	3.73	0.260	1.07
Solar Taurus 70 Turbine	Natural Gas	lb/hr	2.17	8.86	0.514	1.81
Solar Mars 100 Turbine	Natural Gas	lb/hr	3.32	14.0	0.803	2.46
Solar Titan 130 Turbine	Natural Gas	lb/hr	4.37	19.2	1.05	2.75

Notes
1. Control efficiency of SCR not applied during shutdown operations.
2. Control efficiency of Oxidation Catalyst applied during shutdown operations.
3. Lb/hr rates based on one shutdown event (10 minutes) and 50 minutes of normal (NOx, HAP) or low temperature operation (CO, VOC)

Engine and Boiler Emission Factors																
Equipment Type	**Fuel**	**Units**	**NOx**	**CO**	**VOC**	**SO2**	**PMF**	**PMF-10**	**PMF-2.5**	**PMC**	**CO2**	**CH4**	**N2O**	**CO2e**	**NH3**	**Total HAP**
Hurst S45 Boiler	Natural Gas	lb/MMscf	50	84	5.5	3.33	1.9	1.9	1.9	5.7	120,000	2.3	2.2	120,713	0	1.89
ETI Line Heater	Natural Gas	lb/MMscf	10.2	37.7	5.5	3.33	1.22	1.22	1.22	3.67	120,000	2.3	2.2	120,713	0	1.89
Caterpillar G3516C EGen	Natural Gas	lb/hp-hr	1.10E-03	4.41E-03	1.10E-03	2.25E-05	2.65E-04	2.65E-04	2.65E-04	6.84E-05	0.977	8.82E-03	0	1.20	0	1.21E-03

Notes
(1) Emission factors for Hurst S45 Boiler taken from AP-42 Tables 1.4-1 & 1.4-2
(2) Hurst S45 Boiler assumed to have low-NOx burners
(3) NOx, CO, PMF, PMF-10, PMF-2.5, and PMC emission factors for ETI Line Heater provided by ETI and converted to lb/MMscf using 1020 MMBtu/MMscf
(4) For ETI Line Heater, assumed 75% of PM is PMC and 25% of PM is PMF; based on ratio of PMF and PMC emission factors from AP-42 Table 1.4-2
(5) VOC, SO2, CO2, CH4, and N2O emission factors for ETI Line Heater from AP-42 Table 1.4-2
(6) NOx, CO, VOC, CO2, and CH4 emission factors for Caterpillar EGen taken from Caterpillar manufacturer data
(7) SO2, PMF, PMF-10, PMF-2.5, PMC, and N2O emission factors for Caterpillar EGen taken from AP-42 Table 3.2-1 and converted using Caterpillar manufacturer fuel data
(8) Assume PMF=PMF-10=PMF-2.5
(9) CO2e emission rate calculated by multiplying each GHG (CO2, CH4, N2O) by its Global Warming Potential (GWP) and adding them together
(10) CO2 GWP = 1; CH4 GWP = 25; N2O GWP = 298 [40 CFR 98]
(11) See the "HAP Emissions" worksheet for a more detailed breakdown of HAP emissions
(12) SO2 emission factors for Hurst S45 Boiler, ETI Line Heater, and Caterpillar Egen were scaled up based on the sulfur content of the natural gas.

Table C-5 Hazardous Air Pollutant (HAP) Emissions From Combustion Sources

ACP Buckingham Compressor Station - Buckingham County, Virginia

Annual HAP Emissions (lb/yr)								
Quantity @ ACP-2		1	1	1	1	1	4	1
Pollutant	HAP?	Solar Centaur 50L Turbine	Solar Titan 130 Turbine	Solar Taurus 70 Turbine	Solar Mars 100 Turbine	Hurst S45 Boiler	ETI Line Heater	Caterpillar G3516C Egen
		6,276	20,500	11,107	15,900	6.384	21.22	2,175
		hp	hp	hp	hp	MMBTU/hr	MMBTU/hr	bhp
		54.98	157.2	85.62	129.64			
		MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr			
1,1,2,2-Tetrachloroethane	Yes							0.183
1,1,2-Trichloroethane	Yes							0.146
1,1-Dichloroethane	Yes							0.108
1,2,3-Trimethylbenzene	No							0.098
1,2,4-Trimethylbenzene	No							0.307
1,2-Dichloroethane	Yes							0.117
1,2-Dichloropropane	Yes							0.123
1,3,5-Trimethylbenzene	No							0.050
1,3-Butadiene	Yes							2.269
1,3-Dichloropropene	Yes							0.121
2,2,4-Trimethylpentane	Yes							2.341
2-Methylnaphthalene	No					0.001	0.004	0.059
3-Methylchloranthrene	No					0.000	0.000	
7,12-Dimethylbenz(a)anthracene	No					0.001	0.003	
Acenaphthene	No					0.000	0.000	0.004
Acenaphthylene	No					0.000	0.000	0.009
Acetaldehyde	Yes							21.472
Acrolein	Yes							21.527
Anthracene	No					0.000	0.000	0.002
Benz(a)anthracene	No					0.000	0.000	0.001
Benzene	Yes					0.115	0.383	5.368
Benzo(a)pyrene	No					0.000	0.000	0.000
Benzo(b)fluoranthene	No					0.000	0.000	0.000
Benzo(e)pyrene	No							0.000
Benzo(g,h,i)perylene	No					0.000	0.000	0.000
Benzo(k)fluoranthene	No					0.000	0.000	0.000
Biphenyl	Yes							0.011
Butane	No					115.137	382.709	13.143
Butyr/Isobutyraldehyde	No							1.209
Carbon Tetrachloride	Yes							0.168
Chlorobenzene	Yes							0.123
Chloroethane	Yes							
Chloroform	Yes							0.130
Chrysene	No					0.000	0.000	0.002
Cyclohexane	No							0.852
Cyclopentane	No							0.262
Dibenzo(a,h)anthracene	No					0.000	0.000	
Dichlorobenzene	Yes					0.066	0.219	
Ethane	No					169.965	564.951	196.180
Ethylbenzene	Yes							0.299
Ethylene Dibromide	Yes							0.203
Fluoranthene	No					0.000	0.001	0.001
Fluorene	No					0.000	0.001	0.005
Formaldehyde	Yes	693.540	1,982.984	1,080.045	1,635.331	4.112	13.668	1,246.715
Hexane (or n-Hexane)	Yes					98.689	328.036	1.231
Indeno(1,2,3-c,d)pyrene	No					0.000	0.000	0.000
Isobutane	No							10.376

Table C-5 Hazardous Air Pollutant (HAP) Emissions From Combustion Sources

ACP Buckingham Compressor Station - Buckingham County, Virginia

Annual HAP Emissions (lb/yr)								
Quantity @ ACP-2		**1**	**1**	**1**	**1**	**1**	**4**	**1**
Pollutant	**HAP?**	**Solar Centaur 50L Turbine**	**Solar Titan 130 Turbine**	**Solar Taurus 70 Turbine**	**Solar Mars 100 Turbine**	**Hurst S45 Boiler**	**ETI Line Heater**	**Caterpillar G3516C Egen**
		6,276	**20,500**	**11,107**	**15,900**	**6.384**	**21.22**	**2,175**
		hp	**hp**	**hp**	**hp**	**MMBTU/hr**	**MMBTU/hr**	**bhp**
Methanol	Yes							6.862
Methylcyclohexane	No							0.935
Methylene Chloride	Yes							0.407
n-Nonane	No							0.085
n-Octane	No							0.206
Naphthalene	Yes					0.033	0.111	0.266
PAH	Yes							0.371
Pentane (or n-Pentane)	No					142.551	473.830	4.234
Perylene	No							0.000
Phenanthrene	No					0.001	0.003	0.010
Phenol	Yes							0.116
Propane	No					87.724	291.588	79.413
Propylene Oxide	Yes							
Pyrene	No					0.000	0.001	0.002
Styrene	Yes							0.152
Tetrachloroethane	No							
Toluene	Yes					0.186	0.620	2.665
Vinyl Chloride	Yes							0.068
Xylene	Yes							0.742
Arsenic	Yes					0.011	0.036	
Barium	No					0.241	0.802	
Beryllium	Yes					0.001	0.002	
Cadmium	Yes					0.060	0.200	
Chromium	Yes					0.077	0.255	
Cobalt	Yes					0.005	0.015	
Copper	No					0.047	0.155	
Manganese	Yes					0.021	0.069	
Mercury	Yes					0.014	0.047	
Molybdenum	No					0.060	0.200	
Nickel	Yes					0.115	0.383	
Selenium	Yes					0.001	0.004	
Vanadium	No					0.126	0.419	
Zinc	No					1.590	5.285	
Lead	Yes					0.027	0.091	
Total HAPs		734.478	2,100.035	1,143.798	1,731.861			1,314.305
Total HAP/unit (lb/yr)		**734**	**2,100**	**1,144**	**1,732**	**104**	**344**	**1,314**
Total HAP/unit (TPY)		**0.367**	**1.05**	**0.572**	**0.866**	**0.052**	**0.172**	**0.657**

Hazardous Air Pollutant

Notes:
(1) Emissions above are on a per unit basis
(2) Calculations for the Caterpillar G3516C Egen assume 500 hours of operation; all other calculations assume 8,760 hours of operation
(3) Heat rates for Solar Turbines taken from Solar Datasheets
(4) Solar turbines have a 50% HAP control efficiency due to the Oxidation Catalyst

Table C-6 Combustion Source HAP Emission Factors

ACP Buckingham Compressor Station - Buckingham County, Virginia

Pollutant	HAP?	Solar Centaur 50L Turbine	Solar Titan 130 Turbine	Solar Taurus 70 Turbine	Solar Mars 100 Turbine	Hurst S45 Boiler; ETI Line Heater	Caterpillar G3516C Egen
		lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMscf	lb/hp-hr
1,1,2,2-Tetrachloroethane	Yes						1.69E-07
1,1,2-Trichloroethane	Yes						1.34E-07
1,1-Dichloroethane	Yes						9.95E-08
1,2,3-Trimethylbenzene	No						9.01E-08
1,2,4-Trimethylbenzene	No						2.82E-07
1,2-Dichloroethane	Yes						1.07E-07
1,2-Dichloropropane	Yes						1.13E-07
1,3,5-Trimethylbenzene	No						4.58E-08
1,3-Butadiene	Yes						2.09E-06
1,3-Dichloropropene	Yes						1.11E-07
2,2,4-Trimethylpentane	Yes						2.15E-06
2-Methylnaphthalene	No					2.40E-05	5.44E-08
3-Methylchloranthrene	No					1.80E-06	
7,12-Dimethylbenz(a)anthracene	No					1.60E-05	
Acenaphthene	No					1.80E-06	3.38E-09
Acenaphthylene	No					1.80E-06	8.07E-09
Acetaldehyde	Yes						1.97E-05
Acrolein	Yes						1.98E-05
Anthracene	No					2.40E-06	1.83E-09
Benz(a)anthracene	No					1.80E-06	8.55E-10
Benzene	Yes					2.10E-03	4.94E-06
Benzo(a)pyrene	No					1.20E-06	1.45E-11
Benzo(b)fluoranthene	No					1.80E-06	2.17E-11
Benzo(e)pyrene	No						5.95E-11
Benzo(g,h,i)perylene	No					1.20E-06	6.31E-11
Benzo(k)fluoranthene	No					1.80E-06	1.08E-11
Biphenyl	Yes						1.01E-08
Butane	No					2.10E+00	1.21E-05
Butyr/Isobutyraldehyde	No						1.11E-06
Carbon Tetrachloride	Yes						1.54E-07
Chlorobenzene	Yes						1.13E-07
Chloroethane	Yes						
Chloroform	Yes						1.20E-07
Chrysene	No					1.80E-06	1.71E-09
Cyclohexane	No						7.84E-07
Cyclopentane	No						2.41E-07
Dibenzo(a,h)anthracene	No					1.20E-06	
Dichlorobenzene	Yes					1.20E-03	
Ethane	No					3.10E+00	1.80E-04
Ethylbenzene	Yes						2.75E-07
Ethylene Dibromide	Yes						1.87E-07
Fluoranthene	No					3.00E-06	9.19E-10
Fluorene	No					2.80E-06	4.30E-09
Formaldehyde	Yes	2.88E-03	2.88E-03	2.88E-03	2.88E-03	7.50E-02	1.15E-03
Hexane (or n-Hexane)	Yes					1.80E+00	1.13E-06
Indeno(1,2,3-c,d)pyrene	No					1.80E-06	2.53E-11
Isobutane	No						9.54E-06

Table C-6 Combustion Source HAP Emission Factors

ACP Buckingham Compressor Station - Buckingham County, Virginia

Pollutant	HAP?	Solar Centaur 50L Turbine	Solar Titan 130 Turbine	Solar Taurus 70 Turbine	Solar Mars 100 Turbine	Hurst S45 Boiler; ETI Line Heater	Caterpillar G3516C Egen
		lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/MMscf	lb/hp-hr
Methanol	Yes						6.31E-06
Methylcyclohexane	No						8.60E-07
Methylene Chloride	Yes						3.74E-07
n-Nonane	No						7.84E-08
n-Octane	No						1.89E-07
Naphthalene	Yes					6.10E-04	2.45E-07
PAH	Yes						3.41E-07
Pentane (or n-Pentane)	No					2.60E+00	3.89E-06
Perylene	No						1.26E-11
Phenanthrene	No					1.70E-05	8.98E-09
Phenol	Yes						1.07E-07
Propane	No					1.60E+00	7.30E-05
Propylene Oxide	Yes						
Pyrene	No					5.00E-06	1.49E-09
Styrene	Yes						1.39E-07
Tetrachloroethane	No						
Toluene	Yes					3.40E-03	2.45E-06
Vinyl Chloride+A32	Yes						6.28E-08
Xylene	Yes						6.82E-07
Arsenic	Yes					2.00E-04	
Barium	No					4.40E-03	
Beryllium	Yes					1.20E-05	
Cadmium	Yes					1.10E-03	
Chromium	Yes					1.40E-03	
Cobalt	Yes					8.40E-05	
Copper	No					8.50E-04	
Manganese	Yes					3.80E-04	
Mercury	Yes					2.60E-04	
Molybdenum	No					1.10E-03	
Nickel	Yes					2.10E-03	
Selenium	Yes					2.40E-05	
Vanadium	No					2.30E-03	
Zinc	No					2.90E-02	
Lead	Yes					5.00E-04	
Total Haps		3.05E-03	3.05E-03	3.05E-03	3.05E-03	1.89E+00	1.21E-03

Hazardous Air Pollutant

Notes:
(1) Emission factors for Solar turbines from Solar PIL 168 Revision 4 (dated 14 May 2012)
(2) Emission factors for Hurst S45 Boiler and ETI Line Heater from AP-42 Tables 1.4-2, 1.4-3, and 1.4-4
(3) Emission factors for Caterpillar G3516C Egen from AP-42 Table 3.2-1; formaldehyde emission factor from Caterpillar manufacturer data
(4) Emission factors for Solar natural gas turbines and Caterpillar natural gas emergency generators converted using 1 KWh = 3412 Btu and 1 kw = 1.341 hp

Table C-7 Potential Emissions From Fugitive Leaks
ACP Buckingham Compressor Station - Buckingham County, Virginia

Fugitive Emissions (FUG)

Source Designation:	FUG-02

Operational Parameters:

Annual Hours of Operation (hr/yr):	8,760

Pipeline Natural Gas Fugitive Emissions

Equipment	Service	Emission Factor[1]	Source Count[2]	Total HC Potential Emissions		VOC Weight Fraction	VOC Emissions	CO_2 Weight Fraction	CO_2 Emissions	CH_4 Weight Fraction	CH_4 Emissions	HAP Weight Fraction	HAP Emissions
		kg/hr/source		lb/hr	tpy		tpy		tpy		tpy		tpy
Valves	Gas	4.50E-03	755	7.49	32.8	0.026	0.851	0.027	0.875	0.880	28.9	1.61E-03	0.053
Pump Seals	Gas	2.40E-03		0.000	0.000	0.026	0.000	0.027	0.000	0.880	0.000	1.61E-03	0.000
Others (compressors and others)	Gas	8.80E-03	4	0.078	0.340	0.026	0.009	0.027	0.009	0.880	0.299	1.61E-03	5.46E-04
Connectors	Gas	2.00E-04	4	0.002	0.008	0.026	2.00E-04	0.027	2.06E-04	0.880	0.007	1.61E-03	1.24E-05
Flanges	Gas	3.90E-04	509	0.438	1.92	0.026	0.050	0.027	0.051	0.880	1.69	1.61E-03	0.003
Open-ended lines	Gas	2.00E-03		0.000	0.000	0.026	0.000	0.027	0.000	0.880	0.000	1.61E-03	0.000
			Total	8.01	35.1	-	0.910	-	0.936	-	30.9	-	0.056

1. EPA Protocol for Equipment Leaks Emissions Estimate (EPA-453/R-95-017) Table 2-4: Oil and Gas Production Operations Emission Factors.
2. Component count based on Basic Systems Engineering Estimate.
3. Source count for fugitive emissions includes equipment from ACP-2 and the Woods Corner M&R station.

Equations:

Potential Emissions (lb/hr) = Emission Factor (kg/hr/source) * Source Count * (2.20462 lb/1 kg)

Potential Emissions (tons/yr) = $(lb/hr)_{Potential}$ × Hours of Operation (hr/yr) × (1 ton/2,000 lb)

Gas Composition

Pollutant	Molecular Weight (lb/lb-mol)	Molar (Volume) Fraction (mol %)	Weight Fraction (wt %)
Total Stream Molecular Weight	17.17		
Non-VOC			
Carbon Dioxide	44.01	1.041%	**2.67%**
Nitrogen	28.01	0.994%	1.62%
Methane	16.04	94.21%	**88.00%**
Ethane	30.07	2.923%	5.12%
VOC			
Propane	44.10	0.546%	1.40%
n-Butane	58.12	0.084%	0.28%
IsoButane	58.12	0.079%	0.27%
n-Pentane	72.15	0.022%	0.09%
IsoPentane	72.15	0.024%	0.10%
n-Hexane	86.18	0.032%	0.16%
n-Heptane	100.21	0.049%	0.29%
Total VOC Fraction			**2.59%**
Total HAP Fraction			**0.16%**

Gas speciation based on a natural gas hydrocarbon composition
from Engineering Technology Incorporated Combustion Analysis.

Table C-8A Tank Emissions

ACP Buckingham Compressor Station - Buckingham County, Virginia

Source Designation:	TK-1, TK-2, TK-3

Tank Parameters

Source	Type of Tank	Contents	Capacity	Throughput	Tank Diam.	Tank Length	Paint Color	Paint Condition
			(gal)	gal/yr	ft	ft		
TK-1	Horizontal, fixed	Lube Oil	2,500	12,500	5.33	15.0	Light Grey	Good
TK-2	Horizontal, fixed	Produced Fluids	1,000	5,000	4.00	9.83	Light Grey	Good

Total Emissions

Source	VOC Emissions								GHG Emissions			
	Flashing Losses		Working Losses		Breathing Losses		Total Losses		CO2		CH4	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
TK-1[1]	NA	NA	9.70E-07	4.25E-06	4.00E-06	1.75E-05	4.97E-06	2.18E-05	0	0	0	0
TK-2[2]	NA	NA					0.033	0.144	0.002	0.009	0.004	0.017

1. Losses were calculated for TK-1 using EPA's TANKS 4.09d software with default breather vent settings.

2. Losses were calculated for TK-2 using E&P Tanks Software. See attached for output.

3. Losses (Emissions) from TK-3 13,400-gallon Ammonia tank assumed to be insignificant.

Table C-8B Tank Unloading Emissions
ACP Buckingham Compressor Station - Buckingham County, Virginia

Source Designation:	LR-1, LR-2

Chemical Parameters

Chemical	Vapor Mol. Weight [1] (lb/lb-mol)	Avg. Vapor Pressure [1] (psia)	Avg. Temperature [2] (deg. R)	Saturation Factor [3]	Throughput [4] Mgal/yr
Waste Oil	380	0.0001	519.67	0.6	12.5
Pipeline Liquids	65.06	7.7	519.67	0.6	0.500

References:

1. Vapor molecular weight and vapor pressure based on EPA Tanks output for TK-1 and E&P output for TK-2.
2. Based on average ambient temperature data for the area.
3. Saturation Factor based on "Submerged Loading: dedicated normal service" in Table 5.2-1 of AP-42, Ch. 5.2.
4. Throughput based upon expected percent of hydrocarbons. The pipeline liquids tank contains water, with potential for trace oil, estimated at 10% oil max.

Total Potential Emissions

Source	Total Loading Losses[1]		Pump Capacity [2]	Max Hourly Losses[3]
	Average	Annual		
	(lbs/Mgal)	(tpy)	(gal/min)	lb/hr
Waste Oil Truck Loading	5.47E-04	3.42E-06	90	0.001
Pipeline Liquids Truck Loading	7.21	0.002	90	0.720

References:

1. AP-42, Ch. 5.2, Equation 1 (Loading Loss = 12.46 x (Saturation Factor x TVP x Molecular Weight) / Temp.)
2. Assumed pump rate.
3. Emissions based upon expected percent of hydrocarbons in throughput liquid. The pipeline liquids tank contains water with potential for trace oil, estimated at 10% oil max.

Speciated Potential Emissions

Source	Contents	VOC Weight Fraction[1] (%)	HAP Weight Fraction[1] (%)	Total VOC Emissions		Total HAP Emissions		CO2/VOC Ratio	CH4/VOC Ratio	Total CO2 Emissions		Total CH4 Emissions	
				lb/hr	tpy	lb/hr	tpy			lb/hr	tpy	lb/hr	tpy
Waste Oil Truck Loading	Waste Oil	100%	100%	0.001	3.42E-06	0.001	3.42E-06	---	---	0	0	0	0
Pipeline Liquids Truck Loading	Pipeline Liquids	100%	6.94%	0.720	0.002	0.050	1.25E-04	6.25%	11.8%	0.045	1.13E-04	0.085	2.13E-04

References:

1. VOC and HAP weight fractions are based on TK-1 and TK-2 tank emissions speciation. Assumed 100% HAP for TK-1 to be conservative.
2. CO2/VOC and CH4/VOC Ratios based on TK-1 tank emissions.

Table C-9 Project Potential Emissions

ACP Buckingham Compressor Station - Buckingham County, Virginia

Source	ID	Criteria Pollutants (tpy)								GHG Emissions (tpy)				Ammonia (tpy)	HAP (tpy)
		NOx	CO	VOC	SO2	PMF	PMF-10	PMF-2.5	PMC	CO2	CH4	N2O	CO2e	NH3	Total HAP
Solar Mars 100 Turbine	CT-01	8.67	9.54	1.05	2.12	3.58	3.58	3.58	8.87	74,103	6.05	1.88	74,813	8.12	1.11
Solar Taurus 70 Turbine	CT-02	5.72	5.85	0.687	1.40	2.37	2.37	2.37	5.86	48,911	3.96	1.24	49,381	5.77	0.900
Solar Titan 130 Turbine	CT-03	10.5	13.0	1.28	2.57	4.35	4.35	4.35	10.8	89,784	7.48	2.27	90,649	10.2	1.32
Solar Centaur 50L Turbine	CT-04	3.68	4.77	0.444	0.898	1.52	1.52	1.52	3.76	31,455	2.54	0.796	31,755	3.58	0.476
Hurst S45 Boiler	WH-01	1.37	2.30	0.151	0.091	0.052	0.052	0.052	0.156	3,290	0.063	0.060	3,309	0	0.052
ETI Line Heater 1 (Woods Corner)	LH-01	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
ETI Line Heater 2 (Woods Corner)	LH-02	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
ETI Line Heater 3 (Woods Corner)	LH-03	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
ETI Line Heater 4 (Woods Corner)	LH-04	0.929	3.44	0.501	0.304	0.112	0.112	0.112	0.335	10,935	0.210	0.200	11,000	0	0.172
Caterpillar G3516C EGen (Woods Corner)	EG-01	0.599	2.40	0.599	0.012	0.144	0.144	0.144	0.037	531	4.80	0	651	0	0.657
Fugitive Leaks - Blowdowns	FUG-01	-	-	0.421	-	-	-	-	-	0.433	14.3	-	357	-	0.026
Fugitive Leaks - Piping	FUG-02	-	-	0.910	-	-	-	-	-	0.936	30.9	-	772	-	0.056
Accumulator (Waste Oil) Tank	TK-1	-	-	2.52E-05	-	-	-	-	-	-	-	-	-	-	2.52E-05
Pipeline Fluids Tank	TK-2	-	-	0.146	-	-	-	-	-	0.009	0.017	-	0.439	-	0.010
Total (tons/yr)		**34.3**	**51.6**	**7.69**	**8.30**	**12.5**	**12.5**	**12.5**	**30.8**	**291,812**	**70.9**	**7.05**	**295,686**	**27.7**	**5.30**

Source	ID	Criteria Pollutants (lb/hr)								GHG Emissions (lb/hr)				Ammonia (lb/hr)	HAP (lb/hr)
		NOx	CO	VOC	SO2	PMF	PMF-10	PMF-2.5	PMC	CO2	CH4	N2O	CO2e	NH3	Total HAP
Solar Mars 100 Turbine	CT-01	9.27	126	1.09	0.485	0.821	0.821	0.821	2.03	16,963	8.67	0.487	17,121	1.85	4.93
Solar Taurus 70 Turbine	CT-02	6.11	74.5	0.669	0.320	0.542	0.542	0.542	1.34	11,197	5.44	0.365	11,301	1.32	5.12
Solar Titan 130 Turbine	CT-03	11.6	179	1.47	0.588	0.996	0.996	0.996	2.46	20,549	11.9	0.572	20,741	2.33	5.50
Solar Centaur 50L Turbine	CT-04	4.02	70.0	0.560	0.206	0.348	0.348	0.348	0.861	7,201	4.03	0.211	7,268	0.818	2.14
Hurst S45 Boiler	WH-01	0.313	0.526	0.034	0.021	0.012	0.012	0.012	0.036	751	0.014	0.014	756	0	0.012
ETI Line Heater 1 (Woods Corner)	LH-01	0.212	0.785	0.114	0.069	0.025	0.025	0.025	0.076	2,496	0.048	0.046	2,511	0	0.039
ETI Line Heater 2 (Woods Corner)	LH-02	0.212	0.785	0.114	0.069	0.025	0.025	0.025	0.076	2,496	0.048	0.046	2,511	0	0.039
ETI Line Heater 3 (Woods Corner)	LH-03	0.212	0.785	0.114	0.069	0.025	0.025	0.025	0.076	2,496	0.048	0.046	2,511	0	0.039
ETI Line Heater 4 (Woods Corner)	LH-04	0.212	0.785	0.114	0.069	0.025	0.025	0.025	0.076	2,496	0.048	0.046	2,511	0	0.039
Caterpillar G3516C EGen (Woods Corner)	EG-01	2.40	9.59	2.40	0.049	0.577	0.577	0.577	0.149	2,124	19.2	0	2,604	0	2.63
Fugitive Leaks - Blowdowns	FUG-01	-	-	82.8	-	-	-	-	-	85.2	2,810	-	70,330	-	5.13
Fugitive Leaks - Piping	FUG-02	-	-	0.208	-	-	-	-	-	0.214	7.05	-	176	-	0.013
Accumulator Tank	TK-1	-	-	0.001	-	-	-	-	-	-	-	-	-	-	0.001
Hydrocarbon (Waste Oil) Tank	TK-2	-	-	0.753	-	-	-	-	-	0.045	0.085	-	2.17	-	0.052
Total (lb/hr) [1]		**34.5**	**463**	**90.5**	**1.95**	**3.40**	**3.40**	**3.40**	**7.19**	**68,857**	**2,866**	**1.83**	**140,344**	**6.32**	**25.7**

1. Total hourly emission rates represent a worst case value for the purposes of the permit application and do not represent total hourly emissions under normal operation.

Table C-10 Toxic Air Pollutant (TAP) Emissions from Sources Subject to Rule 6-5

ACP Buckingham Compressor Station - Buckingham County, Virginia

Pollutant	CAS No.	TLV (mg/m³)[1]			Exemption Threshold (ET)[1]	
					Hourly	Annual
		TWA	STEL	CEIL	lb/hr	ton/yr
1,3-Butadiene	106990	22	-	-	1.452	3.19
2,2,4-Trimethylpentane	540841	350	-	-	22.8	50.75
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
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 Hourly Emissions (lb/hr)[3]														
Pollutant	CT-01	CT-02	CT-03	CT-04	Stn. Suctn. 1	Stn. Suctn. 2	Stn. Dischrg. 1	Stn. Dischrg. 2	Launcher	Receiver	TK-1	TK-2	Total	ET
1,3-Butadiene	2.94E-04	4.22E-04	2.31E-04	1.45E-04	---	---	---	---	---	---	---	---	0.001	1.452
2,2,4-Trimethylpentane	---	---	---	---	---	---	---	---	---	---	0.001	0.000	0.001	22.8
Acetaldehyde	0.027	0.039	0.022	0.014	---	---	---	---	---	---	---	---	0.102	8.91
Acrolein	0.004	0.006	0.003	0.002	---	---	---	---	---	---	---	---	0.016	0.02277
Benzene	0.008	0.012	0.006	0.004	---	---	---	---	---	---	0.001	0.000	0.032	2.112
Ethylbenzene	0.022	0.031	0.017	0.011	---	---	---	---	---	---	0.001	0.000	0.083	17.919
Formaldehyde	2.56	4.70	3.09	1.17	---	---	---	---	---	---	---	---	11.5	0.0825
Hexane[4]	0.869	0.372	0.966	0.189	---	---	---	---	2.51	2.62	0.001	0.002	7.53	11.616
Naphthalene	8.90E-04	0.001	7.00E-04	4.39E-04	---	---	---	---	---	---	---	---	0.003	2.607
PAH	0.002	0.002	0.001	7.44E-04	---	---	---	---	---	---	---	---	0.006	2.607
Propylene Oxide	0.020	0.028	0.016	0.010	---	---	---	---	---	---	---	---	0.074	3.168
Toluene	0.089	0.128	0.070	0.044	---	---	---	---	---	---	0.001	0.000	0.332	18.645
Xylenes	0.044	0.063	0.034	0.022	---	---	---	---	---	---	0.001	0.000	0.164	21.483

Potential Annual Emissions (ton/yr)[3]														
Pollutant	CT-01	CT-02	CT-03	CT-04	Stn. Suctn. 1	Stn. Suctn. 2	Stn. Dischrg. 1	Stn. Dischrg. 2	Launcher	Receiver	TK-1	TK-2	Total	ET
1,3-Butadiene	1.45E-04	1.07E-04	1.64E-04	6.17E-05	---	---	---	---	---	---	---	---	4.79E-04	3.19
2,2,4-Trimethylpentane	---	---	---	---	---	---	---	---	---	---	2.52E-05	0.000	2.52E-05	50.75
Acetaldehyde	0.014	0.010	0.015	0.006	---	---	---	---	---	---	---	---	0.045	26.1
Acrolein	0.002	0.002	0.002	9.19E-04	---	---	---	---	---	---	---	---	0.007	0.03335
Benzene	0.004	0.003	0.005	0.002	---	---	---	---	---	---	2.52E-05	0.000	0.013	4.64
Ethylbenzene	0.011	0.008	0.012	0.005	---	---	---	---	---	---	2.52E-05	0.000	0.036	62.93
Formaldehyde	1.04	0.848	1.25	0.448	---	---	---	---	---	---	---	---	3.59	0.174
Hexane[4]	0.020	0.017	0.020	0.015	1.91E-06	1.91E-06	1.55E-06	1.55E-06	0.005	0.005	2.52E-05	0.010	0.092	25.52
Naphthalene	4.39E-04	3.25E-04	4.97E-04	1.87E-04	---	---	---	---	---	---	---	---	0.001	7.54
PAH	7.44E-04	5.50E-04	8.41E-04	3.16E-04	---	---	---	---	---	---	---	---	0.002	7.54
Propylene Oxide	0.010	0.007	0.011	0.004	---	---	---	---	---	---	---	---	0.032	6.96
Toluene	0.044	0.032	0.050	0.019	---	---	---	---	---	---	2.52E-05	0.000	0.145	54.665
Xylenes	0.022	0.016	0.024	0.009	---	---	---	---	---	---	2.52E-05	0.000	0.071	62.93

Table C-10 Toxic Air Pollutant (TAP) Emissions from Sources Subject to Rule 6-5
ACP Buckingham Compressor Station - Buckingham County, Virginia

Emissions Modeling Summary		
Unit/Stack ID	Formaldehyde	
	lb/hr	ton/yr
CT-01	2.56	1.04
CT-02	4.70	0.848
CT-03	3.09	1.25
CT-04	1.17	0.448
WH-01	4.69E-04	0.002
LH-01	0.002	0.007
LH-02	0.002	0.007
LH-03	0.002	0.007
LH-04	0.002	0.007
EG-01	2.49	0.623
TOTAL	***14.0***	***4.24***

Key:
Potential Emissions Exceed Exemption Threshold

Notes:
1. TLV and ET values from "Toxics_Spreadsheet.xlsx", downloaded from the Virginia DEQ - Air Toxics website.
2. PAH not listed in Virginia DEQ toxics spreadsheet; to be conservative, assumed the same TLV and ET values as naphthalene.
3. Calculated as follows:
   CT-01 through CT-04; Stn. Suctn. 1 and 2; Stn. Dischrg. 1 and 2; Launcher and Receiver: From Tables C-11 and C-12.
   TK-1: From E&P Tanks.
   TK-2: HAP composition unknown; assumed 100% of VOC emissions for each HAP commonly emitted from hydrocarbon tanks.
4. CT-01 through CT-04 include emissions from CT-01 Vent through CT-04 Vent; hourly rates are from shutdown events. It is not expected that all four units would purge and restart within the same hour. For TK-1, assumed all loading rack HAP emissions are hexane.

Table C-11 Toxic Air Pollutant (TAP) Emissions from Combustion Turbines - Combustion
ACP Buckingham Compressor Station - Buckingham County, Virginia

Hourly Emissions - Normal Operations						
Pollutant	CAS No.	Emission Factor (lb/MMBtu)[1]	Emission Rates (lb/hr)[2,3]			
			CT-01	CT-02	CT-03	CT-04
			129.64	85.62	157.2	54.98
			MMBtu/hr	MMBtu/hr	MMBtu/hr	MMBtu/hr
1,3-Butadiene	106990	4.30E-07	2.79E-05	1.84E-05	3.38E-05	1.18E-05
Acetaldehyde	75070	4.00E-05	0.003	0.002	0.003	0.001
Acrolein	107028	6.40E-06	4.15E-04	2.74E-04	5.03E-04	1.76E-04
Benzene	71432	1.20E-05	7.78E-04	5.14E-04	9.43E-04	3.30E-04
Ethylbenzene	100414	3.20E-05	0.002	0.001	0.003	8.80E-04
Formaldehyde	50000	2.88E-03	0.187	0.123	0.226	0.079
Naphthalene	91203	1.30E-06	8.43E-05	5.57E-05	1.02E-04	3.57E-05
PAH	---	2.20E-06	1.43E-04	9.42E-05	1.73E-04	6.05E-05
Propylene Oxide	75569	2.90E-05	0.002	0.001	0.002	7.97E-04
Toluene	108883	1.30E-04	0.008	0.006	0.010	0.004
Xylenes	1330207	6.40E-05	0.004	0.003	0.005	0.002

Event Emissions - Startup						
Pollutant	CAS No.		Emission Rates (lb/event)[4]			
			CT-01	CT-02	CT-03	CT-04
Total HAP	---		2.6	4.9	3.0	1.2
Formaldehyde	50000		2.4	4.6	2.9	1.1
Non-Formaldehyde HAP	---		0.2	0.3	0.1	0.1

Event Emissions - Startup						
Pollutant	CAS No.	Non-Formaldehyde HAP Composition[5]	Emission Rates (lb/event)[6]			
			CT-01	CT-02	CT-03	CT-04
1,3-Butadiene	106990	0.136%	2.71E-04	4.07E-04	1.36E-04	1.36E-04
Acetaldehyde	75070	12.6%	0.025	0.038	0.013	0.013
Acrolein	107028	2.02%	0.004	0.006	0.002	0.002
Benzene	71432	3.78%	0.008	0.011	0.004	0.004
Ethylbenzene	100414	10.1%	0.020	0.030	0.010	0.010
Formaldehyde	50000	---	2.40	4.60	2.90	1.10
Naphthalene	91203	0.410%	8.19E-04	0.001	4.10E-04	4.10E-04
PAH	---	0.693%	0.001	0.002	6.93E-04	6.93E-04
Propylene Oxide	75569	9.14%	0.018	0.027	0.009	0.009
Toluene	108883	41.0%	0.082	0.123	0.041	0.041
Xylenes	1330207	20.2%	0.040	0.061	0.020	0.020

Event Emissions - Shutdown						
Pollutant	CAS No.		Emission Rates (lb/event)[4]			
			CT-01	CT-02	CT-03	CT-04
Total HAP	---		4.6	3.4	5.1	2.0
Formaldehyde	50000		4.3	3.2	4.8	1.9
Non-Formaldehyde HAP	---		0.3	0.2	0.3	0.1

Event Emissions - Shutdown						
Pollutant	CAS No.	Non-Formaldehyde HAP Composition[5]	Emission Rates (lb/event)[6,7]			
			CT-01	CT-02	CT-03	CT-04
1,3-Butadiene	106990	0.136%	2.03E-04	1.36E-04	2.03E-04	6.78E-05
Acetaldehyde	75070	12.6%	0.019	0.013	0.019	0.006
Acrolein	107028	2.02%	0.003	0.002	0.003	0.001
Benzene	71432	3.78%	0.006	0.004	0.006	0.002
Ethylbenzene	100414	10.1%	0.015	0.010	0.015	0.005
Formaldehyde	50000	---	2.15	1.60	2.40	0.950
Naphthalene	91203	0.410%	6.15E-04	4.10E-04	6.15E-04	2.05E-04
PAH	---	0.693%	0.001	6.93E-04	0.001	3.47E-04
Propylene Oxide	75569	9.14%	0.014	0.009	0.014	0.005
Toluene	108883	41.0%	0.061	0.041	0.061	0.020
Xylenes	1330207	20.2%	0.030	0.020	0.030	0.010

Total HAP Emission Factor (lb/MMBtu)	
AP-42	1.03E-03
Solar Data	3.05E-03

Formaldehyde Emission Factor (lb/MMBtu)	
AP-42	7.10E-04
Solar Data	2.88E-03

Non-Formaldehyde HAP Emission Factor (lb/MMBtu)	
AP-42	3.17E-04
Solar Data	1.70E-04

VOC Control Device Efficiency[10]	
Ox. Cat.	50%

Worst Case Schedule (hr/yr)[10]	
Normal Ops.	8,726.7
Startup	16.7
Shutdown	16.7

Max. Events (event/yr)[11]	
Startup	100
Shutdown	100

Table C-11 Toxic Air Pollutant (TAP) Emissions from Combustion Turbines - Combustion

ACP Buckingham Compressor Station - Buckingham County, Virginia

Maximum Hourly Emissions						
Pollutant	CAS No.		Emission Rates (lb/hr)[8]			
			CT-01	CT-02	CT-03	CT-04
1,3-Butadiene	106990		2.94E-04	4.22E-04	2.31E-04	1.45E-04
Acetaldehyde	75070		0.027	0.039	0.022	0.014
Acrolein	107028		0.004	0.006	0.003	0.002
Benzene	71432		0.008	0.012	0.006	0.004
Ethylbenzene	100414		0.022	0.031	0.017	0.011
Formaldehyde	50000		2.56	4.70	3.09	1.17
Naphthalene	91203		8.90E-04	0.001	7.00E-04	4.39E-04
PAH	---		0.002	0.002	0.001	7.44E-04
Propylene Oxide	75569		0.020	0.028	0.016	0.010
Toluene	108883		0.089	0.128	0.070	0.044
Xylenes	1330207		0.044	0.063	0.034	0.022

Maximum Annual Emissions						
Pollutant	CAS No.		Emission Rates (ton/yr)[9]			
			CT-01	CT-02	CT-03	CT-04
1,3-Butadiene	106990		1.45E-04	1.07E-04	1.64E-04	6.17E-05
Acetaldehyde	75070		0.014	0.010	0.015	0.006
Acrolein	107028		0.002	0.002	0.002	9.19E-04
Benzene	71432		0.004	0.003	0.005	0.002
Ethylbenzene	100414		0.011	0.008	0.012	0.005
Formaldehyde	50000		1.04	0.848	1.25	0.448
Naphthalene	91203		4.39E-04	3.25E-04	4.97E-04	1.87E-04
PAH	---		7.44E-04	5.50E-04	8.41E-04	3.16E-04
Propylene Oxide	75569		0.010	0.007	0.011	0.004
Toluene	108883		0.044	0.032	0.050	0.019
Xylenes	1330207		0.022	0.016	0.024	0.009

Notes:

1. Emission factors (except formaldehyde) from AP-42 Chapter 3, Section 3.1, Table 3.1-3. Formaldehyde emission factor from Solar PIL 168 Revision 4 (dated 14 May 2012)
2. Calculated as: [Fuel Flow (MMBtu/hr) * Emission Factor (lb/MMBtu) * (1 - Control Efficiency)]
3. Based on lower heating value (LHV) of fuel in Solar Turbines Emissions Estimates.
4. Based on Solar estimations.
5. Calculated based on AP-42 Chapter 3, Section 3.1, Table 3.1-3 emission factors. An example is shown below for toluene.

    Non-Formaldehyde HAP Composition of Toluene:

    = Toluene Emission Factor / Total Non-Formaldehyde HAP Emission Factor

    = 1.30E-04 lb/MMBtu / 3.17E-04 lb/MMBtu

    = 41.0%
6. Calculated as (except for formaldehyde): [Non-Formaldehyde HAP Composition * Non-Formaldehyde HAP Emission Rate (lb/event)]
7. Assume oxidation catalyst control for shutdown events.
8. Emissions from startup and shutdown events are higher than emissions from normal operations. Startup and shutdown events are 10 minutes in duration each. However, only one startup or shutdown event would occur in a given hour. Therefore, maximum hourly emissions are calculated as the maximum of the following:

    [Startup Event Emission Rate (lb/event) * 1 event/hr + Normal Operation Emission Rate (lb/hr) * 1 hr / 60 min * 50 min]

    [Shutdown Event Emission Rate (lb/event) * 1 event/hr + Normal Operation Emission Rate (lb/hr) * 1 hr / 60 min * 50 min]
9. Calculated as: [Normal Operations Emission Rate (lb/hr) * Worst-Case Normal Operations Schedule (hr/yr) + Startup Emission Rate (lb/event) * Max. Startup Events (event/yr) + Shutdown Emission Rate (lb/event) * Max. Shutdown Events (event/yr)] * 1 ton/2,0000 lb
10. From Table C-2.
11. From Table C-3.

Table C-12 Toxic Air Pollutant (TAP) Emissions from Combustion Turbines - Blowdowns & Fugitives

ACP Buckingham Compressor Station - Buckingham County, Virginia

Hexane Emissions - Blowdown from Startup Events

Parameter	CT-01 Vent	CT-02 Vent	CT-03 Vent	CT-04 Vent
Blowdown Gas (lb/event)[1]	168	84.0	182	48.8
Hexane Emissions (lb/event)[2]	0.270	0.135	0.292	0.078

Hexane Emissions - Blowdown from Shutdown Events

Parameter	CT-01 Vent	CT-02 Vent	CT-03 Vent	CT-04 Vent
Blowdown Gas (lb/event)[1]	539	229	600	116
Hexane Emissions (lb/event)[2]	0.866	0.368	0.963	0.186

Hexane Emissions - Blowdown from Sitewide Events

Parameter	CT-01 Vent	CT-02 Vent	CT-03 Vent	CT-04 Vent	Stn. Suctn. 1	Stn. Suctn. 2	Stn. Dischrg. 1	Stn. Dischrg. 2
Blowdown Gas (lb/event)[3]	1.37	0.624	1.62	0.250	2.37	2.37	1.94	1.94
Hexane Emissions (lb/event)[2]	0.002	0.001	0.003	4.01E-04	0.004	0.004	0.003	0.003
Blowdown Gas (lb/hr)[3]	1.37	0.624	1.62	0.250	2.37	2.37	1.94	1.94
Hexane Emissions (lb/hr)[2]	0.002	0.001	0.003	4.01E-04	0.004	0.004	0.003	0.003

Hexane Emissions - Fugitive Leaks

Parameter	CT-01	CT-02	CT-03	CT-04
Fugitive Leak Gas (lb/hr)[4]	2.00	2.00	2.00	2.00
Hexane Emissions (lb/hr)[5]	0.003	0.003	0.003	0.003

Hexane Emissions - Pigging Events

Parameter	Launcher	Receiver
Fugitive Leak Gas (lb/event)[1]	1,563	1,630
Hexane Emissions (lb/event)[2]	2.51	2.62

Maximum Hourly Hexane Emissions

Parameter	CT-01 Vent	CT-02 Vent	CT-03 Vent	CT-04 Vent	Stn. Suctn. 1	Stn. Suctn. 2	Stn. Dischrg. 1	Stn. Dischrg. 2	Launcher	Receiver
Hexane Emissions (lb/hr)[6]	0.866	0.368	0.963	0.186	---	---	---	---	2.51	2.62

Maximum Annual Hexane Emissions - Blowdowns

Parameter	CT-01 Vent	CT-02 Vent	CT-03 Vent	CT-04 Vent	Stn. Suctn. 1	Stn. Suctn. 2	Stn. Dischrg. 1	Stn. Dischrg. 2	Launcher	Receiver
Hexane Emissions (ton/yr)[7]	0.006	0.003	0.006	0.001	1.91E-06	1.91E-06	1.55E-06	1.55E-06	0.005	0.005

Maximum Annual Hexane Emissions - Fugitives

Parameter	CT-01	CT-02	CT-03	CT-04
Hexane Emissions (ton/yr)[8]	0.014	0.014	0.014	0.014

Gas Composition (wt. %)[1]

Hexane	0.161%

Maximum Sitewide Blowdown Gas (lb)[1]

Per Event	12.5
Per Hour	12.5

Sitewide Blowdown Gas Stack Distribution (wt. %)[9]

CT-01 Vent	11%
CT-02 Vent	5%
CT-03 Vent	13%
CT-04 Vent	2%
Stn. Suctn. 1	19%
Stn. Suctn. 2	19%
Stn. Dischrg. 1	15.5%
Stn. Dischrg. 2	15.5%

Max. Blowdown Events (event/yr)[1]

Startup	10
Shutdown	10
Sitewide	1

Operating Schedule (hr/yr)[4]

Fug. Leaks	8,760

Pigging Events (event/yr)[1]

Pig Launcher	4
Pig Receiver	4

Notes:

1. From Table C-3.
2. Calculated as: [Blowdown Gas * Hexane Gas Composition]
3. Calculated as: [Maximum Sitewide Blowdown Gas * Sitewide Blowdown Gas Stack Distribution].
4. From Table C-7. Distribuited the total facility-wide fugitive leaks evenly across each turbine.
5. Calculated as: [Fugitive Leak Gas * Hexane Gas Composition]
6. Maximum hourly emissions for CT-01 Vent through CT-04 Vent occur during shutdown events. A sitewide event would not occur in the same hour as shutdown events. To be conservative, assumed a pigging event could occur in the same hour.
7. Calculated as: [Startup Event Emissions (lb/event) * Max. Startup Events (event/yr) + Shutdown Event Emissions (lb/event) * Max. Shutdown Events (event/yr) + Sitewide Event Emissions (lb/event) * Max. Sitewide Events (event/yr)] * 1 ton / 2,000 lb
   Launcher and Receiver emissions calculated as: Pigging Event Emissions (lb/event) * Pigging Events (event/yr) * 1 ton / 2,000 lb
8. Calculated as: [Fugitive Leak Emissions (lb/hr) * Operating Schedule (hr/yr)] * 1 ton / 2,000 lb
9. Based on engineering assumptions. Assumed vol. % is equivalent to wt. %.

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TK-2	
City:		
State:		
Company:		
Type of Tank:	Horizontal Tank	
Description:		

Tank Dimensions

Shell Length (ft):		14.80
Diameter (ft):		5.42
Volume (gallons):		2,500.00
Turnovers:		5.00
Net Throughput(gal/yr):		12,500.00
Is Tank Heated (y/n):	N	
Is Tank Underground (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Light	
Shell Condition	Good	

Breather Vent Settings

Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Lynchburg, Virginia (Avg Atmospheric Pressure = 14.27 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-2 - Horizontal Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Used Oil	All	63.07	54.02	72.12	58.12	0.0001	0.0001	0.0001	380.0000			200.00	Option 1: VP60 = .0001 VP70 = .0001

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-2 - Horizontal Tank

Annual Emission Calcaulations	
Standing Losses (lb):	0.0350
Vapor Space Volume (cu ft):	217.4956
Vapor Density (lb/cu ft):	0.0000
Vapor Space Expansion Factor:	0.0651
Vented Vapor Saturation Factor:	1.0000
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	217.4956
Tank Diameter (ft):	5.4200
Effective Diameter (ft):	10.1087
Vapor Space Outage (ft):	2.7100
Tank Shell Length (ft):	14.8000
Vapor Density	
Vapor Density (lb/cu ft):	0.0000
Vapor Molecular Weight (lb/lb-mole):	380.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0001
Daily Avg. Liquid Surface Temp. (deg. R):	522.7367
Daily Average Ambient Temp. (deg. F):	55.8833
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	517.7933
Tank Paint Solar Absorptance (Shell):	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	1,389.8277
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.0651
Daily Vapor Temperature Range (deg. R):	36.2062
Daily Vapor Pressure Range (psia):	0.0000
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0001
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0001
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0001
Daily Avg. Liquid Surface Temp. (deg R):	522.7367
Daily Min. Liquid Surface Temp. (deg R):	513.6852
Daily Max. Liquid Surface Temp. (deg R):	531.7883
Daily Ambient Temp. Range (deg. R):	21.1000
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	1.0000
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0001
Vapor Space Outage (ft):	2.7100
Working Losses (lb):	0.0085
Vapor Molecular Weight (lb/lb-mole):	380.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0001
Annual Net Throughput (gal/yr.):	12,500.0000
Annual Turnovers:	5.0000
Turnover Factor:	1.0000
Tank Diameter (ft):	5.4200
Working Loss Product Factor:	0.7500
Total Losses (lb):	0.0435

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-2 - Horizontal Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Used Oil	0.01	0.03	0.04

```
******************************************************************************************
*     Project Setup Information                                                          *
******************************************************************************************
Project File              : Untitled.Ept
Flowsheet Selection       : Oil Tank with Separator
Calculation Method        : AP42
Control Efficiency        : 100.0%
Known Separator Stream    : Low Pressure Gas
Entering Air Composition  : No

Well ID                   : TK-1 Produced Fluids Tank 052518
Date                      : 2018.05.25


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

Separator Pressure        : 552.00[psig]
Separator Temperature     : 77.00[F]
Molar GOR                 : 0.0500
Ambient Pressure          : 14.70[psia]
Ambient Temperature       : 70.00[F]
C10+ SG                   : 0.8990
C10+ MW                   : 166.00

-- Low Pressure Gas ----------------------------------------------------------------------
   No.    Component            mol %
   1      H2S                  0.0000
   2      O2                   0.0000
   3      CO2                  1.0410
   4      N2                   0.9940
   5      C1                  94.2060
   6      C2                   2.9230
   7      C3                   0.5460
   8      i-C4                 0.0790
   9      n-C4                 0.0840
   10     i-C5                 0.0240
   11     n-C5                 0.0220
   12     C6                   0.0320
   13     C7+                  0.0490
   14     Benzene              0.0000
   15     Toluene              0.0000
   16     E-Benzene            0.0000
   17     Xylenes              0.0000
   18     n-C6                 0.0000
   19     224Trimethylp        0.0000

   C7+ Molar Ratio: C7  :     C8  :     C9  :     C10+
                    1.0000    1.0000    1.0000    1.0000

-- Sales Oil -----------------------------------------------------------------------------
Production Rate           : 0.3[bbl/day]
Days of Annual Operation  : 365 [days/year]
API Gravity               : 46.0
Reid Vapor Pressure       : 7.70[psia]
Bulk Temperature          : 80.00[F]

-- Tank and Shell Data -------------------------------------------------------------------
Diameter                  : 4.00[ft]
Shell Height              : 10.50[ft]
Cone Roof Slope           : 0.06
Average Liquid Height     : 5.25[ft]
Vent Pressure Range       : 0.06[psi]
Solar Absorbance          : 0.54
```

-- Meteorological Data --

City	: Charleston, WV
Ambient Pressure	: 14.70[psia]
Ambient Temperature	: 70.00[F]
Min Ambient Temperature	: 44.00[F]
Max Ambient Temperature	: 65.50[F]
Total Solar Insolation	: 1123.00[Btu/ft^2*day]

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

-- Emission Summary ---

Item	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
Total HAPs	0.000	0.000
Total HC	0.174	0.040
VOCs, C2+	0.157	0.036
VOCs, C3+	0.144	0.033

Uncontrolled Recovery Info.

Vapor	8.5600 x1E-3	[MSCFD]
HC Vapor	8.0700 x1E-3	[MSCFD]
GOR	26.26	[SCF/bbl]

-- Emission Composition ---

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.001	0.000
2	O2	0.000	0.000
3	CO2	0.009	0.002
4	N2	0.000	0.000
5	C1	0.017	0.004
6	C2	0.013	0.003
7	C3	0.032	0.007
8	i-C4	0.013	0.003
9	n-C4	0.042	0.010
10	i-C5	0.016	0.004
11	n-C5	0.020	0.005
12	C6	0.006	0.001
13	C7	0.006	0.001
14	C8	0.002	0.000
15	C9	0.000	0.000
16	C10+	0.000	0.000
17	Benzene	0.000	0.000
18	Toluene	0.000	0.000
19	E-Benzene	0.000	0.000
20	Xylenes	0.000	0.000
21	n-C6	0.004	0.001
22	224Trimethylp	0.000	0.000
	Total	0.181	0.041

-- Stream Data --

No.	Component	MW	LP Oil mol %	Flash Oil mol %	Sale Oil mol %	Flash Gas mol %	W&S Gas mol %	Total Emissions mol %
1	H2S	34.80	0.0508	0.0349	0.0012	0.6834	0.0805	0.5478
2	O2	32.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	CO2	44.01	0.2437	0.0907	0.0000	6.3467	0.0001	4.9192
4	N2	28.01	0.0102	0.0005	0.0000	0.3990	0.0001	0.3093
5	C1	16.04	0.9543	0.1475	0.0000	33.1362	0.0001	25.6832
6	C2	30.07	0.6701	0.3531	0.0000	13.3133	0.0001	10.3189
7	C3	44.10	2.1827	1.7648	0.3292	18.8508	13.2095	17.5819
8	i-C4	58.12	1.1269	1.0450	0.5518	4.3934	9.4008	5.5197
9	n-C4	58.12	4.6091	4.4100	2.9083	12.5490	34.2470	17.4294
10	i-C5	72.15	3.1066	3.0997	2.7506	3.3810	12.8635	5.5138
11	n-C5	72.15	5.0558	5.0823	4.7524	4.0000	16.2367	6.7523
12	C6	86.16	4.1726	4.2520	4.3869	1.0044	4.6008	1.8133

13	C7	100.20	10.3655	10.6043	11.2593	0.8388	4.0662	1.5648
14	C8	114.23	10.8426	11.1074	11.9135	0.2806	1.4133	0.5354
15	C9	128.28	5.5127	5.6497	6.0790	0.0497	0.2580	0.0965
16	C10+	166.00	45.9695	47.1217	50.7905	0.0099	0.0536	0.0197
17	Benzene	78.11	0.5685	0.5808	0.6106	0.0778	0.3633	0.1420
18	Toluene	92.13	0.2132	0.2183	0.2337	0.0082	0.0400	0.0153
19	E-Benzene	106.17	0.0711	0.0729	0.0783	0.0009	0.0045	0.0017
20	Xylenes	106.17	0.6802	0.6971	0.7498	0.0075	0.0380	0.0144
21	n-C6	86.18	3.5939	3.6672	3.8202	0.6694	3.1239	1.2215
22	224Trimethylp	114.24	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	MW		123.89	126.03	130.00	38.64	65.06	44.59
	Stream Mole Ratio		1.0000	0.9755	0.9684	0.0245	0.0071	0.0316
	Heating Value	[BTU/SCF]				2044.13	3615.99	2397.68
	Gas Gravity	[Gas/Air]				1.33	2.25	1.54
	Bubble Pt. @ 100F	[psia]	56.28	19.66	5.65			
	RVP @ 100F	[psia]	126.75	78.89	35.74			
	Spec. Gravity @ 100F		0.800	0.803	0.811			

APPENDIX D

VENDOR SPECIFICATIONS

Solar Turbines Emissions Estimates

Titan 130-20502S

Assumptions: pipeline natural gas, sea level, 4"/4" inlet/outlet losses, nominal performance

50% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO_2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	11,083	116.71	24.164	9	4.20	25	7.11	25	4.07	2.5	0.407	15,276	0.02	2.57	906	367,603
59	10,015	105.62	24.127	9	3.79	25	6.40	25	3.66	2.5	0.366	13,736	0.02	2.32	991	312,469
100	8,160	96.22	21.577	9	3.38	25	5.73	25	3.28	2.5	0.328	12,281	0.02	2.12	1,050	273,036

75% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO_2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	16,299	137.63	30.132	9	4.96	25	8.38	25	4.80	2.5	0.480	18,005	0.02	3.03	899	413,002
59	15,022	124.33	30.743	9	4.46	25	7.53	25	4.32	2.5	0.432	16,165	0.02	2.74	955	357,845
100	12,240	109.93	28.329	9	3.87	25	6.54	25	3.75	2.5	0.375	14,028	0.02	2.42	1,019	304,112

100% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO_2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	21,732	157.20	35.175	9	5.67	25	9.58	25	5.49	2.5	0.549	20,549	0.02	3.46	900	437,967
59	20,030	142.50	35.765	9	5.11	25	8.64	25	4.95	2.5	0.495	18,518	0.02	3.14	944	392,542
100	16,320	125.55	33.072	9	4.42	25	7.47	25	4.28	2.5	0.428	16,018	0.02	2.76	994	340,129

Controlled Emission Rates w/SCR and Oxidation Catalyst

50% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO_2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	11,083	116.71	24.164	3.75	1.75	2	0.569	25	4.07	1.25	0.204	15,276	0.02	2.57
59	10,015	105.62	24.127	3.75	1.58	2	0.512	25	3.66	1.25	0.183	13,736	0.02	2.32
100	8,160	96.22	21.577	3.75	1.41	2	0.458	25	3.28	1.25	0.164	12,281	0.02	2.12

75% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO_2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	16,299	137.63	30.132	3.75	2.07	2	0.670	25	4.80	1.25	0.240	18,005	0.02	3.03
59	15,022	124.33	30.743	3.75	1.86	2	0.602	25	4.32	1.25	0.216	16,165	0.02	2.74
100	12,240	109.93	28.329	3.75	1.61	2	0.523	25	3.75	1.25	0.188	14,028	0.02	2.42

100% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO_2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	21,732	157.20	35.175	3.75	2.36	2	0.766	25	5.49	1.25	0.275	20,549	0.02	3.46
59	20,030	142.50	35.765	3.75	2.13	2	0.691	25	4.95	1.25	0.248	18,518	0.02	3.14
100	16,320	125.55	33.072	3.75	1.84	2	0.598	25	4.28	1.25	0.214	16,018	0.02	2.76

Example Calculation of ppm to lb/hr conversion

100% load, 0 degrees F, Controlled

H_2O Volume % (Actual)	O_2 (Actual)	Exhaust Flow (lb/hr)	MW(EX)	NWP	O_2% Dry	NOx (ppm)	NOx (ppmA)	MW(P)	NOx (lb/hr)	CO (ppm)	CO (ppmA)	MW(P)	CO (lb/hr)
5.91	14.39	437,967	28.59	0.941	15.3	3.75	3.35	46	2.36	2	1.79	28	0.767

UHC (ppm)	UHC (ppmA)	MW(P)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)
25	22.4	16	5.48	1.25	0.274

Notes:

1. NWP is the non-water fraction portion of the exhaust
2. ppmA is the ppm at actual test conditions
3. MW(EX) is the molecular weight of the exhaust
4. MW(P) is the molecular weight of the pollutant
5. NWP = (100 - H_2O Volume % (Actual)) / 100
6. O_2% Dry = O_2% (Actual) / NWP
7. ppmA = ppm * NWP * (20.9 - O_2% Dry) / (20.9 - 15)
8. lb/hr = (ppmA / 1,000,000) * EMF * (MW(P) / MW(EX))
9. Differences between example calculation and emissions estimates are due to rounding.

Solar Turbines Emissions Estimates

Mars 100-16000S

Assumptions: pipeline natural gas, sea level, 4"/4" inlet/outlet losses, nominal performance

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
50% load																
0	8,962	97.29	23.440	9	3.50	25	5.93	25	3.39	2.5	0.339	12,753	0.02	2.14	864	322,744
59	7,760	85.24	23.162	9	3.05	25	5.16	25	2.96	2.5	0.296	11,107	0.02	1.88	949	275,560
100	6,580	75.95	22.046	9	2.67	25	4.52	25	2.59	2.5	0.259	9,713	0.02	1.67	1,009	240,842
75% load																
Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	13,180	115.67	28.993	9	4.17	25	7.05	25	4.04	2.5	0.404	15,149	0.02	2.54	870	355,319
59	11,640	101.99	29.037	9	3.65	25	6.18	25	3.54	2.5	0.354	13,280	0.02	2.24	916	310,038
100	9,870	90.11	27.869	9	3.17	25	5.36	25	3.07	2.5	0.307	11,519	0.02	1.98	965	271,481
100% load																
Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	17,574	129.64	34.493	9	4.67	25	7.91	25	4.53	2.5	0.453	16,963	0.02	2.85	864	366,922
59	15,519	116.41	33.920	9	4.18	25	7.06	25	4.04	2.5	0.404	15,148	0.02	2.56	908	334,207
100	13,160	104.09	32.169	9	3.67	25	6.20	25	3.55	2.5	0.355	13,299	0.02	2.29	945	298,619

Controlled Emission Rates w/SCR and Oxidation Catalyst

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
50% load														
0	8,962	97.29	23.440	3.75	1.46	2	0.474	25	3.39	1.25	0.170	12,753	0.02	2.14
59	7,760	85.24	23.162	3.75	1.27	2	0.413	25	2.96	1.25	0.148	11,107	0.02	1.88
100	6,580	75.95	22.046	3.75	1.11	2	0.362	25	2.59	1.25	0.130	9,713	0.02	1.67
75% load														
Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	13,180	115.67	28.993	3.75	1.74	2	0.564	25	4.04	1.25	0.202	15,149	0.02	2.54
59	11,640	101.99	29.037	3.75	1.52	2	0.494	25	3.54	1.25	0.177	13,280	0.02	2.24
100	9,870	90.11	27.869	3.75	1.32	2	0.429	25	3.07	1.25	0.154	11,519	0.02	1.98
100% load														
Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	17,574	129.64	34.493	3.75	1.95	2	0.633	25	4.53	1.25	0.227	16,963	0.02	2.85
59	15,519	116.41	33.920	3.75	1.74	2	0.565	25	4.04	1.25	0.202	15,148	0.02	2.56
100	13,160	104.09	32.169	3.75	1.53	2	0.496	25	3.55	1.25	0.178	13,299	0.02	2.29

Example Calculation of ppm to lb/hr conversion

100% load, 0 degrees F, Controlled

H20 Volume % (Actual)	O2 (Actual)	Exhaust Flow (lb/hr)	MW(EX)	NWP	O2% Dry	NOx (ppm)	NOx (ppmA)	MW(P)	NOx (lb/hr)	CO (ppm)	CO (ppmA)	MW(P)	CO (lb/hr)
5.82	14.49	366,922	28.60	0.942	15.4	3.75	3.30	46	1.95	2	1.76	28	0.632
						UHC (ppm)	UHC (ppmA)	MW(P)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)		
						25	22.0	16	4.52	1.25	0.226		

Notes:
1. NWP is the non-water fraction portion of the exhaust
2. ppmA is the ppm at actual test conditions
3. MW(EX) is the molecular weight of the exhaust
4. MW(P) is the molecular weight of the pollutant
5. NWP = (100 - H2O Volume % (Actual)) / 100
6. O2% Dry = O2% (Actual) / NWP
7. ppmA = ppm * NWP * (20.9 - O2% Dry) / (20.9 - 15)
8. lb/hr = (ppmA / 1,000,000) * EMF * (MW(P) / MW(EX))
9. Differences between example calculation and emissions estimates are due to rounding.

Solar Turbines Emissions Estimates

Taurus 70-10802S

Assumptions: pipeline natural gas, sea level, 4"/4" inlet/outlet losses, nominal performance

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
50% load																
0	6,051	62.27	24.724	9	2.24	25	3.79	25	2.17	2.5	0.217	8,156	0.02	1.37	885	198,513
59	5,430	55.14	25.055	9	1.97	25	3.34	25	1.91	2.5	0.191	7,177	0.02	1.21	962	169,254
100	4,342	47.92	23.055	9	1.69	25	2.85	25	1.63	2.5	0.163	6,124	0.02	1.05	1,015	148,260
75% load																
Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	9,076	75.38	30.637	9	2.72	25	4.59	25	2.63	2.5	0.263	9,865	0.02	1.66	868	224,320
59	8,145	66.30	31.259	9	2.38	25	4.02	25	2.30	2.5	0.230	8,625	0.02	1.46	925	192,967
100	6,512	57.05	29.043	9	2.01	25	3.40	25	1.95	2.5	0.195	7,286	0.02	1.26	986	164,067
100% load																
Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	12,102	85.62	35.962	9	3.09	25	5.22	25	2.99	2.5	0.299	11,197	0.02	1.88	854	237,484
59	10,860	79.24	34.869	9	2.84	25	4.81	25	2.75	2.5	0.275	10,301	0.02	1.74	940	213,302
100	8,683	68.40	32.299	9	2.41	25	4.07	25	2.33	2.5	0.233	8,730	0.02	1.50	999	183,855

Controlled Emission Rates w/SCR and Oxidation Catalyst

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
50% load														
0	6,051	62.27	24.724	3.75	0.935	2	0.303	25	2.17	1.25	0.109	8,156	0.02	1.37
59	5,430	55.14	25.055	3.75	0.823	2	0.267	25	1.91	1.25	0.096	7,177	0.02	1.21
100	4,342	47.92	23.055	3.75	0.703	2	0.228	25	1.63	1.25	0.082	6,124	0.02	1.05
75% load														
Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	9,076	75.38	30.637	3.75	1.13	2	0.367	25	2.63	1.25	0.132	9,865	0.02	1.66
59	8,145	66.30	31.259	3.75	0.990	2	0.322	25	2.30	1.25	0.115	8,625	0.02	1.46
100	6,512	57.05	29.043	3.75	0.838	2	0.272	25	1.95	1.25	0.098	7,286	0.02	1.26
100% load														
Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	12,102	85.62	35.962	3.75	1.29	2	0.418	25	2.99	1.25	0.150	11,197	0.02	1.88
59	10,860	79.24	34.869	3.75	1.19	2	0.385	25	2.75	1.25	0.138	10,301	0.02	1.74
100	8,683	68.40	32.299	3.75	1.01	2	0.326	25	2.33	1.25	0.117	8,730	0.02	1.50

Example Calculation of ppm to lb/hr conversion

100% load, 0 degrees F, Controlled

H20 Volume % (Actual)	O2 (Actual)	Exhaust Flow (lb/hr)	MW(EX)	NWP	O2% Dry	NOx (ppm)	NOx (ppmA)	MW(P)	NOx (lb/hr)	CO (ppm)	CO (ppmA)	MW(P)	CO (lb/hr)
5.93	14.36	237,484	28.59	0.941	15.3	3.75	3.37	46	1.29	2	1.80	28	0.418
						UHC (ppm)	UHC (ppmA)	MW(P)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)		
						25	22.5	16	2.99	1.25	0.149		

Notes:
1. NWP is the non-water fraction portion of the exhaust
2. ppmA is the ppm at actual test conditions
3. MW(EX) is the molecular weight of the exhaust
4. MW(P) is the molecular weight of the pollutant
5. NWP = (100 - H2O Volume % (Actual)) / 100
6. O2% Dry = O2% (Actual) / NWP
7. ppmA = ppm * NWP * (20.9 - O2% Dry) / (20.9 - 15)
8. lb/hr = (ppmA / 1,000,000) * EMF * (MW(P) / MW(EX))
9. Differences between example calculation and emissions estimates are due to rounding.

Solar Turbines Emissions Estimates

Centaur 50-6200LS

Assumptions: pipeline natural gas, sea level, 4"/4" inlet/outlet losses, nominal performance

50% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	3,377	39.52	21.741	9	1.42	25	2.41	25	1.38	2.5	0.138	5,188	0.02	0.869	834	140,425
59	3,059	35.43	21.973	9	1.27	25	2.15	25	1.23	2.5	0.123	4,621	0.02	0.779	912	120,608
100	2,472	30.97	20.306	9	1.09	25	1.84	25	1.06	2.5	0.106	3,965	0.02	0.681	962	104,180

75% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	5,066	47.54	27.110	9	1.72	25	2.90	25	1.66	2.5	0.166	6,233	0.02	1.05	845	154,053
59	4,589	42.35	27.569	9	1.52	25	2.57	25	1.47	2.5	0.147	5,520	0.02	0.932	905	134,139
100	3,707	36.96	25.524	9	1.30	25	2.20	25	1.26	2.5	0.126	4,729	0.02	0.813	955	116,535

100% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr	Exhaust Temp (F)	Exhaust Flow (lb/hr)
0	6,754	54.98	31.256	9	1.99	25	3.35	25	1.92	2.5	0.192	7,201	0.02	1.21	867	162,463
59	6,119	51.13	30.450	9	1.84	25	3.10	25	1.78	2.5	0.178	6,656	0.02	1.12	952	145,994
100	4,943	44.78	28.085	9	1.58	25	2.67	25	1.53	2.5	0.153	5,724	0.02	0.985	1,000	128,506

Controlled Emission Rates w/SCR and Oxidation Catalyst

50% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	3,377	39.52	21.741	3.75	0.593	2	0.193	25	1.38	1.25	0.069	5,188	0.02	0.869
59	3,059	35.43	21.973	3.75	0.530	2	0.172	25	1.23	1.25	0.062	4,621	0.02	0.779
100	2,472	30.97	20.306	3.75	0.455	2	0.147	25	1.06	1.25	0.053	3,965	0.02	0.681

75% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	5,066	47.54	27.110	3.75	0.715	2	0.232	25	1.66	1.25	0.083	6,233	0.02	1.05
59	4,589	42.35	27.569	3.75	0.633	2	0.206	25	1.47	1.25	0.074	5,520	0.02	0.932
100	3,707	36.96	25.524	3.75	0.543	2	0.176	25	1.26	1.25	0.063	4,729	0.02	0.813

100% load

Temp, F	HP	fuel flow, mmbtu/hr LHV	Thermal Eff, %	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)	VOC (ppm)	VOC (lb/hr)	CO2 lb/hr	PM10/2.5 lb/mmbtu	PM10/2.5 lb/hr
0	6,754	54.98	31.256	3.75	0.828	2	0.268	25	1.92	1.25	0.096	7,201	0.02	1.21
59	6,119	51.13	30.450	3.75	0.765	2	0.248	25	1.78	1.25	0.089	6,656	0.02	1.12
100	4,943	44.78	28.085	3.75	0.658	2	0.214	25	1.53	1.25	0.077	5,724	0.02	0.985

Example Calculation of ppm to lb/hr conversion

100% load, 0 degrees F, Controlled

H20 Volume % (Actual)	O2 (Actual)	Exhaust Flow (lb/hr)	MW(EX)	NWP	O2% Dry	NOx (ppm)	NOx (ppmA)	MW(P)	NOx (lb/hr)	CO (ppm)	CO (ppmA)	MW(P)	CO (lb/hr)
5.58	14.75	162,463	28.61	0.944	15.6	3.75	3.17	46	0.827	2	1.69	28	0.269
						UHC (ppm)	**UHC (ppmA)**	**MW(P)**	**UHC (lb/hr)**	**VOC (ppm)**	**VOC (lb/hr)**		
						25	21.1	16	1.92	1.25	0.096		

Notes:

1. NWP is the non-water fraction portion of the exhaust
2. ppmA is the ppm at actual test conditions
3. MW(EX) is the molecular weight of the exhaust
4. MW(P) is the molecular weight of the pollutant
5. NWP = (100 - H2O Volume % (Actual)) / 100
6. O2% Dry = O2% (Actual) / NWP
7. ppmA = ppm * NWP * (20.9 - O2% Dry) / (20.9 - 15)
8. lb/hr = (ppmA / 1,000,000) * EMF * (MW(P) / MW(EX))
9. Differences between example calculation and emissions estimates are due to rounding.

SoLoNOx Products:
Emissions in Non-SoLoNOx Modes

Leslie Witherspoon
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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.

Historically, regulatory agencies have not required a specific emissions level to be met at low load or cold ambient operating conditions, but have asked what emissions levels are expected. The expected values are necessary to appropriately estimate emissions for annual emissions inventory purposes and for New Source Review applicability determinations and permitting.

COLD AMBIENT EMISSIONS ESTIMATES

Solar's standard temperature range warranty for gas turbines with *SoLoNOx* combustion is ≥ 0°F (–20°C). The *Titan*™ 250 is an exception, with a lower standard warranty at ≥ –20°F (–29°C). At ambient temperatures below 0°F, many of Solar's turbine engine models are controlled to increase pilot fuel to improve flame stability and emissions are higher. Without the increase in pilot fuel at temperatures below 0°F the engines may exhibit combustor rumble, as operation may be near the lean stability limit.

If a cold ambient emissions warranty is requested, a new production turbine configured with the latest combustion hardware is required. For most models this refers to the inclusion of Cold Ambient Fuel Control Logic.

Emissions warranties are not offered for ambient temperatures below –20°F (–29°C). In addition, cold ambient emissions warranties cannot be offered for the *Centaur*® 40 turbine.

Table 1 provides expected and warrantable (upon Solar's documented approval) emissions levels for Solar's *SoLoNOx* combustion turbines. All emissions levels are in ppm at 15% O_2. Refer to Product Information Letter 205 for *Mercury*™ 50 turbine emissions estimates.

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 (–20°C) for Solar's *SoLoNOx* turbines that do not have current production hardware or for new production hardware that is not equipped with the cold ambient fuel 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.

For more conservative NOx emissions estimate for new equipment, customers can refer to the New Source Performance Standard (NSPS) 40CFR60, subpart KKKK, where the allowable NOx emissions level for ambient temperatures < 0°F (–20°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 depending on the turbine model.

Table 3 summarizes emissions levels for ambient temperatures below –20°F (–29°C) for the *Titan* 250.

Table 1. Warrantable Emissions Between 0°F and –20°F (–20° to –29°C) for New Production

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
Centaur 50	Dual Fuel	Liquid	65 to 100% load	120	150	75
Taurus 60	Dual Fuel	Liquid	65 to 100% load	120	150	75
Taurus 70	Dual Fuel	Liquid	65 to 100% load	120	150	75
Mars 100	Dual Fuel	Liquid	65 to 100% load	120	150	75
Titan 130	Dual Fuel	Liquid	65 to 100% load	120	150	75

Table 2. Expected Emissions below 0°F (–20°C) for SoLoNOx Combustion Turbines

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

Table 3. Expected Emissions below –20°F (–29°C) for the Titan 250 SoLoNOx Combustion Turbine

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

COLD AMBIENT PERMITTING STRATEGY

There are several permitting options to consider when permitting in cold ambient climates. Customers can use a tiered permitting approach or choose to permit a single emission rate over all temperatures. Historically, most construction and operating permits were silent on the ambient temperature boundaries for *SoLoNOx* operation.

Some customers have used a tiered permitting strategy. For purposes of compliance and annual emissions inventories, 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.

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.

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.

If an emissions warranty is desired and ambient temperatures are commonly below –20°F (–29°C), inlet air heating can be used to raise the turbine inlet temperature (T_1) to at least –20°F. In such cases, the values shown in Table 1 can be warranted for new production.

EMISSIONS ESTIMATES IN NON-SOLONOX MODE (LOW LOAD)

At operating loads < 50% (<40% load for the *Titan* 250) on natural gas fuel and < 65% (< 80% load for *Centaur* 40) 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. Note that the load levels are approximate. Engine controls are triggered either by power output for single-shaft engines or gas producer speed for two-shaft engines.

A conservative method for estimating emissions of NOx at low loads is to use the applicable 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%.

Table 4 provides estimates of NOx, CO, and UHC emissions when operating in non-SoLoNOx mode for natural gas or liquid fuel. The estimated emissions can be assumed to vary linearly as load is decreased from just below 50% load for natural gas (or 65% load for liquid fuel) to idle.

The estimates in Table 4 apply for any product for gas only or dual fuel systems using pipeline quality natural gas. Refer to Product Information Letter 205 for *Mercury* 50 emissions estimates.

Table 4. Estimated Emissions in non-SoLoNOx Mode

Ambient	Fuel System	Engine Load	NOx, ppm	CO, ppm	UHC, ppm
***Centaur* 40/50, *Taurus* 60/65/70, *Mars* 90/100, *Titan* 130**					
≥ –20°F (–29°C)	Natural Gas	Less than 50%	70	8,000	800
		Idle	50	10,000	1,000
< –20°F (–29°C)	Natural Gas	Less than 50%	120	8,000	800
		Idle	120	10,000	1,000
***Titan* 250**					
≥ –20°F (–29°C)	Natural Gas	Less than 40%	50	25	20
		Idle	50	2,000	200
< –20°F (–29°C)	Natural Gas	Less than 40%	70	150	50
		Idle	70	2,000	200
***Centaur* 50, *Taurus* 60/70, *Mars* 100, *Titan* 130**					
≥ –20°F (–29°C)	Liquid	Less than 65%	120	1,000	100
		Idle	120	10,000	3,000
< –20°F (–29°C)	Liquid	Less than 65%	120	1,000	150
		Idle	120	10,000	3,000
***Centaur* 40**					
≥ –20°F (–29°C)	Liquid	Less than 80%	120	1,000	100
		Idle	120	10,000	3,000
< –20°F (–29°C)	Liquid	Less than 80%	120	1,000	150
		Idle	120	10,000	3,000

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Volatile Organic Compound, Sulfur Dioxide, and Formaldehyde Emission Estimates

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PURPOSE

This Product Information Letter summarizes methods that are available to estimate emissions of volatile organic compounds (VOC), sulfur dioxide (SO_2), and formaldehyde from gas turbines. Emissions estimates of these pollutants are often necessary during the air permitting process.

INTRODUCTION

In absence of site-specific or representative source test data, Solar refers customers to a United States Environmental Protection Agency (EPA) document titled "AP-42" or other appropriate EPA reference documents. AP-42 is a collection of emission factors for different emission sources. The emission factors found in AP-42 provide a generally accepted way of estimating emissions when more representative data are not available. The most recent version of AP-42 (dated April 2000) can be found at:

http://www.epa.gov/ttn/chief/ap42/ch03/index.html

Solar does not typically warranty the emission rates for VOC, SO_2 or formaldehyde.

Volatile Organic Compounds

Many permitting agencies require gas turbine users to estimate 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 many ways of referring to the non-methane (and non-ethane) portion of an "unburned hydrocarbon" emission estimate.

For natural gas fuel, Solar's customers use 10-20% of the UHC emission rate to represent VOC emissions. The estimate of 10-20% is based on a ratio of total non-methane hydrocarbons to total organic compounds. The use of 10-20% provides a conservative estimate of VOC emissions. The balance of the UHC is assumed to be primarily methane.

For liquid fuel, it is appropriate to estimate that 100% of the UHC emission estimate is VOC.

Sulfur Dioxide

Sulfur dioxide emissions are produced by conversion of sulfur in the fuel to SO_2. Since Solar does not control the amount of sulfur in the fuel, we are unable to predict SO_2 emissions without a site fuel composition analysis. Customers generally estimate SO_2 emissions with a mass balance calculation by assuming that any sulfur in the fuel will convert to SO_2. For reference, the typical mass balance equation is shown below.

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

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

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 0.0034 lb/MMBtu for gas fuel (HHV*) and 0.033 lb/MMBtu for liquid fuel (HHV).

*LHV = Lower Heating Value; HHV = Higher Heating Value

Formaldehyde

In gas turbines, formaldehyde emissions are a result of incomplete combustion. Formaldehyde in the exhaust stream is unstable and very difficult to measure. In addition to turbine characteristics including combustor design, size, maintenance history, and load profile, the formaldehyde emission level is also affected by:

- Ambient temperature
- Humidity
- Atmospheric pressure
- Fuel quality
- Formaldehyde concentration in the ambient air
- Test method measurement variability
- 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 including: mean, median, maximum, and minimum. 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. To estimate formaldehyde emissions from gas turbines, users should use the emission factor(s) that best represent the gas turbines actual / planned operating profile. Refer to the memo for alternative emission factors.

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

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

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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. The commissioning process is also discussed.

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 related to the start-up, shutdown, and commissioning of combustion turbines will not be guaranteed or warranted.

Combustion turbine start-up occurs in one of three modes: cold, warm, or hot. On large, utility size, combustion turbines, the start-up time varies by the "mode". The start-up duration for a hot, warm, or cold *Solar* turbine is less than 10 minutes in simple-cycle and most combined heat and power applications.

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 is not limited. However, some combined heat and power plant applications will desire or dictate longer start-up times, therefore emissions assuming a 60-minute start are also estimated.

A typical shutdown for a *Solar* turbine is <10 minutes. Emissions estimates for an elongated shutdown, 30-minutes, are also included.

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

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.

START-UP SEQUENCE

The start-up sequence, or getting to *SoLoNOx* combustion mode, takes three steps:

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

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[1] 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 hold 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.

Steps 2 and 3 are short-term transient conditions making up less than 10 minutes.

SHUTDOWN PROCESS

Normal, planned cool down/shutdown duration varies by engine model. The *Centaur*® 40, *Centaur* 50, *Taurus*™ 60, and *Taurus* 65 engines take about 5 minutes. The *Taurus* 70, *Mars*® 90 and 100, *Titan*™ 130 and *Titan* 250 engines take about 10 minutes. Typically, once the shutdown process starts, the emissions will remain in *SoLoNOx* mode for approximately 90 seconds and move into a transitional mode for the balance of the estimated shutdown time (assuming the unit was operating at full-load).

START-UP AND SHUTDOWN EMISSIONS ESTIMATES

Tables 1 through 5 summarize the estimated pounds of emissions per start-up and shutdown event for each product. Emissions estimates are presented for both GS and CS/MD applications on both natural gas and liquid fuel (diesel #2). The emissions estimates are calculated using empirical exhaust characteristics.

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, will see the engine start and shutdown a number of times 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 "tune-up" during which the turbine is running at various loads, most likely within low emissions mode (warranted emissions range).

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[1] 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
10 Minute Start-up and 10 Minute Shutdown
Natural Gas Fuel

Data will NOT be warranted under any circumstances

	Centaur 40 4701S				Centaur 50 6201S				Taurus 60 7901S				Taurus 65 8401S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	0.6	58.1	3.3	359	0.8	75.0	4.3	454	0.8	78.5	4.5	482	0.9	85.8	4.9	523
Total Emissions per Shutdown (lbs)	0.3	25.5	1.5	160	0.4	31.1	1.8	194	0.4	34.7	2.0	217	0.4	38.2	2.2	237

	Taurus 70 10801S				Mars 90 13002S GSC				Mars 100 16002S GSC				Titan 130 20501S				Titan 250 30002S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	1.1	103.9	5.9	634	1.4	129.0	7.4	868	1.6	151.2	8.6	952	2.1	195.6	11.2	1,194	2.5	22.7	1.5	1,925
Total Emissions per Shutdown (lbs)	1.3	110.7	6.3	689	1.7	147.9	8.4	912	1.9	166.8	9.5	1,026	2.4	210.0	12.0	1,303	3.0	19.9	1.5	1,993

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

Assumes unit is operating at full load prior to shutdown.

Assumes natural gas fuel; ES 9-98 compliant.

Table 2. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set Applications
60 Minute Start-up and 30 Minute Shutdown
Natural Gas Fuel

Data will NOT be warranted under any circumstances

	Centaur 40 4701S				Centaur 50 6201S				Taurus 60 7901S				Taurus 65 8401S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	4.1	219.4	13.0	3,420	5.0	272.4	16.1	4,219	5.7	299.8	17.8	4,780	6.1	326.5	19.3	5,074
Total Emissions per Shutdown (lbs)	1.8	121.1	7.1	1,442	2.3	163.3	9.5	1,834	2.5	163.5	9.6	1,994	2.6	177.2	10.4	2,119

	Taurus 70 10801S				Mars 90 13002S				Mars 100 16002S				Titan 130 20501S				Titan 250 30002S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	7.6	410.3	24.2	6,164	10.5	570.8	33.7	8,641	11.3	583.5	34.6	9,691	13.8	740.4	43.8	11,495	14.6	75.5	7.3	16,253
Total Emissions per Shutdown (lbs)	3.3	223.0	13.0	2,588	4.3	277.0	16.2	3,685	4.8	308.1	18.0	4,056	6.0	405.3	23.7	4,826	6.2	52.6	4.1	7,222

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

Assumes unit is operating at full load prior to shutdown.

Assumes natural gas fuel; ES 9-98 compliant.

Table 3. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx CS/MD Applications
10 Minute Start-up and 10 Minute Shutdown
Natural Gas Fuel

Data will NOT be warranted under any circumstances

	Centaur 40 4702S				Centaur 50 6102S				Taurus 60 7802S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	0.7	64.4	3.7	392	0.8	69.1	4.0	469	0.7	64.3	3.7	410
Total Emissions per Shutdown (lbs)	0.3	30.2	1.7	181	0.4	35.4	2.0	217	0.4	33.0	1.9	204

	Taurus 70 10302S				Mars 90 13002S CSMD				Mars 100 16002S CSMD				Titan 130 20502S				Titan 250 30002S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	0.8	73.1	4.2	519	1.2	109.3	6.2	805	1.4	123.5	7.1	829	1.9	176.9	10.1	1,161	2.6	26.2	1.7	1,794
Total Emissions per Shutdown (lbs)	1.1	93.4	5.3	575	1.5	132.6	7.6	817	1.7	149.2	8.5	920	2.4	207.6	11.9	1,272	2.9	19.1	1.4	1,918

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

Assumes unit is operating at full load prior to shutdown.

Assumes natural gas fuel; ES 9-98 compliant.

Table 4. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set
10 Minute Start-up and 10 Minute Shutdown
Liquid Fuel (Diesel #2)

Data will NOT be warranted under any circumstances

	Centaur 40 4701S				Centaur 50 6201S				Taurus 60 7901S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	1.3	44.5	7.4	473	1.7	59.0	9.8	601	1.7	59.8	9.9	636
Total Emissions per Shutdown (lbs)	0.6	17.3	2.8	211	0.7	21.2	3.4	256	0.8	23.5	3.8	286

	Taurus 70 10801S				Mars 100 16002S GSC				Titan 130 20501S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	2.3	78.5	13.0	823	3.4	114.1	18.8	1,239	4.3	147.5	24.4	1,547
Total Emissions per Shutdown (lbs)	2.5	73.6	12.0	889	3.8	111.4	18.1	1,331	4.7	139.1	22.6	1,677

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

Assumes unit is operating at full load prior to shutdown.

Assumes #2 Diesel fuel; ES 9-98 compliant.

Table 5. Estimation of Start-up and Shutdown Emissions (lbs/event) for SoLoNOx Generator Set
60 Minute Start-up and 30 Minute Shutdown
Liquid Fuel (Diesel #2)

Data will NOT be warranted under any circumstances

	Centaur 40 4701S				Centaur 50 6201S				Taurus 60 7901S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	11.7	194.7	30.9	4,255	15.2	271.9	43.3	5,302	14.7	282.6	45.0	5,962
Total Emissions per Shutdown (lbs)	4.4	84.7	13.6	1,816	6.7	164.3	27.0	2,334	6.3	159.0	26.0	2,515

	Taurus 70 10801S				Mars 100 16002S				Titan 130 20501S			
	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)	NOx (lbs)	CO (lbs)	UHC (lbs)	CO2 (lbs)
Total Emissions per Start (lbs)	18.4	360.3	57.4	7,375	29.1	552.0	87.7	11,685	34.4	677.0	108.0	13,731
Total Emissions per Shutdown (lbs)	8.0	207.8	34.1	3,156	12.3	302.6	49.4	4,970	15.0	388.5	63.7	5,876

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

Assumes unit is operating at full load prior to shutdown.

Assumes #2 Diesel fuel; ES 9-98 compliant.

DESIGN SUMMARY (PRIMARY EMISSION SOURCE WITH COOLING AIR SKID)

ENQUIRY DETAILS	
Enquiry Number	700211
Datared Revision	5
Date of Revision	30-Apr-2018
Engineer	B Gleitz
Details of Revision	Update

PROJECT DETAILS	
Project Name	ACP DOM BUCKINGHAM
Client	DOMINION
End Client	ACP-DOMINION
Application	Simple Cycle
Number of SCRs	4

PROCESS DATA

T-130 BUCKINGHAM

PROCESS DATA													
Design Case		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12
Customer Design Case		-20	0	59	100	-20	0	59	100	-20	0	59	100
Percent Load	Percent	50%	50%	50%	50%	75%	75%	75%	75%	100%	100%	100%	100%
Fuel Case	Percent	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
EXHAUST GAS EMISSIONS DATA (BEFORE COOLING)													
Exhaust Gas Mass Flowrate, Wet	lb/h	367603	367603	312469	273036	413002	413002	357845	304112	437967	437967	392542	340129
Exhaust Gas Volumetric Flowrate, Wet	ACFM	213387	213387	193564	177916	238671	238671	216159	194113	253534	253534	235461	213508
Exhaust Gas Temperature	degrees F	906.0	906.0	991.0	1050.0	899.0	899.0	955.0	1019.0	900.0	900.0	944.0	994.0
Exhaust Gas Composition													
Component *MW*													
O2 31.999	vol% (wet)	15.14	15.14	14.64	13.97	14.86	14.86	14.47	13.82	14.39	14.39	14.19	13.68
H2O 18.015	vol% (wet)	5.24	5.24	6.42	9.30	5.49	5.49	6.57	9.44	5.91	5.91	6.82	9.56
N2 28.013	vol% (wet)	76.01	76.01	75.19	72.98	75.91	75.91	75.13	72.91	75.74	75.74	75.04	72.87
CO2 44.010	vol% (wet)	2.70	2.70	2.85	2.88	2.83	2.83	2.93	2.96	3.05	3.05	3.05	3.02
Ar 39.948	vol% (wet)	0.91	0.91	0.90	0.87	0.91	0.91	0.90	0.87	0.91	0.91	0.90	0.87
		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Emissions from the Source @ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)													
Nox as NO2	ppmvd	42.00	9.00	9.00	9.00	42.00	9.00	9.00	9.00	42.00	9.00	9.00	9.00
Nox as NO2	lb/h	19.60	4.20	3.79	3.38	23.13	4.96	4.46	3.87	26.46	5.67	5.11	4.42
CO	ppmvd	100.00	25.00	25.00	25.00	100.00	25.00	25.00	25.00	100.00	25.00	25.00	25.00
CO	lb/h	28.44	7.11	6.40	5.73	33.52	8.38	7.53	6.54	38.32	9.58	8.64	7.47
SO2	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2	lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3	lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COOLING AIR DATA													
Cooling Air Mass Flowrate, Wet	lb/h	83801.6	86066.1	123376.0	138340.6	89926.4	92356.3	120186.4	137614.8	96002.2	98596.4	124765.5	139056.5
Cooling Air Volumetric Flowrate, Wet	ACFM	15483	16621	26785	32036	16615	17835	26093	31868	17737	19040	27087	32202
Ambient Air Temperature	degrees F	-20.00	0.00	59.00	100.00	-20.00	0.00	59.00	100.00	-20.00	0.00	59.00	100.00
Relative Humidity	Percent	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00
EXHAUST GAS EMISSIONS DATA (AFTER COOLING)													
Exhaust Gas Mass Flowrate, Wet	lb/h	451405	453669	435845	411377	502928	505358	478031	441727	533969	536563	517308	479186
Exhaust Gas Volumetric Flowrate, Wet	ACFM	224596	225713	217241	208098	250362	251560	238441	223637	266007	267286	258191	242790
Exhaust Gas Temperature (after cooling)	degrees F	750.00	750.00	750.00	760.00	750.00	750.00	750.00	760.00	750.00	750.00	750.00	760.00
Exhaust Gas Composition													
Component *MW*													
O2 31.999	vol% (wet)	16.21	16.23	16.35	16.03	15.94	15.96	16.03	15.77	15.56	15.58	15.75	15.54
H2O 18.015	vol% (wet)	4.28	4.27	4.90	7.48	4.52	4.51	5.18	7.71	4.86	4.85	5.43	7.91
N2 28.013	vol% (wet)	76.39	76.39	75.78	73.68	76.29	76.29	75.67	73.59	76.15	76.15	75.58	73.51
CO2 44.010	vol% (wet)	2.21	2.20	2.06	1.93	2.33	2.32	2.21	2.06	2.51	2.50	2.33	2.16
Ar 39.948	vol% (wet)	0.91	0.91	0.91	0.88	0.91	0.91	0.91	0.88	0.91	0.91	0.91	0.88
		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Emissions from the Source @ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)													
Nox as NO2	ppmvd	42.00	9.00	9.01	9.04	42.00	9.00	9.01	9.04	42.00	9.00	9.01	9.04
Nox as NO2	lb/h	19.64	4.21	3.79	3.39	23.14	4.96	4.46	3.87	26.47	5.67	5.11	4.42
CO	ppmvd	100.00	25.00	25.03	25.12	100.00	25.00	25.02	25.11	100.00	25.00	25.02	25.10
CO	lb/h	28.47	7.12	6.40	5.73	33.55	8.39	7.54	6.54	38.37	9.59	8.64	7.48
SO2	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2	lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3	lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulates	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Trace Elements	mg/Nm3 (dry)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VOC	ppmvd	5.00	2.50	2.50	2.50	5.00	2.50	2.50	2.50	5.00	2.50	2.50	2.50
Amount of Nox as NO2	Percent	50	50	50	50	50	50	50	50	50	50	50	50
Nox Reduction	Percent	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33
CO Reduction	Percent	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00
Aqueous Ammonia Requirement	lb/h	31	14	12	11	37	16	15	13	42	19	17	15
Aqueous Ammonia Requirement	gal/month	3017	1334	1200	1074	3555	1572	1413	1225	4067	1798	1619	1402
Total Mass injected by SCR	lb/h	686	341	339	338	692	343	342	340	697	346	344	342
Exhaust Gas Mass Flowrate, Wet at SCR Outlet	lb/h	452091.0	454010.0	436184.5	411714.8	503620.4	505701.7	478373.2	442066.6	534666.6	536909.1	517651.4	479527.1
Exhaust Gas Vol Flowrate, Wet at SCR Outlet	ACFM	224938	225882	217410	208269	250707	251731	238612	223809	266354	267458	258362	242963
Performance Warranties @ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)													
Nox as NO2	ppmvd	17.5	3.8	3.8	3.8	17.5	3.8	3.8	3.8	17.5	3.8	3.8	3.8
Nox as NO2	lb/h	8.18	1.75	1.58	1.41	9.64	2.07	1.86	1.61	11.03	2.36	2.13	1.84
CO	ppmvd	8.00	2.00	2.00	2.01	8.00	2.00	2.00	2.01	8.00	2.00	2.00	2.01
CO	lb/h	2.28	0.57	0.51	0.46	2.68	0.67	0.60	0.52	3.07	0.77	0.69	0.60
VOC	ppmvd	2.50	1.25	1.25	1.25	2.50	1.25	1.25	1.25	2.50	1.25	1.25	1.25
NH3 Slip	ppmvd	10.00	10.00	10.01	10.05	10.00	10.00	10.01	10.04	10.00	10.00	10.01	10.04
NH3 Slip	lb/h	1.73	1.73	1.56	1.39	2.04	2.04	1.83	1.59	2.33	2.33	2.10	1.82
AFCU Selected		AQEL30	AQEL15	AQEL15	AQEL15	AQEL30	AQEL15	AQEL15	AQEL15	AQEL30	AQEL15	AQEL15	AQEL15

M-100 Buckingham

PROCESS DATA													
Design Case		Case 13	Case 14	Case 15	Case 16	Case 17	Case 18	Case 19	Case 20	Case 21	Case 22	Case 23	Case 24
Customer Design Case		-20	0	59	100	-20	0	59	100	-20	0	59	100
Percent Load	Percent	50%	50%	50%	50%	75%	75%	75%	75%	100%	100%	100%	100%
Fuel Case	Percent	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
EXHAUST GAS EMISSIONS DATA (BEFORE COOLING)													
Exhaust Gas Mass Flowrate, Wet	lb/h	322744	322744	275560	240842	355319	355319	310038	271481	366922	366922	334207	298619
Exhaust Gas Volumetric Flowrate, Wet	ACFM	181519	181519	165505	152459	200872	200872	181972	166767	206754	206754	195210	181051
Exhaust Gas Temperature	degrees F	864.0	864.0	949.0	1009.0	870.0	870.0	916.0	965.0	864.0	864.0	908.0	945.0
Exhaust Gas Composition													
Component *MW*													
O2 31.999	vol% (wet)	15.43	15.43	15.14	14.61	14.99	14.99	14.79	14.32	14.49	14.49	14.45	14.03
H2O 18.015	vol% (wet)	4.99	4.99	5.98	8.75	5.38	5.38	6.29	9.00	5.82	5.82	6.59	9.25
N2 28.013	vol% (wet)	76.10	76.10	75.37	73.18	75.95	75.95	75.24	73.09	75.78	75.78	75.12	73.00
CO2 44.010	vol% (wet)	2.57	2.57	2.61	2.59	2.77	2.77	2.78	2.72	3.00	3.00	2.94	2.85
Ar 39.948	vol% (wet)	0.91	0.91	0.90	0.87	0.91	0.91	0.90	0.87	0.91	0.91	0.90	0.87
		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Emissions from the Source @ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)													
Nox as NO2	ppmvd	42.00	9.00	9.00	9.00	42.00	9.00	9.00	9.00	42.00	9.00	9.00	9.00
Nox as NO2	lb/h	16.35	3.50	3.05	2.67	19.46	4.17	3.65	3.17	21.81	4.67	4.18	3.67
CO	ppmvd	100.00	25.00	25.00	25.00	100.00	25.00	25.00	25.00	100.00	25.00	25.00	25.00
CO	lb/h	23.72	5.93	5.16	4.52	28.20	7.05	6.18	5.36	31.64	7.91	7.06	6.20
SO2	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2	lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3	lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COOLING AIR DATA													
Cooling Air Mass Flowrate, Wet	lb/h	53766.5	55219.4	89841.3	104776.4	62308.6	63992.3	84319.8	97235.6	61126.2	62777.9	86512.6	103303.4
Cooling Air Volumetric Flowrate, Wet	ACFM	9934	10664	19505	24263	11512	12358	18306	22517	11293	12123	18782	23922
Ambient Air Temperature	degrees F	-20.00	0.00	59.00	100.00	-20.00	0.00	59.00	100.00	-20.00	0.00	59.00	100.00
Relative Humidity	Percent	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00
EXHAUST GAS EMISSIONS DATA (AFTER COOLING)													
Exhaust Gas Mass Flowrate, Wet	lb/h	376510	377963	365401	345618	417628	419311	394358	368717	428048	429700	420720	401922
Exhaust Gas Volumetric Flowrate, Wet	ACFM	187337	188053	182111	174839	207932	208762	196731	186787	213310	214124	210013	202059
Exhaust Gas Temperature (after cooling)	degrees F	750.00	750.00	750.00	760.00	750.00	750.00	750.00	760.00	750.00	750.00	750.00	750.00
Exhaust Gas Composition													
Component *MW*													
O2 31.999	vol% (wet)	16.21	16.23	16.51	16.27	15.87	15.89	16.05	15.84	15.40	15.42	15.73	15.59
H2O 18.015	vol% (wet)	4.29	4.28	4.77	7.27	4.59	4.58	5.17	7.65	5.00	4.99	5.45	7.87
N2 28.013	vol% (wet)	76.38	76.38	75.84	73.76	76.26	76.26	75.68	73.61	76.10	76.10	75.56	73.53
CO2 44.010	vol% (wet)	2.21	2.20	1.98	1.82	2.37	2.36	2.20	2.02	2.58	2.57	2.35	2.13
Ar 39.948	vol% (wet)	0.91	0.91	0.91	0.88	0.91	0.91	0.91	0.88	0.91	0.91	0.91	0.88
		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Emissions from the Source @ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)													
Nox as NO2	ppmvd	42.00	9.00	9.01	9.04	42.00	9.00	9.01	9.03	42.00	9.00	9.01	9.03
Nox as NO2	lb/h	16.37	3.51	3.06	2.67	19.48	4.17	3.66	3.17	21.84	4.68	4.18	3.67
CO	ppmvd	100.00	25.00	25.02	25.11	100.00	25.00	25.02	25.09	100.00	25.00	25.02	25.09
CO	lb/h	23.73	5.93	5.18	4.52	28.24	7.06	6.19	5.37	31.65	7.91	7.06	6.21
SO2	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2	lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3	lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulates	ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Trace Elements	mg/Nm3 (dry)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VOC	ppmvd	5.00	2.50	2.50	2.50	5.00	2.50	2.50	2.50	5.00	2.50	2.50	2.50
Amount of Nox as NO2	Percent	50	50	50	50	50	50	50	50	50	50	50	50
Nox Reduction	Percent	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33
CO Reduction	Percent	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00
Aqueous Ammonia Requirement	lb/h	26	12	10	9	31	14	12	10	35	15	14	12
Aqueous Ammonia Requirement	gal/month	2515	1112	970	848	2993	1323	1161	1006	3355	1483	1324	1163
Total Mass injected by SCR	lb/h	681	339	337	336	686	341	339	337	690	342	341	339
Exhaust Gas Mass Flowrate, Wet at SCR Outlet	lb/h	377191.7	378301.9	365738.4	345954.2	418313.8	419652.1	394696.9	369054.0	428738.1	430042.4	421060.4	402261.5
Exhaust Gas Vol Flowrate, Wet at SCR Outlet	ACFM	187676	188221	182279	175009	208274	208932	196900	186958	213654	214295	210183	202230
Performance Warranties @ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)													
Nox as NO2	ppmvd	17.5	3.8	3.8	3.8	17.5	3.8	3.8	3.8	17.5	3.8	3.8	3.8
Nox as NO2	lb/h	6.82	1.46	1.28	1.11	8.12	1.74	1.53	1.32	9.10	1.95	1.74	1.53
CO	ppmvd	8.00	2.00	2.00	2.01	8.00	2.00	2.00	2.01	8.00	2.00	2.00	2.01
CO	lb/h	1.90	0.47	0.41	0.36	2.26	0.56	0.50	0.43	2.53	0.63	0.57	0.50
VOC	ppmvd	2.50	1.25	1.25	1.25	2.50	1.25	1.25	1.25	2.50	1.25	1.25	1.25
NH3 Slip	ppmvd	10.00	10.00	10.01	10.04	10.00	10.00	10.01	10.04	10.00	10.00	10.01	10.04
NH3 Slip	lb/h	1.44	1.44	1.26	1.10	1.72	1.72	1.51	1.31	1.92	1.92	1.72	1.51
AFCU Selected		AQEL30	AQEL15	AQEL15	AQEL15	AQEL30	AQEL15	AQEL15	AQEL15	AQEL30	AQEL15	AQEL15	AQEL15

DESIGN SUMMARY (PRIMARY EMISSION SOURCE WITH COOLING AIR SKID)

ENQUIRY DETAILS	
Enquiry Number	700211
Datared Revision	5
Date of Revision	30-Apr-2018
Engineer	B Gleitz
Details of Revision	Update

PROJECT DETAILS	
Project Name	ACP DOM BUCKINGHAM
Client	DOMINION
End Client	ACP-DOMINION
Application	Simple Cycle
Number of SCRs	4

PROCESS DATA			T-70 Buckingham											
Design Case			Case 25	Case 26	Case 27	Case 28	Case 29	Case 30	Case 31	Case 32	Case 33	Case 34	Case 35	Case 36
Customer Design Case			-20	0	59	100	-20	0	59	100	-20	0	59	100
Percent Load		Percent	50%	50%	50%	50%	75%	75%	75%	75%	100%	100%	100%	100%
Fuel Case		Percent	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
EXHAUST GAS EMISSIONS DATA (BEFORE COOLING)														
Exhaust Gas Mass Flowrate, Wet		lb/h	198513	198513	169254	148260	224320	224320	192967	164067	237484	237484	213302	183855
Exhaust Gas Volumetric Flowrate, Wet		ACFM	113500	113500	102640	94261	126718	126718	114118	102350	132814	132814	127596	115788
Exhaust Gas Temperature		degrees F	885.0	885.0	962.0	1015.0	868.0	868.0	925.0	986.0	854.0	854.0	940.0	999.0
Exhaust Gas Composition														
Component	*MW*													
O2	31.999	vol% (wet)	15.21	15.21	14.85	14.47	14.80	14.80	14.54	14.05	14.36	14.36	14.04	13.63
H2O	18.015	vol% (wet)	5.18	5.18	6.23	8.86	5.54	5.54	6.52	9.24	5.93	5.93	6.96	9.60
N2	28.013	vol% (wet)	76.03	76.03	75.27	73.14	75.89	75.89	75.14	72.99	75.74	75.74	74.97	72.86
CO2	44.010	vol% (wet)	2.67	2.67	2.75	2.65	2.86	2.86	2.90	2.85	3.06	3.06	3.13	3.04
Ar	39.948	vol% (wet)	0.91	0.91	0.90	0.87	0.91	0.91	0.90	0.87	0.91	0.91	0.90	0.87
			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Emissions from the Source	@ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)														
Nox as NO2		ppmvd	42.00	9.00	9.00	9.00	42.00	9.00	9.00	9.00	42.00	9.00	9.00	9.00
Nox as NO2		lb/h	10.47	2.24	1.97	1.69	12.68	2.72	2.38	2.01	14.42	3.09	2.84	2.41
CO		ppmvd	100.00	25.00	25.00	25.00	100.00	25.00	25.00	25.00	100.00	25.00	25.00	25.00
CO		lb/h	15.16	3.79	3.34	2.85	18.36	4.59	4.02	3.40	20.88	5.22	4.81	4.07
SO2		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2		lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3		lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COOLING AIR DATA														
Cooling Air Mass Flowrate, Wet		lb/h	39162.6	40220.8	58787.0	69699.9	38681.1	39726.3	55325.8	68690.3	36092.4	37067.7	66398.0	76772.4
Cooling Air Volumetric Flowrate, Wet		ACFM	7236	7767	12763	16141	7147	7672	12011	15907	6668	7158	14415	17778
Ambient Air Temperature		degrees F	-20.00	0.00	59.00	100.00	-20.00	0.00	59.00	100.00	-20.00	0.00	59.00	100.00
Relative Humidity		Percent	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00
EXHAUST GAS EMISSIONS DATA (AFTER COOLING)														
Exhaust Gas Mass Flowrate, Wet		lb/h	237676	238734	228041	217960	263001	264046	248293	232757	273576	274552	279700	260627
Exhaust Gas Volumetric Flowrate, Wet		ACFM	118270	118792	113674	109329	130984	131499	123894	116892	136378	136859	139636	132046
Exhaust Gas Temperature (after cooling)		degrees F	750.00	750.00	750.00	750.00	750.00	750.00	750.00	750.00	750.00	750.00	750.00	760.00
Exhaust Gas Composition														
Component	*MW*													
O2	31.999	vol% (wet)	16.15	16.17	16.36	16.27	15.69	15.71	15.91	15.83	15.22	15.24	15.61	15.53
H2O	18.015	vol% (wet)	4.34	4.33	4.89	7.26	4.74	4.73	5.30	7.66	5.16	5.15	5.56	7.92
N2	28.013	vol% (wet)	76.36	76.36	75.79	73.76	76.20	76.20	75.62	73.61	76.04	76.04	75.52	73.51
CO2	44.010	vol% (wet)	2.24	2.23	2.06	1.82	2.45	2.44	2.27	2.03	2.67	2.66	2.40	2.16
Ar	39.948	vol% (wet)	0.91	0.91	0.91	0.88	0.91	0.91	0.91	0.88	0.91	0.91	0.91	0.88
			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Emissions from the Source	@ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)														
Nox as NO2		ppmvd	42.00	9.00	9.01	9.04	42.00	9.00	9.01	9.04	42.00	9.00	9.01	9.04
Nox as NO2		lb/h	10.47	2.24	1.98	1.69	12.70	2.72	2.38	2.01	14.42	3.09	2.84	2.41
CO		ppmvd	100.00	25.00	25.02	25.11	100.00	25.00	25.02	25.10	100.00	25.00	25.02	25.10
CO		lb/h	15.18	3.80	3.35	2.86	18.41	4.60	4.02	3.40	20.90	5.23	4.81	4.07
SO2		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2		lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3		lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulates		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Trace Elements		mg/Nm3 (dry)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VOC		ppmvd	5.00	2.50	2.50	2.50	5.00	2.50	2.50	2.50	5.00	2.50	2.50	2.50
Amount of Nox as NO2		Percent	50	50	50	50	50	50	50	50	50	50	50	50
Nox Reduction		Percent	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33
CO Reduction		Percent	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00
Aqueous Ammonia Requirement		lb/h	17	7	7	6	20	9	8	7	23	10	9	8
Aqueous Ammonia Requirement		gal/month	1609	711	627	535	1951	862	753	637	2215	979	901	763
Total Mass injected by SCR		lb/h	344	334	334	333	347	336	335	334	678	337	336	335
Exhaust Gas Mass Flowrate, Wet at SCR Outlet		lb/h	238019.3	239068.2	228374.6	218292.5	263348.4	264382.3	248627.7	233091.0	274254.5	274888.9	280036.4	260962.4
Exhaust Gas Vol Flowrate, Wet at SCR Outlet		ACFM	118441	118958	113841	109495	131157	131667	124061	117059	136716	137027	139804	132216
Performance Warranties	@ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)														
Nox as NO2		ppmvd	17.5	3.8	3.8	3.8	17.5	3.8	3.8	3.8	17.5	3.8	3.8	3.8
Nox as NO2		lb/h	4.36	0.94	0.82	0.70	5.29	1.13	0.99	0.84	6.01	1.29	1.18	1.00
CO		ppmvd	8.00	2.00	2.00	2.01	8.00	2.00	2.00	2.01	8.00	2.00	2.00	2.01
CO		lb/h	1.21	0.30	0.27	0.23	1.47	0.37	0.32	0.27	1.67	0.42	0.38	0.33
VOC		ppmvd	2.50	1.25	1.25	1.25	2.50	1.25	1.25	1.25	2.50	1.25	1.25	1.25
NH3 Slip		ppmvd	10.00	10.00	10.01	10.05	10.00	10.00	10.01	10.04	10.00	10.00	10.01	10.04
NH3 Slip		lb/h	0.92	0.92	0.81	0.69	1.12	1.12	0.98	0.83	1.27	1.27	1.17	0.99
AFCU Selected			AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL30	AQEL15	AQEL15	AQEL15

PROCESS DATA			C-50 Buckingham											
Design Case			Case 37	Case 38	Case 39	Case 40	Case 41	Case 42	Case 43	Case 44	Case 45	Case 46	Case 47	Case 48
Customer Design Case			-20	0	59	100	-20	0	59	100	-20	0	59	100
Percent Load		Percent	50%	50%	50%	50%	75%	75%	75%	75%	100%	100%	100%	100%
Fuel Case		Percent	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
EXHAUST GAS EMISSIONS DATA (BEFORE COOLING)														
Exhaust Gas Mass Flowrate, Wet		lb/h	140425	140425	120608	104180	154053	154053	134139	116535	162463	162463	145994	128506
Exhaust Gas Volumetric Flowrate, Wet		ACFM	77111	77111	70504	63816	85433	85433	78069	71059	91698	91698	88033	80961
Exhaust Gas Temperature		degrees F	834.0	834.0	912.0	962.0	845.0	845.0	905.0	955.0	867.0	867.0	952.0	1000.0
Exhaust Gas Composition														
Component	*MW*													
O2	31.999	vol% (wet)	15.78	15.78	15.42	14.92	15.29	15.29	15.03	14.57	14.75	14.75	14.41	14.03
H2O	18.015	vol% (wet)	4.67	4.67	5.73	8.47	5.11	5.11	6.08	8.78	5.58	5.58	6.62	9.25
N2	28.013	vol% (wet)	76.23	76.23	75.46	73.29	76.06	76.06	75.32	73.18	75.88	75.88	75.12	72.99
CO2	44.010	vol% (wet)	2.41	2.41	2.49	2.44	2.63	2.63	2.67	2.60	2.88	2.88	2.95	2.86
Ar	39.948	vol% (wet)	0.91	0.91	0.90	0.88	0.91	0.91	0.90	0.87	0.91	0.91	0.90	0.87
			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Emissions from the Source	@ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)														
Nox as NO2		ppmvd	42.00	9.00	9.00	9.00	42.00	9.00	9.00	9.00	42.00	9.00	9.00	9.00
Nox as NO2		lb/h	6.64	1.42	1.27	1.09	8.01	1.72	1.52	1.30	9.27	1.99	1.84	1.58
CO		ppmvd	100.00	25.00	25.00	25.00	100.00	25.00	25.00	25.00	100.00	25.00	25.00	25.00
CO		lb/h	9.64	2.41	2.15	1.84	11.60	2.90	2.57	2.20	13.40	3.35	3.10	2.67
SO2		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2		lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3		lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COOLING AIR DATA														
Cooling Air Mass Flowrate, Wet		lb/h	29407.4	30258.0	45158.4	52457.8	34909.6	35919.5	48566.4	49451.6	42401.2	43627.7	56334.1	56993.6
Cooling Air Volumetric Flowrate, Wet		ACFM	5433	5843	9804	12148	6450	6937	10544	11452	7834	8425	12230	13198
Ambient Air Temperature		degrees F	-20.00	0.00	59.00	100.00	-20.00	0.00	59.00	100.00	-20.00	0.00	59.00	100.00
Relative Humidity		Percent	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00
EXHAUST GAS EMISSIONS DATA (AFTER COOLING)														
Exhaust Gas Mass Flowrate, Wet		lb/h	169832	170683	165766	156638	188963	189972	182705	165987	204864	206091	202328	185500
Exhaust Gas Volumetric Flowrate, Wet		ACFM	80936	81338	79137	75250	90114	90591	87280	81576	97751	98330	98804	93129
Exhaust Gas Temperature (after cooling)		degrees F	700.00	700.00	700.00	700.00	700.00	700.00	700.00	725.00	700.00	700.00	725.00	750.00
Exhaust Gas Composition														
Component	*MW*													
O2	31.999	vol% (wet)	16.67	16.69	16.86	16.66	16.33	16.35	16.53	16.22	16.02	16.05	16.16	15.89
H2O	18.015	vol% (wet)	3.87	3.86	4.45	6.93	4.18	4.17	4.74	7.32	4.44	4.43	5.07	7.60
N2	28.013	vol% (wet)	76.54	76.54	75.96	73.89	76.42	76.43	75.84	73.74	76.33	76.33	75.72	73.63
CO2	44.010	vol% (wet)	2.00	1.99	1.83	1.64	2.15	2.14	1.97	1.84	2.30	2.28	2.15	2.00
Ar	39.948	vol% (wet)	0.91	0.91	0.91	0.89	0.91	0.91	0.91	0.88	0.91	0.91	0.91	0.88
			100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Emissions from the Source	@ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)														
Nox as NO2		ppmvd	42.00	9.00	9.01	9.04	42.00	9.00	9.01	9.04	42.00	9.00	9.01	9.04
Nox as NO2		lb/h	6.67	1.43	1.27	1.09	8.01	1.72	1.52	1.30	9.27	1.99	1.84	1.58
CO		ppmvd	100.00	25.00	25.03	25.12	100.00	25.00	25.02	25.11	100.00	25.00	25.03	25.11
CO		lb/h	9.66	2.42	2.15	1.85	11.61	2.90	2.57	2.20	13.44	3.36	3.11	2.67
SO2		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO2		lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SO3		lb/h	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Particulates		ppmvd	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Trace Elements		mg/Nm3 (dry)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VOC		ppmvd	5.00	2.50	2.50	2.50	5.00	2.50	2.50	2.50	5.00	2.50	2.50	2.50
Amount of Nox as NO2		Percent	50	50	50	50	50	50	50	50	50	50	50	50
Nox Reduction		Percent	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33
CO Reduction		Percent	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00	92.00
Aqueous Ammonia Requirement		lb/h	11	5	4	4	13	6	5	4	15	7	6	5
Aqueous Ammonia Requirement		gal/month	1024	453	403	346	1231	544	482	413	1425	630	582	501
Total Mass injected by SCR		lb/h	338	332	331	331	340	333	332	331	342	334	333	332
Exhaust Gas Mass Flowrate, Wet at SCR Outlet		lb/h	170170.0	171014.8	166097.6	156968.4	189302.4	190305.1	183037.4	166317.9	205206.0	206424.3	202661.2	185831.8
Exhaust Gas Vol Flowrate, Wet at SCR Outlet		ACFM	81097	81496	79295	75409	90276	90750	87439	81739	97914	98489	98967	93296
Performance Warranties	@ %O2	15												
Reference applicable for ppmvd and mg/Nm3 (dry)														
Nox as NO2		ppmvd	17.5	3.8	3.8	3.8	17.5	3.8	3.8	3.8	17.5	3.8	3.8	3.8
Nox as NO2		lb/h	2.78	0.60	0.53	0.45	3.34	0.72	0.63	0.54	3.86	0.83	0.76	0.66
CO		ppmvd	8.00	2.00	2.00	2.01	8.00	2.00	2.00	2.01	8.00	2.00	2.00	2.01
CO		lb/h	0.77	0.19	0.17	0.15	0.93	0.23	0.21	0.18	1.08	0.27	0.25	0.21
VOC		ppmvd	2.50	1.25	1.25	1.25	2.50	1.25	1.25	1.25	2.50	1.25	1.25	1.25
NH3 Slip		ppmvd	10.00	10.00	10.01	10.05	10.00	10.00	10.01	10.04	10.00	10.00	10.01	10.04
NH3 Slip		lb/h	0.59	0.59	0.52	0.45	0.71	0.71	0.62	0.54	0.82	0.82	0.76	0.65
AFCU Selected			AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15	AQEL15

HURST

BOILER & WELDING CO., INC.

AVAILABLE WITH LOW NOX

HURST SERIES 45

3-PASS FIREBOX DESIGN
All Steel Wetback Construction

LOW PRESSURE BOILER

Capacities from 8.5 to 813 BHP.
285 to 27215 MBTU/HR.

STEAM
Pressure 15 max PSI.

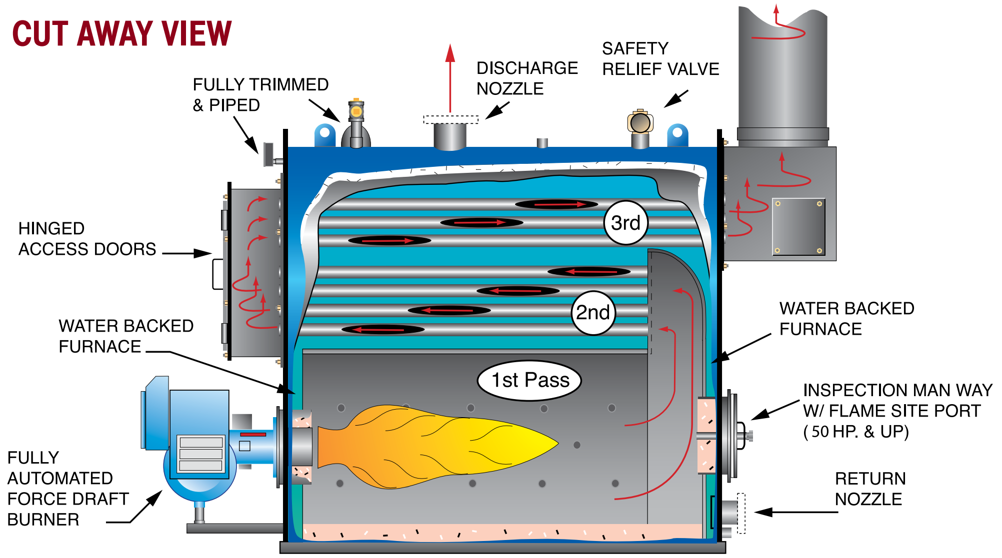
HOT WATER
Section IV
30, 60, 100 PSI.

"Large Furnace Volume for Ultimate Combustion Efficiency."

SKID MOUNTED
MODULAR PACKAGED

HURST PERFORMANCE SERIES BOILERS

CUT AWAY VIEW



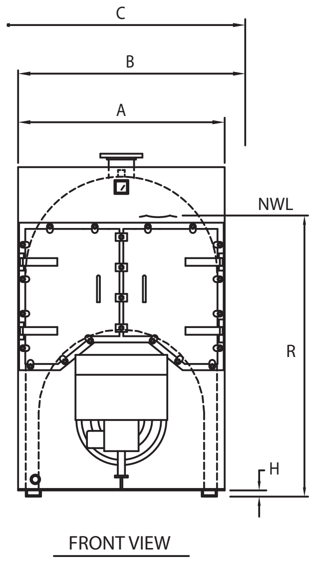
Inspected and registered with the National Board of Boiler & Pressure Vessel Inspectors.

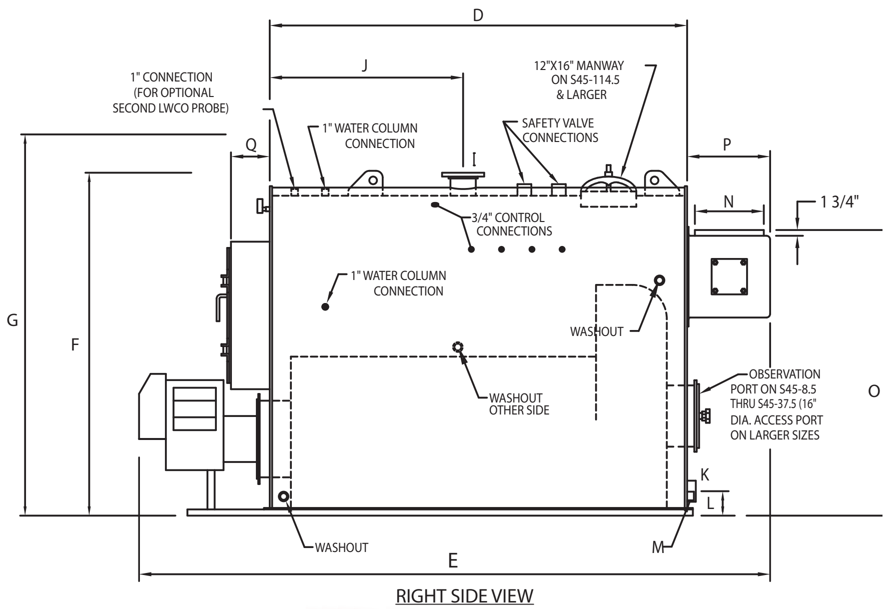
Designed, constructed and stamped in accordance with the requirements of the ASME Boiler Codes.

	SPECIFICATIONS	SERIES 45 MODEL NO.		S45	S45	S45	S45	S45	S45	S45	S45	S45	S45	S45	S45	S45	S45	S45	
	BOILER HORSE POWER			8.5	13.4	16.4	20	25	30	37.5	50	56	62.5	75	87.5	100	114.5	126.3	
	STEAM OUTPUT	FROM & @212° F	LBS/HR	293	462	566	690	863	1035	1294	1725	1932	2156	2588	3019	3450	3950	4357	
	GROSS OUTPUT		MBH	285	449	549	670	837	1004	1255	1674	1875	2092	2511	2929	3348	3833	4228	
	FIRING RATE, GAS	1,000 BTU	CFH	357	563	689	840	1050	1260	1575	2100	2352	2625	3150	3675	4200	4809	5304	
	FIRING RATE, #2 OIL	140,000 BTU	GPH	2.6	4	5	6	7.5	9	11.3	15	17	19	22.5	26	30	34	38	
	FIRING RATE, HEAVY OIL	150,000 BTU	GPH	NA	NA	NA	NA	NA	NA	NA	14	16	17.5	21	25	28	32	35	
	TOTAL HEATING SURFACE	FIRESIDE	SQ.FT.	37	55	67	86	105	125	150	200	225	250	300	350	411	458	505	
	RADIANT HEATING SURFACE	FIRESIDE	SQ.FT.	17.4	22.7	23.5	28.7	32.6	34.2	39.3	48	48.6	55	60	77	87	90.5	92	
	FURNACE VOLUME		CU.FT.	6.8	7.3	9.2	12.4	14.8	18.7	22.5	27.4	30.7	33	40.6	52	67	68	73	
	FURNACE HEAT RELEASE	MBH/CU.FT.		53	77	75	68	71	67	70	77	77	80	78	71	63	71	73	
A	WIDTH WITHOUT TRIM		IN	28	30	30	30	30	36	36	42	42	42	42	48	48	54	54	A
B	WIDTH WITH TRIM	APPROX	IN	35	37	37	37	37	43	43	49	49	49	49	55	55	61	61	B
C	WIDTH WITH GAS TRAIN	APPROX	IN	47	49	49	49	49	55	55	61	61	61	61	67	67	73	73	C
D	LENGTH OVER TUBE SHTS.		IN	31	31	37	49	60	57	68	58	65	70	85	73	85	83	89	D
E	OVERALL LENGTH with/	STD.BURNER	IN	78	78	84	96	107	106	121	113	120	125	145	135	147	148	159	E
F	HEIGHT WITHOUT TRIM		IN	55.75	63.63	63.63	63.63	63.63	63	63	75.5	77.5	77.5	77.5	90	90	90	90	F
G	HEIGHT WITH TRIM	APPROX	IN	60	70	70	70	70	70	70	83	85	85	85	97	97	99	99	G
H	BASE HEIGHT		IN	2	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	H
I	SUPPLY SIZE		IN	3	4	4	4	4	4	4	4	6	6	6	6	6	6	6	I
J	SUPPLY LOCATION		IN	13.5	17	18.5	24.5	24.5	25	30	28.5	30.5	30.5	36.5	31.5	36.5	39.5	42.5	J
K	RETURN SIZE		IN	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	K
L	RETURN LOCATION		IN	6	5	5	5	5	6.25	6.25	6.38	6.38	6.38	6.38	6.38	6.38	6.38	6.38	L
M	DRAIN/ BLWD. SIZE		IN	1	1	1	1	1	1	1.25	1.25	1.25	1.25	1.5	1.5	1.5	1.5	1.5	M
N	EXHAUST STACK DIA.	O.DIA.	IN	6	8	8	8	8	10	10	12	12	12	12	14	14	18	18	N
O	STACK HEIGHT		IN	42.38	52.75	52.75	52.75	52.75	50.5	50.5	62	62	62	62	72.5	72.5	74.63	74.63	O
P	REAR SMOKEBOX DEPTH		IN	10	12	12	12	12	14	14	16	16	16	16	18	18	22	22	P
Q	FRONT SMOKEBOX DEPTH		IN	6.75	7.25	7.25	7.25	7.25	8.25	8.25	10.25	10.25	10.25	10.25	11	11	11	11	Q
R	NORMAL WATER LINE	STEAM	IN	40	51	51	51	51	50.5	50.5	61	61	61	61	71	71	71	71	R
	WATER VOLUME	STEAM	GAL.	50	82	126	143	156	176	217	257	274	289	355	368	454	479	508	
	WATER VOLUME	FLOODED	GAL.	72	102	150	175	195	218	267	312	336	356	436	471	574	608	647	
	SHIPPING WEIGHT APPROX.	STD.TRIM	LBS.	1500	1700	1800	2000	2100	3100	3350	4000	4400	5300	5700	7000	8400	9100	9500	
	BOILER HORSEPOWER			8.5	13.4	16.4	20	25	30	37.5	50	56	62.5	75	87.5	100	114.5	126.3	

NOTE: CONNECTIONS UP TO 4" SIZE ARE NPT. THREAD, CONN'TNS. 6" & ABOVE ARE 150# ANSI FLANGE.

NOTE: 458 SQ.FT. AND LARGER HAS 12" X 16" MANWAY





	S45	S45	S45	S45	S45	S45	S45	S45	S45	S45	S45	S45	
	152	187.8	207.5	225	250	290	331	415	500	625	769	813	
	5244	6479	7159	7763	8625	10005	11420	14318	17250	21563	26531	28049	
	5088	6287	6946	7532	8369	9708	11080	13892	16738	20922	25742	27215	
	6384	7887	8715	9450	10500	12180	13902	17430	21000	26250	32298	34166	
	45.6	56	62	67.5	75	87	99	124.5	150	187.5	231	244	
	42.5	52.5	58	63	70	81	93	116	140	175	215	228	
	625	750	830	900	1000	1160	1325	1660	2000	2500	3075	3250	
	112	121	132	140	150	166	179	207	233	280	327	342	
	92	116	132	142	155	188.7	210	261	329	407	502	535	
	69	68	66	66.5	67.7	64.5	66	67	64	64.5	64	64	
A	54	66.75	66.75	66.75	66.75	72	72	72	84	84	84	84	A
B	61	74	74	74	74	79	79	79	91	91	91	91	B
C	73	86	86	86	86	93	93	93	105	105	105	105	C
D	109	103	113	121	133	109	121	151	136.5	169.5	209.5	223.5	D
E	179	175	185	193	205	184	196	234	230	268	308	322	E
F	90	102	102	102	102	132.88	132.88	132.88	149.25	149.25	149.25	149.25	F
G	99	113	113	113	113	144.38	144.38	144.38	156	156	156	156	G
H	1.63	1.63	1.63	1.63	1.63	8	8	8	8	8	8	8	H
I	6	8	8	8	8	8	8	10	10	10	12	12	I
J	50.5	36.5	48.5	42.5	57.5	39.5	39.5	42.5	50.75	65.25	82.75	92.75	J
K	4	6	6	6	6	6	6	8	8	8	10	10	K
L	6.38	8	8	8	8	15.75	15.75	15.75	15.75	15.75	16.75	16.75	L
M	2	2	2	2	2	2	2	2	2	2	2	2	M
N	18	20	20	20	20	22	22	22	28	28	28	28	N
O	74.63	85.75	85.75	85.75	85.75	112.38	112.38	112.38	123.88	123.88	123.88	123.88	O
P	22	24	24	24	24	26	26	26	32	32	32	32	P
Q	11	13.25	13.25	13.25	13.25	15.25	15.25	15.25	18	18	18	18	Q
R	71	80.25	80.25	80.25	80.25	107.5	107.5	107.5	122	122	122	122	R
	624	603	858	913	1005	1160	1195	1557	1801	2267	2765	2955	
	794	856	1136	1211	1333	1485	1595	2056	2400	3013	3690	3942	
	10200	12000	13500	14750	16000	19000	21000	24000	29000	38000	45000	49000	
	152	187.8	207.5	225	250	290	331	415	500	625	769	813	

ALL DIMENSIONS ARE IN INCHES
CERTIFIED DRAWING AVAILABLE UPON REQUEST.
DIMENSIONS SUBJECT TO CHANGE WITHOUT NOTICE.

BOILER DESIGN: Three-Pass "FireBox" design with stress relieving *"Wetback"* Firetube construction. Pressure designs for steam are
- 8.5-813 HP } 15 psi. max.

Built to *Section-IV ASME Code.* Hot Water pressures models are from
- 8.5-415 HP } 100 psi. max.
- 500-813 HP } 60 psi. max.

Built to *Section-IV ASME Code*. Hot water temperature not to exceed 250° degrees F. at or near the outlet of boiler.

STEAM MODEL TRIM: Safety relief valve, operating pressure control, high limit pressure control with manual reset, steam pressure gauge with syphon, combination pump control and low water cut-off with gauge glass assembly and drain valve, auxiliary low water cut-off with manual reset.

HOT WATER MODEL TRIM: Safety relief valve, operating temperature control, high limit temperature control with manual reset, combination pressure & temperature gauge, low water cut-off control with manual reset.

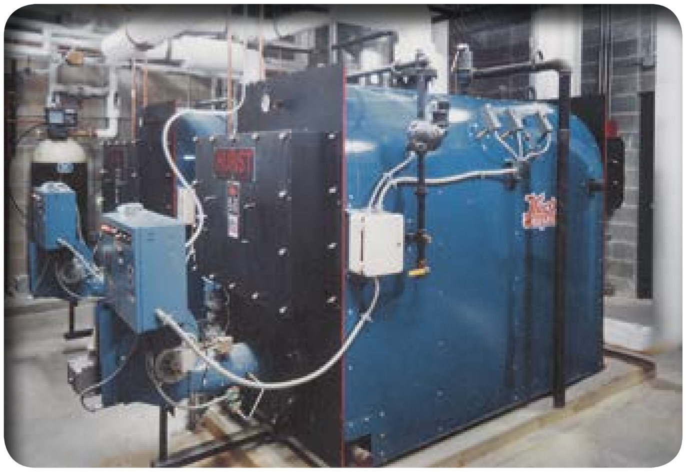
BURNER: Matched UL listed "forced draft" power burners with factory pre-piped, wired and tested fuel configurations for natural gas, propane (LP) gas, No. 2 (diesel) oil, or combination of both gas/oil.

HURST

HURST PERFORMANCE SERIES BOILERS

SERIES 45

- Efficient 3-Pass Design
- Flexibility – Gas, Oil, Heavy Oil, and Combination Gas/Oil
- ASME Code Constructed & Stamped for 15 PSI Steam / 30-100 PSI Water
- Registered with the National Board of Boiler Inspectors
- Competitively Priced, Easily Maintained, Designed for Efficiency
- Large Furnace Volume for Ultimate Combustion Efficiency
- Unified Refractory Base Floor
- Steel Skids and Lifting Eyes
- Low Heat Release
- Factory Insulated – 2" Mineral Wool
- Factory Jacketed & Painted
- Easy Access to Fireside Surfaces
- Ample Waterside Clean-Out Openings
- Fully Automatic Operation
- U.L. Listed, Forced Draft Burners
- Wet Back Construction
- U.L. Listed Controls & Trim
- Factory Test Fired
- Flame Observation Ports Front & Rear



All units are factory packaged with operating controls, relief valves, burner and fuel train. Installation is made simple in that only service connections are needed to place in operation. Flexible burner systems are available for firing natural gas, LP gas, #2 oil, heavy oil, or combinations. High density 2" mineral wool insulation assures lower radiant heat loss. In addition to meeting the requirements of U.L., burner systems are optionally available to meet the requirements of FM, IRI, MILITARY and others.

Standard Steam Trim

- Operating & high limit pressure control
- Modulating pressure control (when appl.)
- Water column with gauge glass, combination low water cut-off & pump control
- Probe Aux, L.W.C.O. w/ Manual Reset Steam pressure gauge, syphon & test cock
- Water column drain valve
- Safety relief valve(s) per ASME Code

Standard Water Trim

- Operating & high limit temperature control
- Modulating temperature control (when appl.)
- Probe type low water cut-off control w/ Manual Reset
- Combination pressure & temperature gauge
- Hot water return baffle for shock resistance
- Safety relief valve(s) per ASME Code

HBC-09509
07/2014

hurstboiler.com

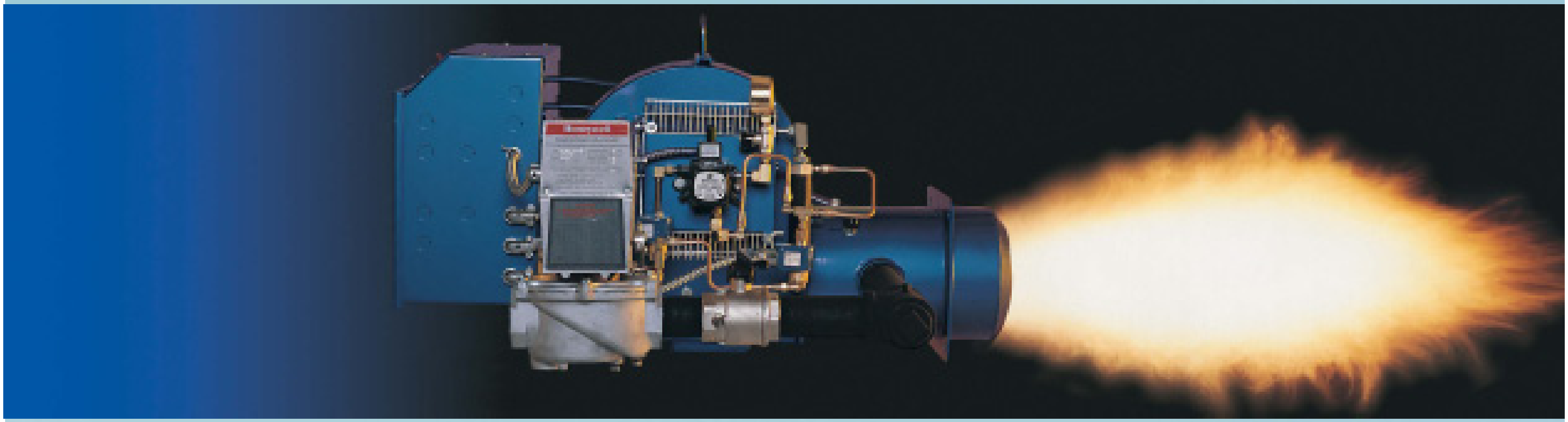
HURST BOILER
& Welding Co., Inc.
100 Boilermaker Lane • Coolidge, GA 31738-0530
Tel: (229) 346-3545 • Fax: (229) 346-3874
email: info@hurstboiler.com

MODEL CGO
MODEL CGO HTD
FORCED DRAFT
BURNERS

GAS
LIGHT OIL

98,000 -
19,100,000
BTU/HR.

Power Flame® Type C



Power Flame's Versatile High Performance Gas-Light Oil Burner

The Power Flame Model CGO dual fuel burner presents optimum state-of-the-art design for maximum combustion efficiency and operating dependability. These packaged combustion systems will fire all types of gaseous fuels, as well as #2 or similar distillate liquid fuels. The Model CGO HTD (High Turndown) will fire natural gas at turndowns up to 10 to 1. The flame retention firing head incorporates a single nozzle pressure atomizing assembly for liquid fuels and a nozzle mix multiport combustor for gaseous fuels. The unique *air sandwich* firing head design produces full range stable performance in both positive or negative combustion chambers. Operating system adjustments have been minimized to provide trouble-free start up and operation.

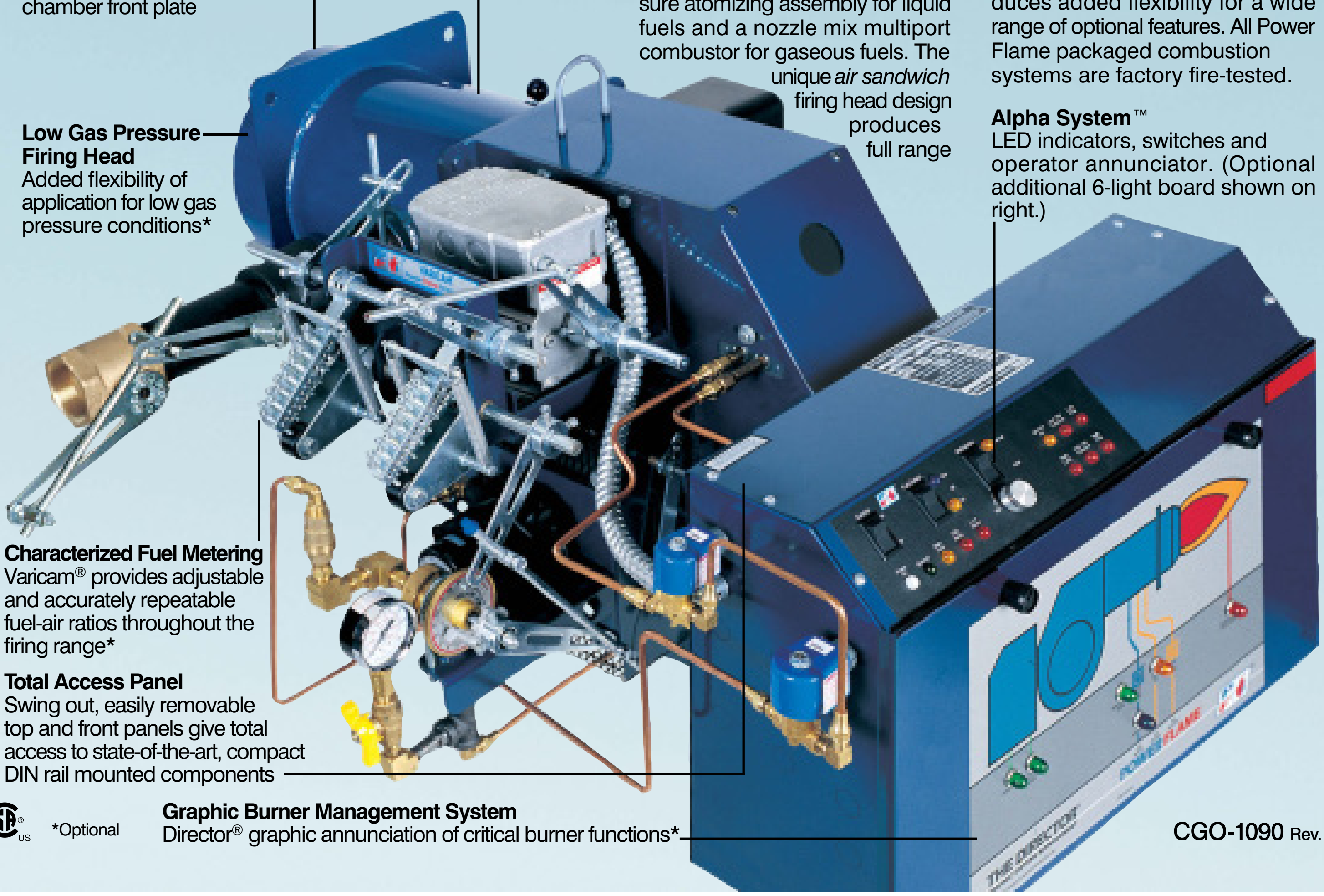
The Model CGO provides efficient combustion without the aid of refractory or other costly flame support devices. Options include the premix and low gas pressure firing heads for limited size combustion chamber configurations or low gas pressure conditions. Modular design produces added flexibility for a wide range of optional features. All Power Flame packaged combustion systems are factory fire-tested.

Adjustable Premix Firing Head
Produces optimum fuel-air mixture within the premix combustion zone*

Circular Furnace Opening
No special cutting of combustion chamber front plate

Low Gas Pressure Firing Head
Added flexibility of application for low gas pressure conditions*

Alpha System™
LED indicators, switches and operator annunciator. (Optional additional 6-light board shown on right.)



Characterized Fuel Metering
Varicam® provides adjustable and accurately repeatable fuel-air ratios throughout the firing range*

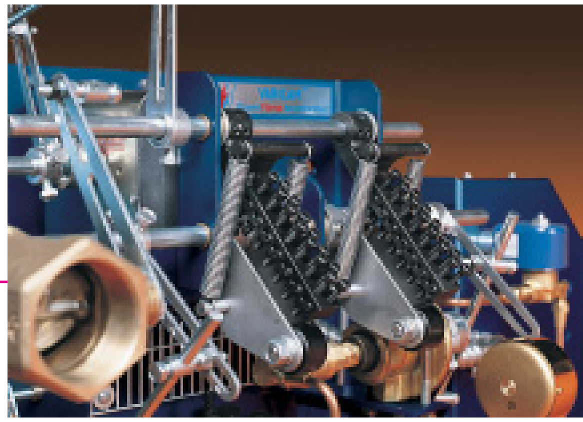
Total Access Panel
Swing out, easily removable top and front panels give total access to state-of-the-art, compact DIN rail mounted components

Graphic Burner Management System
Director® graphic annunciation of critical burner functions*

*Optional

PowerFlame

The Power to Manage Energy



The optional Varicam® has 14 adjustable set-points to maintain optimum fuel/air ratios from low to high fire settings.

STANDARD EQUIPMENT

- Alpha System™ LED indicators (power, demand, main fuel, FSG alarm, customer selectable) & control switch
- Pressure regulators, pilot and main gas cocks
- Oil valve, nozzle assembly, manual fuel selector switch
- Air safety switch & leakage test cock
- Gas electric pilot and gas ignition transformer

ADDED FEATURES

X-Standard **O**-Optional **NA**-Not Available

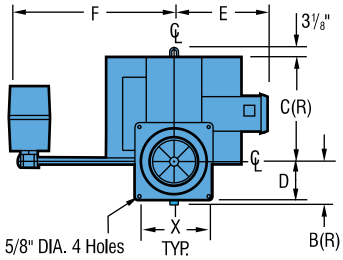
	C1-GO-10 C1-GO-12 C2-GO-15	C2-GO-20A	C2-GO-20B	C3-GO-20 C3-GO-25 C3-GO-25B	C4-GO-25	C4-GO-30 C5-GO-30(B) C6-GO-30	C7-GO-30 C8-GO-30
Flame Safeguard with UV and prepurge with interrupted pilot	X	X	Ⓐ X	Ⓐ X	Ⓐ X	Ⓐ X	Ⓐ X
On-Off diaphragm gas valve with fixed air control manual adjustment	X	NA	NA	NA	NA	NA	NA
Low-Hi-Off motorized gas valve with automatic air control	O	X	X	X	X	NA	NA
Low-Hi-Low motorized gas valve with automatic air control	O	O	O	O	O	NA	NA
Modulation with automatic air control	O	O	O	O	O	X	X
Integral 2 stage fuel unit (C1, C2 single stage)	X	X	X	X	X	NA	NA
Remote mounted 2 stage fuel unit (single stage for C6-C8)	O	O	O	O	O	X	X
Dual gas Ⓑ and dual oil safety valves	X	X	X	X	X	X	X
High and Low gas pressure switches	O	O	X	X	X	X	X
Direct spark ignition (oil)	O	O	O	O	O	O	O
Low fire oil start with automatic air control	O	X	X	X	X	X	X
Man/Auto switch - manual potentiometer - modulation only	X	X	X	X	X	X	X

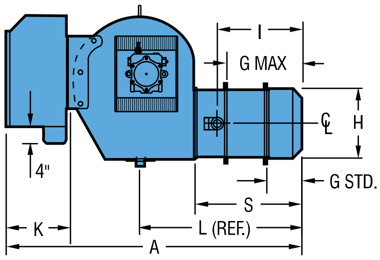
Ⓐ Postpurge standard on C2-GO-20B and all C3 to C8 models

■ Conforms to UL 296 and UL 795

Ⓑ 5,000 MBH and below may be replaced by one (1) proof of closure valve; above 5,000 MBH one (1) of the safety valves will include proof of closure feature.

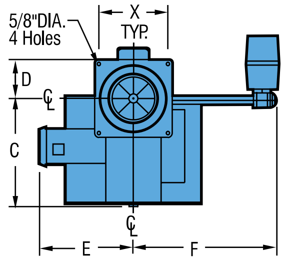
MODEL CR (For low centerline applications)

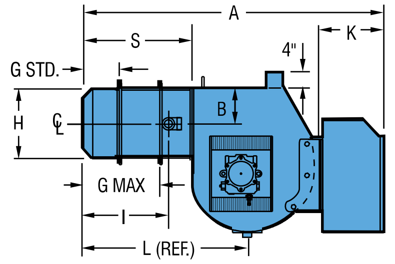




Add 3/8" to "H" for size of opening in boiler front plate

MODEL C





Add 3/8" to "H" for size of opening in boiler front plate

DIMENSIONS (Inches) Standard Models.

* This dimension may be increased. Consult factory.
** This dimension depicts space required to accommodate a standard gas train.

RATINGS & SPECIFICATIONS

Burner Model	A	B	B(R)	C	C(R)	D	E	F**	G Std.	G *Max.	H	I	K	L	S	X	CAPACITY[1] #2 Oil GPH Max.	Natural Gas/MBH Max.	Nominal Boiler H.P. Max.	Blower Motor H.P. (3450 RPM)	Std. Gas Train (In.)	Pressure Pump Suction (GPH)	Gas Pressure Required (In. W.C.)[2]
C1-GO-10	34 1/8	3 13/16	5 9/16	14 1/2	14 1/2	4 5/8	12 1/4	20	3 1/4	4 3/4	7 1/4	7 3/8	10 1/4	17 1/8	12 5/8	7 1/4	7.0	980	23.5	1/3	1	††19	5.6
C1-GO-12	34 1/8	3 13/16	5 9/16	14 1/2	14 1/2	4 5/8	12 1/4	20	3 1/4	4 3/4	7 1/4	7 3/8	10 1/4	17 1/8	12 5/8	7 1/4	9.7	1,360	32.3	1/2	1 1/4	††19	5.3
C2-GO-15	39 1/8	4 1/2	6 1/8	14 7/8	14	5 1/4	14	20	4	6 3/4	8 3/4	8 1/2	10 1/4	18 7/8	13 3/8	8 1/2	15.7	2,200	52.3	3/4	1 1/2	††70	5.2
C2-GO-20A	39 1/8	4 1/2	6 1/8	14 7/8	14	5 1/4	14	20	4	6 3/4	8 3/4	8 1/2	10 1/4	18 7/8	13 3/8	8 1/2	17.5	2,500	60.0	1	2	70	4.8
C2-GO-20B	39 1/8	4 1/2	6 1/8	14 7/8	14	5 1/4	14	20	4	6 3/4	8 3/4	8 1/2	10 1/4	18 7/8	13 3/8	8 1/2	22.0	3,080	73.5	1 1/2	2	70	4.8
C3-GO-20	44	5 1/4	7	16 5/8	15 1/4	6	16	22 3/8	4 1/2	8	10 1/8	11 1/2	10 1/4	22	15 1/2	10	30.0	4,200	100.0	2	2	105	7.6
C3-GO-25	44	5 1/4	7	16 5/8	15 1/4	6	16	22 3/8	4 1/2	8	10 1/8	11 1/2	10 1/4	22	15 1/2	10	33.7	4,718	112.0	2	2 1/2	105	7.0
C3-GO-25B	44	5 1/4	7	16 5/8	15 1/4	6	16	22 3/8	4 1/2	8	10 1/8	11 1/2	10 1/4	22	15 1/2	10	37.5	5,250	125.0	3	2 1/2	135	7.2
C4-GO-25	50	6 1/4	7 5/16	18 7/8	17 11/16	7	18 1/2	28	6	9	12 1/8	14 1/4	10 1/4	26 5/8	19 1/8	12	45.0	6,300	150.0	5	2 1/2	135	8.0
C4-GO-30	50	6 1/4	7 5/16	18 7/8	17 11/16	7	18 1/2	28	6	9	12 1/8	14 1/4	10 1/4	26 5/8	19 1/8	12	56.0	7,840	190.0	5	3	†135	12.1
C5-GO-30(B)	50	6 1/4	7 5/16	18 7/8	17 11/16	7	18 1/2	26 1/2	6	9	12 1/8	14 1/4	10 1/4	26 5/8	19 1/8	12	75.0	10,500	250.0	7 1/2	3	†250	19.9, 17.8
C6-GO-30	49 7/8	6 1/4	7 5/16	18 7/8	17 11/16	7 3/4	19 7/8	26 1/2	5	11 3/4	13 5/8	14 1/8	10 1/4	26 1/2	19	13 1/2	101.5	14,215	340.0	10	3	†250	26.5
C7-GO-30	51 11/16	8 1/8	10 1/8	24 5/16	22 3/8	8 3/4	18	21 13/16	4 7/8	11 1/4	15 5/8	13 7/8	9 1/8	26 1/2	19	13 1/2	121.4	17,000	404.0	15	3	235	40.0
C7-GO-30B	51 11/16	8 1/8	10 1/8	24 5/16	22 3/8	8 3/4	18	21 13/16	4 7/8	11 1/4	15 5/8	13 7/8	9 1/8	26 1/2	19	13 1/2	126.4	17,700	421.0	20	3	235	45.0
C8-GO-30	56 9/16	8 1/8	10 1/8	27 1/8	27 5/8	8 3/4	20	24 3/8	3 1/4	9 5/8	15 5/8	12 1/4	9 1/8	24 7/8	17 5/16	13 1/2	136.4	19,100	454.0	15	3	235	50.0

1. Capacities listed are based on 0.20" W.C. positive pressure, except for C5-GO-30B, which is rated for 250 BHP at +1.2" W.C. Refer to capacity curves for derates based upon combustion chamber pressure.
2. At inlet to main manual shutoff cock to obtain P/F certified ratings with standard U.L. gas train. Optional gas trains and combustion heads available for lower pressures.

† Remote Pump Set with 200 (208) or 230/460/3/60 motor, 3450 RPM - 3/4 HP - C4; 1750 RPM - 1 HP - C5, C6; 1750 RPM - 1-1/2 HP - C7, C8.

†† For On-Off and modulating firing modes only. Refer to C Manual for capacities on other modes.

® Power Flame Incorporated

2001 South 21st Street Phone 620-421-0480
Parsons, KS 67357 Fax 620-421-0948
Web Site: http://www.powerflame.com
E-Mail: csd@powerflame.com

Note: This quotation has been redacted.

ETIengineering.com
John Zink Company LLC
1616 South Main Street | Tulsa, Oklahoma 74119-4410
918-492-0508 | Fax 918-488-9042

ENGINEERING | TECHNOLOGY | INNOVATION

DOMINION

Quotation №:
Date: March 17, 2017
Reference:
Site: Buckingham County, VA

Attention:

Thank you for your inquiry. We appreciate this opportunity to provide a quotation on your equipment requirements for Indirect Gas Fired Water Bath Heaters in accordance with the following specifications, price and delivery.

JOHN ZINK HAMWORTHY COMBUSTION

ITEM II - INDIRECT GAS FIRED WATER BATH HEATER (4 Units Required)

One (1) ETI INDIRECT GAS FIRED WATER BATH HEATER, built to the following specified design conditions:

A. PROCESS SPECIFICATIONS

Process Fluid	Natural Gas
Process Fluid Specific Gravity	0.613
Process Higher Heating Value	1,084 Btu/scf
CASE 1:	
Process Fluid Rate	366.75 MMscfd
CASE 2:	
Process Fluid Rate	269 MMscfd
Process Inlet Temperature	40°F
Process Inlet Pressure	1,185 psig
Process Outlet Temperature After Regulation	47°F
Pressure after Regulation	600 psig
Heater Calculated Duty / Nominal Duty	14.86 / 15.00 MM Btu/hr
Heater Design Bath Temperature	180°F
Heater Gross Thermal Efficiency	72%
Heater Fuel Consumption	18,952 scfh @ calculated duty

B. MECHANICAL SPECIFICATIONS

Heater Shell

Shell	138" OD x 41' Long
Bath Capacity (Net Fill)	21,434 gallons
Bath Fluid	Ethylene Glycol and Water
Glycol Concentration (By Weight)	50%
Design Code	API-12K (Not Stamped)
Design Pressure / M.A.W.P.	0 / 0 psig
Design Temperature	250°F

Corrosion Allowance	None
Head Thickness / Type	1/2" / Flat
Shell Thickness / Material	3/8" / SA36
Lifting Lugs	Two (2)
Saddles	Three (3)

Shell Connections

One (1) Thermometer Connection	3/4" coupling
One (1) High Temperature Shutdown	1" coupling
Two (2) Thermostat Connections	1" coupling (one (1) plugged)
Two (2) Fuel Preheat Coil Connections	1" coupling
One (1) Drain	3" 150# RFWN w/ valve
One (1) Spare	2" coupling (plugged)

Firetube (Removable)

Number of Firetubes	Two (2)
Heat Flux	10,888 Btu/hr ft^2
Heat Release Density	10,426 Btu/hr in^2
Nominal Size	36"
Effective Length / Surface Area	56.67' / 682.15 ft^2
Radiography	None

Process Coil

Design Code	ASME §VIII, Div. 1
Heat Flux	9,198 Btu/hr ft^2
Allowable / Calculated Pressure Drop	10 / 2.58 psi
Corrosion Allowance	0.0625
Design Pressure	1,480 psig
Hydrotest Pressure / Duration	2,220 psig / 8 hours
Design Temperature	-20°F / +500°F
Radiography	100%
Stress Relieved	No
Pipe Straight Length	38'-0"
Pipe Size / Schedule	6" / SCH 80
Material	SA-106 B
Number of Parallel Paths	Six (6)
Number of Passes per Path	Four (4)
Total Number of Tubes	Twenty-four (24)
Available Tube Area / Required Tube Area	1,630.8 ft^2 / 1,523.2 ft^2
Inlet/Outlet Connections	16" 900# RF Flange

Note: Coil design is based on pipe in new and clean condition.

Expansion Reservoir (Non-Removable)	
Shell	36" OD x 38'-0"
Capacity	1,954 Gallons
Design Code	Non-Code
Design Pressure / M.A.W.P.	0 / 0 psig
Design Temperature	250°F
Corrosion Allowance	None
Head Thickness / Type	1/4" / Flat
Shell Thickness / Material	1/4" / SA-53-B ERW
Fill Connection	8" Pressure/Vacuum
Burner Unit	
Type	Forced Draft
Quantity	Two (2)
Manufacturer / Model	Maxon XPO or equivalent Low NOX burner
Maximum Heat Release/Burner	10.61MMBTU/hr
Blower	Two (2) 10HP 3 phase
Estimated Noise Level	93 dba @ 3 ft (See option below to meet required dBA)
NOx Emissions	**13ppm**
Stack	
Quantity	Two (2)
Nominal Diameter / Height	36" / 10'-0"
Type	Tee type with rain cap and bird screen
Material	Carbon Steel

Control Panel

One (1) main control panel for the Indirect Fired Water Bath Heater. The main control panel details include:

NEMA 4X (316SS), wall-mount, 60"H x 36"W x 12"D enclosure.

Modicon M340 PLC for monitoring of all system parameters, control of all field instruments not controlled by the Honeywell RM7898 series below UL/FM listed flame relay. The PLC will be provided programmed with Modicon Unity Pro XL V.80. Includes 10" HMI.

Modbus Plus and Ethernet communications provided.

Cutler-Hammer 10250 series pilot lights and pushbuttons will be provided on the face of the enclosure for local annunciation and local operator interface.

Controls/Status indicators included per burner except power and ESD:

- Power ON switch
- Emergency Shutdown Pushbutton (Red)
- Power ON lamp (White)
- Heater Alarm Acknowledge Pushbutton

- Heater Alarm Reset Pushbutton
- Heater Stop Pushbutton
- Heater Start Pushbutton

The following indications on the HMI include:

- Low/High bath temperature shutdown
- Low/High fuel gas temperature shutdown
- Burner flame failure shutdown
- Burner fuel shutdown valve sequence failure
- Local/remote emergency shutdown
- Watchdog system OK
- Unacknowledged alarm
- Stack high temperature shutdown
- Common (global) alarm

"Dry" relay contacts are included for common shutdown/alarm.

Shroud, filter grill, cooling fan and thermostat will be provided to insure panel temperatures do not exceed specified equipment operating temperatures.

Heater and thermostat will be provided to insure panel temperatures do not fall below specified equipment operating temperatures.

All equipment will be suitable for operation in a Class 1, Division 2, Group C & D hazardous atmosphere.

One (1) NEMA 4/7 window enclosure will be provided, for housing of a Honeywell Slate BMS. This BMS will be utilized to sequence the burner purge (4 minutes), ignition, pilot, main valve action. The BMS includes a display for indication of burner sequencing and flame relay diagnostics.

A NEMA 4X (316SS) junction box will be provided for terminating the above BMS control wiring.

C. <u>VESSEL ACCESSORIES</u>

1. One (1) high pressure fuel gas manifold rated to 1,440 psig, complete with:
   a. one (1) 1-1/2" NPT strainer with bleed valve
   b. two (2) 1" NPT Fisher 627H pressure regulator
   c. one (1) 1" NPT Fisher 627M pressure regulator
   d. one (1) 1" NPT Fisher 627 pressure regulator

2. Two (2) main gas manifolds, each complete with:
   a one (1) 2" 125#FF Fisher 299H pressure regulators
   b. one (1) 2" CL150 temperature control valve
   c. two (2) 2" CL150 manual isolation valves
   d. one (1) 0-200 psig pressure gauge with isolation valve
   e. one (1) 0-15 psig pressure gauge with isolation valve
   f. two (2) 2" CL150 safety shut off valves

3. Two (2) pilot gas manifolds, each complete with:
   a. one (1) 1/2" NPT manual isolation valve
   b. one (1) 1/2" NPT Fisher R622 pressure regulator

c. one (1) 0-15 psig pressure gauge with isolation valve
d. two (2) 1/4" NPT pilot shutdown valve
e. one (1) 1/2" NPT manual pilot shutdown valve

4. One (1) 8" fill hatch
5. One (1) extra-heavy fuel gas preheat coil
6. One (1) 3" bottom drain valve with blind
7. One (1) bath thermometer, 100°F - 1000°F, with separable socket
8. Stainless steel tubing and fittings
9. One (1) bath temperature element
10. One (1) bath high temperature shutdown
11. One (1) pressure relief valve located on coil inlet header

D. SHOP ASSEMBLY

Complete fuel gas and instrument gas system will be fully shop assembled, wired and tested prior to shipment. Various items may be disassembled and shipped separately to prevent damage in shipment. Reassembly of these items is to be done by others.

E. COATING

Vessel to be cleaned and coated per specification.
Stacks to be cleaned and coated per specification.

F. INSULATION

Heater shell to be insulated with 1½" thick fiberglass Easy Wrap insulation and covered with 0.016" thk embossed aluminum jacketing and banded with ½" wide stainless steel bands. Head ends will not be insulated.

G. SKID

None. Ladder and platform included.

H. TESTING

1. Firetube welds to be tested with air and soap at 5 psig internal pressure.
2. Shell to be leak tested with firetube and coil bolted in place.
3. Assembled unit will be test fired through pilot to insure all devices function properly. The main burner will not be ignited during this testing.

I. DOCUMENTATION

1. One (1) hard copy instruction manual and one (1) disc of instruction manual
2. Approval drawings
3. Mill test certificates (coil only if required)
4. Manufacturer's data reports (coil only)

J. <u>WEIGHT</u>

Vessel estimated weight is 120,000 pounds.

Note: This e-mail has been redacted.

Alan Mikowychok

From: Laurence A Labrie
Sent: Monday, May 22, 2017 2:08 PM
To: Andrew Woerner; Robert Sawyer
Subject: FW: Woods Corner Line Heaters - CLARIFICATIONS
Attachments:

More information on Buckingham heaters.

Larry Labrie

From: Jason Barnhouse
Sent: Monday, May 22, 2017 2:03 PM
To: Laurence A Labrie
Cc: Troy Simmons; Scott R Summers
Subject: [External] FW: Woods Corner Line Heaters - CLARIFICATIONS

Larry,
Here is some additional information on the Main Line Heaters at Woods Corner (Attached and below). Please let me know if you need anything else.
Jason

From: Little, Kim
Sent: Monday, May 22, 2017 1:27 PM
To: Troy Simmons
Cc: Jason Barnhouse
Subject: RE: Woods Corner Line Heaters - CLARIFICATIONS

Troy,

The emissions limits are the following:
NOX: .010 LB/MMBTU
CO: .037 LB/MMBTU
PM: .0048 LB/MMBTU

Thanks,

ETI
ENGINEERING | TECHNOLOGY | INNOVATION

Kim Little, P.M.P. | Senior Applications Engineer
Engineering Technology & Innovation
1616 S. Main | Tulsa, OK 74119

G3516C

GENSET APPLICATION

GAS ENGINE SITE SPECIFIC TECHNICAL DATA
Atlantic Coast Pipeline - Buckingham Comp Station

CATERPILLAR®

ENGINE SPEED (rpm):	1800
COMPRESSION RATIO:	11.3
AFTERCOOLER TYPE:	SCAC
AFTERCOOLER - STAGE 2 INLET (°F):	130
AFTERCOOLER - STAGE 1 INLET (°F):	198
JACKET WATER OUTLET (°F):	210
ASPIRATION:	TA
COOLING SYSTEM:	JW+OC+1AC, 2AC
CONTROL SYSTEM:	ADEM3 W/ IM
EXHAUST MANIFOLD:	DRY
COMBUSTION:	LOW EMISSION
NOx EMISSION LEVEL (g/bhp-hr NOx):	0.5
ANCILLARY LOAD (ekW):	61
SET POINT TIMING:	27

RATING STRATEGY:	STANDARD
RATING LEVEL:	STANDBY
FUEL SYSTEM:	CAT LOW PRESSURE WITH AIR FUEL RATIO CONTROL
SITE CONDITIONS:	
FUEL:	ACP - Buckingham
FUEL PRESSURE RANGE(psig): (See note 1)	0.5-5.0
FUEL METHANE NUMBER:	75.8
FUEL LHV (Btu/scf):	981
ALTITUDE(ft):	586
MAXIMUM INLET AIR TEMPERATURE(°F):	100
STANDARD RATED POWER:	2175 bhp@1800rpm
POWER FACTOR:	0.8
VOLTAGE(V):	400-13800

			MAXIMUM RATING	SITE RATING AT MAXIMUM INLET AIR TEMPERATURE		
RATING	**NOTES**	**LOAD**	**100%**	**100%**	**75%**	**50%**
GENSET POWER (WITH ANCILLARY LOAD)	(2)(3)	ekW	1500	1500	1125	750
GENSET POWER (WITH ANCILLARY LOAD)	(2)(3)	kVA	1875	1875	1406	938
ENGINE POWER (WITHOUT FAN)	(3)	bhp	2175	2175	1663	1151
INLET AIR TEMPERATURE		°F	100	100	100	100
GENERATOR EFFICIENCY	(2)	%	96.3	96.3	95.6	94.5
GENSET EFFICIENCY (ISO 3046/1)	(4)	%	34.9	34.9	33.6	30.1
THERMAL EFFICIENCY	(5)	%	49.5	49.5	49.7	51.8
TOTAL EFFICIENCY	(6)	%	84.4	84.4	83.3	81.9
ENGINE DATA						
GENSET FUEL CONSUMPTION (ISO 3046/1)	(7)	Btu/ekW-hr	9770	9770	10166	11326
GENSET FUEL CONSUMPTION (NOMINAL)	(7)	Btu/ekW-hr	10009	10009	10414	11603
ENGINE FUEL CONSUMPTION (NOMINAL)	(7)	Btu/bhp-hr	6903	6903	7044	7561
AIR FLOW (@inlet air temp, 14.7 psia) (WET)	(8)	ft3/min	4816	4816	3834	2796
AIR FLOW (WET)	(8)	lb/hr	20478	20478	16303	11889
FUEL FLOW (60ºF, 14.7 psia)		scfm	255	255	199	148
INLET MANIFOLD PRESSURE	(9)	in Hg(abs)	84.3	84.3	67.6	49.6
EXHAUST TEMPERATURE - ENGINE OUTLET	(10)	°F	867	867	903	927
EXHAUST GAS FLOW (@engine outlet temp, 14.5 psia) (WET)	(11)	ft3/min	12271	12271	10025	7450
EXHAUST GAS MASS FLOW (WET)	(11)	lb/hr	21191	21191	16858	12302
MAX INLET RESTRICTION	(12)	in H2O	10.05	10.05	10.05	10.05
MAX EXHAUST RESTRICTION	(12)	in H2O	20.07	20.07	20.07	20.07
EMISSIONS DATA - ENGINE OUT						
NOx (as NO2)	(13)(14)	g/bhp-hr	0.50	0.50	0.50	0.50
CO	(13)(14)	g/bhp-hr	2.00	2.00	2.10	2.12
THC (mol. wt. of 15.84)	(13)(14)	g/bhp-hr	4.98	4.98	5.91	6.68
NMHC (mol. wt. of 15.84)	(13)(14)	g/bhp-hr	0.98	0.98	1.17	1.32
NMNEHC (VOCs) (mol. wt. of 15.84)	(13)(14)(15)	g/bhp-hr	0.50	0.50	0.59	0.67
HCHO (Formaldehyde)	(13)(14)	g/bhp-hr	0.52	0.52	0.52	0.59
CO2	(13)(14)	g/bhp-hr	443	443	489	516
EXHAUST OXYGEN	(13)(16)	% DRY	10.2	10.2	10.1	10.0
HEAT REJECTION						
LHV INPUT	(17)	Btu/min	250213	250213	195268	145031
HEAT REJ. TO JACKET WATER (JW)	(18)	Btu/min	35859	35859	26537	25425
HEAT REJ. TO ATMOSPHERE	(18)	Btu/min	7856	7856	6624	5391
HEAT REJ. TO LUBE OIL (OC)	(18)	Btu/min	6273	6273	5632	4854
HEAT REJECTION TO EXHAUST (LHV TO 248°F)	(18)	Btu/min	58581	58581	49377	37471
HEAT REJ. TO A/C - STAGE 1 (1AC)	(18)(20)	Btu/min	18838	18838	11245	3899
HEAT REJ. TO A/C - STAGE 2 (2AC)	(18)(20)	Btu/min	6991	6991	5460	3853
PUMP POWER	(19)	Btu/min	1964	1964	1964	1964

COOLING SYSTEM SIZING CRITERIA				
TOTAL JACKET WATER CIRCUIT (JW+OC+1AC)	(21)	Btu/min	70157	70157
TOTAL AFTERCOOLER CIRCUIT (2AC)	(21)	Btu/min	7637	7637
HEAT REJECTION TO EXHAUST (LHV TO 248°F)	(21)	Btu/min	64440	64440
A cooling system safety factor of 0% has been added to the cooling system sizing criteria.				

MINIMUM HEAT RECOVERY				
TOTAL JACKET WATER CIRCUIT (JW+OC+1AC)	(22)	Btu/min	55187	55187
TOTAL AFTERCOOLER CIRCUIT (2AC)	(22)	Btu/min	6642	6642
HEAT REJECTION TO EXHAUST(LHV TO 248°F)	(22)	Btu/min	49404	49404

CONDITIONS AND DEFINITIONS

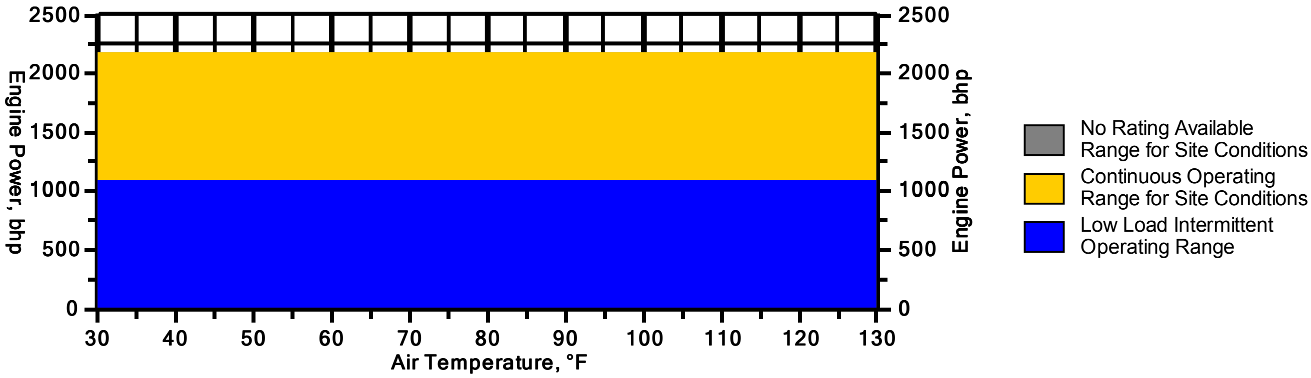
Engine rating obtained and presented in accordance with ISO 3046/1, adjusted for fuel, site altitude and site inlet air temperature. 100% rating at maximum inlet air temperature is the maximum engine capability for the specified fuel at site altitude and maximum site inlet air temperature. Maximum rating is the maximum capability at the specified aftercooler inlet temperature for the specified fuel at site altitude and reduced inlet air temperature. Lowest load point is the lowest continuous duty operating load allowed. No overload permitted at rating shown.

For notes information consult page three.

PREPARED BY: Anthony Fisher, Cleveland Brothers
Data generated by Gas Engine Rating Pro Version 6.04.00
Ref. Data Set EM0753-02-001, Printed 04Jan2017

Engine Power vs. Inlet Air Temperature

Data represents temperature sweep at 586 ft and 1800 rpm



GAS ENGINE SITE SPECIFIC TECHNICAL DATA
Atlantic Coast Pipeline - Buckingham Comp Station

NOTES

1. Fuel pressure range specified is to the engine fuel control valve. Additional fuel train components should be considered in pressure and flow calculations.

2. Generator efficiencies, power factor, and voltage are based on standard generator. [Genset Power (ekW) is calculated as: (Engine Power (bkW) x Generator Efficiency) - Ancillary Load (ekW)], [Genset Power (kVA) is calculated as: ((Engine Power (bkW) x Generator Efficiency) - Ancillary Load (ekW))/ Power Factor]

3. Rating is with two engine driven water pumps. Tolerance is (+)3, (-)0% of full load.

4. Genset Effieciency published in accordance with ISO 3046/1.

5. Thermal Efficiency is calculated based on energy recovery from the jacket water, lube oil, 1st stage aftercooler, and exhaust to 248ºF with engine operation at ISO 3046/1 Genset Efficiency, and assumes unburned fuel is converted in an oxidation catalyst.

6. Total efficiency is calculated as: Genset Efficiency + Thermal Efficiency. Tolerance is ±10% of full load data.

7. ISO 3046/1 Genset fuel consumption tolerance is (+)5, (-)0% at the specified power factor. Nominal genset and engine fuel consumption tolerance is ± 2.5% of full load data at the specified power factor.

8. Air flow value is on a 'wet' basis. Flow is a nominal value with a tolerance of ± 5 %.

9. Inlet manifold pressure is a nominal value with a tolerance of ± 5 %.

10. Exhaust temperature is a nominal value with a tolerance of (+)63°F, (-)54°F.

11. Exhaust flow value is on a "wet" basis. Flow is a nominal value with a tolerance of ± 6 %.

12. Inlet and Exhaust Restrictions are maximum allowed values at the corresponding loads. Increasing restrictions beyond what is specified will result in a significant engine derate.

13. Emissions data is at engine exhaust flange prior to any after treatment.

14. NOx tolerance's are ± 18% of specified value. All other emission values listed are higher than nominal levels to allow for instrumentation, measurement, and engine-to-engine variations. They indicate the maximum values expected under steady state conditions. Fuel methane number cannot vary more than ± 3. THC, NMHC, and NMNEHC do not include aldehydes, adjusted to the specified NOx level at 100% load.

15. VOCs - Volatile organic compounds as defined in US EPA 40 CFR 60, subpart JJJJ

16. Exhaust Oxygen level is the result of adjusting the engine to operate at the specified NOx level. Tolerance is ± 0.5.

17. LHV rate tolerance is ± 2.5%.

18. Heat rejection values are representative of site conditions. Tolerances, based on treated water, are ± 10% for jacket water circuit, ± 50% for atmosphere, ± 20% for lube oil circuit, ± 10% for exhaust, and ± 5% for aftercooler circuit.

19. Pump power includes engine driven jacket water and aftercooler water pumps. Engine brake power includes effects of pump power.

20. Aftercooler heat rejection is nominal for site conditions and does not include an aftercooler heat rejection factor. Aftercooler heat rejection values at part load are for reference only.

21. Cooling system sizing criteria represent the expected maximum circuit heat rejection for the ratings at site, with applied plus tolerances. Total circuit heat rejection is calculated using formulas referenced in the notes on the standard tech data sheet with the following qualifications. Aftercooler heat rejection data (1AC & 2AC) is based on the standard rating. Jacket Water (JW) and Oil Cooler (OC) heat rejection values are based on the respective site or maximum column. Aftercooler heat rejection factors (ACHRF) are specific for the site elevation and inlet air temperature specified in the site or maximum column, referenced from the table on the standard data sheet

22. Minimum heat recovery values represent the expected minimum heat recovery for the site, with applied minus tolerances. Do not use these values for cooling system sizing.

Constituent	Abbrev	Mole %	Norm
Water Vapor	H2O	0.0000	0.0000
Methane	CH4	88.3260	88.3260
Ethane	C2H6	10.1304	10.1304
Propane	C3H8	0.3798	0.3798
Isobutane	iso-C4H1O	0.0301	0.0301
Norbutane	nor-C4H1O	0.0349	0.0349
Isopentane	iso-C5H12	0.0094	0.0094
Norpentane	nor-C5H12	0.0060	0.0060
Hexane	C6H14	0.0000	0.0000
Heptane	C7H16	0.0000	0.0000
Nitrogen	N2	0.8785	0.8785
Carbon Dioxide	CO2	0.2049	0.2049
Hydrogen Sulfide	H2S	0.0000	0.0000
Carbon Monoxide	CO	0.0000	0.0000
Hydrogen	H2	0.0000	0.0000
Oxygen	O2	0.0000	0.0000
Helium	HE	0.0000	0.0000
Neopentane	neo-C5H12	0.0000	0.0000
Octane	C8H18	0.0000	0.0000
Nonane	C9H20	0.0000	0.0000
Ethylene	C2H4	0.0000	0.0000
Propylene	C3H6	0.0000	0.0000
TOTAL (Volume %)		100.0000	100.0000

Fuel Makeup:	ACP - Buckingham
Unit of Measure:	English

Calculated Fuel Properties

Caterpillar Methane Number:	75.8
Lower Heating Value (Btu/scf):	981
Higher Heating Value (Btu/scf):	1086
WOBBE Index (Btu/scf):	1253
THC: Free Inert Ratio:	91.3
Total % Inerts (% N2, CO2, He):	1.08%
RPC (%) (To 905 Btu/scf Fuel):	100%
Compressibility Factor:	0.998
Stoich A/F Ratio (Vol/Vol):	10.22
Stoich A/F Ratio (Mass/Mass):	16.66
Specific Gravity (Relative to Air):	0.614
Fuel Specific Heat Ratio (K):	1.301

CONDITIONS AND DEFINITIONS

Caterpillar Methane Number represents the knock resistance of a gaseous fuel. It should be used with the Caterpillar Fuel Usage Guide for the engine and rating to determine the rating for the fuel specified. A Fuel Usage Guide for each rating is included on page 2 of its standard technical data sheet.

RPC always applies to naturally aspirated (NA) engines, and turbocharged (TA or LE) engines only when they are derated for altitude and ambient site conditions.

Project specific technical data sheets generated by the Caterpillar Gas Engine Rating Pro program take the Caterpillar Methane Number and RPC into account when generating a site rating.

Fuel properties for Btu/scf calculations are at 60F and 14.696 psia.

FUEL LIQUIDS

Field gases, well head gases, and associated gases typically contain liquid water and heavy hydrocarbons entrained in the gas. To prevent detonation and severe damage to the engine, hydrocarbon liquids must not be allowed to enter the engine fuel system. To remove liquids, a liquid separator and coalescing filter are recommended, with an automatic drain and collection tank to prevent contamination of the ground in accordance with local codes and standards.

To avoid water condensation in the engine or fuel lines, limit the relative humidity of water in the fuel to 80% at the minimum fuel operating temperature.

APPENDIX E

RBLC DATABASE SEARCH RESULTS

Appendix E
RBLC Database Search Results:
Flaring of Blowdown Emissions

APC, LLC - Buckngham Compressor Station

Permit No.	Facility	RBLC ID	State	Permit Date	Control Method	Pollutant Controlled	Control Efficiency	Notes
PSDTX1264	ETC Texas Pipeline, LTC - Jackson County Gas Plant	TX-0663	TX	11/17/2017	Flare	VOC	98%	"Blowdowns and starter vent openings"
PSDTX1306 105710	Corpus Christi Liquefication Plant	TX-0672	TX	5/5/2016	Flare	VOC	98%	"2 wet/dry flares are used mainly during maintenance, startup, and shutdown. There is a small flow from such things as compressor seals leaks during normal operation."
131769, PSDTX1456, GHGPSDTX134	Port Arthur LNG Export Terminal	TX-0790	TX	7/29/2016	Flare	VOC	98%	"Natural Gas Vents due to Maintenance, Start-up, and Shutdown (MSS) of the LNG Export Facility. One ground flare and one elevated marine flare will be used."
2012-1026-C PSD	Buffalo Creek Processing Plant	*OK-0148	OK	5/12/2017	N/A	VOC	N/A	Two Solar Taurus 70-10802S turbines. Blowdowns and venting for startup/shutdown.

APPENDIX F

COMPARISON OF FLARING EMISSIONS AND VGR EMISSIONS

Appendix F:
Comparison of Flaring Emissions and VGR Emissions

APC, LLC - Buckngham Compressor Station

Summary

Pollutant	Emissions (ton/yr)		
	Uncontrolled	Flaring	VGR
CO	---	17.7	---
NOx	---	4.11	---
PM	---	5.46	---
SO2	---	0.035	---
VOC	64.1	1.30	0.421
CO2	65.9	6,965	0.433
CH4	2,174	0.133	14.3
N2O	---	0.128	---
CO2e	54,412	7,006	357
Total HAPs	3.97	0.110	0.026

Appendix F:
Comparison of Flaring Emissions and VGR Emissions

APC, LLC - Buckngham Compressor Station

Flaring

Flaring Information	
MMBtu/hr Pilot/Purge Rating[1]	0.618
MMBtu/MMscf NG Heat Content	1,020
MMscf/yr from Startup Events[2]	1.08
MMscf/yr from Shutdown Events[2]	105
MMscf/yr from Site-Wide Event[2]	4.10
MMscf/yr from Pigging Events[2]	0.286
MMscf/yr from Pilot Gas	5.30
Total MMscf/yr	116

Pollutant	Emission Factor (lb/MMBtu)	Emission Factor Reference	Emissions (ton/yr)					
			Startup Events	Shutdown Events	Site-Wide Events	Pigging Events	Pilot/Purge Gas	Total
CO (SU,SD,SW,Pig)	0.31	AP-42 Table 13.5-2	0.171	16.6	0.648	0.045	---	17.7
CO[3] (Pilot/Purge)	0.082	AP-42 Table 1.4-1	---	---	---	---	0.223	
NOx (SU,SD,SW,Pig)	0.068	AP-42 Table 13.5-1	0.038	3.65	0.142	0.010	---	4.11
NOx[3] (Pilot/Purge)	0.098	AP-42 Table 1.4-1	---	---	---	---	0.265	
PM[4] (SU,SD,SW,Pig)	0.096	AP-42 Table 13.5-1	0.053	5.17	0.201	0.014	---	5.46
PM (Pilot/Purge)	7.45E-03	AP-42 Table 1.4-2	---	---	---	---	0.020	
SO2	5.88E-04	AP-42 Table 1.4-2	3.25E-04	0.032	0.001	8.59E-05	0.002	0.035
VOC[5] (SU,SD,SW,Pig)	---	---	0.013	1.22	0.047	0.003	---	1.30
VOC (Pilot/Purge)	5.39E-03	AP-42 Table 1.4-2	---	---	---		0.015	
CO2	118	AP-42 Table 1.4-2	65.0	6,318	246	17.2	318	6,965
CH4	2.25E-03	AP-42 Table 1.4-2	0.001	0.121	0.005	3.29E-04	0.006	0.133
N2O	2.16E-03	AP-42 Table 1.4-2	0.001	0.116	0.005	3.15E-04	0.006	0.128
CO2e[6]	118.35	---	65.4	6,356	247	17.3	320	7,006

VGR

Pollutant	Emissions (ton/yr)[2]				
	Startup Events	Shutdown Events	Site-Wide Events	Pigging Events	Total
VOC	0.063	0.192	1.62E-04	0.166	0.421
CO2	0.064	0.198	1.67E-04	0.170	0.433
CH4	2.13	6.53	0.005	5.62	14.3
CO2e	53.2	163	0.138	141	357

Notes:
1. Initial engineering estimate.
2. From Appendix C.
3. Based on small boilers (<100 MMBtu/hr), uncontrolled.
4. Assumed average flare smoking.
5. Based on destruction efficiency.
6. Based on global warming potentials (GWPs) of CO2 = 1, CH4 = 25, and N2O = 298.

Appendix F:
Comparison of Flaring Emissions and VGR Emissions

APC, LLC - Buckngham Compressor Station

HAPs

Flaring Information[1]	
MMscf/yr from Startup Events	1.08
MMscf/yr from Shutdown Events	105
MMscf/yr from Site-Wide Event	4.10
MMscf/yr from Pigging Events	0.286
MMscf/yr from Pilot/Purge Gas	5.30
Total MMscf/yr	116

		Flaring Emissions (ton/yr)							VGR Emissions (ton/yr)[3]				
Pollutant	HAP?	Emission Factor (lb/MMscf)[2]	Startup Events	Shutdown Events	Site-Wide Events	Pigging Events	Pilot Gas	Total	Startup Events	Shutdown Events	Site-Wide Events	Pigging Events	Total
2-Methylnaphthalene	No	2.40E-05	1.30E-08	1.26E-06	4.92E-08	3.44E-09	6.37E-08	1.39E-06					
3-Methylchloranthrene	No	1.80E-06	9.75E-10	9.48E-08	3.69E-09	2.58E-10	4.77E-09	1.04E-07					
7,12-Dimethylbenz(a)anthracene	No	1.60E-05	8.66E-09	8.42E-07	3.28E-08	2.29E-09	4.24E-08	9.29E-07					
Acenaphthene	No	1.80E-06	9.75E-10	9.48E-08	3.69E-09	2.58E-10	4.77E-09	1.04E-07					
Acenaphthylene	No	1.80E-06	9.75E-10	9.48E-08	3.69E-09	2.58E-10	4.77E-09	1.04E-07					
Anthracene	No	2.40E-06	1.30E-09	1.26E-07	4.92E-09	3.44E-10	6.37E-09	1.39E-07					
Benz(a)anthracene	No	1.80E-06	9.75E-10	9.48E-08	3.69E-09	2.58E-10	4.77E-09	1.04E-07					
Benzene	Yes	2.10E-03	1.14E-06	1.11E-04	4.31E-06	3.01E-07	5.57E-06	1.22E-04					
Benzo(a)pyrene	No	1.20E-06	6.50E-10	6.32E-08	2.46E-09	1.72E-10	3.18E-09	6.96E-08					
Benzo(b)fluoranthene	No	1.80E-06	9.75E-10	9.48E-08	3.69E-09	2.58E-10	4.77E-09	1.04E-07					
Benzo(g,h,i)perylene	No	1.20E-06	6.50E-10	6.32E-08	2.46E-09	1.72E-10	3.18E-09	6.96E-08					
Benzo(k)fluoranthene	No	1.80E-06	9.75E-10	9.48E-08	3.69E-09	2.58E-10	4.77E-09	1.04E-07					
Butane	No	2.10E+00	1.14E-03	1.11E-01	4.31E-03	3.01E-04	5.57E-03	1.22E-01					
Chrysene	No	1.80E-06	9.75E-10	9.48E-08	3.69E-09	2.58E-10	4.77E-09	1.04E-07					
Dibenzo(a,h)anthracene	No	1.20E-06	6.50E-10	6.32E-08	2.46E-09	1.72E-10	3.18E-09	6.96E-08					
Dichlorobenzene	Yes	1.20E-03	6.50E-07	6.32E-05	2.46E-06	1.72E-07	3.18E-06	6.96E-05					
Ethane	No	3.10E+00	1.68E-03	1.63E-01	6.36E-03	4.44E-04	8.22E-03	1.80E-01					
Fluoranthene	No	3.00E-06	1.62E-09	1.58E-07	6.15E-09	4.30E-10	7.96E-09	1.74E-07					
Fluorene	No	2.80E-06	1.52E-09	1.47E-07	5.74E-09	4.01E-10	7.43E-09	1.63E-07					
Formaldehyde	Yes	7.50E-02	4.06E-05	3.95E-03	1.54E-04	1.07E-05	1.99E-04	4.35E-03					
Hexane (or n-Hexane)	Yes	1.80E+00	9.75E-04	9.48E-02	3.69E-03	2.58E-04	4.77E-03	1.04E-01	3.88E-03	1.19E-02	1.00E-05	1.03E-02	2.61E-02
Indeno(1,2,3-c,d)pyrene	No	1.80E-06	9.75E-10	9.48E-08	3.69E-09	2.58E-10	4.77E-09	1.04E-07					
Naphthalene	Yes	6.10E-04	3.30E-07	3.21E-05	1.25E-06	8.73E-08	1.62E-06	3.54E-05					
Pentane (or n-Pentane)	No	2.60E+00	1.41E-03	1.37E-01	5.33E-03	3.72E-04	6.90E-03	1.51E-01					
Phenanthrene	No	1.70E-05	9.21E-09	8.95E-07	3.49E-08	2.43E-09	4.51E-08	9.87E-07					
Propane	No	1.60E+00	8.66E-04	8.42E-02	3.28E-03	2.29E-04	4.24E-03	9.29E-02					
Pyrene	No	5.00E-06	2.71E-09	2.63E-07	1.03E-08	7.16E-10	1.33E-08	2.90E-07					
Toluene	Yes	3.40E-03	1.84E-06	1.79E-04	6.97E-06	4.87E-07	9.02E-06	1.97E-04					
Arsenic	Yes	2.00E-04	1.08E-07	1.05E-05	4.10E-07	2.86E-08	5.30E-07	1.16E-05					
Barium	No	4.40E-03	2.38E-06	2.32E-04	9.02E-06	6.30E-07	1.17E-05	2.55E-04					
Beryllium	Yes	1.20E-05	6.50E-09	6.32E-07	2.46E-08	1.72E-09	3.18E-08	6.96E-07					
Cadmium	Yes	1.10E-03	5.96E-07	5.79E-05	2.26E-06	1.58E-07	2.92E-06	6.38E-05					
Chromium	Yes	1.40E-03	7.58E-07	7.37E-05	2.87E-06	2.00E-07	3.71E-06	8.13E-05					
Cobalt	Yes	8.40E-05	4.55E-08	4.42E-06	1.72E-07	1.20E-08	2.23E-07	4.88E-06					
Copper	No	8.50E-04	4.60E-07	4.48E-05	1.74E-06	1.22E-07	2.25E-06	4.93E-05					
Manganese	Yes	3.80E-04	2.06E-07	2.00E-05	7.79E-07	5.44E-08	1.01E-06	2.21E-05					
Mercury	Yes	2.60E-04	1.41E-07	1.37E-05	5.33E-07	3.72E-08	6.90E-07	1.51E-05					
Molybdenum	No	1.10E-03	5.96E-07	5.79E-05	2.26E-06	1.58E-07	2.92E-06	6.38E-05					
Nickel	Yes	2.10E-03	1.14E-06	1.11E-04	4.31E-06	3.01E-07	5.57E-06	1.22E-04					
Selenium	Yes	2.40E-05	1.30E-08	1.26E-06	4.92E-08	3.44E-09	6.37E-08	1.39E-06					
Vanadium	No	2.30E-03	1.25E-06	1.21E-04	4.72E-06	3.29E-07	6.10E-06	1.33E-04					
Zinc	No	2.90E-02	1.57E-05	1.53E-03	5.95E-05	4.15E-06	7.69E-05	1.68E-03					
Lead	Yes	5.00E-04	2.71E-07	2.63E-05	1.03E-06	7.16E-08	1.33E-06	2.90E-05					
Total HAPs		1.89	0.001	0.099	0.004	2.70E-04	0.005	0.110	0.004	0.012	1.00E-05	0.010	0.026

Hazardous Air Pollutant

Notes:
1. From Page 2.
2. Emission factors from AP-42 Tables 1.4-2, 1.4-3, and 1.4-4.
3. From Appendix C.

APPENDIX G

SCR COST EFFECTIVENESS EVALUATION

COST EFFECTIVENESS SUMMARY									
Equipment Information			Control Device Information			Cost Effectiveness Analysis			
Unit ID	Make/Model	Size (hp)	Control Device Reviewed	Pollutant	Control Efficiency	Total Annual Costs ($/yr)	NOx Emission Rate (tpy)	NOx Removed (tpy)	Cost Effectiveness ($/ton)
CT-01	Solar Mars 100 Turbine	15,900	SCR	NOx	58.3%	$668,650	20.4	11.9	$56,189
CT-02	Solar Taurus 70 Turbine	11,107	SCR	NOx	58.3%	$586,379	13.5	7.88	$74,461
CT-03	Solar Titan 130 Turbine	20,500	SCR	NOx	58.3%	$727,131	24.8	14.5	$50,263
CT-04	Solar Centaur 50 Turbine	6,276	SCR	NOx	58.3%	$522,938	8.68	5.06	$103,279

Dominion Energy Transmission, Inc.
BACT Assessment
ACP Buckingham Compressor Station
Buckingham County, Virginia

Station	**Buckingham Compressor Station**	
Unit Name	**Compressor Turbine 1**	
Unit ID	**CT-01**	
Unit Description	**Natural gas fired simple cycle turbine**	
Make/Model	**Solar Mars 100 Turbine**	
Size	**15,900**	**hp**
Rated Heat Input	**129.64**	**MMBtu/hr**
Pollutant	**NOx**	
Uncontrolled Emission Rate	**20.4**	**tpy**
Max. Operating Schedule	**8760**	**hours**
Control Device Reviewed	**Selective Catalytic Reduction (NOx control)**	
Control Efficiency	**58.3%**	

	COST COMPONENT:	ABBREV.	COST ($1,000)	SOURCE[1]	CALCULATION
DIRECT COSTS					
	Purchased Equipment Costs				
	SCR Equipment Cost	EC	1,220	Vendor	
	Control System (INCL. IN ABOVE COSTS)		---	Vendor	
	Reagent Storage & Delivery (INCL. IN ABOVE COSTS)		---	Vendor	
	Taxes and Freight (INCL. IN ABOVE COSTS)		---	Vendor	
	Subtotal - Purchased Equipment Costs	**PEC**	**1,220**		
	Direct Installation Costs				
	Foundation & Supports (INCL. IN ABOVE COSTS)		---	Vendor	
	Handling and Erection (INCL. IN ABOVE COSTS)		---	Vendor	
	Insulation (INCL. IN ABOVE COSTS)		---	Vendor	
	Painting (INCL. IN ABOVE COSTS)		---	Vendor	
	Emissions Monitoring		25.0	EPA Model	
	Subtotal - Direct Installation Costs	**DIC**	**25.0**		
TOTAL DIRECT COSTS		**DC**	**1,245**		**PEC + DIC**
INDIRECT COSTS					
	Engineering and Home Office Fees (INCL. IN ABOVE COSTS)		---	Vendor	
	General Facilities (INCL. IN ABOVE COSTS)		---	Vendor	
	Process Contingency		62.3	OAQPS	0.05 x DC
	Construction & Field Expenses (INCL. IN ABOVE COSTS)		---	Vendor	
	Contractor Fees (INCL. IN ABOVE COSTS)		---	Vendor	
	Start-Up (INCL. IN ABOVE COSTS)		---	Vendor	
	Performance Testing (INCL. IN ABOVE COSTS)		---	Vendor	
	Emissions Monitoring Startup Test, QA/QC Plan		24.3	EPA Model	
TOTAL INDIRECT COSTS		**IC**	**86.6**		
	Project Contingency	PC	200	OAQPS	0.15 x (DC + IC)
	Pre-Production Cost	PPC	30.6	OAQPS	0.02 x (DC + IC + PC)
TOTAL CAPITAL INVESTMENT		**TCI**	**1,562**		**DC + IC + PC + PPC**

Dominion Energy Transmission, Inc.
BACT Assessment
ACP Buckingham Compressor Station
Buckingham County, Virginia

COST COMPONENT:		ABBREV.	COST ($1,000)	SOURCE[1]	CALCULATION
DIRECT ANNUAL COSTS					
Operating and Maintenance Costs		O&M	1.25	Other[2]	0.015 x TCI
Emissions Monitoring Annual Costs		CAC	26.6	EPA Model	
Natural Gas Costs[3]		NG	64.3		
Additional Pressure Drop (inches w.c.)	*5.00*	PD		Estimate	
Performance Loss (%)	*1.25*			Estimate	0.25 x PD
Natural Gas Cost ($/Mcf)	*4.62*			EIA	
Electricity Costs[4]		ELEC	105		
Electricty Consumption (kwh)	*120*			Estimate	
Electricity Cost ($/kwh)	*0.10*			Estimate	
Reagent Costs (Ammonia)		NH3	121	Other[2]	
Catalyst Costs[5]		CAT	64.6		
Catalyst Life (years)	*3.00*			OAQPS	
Interest Rate (%)	*7.00*			OAQPS	
Annualized Cost Factor[6]	*0.381*			OAQPS	
SCR Catalyst Cost ($1000)	*170*			Other[7]	
TOTAL DIRECT ANNUAL COSTS		**DAC**	**383**		**O&M + CAC + NG + ELEC + NH3 + CAT**
INDIRECT ANNUAL COSTS					
Overhead			0.750	OAQPS	0.60 x O&M
Administrative			31.2	OAQPS	0.02 x TCI
Insurance			15.6	OAQPS	0.01 x TCI
Property Tax			15.6	OAQPS	0.01 x TCI
Capital Recovery			222	OAQPS	ACF x TCI
Period (years)	*10.0*			Estimate	
Interest Rate (%)	*7.00*			OAQPS	
Annualized Cost Factor[6]	*0.142*	ACF		OAQPS	
TOTAL INDIRECT ANNUAL COSTS		**IAC**	**286**		
TOTAL ANNUAL COSTS		**TAC**	**669**		**DAC + IAC**

NOx Emission Rate	**20.4**	**tpy**
NOx Removed	**11.9**	**tpy**
Cost Effectiveness	**$ 56,189**	**$/ton**

NOTES:

1. Sources are as follows:
   - -Vendor: Quote for Buckingham SCR systems. Total of $4,881,082 for all four systems, assumed the same cost for each system.
   - -EPA Model: Continuous Emissions Monitoring System Cost Model, Version 3.0, for SCR.
   - -OAQPS: EPA Air Pollution Control Cost Manual, Section 4.2, Chapter 2, Selective Catalytic Reduction; Sixth Edition, EPA/452/B-02-001, January 2002.
   - -Estimate: Best engineering judgement.
   - -EIA: U.S. Energy Information Administration. Natural gas cost based on five-year average (2011-2015) of import price of natural gas by pipeline.
   - -Other: See footnotes below.
2. Information provided by Peerless SCR.
   - -O&M Costs: Total of $5,000 for all four systems, assumed the same cost for each system.
   - -NH3 Costs: Total of $400,000 for all four systems, ratioed the cost based on NOx removed by each system.
3. Natural Gas Costs = Performance Loss * Size * Max. Operating Schedule * Natural Gas Cost
4. Electricity Costs = Electricity Consumption * Electricty Cost * Max. Operating Schedule
5. Catalyst Costs = SCR Catalyst Cost * Annual Cost Factor
6. Annual Cost Factor = [Interest Rate * (1 + Interest Rate) ^ (# of years)] / [(1 + Interest Rate) ^ (# of years) - 1]
7. SCR Quote for Recip Engine, quote scaled up to turbine hp rating. Reference: Pages 64-65 of PADEP Technical Support Document General Permit GP-5 (January 31, 2013).

Dominion Energy Transmission, Inc.
BACT Assessment
ACP Buckingham Compressor Station
Buckingham County, Virginia

Station	**Buckingham Compressor Station**	
Unit Name	**Compressor Turbine 2**	
Unit ID	**CT-02**	
Unit Description	**Natural gas fired simple cycle turbine**	
Make/Model	**Solar Taurus 70 Turbine**	
Size	**11,107**	**hp**
Rated Heat Input	**85.62**	**MMBtu/hr**
Pollutant	**NOx**	
Uncontrolled Emission Rate	**13.5**	**tpy**
Max. Operating Schedule	**8760**	**hours**
Control Device Reviewed	**Selective Catalytic Reduction (NOx control)**	
Control Efficiency	**58.3%**	

	COST COMPONENT:	ABBREV.	COST ($1,000)	SOURCE[1]	CALCULATION
DIRECT COSTS					
	Purchased Equipment Costs				
	SCR Equipment Cost	EC	1,220	Vendor	
	Control System (INCL. IN ABOVE COSTS)		---	Vendor	
	Reagent Storage & Delivery (INCL. IN ABOVE COSTS)		---	Vendor	
	Taxes and Freight (INCL. IN ABOVE COSTS)		---	Vendor	
	Subtotal - Purchased Equipment Costs	**PEC**	**1,220**		
	Direct Installation Costs				
	Foundation & Supports (INCL. IN ABOVE COSTS)		---	Vendor	
	Handling and Erection (INCL. IN ABOVE COSTS)		---	Vendor	
	Insulation (INCL. IN ABOVE COSTS)		---	Vendor	
	Painting (INCL. IN ABOVE COSTS)		---	Vendor	
	Emissions Monitoring		25.0	EPA Model	
	Subtotal - Direct Installation Costs	**DIC**	**25.0**		
TOTAL DIRECT COSTS		**DC**	**1,245**		**PEC + DIC**
INDIRECT COSTS					
	Engineering and Home Office Fees (INCL. IN ABOVE COSTS)		---	Vendor	
	General Facilities (INCL. IN ABOVE COSTS)		---	Vendor	
	Process Contingency		62.3	OAQPS	0.05 x DC
	Construction & Field Expenses (INCL. IN ABOVE COSTS)		---	Vendor	
	Contractor Fees (INCL. IN ABOVE COSTS)		---	Vendor	
	Start-Up (INCL. IN ABOVE COSTS)		---	Vendor	
	Performance Testing (INCL. IN ABOVE COSTS)		---	Vendor	
	Emissions Monitoring Startup Test, QA/QC Plan		24.3	EPA Model	
TOTAL INDIRECT COSTS		**IC**	**86.6**		
	Project Contingency	PC	200	OAQPS	0.15 x (DC + IC)
	Pre-Production Cost	PPC	30.6	OAQPS	0.02 x (DC + IC + PC)
TOTAL CAPITAL INVESTMENT		**TCI**	**1,562**		**DC + IC + PC + PPC**

Dominion Energy Transmission, Inc.
BACT Assessment
ACP Buckingham Compressor Station
Buckingham County, Virginia

COST COMPONENT:		ABBREV.	COST ($1,000)	SOURCE[1]	CALCULATION
DIRECT ANNUAL COSTS					
Operating and Maintenance Costs		O&M	1.25	Other[2]	0.015 x TCI
Emissions Monitoring Annual Costs		CAC	26.6	EPA Model	
Natural Gas Costs[3]		NG	42.5		
Additional Pressure Drop (inches w.c.)	*5.00*	PD		Estimate	
Performance Loss (%)	*1.25*			Estimate	0.25 x PD
Natural Gas Cost ($/Mcf)	*4.62*			EIA	
Electricity Costs[4]		ELEC	105		
Electricty Consumption (kwh)	*120*			Estimate	
Electricity Cost ($/kwh)	*0.10*			Estimate	
Reagent Costs (Ammonia)		NH3	80.1	Other[2]	
Catalyst Costs[5]		CAT	45.1		
Catalyst Life (years)	*3.00*			OAQPS	
Interest Rate (%)	*7.00*			OAQPS	
Annualized Cost Factor [6]	*0.381*			OAQPS	
SCR Catalyst Cost ($1000)	*118*			Other[7]	
TOTAL DIRECT ANNUAL COSTS		**DAC**	**301**		**O&M + CAC + NG + ELEC + NH3 + CAT**
INDIRECT ANNUAL COSTS					
Overhead			0.750	OAQPS	0.60 x O&M
Administrative			31.2	OAQPS	0.02 x TCI
Insurance			15.6	OAQPS	0.01 x TCI
Property Tax			15.6	OAQPS	0.01 x TCI
Capital Recovery			222	OAQPS	ACF x TCI
Period (years)	*10.0*			Estimate	
Interest Rate (%)	*7.00*			OAQPS	
Annualized Cost Factor [6]	*0.142*	ACF		OAQPS	
TOTAL INDIRECT ANNUAL COSTS		**IAC**	**286**		
TOTAL ANNUAL COSTS		**TAC**	**586**		**DAC + IAC**

NOx Emission Rate	**13.5**	**tpy**
NOx Removed	**7.88**	**tpy**
Cost Effectiveness	**$ 74,461**	**$/ton**

NOTES:

1. Sources are as follows:
   - -Vendor: Quote for Buckingham SCR systems. Total of $4,881,082 for all four systems, assumed the same cost for each system.
   - -EPA Model: Continuous Emissions Monitoring System Cost Model, Version 3.0, for SCR.
   - -OAQPS: EPA Air Pollution Control Cost Manual, Section 4.2, Chapter 2, Selective Catalytic Reduction; Sixth Edition, EPA/452/B-02-001, January 2002.
   - -Estimate: Best engineering judgement.
   - -EIA: U.S. Energy Information Administration. Natural gas cost based on five-year average (2011-2015) of import price of natural gas by pipeline.
   - -Other: See footnotes below.
2. Information provided by Peerless SCR.
   - -O&M Costs: Total of $5,000 for all four systems, assumed the same cost for each system.
   - -NH3 Costs: Total of $400,000 for all four systems, ratioed the cost based on NOx removed by each system.
3. Natural Gas Costs = Performance Loss * Size * Max. Operating Schedule * Natural Gas Cost
4. Electricity Costs = Electricity Consumption * Electricty Cost * Max. Operating Schedule
5. Catalyst Costs = SCR Catalyst Cost * Annual Cost Factor
6. Annual Cost Factor = [Interest Rate * (1 + Interest Rate) ^ (# of years)] / [(1 + Interest Rate) ^ (# of years) - 1]
7. SCR Quote for Recip Engine, quote scaled up to turbine hp rating. Reference: Pages 64-65 of PADEP Technical Support Document General Permit GP-5 (January 31, 2013).

Dominion Energy Transmission, Inc.
BACT Assessment
ACP Buckingham Compressor Station
Buckingham County, Virginia

Station	**Buckingham Compressor Station**	
Unit Name	**Compressor Turbine 3**	
Unit ID	**CT-03**	
Unit Description	**Natural gas fired simple cycle turbine**	
Make/Model	**Solar Titan 130 Turbine**	
Size	**20,500**	**hp**
Rated Heat Input	**157.20**	**MMBtu/hr**
Pollutant	**NOx**	
Uncontrolled Emission Rate	**24.8**	**tpy**
Max. Operating Schedule	**8760**	**hours**
Control Device Reviewed	**Selective Catalytic Reduction (NOx control)**	
Control Efficiency	**58.3%**	

	COST COMPONENT:	ABBREV.	COST ($1,000)	SOURCE[1]	CALCULATION
DIRECT COSTS					
	Purchased Equipment Costs				
	SCR Equipment Cost	EC	1,220	Vendor	
	Control System (INCL. IN ABOVE COSTS)		---	Vendor	
	Reagent Storage & Delivery (INCL. IN ABOVE COSTS)		---	Vendor	
	Taxes and Freight (INCL. IN ABOVE COSTS)		---	Vendor	
	Subtotal - Purchased Equipment Costs	**PEC**	**1,220**		
	Direct Installation Costs				
	Foundation & Supports (INCL. IN ABOVE COSTS)		---	Vendor	
	Handling and Erection (INCL. IN ABOVE COSTS)		---	Vendor	
	Insulation (INCL. IN ABOVE COSTS)		---	Vendor	
	Painting (INCL. IN ABOVE COSTS)		---	Vendor	
	Emissions Monitoring		25.0	EPA Model	
	Subtotal - Direct Installation Costs	**DIC**	**25.0**		
TOTAL DIRECT COSTS		**DC**	**1,245**		**PEC + DIC**
INDIRECT COSTS					
	Engineering and Home Office Fees (INCL. IN ABOVE COSTS)		---	Vendor	
	General Facilities (INCL. IN ABOVE COSTS)		---	Vendor	
	Process Contingency		62.3	OAQPS	0.05 x DC
	Construction & Field Expenses (INCL. IN ABOVE COSTS)		---	Vendor	
	Contractor Fees (INCL. IN ABOVE COSTS)		---	Vendor	
	Start-Up (INCL. IN ABOVE COSTS)		---	Vendor	
	Performance Testing (INCL. IN ABOVE COSTS)		---	Vendor	
	Emissions Monitoring Startup Test, QA/QC Plan		24.3	EPA Model	
TOTAL INDIRECT COSTS		**IC**	**86.6**		
	Project Contingency	PC	200	OAQPS	0.15 x (DC + IC)
	Pre-Production Cost	PPC	30.6	OAQPS	0.02 x (DC + IC + PC)
TOTAL CAPITAL INVESTMENT		**TCI**	**1,562**		**DC + IC + PC + PPC**

COST COMPONENT:		ABBREV.	COST ($1,000)	SOURCE[1]	CALCULATION
DIRECT ANNUAL COSTS					
Operating and Maintenance Costs		O&M	1.25	Other[2]	0.015 x TCI
Emissions Monitoring Annual Costs		CAC	26.6	EPA Model	
Natural Gas Costs[3]		NG	78.0		
Additional Pressure Drop (inches w.c.)	*5.00*	PD		Estimate	
Performance Loss (%)	*1.25*			Estimate	0.25 x PD
Natural Gas Cost ($/Mcf)	*4.62*			EIA	
Electricity Costs[4]		ELEC	105		
Electricty Consumption (kwh)	*120*			Estimate	
Electricity Cost ($/kwh)	*0.10*			Estimate	
Reagent Costs (Ammonia)		NH3	147	Other[2]	
Catalyst Costs[5]		CAT	83.3		
Catalyst Life (years)	*3.00*			OAQPS	
Interest Rate (%)	*7.00*			OAQPS	
Annualized Cost Factor [6]	*0.381*			OAQPS	
SCR Catalyst Cost ($1000)	*219*			Other[7]	
TOTAL DIRECT ANNUAL COSTS		**DAC**	**441**		**O&M + CAC + NG + ELEC + NH3 + CAT**
INDIRECT ANNUAL COSTS					
Overhead			0.750	OAQPS	0.60 x O&M
Administrative			31.2	OAQPS	0.02 x TCI
Insurance			15.6	OAQPS	0.01 x TCI
Property Tax			15.6	OAQPS	0.01 x TCI
Capital Recovery			222	OAQPS	ACF x TCI
Period (years)	*10.0*			Estimate	
Interest Rate (%)	*7.00*			OAQPS	
Annualized Cost Factor [6]	*0.142*	ACF		OAQPS	
TOTAL INDIRECT ANNUAL COSTS		**IAC**	**286**		
TOTAL ANNUAL COSTS		**TAC**	**727**		**DAC + IAC**

NOx Emission Rate	**24.8**	**tpy**
NOx Removed	**14.5**	**tpy**
Cost Effectiveness	**$ 50,263**	**$/ton**

NOTES:

1. Sources are as follows:
   - -Vendor: Quote for Buckingham SCR systems. Total of $4,881,082 for all four systems, assumed the same cost for each system.
   - -EPA Model: Continuous Emissions Monitoring System Cost Model, Version 3.0, for SCR.
   - -OAQPS: EPA Air Pollution Control Cost Manual, Section 4.2, Chapter 2, Selective Catalytic Reduction; Sixth Edition, EPA/452/B-02-001, January 2002.
   - -Estimate: Best engineering judgement.
   - -EIA: U.S. Energy Information Administration. Natural gas cost based on five-year average (2011-2015) of import price of natural gas by pipeline.
   - -Other: See footnotes below.
2. Information provided by Peerless SCR.
   - -O&M Costs: Total of $5,000 for all four systems, assumed the same cost for each system.
   - -NH3 Costs: Total of $400,000 for all four systems, ratioed the cost based on NOx removed by each system.
3. Natural Gas Costs = Performance Loss * Size * Max. Operating Schedule * Natural Gas Cost
4. Electricity Costs = Electricity Consumption * Electricty Cost * Max. Operating Schedule
5. Catalyst Costs = SCR Catalyst Cost * Annual Cost Factor
6. Annual Cost Factor = [Interest Rate * (1 + Interest Rate) ^ (# of years)] / [(1 + Interest Rate) ^ (# of years) - 1]
7. SCR Quote for Recip Engine, quote scaled up to turbine hp rating. Reference: Pages 64-65 of PADEP Technical Support Document General Permit GP-5 (January 31, 2013).

Dominion Energy Transmission, Inc.
BACT Assessment
ACP Buckingham Compressor Station
Buckingham County, Virginia

Station	**Buckingham Compressor Station**	
Unit Name	**Compressor Turbine 4**	
Unit ID	**CT-04**	
Unit Description	**Natural gas fired simple cycle turbine**	
Make/Model	**Solar Centaur 50 Turbine**	
Size	**6,276**	**hp**
Rated Heat Input	**54.98**	**MMBtu/hr**
Pollutant	**NOx**	
Uncontrolled Emission Rate	**8.68**	**tpy**
Max. Operating Schedule	**8760**	**hours**
Control Device Reviewed	**Selective Catalytic Reduction (NOx control)**	
Control Efficiency	**58.3%**	

	COST COMPONENT:	ABBREV.	COST ($1,000)	SOURCE[1]	CALCULATION
DIRECT COSTS					
	Purchased Equipment Costs				
	SCR Equipment Cost	EC	1,220	Vendor	
	Control System (INCL. IN ABOVE COSTS)		---	Vendor	
	Reagent Storage & Delivery (INCL. IN ABOVE COSTS)		---	Vendor	
	Taxes and Freight (INCL. IN ABOVE COSTS)		---	Vendor	
	Subtotal - Purchased Equipment Costs	**PEC**	**1,220**		
	Direct Installation Costs				
	Foundation & Supports (INCL. IN ABOVE COSTS)		---	Vendor	
	Handling and Erection (INCL. IN ABOVE COSTS)		---	Vendor	
	Insulation (INCL. IN ABOVE COSTS)		---	Vendor	
	Painting (INCL. IN ABOVE COSTS)		---	Vendor	
	Emissions Monitoring		25.0	EPA Model	
	Subtotal - Direct Installation Costs	**DIC**	**25.0**		
TOTAL DIRECT COSTS		**DC**	**1,245**		**PEC + DIC**
INDIRECT COSTS					
	Engineering and Home Office Fees (INCL. IN ABOVE COSTS)		---	Vendor	
	General Facilities (INCL. IN ABOVE COSTS)		---	Vendor	
	Process Contingency		62.3	OAQPS	0.05 x DC
	Construction & Field Expenses (INCL. IN ABOVE COSTS)		---	Vendor	
	Contractor Fees (INCL. IN ABOVE COSTS)		---	Vendor	
	Start-Up (INCL. IN ABOVE COSTS)		---	Vendor	
	Performance Testing (INCL. IN ABOVE COSTS)		---	Vendor	
	Emissions Monitoring Startup Test, QA/QC Plan		24.3	EPA Model	
TOTAL INDIRECT COSTS		**IC**	**86.6**		
	Project Contingency	PC	200	OAQPS	0.15 x (DC + IC)
	Pre-Production Cost	PPC	30.6	OAQPS	0.02 x (DC + IC + PC)
TOTAL CAPITAL INVESTMENT		**TCI**	**1,562**		**DC + IC + PC + PPC**

Dominion Energy Transmission, Inc.
BACT Assessment
ACP Buckingham Compressor Station
Buckingham County, Virginia

COST COMPONENT:		ABBREV.	COST ($1,000)	SOURCE[1]	CALCULATION
DIRECT ANNUAL COSTS					
Operating and Maintenance Costs		O&M	1.25	Other[2]	0.015 x TCI
Emissions Monitoring Annual Costs		CAC	26.6	EPA Model	
Natural Gas Costs[3]		NG	27.3		
Additional Pressure Drop (inches w.c.)	*5.00*	PD		Estimate	
Performance Loss (%)	*1.25*			Estimate	0.25 x PD
Natural Gas Cost ($/Mcf)	*4.62*			EIA	
Electricity Costs[4]		ELEC	105		
Electricty Consumption (kwh)	*120*			Estimate	
Electricity Cost ($/kwh)	*0.10*			Estimate	
Reagent Costs (Ammonia)		NH3	51.5	Other[2]	
Catalyst Costs[5]		CAT	25.5		
Catalyst Life (years)	*3.00*			OAQPS	
Interest Rate (%)	*7.00*			OAQPS	
Annualized Cost Factor[6]	*0.381*			OAQPS	
SCR Catalyst Cost ($1000)	*66.9*			Other[7]	
TOTAL DIRECT ANNUAL COSTS		**DAC**	**237**		**O&M + CAC + NG + ELEC + NH3 + CAT**
INDIRECT ANNUAL COSTS					
Overhead			0.750	OAQPS	0.60 x O&M
Administrative			31.2	OAQPS	0.02 x TCI
Insurance			15.6	OAQPS	0.01 x TCI
Property Tax			15.6	OAQPS	0.01 x TCI
Capital Recovery			222	OAQPS	ACF x TCI
Period (years)	*10.0*			Estimate	
Interest Rate (%)	*7.00*			OAQPS	
Annualized Cost Factor[6]	*0.142*	ACF		OAQPS	
TOTAL INDIRECT ANNUAL COSTS		**IAC**	**286**		
TOTAL ANNUAL COSTS		**TAC**	**523**		**DAC + IAC**

NOx Emission Rate	**8.68**	**tpy**
NOx Removed	**5.06**	**tpy**
Cost Effectiveness	**$ 103,279**	**$/ton**

NOTES:

1. Sources are as follows:
   - -Vendor: Quote for Buckingham SCR systems. Total of $4,881,082 for all four systems, assumed the same cost for each system.
   - -EPA Model: Continuous Emissions Monitoring System Cost Model, Version 3.0, for SCR.
   - -OAQPS: EPA Air Pollution Control Cost Manual, Section 4.2, Chapter 2, Selective Catalytic Reduction; Sixth Edition, EPA/452/B-02-001, January 2002.
   - -Estimate: Best engineering judgement.
   - -EIA: U.S. Energy Information Administration. Natural gas cost based on five-year average (2011-2015) of import price of natural gas by pipeline.
   - -Other: See footnotes below.
2. Information provided by Peerless SCR.
   - -O&M Costs: Total of $5,000 for all four systems, assumed the same cost for each system.
   - -NH3 Costs: Total of $400,000 for all four systems, ratioed the cost based on NOx removed by each system.
3. Natural Gas Costs = Performance Loss * Size * Max. Operating Schedule * Natural Gas Cost
4. Electricity Costs = Electricity Consumption * Electricty Cost * Max. Operating Schedule
5. Catalyst Costs = SCR Catalyst Cost * Annual Cost Factor
6. Annual Cost Factor = [Interest Rate * (1 + Interest Rate) ^ (# of years)] / [(1 + Interest Rate) ^ (# of years) - 1]
7. SCR Quote for Recip Engine, quote scaled up to turbine hp rating. Reference: Pages 64-65 of PADEP Technical Support Document General Permit GP-5 (January 31, 2013).

APPENDIX H

VGR SYSTEM DESIGN AND OPERATION DETAILS

Buckingham Compressor Station

Vent Gas Reduction System

Vent Gas Reduction (VGR)

The VGR system that will be installed at the Buckingham Compressor Station is a pressure management system designed to reduce the amount of gas being vented from the station, including during unit shutdowns and startups. At Buckingham, this will be accomplished utilizing an electric pressure management compressor (i.e. Vent Gas Reduction Compressor) that will:

1. Maintain pressurized hold when compressor shuts down to avoid unit blowdowns and venting of the natural gas contained within unit; and
2. Lower the pressure in the unit to reduce the amount of gas to be vented in the event that unit needs to blowdown for maintenance purposes.

Utilization of the pressure management compressor under normal operating scenarios provides the following benefits:

- 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),
- Avoids purging the unit during startup (as this is not needed if unit has been kept in pressurized standby mode), and
- Reduces unit case and piping pressures to a significantly lower pressure before being vented, therefore minimizing the amount of gas vented during maintenance events.

DETI is currently implementing several forms of pressure management systems at eight (8) different compressor stations. In one such case, a seal booster compressor is used to maintain the differential pressure across the units seals for a pressurized hold state and a pump down compressor for lowering the pressure in the unit case pressure. Due to the various layouts of station piping, controls and equipment configurations at each of the stations, pressurized hold times across the fleet vary. However, the concept behind a pressure management to minimize the amount of natural gas venting is not something that is new to Dominion Energy.

Buckingham Station will utilize an enhanced version of the various systems currently being used by utilizing a single compressor to accomplish maintaining the differential pressure across the units seals for a pressurized hold state and a pump down compressor for lowering the pressure in the unit case pressure. Other compressor stations utilizing the same type of vent gas reduction system except that two separate compressors are used.

The following pages provide further discussion on the details of the operation of the vent gas reduction system. The description is adapted from details for the Northampton Station, which has progressed further with detailed design. That station will be installing a similar system as Buckingham. Also included in the description is a process flow diagram. As described, the system will utilize an electric compressor that can maintain a pressurized hold (avoiding need to blowdown) and reduce system pressure if a blowdown is required.

PART I – VENT GAS REDUCTION SYSTEM

1 GOAL

1.1 Reduce the amount of natural gas vented to the atmosphere as a result of normal operations of a centrifugal gas compressor.

2 PURPOSE

2.1 The purpose of the vent gas recovery system is to;

2.1.1 Allow a centrifugal compressor to remain in a pressurized hold after a normal shutdown. When the unit remains in a pressurized hold, two events which release natural gas are avoided; a) the release of the volume of natural gas contained in the compressor and associated unit piping to the atmosphere (i.e. blowdown), b) the venting of natural gas that occurs during the purge sequence at the beginning of each compressor start to insure that there is no air contained within the gas piping when the compressor and unit piping have been blown down to atmospheric pressure.

2.1.2 Remove gas from the compressor and associated piping in preparation for maintenance or extended shutdown.

3 NEED

3.1 Past practice for reasons of safety have been to blow down the compressor and associated piping after each stop. When the compressor is needed for operation, it is purged and re-pressurized and then put into service.

3.2 A centrifugal compressor needs seals on each end of the impeller shaft in order to prevent gas from leaking out of the compressor to the surrounding atmosphere. Such leakage would be a safety, emissions and economic problem. Dry gas seals are used in all Solar units at the Buckingham Station. For the proper operation of these seals there needs to be source of clean gas that is higher in pressure than the suction pressure in the compressor case. Solar specifies this differential must be 100 psi or higher. For safety reasons the compressor control system will automatically blowdown the compressor if it detects a failure in the seal gas system.

3.3 In order to minimize emissions of natural gas by minimizing the number of blowdowns it is necessary to maintain the proper operation of the dry gas seal system, by maintaining a clean dry source of gas to the seals at the prescribed differential pressure recommended by the seal and compressor manufacturers.

3.4 Three of the ways of doing this are;

3.4.1 Select a source of seal gas that is above the prescribed differential pressure. Gas from station discharge is the normal source of seal gas when the compressor is running in normal operation or is stopped and the station discharge pressure is high enough to create the prescribed differential pressure.

3.4.2 Pump the seal gas source to create the prescribed differential pressure. At Buckingham, this will normally be done by the seal gas boost pumps on the Solar skids.

3.4.3 Evacuate the compressor and associated piping to a pressure low enough to create the prescribed differential pressure required for the seal gas system. This is the method used by the VGR system when the compressor is in a pressurized hold mode and there is not sufficient discharge pressure to create the prescribed differential pressure.

4 SYSTEM DESCRIPTION

4.1 The Vent Gas Reduction (VGR) system consist of these main components

4.1.1 The Vent Gas Reduction Compressor (VGRC)

4.1.1.1 The VGRC is an Ariel JGN/2 compressor driven by a 75 HP electric motor. The Dearing compression package includes a two throw, three stage compressor, Siemens 75 HP IEEE electric motor, lubricating system, an air cooled, forced draft gas and oil cooler, Hoffman electrical junction box, and all instrumentation and valve required for normal operation and monitoring.

4.1.2 The piping system

4.1.2.1 The piping for the VGR system consists of an automated VGR valve and check valve on each unit, automated suction, discharge, and vent valves for the VGRC, and interconnecting piping. The VGRC skid includes a suction throttle valve and recycle valve. Figure 1 in Appendix A shows the Northampton Compressor Station VGR system (highlighted in blue) and the compressors and associated piping that are affected by the operation of the VGR system (highlighted in green). Buckingham Compressor Station is similar except there are four (4) compressor units instead of three.

4.1.2.2 For example, the VGR valve on unit #1 at Northampton is VB-151. The pneumatic actuator on each VGR valve has two solenoids. One is controlled by Solar and is always open, allowing the valve to be opened at any time, unless the unit vent valve receives a signal to open. Then Solar sends a signal for the VGR solenoid to be closed, preventing the unit vent valve and VGR valve from being open at the same time. The second solenoid is controlled from the station control panel. When the VGR function is to be used for a unit pressurized hold/blowdown, the second solenoid is opened, which causes the valve to be opened. The VGR valves are located at the main compressors.

4.1.2.3 The unit VGR valves are connected to a common vent gas recovery header which is run to the VGRC.

4.1.2.4 The VGRC suction valve is tagged VB-1600 at each station and is located on the common vent gas recovery header upstream of the VGRC. It is normally open and energized by a 24 VDC control signal sent from the SCP to the VGR control panel which is relayed to the valve. On loss of this signal or the 150 psig instrument air, the valve will fail closed.

4.1.2.5 The VGRC discharge valve is tagged VB-1608 at each station and is located directly downstream of the VGRC on the vent gas recovery discharge header. This header is connected to the station suction upstream of the station separators to collect any lube oils in the gas stream from the VGRC. The VGR discharge valve is normally open and energized by a 24 VDC control signal sent from the SCP to the

VGR control panel which is relayed to the valve. On loss of this signal or the 150 psig instrument air, the valve will fail closed.

4.1.2.6 The VGRC vent valve is tagged VB-1601 at each station and is located on the vent gas recovery discharge header upstream of the VGR discharge valve. The pneumatic actuator operates on ESD air and will open upon an ESD event.

4.1.3 Unit Control logic

4.1.3.1 The Unit Control logic recognizes when the unit has been put in pressurized hold or normal depressurize mode and allows the unit to be connected to the VGR system if it is needed. If there is sufficient discharge pressure in the station, the normal operation of the pressurized hold mode would be to use the unit suction loading valve to vent the case back to the suction header and thus maintain the necessary differential pressure.

4.1.4 Station Control logic

4.1.4.1 The Station Control logic recognizes when any unit requires the VGR system and opens the applicable unit VGR valve to connect that unit to the VGRC and then runs the VGRC as required to meet the needs. The VGRC can service multiple units at one time.

4.1.4.2 When the VGRC is needed to maintain a pressurized hold, the Station Control logic monitors the differential between seal gas supply pressure and the unit(s) case pressure. The seal gas supply pressure comes from transmitters (e.g. PIT-1402 and PIT-1403 at Northampton. When this differential drops to 110 psig, the station control panel sends a signal to open the unit VGR valve, then starts the VGRC. The VGRC recycle valve is full open to start the unit with no load. After 5 seconds to allow the compressor to accelerate, the recycle valve is turned over to control so it will start to close. The VGRC will pump the unit pressure down 200 psig to 310 psig between case pressure and seal gas supply, then the SCP will send a signal to open the recycle valve and stop the VGRC. Once the VGRC is stopped, the SCP will close the unit VGR valve.

4.1.4.3 At Northampton and Buckingham, the SCP communicates with RSCP-B and RSCP-C respectively to send signals to the VGRC.

4.2 The VGRC provides service in three modes of operation

4.2.1 Pressurized Hold

4.2.1.1 During a pressurized hold, the VGRC will only be needed if the differential across the station is less than the required 110 psi between the case pressure (suction) and seal gas supply pressure (discharge). If the differential pressure between the station suction and discharge headers is sufficient, then the unit loading valves will be used maintain pressurized hold. Leakage across the labyrinth seals will cause the case pressure and associated piping pressure to rise. When it reaches within 110 psi of the seal gas pressure, the unit loading valve will be opened to bring the case pressure back down to suction pressure. This process can be repeated as needed until the unit is taken out of pressurized hold or there is no longer sufficient differential across the station to support this mode of operation.

4.2.1.2 If there is not sufficient differential across the station, then the VGRC will run to depressurize the compressor case and associated unit piping to create the necessary differential pressure for proper operation of the dry gas seals. Station

Control logic will follow the procedure described in Section 4.1.4.2 to maintain the pressurized hold until the main compressor is either brought fully off line (vented) or put back into service.

4.2.2 Depressurize for extended shutdown or maintenance

4.2.2.1 When selected to depressurize a compressor and its associated unit piping, the VGRC will run to depressurize the system. The VGRC will stop when the pressure has been reduced to approximately 30 psig. From that point on the remaining gas would be vented to atmosphere. Pumping lower than this pressure increases the risk of interfering with the unit control system safety logic which will automatically open the unit blow down valve.

4.2.2.2 To depressurize a compressor, the unit is first stopped in pressurized hold mode following the normal procedure. A Station Operator will select the unit to depressurize in the SCP, which will then send a signal to open the respective unit VGR valve. A signal is then sent to start the VGRC. Case pressure is sent to the SCP from the UCP. When the case pressure declines to 30 psig, the SCP stops the VGRC and closes the unit VGR valve. The operator puts the unit in normal stop mode and the UCP then opens the unit vent valve to vent the remaining gas to atmosphere through the silencer.

4.2.3 In either of these modes the VGRC discharges the gas back into the station suction upstream of the station scrubbers thus avoiding releasing the gas to atmosphere.

4.2.4 Capacity Control

4.2.4.1 The VGRC runs at a constant speed (1800 RPM) and has no capacity control devices (clearance pockets or cylinder deactivation). During pressurized hold maintenance and pump down modes, there is normally no need to reduce capacity. Under very high station suction pressure and certain VGRC suction conditions motor horsepower may exceed nameplate. There is a motor power transmitter (JT-102) which provides a kW signal to RSCP-A at Northampton and Buckingham. If kW exceeds nameplate then use the suction throttle valve via kW PID controller to reduce suction pressure until kW is less than or equal to nameplate. Place a minimum closing limit on the suction throttle so that the valve can never be completely closed.

FIGURE 1
NORTHAMPTON COMPRESSOR STATION