TABLE 2.0
NOISE QUALITY ANALYSIS FOR THE NORTHAMPTON COMPRESSOR STATION

Ambient Sound Levels, Predicted Sound Levels from the Three Proposed Turbine Compressor Units and Predicted Total Sound Levels

A-Weighted Sound Levels in dBA re 20 microPa

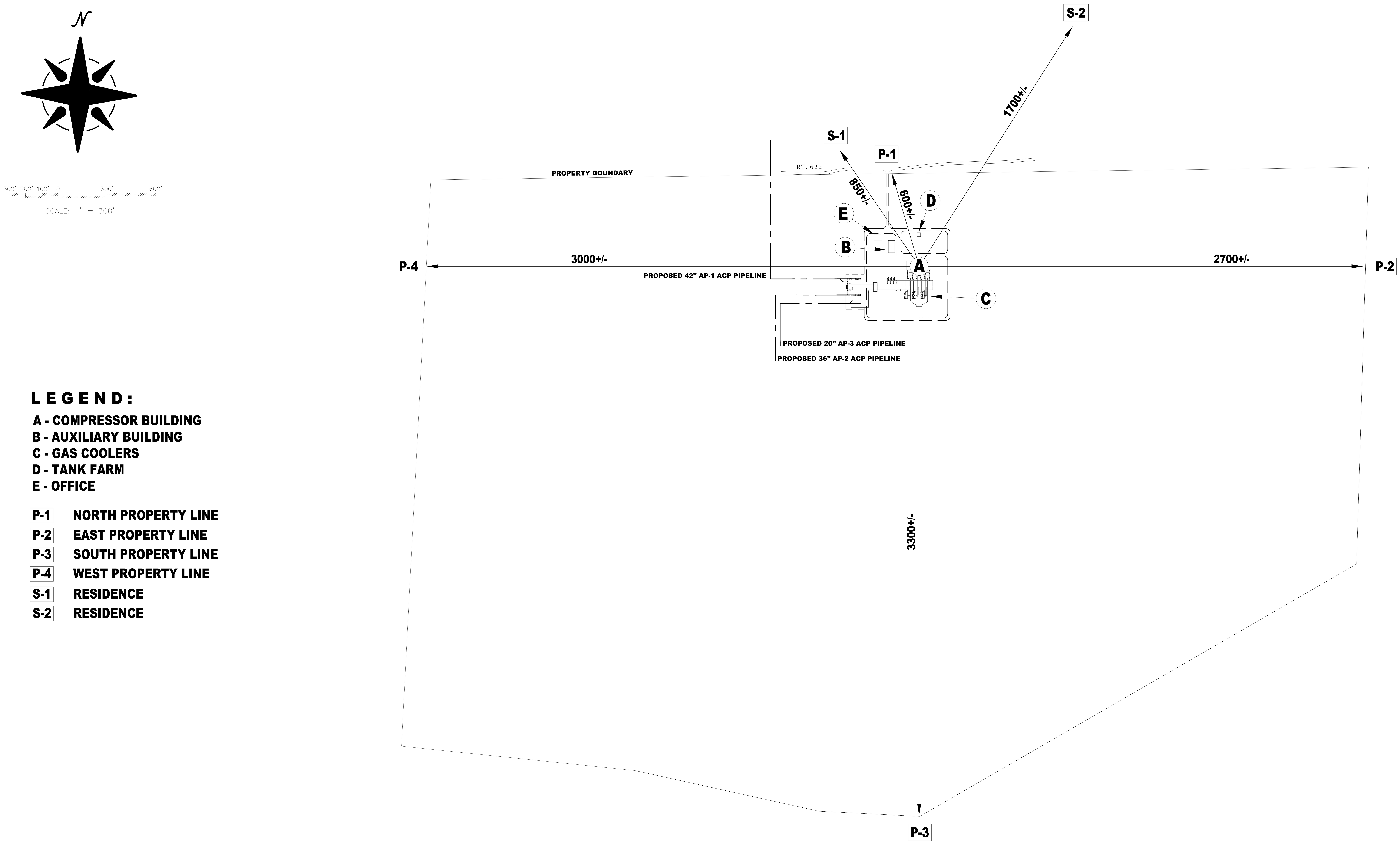
| Location/ Description | Distance/ Direction | Existing (1) $L_{eq}(d)$ | $L_{eq}(n)$ | $L_{dn}$ | Predicted $L_{dn}$ (2) | Total $L_{dn}$ (3) | Noise (4) Increase |
|---|---|---|---|---|---|---|---|
| P1. Prop Line | 600 ft N | 41.0 | 28.7 | 40.3 | 48.4 | 49.0 | 8.7 |
| P2. Prop Line | 2700 ft E | 42.8 | 27.4 | 41.5 | 32.4 | 42.0 | 0.5 |
| P3. Prop Line | 3300 ft S | 38.0 | 27.4 | 37.8 | 29.4 | 38.4 | 0.6 |
| P4. Prop Line | 3000 ft W | 40.8 | 29.9 | 40.5 | 30.4 | 40.9 | 0.4 |
| S1. Residence | 850 ft NNW | 39.2 | 25.9 | 38.2 | 45.4 | 46.2 | 8.0 |
| S2. Residence | 1700 ft NE | 39.9 | 26.3 | 38.9 | 37.4 | 41.2 | 2.3 |

(1) Ambient daytime and nighttime $L_{eq}$ sound levels measured on 23 April 2015, and calculated ambient $L_{dn}$ sound levels. These ambient sound levels were due to wind blowing through the trees, dogs barking, airplanes, a train, traffic on Route 301, spring peepers, insects and owls.

(2) Predicted $L_{dn}$ sound levels from the three proposed Northampton Compressor Station turbine compressor units with Noise Control Measures/Specifications Nos. 1 through 16 installed.

(3) Predicted total $L_{dn} = 10 \log (10^{(\text{Ambient } L_{dn}/10)} + 10^{(\text{Predicted } L_{dn}/10)})$.

(4) Predicted increase of the ambient $L_{dn}$ sound levels due to the three proposed Northampton Compressor Station turbine compressor units with Noise Control Measures/Specifications Nos. 1 through 16 installed.




**LEGEND:**

- A - COMPRESSOR BUILDING
- B - AUXILIARY BUILDING
- C - GAS COOLERS
- D - TANK FARM
- E - OFFICE

| | |
|---|---|
| P-1 | NORTH PROPERTY LINE |
| P-2 | EAST PROPERTY LINE |
| P-3 | SOUTH PROPERTY LINE |
| P-4 | WEST PROPERTY LINE |
| S-1 | RESIDENCE |
| S-2 | RESIDENCE |

GENERAL NOTES AND COMMENTS:

| SYM. | DATE | BY | REVISION INFORMATION | PROJECT/TASK | APP. |
|---|---|---|---|---|---|
| A | 6/9/2015 | RRC | ISSUED FOR REVIEW | | |

SEAL

I3 Engineering and Consulting, LLC
INTEGRITY • INITIATIVE • INNOVATION

| | | |
|---|---|---|
| DRAWN: | RRC | 6/9/2015 |
| CHECKED: | DLM | 6/9/2015 |
| APP. FOR BID: | | |
| APP. FOR CONST.: | | |
| SCALE: | 1"=300' | |

**Atlantic Coast Pipeline, LLC**

445 West Main St. Clarksburg, West Virginia 26301 / Phone: (304) 623-8000

TITLE: NORTHAMPTON COMPRESSOR STATION SOUND STUDY PLOT PLAN

DISTRICT: | COUNTY: NORTHAMPTON | STATE: NC | GROUP: PD | DWG. NO.: 2085C | REV.: A

DIR/FILE: DOM/ACP/Sound Study Drawings/CS3 Northampton

**ENVIRONMENTAL NOISE CONTROL**
260 Arbor Street
Lunenburg, MA 01462-1458
(978) 582-9204
Fax (978) 582-7102

17 July 2015

Dominion Transmission, Inc.
445 West Main Street
PO Box 2450
Clarksburg, West Virginia 26302-2450

Attention: Mr. Justin P. Ammons

Subject: ENC Report No. 539:
Sound Survey and Noise Analysis for the Addition of Two Turbine Compressor Units at the Mockingbird Hill Compressor Station for the Supply Header Project
ENC Project No. 14-20

Dear Mr. Ammons:

Environmental Noise Control (ENC) has conducted a sound survey of the existing compressor station with the Solar Taurus Model 60S turbine compressor unit operating on 14 January 2015 and a noise analysis of the sound levels due to the addition of two Solar Titan Model 130S turbine compressor units at the Mockingbird Hill Compressor Station for the Supply Header Project.

## 1.0 PURPOSE

The purpose of the noise sensitive area (NSA) sound survey was to document the existing station sound levels for the environmental report to be submitted for the addition of two Solar Titan Model 130S turbine compressor units at the Mockingbird Hill Compressor Station. Presented below are descriptions of the existing Mockingbird Hill Compressor Station, the sound survey measurement locations, and the measured existing station sound levels.

### 1.1 STATION DESCRIPTION

The Mockingbird Hill Compressor Station is located in the unincorporated town of Hastings, Wetzel County, West Virginia east of State Route 20. This compressor station consists of the Solar Taurus Model 60S turbine compressor unit that was installed in 2008. It is planned that the two additional turbine compressor units will be located in a new acoustically insulated compressor building approximately 1850 feet north-northeast of the existing compressor building.

The land uses surrounding the station are residential, industrial and forested areas. The Dominion Transmission, Inc. (DTI) Lewis Wetzel Compressor Station is approximately 2800 feet west-southwest, the DTI Hastings Compressor Station is approximately 3000 feet west-southwest, the DTI Hastings Extraction Plant is approximately 4100 feet west and the Eureka Hunter Pipeline Compressor Station is approximately 5000 feet south of the additional compressor building at the

Mockingbird Hill Compressor Station. The CSX railroad tracks run along the west side of State Route 20 along Fishing Creek. There are two company houses (S2 and S3) approximately 3300 and 3100 feet west. The additional compressor building is planned to be located on property directly north of the existing station property. It is planned that the house (S4) on this property will be torn down.

The nearest NSAs around the station are all residences. These residences are approximately 4500 feet west-northwest, 750 feet north-northwest, 2600 feet south-southeast, 2800 feet south, and 2400, 2500 and 3000 feet south-southwest. (See attached plot plan drawing). No one is living in the house at 4500 feet west-northwest because the bridge over Fishing Creek went out during the flood in September 2004. The sound level measurement at this NSA was conducted on the roadside of the creek since there was no way to cross the creek to get to the house.

## 1.2 SOUND SURVEY MEASUREMENTS

Sound survey measurements were conducted at the nearest NSAs on 14 January 2015 with the existing turbine compressor unit operating at 100% of full rated load. The weather conditions were a temperature of 22 degrees F increasing to 30 degrees F, a relative humidity of 60% increasing to 70%, overcast skies with snow showers and light north-northwest winds (1 to 4 mph).

The Mockingbird Hill Station was audible at NSAs S5, S8, S9 and S10. At NSAs S1, S6, and S7 and the company houses S2 and S3, the compressor station was not audible. Other audible sound sources (ambient sound sources) were traffic on State Route 20, birds, dogs barking, aircraft, an off-road vehicle, the Eureka Hunter Pipeline Compressor Station, a tractor at S6 and S7, and the Hasting Extraction Plant at S1, S2 and S3.

The measured station $L_{eq}$ sound levels at the NSAs (S5, S8, S9 andS10) where the Mockingbird Hill Compressor Station was audible ranged from 35.3 to 43.2 dBA, with calculated $L_{dn}$ sound levels ranging from 41.7 to 49.6 dBA. At the NSAs (S1, S6, and S7) where the Mockingbird Hill Compressor Station was not audible, the measured ambient $L_{eq}$ sound levels were 39.5 to 43.5 dBA with calculated $L_{dn}$ sound levels of 45.9 and 49.9 dBA.

## 2.0 NOISE ANALYSIS OF THE TWO ADDITIONAL TURBINE COMPRESSOR UNITS FOR THE MOCKINGBIRD HILL COMPRESSOR STATION

The Mockingbird Hill Compressor Station Addition sound levels will be the sound levels from two Solar Titan Model 130S turbine compressor units with the noise control materials installed. Presented below are the predicted sound levels from the two additional Solar turbine compressor units, the noise control measures/specifications necessary to reduce the sound levels from these compressor units, and the total sound levels predicted after the installation of the two additional Solar turbine compressor units at the Mockingbird Hill Compressor Station.

## 2.1 PREDICTED SOUND LEVELS FROM THE TWO ADDITIONAL TURBINE COMPRESSOR UNITS

The two additional Solar Titan Model 130S turbine compressor units have been designed so that the continuous sound from these compressor units operating at full load will not exceed a day-night sound level ($L_{dn}$) of 55 dBA at the NSAs around the station. These two compressor units have also been designed so that the sum of the $L_{dn}$ sound levels from these compressor units and the existing station and ambient $L_{dn}$ sound levels are below the FERC limit at the NSAs. The predicted sound levels from the two additional turbine compressor units are based upon sound level information provided by the turbine manufacturer (Solar Turbines Incorporated). Minimum dynamic insertion loss (DIL) requirements for the turbine exhaust mufflers, the turbine air intake cleaners/silencers, and the additional compressor building air handling unit, ventilation air inlet and ventilation air discharge mufflers have been specified. Specifications for minimum sound transmission loss (STC) requirements for the additional compressor building wall and roof panels, and personnel doors are included. Maximum sound levels for the air handling units, the emergency wall air inlet fans and the turbine compressor unit lube oil coolers have been specified. Also, maximum sound power levels for the turbine compressor unit gas coolers have been specified. Insulation minimum insertion loss (IL) values have been specified for the noise control insulations to be used on the turbine exhaust pipes, the turbine air intake ducts, all aboveground compressor unit suction, discharge and bypass lines, and the gas cooler inlet and outlet headers and piping.

## 2.2 NOISE CONTROL MEASURES/SPECIFICATIONS FOR THE TWO ADDITIONAL TURBINE COMPRESSOR UNITS

Implementation of the following noise control measures/specifications is necessary to ensure that the continuous sound from the two additional Solar Titan Model 130S turbine compressor units will not exceed a day-night sound level ($L_{dn}$) of 55 dBA at the NSAs.

1. Mufflers must be installed on the exhausts of the two Solar Titan Model 130S turbines. Each turbine exhaust muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Solar Titan Model 130S Turbine Exhaust Muffler Minimum DIL in dB

| | Octave Band Center Frequency in Hz | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
| dB | 13 | 24 | 31 | 41 | 49 | 46 | 42 | 33 | 24 |

2. The exhaust pipes of the two Solar Titan Model 130S turbines must be acoustically insulated from the compressor building wall to the exhaust muffler flanges (including expansion joints). This acoustic pipe insulation must have minimum Insertion Loss (IL) values as follows:

Turbine Exhaust Pipe Acoustic Insulation Minimum IL in dB

| | Octave Band Center Frequency in Hz | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
| dB | 0 | 0 | 0 | 0 | 5 | 10 | 25 | 25 | 20 |

3. Air cleaners/silencers must be installed on the air intakes of the two Solar Titan Model 130S turbines. Each turbine air intake cleaner/silencer must have minimum Dynamic Insertion Loss (DIL) values as follows:

Solar Titan Model 130S Turbine Air Intake Cleaner/Silencer Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 5 | 18 | 33 | 41 | 46 | 50 | 57 | 88 | 81 |

4. The air intake ducts of the two Solar Titan Model 130S turbines must be acoustically insulated from the compressor building wall to the air cleaner housings (including expansion joints). This acoustic insulation must have minimum Insertion Loss (IL) values as follows:

Turbine Air Intake Duct Acoustic Insulation Minimum IL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 0 | 0 | 0 | 6 | 12 | 20 | 26 | 26 | 22 |

5. The wall and roof panels of the additional Mockingbird Hill Station compressor building must have a minimum Sound Transmission Class (STC) of 49 and a minimum Noise Reduction Coefficient (NRC) of 0.90. In addition, these panels must have minimum Sound Transmission Loss (TL) values as follows:

Compressor Building Wall and Roof Panel Minimum TL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 9 | 15 | 22 | 38 | 46 | 48 | 52 | 53 | 54 |

6. The additional Mockingbird Hill Station compressor building personnel doors must be insulated, metal doors with full weather-stripping. The STC rating of these doors must be a minimum of 38 as provided by CECO Medallion doors or equal. Any windows in these doors must be double glazed using minimum 1/4 inch thick glass or acrylic panels separated by a minimum 1/2 inch airspace.

7. The additional Mockingbird Hill Station compressor building equipment door must be an insulated, metal door with full weather-stripping.

8. The additional Mockingbird Hill Station compressor building must have a ventilation system installed to provide adequate cooling of the building to allow full load operation of the two additional turbine compressor units with all doors closed.

8A. The additional Mockingbird Hill Station compressor building ventilation system can have a maximum of three air handling units. The maximum A-weighted sound level from each air handling unit must not exceed 70 dBA at 3 feet when measured outside of each air handling unit in all directions with maximum octave band sound pressure levels (SPL) as follows:

Air Handling Unit Maximum SPL at 3 feet in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 92 | 89 | 79 | 71 | 64 | 60 | 55 | 54 | 54 |

8B. Ventilation air inlet mufflers must be located in the air paths between the three air handing units and the additional compressor building wall penetrations to reduce the sound from the two additional turbine compressor units that escapes through these openings. Each air handling unit muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Air Handling Unit Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |

8C. The additional Mockingbird Hill Station compressor building ventilation system can have a maximum of four emergency wall air inlet fans. The maximum A-weighted sound level from each emergency wall air inlet fan must not exceed 90 dBA at 3 feet when measured inside the compressor building without the two additional turbine compressor units operating with maximum octave band sound pressure levels (SPL) as follows:

Emergency Wall Air Inlet Fan Maximum SPL at 3 feet in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 99 | 97 | 95 | 90 | 86 | 84 | 82 | 80 | 77 |

8D. Ventilation air inlet mufflers must be located in the walls of the additional Mockingbird Hill Station compressor building directly outside of the four emergency wall air inlet fans to reduce the sound from the two additional turbine compressor units that escapes through these openings. Each ventilation air inlet muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Ventilation Air Inlet Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |

8E. The additional Mockingbird Hill Station compressor building ventilation system can have a maximum of four roof air discharge hoods with a maximum total area of 121 square feet. Ventilation air discharge mufflers must be located above the roof and under each roof air discharge hood to reduce the sound from the two additional turbine compressor units that escapes through these openings. Each ventilation air discharge muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Ventilation Air Discharge Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 3 | 9 | 17 | 25 | 39 | 46 | 45 | 40 | 25 |

9. The maximum noise from the lube oil cooler for each additional turbine compressor unit must not exceed an A-weighted sound level of 50 dBA at 50 feet from the centerline of the cooler with all fans running at maximum speed. Each lube oil cooler (including all fans, motors and drives) must have maximum octave band sound pressure levels (SPL) as follows:

Lube Oil Cooler Maximum SPL at 50 feet in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 54 | 61 | 58 | 51 | 46 | 43 | 39 | 35 | 30 |

10. The maximum noise from the gas cooler for each additional turbine compressor unit must not exceed an A-weighted sound power level of 87 dBA with all fans running at maximum speed. Each gas cooler (including all fans, motors and drives) must have maximum octave band sound power levels (PWL) as follows:

Compressor Unit Gas Cooler Maximum PWL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 92 | 93 | 92 | 89 | 84 | 82 | 76 | 70 | 64 |

11. All aboveground sections of the unit suction, discharge and bypass lines and gas cooler inlet and outlet headers and piping (including the pipe supports) of the two additional turbine compressor units must be acoustically insulated. This acoustic pipe insulation must have minimum Insertion Loss (IL) values as follows:

Piping Insulation Minimum IL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 0 | 0 | 0 | 6 | 12 | 20 | 26 | 26 | 22 |

12. The maximum A-weighted sound level from each silenced unit blowdown vent must not exceed 60 dBA at 50 feet.

## 2.3 PREDICTED MOCKINGBIRD HILL COMPRESSOR STATION SOUND LEVELS

The octave band sound pressure levels and A-weighted sound levels predicted at the nearest NSA (S5) approximately 750 feet north-northwest of the two additional turbine compressor units are shown in Table 1.0. Sheets 1 through 3 of this table present the calculations that predict the sound levels from the two additional Solar Titan Model 130S turbine compressor units at this NSA. Detailed line item descriptions are presented on Sheets 4 through 7 of this table. The attached noise control analysis indicates a predicted continuous $L_{eq}$ sound level of 40 dBA at the nearest NSA with a corresponding $L_{dn}$ sound level of 46.4 dBA. At the other NSAs approximately 2400 to 4500 feet from the additional turbine compressor units, the $L_{eq}$ sound levels are predicted to range from 19 to 28 dBA, with corresponding $L_{dn}$ sound levels ranging from 25.4 to 34.4 dBA. The predicted $L_{dn}$ sound levels from two additional Solar Titan Model 130S turbine compressor units are below 55 dBA at all of the NSAs around the station.

Table 2.0 presents the sound levels at the NSAs around the station. Shown are:

- the existing station and ambient $L_d$, $L_n$ and $L_{dn}$ sound levels,
- the predicted $L_{dn}$ sound levels from the station discharge gas cooler to be installed in 2016 for the Monroe to Cornwell Project,
- the baseline $L_{dn}$ sound levels resulting from summing the existing station and ambient $L_{dn}$ sound levels with the predicted $L_{dn}$ sound levels from the station discharge gas cooler to be installed in 2016 for the Monroe to Cornwell Project,
- the predicted $L_{dn}$ sound levels from two additional Solar Titan Model 130S turbine compressor units,
- the predicted total $L_{dn}$ sound levels resulting from summing the $L_{dn}$ sound levels from two additional Solar Titan Model 130S turbine compressor units with the baseline $L_{dn}$ sound levels, and
- the increase in the baseline $L_{dn}$ sound levels due to the two additional turbine compressor units for the Supply Header Project.

At the NSAs, the predicted total $L_{dn}$ sound levels range from 43.5 to 51.3 dBA. These total $L_{dn}$ sound levels are below 55 dBA at all of the NSAs around the station.

Sincerely yours,
ENVIRONMENTAL NOISE CONTROL

William E. Biker

William E. Biker
Principal Engineer
Noise and Vibration Control

MOCKINGBIRD HILL COMPRESSOR STATION COMPONENT NOISE ANALYSIS
FOR TWO (2) SOLAR TITAN MODEL 130S TURBINE COMPRESSOR UNITS

Sound Pressure Levels (SPL) in dB re 20 microPa
Sound Power Levels (PWL) in dB re $10^{-12}$ watts

| | OCTAVE BAND CENTER FREQUENCIES IN Hz | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Description* | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
| 1. SPL | 92 | 96 | 94 | 97 | 101 | 96 | 88 | 78 | 68 |
| 2. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 3. = PWL | 124 | 128 | 126 | 129 | 133 | 128 | 120 | 110 | 100 |
| 4. + NF | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 5. = PWL | 127 | 131 | 129 | 132 | 136 | 131 | 123 | 113 | 103 |
| 6. – DIL | 13 | 24 | 31 | 41 | 49 | 46 | 42 | 33 | 24 |
| 7. = PWL | 114 | 107 | 98 | 91 | 87 | 85 | 81 | 80 | 79 |
| 8. SPL | 82 | 88 | 94 | 95 | 96 | 98 | 101 | 131 | 123 |
| 9. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 10. = PWL | 114 | 120 | 126 | 127 | 128 | 130 | 133 | 163 | 155 |
| 11. + NF | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 12. = PWL | 117 | 123 | 129 | 130 | 131 | 133 | 136 | 166 | 158 |
| 13. – DIL | 5 | 18 | 33 | 41 | 46 | 50 | 57 | 88 | 81 |
| 14. = PWL | 112 | 105 | 96 | 89 | 85 | 83 | 79 | 78 | 77 |
| 15. SPL | 82 | 81 | 89 | 86 | 83 | 79 | 80 | 92 | 85 |
| 16. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 17. = PWL | 114 | 113 | 121 | 118 | 115 | 111 | 112 | 124 | 117 |
| 18. + NF | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 19. = PWL | 117 | 116 | 124 | 121 | 118 | 114 | 115 | 127 | 120 |
| 20. – TL | 9 | 15 | 22 | 35 | 41 | 41 | 42 | 42 | 42 |
| 21. = PWL | 108 | 101 | 102 | 86 | 77 | 73 | 73 | 85 | 78 |
| 22. SPL | 92 | 89 | 79 | 71 | 64 | 60 | 55 | 54 | 54 |
| 23. + DT | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| 24. = PWL | 100 | 97 | 87 | 79 | 72 | 68 | 63 | 62 | 62 |
| 25. + NF | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 26. = PWL | 105 | 102 | 92 | 84 | 77 | 73 | 68 | 67 | 67 |
| 27. SPL | 103 | 100 | 107 | 104 | 101 | 97 | 98 | 110 | 103 |
| 28. + AT | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |

TABLE 1.0 (cont.) 

MOCKINGBIRD HILL COMPRESSOR STATION COMPONENT NOISE ANALYSIS
FOR TWO (2) SOLAR TITAN MODEL 130S TURBINE COMPRESSOR UNITS

Sound Pressure Levels (SPL) in dB re 20 microPa
Sound Power Levels (PWL) in dB re $10^{-12}$ watts

| | OCTAVE BAND CENTER FREQUENCIES IN Hz | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Description* | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
| 29. = PWL | 107 | 104 | 111 | 108 | 105 | 101 | 102 | 114 | 107 |
| 30. – DIL | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |
| 31. = PWL | 103 | 92 | 91 | 85 | 63 | 53 | 57 | 76 | 86 |
| 32. SPL | 99 | 97 | 95 | 90 | 86 | 84 | 82 | 80 | 77 |
| 33. + DT | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| 34. = PWL | 107 | 105 | 103 | 98 | 94 | 92 | 90 | 88 | 85 |
| 35. + NF | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| 36. = PWL | 113 | 111 | 109 | 104 | 100 | 98 | 96 | 94 | 91 |
| 37. – DIL | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |
| 38. = PWL | 109 | 99 | 89 | 81 | 58 | 50 | 51 | 56 | 70 |
| 39. SPL | 103 | 100 | 107 | 104 | 101 | 97 | 98 | 110 | 103 |
| 40. + AT | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| 41. = PWL | 111 | 108 | 115 | 112 | 109 | 105 | 106 | 118 | 111 |
| 42. – DIL | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |
| 43. = PWL | 107 | 96 | 95 | 89 | 67 | 57 | 61 | 80 | 90 |
| 44. SPL | 101 | 96 | 102 | 98 | 95 | 91 | 92 | 104 | 97 |
| 45. + AT | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| 46. = PWL | 112 | 107 | 113 | 109 | 106 | 102 | 103 | 115 | 108 |
| 47. – DIL | 3 | 9 | 17 | 25 | 39 | 46 | 45 | 40 | 25 |
| 48. = PWL | 109 | 98 | 96 | 84 | 67 | 56 | 58 | 75 | 83 |
| 49. SPL | 54 | 61 | 58 | 51 | 46 | 43 | 39 | 35 | 30 |
| 50. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 51. = PWL | 86 | 93 | 90 | 83 | 78 | 75 | 71 | 67 | 62 |
| 52. + NF | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 53. = PWL | 89 | 96 | 93 | 86 | 81 | 78 | 74 | 70 | 65 |
| 54. PWL | 92 | 93 | 92 | 89 | 84 | 82 | 76 | 70 | 64 |
| 55. + NF | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |

TABLE 1.0 (cont.) Sheet 3 of 7

MOCKINGBIRD HILL COMPRESSOR STATION COMPONENT NOISE ANALYSIS
FOR TWO (2) SOLAR TITAN MODEL 130S TURBINE COMPRESSOR UNITS

Sound Pressure Levels (SPL) in dB re 20 microPa
Sound Power Levels (PWL) in dB re $10^{-12}$ watts

| Description* | | OCTAVE BAND CENTER FREQUENCIES IN Hz 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|---|
| 56. = PWL | | 95 | 96 | 95 | 92 | 87 | 85 | 79 | 73 | 67 |
| 57. PWL | | 119 | 111 | 106 | 98 | 92 | 90 | 85 | 88 | 92 |
| 58. – DT | | 55 | 55 | 56 | 56 | 56 | 57 | 59 | 63 | 68 |
| 59. = SPL | 40 dBA | 64 | 56 | 50 | 42 | 36 | 33 | 26 | 25 | 24 |
| 60. Ldn | 46.4 dBA | | | | | | | | | |

* Detailed Line Item Descriptions are listed on Sheets 4 through 7.

TABLE 1.0 (cont.)



Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 through 3

1. Unmuffled exhaust sound pressure levels (SPL) at 50 feet and 90 degrees to stack axis of one (1) Solar Titan Model 130S turbine. These data were supplied by Solar Turbines Incorporated.

2. Distance Term (DT) to convert turbine exhaust SPL at 50 feet to turbine exhaust sound power levels (PWL) of one (1) Solar Titan Model 130S turbine.

3. Unmuffled exhaust PWL of one (1) Solar Titan Model 130S turbine.

4. Number Factor (NF) to account for two (2) Solar Titan Model 130S turbines.

5. Unmuffled exhaust PWL of two (2) Solar Titan Model 130S turbines.

6. Specified Dynamic Insertion Loss (DIL) of the turbine exhaust muffler for each Solar Titan Model 130S turbine (Noise Control Measure/Specification No. 1).

7. Muffled exhaust PWL of two (2) Solar Titan Model 130S turbines: result of lines 1 through 6.

8. Unmuffled intake SPL at 50 feet of one (1) Solar Titan Model 130S turbine. These data were supplied by Solar Turbines Incorporated.

9. Distance Term (DT) to convert turbine intake SPL at 50 feet to turbine intake PWL of one (1) Solar Titan Model 130S turbine.

10. Unmuffled intake PWL of one (1) Solar Titan Model 130S turbine.

11. Number Factor (NF) to account for two (2) Solar Titan Model 130S turbines.

12. Unmuffled intake PWL of two (2) Solar Titan Model 130S turbines.

13. Specified Dynamic Insertion Loss (DIL) of the turbine intake air cleaner/silencer for each Solar Titan Model 130S (Noise Control Measure/Specification No. 3).

14. Muffled intake PWL of two (2) Solar Titan Model 130S turbines: result of lines 8 through 13.

15. Casing SPL at 50 feet of one (1) Solar Titan Model 130S turbine. These data were supplied by Solar Turbines Incorporated.

16. Distance Term (DT) to convert turbine casing SPL at 50 feet to turbine casing PWL of one (1) Solar Titan Model 130S turbine.

Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 through 3

17. Casing PWL of one (1) Solar Titan Model 130S turbine.

18. Number Factor (NF) to account for two (2) Solar Titan Model 130S turbines.

19. Casing PWL of two (2) Solar Titan Model 130S turbines.

20. Composite sound transmission loss (TL) of compressor building walls, roof and doors using the specified STC 49 wall and roof panels, the specified STC 38 personnel doors and the specified equipment doors (Noise Control Measures/Specifications Nos. 5, 6, and 7).

21. PWL of compressor building radiated casing noise from two (2) Solar Titan Model 130S turbines: result of lines 15 through 20.

22. Specified maximum SPL at three (3) feet for one (1) air handling unit (Noise Control Measure/Specification No. 8A).

23. Distance Term (DT) to convert maximum air handling unit SPL at three (3) feet to PWL.

24. PWL of one (1) air handling unit.

25. Number Factor (NF) to account for three (3) air handling units.

26. PWL of three (3) air handling units: result of lines 22 through 25.

27. SPL calculated at the walls of the additional compressor building with two (2) Solar Titan Model 130S turbines operating. This is based upon the amount of sound absorption provided by the compressor building walls and roof, and upon the distance from the turbines to the building walls.

28. Conversion of SPL in line 27 to represent PWL of turbine casing noise at the three (3) air handling unit penetrations in the additional compressor building walls.

29. PWL of the turbine casing noise at the three (3) air handling unit penetrations in the additional compressor building walls.

30. Specified Dynamic Insertion Loss (DIL) of each air handling unit muffler (Noise Control Measure/Specification No. 8B).

31. PWL of the turbine casing noise at the three (3) air handling unit penetrations in the additional compressor building walls with mufflers: result of lines 27 through 30.

Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 through 3

32. Specified maximum SPL for one (1) emergency wall air inlet fan at 3 feet (Noise Control Measure/Specification No. 8C).

33. Distance Term (DT) to convert maximum emergency wall air inlet fan SPL at 3 feet to PWL.

34. PWL of one (1) emergency wall air inlet fan.

35. Number Factor (NF) to account for four (4) emergency wall air inlet fans.

36. PWL of four (4) emergency wall air inlet fans.

37. Specified Dynamic Insertion Loss (DIL) of each ventilation air inlet muffler (Noise Control Measure/Specification No. 8D).

38. PWL of the four (4) emergency wall air inlet fans in the additional compressor building walls with mufflers: result of lines 32 through 37.

39. SPL calculated at the walls of the additional compressor building with two (2) Solar Titan Model 130S turbines operating. This is based upon the amount of sound absorption provided by the compressor building walls and roof, and upon the distance from the turbines to the building walls.

40. Conversion of SPL in line 39 to represent PWL of turbine casing noise at the four (4) wall fan openings in the additional compressor building walls.

41. PWL of the turbine casing noise at the four (4) wall fan openings in the additional compressor building walls.

42. Specified Dynamic Insertion Loss (DIL) of each ventilation air inlet muffler (Noise Control Measure/Specification No. 8D).

43. PWL of the turbine casing noise at the four (4) wall fan openings in the additional compressor building walls with mufflers: result of lines 39 through 42.

44. SPL calculated under the roof of the additional compressor building with two (2) Solar Titan Model 130S turbines operating. This is based upon the amount of sound absorption provided by the compressor building walls and roof, and upon the distance from the turbines to the building roof.

45. Conversion of SPL in line 44 to represent PWL of turbine casing noise at four (4) roof air discharge openings in the additional compressor building roof.

Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 through 3

46. PWL of the turbine casing noise at the four (4) roof air discharge openings in the additional compressor building roof.

47. Specified Dynamic Insertion Loss (DIL) of each ventilation air discharge muffler (Noise Control Measure/Specification No. 8E).

48. PWL of the turbine casing noise at the four (4) roof air discharge openings in the additional compressor building roof with mufflers: result of lines 44 through 47.

49. Specified maximum SPL at 50 feet from one (1) turbine compressor unit lube oil cooler with the fan(s) running at maximum speed (Noise Control Measure/Specification No. 9).

50. Distance Term (DT) to convert maximum turbine compressor unit lube oil cooler SPL at 50 feet to PWL.

51. PWL of one (1) turbine compressor unit lube oil cooler with the fan(s) running at maximum speed.

52. Number Factor (NF) to account for two (2) turbine compressor unit lube oil coolers.

53. PWL of two (2) turbine compressor unit lube oil coolers with the fan(s) running at maximum speed: result of lines 49 through 52.

54. Specified maximum PWL of one (1) turbine compressor unit gas cooler with the fan(s) running at maximum speed (Noise Control Measure/Specification No. 10).

55. Number Factor (NF) to account for two (2) turbine compressor unit gas coolers.

56. PWL of two (2) turbine compressor unit gas coolers with the fans running at maximum speed: result of lines 54 and 55.

57. Total PWL of two (2) Solar Titan Model 130S turbine compressor units: logarithmic sum of lines 7, 14, 21, 26, 31, 38, 43, 48, 53, and 56.

58. Distance Term (DT) to convert total PWL to SPL at the nearest NSA (S5) 750 feet north-northwest of two (2) Solar Titan Model 130S turbine compressor units.

59. Energy equivalent sound level ($L_{eq}$) at the nearest NSA (S5) 750 feet north-northwest of two (2) Solar Titan Model 130S turbine compressor units at the Mockingbird Hill Compressor Station: result of lines 57 and 58.

60. Day-night sound level ($L_{dn}$) at the nearest NSA (S5) from two (2) Solar Titan Model 130S turbine compressor units at the Mockingbird Hill Compressor Station.

TABLE 2.0

NOISE QUALITY ANALYSIS FOR THE MOCKINGBIRD HILL COMPRESSOR STATION

Existing Station and Ambient Sound Levels, Predicted Station Discharge Gas Cooler Sound Levels, Baseline Station Sound Levels, Predicted Sound Levels from the Two Additional Solar Turbine Compressor Units and Predicted Total Sound Levels

A-Weighted Sound Levels in dBA re 20 microPa

| Location/ Description | Distance/ Direction | Existing [(1)] $L_{eq}(d)$ | $L_{eq}(n)$ | $L_{dn}$ | Gas Cooler $L_{dn}$ [(2)] | Baseline $L_{dn}$ [(3)] | Predicted $L_{dn}$ [(4)] | Total $L_{dn}$ [(5)] | Noise [(6)] Increase |
|---|---|---|---|---|---|---|---|---|---|
| S1. Residence | 4500 ft WNW | 43.5 | 43.5 | 49.9 | 18.4 | 49.9 | 25.4 | 49.9 | 0.0 |
| S2. Co. House | 3300 ft W | 64.0 | 64.0 | 70.4 | 26.4 | 70.4 | 30.4 | 70.4 | 0.0 |
| S3. Co. House | 3100 ft W | 60.4 | 60.4 | 66.8 | 27.4 | 66.8 | 31.4 | 66.8 | 0.0 |
| S5. Residence | 750 ft NNW | 43.2 | 43.2 | 49.6 | 28.4 | 49.6 | 46.4 | 51.3 | 1.7 |
| S6. Residence | 2600 ft SSE | 39.5 | 39.5 | 45.9 | 31.4 | 46.1 | 33.4 | 46.3 | 0.2 |
| S7. Residence | 2800 ft S | 40.5 | 40.5 | 46.9 | 30.4 | 47.0 | 32.4 | 47.1 | 0.1 |
| S8. Residence | 2400 ft SSW | 39.0 | 39.0 | 45.4 | 38.4 | 46.2 | 34.4 | 46.5 | 0.3 |
| S9. Residence | 2500 ft SSW | 35.3 | 35.3 | 41.7 | 37.4 | 43.1 | 33.4 | 43.5 | 0.4 |
| S10. Residence | 3000 ft SSW | 38.9 | 38.9 | 45.3 | 33.4 | 45.6 | 31.4 | 45.8 | 0.2 |

TABLE 2.0 (cont.) Sheet 2 of 2

NOISE QUALITY ANALYSIS FOR THE MOCKINGBIRD HILL COMPRESSOR STATION

(1) Existing station and ambient $L_{eq}$ sound levels measured on 14 January 2015 with the turbine compressor unit operating at the Mockingbird Hill Compressor Station, and calculated $L_{dn}$ sound levels. The Mockingbird Hill Station was audible at NSAs S5, S8, S9 and S10. At NSAs S1, S6 and S7 and the company houses S2 and S3, the compressor station was not audible. Other audible sound sources (ambient sound sources) were traffic on State Route 20, birds, dogs barking, aircraft, an off-road vehicle, the Eureka Hunter Pipeline Compressor Station, a tractor at S6 and S7, and the Hasting Extraction Plant at S1, S2 and S3.

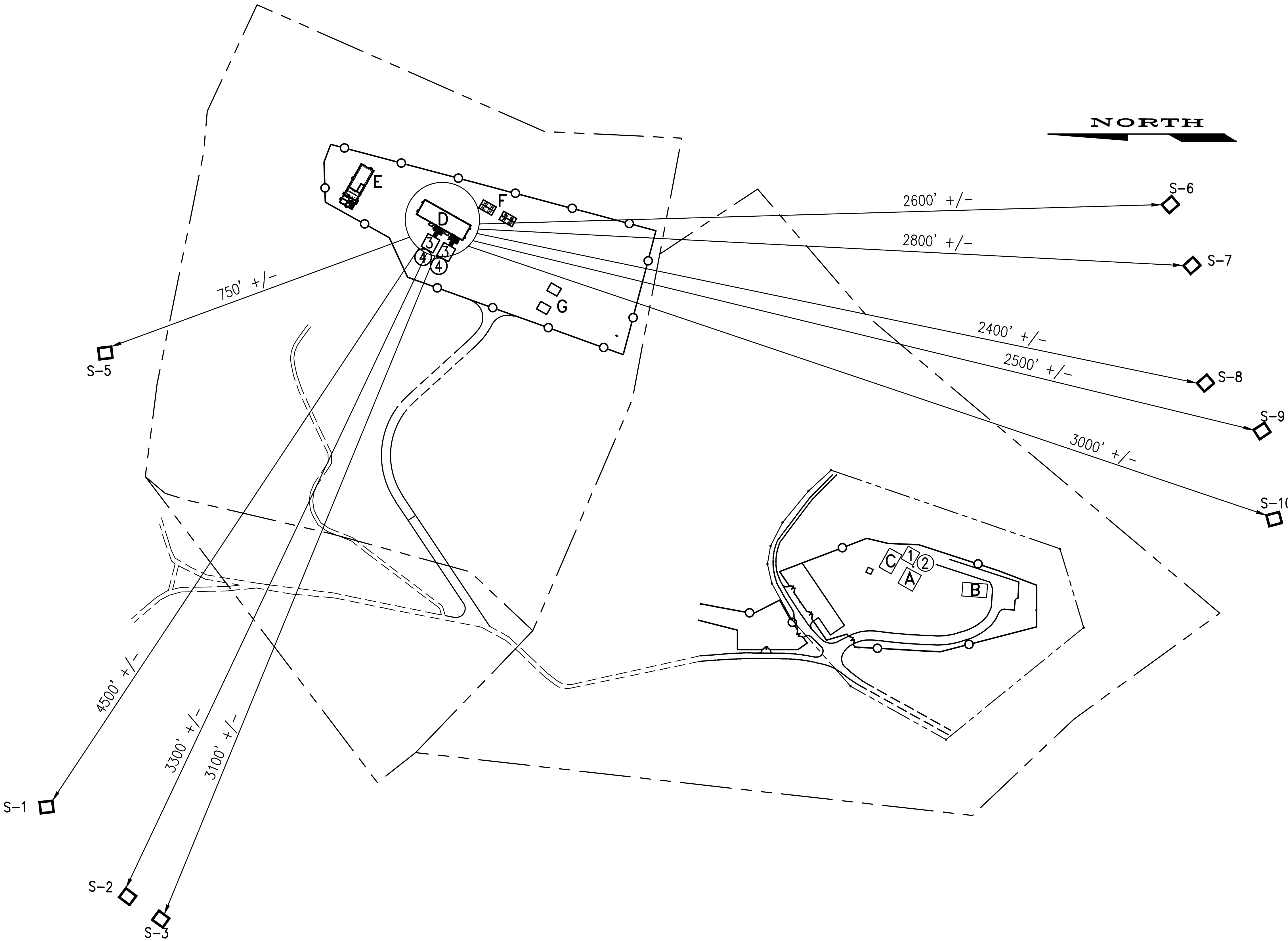
(2) Predicted $L_{dn}$ sound levels from the station discharge gas cooler to be installed in 2016 for the Monroe to Cornwell Project. Refer to ENC Report No. 522 dated 26 January 2015.

(3) Baseline $L_{dn}$ sound levels for the addition of two (2) Solar Titan Model 130S turbine compressor units at the Mockingbird Hill Compressor Station. These $L_{dn}$ sound levels are the sum of the existing station and ambient $L_{dn}$ sound levels and the predicted $L_{dn}$ sound levels from the station discharge gas cooler to be installed in 2016 for the Monroe to Cornwell Project.

(4) Predicted $L_{dn}$ sound levels from two (2) Solar Titan Model 130S turbine compressor units with Noise Control Measures/Specifications Nos. 1 through 12 installed.

(5) Predicted total $L_{dn} = 10 \log (10^{(\text{Baseline } L_{dn}/10)} + 10^{(\text{Predicted } L_{dn}/10)})$.

(6) Predicted increase of the baseline station $L_{dn}$ sound levels due to two (2) Solar Titan Model 130S turbine compressor units at the Mockingbird Hill Compressor Station.




## LEGEND:

- —·—·— = PROPERTY LINE
- —o—— = FENCE LINE
- A = EXISTING COMPRESSOR BLDG. W/7800 HP TURBINE
- B = EXIST. AUX. BLDG.
- C = EXISTING GAS COOLERS (2016)
- 1 = EXISTING AIR INTAKE
- 2 = EXISTING EXHAUST
- D = PROPOSED NEW COMPRESSOR BLDG. W/2 20,500 HP UNITS (2018)
- E = PROPOSED NEW AUX. BLDG.
- F = PROPOSED NEW GAS COOLERS
- G = PROPOSED NEW REGULATION BLDGS.
- 3 = PROPOSED AIR INTAKES
- 4 = PROPOSED NEW EXHAUSTS

S-1 = RESIDENCE 4500'±
S-2 = COMPANY HOUSE 3300'±
S-3 = COMPANY HOUSE 3100'±

S-5 = RESIDENCE 750'±
S-6 = RESIDENCE 2600'±
S-7 = RESIDENCE 2800'±
S-8 = RESIDENCE 2400'±
S-9 = RESIDENCE 2500'±
S-10 = RESIDENCE 3000'±

| SYM. | DATE | BY | REVISION DESCRIPTION | PRJ/TSK | APP. |
|---|---|---|---|---|---|
| 6a | 07/15/15 | PWB | REVISED UNIT HORSEPOWER INFORMATION | | |
| 5a | 03/04/15 | PWB | REVISED RECEPTORS AND DISTANCES PER BILL BIKER | | |
| 4a | 2/19/15 | PWB | PROPOSED NEW 40,035 HP – 2018 CONST. | | |
| 3a | 09/12/14 | PWB | PROPOSED ADDTION OF GAS COOLERS – REVISED PER BILL BIKER – 2016 CONST. | | |
| 2 | 2/13/04 | PWB | PROPOSED REPLACEMENT OF 5000 HP TURBINE WITH 7800 HP TURBINE – 2005 CONST. | | |

| SCALE 1" = 300' | DATE |
|---|---|
| DRAWN | |
| CHECKED | |
| APP. FOR BID | |
| APP. FOR CONST. | |
| TOWN: | COUNTY: |

**Dominion Transmission, Inc.**
445 West Main St. Clarksburg, West Virginia 26301 / Phone: (304) 623-8000

FOR: SUPPLY HEADER PROJECT
TITLE: SOUND STUDY PLOT PLAN
MOCKINGBIRD HILL COMPRESSOR STATION

| DIR: | | GROUP | DWG. NO. | REV. |
|---|---|---|---|---|
| FILE: | PRJ/TSK: | ST | X3398 | 6a |

Appendix III
Page 770

STX3398.dwg 07/15/15 17:13 PWB

**ENVIRONMENTAL NOISE CONTROL**
260 Arbor Street
Lunenburg, MA 01462-1458
(978) 582-9204
Fax (978) 582-7102

17 July 2015

Dominion Transmission, Inc.
445 West Main Street
PO Box 2450
Clarksburg, West Virginia 26302-2450

Attention: Mr. Justin P. Ammons

Subject: ENC Report No. 538:
Sound Survey and Noise Analysis for the Addition of Two Turbine Compressor Units at the J.B. Tonkin Compressor Station for the Supply Header Project
ENC Project No. 14-19

Dear Mr. Ammons:

Environmental Noise Control (ENC) has conducted a sound survey of the existing compressor station with the reciprocating engine compressor unit operating on 15 January 2015 and a noise analysis of the sound levels due to the addition of two Solar Taurus Model 70S turbine compressor units at the J.B. Tonkin Compressor Station for the Supply Header Project.

## 1.0 PURPOSE

The purpose of the property line and noise sensitive area (NSA) sound survey was to document the existing station sound levels for the environmental report to be submitted for the addition of two Solar Taurus Model 70S turbine compressor units at the J.B. Tonkin Compressor Station. Presented below are descriptions of the existing J.B. Tonkin Compressor Station, the sound survey measurement locations, and the measured existing station sound levels.

## 1.1 STATION DESCRIPTION

The J.B. Tonkin Compressor Station is located at 4885 Hills Church Road, Murrysville, Pennsylvania. This compressor station consists of one Cooper-Bessemer Model 12V330 reciprocating engine compressor unit that was installed in 1985. It is planned that the two additional turbine compressor units will be installed in a new acoustically insulated compressor building immediately west of the existing compressor building.

The land uses surrounding the station are residential, farm fields and forested areas. Residences are located approximately 1300 feet northwest, 1200 and 1400 feet north-northeast, 1100 and 1300 feet northeast, 1000 and 1500 feet east-northeast, 600, 650 and 1300 feet east, 650 feet east-southeast, 450 and 1000 feet southeast, 1400 feet south, 2100 feet west-southwest and 1700 feet west. (See the attached plot plan drawing). The house at 375 feet northwest (S1) was for sale and has been purchased by Dominion Transmission, Inc. and is now a company house.

## 1.2 SOUND SURVEY MEASUREMENTS

Sound survey measurements were conducted at the property lines and nearest NSAs on 15 January 2015 with the existing reciprocating engine compressor unit operating at 100% of full rated load and speed. The weather conditions were a temperature of 21 degrees F increasing to 24 degrees F, a relative humidity of 75% decreasing to 70%, clear skies and light northeast winds (1 to 2 mph) changing to northwest winds (1 to 4 mph).

The J.B. Tonkin Station was audible at NSAs S3 through S15, and property line locations P1 through P4. At NSAs S2, S16, and S17, the compressor station was not audible. Other audible sound sources (ambient sound sources) were birds, traffic, aircraft, dogs barking, wind blowing through the trees, a heat pump at S9 and water flowing in the creek at S16.

At the property lines, the measured station $L_{eq}$ sound levels ranged from 41.5 to 57.0 dBA with calculated $L_{dn}$ sound levels ranging from 47.9 to 63.4 dBA. The measured station $L_{eq}$ sound levels ranged from 36.3 to 62.1 dBA at the NSAs (S3 through S15) where the J.B. Tonkin Compressor station was audible with calculated $L_{dn}$ sound levels ranging from 42.7 to 68.5 dBA. The station $L_{dn}$ sound levels of 60.0 dBA at S10, 68.5 dBA at S11, 57.2 dBA at S12 and 58.9 dBA at S14 although over the FERC limit of an $L_{dn}$ sound level of 55 dBA are grandfathered since the existing compressor unit was installed in 1985. At the three NSAs (S2, S16, and S17) where the J.B. Tonkin Compressor Station was not audible, the measured ambient $L_{eq}$ sound levels ranged from 32.1 to 38.0 dBA with calculated $L_{dn}$ sound levels of 38.5 to 44.4 dBA.

## 2.0 NOISE ANALYSIS OF THE TWO ADDITIONAL TURBINE COMPRESSOR UNITS FOR THE J.B. TONKIN COMPRESSOR STATION

The J.B. Tonkin Compressor Station Addition sound levels will be the sound levels from two Solar Taurus Model 70S turbine compressor units with the noise control materials installed. Presented below are the predicted sound levels from the two additional Solar turbine compressor units, the noise control measures/specifications necessary to reduce the sound levels from these compressor units, and the total sound levels predicted after the installation of the two additional Solar turbine compressor units at the J.B. Tonkin Compressor Station.

## 2.1 PREDICTED SOUND LEVELS FROM THE TWO ADDITIONAL TURBINE COMPRESSOR UNITS

The two additional Solar Taurus Model 70S turbine compressor units have been designed so that the continuous sound from these compressor units operating at full rated load will not exceed a day-night sound level ($L_{dn}$) of 55 dBA at the NSAs around the station. These two turbine compressor units have also been designed so that the sum of the $L_{dn}$ sound levels from these compressor units and the existing station and ambient $L_{dn}$ sound levels are below the FERC limit at NSAs S2 through S9, S13, S15, S16 and S17 where the existing station and ambient $L_{dn}$ sound levels are below 55 dBA. At the four NSAs (S10, S11, S12 and S14) where the existing station $L_{dn}$ sound levels are above 55 dBA, these grandfathered $L_{dn}$ sound levels will not be increased due the reduction of the existing station $L_{dn}$ sound levels from the recommended installation of additional noise control measures on existing station equipment. The predicted sound levels from the two additional turbine compressor units are based upon sound level information provided by the turbine manufacturer (Solar Turbines Incorporated). Minimum dynamic insertion loss (DIL) requirements for the turbine exhaust mufflers, the turbine air intake cleaners/silencers, and the additional compressor building air handling unit, ventilation air inlet and ventilation air discharge mufflers have been specified. Specifications for minimum sound transmission loss (STC) requirements for the additional compressor building wall and roof panels, and personnel doors are included. Maximum sound levels for the air handling units, the emergency wall air inlet fans and the turbine compressor unit lube oil coolers have been specified. Also, maximum sound power levels for the turbine compressor unit gas coolers have been specified. Insulation minimum insertion loss (IL) values have been specified for the noise control insulations to be used on the turbine exhaust pipes, the turbine air intake ducts, all aboveground compressor unit suction, discharge and bypass lines, and the gas cooler inlet and outlet headers and piping.

## 2.2 NOISE CONTROL MEASURES/SPECIFICATIONS FOR THE TWO ADDITIONAL TURBINE COMPRESSOR UNITS

Implementation of the following noise control measures/specifications is necessary to ensure that the continuous sound from the two additional Solar Taurus Model 70S turbine compressor units will not exceed a day-night sound level ($L_{dn}$) of 55 dBA at the NSAs.

1. Mufflers must be installed on the exhausts of the two Solar Taurus Model 70S turbines. Each turbine exhaust muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Solar Taurus Model 70S Turbine Exhaust Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 13 | 22 | 29 | 41 | 51 | 46 | 39 | 32 | 25 |

2. The exhaust pipes of the two Solar Taurus Model 70S turbines must be acoustically insulated from the compressor building wall to the exhaust muffler flanges (including expansion joints). This acoustic pipe insulation must have minimum Insertion Loss (IL) values as follows:

Turbine Exhaust Pipe Acoustic Insulation Minimum IL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 0 | 0 | 0 | 0 | 5 | 10 | 25 | 25 | 20 |

3. Air cleaners/silencers must be installed on the air intakes of the two Solar Taurus Model 70S turbines. Each turbine air intake cleaner/silencer must have minimum Dynamic Insertion Loss (DIL) values as follows:

Solar Taurus Model 70S Turbine Air Intake Cleaner/Silencer Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 3 | 15 | 31 | 40 | 49 | 50 | 52 | 80 | 78 |

4. The air intake ducts of the two Solar Taurus Model 70S turbines must be acoustically insulated from the compressor building wall to the air cleaner housings (including expansion joints). This acoustic insulation must have minimum Insertion Loss (IL) values as follows:

Turbine Air Intake Duct Acoustic Insulation Minimum IL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 0 | 0 | 0 | 6 | 12 | 20 | 26 | 26 | 22 |

5. The wall and roof panels of the additional J.B. Tonkin Station compressor building must have a minimum Sound Transmission Class (STC) of 49 and a minimum Noise Reduction Coefficient (NRC) of 0.90. In addition, these panels must have minimum Sound Transmission Loss (TL) values as follows:

Compressor Building Wall and Roof Panel Minimum TL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 9 | 15 | 22 | 38 | 46 | 48 | 52 | 53 | 54 |

6. The additional J.B. Tonkin Station compressor building personnel doors must be insulated, metal doors with full weather-stripping. The STC rating of these doors must be a minimum of 38 as provided by CECO Medallion doors or equal. Any windows in these doors must be double glazed using minimum 1/4 inch thick glass or acrylic panels separated by a minimum 1/2 inch airspace.

7. The additional J.B. Tonkin Station compressor building equipment door must be an insulated, metal door with full weather-stripping.

8. The additional J.B. Tonkin Station compressor building must have a ventilation system installed to provide adequate cooling of the building to allow full load operation of the two additional turbine compressor units with all doors closed.

8A. The additional J.B. Tonkin Station compressor building ventilation system can have a maximum of three air handling units. The maximum A-weighted sound level from each air handling unit must not exceed 70 dBA at 3 feet when measured outside of each air handling unit in all directions with maximum octave band sound pressure levels (SPL) as follows:

Air Handling Unit Maximum SPL at 3 feet in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 92 | 89 | 79 | 71 | 64 | 60 | 55 | 54 | 54 |

8B. Ventilation air inlet mufflers must be located in the air paths between the three air handing units and the additional compressor building wall penetrations to reduce the sound from the two additional turbine compressor units that escapes through these openings. Each air handling unit muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Air Handling Unit Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |

8C. The additional J.B. Tonkin Station compressor building ventilation system can have a maximum of four emergency wall air inlet fans. The maximum A-weighted sound level from each emergency wall air inlet fan must not exceed 90 dBA at 3 feet when measured inside the compressor building without the two additional turbine compressor units operating with maximum octave band sound pressure levels (SPL) as follows:

Emergency Wall Air Inlet Fan Maximum SPL at 3 feet in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 99 | 97 | 95 | 90 | 86 | 84 | 82 | 80 | 77 |

8D. Ventilation air inlet mufflers must be located in the walls of the additional J.B. Tonkin Station compressor building directly outside of the four emergency wall air inlet fans to reduce the sound from the two additional turbine compressor units that escapes through these openings. Each ventilation air inlet muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Ventilation Air Inlet Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |

8E. The additional J.B. Tonkin Station compressor building ventilation system can have a maximum of four roof air discharge hoods with a maximum total area of 121 square feet. Ventilation air discharge mufflers must be located above the roof and under each roof air discharge hood to reduce the sound from the two additional turbine compressor units that escapes through these openings. Each ventilation air discharge muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Ventilation Air Discharge Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 3 | 9 | 17 | 25 | 39 | 46 | 45 | 40 | 25 |

9. The maximum noise from the lube oil cooler for each turbine compressor unit must not exceed an A-weighted sound level of 50 dBA at 50 feet from the centerline of the cooler with all fans running at maximum speed. Each lube oil cooler (including all fans, motors and drives) must have maximum octave band sound pressure levels (SPL) as follows:

Lube Oil Cooler Maximum SPL at 50 feet in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 54 | 61 | 58 | 51 | 46 | 43 | 39 | 35 | 30 |

10. The maximum noise from the gas cooler for each turbine compressor unit must not exceed an A-weighted sound power level of 87 dBA with all fans running at maximum speed. Each gas cooler (including all fans, motors and drives) must have maximum octave band sound power levels (PWL) as follows:

Compressor Unit Gas Cooler Maximum PWL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 92 | 93 | 92 | 89 | 84 | 82 | 76 | 70 | 64 |

11. All aboveground sections of the unit suction, discharge and bypass lines and gas cooler inlet and outlet headers and piping (including the pipe supports) of the two additional turbine compressor units must be acoustically insulated. This acoustic pipe insulation must have minimum Insertion Loss (IL) values as follows:

Piping Insulation Minimum IL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 0 | 0 | 0 | 6 | 12 | 20 | 26 | 26 | 22 |

12. The maximum A-weighted sound level from each silenced unit blowdown vent must not exceed 60 dBA at 50 feet.

## 2.3 NOISE CONTROL MEASURES/SPECIFICATIONS FOR THE EXISTING COMPRESSOR STATION

The existing grandfathered $L_{dn}$ sound levels of 60.0 dBA at S10, 68.5 dBA at S11, 57.2 dBA at S12 and 58.9 dBA at S14 were due to noise from a section of 20 inch aboveground piping east-northeast of the existing compressor building, and noise from a vertical pipe with attached valve and four regulator valve actuators northeast of the existing compressor building. To reduce the sound from the existing station so that the total sound levels after the installation of the two additional turbine compressor units do not exceed the existing grandfathered $L_{dn}$ sound levels at these four NSAs, the section of 20 inch aboveground piping and the vertical pipe including the valve must be acoustically insulated, and the regulator valve actuators must be enclosed in acoustically insulated enclosures as follows:

13. The section of 20 inch aboveground piping (including the pipe supports) and the vertical pipe including the valve must be acoustically insulated. This acoustic pipe insulation must have minimum Insertion Loss (IL) values as follows:

Piping Insulation Minimum IL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 0 | 0 | 0 | 6 | 12 | 20 | 26 | 26 | 22 |

14. The four regulator valve actuators must be enclosed in two acoustically insulated enclosures. The walls and roofs of these enclosures must have a minimum Sound Transmission Class (STC) of 29 and a minimum Noise Reduction Coefficient (NRC) of 0.90. In addition, these panels must have minimum Sound Transmission Loss (TL) values as follows:

Valve Actuator Enclosure Wall and Roof Panel Minimum TL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 2 | 8 | 13 | 18 | 23 | 31 | 38 | 40 | 40 |

15. The personnel doors for the regulator valve actuator enclosures must be insulated, metal doors with full weather-stripping. Any windows in these doors must be double glazed using minimum 1/4 inch thick glass or acrylic panels separated by a minimum 1/2 inch airspace.

16. Acoustic louvers must be located in any ventilation openings in the walls of the regulator valve actuator enclosures to reduce the sound from the regulator valve actuators that escapes through these openings. Each acoustic louver must have minimum Sound Transmission Loss (TL) values as follows:

Acoustic Louver Minimum TL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 2 | 6 | 9 | 10 | 11 | 15 | 19 | 17 | 16 |

## 2.4 PREDICTED J.B. TONKIN COMPRESSOR STATION SOUND LEVELS

The octave band sound pressure levels and A-weighted sound levels predicted at the nearest NSA (S14) approximately 450 feet southeast of the two additional turbine compressor units are shown in Table 1.0. Sheets 1 through 3 of this table present the calculations that predict the sound levels from the two additional Solar Taurus Model 70S turbine compressor units at this NSA. Detailed line item descriptions are presented on Sheets 4 through 7 of this table. The attached noise control analysis indicates a predicted continuous $L_{eq}$ sound level of 44 dBA at the nearest NSA with a corresponding $L_{dn}$ sound level of 50.4 dBA. At the other NSAs approximately 600 to 2100 feet from the two additional turbine compressor units, the $L_{eq}$ sound levels are predicted to range from 28 to 42 dBA, with corresponding $L_{dn}$ sound levels ranging from 34.4 to 48.4 dBA. The predicted $L_{dn}$ sound levels from the two additional Solar turbine compressor units are below 55 dBA at all of the NSAs around the station.

Table 2.0 presents the sound levels at the NSAs around the station. Shown are:

- the existing station and ambient $L_d$, $L_n$ and $L_{dn}$ sound levels,
- the baseline station and ambient $L_{dn}$ sound levels with the aboveground piping acoustically insulated and the regulator valve actuators enclosed,
- the predicted $L_{dn}$ sound levels from the two additional Solar Taurus Model 70S turbine compressor units,
- the predicted total $L_{dn}$ sound levels resulting from summing the $L_{dn}$ sound levels from the two additional Solar Taurus Model 70S turbine compressor units with the baseline station and ambient $L_{dn}$ sound levels, and
- the predicted increase in the existing station and ambient $L_{dn}$ sound levels due to the two additional Solar Taurus Model 70S turbine compressor units.

At the NSAs (S2 through S9, S13, S15, S16, and S17) where the existing station and ambient $L_{dn}$ sound levels are below 55 dBA, the predicted total $L_{dn}$ sound levels after installation of the two additional Solar turbine compressor units range from 39.9 to 50.0 dBA. These total $L_{dn}$ sound levels are below 55 dBA at all of the NSAs around the station. At the four NSAs (S10, S11, S12 and S14) where the grandfathered station $L_{dn}$ sound levels were above 55 dBA, the predicted total $L_{dn}$ sound levels with the aboveground piping acoustically insulated and the regulator valve actuators enclosed are lower than the grandfathered station $L_{dn}$ sound levels by 1.1 to 3.9 dBA.

Sincerely yours,
ENVIRONMENTAL NOISE CONTROL

William E. Biker

William E. Biker
Principal Engineer
Noise and Vibration Control

TABLE 1.0



J.B. TONKIN COMPRESSOR STATION COMPONENT NOISE ANALYSIS
FOR TWO (2) SOLAR TAURUS MODEL 70S COMPRESSOR UNITS

Sound Pressure Levels (SPL) in dB re 20 microPa
Sound Power Levels (PWL) in dB re $10^{-12}$ watts

| | OCTAVE BAND CENTER FREQUENCIES IN Hz | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Description* | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
| 1. SPL | 91 | 94 | 91 | 95 | 97 | 93 | 87 | 80 | 67 |
| 2. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 3. = PWL | 123 | 126 | 123 | 127 | 129 | 125 | 119 | 112 | 99 |
| 4. + NF | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 5 = PWL | 126 | 129 | 126 | 130 | 132 | 128 | 122 | 115 | 102 |
| 6. – DIL | 13 | 22 | 29 | 41 | 51 | 46 | 39 | 32 | 25 |
| 7. = PWL | 113 | 107 | 97 | 89 | 81 | 82 | 83 | 83 | 77 |
| 8. SPL | 79 | 85 | 91 | 92 | 93 | 95 | 98 | 126 | 118 |
| 9. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 10. = PWL | 111 | 117 | 123 | 124 | 125 | 127 | 130 | 158 | 150 |
| 11. + NF | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 12. = PWL | 114 | 120 | 126 | 127 | 128 | 130 | 133 | 161 | 153 |
| 13. – DIL | 3 | 15 | 31 | 40 | 49 | 50 | 52 | 80 | 78 |
| 14. = PWL | 111 | 105 | 95 | 87 | 79 | 80 | 81 | 81 | 75 |
| 15. SPL | 82 | 82 | 85 | 87 | 87 | 82 | 90 | 88 | 83 |
| 16. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 17. = PWL | 114 | 114 | 117 | 119 | 119 | 114 | 122 | 120 | 115 |
| 18. + NF | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 19 = PWL | 117 | 117 | 120 | 122 | 122 | 117 | 125 | 123 | 118 |
| 20. – TL | 9 | 15 | 22 | 35 | 41 | 41 | 42 | 42 | 42 |
| 21. = PWL | 108 | 102 | 98 | 87 | 81 | 76 | 83 | 81 | 76 |
| 22. SPL | 92 | 89 | 79 | 71 | 64 | 60 | 55 | 54 | 54 |
| 23. + DT | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| 24. = PWL | 100 | 97 | 87 | 79 | 72 | 68 | 63 | 62 | 62 |
| 25. + NF | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 26. = PWL | 105 | 102 | 92 | 84 | 77 | 73 | 68 | 67 | 67 |

TABLE 1.0 (cont.) 

J.B. TONKIN COMPRESSOR STATION COMPONENT NOISE ANALYSIS
FOR TWO (2) SOLAR TAURUS MODEL 70S COMPRESSOR UNITS

Sound Pressure Levels (SPL) in dB re 20 microPa
Sound Power Levels (PWL) in dB re $10^{-12}$ watts

| | OCTAVE BAND CENTER FREQUENCIES IN Hz | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Description* | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
| 27. SPL | 103 | 101 | 103 | 105 | 105 | 100 | 108 | 106 | 101 |
| 28. + AT | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| 29. = PWL | 107 | 105 | 107 | 109 | 109 | 104 | 112 | 110 | 105 |
| 30. – DIL | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |
| 31. = PWL | 103 | 93 | 87 | 86 | 67 | 56 | 67 | 72 | 84 |
| 32. SPL | 99 | 97 | 95 | 90 | 86 | 84 | 82 | 80 | 77 |
| 33. + DT | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| 34. = PWL | 107 | 105 | 103 | 98 | 94 | 92 | 90 | 88 | 85 |
| 35. + NF | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| 36. = PWL | 113 | 111 | 109 | 104 | 100 | 98 | 96 | 94 | 91 |
| 37. – DIL | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |
| 38. = PWL | 109 | 99 | 89 | 81 | 58 | 50 | 51 | 56 | 70 |
| 39. SPL | 103 | 101 | 103 | 105 | 105 | 100 | 108 | 106 | 101 |
| 40. + AT | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| 41. = PWL | 111 | 109 | 111 | 113 | 113 | 108 | 116 | 114 | 109 |
| 42. – DIL | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |
| 43. = PWL | 107 | 97 | 91 | 90 | 71 | 60 | 71 | 76 | 88 |
| 44. SPL | 101 | 97 | 98 | 99 | 99 | 94 | 102 | 100 | 95 |
| 45. + AT | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| 46. = PWL | 112 | 108 | 109 | 110 | 110 | 105 | 113 | 111 | 106 |
| 47. – DIL | 3 | 9 | 17 | 25 | 39 | 46 | 45 | 40 | 25 |
| 48. = PWL | 109 | 99 | 92 | 85 | 71 | 59 | 68 | 71 | 81 |
| 49. SPL | 54 | 61 | 58 | 51 | 46 | 43 | 39 | 35 | 30 |
| 50. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 51. = PWL | 86 | 93 | 90 | 83 | 78 | 75 | 71 | 67 | 62 |
| 52. + NF | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 53. = PWL | 89 | 96 | 93 | 86 | 81 | 78 | 74 | 70 | 65 |

J.B. TONKIN COMPRESSOR STATION COMPONENT NOISE ANALYSIS
FOR TWO (2) SOLAR TAURUS MODEL 70S COMPRESSOR UNITS

Sound Pressure Levels (SPL) in dB re 20 microPa
Sound Power Levels (PWL) in dB re $10^{-12}$ watts

| Description* | | OCTAVE BAND CENTER FREQUENCIES IN Hz | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
| 54. PWL | | 92 | 93 | 92 | 89 | 84 | 82 | 76 | 70 | 64 |
| 55. + NF | | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 56. = PWL | | 95 | 96 | 95 | 92 | 87 | 85 | 79 | 73 | 67 |
| 57. PWL | | 118 | 112 | 104 | 98 | 90 | 88 | 88 | 87 | 90 |
| 58. – DT | | 51 | 51 | 51 | 52 | 52 | 52 | 53 | 56 | 59 |
| 59. = SPL | 44 dBA | 67 | 61 | 53 | 46 | 38 | 36 | 35 | 31 | 31 |
| 60. Ldn | 50.4 dBA | | | | | | | | | |

* Detailed Line Item Descriptions are listed on Sheets 4 through 7.

TABLE 1.0 (cont.)



Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 through 3

1. Unmuffled exhaust sound pressure levels (SPL) at 50 feet and 90 degrees to stack axis of one (1) Solar Taurus Model 70S turbine. These data were supplied by Solar Turbines Incorporated.

2. Distance Term (DT) to convert turbine exhaust SPL at 50 feet to turbine exhaust sound power levels (PWL) of one (1) Solar Taurus Model 70S turbine.

3. Unmuffled exhaust PWL of one (1) Solar Taurus Model 70S turbine.

4. Number Factor (NF) to account for two (2) Solar Taurus Model 70S turbines.

5. Unmuffled exhaust PWL of two (2) Solar Taurus Model 70S turbines.

6. Specified Dynamic Insertion Loss (DIL) of the turbine exhaust muffler for each Solar Taurus Model 70S turbine (Noise Control Measure/Specification No. 1).

7. Muffled exhaust PWL of two (2) Solar Taurus Model 70S turbines: result of lines 1 through 6.

8. Unmuffled intake SPL at 50 feet of one (1) Solar Taurus Model 70S turbine. These data were supplied by Solar Turbines Incorporated.

9. Distance Term (DT) to convert turbine intake SPL at 50 feet to turbine intake PWL of one (1) Solar Taurus Model 70S turbine.

10. Unmuffled intake PWL of one (1) Solar Taurus Model 70S turbine.

11. Number Factor (NF) to account for two (2) Solar Taurus Model 70S turbines.

12. Unmuffled intake PWL of two (2) Solar Taurus Model 70S turbines.

13. Specified Dynamic Insertion Loss (DIL) of the turbine intake air cleaner/silencer for each Solar Taurus Model 70S turbine (Noise Control Measure/Specification No. 3).

14. Muffled intake PWL of two (2) Solar Taurus Model 70S turbines: result of lines 8 through 13.

15. Casing SPL at 50 feet of one (1) Solar Taurus Model 70S turbine. These data were supplied by Solar Turbines Incorporated.

16. Distance Term (DT) to convert turbine casing SPL at 50 feet to turbine casing PWL of one (1) Solar Taurus Model 70S turbine.

Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 through 3

17. Casing PWL of one (1) Solar Taurus Model 70S turbine.

18. Number Factor (NF) to account for two (2) Solar Taurus Model 70S turbines.

19. Casing PWL of two (2) Solar Taurus Model 70S turbines.

20. Composite sound transmission loss (TL) of additional compressor building walls, roof and doors using the specified STC 49 wall and roof panels, the specified STC 38 personnel doors and the specified equipment door (Noise Control Measures/Specifications Nos. 5, 6, and 7).

21. PWL of compressor building radiated casing noise from two (2) Solar Taurus Model 70S turbines: result of lines 15 through 20.

22. Specified maximum SPL at three (3) feet for one (1) air handling unit (Noise Control Measure/Specification No. 8A).

23. Distance Term (DT) to convert maximum air handling unit SPL at three (3) feet to PWL.

24. PWL of one (1) air handling unit.

25. Number Factor (NF) to account for three (3) air handling units.

26. PWL of three (3) air handling units: result of lines 22 through 25.

27. SPL calculated at the walls of the additional compressor building with two (2) Solar Taurus Model 70S turbines operating. This is based upon the amount of sound absorption provided by the compressor building walls and roof, and upon the distance from the turbines to the building walls.

28. Conversion of SPL in line 27 to represent PWL of turbine casing noise at the three (3) air handling unit penetrations in the additional compressor building walls.

29. PWL of the turbine casing noise at the three (3) air handling unit penetrations in the additional compressor building walls.

30. Specified Dynamic Insertion Loss (DIL) of each air handling unit muffler (Noise Control Measure/Specification No. 8B).

31. PWL of the turbine casing noise at the three (3) air handling unit penetrations in the additional compressor building walls with mufflers: result of lines 27 through 30.

TABLE 1.0 (cont.)



Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 through 3

32. Specified maximum SPL for one (1) emergency wall air inlet fan at 3 feet (Noise Control Measure/Specification No. 8C).

33. Distance Term (DT) to convert maximum emergency wall air inlet fan SPL at 3 feet to PWL.

34. PWL of one (1) emergency wall air inlet fan.

35. Number Factor (NF) to account for four (4) emergency wall air inlet fans.

36. PWL of four (4) emergency wall air inlet fans.

37. Specified Dynamic Insertion Loss (DIL) of each ventilation air inlet muffler (Noise Control Measure/Specification No. 8D).

38. PWL of the four (4) emergency wall air inlet fans in the additional compressor building walls with mufflers: result of lines 32 through 37.

39. SPL calculated at the walls of the additional compressor building with two (2) Solar Taurus Model 70S turbines operating. This is based upon the amount of sound absorption provided by the compressor building walls and roof, and upon the distance from the turbines to the building walls.

40. Conversion of SPL in line 39 to represent PWL of turbine casing noise at the four (4) wall fan openings in the additional compressor building walls.

41. PWL of the turbine casing noise at the four (4) wall fan openings in the additional compressor building walls.

42. Specified Dynamic Insertion Loss (DIL) of each ventilation air inlet muffler (Noise Control Measure/Specification No. 8D).

43. PWL of the turbine casing noise at the four (4) wall fan openings in the additional compressor building walls with mufflers: result of lines 39 through 42.

44. SPL calculated under the roof of the additional compressor building with two (2) Solar Taurus Model 70S turbines operating. This is based upon the amount of sound absorption provided by the compressor building walls and roof, and upon the distance from the turbines to the building roof.

45. Conversion of SPL in line 44 to represent PWL of turbine casing noise at four (4) roof air discharge openings in the additional compressor building roof.

Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 through 3

46. PWL of the turbine casing noise at the four (4) roof air discharge openings in the additional compressor building roof.

47. Specified Dynamic Insertion Loss (DIL) of each ventilation air discharge muffler (Noise Control Measure/Specification No. 8E).

48. PWL of the turbine casing noise at the four (4) roof air discharge openings in the additional compressor building roof with mufflers: result of lines 44 through 47.

49. Specified maximum SPL at 50 feet from one (1) turbine compressor unit lube oil cooler with the fan(s) running at maximum speed (Noise Control Measure/Specification No. 9).

50. Distance Term (DT) to convert maximum turbine compressor unit lube oil cooler SPL at 50 feet to PWL.

51. PWL of one (1) turbine compressor unit lube oil cooler with the fan(s) running at maximum speed.

52. Number Factor (NF) to account for two (2) turbine compressor unit lube oil coolers.

53. PWL of two (2) turbine compressor unit lube oil coolers with the fan(s) running at maximum speed: result of lines 49 through 52.

54. Specified maximum PWL of one (1) turbine compressor unit gas cooler with the fan(s) running at maximum speed (Noise Control Measure/Specification No. 10).

55. Number Factor (NF) to account for two (2) turbine compressor unit gas coolers.

56. PWL of two (2) turbine compressor unit gas coolers with the fan(s) running at maximum speed: results of lines 54 and 55.

57. Total PWL of two (2) Solar Taurus Mode 70S turbine compressor units: logarithmic sum of lines 7, 14, 21, 26, 31, 38, 43, 48, 53, and 56.

58. Distance Term (DT) to convert total PWL to SPL at the nearest NSA (S14) 450 feet east of the two (2) additional Solar turbine compressor units.

59. Energy equivalent sound level ($L_{eq}$) at the nearest NSA (S14) 450 feet east of the two (2) additional Solar turbine compressor units at the J.B. Tonkin Compressor Station: result of lines 57 and 58.

60. Day-night sound level ($L_{dn}$) at the nearest NSA (S14) 450 feet east of the two (2) additional Solar turbine compressor units at the J.B. Tonkin Compressor Station.

TABLE 2.0

NOISE QUALITY ANALYSIS FOR THE J.B.TONKIN COMPRESSOR STATION

Existing Station and Ambient Sound Levels, Baseline Station Sound Levels, Predicted Sound Levels from the Two Additional Solar Turbine Compressor Units and Predicted Total Sound Levels

A-Weighted Sound Levels in dBA re 20 microPa

| Location/ Description | Distance/ Direction | | Existing [(1)] | | Baseline | Predicted | Total | Noise [(5)] |
|---|---|---|---|---|---|---|---|---|
| | | $L_{eq}(d)$ | $L_{eq}(n)$ | $L_{dn}$ | $L_{dn}$ [(2)] | $L_{dn}$ [(3)] | $L_{dn}$ [(4)] | Increase |
| P1. Prop Line | 650 ft N | 41.9 | 41.9 | 48.3 | 47.3 | 47.4 | 50.4 | 2.1 |
| P2. Prop Line | 425 ft E | 57.0 | 57.0 | 63.4 | 60.4 | 51.4 | 60.9 | –2.5 |
| P3. Prop Line | 900 ft S | 43.1 | 43.1 | 49.5 | 47.5 | 43.4 | 48.9 | –0.6 |
| P4. Prop Line | 650 ft SW | 41.5 | 41.5 | 47.9 | 46.9 | 47.4 | 50.2 | 2.3 |
| S1. Co. House | 375 ft NW | 50.5 | 50.5 | 56.9 | 54.9 | 53.4 | 57.2 | 0.3 |
| S2. Residence | 1300 ft NW | 38.0 | 38.0 | 44.4 | 44.4 | 39.4 | 45.6 | 1.2 |
| S3. Residence | 1400 ft NNE | 36.3 | 36.3 | 42.7 | 41.7 | 38.4 | 43.4 | 0.7 |
| S4. Residence | 1200 ft NNE | 39.7 | 39.7 | 46.1 | 45.1 | 40.4 | 46.4 | 0.3 |
| S5. Residence | 1300 ft NE | 38.6 | 38.6 | 45.0 | 44.0 | 39.4 | 45.3 | 0.3 |

TABLE 2.0 (cont.)

NOISE QUALITY ANALYSIS FOR THE J.B.TONKIN COMPRESSOR STATION

Existing Station and Ambient Sound Levels, Baseline Station Sound Levels, Predicted Sound Levels from the Two Additional Solar Turbine Compressor Units and Predicted Total Sound Levels

A-Weighted Sound Levels in dBA re 20 microPa

| Location/ Description | Distance/ Direction | | Existing [1] | | Baseline | Predicted | Total | Noise [5] |
|---|---|---|---|---|---|---|---|---|
| | | $L_{eq}(d)$ | $L_{eq}(n)$ | $L_{dn}$ | $L_{dn}$ [2] | $L_{dn}$ [3] | $L_{dn}$ [4] | Increase |
| S6. Residence | 1100 ft NE | 45.0 | 45.0 | 51.4 | 49.4 | 41.4 | 50.0 | –1.4 |
| S7. Residence | 1000 ft ENE | 42.0 | 42.0 | 48.4 | 46.4 | 42.4 | 47.9 | –0.5 |
| S8. Residence | 1500 ft ENE | 37.4 | 37.4 | 43.8 | 41.8 | 38.4 | 43.4 | –0.4 |
| S9. Residence | 1300 ft E | 41.5 | 41.5 | 47.9 | 45.9 | 39.4 | 46.8 | –1.1 |
| S10. Residence | 650 ft E | 53.6 | 53.6 | 60.0 | 57.0 | 47.4 | 57.5 | –2.5 |
| S11. Residence | 600 ft E | 62.1 | 62.1 | 68.5 | 64.5 | 48.4 | 64.6 | –3.9 |
| S12. Residence | 650 ft ESE | 50.8 | 50.8 | 57.2 | 55.2 | 47.4 | 55.9 | –1.3 |
| S13. Residence | 1000 ft SE | 42.9 | 42.9 | 49.3 | 48.3 | 42.4 | 49.3 | 0.0 |
| S14. Residence | 450 ft SE | 52.5 | 52.5 | 58.9 | 56.9 | 50.4 | 57.8 | –1.1 |

TABLE 2.0 (cont.)



NOISE QUALITY ANALYSIS FOR THE J.B.TONKIN COMPRESSOR STATION

Existing Station and Ambient Sound Levels, Baseline Station Sound Levels, Predicted Sound Levels from the Two Additional Solar Turbine Compressor Units and Predicted Total Sound Levels

A-Weighted Sound Levels in dBA re 20 microPa

| Location/ Description | Distance/ Direction | | Existing (1) | | Baseline | Predicted | Total | Noise (5) |
|---|---|---|---|---|---|---|---|---|
| | | $L_{eq}(d)$ | $L_{eq}(n)$ | $L_{dn}$ | $L_{dn}$ (2) | $L_{dn}$ (3) | $L_{dn}$ (4) | Increase |
| S15. Residence | 1400 ft S | 38.8 | 38.8 | 45.2 | 43.2 | 38.4 | 44.4 | –0.8 |
| S16. Residence | 2100 ft WSW | 32.1 | 32.1 | 38.5 | 38.5 | 34.4 | 39.9 | 1.4 |
| S17. Residence | 1700 ft W | 33.2 | 33.2 | 39.6 | 39.6 | 37.4 | 41.6 | 2.0 |

TABLE 2.0 (cont.) Sheet 4 of 4

NOISE QUALITY ANALYSIS FOR THE J.B. TONKIN COMPRESSOR STATION

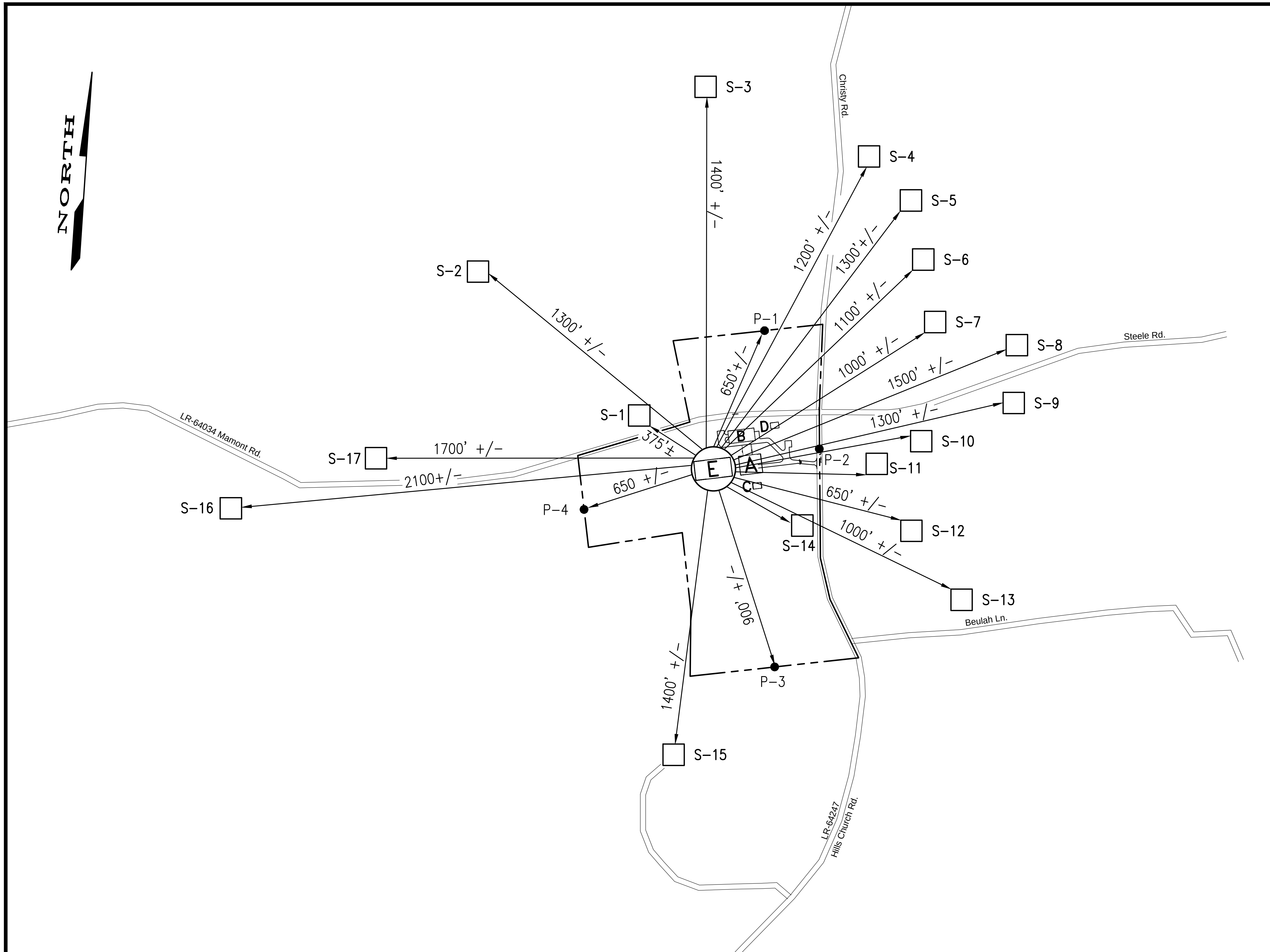
(1) Existing station and ambient $L_{eq}$ sound levels measured on 15 January 2015 with the reciprocating engine compressor unit operating at the J.B. Tonkin Compressor Station, and calculated $L_{dn}$ sound levels. The J.B. Tonkin Station was audible at NSAs S3 through S15, and property line locations P1 through P4. At NSAs S2, S16, and S17, the compressor station was not audible. Other audible sound sources (ambient sound sources) birds, traffic, aircraft, dogs barking, and wind blowing through the trees, a heat pump at S9 and water flowing in the creek at S16.

(2) Baseline station and ambient $L_{dn}$ sound levels for the installation of two additional Solar turbine compressor units at the J.B. Tonkin Compressor Station. The existing station $L_{dn}$ sound levels will be reduced at the thirteen NSAs (S3 through S15) and the property line locations (P1 through P4) where the existing station is audible after the aboveground piping is acoustically insulated and the regulator valve actuators are enclosed (Noise Control Measures/ Specifications Nos. 13 through 16). The baseline $L_{dn}$ sound levels are the existing ambient $L_{dn}$ sound levels at the three NSAs (S2, S16 and S17) where the existing station was not audible during the sound survey.

(3) Predicted $L_{dn}$ sound levels from the two additional Solar turbine compressor units with Noise Control Measures/Specifications Nos. 1 through 12 installed.

(4) Predicted total $L_{dn} = 10 \log (10^{(\text{Baseline } L_{dn}/10)} + 10^{(\text{Predicted } L_{dn}/10)})$.

(5) Predicted increase of the existing station and ambient $L_{dn}$ sound levels due to the two additional Solar turbine compressor units at the J.B. Tonkin Compressor Station with the existing station aboveground piping acoustically insulated and the regulator valve actuators enclosed (Noise Control Measures/Specifications Nos. 13 through 16).




# LEGEND:

— — — = APPROX. PROPERTY LINE

A = EXISTING COMPRESSOR BLDG. W/(1) 6000 HP UNIT

B = EXISTING AUX. BLDG.

C = EXISTING GAS COOLER

D = EXISTING REGULATORS

E = PROPOSED COMPRESSOR BLDG. W/(2) 10,915 HP UNITS (2018)

S-1 = CO. HOUSE 375'±
S-2 = RESIDENCE 1300'±
S-3 = RESIDENCE 1400'±
S-4 = RESIDENCE 1200'±
S-5 = RESIDENCE 1300'±
S-6 = RESIDENCE 1100'±
S-7 = RESIDENCE 1000'±
S-8 = RESIDENCE 1500'±
S-9 = RESIDENCE 1300'±
S-10 = RESIDENCE 650'±
S-11 = RESIDENCE 600'±
S-12 = RESIDENCE 650'±
S-13 = RESIDENCE 1000'±
S-14 = RESIDENCE 450'±
S-15 = RESIDENCE 1400'±
S-16 = RESIDENCE 2100'±
S-17 = RESIDENCE 1700'±
P-1 = DTI N PROPERTY LINE 650'±
P-2 = DTI E PROPERTY LINE 425'±
P-3 = DTI S PROPERTY LINE 900'±
P-4 = DTI W PROPERTY LINE 650'±

| SYM. | DATE | BY | REVISION DESCRIPTION | PRJ/TSK | APP. |
|---|---|---|---|---|---|
| h | 07/15/15 | PWB | REVISED UNIT HORSEPOWER INFORMATION | 65346.CS.JB.1 | |
| g | 04/16/15 | PWB | REVISED UNIT HORSEPOWER INFORMATION | 65346.CS.JB.1 | |
| f | 04/06/15 | PWB | REVISED LEGEND PER BILL BIKER | 65346.CS.JB.1 | |
| e | 03/04/15 | PWB | REVISED RECEPTORS AND DISTANCES PER BILL BIKER | | |
| d | 02/27/15 | PWB | ADDED TWO 13220 HP UNITS (SUPPLY HEADER PROJECT 2018) | 55656.1.1.25 | |

| SCALE | 1" = 500' | DATE |
|---|---|---|
| DRAWN | PWB | 03/07/13 |
| CHECKED | | |
| APP. FOR BID | | |
| APP. FOR CONST. | | |
| TOWN: | FRANKLIN | COUNTY WESTMORELAND, PA |

**Dominion Transmission, Inc.**
445 West Main St. Clarksburg, West Virginia 26301 / Phone: (304) 623-8000

FOR: SUPPLY HEADER PROJECT (2018)

TITLE: SOUND STUDY PLOT PLAN
J. B. TONKIN COMPRESSOR STATION

DIR: COMPSTA\JB TONKIN | GROUP: ST | DWG. NO.: X1532 | REV.: h

FILE: STX1532 | PRJ/TSK: 55656.1.1.25



STX1532.dwg 07/15/15 17:14 PWB

**ENVIRONMENTAL NOISE CONTROL**
260 Arbor Street
Lunenburg, MA 01462-1458
(978) 582-9204
Fax (978) 582-7102

2 April 2015

Dominion Transmission, Inc.
445 West Main Street
PO Box 2450
Clarksburg, West Virginia 26302-2450

Attention: Mr. Justin P. Ammons

Subject: ENC Report No. 529:
Sound Survey and Noise Analysis for the Addition of One Turbine Compressor Unit at the Crayne Compressor Station for the Supply Header Project
ENC Project No. 14-18

Dear Mr. Ammons:

Environmental Noise Control (ENC) has conducted a sound survey of the existing compressor station with all three Solar Taurus Model 60S turbine compressor units operating on 13 January 2015 and a noise analysis of the sound levels due to the addition of one Solar Taurus Model 60S turbine compressor unit at the Crayne Compressor Station for the Supply Header Project.

## 1.0 PURPOSE

The purpose of the noise sensitive area (NSA) sound survey was to document the existing station sound levels for the environmental report to be submitted for the addition of one Solar Taurus Model 60S turbine compressor unit at the Crayne Compressor Station. Presented below are descriptions of the existing Crayne Compressor Station, the sound survey measurement locations and the measured existing station sound levels.

### 1.1 STATION DESCRIPTION

The Crayne Compressor Station is located in Greene County, Pennsylvania north of State Route 188 and about two miles east of Interstate 79. This compressor station consists of the Solar Taurus Model 60S turbine compressor units (Units 1 and 2) that were installed in 2004 and the Solar Taurus Model 60S turbine compressor unit (Unit 3) that was installed in 2014. Unit 3 was installed in a new compressor building approximately 520 feet east-southeast of the Units 1 and 2 compressor building. It is planned that the additional turbine compressor unit will be installed in an addition at the east end of the Unit 3 compressor building.

The land uses surrounding the station are residential, industrial and farm fields. A Texas Eastern compressor station and measurement and regulation (M&R) station are adjacent to the west property line, and the EQT Pratt Compressor Station is approximately 2500 feet southwest. The nearest noise sensitive areas (NSAs) around the station are all residences. These residences are approximately 1700 feet north-northwest, 1450 feet north, 900 and 1100 feet north-northeast, 800 feet northeast, 500 feet east-northeast, 450 and 1800 feet east-southeast, 3100 feet southeast, 3600 feet south-southeast, 1900 and 2000 feet south-southwest (two residences with a no trespassing sign at the driveway), 1900 and 2500 feet southwest and 3200 feet west of the Unit 4 compressor building addition (see the attached plot plan drawing). The company office building (S7) that was located to the east has been torn down.

## 1.2 SOUND SURVEY MEASUREMENTS

Sound survey measurements were conducted on 13 January 2015 with all three existing Solar Taurus Model 60 turbine compressor units operating at an average of 96% of full rated load. The weather conditions were a temperature of 21 degrees F increasing to 23 degrees F, a relative humidity of 65% decreasing to 50%, mostly clear skies and light northeast winds (0 to 2 mph). The Crayne compressor station was only audible at NSAs S5, S6 and S8, and property line location S17. The compressor station was not audible at NSAs S1 through S4, and S9 through S16.

The $L_{eq}$ sound levels were measured to the greatest extent possible when sound sources other than the Crayne Compressor Station were not audible. Audible sources of sound other than the Crayne Compressor Station (ambient sound sources) were traffic, birds, dogs barking, cows, aircraft, wind blowing through the trees, a water fountain at S10, power line tree trimming at S11, water flowing in the stream at S16 and the Texas Eastern compressor station at S14, S15, and S17. The station sound levels at S12 and S13 have been projected from the $L_{eq}$ sound levels measured at the south-southwest property corner (S17) since access to these two NSAs was denied by a no trespassing sign at the driveway.

At the nearest NSAs (S1 through S6 and S8 through S16), the measured and projected $L_{eq}$ sound levels with the three existing turbine compressor units operating ranged from 32.3 to 46.2 dBA with calculated $L_{dn}$ sound levels ranging from 38.7 to 52.6 dBA.

# 2.0 NOISE ANALYSIS OF THE ADDITIONAL TURBINE COMPRESSOR UNIT FOR THE CRAYNE COMPRESSOR STATION

The Crayne Compressor Station Addition sound levels will be the sound levels from the additional Solar Taurus Model 60S turbine compressor unit with the noise control materials installed. Presented below are the predicted sound levels from the additional Solar turbine compressor unit, the noise control measures/specifications necessary to reduce the sound levels from this compressor unit and the total sound levels predicted after the installation of the additional Solar turbine compressor unit at the Crayne Compressor Station.

## 2.1 PREDICTED SOUND LEVELS FROM THE ADDITIONAL TURBINE COMPRESSOR UNIT

The additional Solar Taurus Model 60S turbine compressor unit has been designed so that the continuous sound from this compressor unit operating at full rated load will not exceed a day-night sound level ($L_{dn}$) of 55 dBA at the NSAs around the station. This turbine compressor unit has also been designed so that the sum of the $L_{dn}$ sound levels from this compressor unit and the existing station and ambient $L_{dn}$ sound levels are below the FERC limit at the NSAs. The predicted sound levels from the additional turbine compressor unit are based upon sound level information provided by the turbine manufacturer (Solar Turbines Incorporated). Minimum dynamic insertion loss (DIL) requirements for the turbine exhaust muffler, turbine air intake cleaner/silencer, and compressor building addition air handling unit, ventilation air inlet and ventilation air discharge mufflers have been specified. Specifications for minimum sound transmission loss (STC) requirements for the compressor building wall and roof panels, and personnel doors are included. Maximum sound levels for the air handling unit, the emergency wall air inlet fans, and the turbine compressor unit lube oil cooler have been specified. Also, maximum sound power levels for the turbine compressor unit gas cooler have been specified. Insulation minimum insertion loss (IL) values have been specified for the noise control insulations to be used on the turbine exhaust pipe, the turbine air intake duct, all aboveground compressor unit suction, discharge and bypass lines, and gas cooler inlet and outlet headers and piping.

## 2.2 NOISE CONTROL MEASURES/SPECIFICATIONS FOR THE ADDITIONAL TURBINE COMPRESSOR UNIT

Implementation of the following noise control measures/specifications is necessary to ensure that the continuous sound from the additional Solar Taurus Model 60S turbine compressor unit will not exceed a day-night sound level ($L_{dn}$) of 55 dBA at the NSAs.

1. A muffler must be installed on the exhaust of the Solar Taurus Model 60S turbine. This turbine exhaust muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Solar Taurus Model 60S Turbine Exhaust Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 13 | 22 | 29 | 41 | 51 | 46 | 39 | 32 | 25 |

2. The exhaust pipe of the Solar Taurus Model 60S turbine must be acoustically insulated from the compressor building wall to the exhaust muffler flange (including expansion joints). This acoustic pipe insulation must have minimum Insertion Loss (IL) values as follows:

Turbine Exhaust Pipe Acoustic Insulation Minimum IL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 0 | 0 | 0 | 0 | 5 | 10 | 25 | 25 | 20 |

3. An air cleaner/silencer must be installed on the air intake of the Solar Taurus Model 60S turbine. This turbine air intake cleaner/silencer must have minimum Dynamic Insertion Loss (DIL) values as follows:

Solar Taurus Model 60S Turbine Air Intake Cleaner/Silencer Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 3 | 15 | 29 | 39 | 46 | 51 | 54 | 80 | 73 |

4. The air intake duct of the Solar Taurus Model 60S turbine must be acoustically insulated from the building wall to the air cleaner housing (including expansion joints). This acoustic insulation must have minimum Insertion Loss (IL) values as follows:

Turbine Air Intake Duct Acoustic Insulation Minimum IL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 0 | 0 | 0 | 6 | 12 | 20 | 26 | 26 | 22 |

5. The wall and roof panels of the Crayne Station compressor building addition must have a minimum Sound Transmission Class (STC) of 49 and a minimum Noise Reduction Coefficient (NRC) of 0.90. In addition, these panels must have minimum Sound Transmission Loss (TL) values as follows:

Compressor Building Addition Wall and Roof Panel Minimum TL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 9 | 15 | 22 | 38 | 46 | 48 | 52 | 53 | 54 |

6. The Crayne Station compressor building addition personnel doors must be insulated, metal doors with full weather-stripping. The STC rating of these doors must be a minimum of 38 as provided by CECO Medallion doors or equal. Any windows in these doors must be double glazed using minimum 1/4 inch thick glass or acrylic panels separated by a minimum 1/2 inch airspace.

7. The Crayne Station compressor building addition must have a ventilation system installed to provide adequate cooling of the building to allow full load operation of the additional turbine compressor unit with all doors closed.

7A. The Crayne Station compressor building addition ventilation system can have a maximum of one air handling unit. The maximum A-weighted sound level from this air handling unit must not exceed 70 dBA at 3 feet when measured outside of each air handling unit in all directions with maximum octave band sound pressure levels (SPL) as follows:

Air Handling Unit Maximum SPL at 3 feet in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 92 | 89 | 79 | 71 | 64 | 60 | 55 | 54 | 54 |

7B. A ventilation air inlet muffler must be located in the air path between the air handing unit and the compressor building addition wall penetration to reduce the sound from the additional turbine compressor unit that escapes through this opening. This air handling unit muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Air Handling Unit Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |

7C. The Crayne Station compressor building addition ventilation system can have a maximum of two emergency wall air inlet fans. The maximum A-weighted sound level from each emergency wall air inlet fan must not exceed 90 dBA at 3 feet when measured inside the compressor building without the additional turbine compressor unit operating with maximum octave band sound pressure levels (SPL) as follows:

Emergency Wall Air Inlet Fan Maximum SPL at 3 feet in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 99 | 97 | 95 | 90 | 86 | 84 | 82 | 80 | 77 |

7D. Ventilation air inlet mufflers must be located in the walls of the Crayne Station compressor building addition directly outside of the two emergency wall air inlet fans to reduce the sound from the additional turbine compressor unit that escapes through these openings. Each ventilation air inlet muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Ventilation Air Inlet Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |

7E. The Crayne Station compressor building addition ventilation system can have a maximum of two roof air discharge hoods with a maximum total area of 61 square feet. Ventilation air discharge mufflers must be located above the roof and under each roof air discharge hood to reduce the sound from the additional turbine compressor unit that escapes through these openings. Each ventilation air discharge muffler must have minimum Dynamic Insertion Loss (DIL) values as follows:

Ventilation Air Discharge Muffler Minimum DIL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 3 | 9 | 17 | 25 | 39 | 46 | 45 | 40 | 25 |

8. The maximum noise from the lube oil cooler for the additional turbine compressor unit must not exceed an A-weighted sound level of 50 dBA at 50 feet from the centerline of the cooler with all fans running at maximum speed. This lube oil cooler (including all fans, motors and drives) must have maximum octave band sound pressure levels (SPL) as follows:

Lube Oil Cooler Maximum SPL at 50 feet in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 54 | 61 | 58 | 51 | 46 | 43 | 39 | 35 | 30 |

9. The maximum noise from the gas cooler for the additional turbine compressor unit must not exceed an A-weighted sound power level of 87 dBA with all fans running at maximum speed. This gas cooler (including all fans, motors and drives) must have maximum octave band sound power levels (PWL) as follows:

Compressor Unit Gas Cooler Maximum PWL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 92 | 93 | 92 | 89 | 84 | 82 | 76 | 70 | 64 |

10. All aboveground sections of the unit suction, discharge and bypass lines and gas cooler inlet and outlet headers and piping (including the pipe supports) of the additional turbine compressor unit must be acoustically insulated. This acoustic pipe insulation must have minimum Insertion Loss (IL) values as follows:

Acoustic Pipe Insulation Minimum IL in dB
Octave Band Center Frequency in Hz

| | 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| dB | 0 | 0 | 0 | 6 | 12 | 20 | 26 | 26 | 22 |

11. The maximum A-weighted sound level from the silenced unit blowdown vent must not exceed 60 dBA at 50 feet.

## 2.3 PREDICTED CRAYNE COMPRESSOR STATION SOUND LEVELS

The octave band sound pressure levels and the A-weighted sound levels predicted at the nearest NSA (S8) approximately 450 feet east-southeast of the additional turbine compressor unit are shown in Table 1.0. Sheets 1 and 2 of this table present the calculations that predict the sound level from the additional Solar Taurus Model 60S turbine compressor unit at this NSA. Detailed line item descriptions are presented on Sheets 3 through 6 of this table. The attached noise control analysis indicates a predicted continuous $L_{eq}$ sound level of 39 dBA at the nearest NSA with a corresponding $L_{dn}$ sound level of 45.4 dBA. At the other NSAs (S1 through S6 and S9 through S16) approximately 500 to 3600 feet from the additional turbine compressor unit, the $L_{eq}$ sound levels are predicted to range from 17 to 38 dBA, with corresponding $L_{dn}$ sound levels ranging from 23.4 to 44.4 dBA. The predicted $L_{dn}$ sound levels from the additional Solar Taurus Model 60S turbine compressor unit are below 55 dBA at all of the NSAs around the station.

Table 2.0 presents the sound levels at the NSAs around the station. Shown are:

- the existing station and ambient $L_d$, $L_n$ and $L_{dn}$ sound levels,
- the predicted $L_{dn}$ sound levels from the additional Solar Taurus Model 60S turbine compressor unit,
- the predicted total $L_{dn}$ sound levels resulting from summing the $L_{dn}$ sound levels from the additional Solar Taurus Model 60S turbine compressor unit with the existing $L_{dn}$ sound levels, and
- the predicted increase in the existing station and ambient $L_{dn}$ sound levels due to the additional Solar Taurus Model 60S turbine compressor unit.

At the NSAs, the predicted total $L_{dn}$ sound levels range from 38.9 to 53.1 dBA. These total $L_{dn}$ sound levels are below 55 dBA at all of the NSAs around the station.

Sincerely yours,
ENVIRONMENTAL NOISE CONTROL

William E. Biker

William E. Biker
Principal Engineer
Noise and Vibration Control

TABLE 1.0 Sheet 1 of 6

CRAYNE COMPRESSOR STATION
COMPONENT NOISE ANALYSIS FOR ONE (1) ADDITIONAL
SOLAR TAURUS MODEL 60S TURBINE COMPRESSOR UNIT

Sound Pressure Levels (SPL) in dB re 20 microPa
Sound Power Levels (PWL) in dB re $10^{-12}$ watts

| Description* | Octave Band Center Frequency in Hz 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|
| 1. SPL | 88 | 91 | 88 | 91 | 95 | 87 | 80 | 72 | 64 |
| 2. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 3. = PWL | 120 | 123 | 120 | 123 | 127 | 119 | 112 | 104 | 96 |
| 4. – DIL | 13 | 22 | 29 | 41 | 51 | 46 | 39 | 32 | 25 |
| 5. = PWL | 107 | 101 | 91 | 82 | 76 | 73 | 73 | 72 | 71 |
| 6. SPL | 76 | 82 | 88 | 89 | 90 | 92 | 95 | 120 | 112 |
| 7. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 8. = PWL | 108 | 114 | 120 | 121 | 122 | 124 | 127 | 152 | 144 |
| 9. – DIL | 3 | 15 | 29 | 39 | 46 | 51 | 54 | 80 | 73 |
| 10. = PWL | 105 | 99 | 91 | 82 | 76 | 73 | 73 | 72 | 71 |
| 11. SPL | 81 | 81 | 84 | 86 | 86 | 81 | 79 | 78 | 79 |
| 12. + DT | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 13. = PWL | 113 | 113 | 116 | 118 | 118 | 113 | 111 | 110 | 111 |
| 14. – TL | 9 | 15 | 22 | 35 | 41 | 41 | 42 | 42 | 42 |
| 15. = PWL | 104 | 98 | 94 | 83 | 77 | 72 | 69 | 68 | 69 |
| 16. SPL | 92 | 89 | 79 | 71 | 64 | 60 | 55 | 54 | 54 |
| 17. + DT | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| 18. = PWL | 100 | 97 | 87 | 79 | 72 | 68 | 63 | 62 | 62 |
| 19. SPL | 99 | 97 | 99 | 101 | 101 | 96 | 94 | 93 | 94 |
| 20. + AT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21. = PWL | 99 | 97 | 99 | 101 | 101 | 96 | 94 | 93 | 94 |
| 22. – DIL | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |
| 23. = PWL | 95 | 85 | 79 | 78 | 59 | 48 | 49 | 55 | 73 |
| 24. SPL | 99 | 97 | 95 | 90 | 86 | 84 | 82 | 80 | 77 |
| 25. + DT | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |

Sheet 2 of 6

TABLE 1.0 (cont.)
CRAYNE COMPRESSOR STATION
COMPONENT NOISE ANALYSIS FOR ONE (1) ADDITIONAL
SOLAR TAURUS MODEL 60S TURBINE COMPRESSOR UNIT

Sound Pressure Levels (SPL) in dB re 20 microPa
Sound Power Levels (PWL) in dB re $10^{-12}$ watts

| Description* | | Octave Band Center Frequency in Hz 31.5 | 63 | 125 | 250 | 500 | 1000 | 2000 | 4000 | 8000 |
|---|---|---|---|---|---|---|---|---|---|---|
| 26. = PWL | | 107 | 105 | 103 | 98 | 94 | 92 | 90 | 88 | 85 |
| 27. + NF | | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 28. = PWL | | 110 | 108 | 106 | 101 | 97 | 95 | 93 | 91 | 88 |
| 29. – DIL | | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |
| 30. = PWL | | 106 | 96 | 86 | 78 | 55 | 47 | 48 | 53 | 67 |
| 31. SPL | | 99 | 97 | 99 | 101 | 101 | 96 | 94 | 93 | 94 |
| 32. + AT | | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| 33. = PWL | | 104 | 102 | 104 | 106 | 106 | 101 | 99 | 98 | 99 |
| 34. – DIL | | 4 | 12 | 20 | 23 | 42 | 48 | 45 | 38 | 21 |
| 35. = PWL | | 100 | 90 | 84 | 83 | 64 | 53 | 54 | 60 | 78 |
| 36. SPL | | 97 | 93 | 94 | 95 | 95 | 90 | 88 | 87 | 88 |
| 37. + AT | | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| 38. = PWL | | 105 | 101 | 102 | 103 | 103 | 98 | 96 | 95 | 96 |
| 39. – DIL | | 3 | 9 | 17 | 25 | 39 | 46 | 45 | 40 | 25 |
| 40. = PWL | | 102 | 92 | 85 | 78 | 64 | 52 | 51 | 55 | 71 |
| 41. SPL | | 54 | 61 | 58 | 51 | 46 | 43 | 39 | 35 | 30 |
| 42. + DT | | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 43. = PWL | | 86 | 93 | 90 | 83 | 78 | 75 | 71 | 67 | 62 |
| 44. PWL | | 92 | 93 | 92 | 89 | 84 | 82 | 76 | 70 | 64 |
| 45. PWL | | 113 | 106 | 100 | 93 | 87 | 84 | 80 | 78 | 81 |
| 46. – DT | | 51 | 51 | 51 | 52 | 52 | 52 | 53 | 56 | 59 |
| 47. = SPL | 39 dBA | 62 | 55 | 49 | 41 | 35 | 32 | 27 | 22 | 22 |
| 48. Ldn | 45.4 dBA | | | | | | | | | |

* Detailed Line Item Descriptions are listed on Sheets 3 through 6.

TABLE 1.0 (cont.)



Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 and 2

1. Unmuffled exhaust sound pressure levels (SPL) at 50 feet and 90 degrees to stack axis of one (1) Solar Taurus Model 60S turbine. These data were supplied by Solar Turbines Incorporated.

2. Distance Term (DT) to convert turbine exhaust SPL at 50 feet to turbine exhaust sound power levels (PWL) of one (1) Solar Taurus Model 60S turbine.

3. Unmuffled exhaust PWL of one (1) Solar Taurus Model 60S turbine.

4. Specified Dynamic Insertion Loss (DIL) of the turbine exhaust muffler for the Solar Taurus Model 60S turbine (Noise Control Measure/Specification No. 1).

5. Muffled exhaust PWL of one (1) Solar Taurus Model 60S turbine: result of lines 1 through 4.

6. Unmuffled intake SPL at 50 feet of one (1) Solar Taurus Model 60S turbine. These data were supplied by Solar Turbines Incorporated.

7. Distance Term (DT) to convert turbine intake SPL at 50 feet to turbine intake PWL of one (1) Solar Taurus Model 60 turbine.

8. Unmuffled intake PWL of one (1) Solar Taurus Model 60S turbine.

9. Specified Dynamic Insertion Loss (DIL) of the turbine intake air cleaner/silencer for the Solar Taurus Model 60S turbine (Noise Control Measure/Specification No. 3).

10. Muffled intake PWL of one (1) Solar Taurus Model 60S turbine: result of lines 6 through 9.

11. Casing SPL at 50 feet of one (1) Solar Taurus Model 60S turbine. These data were supplied by Solar Turbines Incorporated.

12. Distance Term (DT) to convert turbine casing SPL at 50 feet to turbine casing PWL of one (1) Solar Taurus Model 60S turbine.

13. Casing PWL of one (1) Solar Taurus Model 60S turbine.

TABLE 1.0 (cont.) Sheet 4 of 6

Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 and 2 (cont.)

14. Composite sound transmission loss (TL) of the compressor building walls, roof and doors using the specified STC 49 wall and roof panels and the specified STC 38 personnel doors (Noise Control Measures/Specifications Nos. 5 and 6).

15. PWL of compressor building radiated casing noise from one (1) Solar Taurus Model 60S turbine: result of lines 11 through 14.

16. Specified maximum SPL at three (3) feet for one (1) air handling unit (Noise Control Measure/Specification No. 7A).

17. Distance Term (DT) to convert maximum air handling unit SPL at three (3) feet to PWL.

18. PWL of one (1) air handling unit: results of lines 16 and 17.

19. SPL calculated at the walls of the compressor building addition with one (1) Solar Taurus Model 60S turbine operating. This is based upon the amount of sound absorption provided by the compressor building walls and roof, and upon the distance from the turbine to the building walls.

20. Conversion of SPL in line 19 for PWL of the turbine casing noise at one (1) air handling unit penetration in the compressor building addition walls.

21. PWL of the turbine casing noise at one (1) air handling unit penetration in the compressor building addition walls.

22. Specified Dynamic Insertion Loss (DIL) of the air handling unit muffler (Noise Control Measure/Specification No. 7B).

23. PWL of the turbine casing noise at one (1) air handling unit penetration in the compressor building addition walls with muffler: result of lines 19 through 22.

24. Specified maximum SPL for one (1) emergency wall air inlet fan at 3 feet (Noise Control Measure/Specification No. 7C).

25. Distance Term (DT) to convert maximum emergency wall air inlet fan SPL at 3 feet to PWL.

Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 and 2 (cont.)

26. PWL of one (1) emergency wall air inlet fan.

27. Number Factor (NF) to account for two (2) emergency wall air inlet fans.

28. PWL of two (2) emergency wall air inlet fans.

29. Specified Dynamic Insertion Loss (DIL) of each ventilation air inlet muffler (Noise Control Measure/Specification No. 7D).

30. PWL of the two (2) emergency wall air inlet fans in the compressor building addition walls with mufflers: result of lines 24 through 29.

31. SPL calculated at the walls of the compressor building addition with one (1) Solar Taurus Model 60S turbine operating. This is based upon the amount of sound absorption provided by the compressor building walls and roof, and upon the distance from the turbine to the building walls.

32. Conversion of SPL in line 31 for PWL of the turbine casing noise at the two (2) emergency wall air inlet fan openings in the compressor building addition walls.

33. PWL of the turbine casing noise at the two (2) emergency wall air inlet fan openings in the compressor building addition walls.

34. Specified Dynamic Insertion Loss (DIL) of each ventilation air inlet muffler (Noise Control Measure/Specification No. 7D).

35. PWL of the turbine casing noise at the two (2) emergency wall air inlet fan openings in the Units 3 and 4 compressor building walls with mufflers: result of lines 31 through 34.

36. SPL calculated under the roof of the compressor building addition with one (1) Solar Taurus Model 60S turbine operating. This is based upon the amount of sound absorption provided by the compressor building walls and roof, and upon the distance from the turbine to the building roof.

37. Conversion of SPL in line 36 to represent PWL of turbine casing noise at the two (2) roof air discharge openings in the compressor building addition roof.

TABLE 1.0 (cont.) Sheet 6 of 6

Detailed Line Item Descriptions
To Support Noise Analysis on Sheets 1 and 2 (cont.)

38. PWL of the turbine casing noise at the two (2) roof air discharge openings in the compressor building addition roof.

39. Specified Dynamic Insertion Loss (DIL) of each ventilation air discharge muffler (Noise Control Measure/Specification No. 7E).

40. PWL of the turbine casing noise at the two (2) roof air discharge openings in the compressor building addition roof with mufflers: result of lines 36 through 39.

41. Specified maximum SPL at 50 feet from one (1) turbine compressor unit lube oil cooler with the fan(s) running at maximum speed (Noise Control Measure/Specification No. 8).

42. Distance Term (DT) to convert maximum turbine compressor unit lube oil cooler SPL at 50 feet to PWL.

43. PWL of one (1) turbine compressor unit lube oil cooler with the fan(s) running at maximum speed: result of lines 41 and 42.

44. Specified maximum PWL of one (1) compressor unit gas cooler with the fan(s) running at maximum speed (Noise Control Measure/Specification No. 9).

45. Total PWL of one (1) Solar Taurus Model 60 turbine compressor unit: logarithmic sum of lines 5, 10, 15, 18, 23, 30, 35, 40, 43, and 44.

46. Distance Term (DT) to convert total PWL to SPL at the nearest NSA (S8) 450 feet east-southeast of one (1) Solar Taurus Model 60 turbine compressor unit.

47. Energy equivalent sound level ($L_{eq}$) at the nearest NSA (S8) 450 feet east-southeast of one (1) Solar Taurus Model 60S turbine compressor unit at the Crayne Compressor Station: result of lines 45 and 46.

48. Day-night sound level ($L_{dn}$) at the nearest NSA (S8) 450 feet east-southeast of one (1) Solar Taurus Model 60S turbine compressor unit at the Crayne Compressor Station.

TABLE 2.0



NOISE QUALITY ANALYSIS FOR THE CRAYNE COMPRESSOR STATION

Existing Station and Ambient Sound Levels, Predicted Sound Levels from One Additional Solar Taurus Turbine Compressor Unit and Predicted Total Sound Levels

A-Weighted Sound Levels in dBA re 20 microPa

| Location/ Description | Distance/ Direction | Existing (1) $L_{eq}(d)$ | $L_{eq}(n)$ | $L_{dn}$ | Predicted $L_{dn}$ (2) | Total $L_{dn}$ (3) | Noise (4) Increase |
|---|---|---|---|---|---|---|---|
| S1. Residence | 1700 ft NNW | 40.1 | 40.1 | 46.5 | 32.4 | 46.7 | 0.2 |
| S2. Residence | 1450 ft N | 37.2 | 37.2 | 43.6 | 33.4 | 44.0 | 0.4 |
| S3. Residence | 1100 ft NNE | 36.0 | 36.0 | 42.4 | 36.4 | 43.4 | 1.0 |
| S4. Residence | 900 ft NNE | 35.3 | 35.3 | 41.7 | 38.4 | 43.4 | 1.7 |
| S5. Residence | 800 ft NE | 39.0 | 39.0 | 45.4 | 40.4 | 46.6 | 1.2 |
| S6. Residence | 500 ft ENE | 44.2 | 44.2 | 50.6 | 44.4 | 51.5 | 0.9 |
| S8. Residence | 450 ft ESE | 45.9 | 45.9 | 52.3 | 45.4 | 53.1 | 0.8 |
| S9. Residence | 1800 ft ESE | 43.7 | 43.7 | 50.1 | 31.4 | 50.2 | 0.1 |
| S10. Residence | 3100 ft SE | 38.8 | 38.8 | 45.2 | 25.4 | 45.2 | 0.0 |
| S11. Residence | 3600 ft SSE | 36.2 | 36.2 | 42.6 | 23.4 | 42.7 | 0.1 |
| S12. Residence | 1900 ft SSW | 43.4 | 43.4 | 49.8 | 31.4 | 49.9 | 0.1 |
| S13. Residence | 2000 ft SSW | 42.9 | 42.9 | 49.3 | 30.4 | 49.4 | 0.1 |
| S14. Residence | 1900 ft SW | 46.2 | 46.2 | 52.6 | 31.4 | 52.6 | 0.0 |
| S15. Residence | 2500 ft SW | 40.2 | 40.2 | 46.6 | 27.4 | 46.7 | 0.1 |
| S16. Residence | 3200 ft W | 32.3 | 32.3 | 38.7 | 24.4 | 38.9 | 0.2 |
| S17. Prop Corner | 850 ft SSW | 50.9 | 50.9 | 57.3 | 39.4 | 57.4 | 0.1 |

TABLE 2.0 (cont.) Sheet 2 of 2

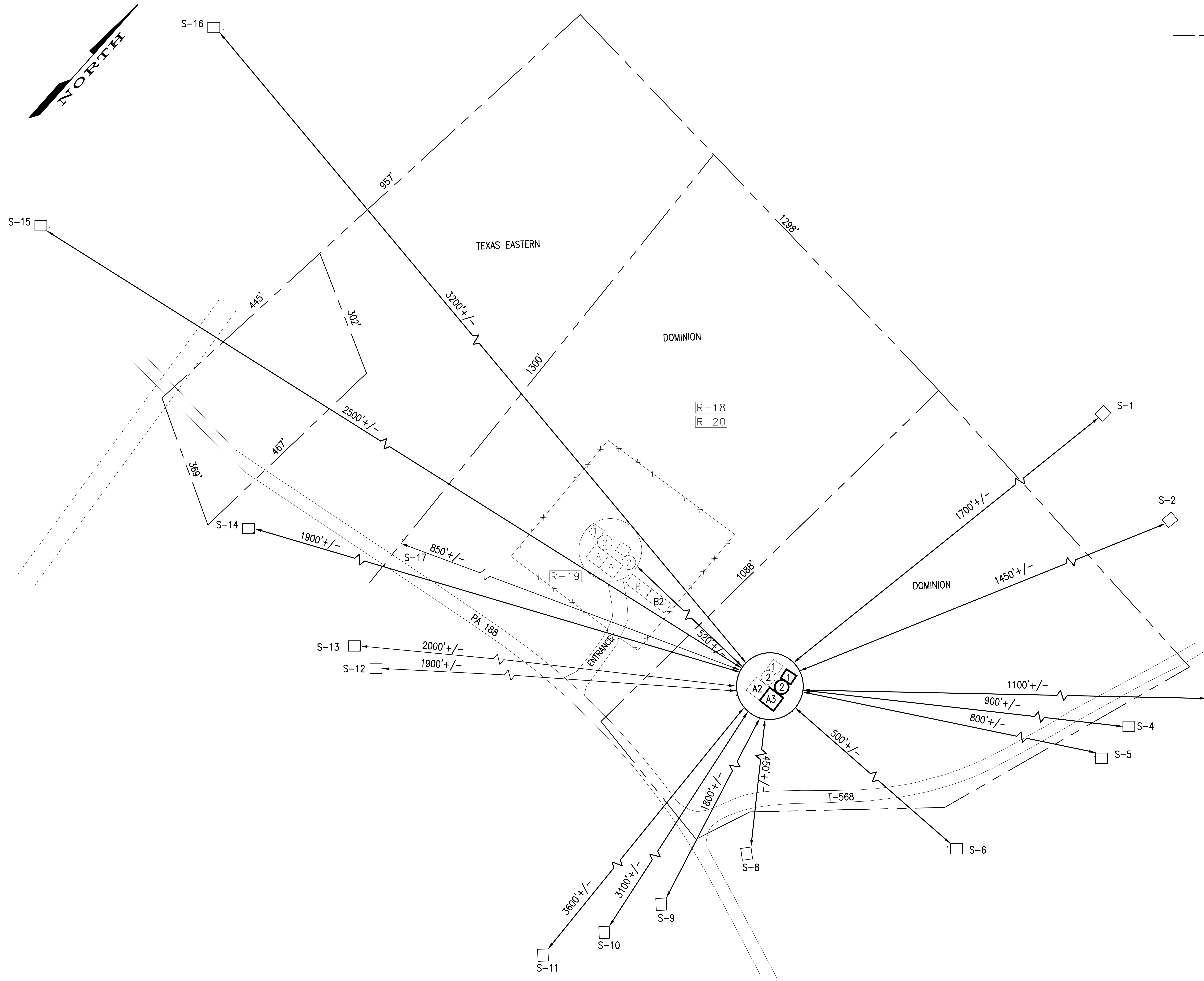
NOISE QUALITY ANALYSIS FOR THE CRAYNE COMPRESSOR STATION

(1) Existing station and ambient $L_{eq}$ sound levels measured on 13 January 2015 with all three turbine compressor unit operating at the Crayne Compressor Station, and calculated $L_{dn}$ sound levels. The Crayne compressor station was only audible at NSAs S5, S6 and S8, and property line location S17. The compressor station was not audible at NSAs S1 through S4, and S9 through S16.The $L_{eq}$ sound levels were measured to the greatest extent possible when sound sources other than the Crayne Compressor Station were not audible. Audible sources of sound other than the Crayne Compressor Station (ambient sound sources) were traffic, birds, dogs barking, cows, aircraft, wind blowing through the trees, a water fountain at S10, power line tree trimming at S11, water flowing in the stream at S16 and the Texas Eastern compressor station at S14, S15, and S17.

(2) Predicted $L_{dn}$ sound levels from the additional Solar Taurus Model 60S turbine compressor unit with Noise Control Measures/Specifications Nos. 1 through 11 installed.

(3) Predicted total $L_{dn} = 10 \log (10^{(\text{Existing } L_{dn}/10)} + 10^{(\text{Predicted } L_{dn}/10)})$.

(4) Predicted increase of the existing station and ambient $L_{dn}$ sound levels due to the additional Solar Taurus Model 60S turbine compressor unit at the Crayne Compressor Station.




## LEGEND:

| | |
|---|---|
| — — — | = APPROX. PROPERTY LINE |
| -x-x-x- | = APPROX. FENCE LINE |
| A A | = EXISTING COMPRESSOR BLDG. W/(2) 7800 HP TURBINES |
| A2 | = EXISTING COMPRESSOR BLDG. W/(1) 7800 HP TURBINE (2014) |
| A3 | = PROPOSED COMPRESSOR BLDG. W/(1) 7800 HP TURBINE (2018) |
| B | = EXISTING AUX. BLDG. |
| B2 | = EXISTING AUX. BLD. EXTENSION (2014) |
| 1 | = AIR INTAKE |
| 2 | = EXHAUST |

S-1 = RESIDENCE 1700' +/-
S-2 = RESIDENCE 1450' +/-
S-3 = RESIDENCE 1100' +/-
S-4 = RESIDENCE 900' +/-
S-5 = RESIDENCE 800' +/-
S-6 = RESIDENCE 500' +/-

S-8 = RESIDENCE 450' +/-
S-9 = RESIDENCE 1800' +/-
S-10 = RESIDENCE 3100' +/-
S-11 = RESIDENCE 3600' +/-
S-12 = RESIDENCE 1900' +/-
S-13 = RESIDENCE 2000' +/-
S-14 = RESIDENCE 1900' +/-
S-15 = RESIDENCE 2500' +/-
S-16 = RESIDENCE 3200' +/-
S-17 = COMPANY PROPERTY CORNER
R-18 = TL-590/591 REGULATION (IN BLDG.)
R-19 = TET REGULATION (OUTSIDE)
R-20 = TET REGULATION (IN BLDG.)

| SYM. | DATE | BY | REVISION INFORMATION | PROJECT/TASK | APP. |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| | | | | | |
| e | 03/04/15 | PWB | REVISED RECEPTOR DISTANCES PER BILL BIKER | | |
| d | 02/27/15 | PWB | ADDED A3 (7800 HP) SUPPLY HEADER PROJECT (2018) | | |
| c | 09/14/12 | PWB | REVISED RECEPTOR LOCATION AND DISTANCES PER BILL BIKER | 55490.1.3 | |
| b | 09/13/12 | PWB | REVISED RECEPTOR LOCATION AND DISTANCES PER BILL BIKER | 55490.1.3 | |

SEAL

**ORIGINAL CONSTRUCTION INFORMATION**

| | | |
|---|---|---|
| PROJECT/TASK: | 55490.1.3 | |
| DRAWN: | PWB | 09/08/12 |
| CHECKED: | | |
| APP. FOR BID: | | |
| APP. FOR CONST.: | | |
| SCALE: | NONE | |

**Dominion Transmission, Inc.**
445 West Main St. Clarksburg, West Virginia 26301 / Phone (304) 623-8000

FOR: SUPPLY HEADER PROJECT

TITLE: SOUND STUDY PLOT PLAN
CRAYNE COMPRESSOR STATION

| TOWN: | COUNTY: GREENE, PA | GROUP | DWG. NO. | REV. |
|---|---|---|---|---|
| DIR/FILE: COMPSTA\CRAYNE | | ST | Y3371B | e |

STY3371B.dwg 03/04/15 08:55 PWB

# Exhibit 1

# Review of Reasonableness of $NO_x$ Emission Limits for Two Titan Turbines at Proposed Joelton, Tennessee Compressor Station

Bill Powers, P.E., Powers Engineering, San Diego, California

July 26, 2016

## I. Summary

The Tennessee Gas Pipeline Company, L.L.C.[1] (TGP) has submitted a Reasonably Available Control Technology (RACT) analysis that uses outdated and incomplete information to incorrectly conclude that an oxides of nitrogen ($NO_x$) limit of 25 ppm is RACT for the two Titan 250 turbines at the proposed Joelton Compressor Station. The Metro Nashville/Davidson County Air Pollution Control Division erroneously accepted the TGP RACT analysis with essentially no critical or independent review.

Properly determined $NO_x$ RACT for the two Titan 250 turbines is either 9 ppm $NO_x$ using advanced dry low $NO_x$ technology or 2.5 ppm $NO_x$ using selective catalytic reduction. Both of these alternatives are technically and economically feasible using a $NO_x$ RACT cost-effectiveness ceiling of $2,500/ton to $5,000/ton.

As proposed, the Joelton Compressor Station has the highest permitted $NO_x$ emission rate by far among similar compressor stations that have applied for air permits within the last two years.[2] This is the case despite Joelton Compressor Station being the only compressor station among these similar compressor stations that will be a major source of $NO_x$ emissions under the federal Title V operating permit program, for its potential to emit more than 100 tons per year.

## II. Project Description

A Part 70 air operating permit application prepared by TGP for a new natural gas compressor station in Joelton, Tennessee was received on September 15, 2015 by the Air Pollution Control Division of the Metro Nashville/Davidson County Health Department. The proposed natural gas compressor station will consist of two Solar Titan 250-30000S natural gas-fired turbines and ancillary equipment, including one small heater and a back-up internal combustion engine.[3] Table 1 lists the annual air emissions potential of the two Titan 250 turbines at the Joelton Compressor Station.

---

[1] Tennessee Gas Pipeline Company, L.L.C. is a wholly-owned subsidiary of Kinder Morgan.

[2] The one exception is a substantially smaller TGP compressor station in Kanawha County, West Virginia - Compressor Station 119A. This station, like the proposed Joelton Compressor Station, is part of TGP's Broad Run Expansion Project and has the same 25 ppm $NO_x$ limit proposed for the turbines at the Joelton Compressor Station.

[3] B. McClain – Air Pollution Control Division, Joelton Compressor Station Construction Permit Review, June 2016, pdf p. 11.

**Table 1. Draft Permit Annual Air Emissions Limits – Two Titan 250 Turbines, TGP Joelton Compressor Station**[4]

| Pollutant | Annual emission limit (tpy), 12-month rolling average |
|---|---|
| $NO_x$ | 167.4 |
| VOC | 11.5 |
| CO | 107.6 |
| $PM_{10}$ | 12.0 |
| $SO_2$ | 6.2 |

$NO_x$ = oxides of nitrogen; VOC = volatile organic compounds; CO = carbon monoxide; $PM_{10}$ = particulate matter with aerodynamic diameter less than 10 microns; $SO_2$ = sulfur dioxide.

The Joelton Compressor Station is classified as a major source under Metro Nashville/Davidson County air quality regulations, due to its potential to emit more than 100 tons per year (tpy) of $NO_x$.[5] Major sources are subject to the federal Title V operating permit program and are required to apply RACT to reduce $NO_x$ emissions.[6] RACT is the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.[7]

The proposed compressor station is not a major source under the federal Prevention of Significant Deterioration (PSD) program, which has a trigger level of 250 tpy for compressor stations as an industrial category.

## III. The Joelton Compressor Station, as Proposed, Will Add Significantly to $NO_x$ and VOC Emissions in Metro Nashville

The Joelton Compressor Station will add a significant quantity of additional $NO_x$ and VOC emissions from point sources of fuel combustion in Davidson County when the compressor station becomes operational. $NO_x$ emissions from point sources of fuel combustion will increase 22 percent, from 760 tpy to 927 tpy.[8] VOC emissions from point sources of fuel combustion will also increase 22 percent, from 52.6 tpy to 64.1 tpy.[9,10]

---

[4] Metro Nashville/Davidson County Health Department Air Pollution Control Division, *Draft/Proposed Part 70 (Title V) Operating Permit, Permit Number 70-0XXX, Tennessee Gas Pipeline Company, L.L.C. – Compressor Station 563, Joelton, TN*, June 2016, p. 13.

[5] Metro Nashville/Davidson County Health Department Division of Air Pollution Control, Regulation No. 13 - Part 70 Operating Permit Program, Section 13-1: Definitions, (p)(2), as amended December 2, 2010, p. 3.

[6] Ibid, Regulation 13-2: Applicability, (a)(1).

[7] Metropolitan Health Department Air Pollution Control Division, Regulation No. 14-1(f): Definitions.

[8] Metro Nashville/Davidson County Health Department Pollution Control Division, *Air Pollution Control – 2013 Annual Report* (publication pending), Table 1 – 2013 Davidson County Annual Emission Inventory, p. 5. 167.4 tpy/759.6 tpy = 0.22 (22 percent).

[9] Ibid. 11.5 tpy/52.6 tpy = 0.22 (22 percent).

[10] A second pipeline compressor station, Cane Ridge, has also been proposed for location in Davidson County. Cane Ridge will consist of two Titan 130 gas turbines with combined potential $NO_x$ emissions of 78.2 tpy and VOC emissions of 10.2 tpy. The proposed $NO_x$ limit for the Cane Ridge Titan 130 turbines is 25 ppm. See: Columbia Pipeline Group, *Columbia Gulf Transmission LLC, Cane Ridge Compressor Station, Air Quality Construction Permit and Initial Part 70 Operating Permit Application*, May 26, 2016, pdf pp. 16-17 and pdf pp. 26-27.

$NO_x$ and VOC are ozone precursors, meaning these are necessary ingredients, in the presence of sunlight, to form ozone in ambient air. Ozone is a lung irritant, and inhalation of ground-level ozone can trigger a range of health effects. EPA revised the primary and secondary ozone standards to 0.070 ppm in 2015, a decrease from the 2008 ozone standard of 0.075 ppm. The 2008 standards will be revoked in 2018-2019, and the 0.070 ppm standard will be incorporated into State Implementation Plans shortly thereafter.[11] Although Davidson County remains in attainment based with the 2008 ozone standard, 8-hour ozone levels have been exceeded 0.070 ppm five times in the past two years, indicating that Davidson County may face challenges achieving continuous compliance with the 0.070 ppm ozone standard, even at the current emissions rate.[12]

## IV. TGP's RACT Evaluation for the Joelton Compressor Station Was Incomplete and Inadequate

### *A. Scope of RACT Evaluation as Defined in Metro Regulation 14-3*

Metro Nashville/Davidson County Air Pollution Control Division Regulation 14-3 defines in detail the RACT analysis procedure.[13] The owner or operator of each source of $NO_x$ subject to the Regulation (except large utility boilers) must:

- Fully describe the applicable emission points and basis for estimating current and potential emissions.
- List the emission points and possible source emission points available for emission reductions.
- List each alternative nitrogen oxides control technique for each emission point such as burner modifications, process modifications, add-on control devices, etc., along with the emission reduction achievable by use of each alternative.
- List the cost of each alternative control technique, including initial costs as well as cost effectiveness (cost of control per ton of emission reduction).
- Where applicable, list regulatory requirements in other states in which identical or similar sources are subject to nitrogen oxide RACT requirement.
- Recommend the level of control considered to be RACT.

The Metro Nashville/Davidson County Health Department Air Pollution Control Division is responsible for determining whether or not the RACT demonstration is adequate to justify the RACT recommendation. This is to be accomplished by reviewing the list of alternative control techniques evaluated to ensure that all reasonable available and demonstrated control techniques were considered, by reviewing the cost analysis for reasonableness, by independently contacting

[11] EPA. "2015 Ozone NAAQS Timelines." *Ozone Pollution.* Accessed at: https://www.epa.gov/ozone-pollution/2015-ozone-naaqs-timelines
[12] Metro Nashville/Davidson County Health Department Air Pollution Control Division, *Air Pollution Control – 2013 Annual Report* (publication pending).
[13] Regulation 14-3(a) – Procedure for Determining RACT.

other air pollution control agencies and the U.S. EPA to determine what level of control is required or suggested at identical or similar sources in other areas of jurisdiction.[14]

### *B. The RACT Evaluation Conducted by TGP and Accepted by Metro Nashville/Davidson County Health Department Was Inadequate and as a Result Reached the Wrong Conclusion*

The TGP RACT evaluation included in the September 15, 2015 application concludes that a $NO_x$ limit of 25 ppm using dry low $NO_x$ combustion is RACT for the two Titan 250 turbines at the Joelton Compressor Station.[15] This application identifies the following technically feasible $NO_x$ control technologies for the two Titan 250 turbines proposed for the Joelton Compressor Station:[16]

- Selective catalytic reduction (SCR)
- Dry low $NO_x$ combustion (DLN or SoLoNO$_x$™)
- Steam/water injection
- Good operating practices

However, following the identification of these technically feasible $NO_x$ control technologies, the TGP RACT analysis is completely inadequate in its assessment of the range and cost-effectiveness of the technologically feasible controls. As a result the analysis reaches the wrong conclusion regarding RACT for the Titan turbines. The principal inadequacies of the TGP RACT evaluation are:

1. An almost exclusive reliance on the EPA's RACT/BACT/LAER Clearinghouse to evaluate $NO_x$ limits and controls for gas turbines.
2. No identification or discussion of the three different DLN $NO_x$ control levels offered by the manufacturer for the Titan turbine: 25 ppm, 15 ppm, and 9 ppm, or of $NO_x$ limits in contemporaneous Titan (or smaller) gas turbine compressor station air permit applications.
3. Reliance on generic and obsolete SCR and DLN cost data from 1990.[17]
4. No identification of an appropriate $/ton cost-effectiveness ceiling by which to compare the cost feasibility of available RACT options.

Each of these inadequacies in the TGP RACT evaluation is discussed in more detail in the following sections.

---

[14] Ibid, Regulation 14-3(b).
[15] Tennessee Gas Pipeline Company, L.L.C., *Compressor Station 563, Davidson County, Joelton, TN – MHDDPC Title V Permit Application Updates and Supplemental Information*, September 11, 2015, p. 29.
[16] Ibid, p. 26.
[17] Ibid, p. 26.

### 1. Reliance Solely on the EPA's Voluntary RACT/BACT/LAER Clearinghouse to Evaluate the Universe of $NO_x$ Limits Is Inappropriate

The RACT/BACT/LAER Clearinghouse is EPA's voluntary compilation of emission limits for a wide variety of air emission sources, including gas turbines. However, this database is known to be substantially incomplete for gas turbine applications.[18] While review of the RACT/BACT/ LAER Clearinghouse is a necessary part of a review of current $NO_x$ control levels, it is a starting point, not the entirety of the review to be undertaken. Regulation 14-3, which applies to the Metro Nashville/Davidson County Health Department reviewer, also necessarily applies to the scope of the RACT analysis conducted by the applicant: ". . . independently contacting other air pollution control agencies and the U.S. EPA to determine what level of control is required or suggested at identical or similar sources in other areas of jurisdiction."[19]

Contacting the manufacturer of the Titan turbine, Solar Turbines, Inc., should have been part of the RACT assessment process. This should have been done to: 1) collect current information on the range of $NO_x$ emission guarantees provided by Solar Turbines for its turbines in compressor drive or simple cycle power generation applications, and 2) obtain accurate, current information on the incremental cost of progressively more stringent $NO_x$ control measures on the Titan turbine.

A basic google search using the terms "*Titan compressor turbine air permit application*" would have produced multiple contemporaneous Titan compressor station (or smaller Solar Turbines models) air permit applications. A partial list of compressor station applications contemporaneous with the Joelton Compressor Station application is provided in Table 2. This basic search conducted by Powers Engineering produced numerous regional pipeline compressor station applications in the same region, several also using the Titan turbine.

The Joelton Compressor Station has the highest $NO_x$ emissions by far among these compressor station applications. This is the case despite Joelton Compressor Station being only compressor station among the six compressor stations evaluated that will be a major source of $NO_x$ emissions, for its potential to emit more than 100 tons per year, under the federal Title V air permit program.[20]

[18] N.H. Hydari et al - EnvironPlan Consulting, *Comparison of the Most Recent BACT/LAER Determinations for Combustion Turbines by State Air Pollution Control Agencies*, presented at 2002 A&WMA Annual Conference, 2002, p.2. "Only 13% of the most recent BACT/LAER determinations in this survey were included in the [RACT/BACT/LAER Clearinghouse] database."

[19] Regulation 14-3(b).

[20] As noted in Table 1, the Sabal Trail Compressor Station was classified as major source under the Title V operating permit program even though potential $NO_x$ emissions were only 46.8 tpy. A Supreme Court ruling in June 2014 vacated the rationale, based on the annual $CO_2$ emission rate, used to classify Sabal Trail as major source under the Title V air operating permit program. See Reference 2 to Table 1 for further explanation.

**Table 2. Contemporaneous Compressor Station Air Permit Applications – Comparison of Projected $NO_x$ Annual Emission Rates and Permit Requirements Applicable to Each Compressor Station**

| Permittee/project | Date of application | State | County | Attainment area status for the 8-hour ozone (2008) NAAQS | Turbine type and number | Facilitywide $NO_x$ emissions (tpy) | Title V Major Source? (>100 tpy) | PSD Major Source? (>250 tpy) |
|---|---|---|---|---|---|---|---|---|
| TGP (Kinder-Morgan)/ Joelton Compressor Station | 9/15/15 | TN | Davidson | In attainment | Titan 250 (2) | 170.2 | Y | N |
| Spectra Energy, NextEra, Duke Energy/ Sabal Trail Compressor Station | 5/30/14 | GA | Dougherty | In attainment | Titan 130 (2) | 46.8 | Y (Ref. 2) | Y (Ref. 2) |
| Dominion/ Mockingbird Hill Compressor Station | 9/16/15 | WV | Wetzel | In attainment | Titan 130 (2) | 55.5 | Y | N |
| Mountain Valley Pipeline/ Harris Compressor Station | 10/23/15 | WV | Braxton | In attainment | Titan 130 (2) | 86.7 | N | N |
| TGP (Kinder-Morgan)/ NE Energy Direct/ Supply Path Head Compressor Station | 11/1/15 | PA | Susquehanna | In attainment | Titan 130 (1)<br>Mars 100 (2) | 66.6 | N | N |
| Dominion/ Buckingham Compressor Station | 9/16/15 | VA | Buckingham | In attainment | Mars 100 (1)<br>Taurus 70 (2)<br>Centaur 50L (1) | 41.5 | N | N |

References:


1. 2008 National Ambient Air Quality Standards (NAAQS): EPA. "8-Hour Ozone (2008) Area Information." Green Book Nonattainment Areas. Accessed at: https://www3.epa.gov/airquality/greenbook/hindex.html.
2. Joelton Compressor Station: Tennessee Gas Pipeline Company , L.L.C., *Compressor Station 563, Davidson County, Joelton, TN – MHDDPC Title V Permit Application Updates and Supplemental Information*, September 11, 2015, p. 1, p.8, and Table 3, p. 4.
3. Sabal Trail Compressor Station: Trinity Consultants, *Sabal Trail Transmission – Construction and Operating Permit Application, Volume I*, May 30, 2014, p. 1-2 and p. 1-3. Note – at the time the application was filed, the projected CO2 emissions from the projected exceeded the CO2 PSD major source threshold. This triggered classification of $NO_x$ and VOC as PSD pollutants subject to BACT for exceeding the PSD Significant Emission Rate (SER) for these pollutants of 40 tpy. Subsequent to the filing of the application, on June 23, 2014, the

Supreme Court issued a decision that vacated the PSD applicability interpretation that resulted in Sabal Trail being classified as a PSD source for NOx based on $CO_2$ PSD major source status only: https://www.epa.gov/nsr/clean-air-act-permitting-greenhouse-gases.

4. Mockingbird Hill Compressor Station: Dominion Resources Services, Inc., *Construction/Major Modification (45CSR13), Mockingbird Hill Compressor Station (Facility ID#017-00003)*, September 16, 2015, p. 3, p. 16, Table 4-2, p. 17.
5. Harris Compressor Station: Trinity Consultants, *R13 Permit Application – Mountain Valley Pipeline, L.L.C. – Harris Compressor Station*, October 2015, Attachment D – Regulatory Applicability; Attachment N – Supporting Emission Calculations, Table 11.
6. Supply Path Head Compressor Station: TetraTech, Inc., *Tennessee Gas Pipeline Company, L.L.C. Northeast Energy Direct Project - Plan Approval Permit Application Supply Path Head Compressor Station*, November 2015, p. 4, Table 1, p. 9.
7. Buckingham Compressor Station: Dominion Resources Services, Inc., *Buckingham Compressor Station – Article 6 New Source Permit Application*, September 16, 2015, p. 21. The Buckingham Compressor Station is subject to state-level BACT only as it triggers state rule 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." Table 6.1, p. 24: NOx UER exemption level = 40 tpy; VOC UER exemption level = 25 tpy.

$NO_x$ limits in RACT/BACT/LAER Clearinghouse search conducted by TGP: Despite the limitations of the RACT/BACT/LAER Clearinghouse, several relevant permits with limits lower than the 25 ppm $NO_x$ limit proposed for the Titan 250 turbines at the Joelton Compressor Station are shown for turbines in compress drive or simple cycle power generation, when the RBLC search terms used by TGP are utilized (process type 16.110, small combustion turbines < 25 MW, simple cycle, natural gas fired). These permit limits, and associated $NO_x$ controls, are shown in Table 3.

**Table 3. RBLC Simple Cycle < 25 MW Turbine Permits with $NO_x$ Limits Lower than Limit Proposed for Joelton Compressor Station Titan Turbines**

| Year | State | RBLC number | Turbine application | Turbine size (MW) | Number of turbines | $NO_x$ control technology | $NO_x$ limit (@ 15% oxygen) |
|---|---|---|---|---|---|---|---|
| 2009 | WY | WY-0067 | compressor | ~10 | 2 | DLN | 15 |
| 2009 | LA | LA-0232 | compressor | ~8 | 2 | DLN | 15 |
| 2007 | MD | MD-0035 | power for electric drive compressors | 21.7 | 2 | DLN + SCR | 2.5 |
| 2003 | WA | WA-0304 | power | 22 | 7 | SCR | 9 |

Simple cycle: No heat recovery in use downstream of gas turbine to utilize heat and reduce exhaust gas temperature.
DLN - Dry Low $NO_x$; SCR – selective catalytic reduction.

Two compressor drive gas turbines permitted in Tennessee in the last decade, but not reported in the RACT/BACT/LAER Clearinghouse, are examples of the incomplete nature of Clearinghouse listings. The permit conditions for these two turbines are shown in Table 4.

**Table 4. Compressor Turbine Permits Issued in Tennessee and Not Reported to the RACT/BACT/LAER Clearinghouse**

| Initial application date | State | Turbine type | Turbine application | Turbine size (MW) | Number of turbines | $NO_x$ control technology | $NO_x$ limit (@ 15% oxygen) |
|---|---|---|---|---|---|---|---|
| 2015[21] | TN | Mars 100 | compressor | 11.4 | 1 | DLN | 15 |
| 2008[22] | TN | Titan 250 | compressor | 21.7 | 1 | DLN | 25 |

$NO_x$ and VOC limits in contemporaneous compressor station permit applications: The turbine types, turbine $NO_x$ and VOC limits, and the turbine $NO_x$ and VOC control technologies proposed in the contemporaneous compressor station permit applications are provided in Table 5. One of the listed contemporaneous applications is another TGC application, for a Titan 130 in Pennsylvania with a 9 ppm $NO_x$. TGC had to have been aware when it submitted the Joelton

[21] ANR Pipeline Company, NSR Application for Construction of Brownsville Compressor Station, Haywood County, TN, May 2015.
[22] Columbia Gulf Transmission Company, Columbia Gulf Transmission Hartsville Compressor Station (Reference No. 56-0004) - Revised Air Permit Application, February 24, 2009, pdf p. 1. Note: This Titan 250 was among the first Titan 250 turbines built, as installation of the Titan 250 did not begin until 2009. See (p. 2): https://www.vgb.org/vgbmultimedia/V04_NEU090608-p-3199.pdf.

Compressor Station air permit application in September 2015 that it would also be submitting an air application in Pennsylvania a few weeks later for a Titan turbine at the Supply Path Head Compressor Station with a proposed $NO_x$ limit of 9 ppm.

**Table 5. $NO_x$ and VOC Emission Limits in Compressor Station Air Permit Applications Contemporaneous to the TGP Joelton Compressor Station Application**

| Permittee/project/state | Date of application | Turbine type and number | $NO_x$/VOC limits (ppm) | $NO_x$/VOC control systems |
|---|---|---|---|---|
| TGP (Kinder-Morgan)/ Joelton - TN | 9/15/15 | Titan 250 (2) | $NO_x$ = 25<br>VOC = 2.5 | DLN1 |
| Spectra, NextEra, Duke / Sabal Trail - GA | 5/30/14 | Titan 130 (2) | $NO_x$ = 9<br>VOC = 2-3 | DLN3 + OxCat |
| Dominion/ Mockingbird Hill - WV | 9/16/15 | Titan 130 (2) | $NO_x$ = 9<br>VOC = 1.3 | DLN3 + OxCat |
| Mountain Valley Pipeline, L.L.C./ Harris - WV | 10/23/15 | Titan 130 (2) | $NO_x$ = 15<br>VOC = 2.5 | DLN2 |
| TGP (Kinder-Morgan)/ NE Energy Direct/ Supply Path Head - PA | 11/1/15 | Titan 130 (1)<br>Mars 100 (2) | $NO_x$ = 9<br>VOC = 1.5 | DLN3 + OxCat |
| Dominion/ Buckingham - VA | 9/16/15 | Mars 100 (1)<br>Taurus 70 (1)<br>Taurus 60 (1)<br>Centaur 50L (1) | $NO_x$ = 5<br>VOC = 1.3 | SCR + OxCat |

MW equivalent capacity of turbines listed: Titan 250 = 21.7 MW; Titan 130 = 15.0 MW; Mars 100 = 11.4 MW; Taurus 70 =8.0 MW; Centaur 50 = 4.6 MW.

The Sabal Trail, L.L.C. May 30, 3014 air permit application (Albany, GA) proposed a $NO_x$ limit of 9 ppm on two Titan 130 turbines using advanced DLN technology offered by the turbine manufacturer, Solar Turbines. This was the first instance of the 9 ppm $NO_x$ limit being proposed by a compressor station applicant using the Titan turbine.[23] The Sabal Trail application notes that, "*Sabal Trail will the first customer of Solar to receive the 9 ppm $NO_x$ vendor guarantee for a Solar Titan 130 turbine, all previous units have been guaranteed at 15 ppm $NO_x$.*"[24] The Sabal Trail application was filed sixteen months before TGP filed the Joelton Compressor Station application with a proposed Titan $NO_x$ limit of 25 ppm, despite the fact that the Titan turbine had been previously guaranteed by the manufacturer at 15 ppm and 9 ppm.

### 2. TGP Analysis of $NO_x$ RACT Alternatives Was Incomplete and Flawed

TGP only identified one DLN control level for the Titan 250 turbines proposed for the Joelton Compressor Station – 25 ppm.[25] Significantly, the manufacturer of the Titan 250 turbine, Solar Turbines, has offered a 15 ppm $NO_x$ guarantee on the Titan 250 since at least 2012.[26] As noted, the 9 ppm $NO_x$ DLN level was guaranteed on the Titan turbine for the first time in 2014, as noted in the May 30, 2014 Sabal Trail air permit application. For the purposes of this comment letter,

[23] Sabal Trail application, p.5-34.
[24] Ibid, 5-34.
[25] Corrected to 15 percent exhaust gas oxygen concentration.
[26] Solar Turbines, *PIL 167: SoLoNO$_x$ Products: Emissions in Non-SoLoNO$_x$ Modes*, June 6, 2012, Table 1.

the levels of Titan 250 DLN control, 25 ppm, 15 ppm, and 9 ppm, are respectively identified in Table 2 as "DLN1", "DLN2", and "DLN3" to avoid confusion.

TGP states in the RACT analysis it prepared for the two Joelton Compressor Station Titan 250 turbines that "Based on vendor information, the Titan 250-30000S model turbine is available with *SoLoNO$_x$* control, which is designed to achieve 25 ppmv $NO_x$." TGP must have been aware of all three DLN $NO_x$ control alternatives at the time it was preparing the Joelton Compressor Station RACT analysis. In fact, TGP opted for the 9 ppm $NO_x$ DLN package for the Titan 130 turbine in the air application it filed on November 1, 2015 for its Supply Path Head Compressor Station in Pennsylvania. This application was filed approximately seven weeks after the Joelton Compressor Station application was filed.

There is no discussion in the TGP RACT evaluation of the Titan turbines that have been equipped with SCR and oxidation catalyst in combined heat and power (CHP) applications to limit NOx emissions to 2.5 ppm. Titan turbines in CHP applications at Cornell University (NY) and Kimberly-Clark (CT) each have $NO_x$ limits of 2.5 ppm are equipped with SCR and oxidation catalyst.[27,28] The exhaust gas temperature of gas turbines in compressor drive applications can be significantly higher than in CHP applications, as compressor drive applications do not have heat recovery systems upstream of the SCR catalyst. The higher exhaust gas temperature can shorten the useful life of the SCR catalyst. To overcome the potential for high exhaust gas temperature to damage a standard temperature SCR catalyst in a compressor drive application, a dilution air blower is added to reduce peak exhaust gas temperature and protect the SCR catalyst.[29]

Dominion voluntarily selected SCR and oxidation catalyst as its air emission control package on each turbine of a four-turbine compressor station, the Buckingham Compressor Station, in Virginia. The Buckingham application was filed on September 16, 2015, almost the same day TGP filed the Joelton Compressor Station application. The $NO_x$ limit in the Buckingham Compressor Station application is 5 ppm $NO_x$. The Buckingham Compressor Station turbines will be equipped with dilution air systems to protect the SCR catalyst.[30]

The $NO_x$ and VOC emissions reduction impacts of DLN2, DLN3, or SCR with oxidation catalyst, relative to the basic DLN1 package identified by TGP and the Metro Nashville/Davidson County Health Department Air Pollution Control Division as RACT, are shown in Table 6. Major reductions in $NO_x$, and to a lesser extent VOC, would be achieved by selecting any of these alternatives as RACT for the Titan turbines at the Joelton Compressor Station.

---

[27] Combined Cycle Journal, *Pacesetter Plants: Class of 2009/2010 Cornell Combined Heat and Power Plant*, 2nd Quarter 2010. "Emissions limits for the CHP facility are 10 ppm CO, 2.5 ppm $NO_x$, and 5 ppm ammonia slip. Annual limit on $NO_x$ is 40 tons."
[28] Connecticut Department of Energy & Environmental Protection - Bureau of Air Management, New Source Review Permit Numbers 130-0070 and 130-0071, Kimberly-Clark Corporation, New Milford, CT, August 15, 2012.
[29] Sabal Trail Application, Table C-12.
[30] Dominion, *Buckingham Compressor Station Article 6 New Source Permit Application*, September 26, 2015, p. 26.

**Table 6. $NO_x$/VOC Emissions Reductions that would Be Achieved at Joelton Compressor Station by Technically Feasible $NO_x$/VOC Control Measures on the Titan Gas Turbine**

| $NO_x$ limit (ppm @ 15% $O_2$) | $NO_x$/VOC Technology | $NO_x$ & VOC PTE (tpy) | | $NO_x$ & VOC reductions (tpy) | | Total $NO_x$ & VOC reductions (tpy) |
|---|---|---|---|---|---|---|
| | | $NO_x$ | VOC | $NO_x$ | VOC | |
| 25 | DLN1 | 167.4 | 11.5 | -- | -- | base case |
| 15 | DLN2 | 100.4 | 11.5 | 67.0 | -- | 67.0 |
| 9 (from Mockingbird Hill application, Table N-2) | DLN3 + oxidation catalyst + noise control | 53.2 | 4.8 | 114.2 | 6.7 | 120.9 |
| 2.5 | SCR[31] + oxidation catalyst | 16.7 | 5.8 | 150.7 | 5.8 | 156.5 |

### 3. Overreliance on Generic and Obsolete SCR and DLN Cost Data from 1990

TGP concluded that SCR is technically feasible for the turbines at the Joelton Compressor Station.[32] TGP indicates a control cost effectiveness range for SCR of $350/ton to $4,500/ton, with the cost effectiveness declining as the size of the turbine increases.[33] After concluding that SCR is technically feasible, TGP dismisses SCR as "not for compressor stations."[34] In effect, TGP finds SCR to be technically feasible and then, a few pages later, implies it is not technically feasible without substantiating that claim. TGP ignores that the use of a dilution blower eliminates the high exhaust gas temperature concern associated with use of SCRs in turbine compressor drive and other simple cycle applications.[35]

Dominion's choice of SCR for four turbines at its proposed Buckingham Compressor Station further undercuts TGP's assertion that SCR is not for compressor stations. Dominion found multiple instances of SCR installed on simple cycle turbines. "Simple cycle" means the turbine exhaust gas does not pass through any heat recovery system. Two examples of simple cycle turbine operation would be a peaking turbine power generation application and a compressor drive application. In either case, the higher exhaust gas temperatures must be addressed to protect the SCR catalyst. Following its review of the RACT/BACT/LAER Clearinghouse, Dominion determined that SCR was in use on simple cycle gas turbines and therefore SCR is a technically viable $NO_x$ control alternative for compressor applications:[36,37]

[31] 90 percent $NO_x$ reduction across the SCR is assumed per: EPA, *Catalog of CHP Technologies: Section 3. Technology Characterization – Combustion Turbines*, March 2015, Table 3-8, p. 3-17 (System 4, 20,336 kW). A 2.5 ppm $NO_x$ SCR outlet concentration is assumed per 90 percent $NO_x$ reduction and 25 ppm $NO_x$ at SCR inlet. May 30, 2014 Sabal Trails application, Table C-12, footnote 2 ("This is consistent with the vendor estimate for SCR outlet $NO_x$ concentration of 2.5 ppm.")

[32] Joelton Application, p. 26.

[33] Ibid, p. 27. "Capital costs (for SCR) on a $/MW basis are highest for the smallest turbine . . . and decrease exponentially with increasing turbine size."

[34] Ibid, p. 29.

[35] Dominion Buckingham Application, pp. 26-27.

[36] Dominion Buckingham Application, p. 29.

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.

Dominion identified DLN $NO_x$ control at 9 ppm as BACT for the turbines at the Buckingham Compressor Station. However, Dominion opted to add SCR to each turbine to further reduce $NO_x$ emissions to 5 ppm.[38] The decision by Dominion to add SCR to each turbine at the Buckingham Compressor Station indicates that SCR in this application is both cost feasible and cost reasonable.

The cost of DLN identified by TGP is essentially de minimus at $55/ton to $138/ton.[39] However, because TGP identifies only one of three types of DLN available for the Titan turbine, it is not clear whether this DLN cost-effectiveness range identified in the RACT analysis applies generally to any form of DLN, the 25 ppm $NO_x$ DLN level identified by TGP as RACT for Joelton, or some other unrelated turbine installation.

Current, accurate installed capital costs for DLN2, DLN3, and SCR + oxidation catalyst for the Titan 250 turbine are provided in Table 7.

**Table 7. Capital Cost of Technically Feasible $NO_x$/VOC Control Measures for Titan 250 Gas Turbine**

| $NO_x$ limit (ppm @ 15% $O_2$) | Technology | Installed capital cost ($) | Source of cost estimate | Month/year of cost estimate |
|---|---|---|---|---|
| 25 | DLN1 | base case | not applicable | not applicable |
| 15 | DLN2 | 500,000 | Solar Turbines, Pittsburgh office[40] | July 2016 |
| 9 | DLN3 + oxidation catalyst + noise control | 1,300,000 | Solar Turbines, Pittsburgh office | July 2016 |
| 2.5 | SCR + oxidation catalyst | 2,400,000 | EPA, CHP turbine report[41] | March 2015 |

[37] The primary distinction between BACT and RACT in the context of economic feasibility is BACT would generally have a higher control cost-effectiveness ceiling than RACT.

[38] Dominion Resources Services, Inc., *Buckingham Compressor Station – Article 6 New Source Permit Application*, September 16, 2015, p. 33.

[39] Ibid, p. 28. TGP identified the $NO_x$ control cost effectiveness of DLN as declining as the size of the turbine increases: "On a unit basis, corresponding capital cost figures for DLN combustion range from $85/hp for a 3.3 MW unit to $19/hp for an 85 MW machine."

[40] Telephone communication between B. Powers, Powers Engineering, and Solar Turbines Pittsburgh, PA office, July 12, 2016.

[41] EPA, Catalog of CHP Technologies: Section 3. Technology Characterization – Combustion Turbines, March 2015, Table 3-5, p. 3-14. Equipment cost for SCR + oxidation catalyst + continuous emissions monitoring system (CEMS) for 21.7 MW (Titan) turbine = $1.516 million. Installed capital cost multiplier = $30,879,300 /$19,397,900 = 1.59. Therefore, installed capital cost of SCR + oxidation catalyst + CEMS = $1.516 million × 1.59 = $2.41 million. It is assumed by Powers Engineering that a tempering air fan (dilution blower) is included in the SCR

### 4. No Identification of An Appropriate $/ton Cost-Effectiveness Ceiling

TGP makes no effort to define the term "cost feasible" in its RACT analysis. As a result it is not known what cost-effectiveness TGP would consider cost feasible from a RACT standpoint. In contrast, numerous state air quality agencies have defined cost-effectiveness ceilings for $NO_x$ RACT determinations. A partial list of these agency RACT cost-effectiveness ceiling determinations is provided in Table 8.

**Table 8. Partial List of Air Agencies with Defined $NO_x$ RACT Cost-Effectiveness Ceilings**

| Air Agency[42] | $NO_x$ RACT cost-effectiveness ceiling ($/ton) |
|---|---|
| New York | 5,000 – 5,500 |
| Ohio | 5,000 |
| Maryland | 3,500 – 5,000 |
| Pennsylvania | 3,500 |
| Illinois | 2,500 – 3,000 |
| Wisconsin[43] | 2,500 |

The $NO_x$ cost-effectiveness of the DLN2, DLN3, and SCR control alternatives are shown in Table 9. Assuming a RACT cost feasibility ceiling of $2,500/ton to $5,500/ton, the DLN3 control level on the Titan turbine, at just over $1,000/ton, is clearly economically feasible as a $NO_x$ RACT control measure on the Joelton Compressor Station turbines. SCR is also economically feasible as RACT, at a cost-effectiveness of $2,842/ton, if TGP prefers to utilize an end-of-pipe $NO_x$ emissions control system as an alternative to the DLN3 control level.

**Table 9. Cost-Effectiveness of Technically Feasible $NO_x$/VOC Control Measures for Titan Gas Turbine**

| $NO_x$ limit (ppm @ 15% $O_2$) | Installed capital cost ($) | Annualized capital cost[44] ($/yr) | $NO_x$ and VOC reduced (tpy) | Cost effectiveness ($/ton) |
|---|---|---|---|---|
| 25 | base case | base case | 0 | not applicable |
| 15 | 500,000 | 47,200 | 67.0 | 704 |
| 9 | 1,300,000 | 122,720 | 120.9 | 1,015 |
| 2.5 | 2,400,000 | 428,325[45,46,47] | 150.7 | 2,842 |

system design in a Titan compressor application to allow use of standard SCR catalyst (instead of high temperature catalyst). A 100 hp dilution blower is assumed consistent with the May 30, 2014 Sabal Trails application, Table C-12.

[42] Pennsylvania Department of Environmental Protection, *Responses to Frequently Asked Questions - Final Rulemaking, Additional RACT Requirements for Major Sources of $NO_x$ and VOCs, 25 Pa. Code Chapters 121 and 129, 46 Pa. B. 2036 (April 23, 2016)*, June 21, 2016, p. 9.

[43] Ibid, p. 1.

[44] Assume 20-year financial term at 7% interest per May 30, 2014 Sabal Trail application, SCR assumptions, Table C-12.

[45] The annualized installed capital cost of the SCR + oxidation catalyst + CEMS = $2,400,000 × 0.0944 = $226,560/yr. SCR catalyst may require replacement at 3-year intervals. Assuming Titan SCE catalyst replacement costs in the May 30, 2014 Sabal Trail application, Table C-12, this periodic cost would add approximately $17,000 per year to the annualized SCR cost (282.52 ft³ × 159/ft³ × 0.3811 = $17,119/yr). This would increase the SCR annualized cost from $188,800/yr to: $226,560/yr + $17,119/yr = $243,679/yr.

TGP states in its RACT analysis for the Joelton Compressor Station, after listing a dozen states with RACT requirements, including New York, Ohio, Maryland, and Pennsylvania, among others, that:[48]

> A number of other states have RACT requirements . . . (and) Because the proposed (25 ppm $NO_x$) limit is equivalent to BACT values listed in the RBLC, TGP assumes that the proposed $NO_x$ RACT (for Joelton) is comparable to RACT in other states.

This is an incorrect assumption by TGP. The control cost-effectiveness of the RACT control levels shown in Table 8, including a 2.5 ppm $NO_x$ limit using SCR, is well below the $NO_x$ RACT cost-effectiveness ceilings of \$3,500/ton to \$5,000/ton in New York, Ohio, Maryland, and Pennsylvania, as shown in Table 7.

## V. Review of TGP RACT Determination by Metro Nashville/Davidson County Health Department Was Inadequate

The Metro Nashville/Davidson County Air Pollution Control Division did no independent corroboration of the information provided in the TGP RACT analysis. The engineering review repeats the SCR and DLN $NO_x$ control cost-effectiveness ranges provided in the TGP RACT analysis, makes no assessment of the applicability of SCR to the Joelton Compressor Station turbines, and concludes that DLN with a 25 ppm $NO_x$ limit satisfies RACT for the source. No ". . . *independently contacting other air pollution control agencies and the U.S. EPA to determine what level of control is required or suggested at identical or similar sources in other areas of jurisdiction*" took place, as required by Regulation 14-3(b). If it had, the Air Pollution Control Division would identified current $NO_x$ control practices on compressor turbines that are substantially more rigorous than 25 ppm, would have identified RACT cost-effectiveness ranges considered reasonable in other jurisdictions, and would not have concluded that 25 ppm is NOx RACT for the two Titan turbines at the Joelton Compressor Station.

## VI. Conclusion

The TGP RACT analysis uses outdated and incomplete information to incorrectly conclude that a $NO_x$ limit of 25 ppm is RACT for the two Titan 250 turbines at the proposed Joelton Compressor Station. The Metro Nashville/Davidson County Air Pollution Control Division

---

[46] Approximately 3.2 tons of 29% aqueous ammonia must be injected into the SCR per ton of NOx removed per the Sabal Trails application, Table C-12. (49.93 tons aqueous $NH_3$/15.57 tons $NO_x$ removed) × 150.7 tons $NO_x$ removed × \$292.83/ton aqueous ammonia = \$141,515/yr. Therefore total annual SCR cost, to achieve a 2.5 ppm $NO_x$ at the SCR outlet assuming a 25 ppm $NO_x$ inlet concentration (90% reduction) = \$243,679/yr + \$141,515/yr = \$385,194/yr.

[47] Annual operating cost of 100 hp dilution blower = 100 hp × (0.746 kW/hp) × \$0.066/kW (Sabal Trails application, Table C-12) × 8,760 hr/yr = \$43,131/yr. Therefore, total annual costs for SCR + oxidation catalyst + CEMS, including installed capital cost, periodic catalyst replacement, aqueous ammonia supply, and dilution blower operating cost = \$385,194/yr + \$43,131/yr = \$428,325/yr.

[48] Joelton Application, p. 28.

erroneously accepted the TGP RACT analysis with no critical or independent review. Properly determined $NO_x$ RACT for the two Titan 250 turbines is either 9 ppm $NO_x$ using DLN3 technology or 2.5 ppm using SCR. Both of these alternatives are technically and economically feasible assuming a RACT cost-effectiveness ceiling of $2,500/ton to $5,000/ton.

# Exhibit 2

# Electric Motor Drive Is Viable RACT Alternative to Two Titan Turbines at Proposed Joelton, Tennessee Compressor Station

Bill Powers, P.E., Powers Engineering, San Diego, California

November 18, 2016

This letter addressing the EMD alternative supplements the August 1, 2016 Southern Environmental Law Center comment letter on RACT-level controls for the Titan 250 compressor drive gas turbines at the proposed Joelton Compressor Station. Electric motor drive (EMD) is a technically and economically feasible alternative to the Titan 250 gas turbines currently proposed by the Tennessee Gas Pipeline Company, L.L.C. (TGP) to drive the two compressors at the Joelton Compressor Station. EMD would eliminate air emissions and lower noise levels at the Joelton Compressor Station.[1] This is a viable alternative to the proposed Titan 250 gas turbines and should have been presented by Kinder Morgan as an alternative in its application to the Metro Nashville/Davidson County Air Pollution Control Division.

Electric motor drive (EMD) is in common use in pipeline compressor applications. See Attachment A. EMD is also in use to drive compressors on the Tennessee Gas Pipeline (a Kinder Morgan company).[2]

> Emissions regulations addressed with electric motor driver . . . When El Paso Pipeline Partners (now Kinder Morgan) required additional compression at its Coudersport, PA Station 313 on the Tennessee Gas Pipeline in December 2009, they considered the tradeoffs associated with each of the potential technologies. . . Permitting was avoided by selecting an electric motor driver instead of a natural gas fired engine or turbine.

Selection of EMD to drive the compressors at the Joelton Compressor Station would eliminate combustion air emissions at the site. EMD has the following air permitting advantages over gas turbine drive for pipeline compressor applications:[3]

- Electric motors reduce the time for a project often by many months considering air permits may not be required compared to gas turbine or engine drive.
- The electric motor drive selection will be a way to avoid having to do a Best Available Control Technology (or Reasonably Available Control Technology) review or air dispersion modeling.

---

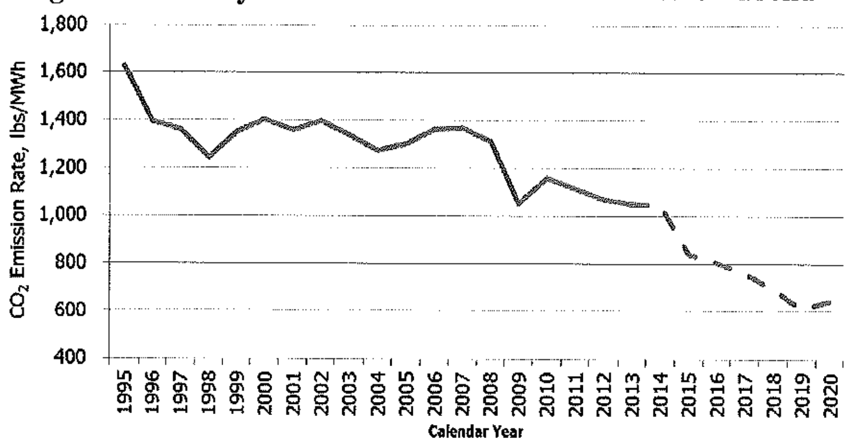
[1] Siemens Industry, Inc., *Application Notes - Compression in the Oil and Gas Industry*, 2013: https://www.industry.usa.siemens.com/verticals/us/en/oil-gas/Documents/Application%20Note%20-%20Compression%20for%20OG.pdf.

[2] Dresser-Rand News, *Unique Compressor Design Allows Efficient Operation Over Wide Range*, Autumn/Winter 2013. See: http://www.dresser-rand.com/news-insights/unique-compressor-design-allows-efficient-operation-over-wide-range/.

[3] Gas Electric Partnership Research Consortium, *Reliability Review of Electric Motor Drives for Pipeline Centrifugal Compressor Stations, presented at Gas Electric Partnership Conference*, Southwest Research Institute, February 9, 2012, p. 11.

Selection of EMD for the compressors at the Joelton Compressor Station would also result in substantially less greenhouse gas emissions than would otherwise be emitted by the Titan 250 gas turbines. The project site is in TVA service territory. TVA forecasts that its average systemwide greenhouse gas emission rate will be approximately 600 pounds per megawatt-hour (lb/MWh) by 2019.[4] The TVA greenhouse gas emission trend is shown in Figure 1. In contrast, the Titan 250 emits over 1,100 lb/MWh of greenhouse gas emissions, almost double the TVA systemwide average projected for 2019.[5] If EMD was selected for the compressors at Joelton, the TVA electric power serving the compressor EMDs would have a substantially lower greenhouse gas footprint than the proposed Titan 250 gas turbines.

**Figure 1. TVA Systemwide Greenhouse Gas Emission Trend**[6]




Electric motors and natural gas-fired combustion turbines have approximately the same installed cost.[7] The cost of electricity drives the operating cost of EMD compressors. Wholesale electricity prices have declined substantially in recent years. The average wholesale electricity price in TVA service territory in 2015 was about $38 per megawatt-hour (3.8 cents per kilowatt-hour).[8] Wholesale electricity prices were even lower in

[4] TVA, *Key Facts about TVA and Carbon Emissions*, September 2015: https://www.tva.com/file_source/TVA/Site%20Content/News/Features/2016%20Features/Fact%20Sheet%20-%20TVA%20and%20Carbon.pdf.

[5] Gas Turbine World, *2016 Performance Specifications – 32nd Edition*, January-February 2016, Volume 46, No. 1, p. 6 and p. 18. Titan 250 lower heating value (LHV) heat rate = 8,775 Btu per kilowatt-hour (Btu/kWh). Assume natural gas LHV to higher heating value (HHV) ratio is 0.90. Therefore Titan 250 heat rate (HHV) = 8,775 Btu/kWh ÷ 0.9 = 9,750 Btu/kWh. The $CO_2$ emission rate per million Btu (MMBtu) = 117 lb/MMBtu. The Titan 250, in electrical generation applications, has a rated output of 21.745 MW (21,745 kW). Therefore the hourly $CO_2$ emission rate of the Titan 250 at rated capacity = 21,745 kW x 9,750 Btu/kWh = 212 MMBtu/hr. Pounds of $CO_2$ emitted per hour = 117 lb/MMBtu x 212 MMBtu/hr = 24,804 lb/hr. Titan 250 $CO_2$ emission factor = (24,804 lb/hr) ÷ 21.745 MW = 1,141 lb/MWh.

[6] TVA, *Key Facts about TVA and Carbon Emissions*, September 2015.

[7] Interstate Natural Gas Association of America, *Interstate Natural Gas Pipeline Efficiency*, October 2010, p. 35.

[8] TVA, *Refining the Wholesale Pricing Structure, Products, Incentives and Adjustments for Providing Electricity to TVA Customers - Final Environmental Assessment: Appendix A - Wholesale Power Rates and Charges for Standard Service Customers*, July 2015, p. 31. Average of summer, winter, and transition on-peak and off-peak wholesale rates is approximately $38 per megawatt-hour.

neighboring service territories. For example, the average wholesale electricity price in Midwest in 2015 was $28.91 per megawatt-hour (less than 3 cents per kilowatt-hour).[9] Low electricity prices increase the competitiveness of EMD compared to gas turbine drive.

EMD is a technically and economically feasible alternative for the compressors at the Joelton Compressor Station, and should therefore be thoroughly evaluated by the Metro Nashville/Davidson County Air Pollution Control Division as a RACT alternative for the Joelton Compressor Station.

[9] Midcontinent Independent System Operator, *2015 State of the Market Report for the MISO Electricity Markets*, June 2016, p. 2.

## Attachment A. Representative EMD Compressors in Pipeline Service

From EN Engineering website, accessed October 28, 2016: http://www.enengineering.com/projects/

### Compressor Replacement at Station 104

Found In / Posted On / 07.9.2013

KINDER MORGAN

**Client:** Kinder Morgan / NGPL
**Project Description:** Mainline Electric Drive Compressor Unit Replacement
**Project Title:** Compressor Replacement at Station 104
**Location:** Kansas USA
Responsible for detailed engineering and design, preparation of construction documents and procurement for the installation of a 13,000 HP Siemens motor driven Dresser Rand 50 PDI-HS compressor to replace an existing compressor unit. **CSP-5**

### East End Expansion Project

Found In / Posted On / 07.9.2013

Spectra Energy

**Client:** Ozark Gas Transmission (Spectra Energy)
**Project Description:** Preliminary Design of Two Mainline Electric Drive Compressor Stations
**Project Title:** East End Expansion Project
**Location:** Arkansas, Missouri, Illinois USA
Provided project management, FERC resource reports, detailed design, construction documents and procurement for three new compressor stations. Each compressor station consists of 2-10,000 hp electric motor driven centrifugal compressor units and the associated ancillary systems. **CSP-16**

## Compressor Station Expansion Project

Found In / Posted On / 07.9.2013

Northern Border Pipeline Company
Operated by TransCanada

**Client:** Northern Border Pipeline
**Project Description:** Greenfield Electric Drive Compressor Station
**Project Title:** Compressor Station Expansion Project
**Location:** Iowa USA
Detailed design, project management, and preparation of material lists and construction documents were provided for a new mainline compressor station. The unit was a 16,000 hp electric motor VFD centrifugal compressor package. **CSP-10**

## Ozark Gas Transmission (Spectra Energy) – Preliminary Design of Two Mainline Electric Drive Compressor Stations

Found In / Posted On / 05.31.2013

Spectra Energy

**Client:** Ozark Gas Transmission (Spectra Energy)
**Project Description:** Preliminary Design of Two Mainline Electric Drive Compressor Stations
**Project Title:** East End Expansion Project
**Location:** Arkansas, Missouri, Illinois USA
Provided project management, FERC resource reports, detailed design, construction documents and procurement for three new compressor stations. Each compressor station consists of 2-10,000 hp electric motor driven centrifugal compressor units and the associated ancillary systems.

# Exhibit 3

# Selective Catalytic Reduction (SCR) at 2.5 ppm $NO_x$ and Dry Low $NO_x$ Combustion at 9 ppm and 15 ppm are Cost-Reasonable RACT Alternatives to Two Titan Turbines at Proposed Joelton, Tennessee Compressor Station

Bill Powers, P.E., Powers Engineering, San Diego, California

January 5, 2017

This letter addresses the cost-reasonableness of nitrogen oxide ($NO_x$) control cost-effectiveness levels of 2.5 parts per million (ppm), 9 ppm, and 15 ppm for the two Titan 250 gas turbines currently proposed by the Tennessee Gas Pipeline Company, LLC, a Kinder Morgan (KM) company, for the Joelton Compressor Station. This comment letter supplements the August 1, 2016 Southern Environmental Law Center (SELC) comment letter on RACT-level controls for the Titan 250 compressor drive gas turbines at the proposed Joelton Compressor Station. The revised $NO_x$ control cost-effectiveness for selective catalytic reduction (SCR) of greater than $16,000/ton alleged by KM in its updated RACT analysis to achieve a 2.5 ppm $NO_x$ limit is in error, as explained in this supplemental comment letter. The approximate $NO_x$ control cost-effectiveness for 2.5 ppm, 9 ppm, and 15 ppm control levels are $4,100/ton, $3,500/ton, and $1,200/ton, respectively. All of these $NO_x$ control cost-effectiveness levels are less than the RACT cost-reasonableness ceiling of $5,500/ton described in the August 1, 2016 SELC comment letter. All of these $NO_x$ control cost-effectiveness levels are also below the control cost-effectiveness range of $350/ton to $4,500/ton identified by KM in its original RACT analysis submitted to Metropolitan Government of Nashville and Davidson County Air Pollution Control Division (Metro Nashville) in September 2015.

KM has failed to present accurate and complete information about RACT alternatives to regulators.[1] Issuance of the Joelton Compressor Station construction permit, as well as the Part 70 Operating Permit as issued for comment in draft form, would violate the standards in applicable regulations as these permits fail to require RACT to reduce $NO_x$. SCR with a $NO_x$ outlet concentration of 2.5 ppm is $NO_x$ RACT if gas turbines are utilized on the Joelton compressors.

## I. SELECTIVE CATALYTIC REDUCTION IS COST-REASONABLE FOR THE JOELTON GAS TURBINES AT APPROXIMATELY $4,000/TON OF $NO_X$ REMOVED

Proper RACT analysis shows that SCR is cost-reasonable for the Joelton Compressor Station at approximately $4,100/ton of $NO_x$ removed. Indeed, KM originally identified the $NO_x$ control cost-effectiveness range for SCR on gas turbines as $350/ton to

[1] This includes the $NO_x$ control measures discussed in this letter and the electric motor drive (EMD) alternative to the proposed gas turbines. As explained in my supplemental letter dated November 18, 2016, EMD is a technically and economically feasible alternative to the Titan 250 gas turbines currently proposed by KM. KM did not present EMD alternative to Metro Nashville as RACT option for the Joelton Compressor Station, making its application incomplete.

$4,500/ton in its air permit application.[2] However, in its supplemental September 27, 2016 letter to Metro Nashville, obtained by SELC through a public records act request, KM claims a $NO_x$ control cost-effectiveness for SCR of greater than $16,000/ton.[3] No mention is made in KM's September 27, 2016 letter of its own earlier statement in the Joelton air permit application that the $NO_x$ control cost-effectiveness range for SCR on gas turbines is $350/ton to $4,500/ton. This huge inflation by KM of the SCR $NO_x$ control cost-effectiveness for the Titan 250 gas turbines proposed for Joelton is simply ignored by KM.

### A. KM relies on generic SCR calculations meant for larger units to justify a cost-effectiveness figure nearly four times its original calculation

KM now relies on the 6th (2002) and 7th (2016) editions on the *EPA Air Pollution Control Cost Control Manual*, specifically the chapters on selective catalytic reduction, as the basis for its claim of a $NO_x$ control cost-effectiveness greater than $16,000/ton.[4] These SCR chapters present a "first principles" approach to generic SCR design and cost for high-dust coal-fired boilers. As stated in the 6th Edition chapter on SCR:[5]

> The capital and annual cost equations were developed for coal-fired wall and tangential utility and industrial boilers with heat input rates ranging from 250 MMBtu/hr to 6,000 MMBtu/hr (25 MW to 600 MW). The SCR system design is a high-dust configuration with one SCR reactor per combustion unit.

The 7th Edition identifies the SCR cost calculations as applicable to coal-fired and oil- and gas-fired utility boilers greater than 25 MW, stating:[6]

> Capital cost equations are provided for both coal-fired and oil- or gas-fired units. The capital cost equations are applicable to coal-fired utility boilers and to oil- or gas-fired utility boilers at facilities with generating capacity greater than or equal to (≥) 25 MW.

Neither the EPA 6th Edition or 7th Edition make any claim that the generic SCR cost calculations provided in these documents are applicable to natural gas-fired gas turbines

---

[2] S. Chhabra – Kinder Morgan, MHDDPC Title V Permit Application Update and Supplemental Information, Tennessee Gas Pipeline Company LLC Compressor Station 563, Davidson County, Joelton, TN, September 11, 2015, Attachment 1 – Title V Permit Application, p. 27.

[3] S. Chhabra – Kinder Morgan, Updated RACT Analysis for Tennessee Gas Pipeline Company LLC Compressor Station 563, Davidson County, Joelton, TN, September 27, 2016, p. 2. KM estimate of $NO_x$ control cost-effectiveness is $16,696/ton.

[4] S. Chhabra – Kinder Morgan, Letter to Metro Public Health Department – Updated RACT Analysis for Tennessee Gas Pipeline Company LLC Compressor Station 563, Davidson County, Joelton, TN, September 27, 2016, p. 2.

[5] EPA, *EPA Air Pollution Control Cost Manual*, 6th Edition, Section 4 $NO_x$ Controls, Section 4.2 $NO_x$ Post-Combustion, Chapter 2 Selective Catalytic Reduction, EPA/452/B-02-001, January 2002, p. 2-40.

[6] EPA, *EPA Air Pollution Control Cost Manual*, 7th Edition, Chapter 2 Selective Catalytic Reduction, May 2016, p. 2-63.

less than 25 MW in output. The Titan 250 is rated at 21.7 MW when utilized in an electric generation configuration.[7]

**B. A proper cost estimate for SCR on an equivalently sized turbine to the Joelton Compressor would reference vendor quotations, as recommended by EPA.**

In contrast, the EPA published in March 2015 a cost estimate for SCR, oxidation catalyst (OxCat), and continuous emission monitors for a 21.7 MW gas turbine in combined heat and power (CHP) service.[8] The heat input and exhaust gas flowrate assumed by EPA for the 21.7 MW turbine match those of the Titan 250.[9,10]

The EPA cost estimate for SCR is based on SCR vendor quotations. Since the EPA's 6th Edition was published in 2002, hundreds of gas turbines have been equipped with SCR in the U.S. SCR manufacturing and supply is a highly competitive business and vendor quotations are readily available for all makes and models of gas turbines. All eleven compressor drive gas turbines, including Titan turbines, included in the proposed Atlantic Coast Pipeline (ACP) will utilize SCR for $NO_x$ control.[11] Peerless Manufacturing, a major U.S. supplier of SCRs to the power industry, provided the performance specifications for these SCRs to the ACP project development team.[12] The EPA relied on SCR vendor quotations in its March 2015 CHP document to estimate a total installed cost of an SCR/oxidation catalyst/continuous emissions monitor package for the Titan 250 gas turbine of approximately $2,400,000.[13]

The cost of the OxCat in the EPA cost estimate must be deducted to determine the cost of the SCR alone. The installed capital cost of the OxCat component of this control package is approximately $400,000 according to Solar Turbines, Inc., the manufacturer of the Titan 250.[14] When the $400,000 cost of the OxCat is deducted, the all-in cost for the SCR

---

[7] Solar Turbines, Inc, *Industrial Gas Turbine Product Line and Performance* (brochure), 2016, p. 2.

[8] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies - Section 3. Technology Characterization – Combustion Turbines, March 2015, p. 15: https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf.

[9] Ibid, Table 3-2, p. 3-6 and p. 3-7.

[10] Solar Turbines, Inc, *Industrial Gas Turbine Product Line and Performance* (brochure), 2016, p. 2. Titan 250 exhaust mass flow: 541,400 lb/hr. Titan 250 fuel heat input: lower heating value (LHV) 190.8 MMBtu/hr (estimated higher heating value = 1.1 × LHV = 210 MMBtu/hr).

[11] Atlantic Coast Pipeline, LLC, Dominion Transmission, Inc. Supply Header Project, FERC Docket No. CP15-554-000 , Resource Report 9 Air and Noise Quality, September 2015, p. 9-24. See **Attachment A.**

[12] Atlantic Coast Pipeline, LLC, *Atlantic Coast Pipeline Project Permit Application - Marts Compressor Station, Lewis County*, West Virginia, October 2015, Attachment M – Air Pollution Control Device Sheet(s) and Attachment N (pdf p. 161).

[13] EPA CHP, Table 3-5, p. 3-14. Equipment cost of SCR/OxCat/CEM, 21.7 MW turbine, 90% NOx control from 15 ppm to 1.5 ppm = $1,516,400. Ratio of CHP total installed cost to equipment cost = $30,879,300 ÷ $19,397,900 = 1.59. Therefore, total installed cost of SCR/OxCat/CEM = 1.59 × $1,512,400 = $2,404,716. See **Attachment B.**

[14] Telephone communication between B. Powers/Powers Engineering and J. Belmont/Solar Turbines, Inc. (Pittsburg office), July 12, 2016.

and continuous emission monitors is about $2,000,000. The only difference in the SCR design for a Titan 250 in a CHP application and a Titan 250 in a pipeline compressor application like Joelton is the addition of a low-cost tempering air fan in the compressor-drive application to maintain the exhaust gas temperature within the normal operating range of a standard SCR catalyst.[15]

Finally, the installed cost of the continuous emissions monitoring package for the gas turbine is estimated at $250,000 based on an actual CHP project consisting of two Solar Taurus turbines in Southern California.[16] When the installed cost of continuous emissions monitoring package is excluded, the total installed cost of the SCR is $1.75 million.

EPA does not include the cost of continuous emissions monitors as a component of the SCR cost-effectiveness calculation in the 6th and 7th Edition cost manuals. Air permits for gas turbines in compressor service in Tennessee allow the project owner to determine whether to conduct continuous parametric monitoring, such as monitoring SCR ammonia injection rate, or install continuous emission monitors.[17]

### C. KM's erroneous SCR cost assumptions drive its highly inflated SCR cost-effectiveness estimate

KM highly inflates several critical inputs to the SCR cost-effectiveness calculation in its most recent calculation of SCR cost-effectiveness. The discrepancies between EPA 2015 and 2016 SCR cost assumptions and the assumptions used by KM in its September 27, 2016 RACT update letter to Metro Nashville are listed in Table 1. The magnitude of the cost inflation by KM is described in the right-hand column of Table 1.

***Table 1. Discrepancies between EPA (2015 CHP Plant Cost and 2016 Control Cost Manual 7th Edition), and KM SCR control cost-effectiveness calculations***

| Element | EPA basis | KM basis | Magnitude of cost inflation by KM |
|---|---|---|---|
| Capital cost | $1.75 million (EPA March 2015 SCR in 21.7 MW CHP application, SCR only). | $4.1 million (EPA generic SCR cost calculation developed for utility boilers > 25 MW.) | 2.5x higher capital cost of SCR |
| Capital recovery factor (CRF) | 7% interest, 30 years. CRF = 0.0805 | 10% interest, 30 years. CRF = 0.1071 | 25% higher annualized capital cost of SCR. |

[15] E-mail communication between B. Powers/Powers Engineering and J. Harber/AHM Associates (Peerless Manufacturing representative), June 24, 2014.
[16] E-mail communication between B. Powers/Powers Engineering and Q. Giuseppe/Syska Hennessy (CHP plant design firm) regarding installed cost of $NO_x$/CO continuous monitoring systems on 5.8 MW Solar Taurus gas turbines, County of Orange Government Center, Santa Ana, California, December 5, 2016.
[17] Tennessee Air Pollution Control Board, Construction Permit 970299P to ANR Pipeline Company – Brownsville Compressor Station, issued August 12, 2015 for Solar Mars 100 compressor turbine (15,437 hp). Condition S-5(d), p. 4.

| | | | |
|---|---|---|---|
| SCR catalyst cost | $160/ft$^3$ | $257.96/ft$^3$ | 60% higher SCR catalyst cost. |
| SCR catalyst life | 40,000 hours (5 years) in gas-fired service.[18] Future worth factor at 7% interest = 0.174. | 3 years. Future worth factor = 0.3111 (EPA 7$^{th}$ Edition, SCR, p. 2-85) | 80% higher annual catalyst replacement cost. |
| Ammonia reagent cost | $0.475 per pound of reagent | $0.49 per pound of solution, 19% aqueous ammonia | 5x higher annual ammonia reagent cost. |

### D. Using EPA assumptions and omitting KM's erroneous assumptions shows that KM overestimates the $NO_x$ cost-effectiveness of SCR on the Joelton gas turbines by a factor of four.

Substituting accurate and current EPA's assumptions for KM's erroneous assumptions demonstrates that the actual $NO_x$ cost-effectiveness of SCR on the Joelton gas turbines is approximately $4,100/ton. This figure is within the SCR $NO_x$ control cost-effectiveness range of $350/ton to $4,500/ton identified by KM in its original RACT analysis submitted to Metro Nashville in September 2015. The actual cost-effectiveness of SCR on the Joelton gas turbines is consistent with the original KM estimate of SCR cost-effectiveness and approximately one-fourth the $NO_x$ control cost-effectiveness presented in KM's more recent analysis.

For example, KM's analysis erroneously assumes that full-time staff must be onsite at the Joelton facility solely to operate the SCR. However, SCR can be operated remotely at unmanned compressor stations using supervisory control and data acquisition (SCADA) technology.[19] KM's assumption regarding staffing results in KM applying a large ($268,000/yr) and unsupported labor cost solely to support of the operation of SCR on the Joelton gas turbines. At a minimum, the only unique SCR parameter that must be remotely monitored is the ammonia reagent injection rate. Monitoring of this one parameter does not require onsite personnel. No operating cost should be assigned by KM to SCR use at Joelton.

The cost inputs to the calculation of the total annual SCR cost for the Titan 250 gas turbines at Joelton are provided in Table 2, along with the calculation of the $NO_x$ control cost effectiveness assuming 90 percent $NO_x$ reduction to a 2.5 ppm limit.

[18] EPA 7$^{th}$ Edition, SCR, p. 2-75. "For oil- and gas-fired units, the SCR catalyst life is assumed to be 40,000 hours, and the catalyst life for some gas-fired units has been reported to be up to 60,000 hours."
[19] Ozone Transport Commission, Technical Information:
Oil and Gas Sector Significant Stationary Sources of $NO_x$ Emissions – Final, October 17, 2012, p. 26. "Another stated (industry) issue is that many compressor facilities are unmanned and that SCR installations have not been demonstrated in unmanned facilities. Other industry information indicates that while it may be true that there are currently few SCRs in unmanned facilities, with modern software based controls and supervisory control and data acquisition (SCADA) type communication technologies there does not appear to be any technical barrier to operating the SCR related controls and auxiliaries successfully from a remote location."

***Table 2. SCR $NO_x$ control cost-effectiveness using EPA assumptions for Titan 250 gas turbine, 25 ppm to 2.5 ppm (90 percent reduction)***

| Element | Inputs | Annualized Cost ($/yr) |
|---|---|---|
| Annualized capital cost | $1,750,000 x 0.0805 | 140,875 |
| Annualized catalyst replacement cost[20] | $183,840 x 0.174 | 31,988 |
| Ammonia reagent[21] | 65,875 lb/yr x $0.475/lb | 31,291 |
| Operating labor | SCR reagent injection and exhaust gas temperature monitored remotely using SCADA technology. | 0 |
| Maintenance costs | 0.015 of total capital investment (KM base case): 0.015 x $1.75 million, | 26,000 |
| Electricity, including tempering air fan | $34,914 (KM base case) + $46,647 (75 kW tempering air fan x $0.071/kW-hr x 8,760 hr/yr), | 81,563 |
| Total annual SCR cost, $/yr | | $311,717/yr |
| Total $NO_x$ reduction, 25 ppm to 2.5 ppm, tons/yr[22] | | 75.3 tons/yr |
| $NO_x$ control cost-effectiveness, $/ton[23] | | $4,140/ton |

Use of accurate SCR cost inputs results in a SCR $NO_x$ control cost-effectiveness of $4,140/ton, not the $16,696/ton presented by KM. KM overestimates the $NO_x$ cost-effectiveness of SCR on the Joelton gas turbines by a factor of four in its September 27, 2016 updated RACT analysis.

## II. DRY LOW $NO_X$ COMBUSTION WITH A GUARANTEE OF 9 PPM IS COST-REASONABLE AT A COST-EFFECTIVENESS OF APPROXIMATELY $3,500/TON OF $NO_X$ REMOVED

Solar Turbines, Inc. indicates the added cost of a 9 ppm $NO_x$ guarantee on the Titan gas turbine is $1.2 to $1.3 million.[24] This $NO_x$ control level requires use of a tempering air fan with the SCR, as an OxCat is incorporated as an element of the control system.

---

[20] KM, September 27, 2016 comment letter, Attachment 1. Catalyst volume = 1,149.43 $ft^3$. Therefore, at a EPA 7th Edition SCR catalyst cost of $160/$ft^3$, initial catalyst cost = 1,149.43 $ft^3 \times$ $160/$ft^3$ = $183,840.

[21] Ibid, 7.35 lb/hr ammonia reagent flow rate for 88 percent $NO_x$ reduction from 25 ppm to 3 ppm. Ammonia reagent flow rate for 90 percent $NO_x$ reduction to 2.5 ppm = 7.35 lb/hr × (0.90/0.88) = 7.52 lb/hr. Therefore, annual reagent consumption = 7.52 lb/hr x 8,760 hr/yr = 65,875 lb/yr.

[22] Joelton Compressor Station Application, September 11, 2015, Attachment 1, Table 3, p. 4. Potential To Emit (PTE), each Titan 250 turbine = 83.65 tons per year (tpy). Ninety percent reduction = 83.65 tpy × 0.90 = 75.3 tpy per turbine.

[23] $311,717/yr ÷ 75.3 tons/yr = $4,140/ton.

[24] Telephone communication between B. Powers/Powers Engineering and J. Belmont/Solar Turbines, Inc. (Pittsburg office), July 12, 2016.

Assuming a capital cost of $1.3 million for the Titan 250 turbine, capital recovery factor based on 7 percent interest over 30 years consistent with EPA 7th Edition, and a 75 kW tempering air fan, the $NO_x$ control cost-effectiveness of the 9 ppm guarantee alternative is $3,481/ton.[25,26]

## III. DRY LOW $NO_X$ COMBUSTION WITH A GUARANTEE OF 15 PPM IS COST-REASONABLE AT A COST-EFFECTIVENESS OF APPROXIMATELY $1,000/TON OF $NO_X$ REMOVED

Solar Turbines, Inc. indicates the cost of a 15 ppm $NO_x$ guarantee on the Titan gas turbine is $500,000.[27] Assuming a capital recovery factor based on 7 percent interest over 30 years consistent with EPA 7th Edition, the $NO_x$ control cost-effectiveness of the 15 ppm guarantee alternative is $1,201/ton.[28,29]

There is one operational Titan 250 gas turbine in pipeline compressor drive service in Tennessee, in use since 2010 at the Columbia Gulf Transmission Compressor Station in Hartsville, TN, that is guaranteed by Solar Turbines at 15 ppm $NO_x$.[30] The Solar Turbines documentation verifying the Hartsville Compressor Station Titan 250 is guaranteed at 15 ppm $NO_x$ is provided in **Attachment C**. Although Solar Turbines guaranteed the Hartsville Titan 250 at 15 ppm $NO_x$, the air permit issued for the project only limits the turbine to 25 ppm $NO_x$.[31]

## IV. CONCLUSION

The approximate $NO_x$ control cost effectiveness of 2.5 ppm, 9 ppm, and 15 ppm control levels are $4,100/ton, $3,500/ton, and $1,200/ton, respectively. All of these $NO_x$ control cost-effectiveness levels are less than the RACT cost-reasonableness ceiling of $5,500/ton documented in the August 1, 2016 SELC comment letter. For this reason, KM's analysis and application asserting that a 25 ppm $NO_x$ limit is RACT for the Joelton gas turbines do not comply with applicable law.

---

[25] The $NO_x$ base case is 25 ppm with a PTE of 83.65 tpy. A $NO_x$ emission limit of 9 ppm would reduce the annual $NO_x$ PTE by: [(25 ppm – 9 ppm) ÷ 25 ppm] x 83.65 tpy = 53.5 tpy.
[26] $1,300,000 × 0.0805 = $104,650/yr. Tempering air fan electricity cost = $81,563/yr (see Table 2). NOx control cost-effectiveness = ($104,650/yr + $81,563/yr) ÷ 53.5 tpy = $3,481/ton.
[27] Telephone communication between B. Powers/Powers Engineering and J. Belmont/Solar Turbines, Inc. (Pittsburg office), July 12, 2016.
[28] The $NO_x$ base case is 25 ppm with a PTE of 83.65 tpy. A $NO_x$ emission limit of 15 ppm would reduce the annual $NO_x$ PTE by: [(25 ppm – 15 ppm) ÷ 25 ppm] x 83.65 tpy = 33.5 tpy.
[29] $500,000 × 0.0805 = $40,250/yr. NOx control cost-effectiveness = $40,250/yr ÷ 33.5 tpy = $1,201/ton.
[30] Columbia Gulf Transmission, Revised Air Permit Application for Hartsville Compressor Station, February 24, 2009,
[31] Ibid, p. 2-1.

Attachment A

# ATLANTIC COAST PIPELINE, LLC
# ATLANTIC COAST PIPELINE
# Docket Nos. CP15-___-000
# CP15-___-000
# CP15-___-000

**and**

# DOMINION TRANSMISSION, INC.
# SUPPLY HEADER PROJECT
# Docket No. CP15-___-000

# Resource Report 9
# Air and Noise Quality

*Final*

**Prepared by**

NATURAL RESOURCE GROUP

an ERM Group company

**September 2015**

used only as emergency use engines. The emissions limits specified in Subpart JJJJ for emergency spark ignition engines greater than 130 hp for NOx, CO, and VOC are 2.0, 4.0, and 1.0 grams per hp-hour, respectively. Both engines have emissions guarantees that are at or below these limits.

All auxiliary generators at the ACP and SHP stations will be subject to NSPS notification and recordkeeping requirements, including records of notifications, maintenance, and documentation that the engines are certified to meet applicable emissions standards. If the engines are not certified by the manufacturer, then additional recordkeeping requirements apply.

**Subpart KKKK – Standards of Performance for Stationary Gas 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 NOx emissions limitations. All proposed turbines, except the Solar Centaur 40 turbine, fall within the "medium sized" (>50MMBtu/hr, < 850 MMBtu/hr) category for natural gas turbines. The Solar Centaur 40 turbine falls within the "small sized, mechanical drive" (< 50 MMBtu/hr) category for natural gas turbines. "Medium sized" turbines must meet a NOx limitation of 25 parts per million by volume (ppmv) at 15 percent oxygen ($O_2$), and "small sized, mechanical drive" turbines must meet a NOx limitation of 100 ppmv at 15 percent $O_2$ under the requirements of Subpart KKKK and will minimize emissions consistent with good air pollution control practices during startup, shutdown and malfunction.

Solar provides an emissions guarantee of 9 parts per million volume dry (ppmvd) NOx at 15 percent $O_2$ for SoLoNOx equipped units, except for the Solar Centaur 40 equipped with SoLoNOx, which has an emissions guarantee of 25 ppmvd NOx at 15 percent $O_2$. 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 installed at the new ACP compressor Stations to further reduce NOx emissions to 5 ppmvd at 15 percent $O_2$, except during periods of start-up and shutdown and periods with ambient temperatures below 0°F.

The ACP and SHP compressor stations plan 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 ensures compliance with the $SO_2$ standard due to the low sulfur content of pipeline quality natural gas.

Attachment B

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

# Catalog of CHP Technologies

## Section 3. Technology Characterization – Combustion Turbines

U.S. Environmental Protection Agency
Combined Heat and Power Partnership

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

CHP
EPA COMBINED HEAT AND POWER PARTNERSHIP

March 2015

**Table 3-5. Estimated Capital Cost for Representative Gas Turbine CHP Systems**[53]

| Cost Component | System | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| Nominal Turbine Capacity (kW) | 3,510 | 7,520 | 10,680 | 21,730 | 45,607 |
| Net Power Output (kW) | 3,304 | 7,038 | 9,950 | 20,336 | 44,488 |
| **Equipment** | | | | | |
| Combustion Turbines | $2,869,400 | $4,646,000 | $7,084,400 | $12,242,500 | $23,164,910 |
| Electrical Equipment | $1,051,600 | $1,208,200 | $1,304,100 | $1,490,300 | $1,785,000 |
| Fuel System | $750,400 | $943,000 | $1,177,300 | $1,708,200 | $3,675,000 |
| Heat Recovery Steam Generators | $729,500 | $860,500 | $1,081,000 | $1,807,100 | $3,150,000 |
| SCR, CO, and CEMS | $688,700 | $943,200 | $983,500 | $1,516,400 | $2,625,000 |
| Building | $438,500 | $395,900 | $584,600 | $633,400 | $735,000 |
| Total Equipment | $6,528,100 | $8,996,800 | $12,214,900 | $19,397,900 | $35,134,910 |
| **Installation** | | | | | |
| Construction | $2,204,000 | $2,931,400 | $3,913,700 | $6,002,200 | $10,248,400 |
| Total Installed Capital | $8,732,100 | $11,928,200 | $16,128,600 | $25,400,100 | $45,383,310 |
| **Other Costs** | | | | | |
| Project/Construction Management | $678,100 | $802,700 | $1,011,600 | $1,350,900 | $2,306,600 |
| Shipping | $137,600 | $186,900 | $251,300 | $394,900 | $674,300 |
| Development Fees | $652,800 | $899,700 | $1,221,500 | $1,939,800 | $3,312,100 |
| Project Contingency | $400,700 | $496,000 | $618,500 | $894,200 | $1,526,800 |
| Project Financing | $238,500 | $322,100 | $432,700 | $899,400 | $2,303,500 |
| **Total Installed Cost** | | | | | |
| Total Plant Cost | $10,839,800 | $14,635,600 | $19,664,200 | $30,879,300 | $55,506,610 |
| Installed Cost, $/kW | $3,281 | $2,080 | $1,976 | $1,518 | $1,248 |

Source: Compiled by ICF from vendor-supplied data.

### 3.4.6 Maintenance

Non-fuel operation and maintenance (O&M) costs are presented in **Table 3-6**. These costs are based on gas turbine manufacturer estimates for service contracts, which consist of routine inspections and scheduled overhauls of the turbine generator set. Routine maintenance practices include on-line running maintenance, predictive maintenance, plotting trends, performance testing, fuel consumption, heat rate, vibration analysis, and preventive maintenance procedures. The O&M costs presented in **Table 3-6** include operating labor (distinguished between unmanned and 24 hour manned facilities) and total maintenance costs, including routine inspections and procedures and major overhauls.

[53] Combustion turbine costs are based on published specifications and package prices. Installation estimates are based on vendor cost estimation models and developer-supplied information.

**Table 3-8. Gas Turbine Emissions Characteristics**

| Emissions Characteristics | System | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| Electricity Capacity (kW) | 3,304 | 7,038 | 9,950 | 20,336 | 44,488 |
| Electrical Efficiency (HHV) | 24.0% | 28.9% | 27.3% | 33.3% | 36.0% |
| **Emissions Before After-treatment** | | | | | |
| $NO_x$ (ppm) | 25 | 15 | 15 | 15 | 15 |
| $NO_x$ (lb/MWh) | 1.31 | 0.65 | 0.69 | 0.57 | 0.52 |
| CO (ppmv) | 50 | 25 | 25 | 25 | 25 |
| CO (lb/MWh) | 1.60 | 0.66 | 0.70 | 0.58 | 0.53 |
| NMHC (ppm) | 5 | 5 | 5 | 5 | 5 |
| NMHC (lb/MWh) | 0.09 | 0.08 | 0.08 | 0.07 | 0.06 |
| **Emissions with SCR/CO/CEMS** | | | | | |
| $NO_x$ (ppm) | 2.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| $NO_x$ (lb/MWh) | 0.09 | 0.05 | 0.05 | 0.05 | 0.05 |
| CO (ppmv) | 5.0 | 2.5 | 2.5 | 2.5 | 2.5 |
| CO (lb/MWh) | 0.11 | 0.05 | 0.05 | 0.05 | 0.05 |
| NMHC (ppm) | 4.3 | 4.3 | 4.3 | 4.3 | 2.0 |
| NMHC (lb/MWh) | 0.08 | 0.06 | 0.07 | 0.06 | 0.02 |
| **$CO_2$ Emissions** | | | | | |
| Generation $CO_2$ (lb/MWh) | 1,667 | 1,381 | 1,460 | 1,201 | 1,110 |
| Net $CO_2$ with CHP (lb/MWh) | 797 | 666 | 691 | 641 | 654 |

*Source: Compiled by ICF from vendor supplied data, includes heat recovery*

**Table 3-8** also shows the net $CO_2$ emissions after credit is taken for avoided natural gas boiler fuel. The net $CO_2$ emissions range from 641-797 lbs/MWh. A natural gas combined cycle power plant might have emissions in the 800-900 lb/MWh range whereas a coal power plant's $CO_2$ emissions would be over 2000 lb/MWh. Natural gas fired CHP from gas turbines provides savings against both alternatives.

### 3.5.2 Emissions Control Options

Emissions control technology for gas turbines has advanced dramatically over the last 20 years in response to technology forcing requirements that have continually lowered the acceptable emissions levels for nitrogen oxides ($NO_x$), carbon monoxide (CO), and volatile organic compounds (VOCs). When burning fuels other than natural gas, pollutants such as oxides of sulfur ($SO_x$) and particulate matter (PM) can be an issue. In general, $SO_x$ emissions are greater when heavy oils are fired in the turbine. $SO_x$ control is generally addressed by the type of fuel purchased, than by the gas turbine technology. Particulate matter is a marginally significant pollutant for gas turbines using liquid fuels. Ash and metallic additives in the fuel may contribute to PM in the exhaust.

A number of control options can be used to control emissions. Below are descriptions of these options.

**Attachment C**

Columbia Gulf Transmission

*A NiSource Company*

1700 MacCorkle Avenue S.E.
Charleston, WV 25314

2009 FEB 27 PM 4: 01

February 24th 2009

TDEC-Division of Air Pollution Control
*Attn: Greg Forte-Permits section*
401 Church St.
9th Floor – L&C Annex
Nashville, TN 37243-1531

RE: Columbia Gulf Transmission
Hartsville C.S. (Reference No. 56-0004)

Columbia Gulf Transmission Company (Columbia Gulf) herein submits revised air permit application for the second phase of a multi-year project to replace equipment destroyed during multiple tornados in early February 2008 at its Hartsville Compressor Station located in Macon County. Columbia Gulf submitted an application in September 2008 for the installation and operation of a new Solar Titan 250 (Emission Unit 309) turbine, repaired Pratt & Whitney GG4 (Emission Unit 305) turbine and 880 horsepower Waukesha VGF36GL emergency generator to replace equipment installed under the significant Title V modification issued July 15th 2008.

This revised application is being submitted with information in format requested from TDEC representatives for inclusion of an additional 440 horsepower Waukesha VGF18GL emergency generator (Emission Unit G5). If you have any questions or need additional information, please feel free to contact me at either (304) 357-2079 or kgabbard@nisource.com .

Sincerely,

Kasey Gabbard

Kasey Gabbard, NiSource EH&S
Permitting & Compliance Team Leader

Enclosures

cc: *Srinivasa Kusumancha-TDEC*
*Hartsville C.S. Files*
*Clark Bourque-Columbia Gulf EH&S*
*Corporate EH&S Files*

## 2.0 SOURCE DESCRIPTIONS AND HOURLY EMISSION RATES

This section describes the sources to be installed and associated hourly emission rates.

### 2.1 Solar Titan Turbine

The proposed Solar Titan 250-30000 turbine is a natural gas-fired combustion turbine. It is ISO rated at 28,500 hp of power output and 212.0 MMBtu/hr of fuel input (all heat input ratings presented in this document are based on fuel higher heating value). Based on the ISO rated heat input, the turbine is subject to the emission limits in NSPS Subpart KKKK of 25 ppmv $NO_X$ at 15% $O_2$ and 0.060 lb/MMBtu $SO_2$. The proposed turbines will be equipped with Solar's dry low $NO_X$ combustion control system and will maintain stack emissions of ≤25 ppmv $NO_X$, ≤50 ppmv CO, and ≤2.5 ppmv VOC at loads ≥50% of full load and ambient temperatures ≥0 °F. At <50% of full load and ambient temperatures below 0 °F, combustion system operation is altered to maintain stable combustion, but higher emission rates occur. Stack gas concentrations of $NO_X$, CO, and VOC at each of the operating conditions are summarized in Table 2-1.

**Table 2-1. Emission Concentrations for Solar Titan 250-30000 Turbine (ppmv @ 15% $O_2$)**

| Operating Condition | $NO_X$ | CO | VOC |
|---|---|---|---|
| Normal Operation | 25 | 50 | 2.5 |
| <50% of Rated Load | 70 | 2200 | 30 |
| 0 to -20 °F Ambient | 42 | 100 | 5 |

Power output and exhaust flow rate are a function of ambient conditions (the mass flow of exhaust gas will increase as ambient temperature decreases due to the increase in combustion air density) and compressor load (which varies with compressor throughput requirements and pressure differential). Due to the variation in exhaust flow rates, criteria pollutant mass emission rates will also vary. In addition, emissions also vary during turbine startup and shutdown due to incomplete fuel combustion and flame stability requirements during these periods. The startup cycle for the Titan takes approximately 9 minutes and the shutdown cycle takes approximately 10 minutes. During the startup and shutdown period, the turbine's dry low $NO_X$ combustion system is not in operation.

Table 2-2 presents turbine power output, exhaust flow rate, and hourly emission rates for the Titan turbine during each of the above operating conditions. The $NO_X$, CO, and VOC emission rates in the table represent the maximum rates within each operating mode (i.e., full load operation at 0 °F ambient, low load, and full load at an ambient temperature of -17 °F which is the record low temperature recorded in the Hartsville area) based on turbine performance data provided by the manufacturer. Emission rates for $SO_2$, $PM_{10}$ , and formaldehyde ($CH_2O$) are based on emission factors in AP-42, Section 3.1. Supporting data and calculations are provided in Appendix B-2.

Attachment C

**Solar Turbines**
*A Caterpillar Company*

## PREDICTED EMISSION PERFORMANCE

| | |
|---|---|
| Customer<br>**NiSource** | Engine Model<br>**TITAN 250-30000S**<br>**CS/MD 59F MATCH** |
| Job ID<br>**Hartsville** | Fuel Type<br>**SD NATURAL GAS** |
| Inquiry Number | Water Injection<br>**NO** |
| Run By<br>**William C Oliver III** | Date Run<br>**20-Jun-08** |
| | Engine Emissions Data<br>**REV. 2.0** |

1 — 28500 Hp — 100.0% Load — Elev. 0 ft — Rel. Humidity 60.0% — Temperature 59.0 Deg. F

| | NOx EMISSIONS | CO EMISSIONS | UHC EMISSIONS |
|---|---|---|---|
| PPMvd at 15% O2 | 15.00 | 25.00 | 25.00 |
| ton/yr | 50.00 | 50.74 | 29.06 |
| lbm/MMBtu (Fuel LHV) | 0.060 | 0.061 | 0.035 |
| lbm/(MW-hr) (gas turbine shaft pwr) | 0.54 | 0.55 | 0.31 |
| lbm/hr | 11.42 | 11.58 | 6.63 |

Notes

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

Attachment C

**Solar Turbines**
*A Caterpillar Company*

## PREDICTED ENGINE PERFORMANCE

| | |
|---|---|
| Customer: NiSource | |
| Job ID: Hartsville | |
| Run By: William C Oliver III | Date Run: 20-Jun-08 |
| Engine Performance Code: REV. 3.40 | Engine Performance Date: REV. 2.1 |

| | |
|---|---|
| Model | TITAN 250-30000S |
| Package Type | CS/MD |
| Match | 59F MATCH |
| Fuel System | GAS |
| Fuel Type | SD NATURAL GAS |

## DATA FOR MINIMUM PERFORMANCE

| | | |
|---|---|---|
| Elevation | feet | 0 |
| Inlet Loss | in H20 | 0 |
| Exhaust Loss | in H20 | 0 |
| Engine Inlet Temperature | deg F | 59.0 |
| Relative Humidity | % | 60.0 |
| Driven Equipment Speed | RPM | 6299 |
| Specified Load | HP | FULL |
| Net Output Power | HP | 28500 |
| Fuel Flow | mmBtu/hr | 190.83 |
| Heat Rate | Btu/HP-hr | 6696 |
| Therm Eff | % | 38.000 |
| Engine Exhaust Flow | lbm/hr | 541390 |
| Exhaust Temperature | deg F | 865 |

Fuel Gas Composition (Volume Percent)

| | |
|---|---|
| Methane (CH4) | 92.79 |
| Ethane (C2H6) | 4.16 |
| Propane (C3H8) | 0.84 |
| N-Butane (C4H10) | 0.18 |
| N-Pentane (C5H12) | 0.04 |
| Hexane (C6H14) | 0.04 |
| Carbon Dioxide (CO2) | 0.44 |
| Hydrogen Sulfide (H2S) | 0.0001 |
| Nitrogen (N2) | 1.51 |

Fuel Gas Properties

| | | | | | |
|---|---|---|---|---|---|
| LHV (Btu/Scf) | 939.2 | Specific Gravity | 0.5970 | Wobbe Index at 60F | 1215.6 |

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

## Attachment C

**Solar Turbines**
*A Caterpillar Company*

# PREDICTED EMISSION PERFORMANCE

| | |
|---|---|
| Customer<br>NiSource | Engine Model<br>TITAN 250-30000S<br>CS/MD 59F MATCH |
| Job ID<br>Hartsville | Fuel Type: SD NATURAL GAS<br>Water Injection: NO |
| Inquiry Number | Engine Emissions Data<br>REV. 2.0 |
| Run By: William C Oliver III<br>Date Run: 20-Jun-08 | |

| | NOx EMISSIONS | CO EMISSIONS | UHC EMISSIONS |
|---|---|---|---|
| **2** — 31431 Hp 100.0% Load — Elev. 660 ft — Rel. Humidity 60.0% — Temperature 0 Deg. F | | | |
| PPMvd at 15% O2 | 15.00 | 25.00 | 25.00 |
| ton/yr | 55.32 | 56.13 | 32.15 |
| lbm/MMBtu (Fuel LHV) | 0.060 | 0.061 | 0.035 |
| lbm/(MW-hr) (gas turbine shaft pwr) | 0.54 | 0.55 | 0.31 |
| lbm/hr | 12.63 | 12.82 | 7.34 |
| **3** — 12572 Hp 40.0% Load — Elev. 660 ft — Rel. Humidity 60.0% — Temperature 0 Deg. F | | | |
| PPMvd at 15% O2 | 15.00 | 25.00 | 25.00 |
| ton/yr | 32.43 | 32.91 | 18.85 |
| lbm/MMBtu (Fuel LHV) | 0.060 | 0.061 | 0.035 |
| lbm/(MW-hr) (gas turbine shaft pwr) | 0.79 | 0.80 | 0.46 |
| lbm/hr | 7.40 | 7.51 | 4.30 |
| **4** — 27249 Hp 100.0% Load — Elev. 660 ft — Rel. Humidity 60.0% — Temperature 59.0 Deg. F | | | |
| PPMvd at 15% O2 | 15.00 | 25.00 | 25.00 |
| ton/yr | 48.33 | 49.04 | 28.09 |
| lbm/MMBtu (Fuel LHV) | 0.060 | 0.061 | 0.035 |
| lbm/(MW-hr) (gas turbine shaft pwr) | 0.54 | 0.55 | 0.32 |
| lbm/hr | 11.03 | 11.20 | 6.41 |

Notes

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

Attachment C

**Solar Turbines**
*A Caterpillar Company*

## PREDICTED ENGINE PERFORMANCE

| | |
|---|---|
| Customer<br>NiSource | Model<br>TITAN 250-30000S |
| | Package Type<br>CS/MD |
| Job ID<br>Hartsville | Match<br>59F MATCH |
| Run By: William C Oliver III — Date Run: 20-Jun-08 | Fuel System<br>GAS |
| Engine Performance Code: REV. 3.40 — Engine Performance Data: REV. 2.1 | Fuel Type<br>SD NATURAL GAS |

## DATA FOR MINIMUM PERFORMANCE

| | | |
|---|---|---|
| Elevation | feet | 660 |
| Inlet Loss | in H20 | 4.0 |
| Exhaust Loss | in H20 | 4.0 |

| | | 1 | 2 | 3 | 4 |
|---|---|---|---|---|---|
| Engine Inlet Temperature | deg F | -17.0 | 0 | 0 | 59.0 |
| Relative Humidity | % | 60.0 | 60.0 | 60.0 | 60.0 |
| Driven Equipment Speed | RPM | 6804 | 6696 | 4953 | 6265 |
| Specified Load | HP | FULL | FULL | 40.0% | FULL |
| Net Output Power | HP | 32376 | 31431 | 12572 | 27249 |
| Fuel Flow | mmBtu/hr | 216.30 | 209.87 | 131.00 | 184.48 |
| Heat Rate | Btu/HP-hr | 6681 | 6677 | 10420 | 6770 |
| Therm Eff | % | 38.086 | 38.106 | 24.419 | 37.582 |
| Engine Exhaust Flow | lbm/hr | 589180 | 577256 | 438789 | 523327 |
| Exhaust Temperature | deg F | 833 | 839 | 818 | 871 |

Fuel Gas Composition (Volume Percent)

| | |
|---|---|
| Methane (CH4) | 92.79 |
| Ethane (C2H6) | 4.16 |
| Propane (C3H8) | 0.84 |
| N-Butane (C4H10) | 0.18 |
| N-Pentane (C5H12) | 0.04 |
| Hexane (C6H14) | 0.04 |
| Carbon Dioxide (CO2) | 0.44 |
| Hydrogen Sulfide (H2S) | 0.0001 |
| Nitrogen (N2) | 1.51 |

Fuel Gas Properties

| | | | | | |
|---|---|---|---|---|---|
| LHV (Btu/Scf) | 939.2 | Specific Gravity | 0.5970 | Wobbe Index at 60F | 1215.6 |

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

Attachment C

**Solar Turbines**
*A Caterpillar Company*

## PREDICTED ENGINE PERFORMANCE

| | |
|---|---|
| Customer<br>NiSource | |
| Job ID<br>Hartsville | |
| Run By<br>William C Oliver III | Date Run<br>23-Jun-08 |
| Engine Performance Code<br>REV. 3.40 | Engine Performance Data<br>REV. 3.0 |

| |
|---|
| Model<br>TITAN 250-30000S |
| Package Type<br>CS/MD |
| Match<br>59F MATCH |
| Fuel System<br>GAS |
| Fuel Type<br>SD NATURAL GAS |

## DATA FOR MINIMUM PERFORMANCE

| | | |
|---|---|---|
| Elevation | feet | 660 |
| Inlet Loss | in H20 | 4.0 |
| Exhaust Loss | in H20 | 4.0 |
| Engine Inlet Temperature | deg F | -17.0 |
| Relative Humidity | % | 60.0 |
| Driven Equipment Speed | RPM | 4835 |
| Specified Load | HP | 40.0% |
| Net Output Power | HP | 12956 |
| Fuel Flow | mmBtu/hr | 144.84 |
| Heat Rate | Btu/HP-hr | 11179 |
| Therm Eff | % | 22.760 |
| Engine Exhaust Flow | lbm/hr | 480917 |
| Exhaust Temperature | deg F | 817 |

Fuel Gas Composition (Volume Percent)

| | |
|---|---|
| Methane (CH4) | 92.79 |
| Ethane (C2H6) | 4.16 |
| Propane (C3H8) | 0.84 |
| N-Butane (C4H10) | 0.18 |
| N-Pentane (C5H12) | 0.04 |
| Hexane (C6H14) | 0.04 |
| Carbon Dioxide (CO2) | 0.44 |
| Hydrogen Sulfide (H2S) | 0.0001 |
| Nitrogen (N2) | 1.51 |

Fuel Gas Properties

| | | | | | |
|---|---|---|---|---|---|
| LHV (Btu/Scf) | 939.2 | Specific Gravity | 0.5970 | Wobbe Index at 60F | 1215.6 |

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

# Exhibit 4

# Powers Engineering Response to Metro Public Health Department Questions Regarding (1) Selective Catalytic Reduction Cost and (2) the 9 ppm $NO_x$ Limit as RACT for the Titan 250 Gas Turbines at Proposed Joelton, Tennessee Compressor Station

Bill Powers, P.E., Powers Engineering, San Diego, California

March 14, 2017

This letter addresses two questions directed by the Metro Public Health Department (MPHD) to the Southern Environmental Law Center (SELC) by e-mail on March 10, 2017:

1. MPHD has identified a few issues with the (selective catalytic reduction) SCR analysis submitted by Bill Powers. Based on our review, the cost breakdown does not appear to include indirect costs such as design, construction, and labor.

2. Also, regarding the 9 ppm, we are being told that there are no Titan 250 models in operation with that technology. If Mr. Powers explained, in sufficient detail, how the technology worked on the smaller models and if it could be applied in the same manner to the larger models, we would be in a better position to evaluate that as well.

These two questions are answered in the following sections.

In addition, three previous Powers Engineering reports demonstrate that (1) SCR at 2.5 ppm $NO_x$ is a cost-reasonable RACT alternative for the permit application under consideration by MPHD,[1] and that (2) an electric motor drive, which would eliminate combustion air emissions at the Joelton Compressor Station, is a technologically and economically feasible RACT alternative that should be fully evaluated by MPHD.[2]

## I. POWERS ENGINEERING SCR COST ANALYSIS DOES INCLUDE INDIRECT COSTS INCLUDING DESIGN, CONSTRUCTION, AND LABOR

Powers Engineering relies on the March 2015 EPA cost estimate for SCR, oxidation catalyst, and continuous emission monitors for a 21.7 MW gas turbine in combined heat and power (CHP) service in the January 2017 Powers Engineering evaluation of the cost

---

[1] Bill Powers, *Selective Catalytic Reduction (SCR) at 2.5 ppm $NO_x$ and Dry Low $NO_x$ Combustion at 9 ppm and 15 ppm are Cost-Reasonable RACT Alternatives to Two Titan Turbines at Proposed Joelton, Tennessee Compressor Station* (Jan. 5, 2017); Bill Powers, *Review of Reasonableness of $NO_x$ Emission Limits for Two Titan Turbines at Proposed Joelton, Tennessee Compressor Station* (July 26, 2016).

[2] Bill Powers, *Electric Motor Drive Is Viable RACT Alternative to Two Titan Turbines at Proposed Joelton, Tennessee Compressor Station* (Nov. 18, 2016).

of SCR submitted by SELC to MPHD.[3] The heat input and exhaust gas flowrate assumed by EPA for the 21.7 MW turbine match those of the Titan 250.[4,5]

As Powers Engineering explained in that letter, the EPA relied on SCR vendor quotations in its March 2015 CHP document to estimate a total installed cost of an SCR/oxidation catalyst/continuous emissions monitor package for the Titan 250 gas turbine.[6] Powers Engineering subsequently deducted the cost of the oxidation catalyst and continuous emissions monitor package to estimate the total capital cost of the SCR.

The EPA cost estimate includes construction labor, project and construction management, development fees, project contingency, and project financing charges, in addition to equipment cost. A list of costs included in the EPA installed cost estimate is provided as an attachment to this response letter.[7]

## II. A CONTROL TECHNOLOGY DOES NOT HAVE TO BE IN OPERATION TO MEET THE "REASONABLY AVAILABLE" REQUIREMENT OF RACT

As explained by EPA in the attached materials and as summarized below, determining what constitutes a reasonably available control technology (RACT) requires a case-by-case analysis, and technology that is RACT does not have to be off-the-shelf or in operation. This principle is consistent with the MPDH regulation that describes a procedure for determining RACT, which includes a requirement that the permittee investigate demonstrated "reasonably available emission reduction methods" before MPHD then determines RACT. [8] MPDH's regulation does not define RACT, therefore EPA's guidance controls.

Here, Tennessee Gas Pipeline Company (TGP) voluntarily proposed meeting a 9 ppm $NO_x$ standard on Titan 250 gas turbines in compressor station applications, in the same year, 2015, that it submitted the air permit application to MPHD for the Joelton Compressor Station.[9] MPHD has confirmed that the manufacturer of the Titan 250, Solar

---

[3] EPA Combined Heat and Power Partnership, *Catalog of CHP Technologies - Section 3. Technology Characterization – Combustion Turbines*, March 2015, p. 15: https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf.
[4] *Ibid.*, Table 3-2, p. 3-6 and p. 3-7.
[5] Solar Turbines, Inc, *Industrial Gas Turbine Product Line and Performance* (brochure), 2016, p. 2. Titan 250 exhaust mass flow: 541,400 lb/hr. Titan 250 fuel heat input: lower heating value (LHV) 190.8 MMBtu/hr (estimated higher heating value = 1.1 × LHV = 210 MMBtu/hr).
[6] EPA Combined Heat and Power Partnership, *Catalog of CHP Technologies - Section 3. Technology Characterization – Combustion Turbines*, March 2015, Table 3-5, p. 3-14, System 4.
[7] *Id.* (**Attachment 1**).
[8] Metro Nashville/Davidson County Health Department Division of Air Pollution Control, Regulation No. 14-3 ("Regulation For Control of Nitrogen Oxides").
[9] TGP, *Environmental Report: Northeast Energy Direct Project, Resource Report 9, Air and Noise Quality*, FERC Docket No. CP16-21, November 2015.

Turbines, has already sold two Titan 250 gas turbines guaranteed at 9 ppm $NO_x$.[10] There is no question that the manufacturer of the Titan 250 is willing and able to guarantee 9 ppm $NO_x$ on the Titan 250, and that the manufacturer was able to do so the year (2015) the Joelton air permit application was filed with MPHD.

The applicable standard for a technology to be technically feasible for application under RACT is "reasonable available."[11] It is not limited to technologies that are currently in operation. The EPA defines "reasonably available" as a stringent and technology forcing requirement that goes beyond off-the-shelf technology.[12] The claim that a 9 ppm $NO_x$ limit on the Titan 250 gas turbine cannot be considered RACT because no Titan 250 with the 9 ppm $NO_x$ control package is yet operational has no merit in the context of the EPA definition of "reasonably available."

## III. CONCLUSION

The SCR cost estimate included in the Powers Engineering January 4, 2017 evaluation of the cost of SCR on a Titan 250 gas turbine includes indirect costs.

Solar Turbines, the manufacturer of the Titan 250, will guarantee 9 ppm $NO_x$, and has offered such guarantees on the Titan 250 since 2015. TGP voluntarily proposed a 9 ppm $NO_x$ limit on the Titan 250 in other compressor station applications in 2015. The manufacturer of the Titan 250 has sold two units equipped with the 9 ppm $NO_x$ control package. The EPA defines "reasonably available" as a stringent and technology-forcing requirement that goes beyond off-the-shelf technology.

Based on my education and experience gained throughout my 35-year career, it is my professional opinion that the 9 ppm $NO_x$ guarantee level offered by Solar Turbines for the Titan 250 meets the EPA definition of "reasonably available" technology. The claim by TGP that the 9 ppm $NO_x$ limit cannot be RACT because a Titan 250 with the 9 ppm $NO_x$ control package is not yet in operation (although two such units have been sold) has no merit as a justification for rejecting the 9 ppm $NO_x$ limit as RACT for the two Titan 250 gas turbines proposed for the Joelton Compressor Station. In addition, SCR at 2.5 ppm $NO_x$, or an electric motor drive which would eliminate combustion air emissions at Joelton, are RACT for this project.

---

[10] Brief of Respondents, *Tennessee Gas Pipeline Co. v. William S. Paul et al*, No. 17-1048 (D.C. Cir. March 2, 2017), pp. 10-11.

[11] EPA, *Implementing Reasonably Available Control Technology Requirements for Sources Covered by the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry*, October 20, 2016, p. 2. "The EPA has defined RACT as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." (**Attachment 2**).

[12] EPA, *Environmental Protection Agency Memorandum on Acceptability of Implementation Plan Regulations in Non-Attainment Areas, 1. Reasonably Available Control Measures, a. Stationary Sources*, December 9, 1976, p. 1210. "RACT encompasses stringent, or even "technology forcing" requirement, that goes beyond simple "off-the-shelf" technology." (**Attachment 3**).

# Catalog of CHP Technologies

## Section 3. Technology Characterization – Combustion Turbines

U.S. Environmental Protection Agency
Combined Heat and Power Partnership

March 2015

**Table 3-5. Estimated Capital Cost for Representative Gas Turbine CHP Systems**[53]

| Cost Component | System | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| Nominal Turbine Capacity (kW) | 3,510 | 7,520 | 10,680 | 21,730 | 45,607 |
| Net Power Output (kW) | 3,304 | 7,038 | 9,950 | 20,336 | 44,488 |
| **Equipment** | | | | | |
| Combustion Turbines | $2,869,400 | $4,646,000 | $7,084,400 | $12,242,500 | $23,164,910 |
| Electrical Equipment | $1,051,600 | $1,208,200 | $1,304,100 | $1,490,300 | $1,785,000 |
| Fuel System | $750,400 | $943,000 | $1,177,300 | $1,708,200 | $3,675,000 |
| Heat Recovery Steam Generators | $729,500 | $860,500 | $1,081,000 | $1,807,100 | $3,150,000 |
| SCR, CO, and CEMS | $688,700 | $943,200 | $983,500 | $1,516,400 | $2,625,000 |
| Building | $438,500 | $395,900 | $584,600 | $633,400 | $735,000 |
| Total Equipment | $6,528,100 | $8,996,800 | $12,214,900 | $19,397,900 | $35,134,910 |
| **Installation** | | | | | |
| Construction | $2,204,000 | $2,931,400 | $3,913,700 | $6,002,200 | $10,248,400 |
| Total Installed Capital | $8,732,100 | $11,928,200 | $16,128,600 | $25,400,100 | $45,383,310 |
| **Other Costs** | | | | | |
| Project/Construction Management | $678,100 | $802,700 | $1,011,600 | $1,350,900 | $2,306,600 |
| Shipping | $137,600 | $186,900 | $251,300 | $394,900 | $674,300 |
| Development Fees | $652,800 | $899,700 | $1,221,500 | $1,939,800 | $3,312,100 |
| Project Contingency | $400,700 | $496,000 | $618,500 | $894,200 | $1,526,800 |
| Project Financing | $238,500 | $322,100 | $432,700 | $899,400 | $2,303,500 |
| **Total Installed Cost** | | | | | |
| Total Plant Cost | $10,839,800 | $14,635,600 | $19,664,200 | $30,879,300 | $55,506,610 |
| Installed Cost, $/kW | $3,281 | $2,080 | $1,976 | $1,518 | $1,248 |

Source: Compiled by ICF from vendor-supplied data.

### 3.4.6 Maintenance

Non-fuel operation and maintenance (O&M) costs are presented in **Table 3-6**. These costs are based on gas turbine manufacturer estimates for service contracts, which consist of routine inspections and scheduled overhauls of the turbine generator set. Routine maintenance practices include on-line running maintenance, predictive maintenance, plotting trends, performance testing, fuel consumption, heat rate, vibration analysis, and preventive maintenance procedures. The O&M costs presented in **Table 3-6** include operating labor (distinguished between unmanned and 24 hour manned facilities) and total maintenance costs, including routine inspections and procedures and major overhauls.

[53] Combustion turbine costs are based on published specifications and package prices. Installation estimates are based on vendor cost estimation models and developer-supplied information.

Attachment 2

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
RESEARCH TRIANGLE PARK, NC 27711

**OCT 20 2016**

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

**MEMORANDUM**

**SUBJECT:** Implementing Reasonably Available Control Technology Requirements for Sources Covered by the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry

**FROM:** Anna Marie Wood, Director Anna Marie Wood
Air Quality Policy Division, OAQPS (C504-01)

**TO:** Regional Air Division Directors, 1 - 10

The purpose of this memorandum is to provide information and guidance on State Implementation Plan (SIP) revisions resulting from the newly-issued Control Techniques Guidelines (CTG) document for the Oil and Natural Gas Industry. The CTG provides recommendations to inform state determinations as to what constitutes reasonably available control technology (RACT) for emission sources covered by this CTG. The 2016 Oil and Gas CTG is available on our website at: *https://www.epa.gov/ozone-pollution/state-implementation-plan-sip-checklist-guide.*

States that contain certain ozone nonattainment areas and states in the Ozone Transport Region (OTR) are required to submit a revision to the RACT provisions in their ozone SIP in response to any newly-issued CTG document. In accordance with the timing set forth in the Oil and Gas CTG, the revision to SIP RACT provisions for sources covered by the CTG are due 2 years after the CTG Notice of Availability is published in the *Federal Register*. Sources covered by this CTG include those located in 2008 ozone National Ambient Air Quality Standards (NAAQS) nonattainment areas classified as Moderate (or higher) and the states in the OTR, although states may also apply the recommendations in this CTG to sources in other areas. The emissions controls determined by the state to be RACT for sources covered by the Oil and Gas CTG must be implemented as soon as practicable, but in no case later than January 1, 2021.

Tribes may choose to adopt RACT provisions in a Tribal Implementation Plan (TIP) to address the Oil and Gas CTG in Indian country.[1] Consistent with the Clean Air Act (CAA) and the Tribal Authority Rule (TAR), where tribes do not develop a TIP for nonattainment areas of Indian country classified as

[1] On January 17, 2014, the United States Court of Appeals for the District of Columbia Circuit issued a decision vacating the Environmental Protection Agency's 2011 rule titled, "Review of New Sources and Modifications in Indian Country" (76 FR 38748) with respect to non-reservation areas of Indian country unless a tribe or the EPA demonstrates that a tribe has jurisdiction in a particular area (*See Oklahoma Department of Environmental Quality v. EPA*, 740 F.3d 185 (D.C. Cir. 2014)). Under the court's reasoning, with respect to CAA SIPs, a state has primary regulatory jurisdiction in non-reservation areas of Indian country (i.e., Indian allotments located outside of reservations and dependent Indian communities) within its geographic boundaries unless the EPA or a tribe has demonstrated that a tribe has jurisdiction over a particular area of non-reservation Indian country within the state.

Moderate (or higher) for the 2008 ozone NAAQS, the EPA will adopt a Federal Implementation Plan if it determines that doing so is necessary or appropriate to protect air quality. *See* CAA §301(d), 40 CFR 49.4, and 40 CFR 49.11.

The Oil and Gas CTG includes model rule language for air agencies to consider in developing their RACT provisions. The model rule language was developed to assist air agencies in situations where they may not have monitoring, inspection and performance testing provisions necessary for RACT. In some cases, the model rule language may need to be revised to make it adequate for SIP approval purposes. The model rule language may assist with determining compliance requirements where air agencies determine the recommendations in the Oil and Gas CTG constitute RACT.

The EPA has provided RACT implementation policies in previous guidance documents available at *https://www.epa.gov/ozone-pollution/state-implementation-plan-sip-checklist-guide*. The RACT policies describe the general process for case-by-case RACT determinations and how air agencies can judge the feasibility of imposing the recommended controls within their particular jurisdictions and adjust the control recommendations as appropriate and justified. The recommended controls in the Oil and Gas CTG are the "presumptive norm" based on general industry parameters and published assumptions. In its review and approval process for case-by-case RACT determinations, the EPA will consider the information in the CTG, as well as information submitted by the air agencies and the public.

The EPA has defined RACT as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.[2] The General Preamble Supplement (September 17, 1979; 44 FR 53761), goes on to indicate that RACT for a particular source is determined on a case-by-case basis, considering the technological and economic circumstances of the individual source. In evaluating economic feasibility for RACT determinations, the EPA gives significant weight to economic efficiency and relative cost-effectiveness.[3] The EPA has not established universal decision criteria for technological and economic feasibility that would apply in every case, and did not establish decision rules that would have restricted the cost consideration in determining whether an emissions control is considered "cost effective." Therefore, all RACT determinations are considered case-by-case determinations.

The Oil and Gas CTG contains recommended controls that states may readily adopt, subject to EPA approval, for groups of covered sources. However, a state may also consider the uniqueness of a specific source's operations in evaluating whether the recommended controls are RACT for that source. The air agency should provide EPA with the information supporting the source-specific determination of RACT for each source. This demonstration could take into account cost effectiveness. Where the EPA determines that the air agency has shown that an alternative to the controls recommended in the CTG satisfies the requirements for RACT, the EPA will propose to approve the RACT demonstration.

The attached RACT Questions and Answers (Q&A) document addresses issues raised during the comment period on the draft Oil and Gas CTG. The Q&A document provides additional clarifications that we believe may be helpful to the air agencies preparing the ozone SIP revisions triggered by the issuance of the 2016 Oil and Gas CTG. Please distribute this document to your states, local control

[2] The EPA articulated this definition of RACT in a memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management, to Regional Administrators Regions I-X, titled "Guidance for Determining Acceptability of SIP Regulations in Non-attainment Areas," (December 9, 1976).

[3] The role of economic feasibility is discussed in the June 19, 1985, EPA memorandum titled, "Criteria for Determining RACT in Region IV."

agencies and tribal governments. Regional office staff may contact Butch Stackhouse at (919) 541-5208 or *stackhouse.butch@epa.gov*, with questions about RACT policy, and Bruce Moore at (919) 541-5460 or *moore.bruce@epa.gov*, with questions about the CTG recommendations.

Attachment

## Attachment

## Questions and Answers Regarding the Control Techniques Guidelines (CTG) for the Oil and Natural Gas Industry (Oil and Gas CTG)

Reasonably Available Control Technology (RACT) Requirements for 2008 Ozone National Ambient Air Quality Standards (NAAQS) Nonattainment Areas and Ozone Transport Region (OTR) States

Q1: When do the states with Moderate (or higher) ozone nonattainment areas for the 2008 ozone NAAQS and states in the OTR need to submit State Implementation Plan (SIP) revisions to address the Oil and Gas Control Techniques Guidelines (CTG)?

A1: Clean Air Act (CAA) section 182(b)(2) provides that the EPA Administrator will establish a deadline for SIP revisions addressing RACT for sources covered by any new CTG. The 2016 Oil and Gas CTG is considered to have been issued upon its effective date which is the same date that it is published in the *Federal Register*. The SIP revisions are due to the EPA 2 years after the CTG is issued. This deadline applies for areas classified as Moderate (or higher) for the 2008 ozone NAAQS, and to states in the OTR as of the date the CTG is issued.

Q2: What is the maximum amount of time that a SIP revision for the 2008 ozone NAAQS RACT requirements arising from the 2016 Oil and Gas CTG may allow for subject sources to comply with the new RACT requirements?

A2: The SIP revision should provide for RACT to be implemented as expeditiously as practicable. For the previous 1-hour ozone NAAQS, section 182(b)(2) of the CAA provided a time limit for implementation of approximately 30 months. For the 2008 ozone NAAQS, the EPA adopted similar timing for RACT submissions triggered by area designations, setting a deadline of January 1 of the 5th year after the effective date of designation for that NAAQS (*see* 40 CFR 51.1112(a)(3)). For purposes of the 2016 Oil and Gas CTG, we are applying similar deadlines as provided in 40 CFR 51.1112(a)(3), which means that all RACT requirements must be implemented by January 1 of the 5th year after the CTG is issued, *i.e.*, by January 1, 2021. We also note that the ozone implementation rules at 40 CFR 51.1108(d) provide that all measures a state intends to rely on for attainment must be implemented no later than the beginning of the last full ozone season before the attainment date. So, if a state intends to rely on reductions from new Oil and Gas measures for purposes of attaining the 2008 ozone NAAQS, the RACT rules must require compliance no later than the beginning of the 2017 ozone season for Moderate areas, and the beginning of the 2020 ozone season for Serious areas.

Q3: Do tribes need to meet the same submittal and implementation deadlines if they choose to develop a Tribal Implementation Plan (TIP)?

A3: The Tribal Authority Rule (TAR) at 40 CFR 49.4 states that tribes will not be treated as states with respect to certain plan submittal and implementation deadlines for the NAAQS and other CAA deadlines including requirements under CAA §182. While the TAR provides that the EPA "[s]hall promulgate without an unreasonable delay such federal implementation plan provisions as are necessary or appropriate to protect air quality" where a TIP is not adopted by a tribe, the EPA has flexibility with regard to the timing for doing so. *See* CAA §301(d) and 40 CFR 49.11.

Q4: Does issuance of the 2016 Oil and Gas CTG create a separate RACT determination obligation for areas that were nonattainment for the 1997 ozone NAAQS at the time it was revoked?

A4: No. We revoked the 1997 ozone NAAQS effective April 6, 2015, but retained certain requirements for areas under our regulatory anti-backsliding provisions. *See* 40 CFR 51.1105. Under the anti-backsliding provisions, only the CTG-related RACT requirements under the 1997 ozone NAAQS that applied to an area at the time of revocation of the 1997 ozone NAAQS (April 6, 2015) were retained. Since the new Oil and Gas CTG was issued after April 6, 2015, it is not an applicable anti-backsliding requirement for the previous 1997 ozone nonattainment areas under our anti-backsliding regulations.

Q5: Can the recommendations in the 2016 Oil and Gas CTG be applied to relevant sources not otherwise subject to the CAA's RACT requirement?

A5: Yes. States may use the CTG, including the model rule language, as a reference for establishing emissions controls for existing oil and gas sources not subject to the CAA's RACT requirements. This would include sources located in attainment areas and in Marginal nonattainment areas. Because controls for such sources are optional, the CAA and EPA's rules do not specify an implementation deadline for such controls.

RACT Determinations

Q6: What flexibility do states with established oil and gas sector regulations have in establishing RACT for their sources covered by the 2016 Oil and Gas CTG?

A6: The Oil and Gas CTG provides presumptions of what technology is reasonably available. These presumptions are provided for the purpose of informing RACT determinations made by air agencies. These presumptions, however, are not binding. The air agencies may justify the implementation of other technically-sound approaches that are consistent with the CAA, the EPA's implementing regulations, and policies on interpreting RACT. Regardless of whether an air agency chooses to adopt rules implementing the recommendations contained in the CTG or to issue rules that adopt different approaches for RACT for volatile organic compounds emitted from oil and natural gas industry sources located in the OTR states or in the relevant nonattainment areas in its jurisdiction, air agencies must submit their RACT rules to the EPA for review and approval using the SIP process. The EPA will evaluate the submissions and determine, through notice and comment rulemaking, whether the submitted rules meet the RACT requirements of the CAA and the EPA's regulations.

Q7: Can an air agency determine that the RACT requirement for oil and natural gas sources is met with the federal oil and natural gas New Source Performance Standards (NSPS)?

A7: The EPA has not made a determination that the NSPS (40 CFR part 60, subpart OOOOa), which differs from the 2016 Oil and Gas CTG in several respects, is presumptively RACT. Moreover, the federal oil and gas NSPS does not apply to existing sources. If the air agency believes that the NSPS establishes RACT-level controls for one or more sources, the air agency may submit those rules as a SIP revision. Any such SIP would need to clearly apply the control requirement contained in the NSPS to relevant existing sources in the specific nonattainment area or OTR state. The EPA will evaluate the submitted rules and determine, through notice and comment rulemaking in the SIP revision process, whether the submitted rules meet the RACT requirements of the CAA and the EPA's regulations.

Q8: Can an air agency submit a negative declaration that a specific nonattainment area or entire OTR state has no sources covered by the 2016 Oil and Gas CTG?

A8: Yes. The air agency must provide and submit such a declaration as a formal SIP revision that complies with the requirements of the CAA and 40 CFR part 51, Appendix V (e.g., the declaration is subject to public process) and provide documentation supporting the negative declaration.

Q9: Can an air agency demonstrate that implementing the recommended RACT controls in the CTG is not technologically and economically feasible due to particular circumstances of a specific source (e.g., considering the cost-effectiveness of the control when the VOC content of the gas is very low)?

A9: Yes. Cost-effectiveness can be a relevant consideration when evaluating the technological and economic feasibility of a control. Such a demonstration would need to include documentation of the specific factors that lead to the agency's conclusion that an alternative control is justified as RACT in lieu of the CTG-recommended RACT for the relevant source or sources.

Q10: Can an air agency use the VOC content of an oil or gas stream as an applicability threshold for determining whether a RACT determination is required for a source covered by the 2016 Oil and Gas CTG?

A10: No. The emissions sources covered by the 2016 Oil and Gas CTG's recommendations do not depend on and are not defined by VOC content thresholds. However, an air agency could determine that, based on the VOC content of an oil or gas stream at a specific source, the recommended RACT is not technologically or economically feasible. This should be a source-specific conclusion, and not a conclusion that is applied to all sources with relatively low VOC concentration oil or gas streams without regard to volume or throughput. The EPA's policies encourage air agencies to consider the VOC emission potential of sources in their area and how they may differ from those considered in the analyses that support the recommendations in the 2016 Oil and Gas CTG when they make their RACT determinations.

Q11: Can an air agency determine that VOC reductions will not improve ozone air quality in the nonattainment area (*i.e.*, the area is nitrogen oxide (NOx) limited) and, therefore, determine no further VOC controls are required to meet RACT requirements triggered by the 2016 Oil and Gas CTG?

A11: No. The CAA does not exempt areas that are NOx-limited from meeting RACT requirements for sources of VOC. Section 182(b)(2)(A) of the CAA provides that for Moderate (or higher) ozone nonattainment areas, air agencies must revise their SIPs to include RACT for each category of VOC sources covered by a CTG document issued between November 15, 1990, and the date of attainment. CAA Section 184(b) requires that state air agencies in the OTR must revise their SIPs to implement RACT with respect to all sources of VOC in the state covered by a CTG. Therefore, all states in the OTR and all Moderate (or higher) ozone nonattainment areas are required to make RACT determinations for sources covered by the 2016 Oil and Gas CTG.

Q12: Can an air agency establish a framework for implementing voluntary measures for sources covered by the CTG to fulfill the statutory RACT requirement?

A12: No. RACT measures must be permanent and enforceable emission controls.

Q13: Can an air agency exclude from their RACT determinations those sources implementing best management practices?

A13: No. RACT determinations must be made for all sources covered by the 2016 Oil and Gas CTG.

RACT Requirements for Nonattainment Areas and OTR States Associated With the 2015 Ozone NAAQS

Q14: Will an air agency's RACT determination for oil and natural gas sources in their state, required for purposes of the 2008 ozone NAAQS, also satisfy the future RACT requirement for those same sources for purposes of the 2015 ozone NAAQS?

A14: For air agencies submitting SIP revisions to address RACT for sources covered by the 2016 Oil and Gas CTG during the first few years after nonattainment designations for the 2015 ozone NAAQS, it is likely any RACT determinations just recently completed for the 2008 ozone NAAQS would not change. However, air agencies required to address RACT under the 2015 ozone NAAQS will need to review existing RACT determinations to determine whether existing rules still meet RACT for all covered sources at the appropriate time for purposes of the 2015 ozone NAAQS. This review should take into account any sources affected by any differences that might exist between the nonattainment area boundaries for the 2015 and 2008 ozone NAAQS. For example, a larger nonattainment area for the 2015 NAAQS might result in RACT determinations for additional sources. If the air agency determines that the RACT requirement for the 2015 ozone NAAQS is the same as the determination made for the 2008 ozone NAAQS, the air agency could submit a certification letter explaining the basis for this determination. A state's SIP submission in the form of a certification letter attesting that the state's SIP already contains adequate provisions to satisfy the RACT requirement for sources covered by the 2016 Oil and Gas CTG must come to the EPA as a SIP submission in accordance with 40 CFR part 51, Appendix V, which includes a state notice-and-comment process.

Q15: Where an air agency submits a negative declaration (that the area in question has no sources to which the CTG is applicable) under the 2008 ozone NAAQS, are they required to submit a new negative declaration for the RACT requirement for the 2015 ozone NAAQS?

A15: Yes. Air agencies may not rely on negative declarations submitted for purposes of any prior ozone standard to fulfill a new RACT determination requirement triggered by the establishment of a new ozone standard. It is possible that since the period of the last negative declaration, new CTG-covered sources have been located in the area where RACT must be addressed. Air agencies, therefore, must provide and submit a new SIP revision (which is subject to public notice and comment) containing either new RACT determinations or a new negative declaration.

Q16: When must air agencies governing nonattainment areas or OTR states submit a SIP revision for RACT to the EPA? What is the required implementation date for any emission limits/controls determined to be RACT in the state's SIP revisions for the 2015 ozone NAAQS?

A16: These deadlines are derived from the RACT requirements in CAA section 182(b)(2). The EPA has not yet finalized an Implementation Rule for the 2015 ozone NAAQS, but we anticipate that the RACT deadlines for the 2015 ozone NAAQS will follow the same schedule as those associated with the 1997 and 2008 ozone NAAQS. For both the 1997 and 2008 ozone NAAQS, the EPA's implementation rules provided that RACT SIP submissions were due 24 months after the effective date of area designation.

Those rules further provided that air agencies must require affected sources to implement RACT rules as expeditiously as practicable, but no later than January 1 of the 5th year after the effective date of designation. Those rules also indicate that any measures relied on for demonstrating attainment must be implemented no later than the beginning of the final full ozone season preceding the attainment date. *See* 40 CFR 51.1108. In some circumstances, that date would precede the latest date for implementing RACT under the RACT regulatory provisions.[4]

Q17: If an air agency applies CTG-recommended controls to oil and gas sources located in attainment areas outside the OTR, can the reductions be credited in the state's ozone SIP?

A17: In certain cases VOC emissions controls on oil and gas sources located outside ozone nonattainment areas may help improve air quality in the downwind nonattainment areas. Reductions from sources outside a nonattainment are not creditable toward fulfillment of CAA-required reasonable further progress goals in those nonattainment areas. However, if states determine that such reductions are beneficial, CAA section 172(c)(6) indicates that these control measures should be considered for inclusion in the state's attainment plan.

[4] For reference, the SIP revision schedule for RACT for the 2008 ozone NAAQS can be found at 40 CFR 51.1112(a)(2) and (3). Additional information regarding RACT requirements for the 2008 ozone NAAQS can be found in the March 6, 2015, *Federal Register* notice (80 FR 12263) on page 12278 in section 1, and in the EPA's responses to questions 14, 36 and 37 of the May 18, 2006, Q&A document (available *at https://www3.epa.gov/ttn/caaa/t1/memoranda/ractqanda.pdf*).

JOHN SILVASI
Attachment 3
Boch

**Full Text**

TABLE OF CONTENTS



## ENVIRONMENTAL PROTECTION AGENCY MEMORANDUM ON ACCEPTABILITY OF IMPLEMENTATION PLAN REGULATIONS IN NONATTAINMENT AREAS

**December 9, 1976**

SUBJECT: Guidance for determining Acceptability of SIP Regulations In Non-attainment Areas

FROM: Roger Strelow, Assistant Administrator for Air and Waste Management

MEMO TO: Regional Administrators, Regions I-X

The basis for fully approving state-submitted SIP regulations continues to be demonstrated attainment and maintenance of all national ambient air quality standards as expeditiously as practicable. If the plan demonstrates attainment and maintenance, EPA is required to approve the state regulations. EPA cannot disapprove them because they are too stringent or because EPA considers them not stringent enough (for example, because they are less stringent than a comparable Federal regulation or because they control fewer sources than controlled by Federal regulations), providing the overall SIP shows attainment and maintenance as quickly or quicker than any other available control strategy. If the state plan shows attainment and maintenance, Federal regulations may be revoked at the time of approval.

Especially for oxidant, carbon monoxide, and particulate matter (in areas dominated by urban fugitive dust), control measures required to attain the standards may be technically impossible or socially or economically unacceptable within a short time frame. In this situation, EPA still cannot disapprove state regulations because they are "too stringent," and industry cannot successfully challenge an approval on the ground that the requirements are technologically or economically infeasible. On the other hand, EPA must disapprove the state regulations if they are not stringent enough. The test for approvability of individual regulations is whether they require, at a minimum, all reasonably available controls on a source as expeditiously as practicable. This memorandum seeks to provide guidance as to how to ascertain if state regulations meet these minimum requirements. The use of any given level of control which fails to assure attainment should only be considered to be an interim measure. As control technology improves and as new control measures become feasible for an area, it will be necessary for the SIP to be periodically revised to include these measures until attainment and maintenance can be demonstrated.*

### 1. Reasonably Available Control Measures

*a. Stationary Sources*

With respect to individual point sources and area sources with defined emission points (i.e., those amenable to the application of "classical" control equipment), reasonably available control technology (RACT) defines the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. Thus, RACT encompasses stringent, or even "technology forcing," requirement that goes beyond simple "off-the-shelf" technology. As noted, RACT is the minimum EPA can accept in non-attainment state plans.

The determination of RACT and the corresponding emission rate, ensuring the proper application and operation of RACT, may vary from source to source due to source configuration, retrofit feasibility, operation procedures, raw materials, and other technical or economic characteristics of an individual source or group of sources. In order to assist the Regions in determining the impact of these variables on RACT, OAQPS is continuing to develop RACT guidance materials (see attached status report). This material describes what can be accomplished with good technology

* As stated at the outset of this memorandum, the test for approving the entire control strategy — and for EPA thus not having to promulgate any measures — continues to be demonstrated attainment and maintenance of the NAAQS.

and defines things that should be considered in establishing an emission limit for a specific source of that type. In determining RACT for an individual source or group of sources, the control agency, using the available guidance, should select the best available controls, deviating from those controls only where local conditions are such that they cannot be applied there and imposing even tougher controls where conditions allow. For example, the best available control for a boiler burning coal and bark at a pulp mill is multiclone followed by an electrostatic precipitator (ESP), the two control devices having an overall collection efficiency of 99.5%. However, in areas where the bark or similar fuel has a high salt content as a result of the logs being floated in the estuary portion of the river, it may be that the technological and economic problems of installing and operating a large, corrosion resistant ESP may prove unreasonable. More technological and economically feasible controls consisting of a multiclone and wet collector designed to withstand the corrosive conditions, and perhaps functioning more effectively on a salt fume than an ESP, depending on the pressure drop employed, may constitute RACT under the conditions cited. In every case RACT should represent the toughest controls considering technological and economic feasibility that can be applied to a specific situation. Anything less than this is by definition less than RACT and not acceptable for areas where it is not possible to demonstrate attainment.

As a further assistance to the Regions in defining RACT for the more difficult or the far from textbook situations, OAQPS's Emission Standards and Engineering Division (ESED) will establish a consulting group to support the Regions. This group will include ESED staff but will also include technical expertise from OE and the Regional Offices. In specific instances, the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) may be asked to assist in a RACT determination. The consulting group is being established as a service to the Regions and it should not be looked at as a clearinghouse for regional RACT determinations. These decisions are yours to make. The group is designed to help you as needed on the most difficult cases.

b. Mobile and Area Sources

As with point sources, measures which constitute reasonably available controls for mobile sources and area sources with undefined emission points may represent relatively stringent requirements which in many situtations forces the application of measures not previously adopted or implemented in a given area. These measures include vehicle inspection and maintenance, transportation control and land use measures, certain controls on fugitive and reentrained dust, and other measures which may influence customary life styles. They do not include clearly unreasonable measures such as substantial gasoline rationing. Moreover, what may be reasonable in one area may be unreasonable in another. For example, while it may be reasonable as a transportation control measure to quickly reduce the number of cars permitted to enter the central business district in a city with a good mass transit system, it would not be reasonable to do this on the same timetable in a city with a poor mass transit system.

2. Documentation

In those situations where the State's control strategy cannot demonstrate attainment it will be necessary for the State to document that their control strategy represents the application of reasonably available control measures to all available source categories. The Region should not approve a control strategy that does not contain sufficient documentation to show that the required control measures are the toughest that are reasonably available for the sources in the area covered by the control strategy.

3. Replacement of Federal Regulations

In some areas the SIPs already contain EPA regulations representing reasonably available controls that generally reflect a national definition of reasonably available controls for that source category and that were arrived at by EPA after proposal and public hearing, (e.g., Stage I and II gasoline marketing regulations in 16 AQCRs; transportation control measures in 28 AQCRs).

In these situations there is inherently less flexibility in the definition by the state of reasonably available controls and specific justification will be needed before EPA could approve a regulation which exempts significantly more sources, or which imposes controls significantly less stringent, than the Federal regulations. This justification should document the specific case-by-case economic, technical or other factors which cause the state's regulations, although significantly different from the Federal regulation, to include all that is reasonable for a specific area. (The state regulation would still have to conform to the criteria outlined for defining reasonable control measures.) Such justification must be provided not only as a basis for approval of the state regulations, but also to protect the enforceability of comparable Federal and state regulations in other areas. In the absence of acceptable justification, the state regulation exempting some sources can be approved as far as it goes and the Federal regulation should remain in effect to cover sources for which the state's regulation does not apply. Of course, nothing should preclude a state from adopting and this Agency approving a regulation which requires more control than the Federally promulgated regulation.

Since it is the Agency's objective to encourage the states to develop and implement regulations to replace EPA regulations, the Agency may approve state regulations that are only marginally different from the Federal regulations without the detailed justification noted above if, in the Regional Administrator's judgment, the impact on emissions differs imperceptibly (less than 5% in cases where it is possible to quantify the difference) from that of the Federal regulations and there is no significant threat of undermining EPA activities elsewhere in the nation. When determining if a state regulation is environmentally equivalent to the Federal regulation, EPA can only look at the particular measure being implemented. In other words, it would be unacceptable to approve a measure requiring significantly less control than the corresponding Federal measure on the basis that other control measures implemented in the same area are significantly more stringent than the comparable Federal measures. In areas where attainment cannot be demonstrated, all reasonable measures on all source categories are needed.

To further encourage states to replace EPA regulations, reasonable additional time generally may be granted to comply with replacement regulations providing the new compliance dates (effective dates) are not clearly excessive. We cannot expect a state to adopt regulations which depend upon the prior Federal regulations to alert sources to the steps needed for control, except in those cases where the state regulation is substantially identical to the Federal regulation which it replaces. On the other hand, granting of additional time must be done with care so as not to undermine the action-forcing role of firm deadlines in EPA efforts elsewhere. The use of a "good faith efforts" test will be appropriate in some circumstances.

4. Conclusion

In concluding, I would like to reiterate the fact that the air quality standards are not being attained in many of these RACT areas. Therefore, we cannot relax the intensity of the air pollution control effort. We should ensure that all sources contributing to the nonattainment situation are required to implement restrictive available control measures even if it requires significant sacrifices.

cc: Mr. Tuerk, Mr. Barber, Mr. Legro, Mr. Bonine, Mr. Hidinger.

## ENVIRONMENTAL PROTECTION AGENCY TRANSITION ISSUE PAPER ON FUNDING FOR THE SEWAGE TREATMENT CONSTRUCTION GRANTS PROGRAM

Transition Issue Paper
Funding for the Construction Grants Program

*Issues.*

EPA is requesting additional funding authorizations for the grants program for construction of municipal wastewater treatment works totalling $4.5 billion per year for 10 years, beginning in FY 1977. [1] Concurrently, amendments are proposed to extend the length of the reallotment period by one year and to change eligible treatment categories. [2] The $45 billion total will supplement the $18 billion authorized under Public Law 92-500 and the $480 million appropriated for Title III of the Public Works Employment Act (P. L. 94-369). The new authorizations will provide sufficient funding to satisfy the federal share of construction needs for those treatment works categories eligible for federal grants if the EPA amendments are adopted. Outlays for this program result in about one quarter million jobs annually, considering both direct and indirect employment.

EPA has projected a personnel need for over 400 new positions in the regional offices in FY 1978 for the construction grants program, and approximately 300 of these positions are needed in FY 1977. The needs projection is based on a task-by-task analysis of the minimum needs necessary to operate the program in FY 1978, assuming $4.5 billion would be appropriated starting in FY 1977 and continued for several years thereafter. Assignments to the construction grants program in FY 1977 now total 907, with 69 in Headquarters and 838 in the regional offices.

EPA has revised its request after receiving the OMB passback to at least 300 new positions in FY 1978. The November OMB passback provided no new positions. The EPA construction grants program under P. L. 92-500 has never been at full strength. Over 300 new positions are necessary to just cover the accelerated workload required under the law from increased obligation rates and higher numbers of active projects. The workload resulting from increased management initiatives to ensure both program and fiscal integrity has *not* been considered in the basic needs methodology, although addition of the new positions will allow these initiatives to begin. If no new positions are allocated in either FY 1977 or FY 1978 to cover the greatly increased program workload, the impact on program quality would be severe. Without new resources beyond the level required for routine processing, the potential for major irregularity remains extremely high.

1. *Current Program Status — Construction Grants Program.*

Funding for new grants is now available from two sources: $18 billion in P. L. 92-500 contract authority funds and $480 million appropriated by P. L. 94-447 for P. L. 94-369. The contract authority funds were allotted to the States in four segments — $2 billion in FY 1973; $3 billion in FY 1974; $4 billion in FY 1975; and, $9 billion in FY 1976. The funds are currently available to the states for one year after the end of the fiscal year for which they are alloted. The unobligated balances at the end of the allotment period are subject to reallotment to the remaining states. The funds available under P. L. 94-369 are to remain available until expended. P. L. 94-369 funds were released to the states for obligation on November 19, 1976, and only small amounts have been obligated to date.

As of October 31, 1976, $11.5 billion has been obligated from contract authority funds and $3.8 billion has been expended. Tables II and III present the obligations and outlays by state. About 90% of the obligations have been for construction projects, with the remainder divided among preliminary planning and design work.

Of the 7,600 currently active P. L. 92-500 projects, approximately 4,300 are in the facilities planning stage, 1,000 are under design, and 2,300 have received construction awards. An additional 1,200 projects, totalling $4.0 billion in grants, still remain active from funds awarded under laws prior to P. L. 92-500.

2. *Reimbursable Grants.*

Total claims for reimbursement under Section 206(a) as of January 31, 1974, including disputed claims, are $2,668 million on approximately 5,100 projects. Funding currently appropriated to cover these claims totals $2,100 million and the total cumulative reimbursement to each project will be 78.7% of the amount claimed. In order for EPA to award the remaining $568 million in eligible reimbursable claims, an additional $68 million would have to be authorized and an additional $568 million would have to be appropriated.

EPA requested $200 million in the FY 1978 budget to reimburse projects eligible under Section 206(a) of P. L. 92-500. The additional $200 million would raise the percentage awarded to each project to over 85%. The $200 million EPA request was not included in the FY 1978 budget passback from OMB.

3. *State FY 1976 Funding Problems.*

Eleven states are projected to run out of currently available funds sometime before the last month of FY 1977. Eight other states are now expected to lose money if the reallotment date for the FY 1976 allotment is not extended.

4. *Total Needs for Construction Grants.*

Enactment of the proposed amendments reduces the Federal share of needs to approximately $45 to $55 billion. The 10 year funding request is based on incomplete FY 1976 Needs Survey figures. More complete figures are expected to be available in January.

5. *The FY 1978 Construction Grants Budget.*

As part of the multiyear funding strategy, EPA has requested new authority in FY 1977 and FY 1978 of $4.5 billion per year. The FY 1977 request will be a supplemental to the current FY 1977 budget. It assumes enactment of the

[1] The original EPA request to OMB was for $5 billion per year for ten years, starting in FY 1977. EPA revised its request based on the November budget passback.

[2] The five construction grants amendments are being proposed in an authorization package to be sent to Congress through OMB in January 1977. See Table I.

# Exhibit 5

# Comments on Proposed Joelton Compressor Station Air Permit Conditions and the Reasonably Available Control Technology Analysis Relied On by Metro Nashville to Justify Its $NO_x$ RACT Determination

Bill Powers, P.E., Powers Engineering, San Diego, California

June 15, 2017

This comment letter addresses deficiencies in the draft air permit conditions prepared by Metropolitan Nashville and Davidson County Health Department, Pollution Control Division (Metro Nashville) for the two Titan 250 gas turbines currently proposed by the Tennessee Gas Pipeline Company, LLC, a Kinder Morgan (KM) company, for the Joelton Compressor Station in Nashville, TN. This comment letter also addresses deficiencies in the Metro Nashville Reasonably Available Control Technology (RACT) analysis for nitrogen oxides ($NO_x$) included in the Responses to Comments Document (RTC).

Shortcomings in the draft permit conditions and suggested corrective actions are discussed in **Section I** of these comments. Primary among deficiencies in the draft permit conditions is the lack of adequate monitoring and reporting requirements to assure continuous compliance with the air permit $NO_x$ limits. Metro Nashville proposes a $NO_x$ limit of 9 ppm (corrected to 15 percent oxygen) when the gas turbine(s) operate between 80 and 100 percent of full capacity, and 15 ppm when the gas turbine(s) operate between 40 and 80 percent of full capacity. Without sufficient monitoring and reporting, regulators will be unable to verify that the turbines are meeting these tiered emissions limits. To demonstrate compliance with permit limits, a $NO_x$ continuous emission monitoring systems (CEMS) must be installed on each gas turbine at Joelton.

**Section II** of these comments discusses deficiencies in Metro Nashville's RACT analysis. Selective catalytic reduction (SCR) with a $NO_x$ outlet concentration of 2.5 ppm should have been selected as $NO_x$ RACT for the proposed gas turbines. Metro Nashville uses numerous erroneous inputs to inflate the cost-effectiveness of SCR emissions control technology to $13, 471/ton in the $NO_x$ RACT analysis it includes in the RTC, and relies on this flawed analysis to incorrectly assert that SCR is cost infeasible for the Joelton gas turbines. Proper RACT analysis shows that SCR is cost-reasonable for the Joelton Compressor Station at approximately $4,745/ton of $NO_x$ removed.

## I. THE DRAFT AIR PERMIT CONDITIONS CONTAIN NUMEROUS DEFICIENCIES, INCLUDING A LACK OF ADEQUATE MONITORING TO ENSURE THAT THE TURBINES COMPLY WITH $NO_X$ LIMITS.

Should EPA determine that the $NO_x$ limits proposed by Metro Nashville are adequate, there are a number of deficiencies in the draft air permit that must be corrected. The deficiencies in the draft air permit, and recommended corrective action, are listed in Table 1.

***Table 1. Joelton Draft Air Permit Deficiencies and Recommended Corrective Action***

| Draft Permit Condition Number | Deficiency | Corrective Action |
|---|---|---|
| 6 (Table – Mass Emission Standards) | High load $NO_x$ limit is 9 ppm, yet annual $NO_x$ emission limit of 50.0 tpy assumes continuous 15 ppm limit. | The annual $NO_x$ limit must be based on the high load $NO_x$ limit of 9 ppm and must be set at 30 tpy $NO_x$. Permittee can petition for waiver if annual $NO_x$ emission 30 tpy limit is exceeded due to continuous or near-continuous operation at less than 80% of turbine capacity. |
| 6 (Table – Mass Emission Standards) | No ppm limits are set for CO or VOC. The hourly emission limits imply the CO limit is 25 ppm and the VOC limit is 5 ppm (as $CH_4$). | Explicitly state the hourly CO and VOC ppm limits in the air permit. |
| 7 | Logging of daily fuel flow is insufficient. Emission standard is hourly. | Log hourly fuel flow on each turbine. Report hourly fuel flow. Identify in permit hourly fuel flow that represents 80% of gas turbine capacity. |
| 12(d) | A $NO_x$ continuous emissions monitor (CEM) is not required on each turbine. | Require use of $NO_x$ CEM on each turbine, identified as a monitoring alternative in 12(d), Report hourly average $NO_x$ level. |
| 12(j) | No initial compliance testing is required for CO or VOC. | Require initial compliance testing for CO and VOC, both below and above 80% gas turbine capacity level. Monitor and report exhaust gas temperature during compliance testing. |
| None | There is no statement that the Titan 250s will utilize oxidation catalyst for CO and VOC control. | State that the gas turbines will utilize oxidation catalyst for CO and VOC control. |
| None | No continuous monitoring of exhaust gas temperature is required to confirm oxidation catalyst is functional. | A. Identify minimum exhaust gas temperature at which oxidation catalyst is fully operational.<br>B. Require monitoring of exhaust gas temperature and report hourly average of exhaust gas temperature in quarterly excess emissions report. |

Metro Nashville must address these issues before the permit is issued. Given the proposed $NO_x$ emission permit conditions, requiring continuous emissions monitoring is especially important. This issue is discussed in more detail below.

### A. A continuous emission monitoring system is necessary to demonstrate that the $NO_x$ limit is achieved.

The unusual tiered $NO_x$ permit limits proposed by Metro Nashville in the draft permit necessitate continuous monitoring to ensure continuous compliance with permit conditions. Metro Nashville proposes a $NO_x$ limit of 9 ppm (corrected to 15 percent oxygen) when the gas turbine(s) operate between 80 and 100 percent of full capacity, and 15 ppm when the gas turbine(s) operate between 40 and 80 percent of full capacity. The capacity level will be determined by the fuel flowrate. No monitoring of exhaust gas temperature is proposed to assure the oxidation catalyst that will be installed on the gas turbine(s) to control CO and VOC emissions is fully operational. No continuous $NO_x$ monitoring is proposed to determine whether or not the turbine(s) is achieving a 9 ppm $NO_x$ limit when it is operating at or above 80 percent of full capacity.

Numerous gas turbines in compressor applications around the country utilize $NO_x$ CEMS to continuously monitor $NO_x$ emissions. Examples of gas turbines in compressor applications that utilize $NO_x$ CEMS are provided in Table 2.

***Table 2. Examples of gas turbines in compressor applications with $NO_x$ CEMS***

| Name | State | Turbine type | Unmanned (Y/N)? | $NO_x$ CEMS (Y/N)? |
|---|---|---|---|---|
| Seligman[1] | AZ | Frame 5 | Y | Y |
| Armagh[2] | PA | GE Frame 5 | Y | Y |
| Leesburg[3] | VA | Taurus 60 | Y | Y |
| Cove Point[4] | MD | Frame 7 | N | Y |

[1] Arizona Department of Environmental Quality, Technical Review and Evaluation, Air Quality Permit No. 48823 El Paso Natural Gas Company Seligman Compressor Station, April 25, 2011, p. 2.

[2] Pennsylvania Department of Environmental Protection, Memorandum – Review of Application for Synthetic Minor Permit, Texas Eastern Armagh Compressor Station, New Florence, PA, May 15, 2007. See: http://gasp-pgh.org/wp-content/uploads/OP-32-00230-Review-Memo.pdf. $NO_x$ and CO CEMS were operated for five years to demonstrate dry low $NO_x$ combustion-equipped gas turbine could meet $NO_x$ and CO permit limits.

[3] Virginia Department of Environmental Quality Northern Regional Office, Statement of Legal and Factual Basis, Dominion Transmission, Inc. Leesburg Compressor Station, Loudoun County, Virginia Permit No. NRO71978, June 2015, p. 6. "A continuous emissions monitoring system (CEMS) replaced the parametric monitoring initially used to monitor $NO_x$ emissions. The $NO_x$ CEMS data shall be used to determine compliance with the NOx limits in Condition 4. Malfunction of the CEMS may be grounds for DEQ to request stack testing to demonstrate compliance."

[4] Maryland Public Service Commission, ORDER NO. 86372 - CASE No. 9318, *Dominion Cove Point LNG LP for a Certificate of Public Convenience and Necessity to Construct a Generating Station with a Name-Plate Capacity of 130 MW*, May 30, 2014, Table A-1, p. A-37.

The Armagh Compressor Station $NO_x$ CEMS was specifically installed and operated from 2002 to 2007 due to uncertainty over whether the dry low $NO_x$ combustion system could achieve $NO_x$ emission limits.[5] The situation at Joelton is analogous. Without continuous monitoring, the facility cannot demonstrate when the turbines achieve the 9 ppm $NO_x$ limit. Continuous monitoring is necessary to demonstrate that the $NO_x$ limit is achieved as load on the gas turbine increases beyond 80 percent. If continuous $NO_x$ monitoring demonstrates that the Joelton gas turbines actually achieves the 9 ppm limit at lower load than Solar Turbines, Inc. is currently willing to warranty, the air permit should be modified to accurately reflect the capabilities of the $NO_x$ control systems on the Joelton gas turbines.

## II. SELECTIVE CATALYTIC REDUCTION IS COST-REASONABLE FOR THE JOELTON GAS TURBINES AT APPROXIMATELY $4,745/TON OF $NO_X$ REMOVED.

Metro Nashville should have selected SCR with a NOx outlet concentration of 2.5 ppm as NOx RACT for the turbines. Instead, Metro Nashville uses numerous erroneous inputs to inflate the cost-effectiveness of SCR and relies on this flawed analysis to incorrectly assert that SCR is cost infeasible for the Joelton gas turbines. Proper RACT analysis shows that SCR is cost-reasonable for the Joelton Compressor Station.

### A. A proper cost estimate for SCR on an equivalently sized turbine to those proposed at Joelton Compressor Station would reference independently obtained vendor quotations, as demonstrated by EPA.

The Metro Nashville RACT evaluation included in the Metro Response to Comments (RTC) Document: 1) ignored current RACT $NO_x$ cost ceilings as high as $5,500/ton other states and instead relied on a quarter-century old EPA RACT cost-effectiveness memo – based on $NO_x$ RACT for utility boilers – to assert SCR was not cost feasible in this application, and 2) inflated inputs to the SCR cost-effectiveness calculation despite having full access to EPA-developed SCR cost-effectiveness inputs provided by SELC to Metro Nashville in January 2017. A proper analysis indicates that SCR with a $NO_x$ outlet concentration of 2.5 ppm should have been selected as $NO_x$ RACT for the proposed gas turbines.

The Titan 250 gas turbine is manufactured by Solar Turbines, Inc. (San Diego) and is the largest gas turbine made by the company. All other medium and large gas turbine models made by the company, including the Titan 130, Mars 100, and Taurus 60 and 70, are guaranteed by Solar Turbines across their entire operating range at 9 ppm $NO_x$. All of these models are also being permitted with SCR at compressor stations to further reduce $NO_x$ emissions.

According to the Metro Nashville RACT analysis included in the RTC, the Titan 250s to be used at Joelton will only achieve the 9 ppm $NO_x$ limit about 3 months of the year, or

[5] Pennsylvania Department of Environmental Protection, Memorandum – Review of Application for Synthetic Minor Permit, Texas Eastern Armagh Compressor Station, New Florence, PA, May 15, 2007.

25 percent of the time.[6] The relatively poor $NO_x$ control performance of the Titan 250, when compared to other smaller models of Solar Turbines, Inc. gas turbines planned for use at other new compressor stations in nearby states, underscores the need to identify SCR as $NO_x$ RACT to adequately control $NO_x$ emissions from the Joelton gas turbines.

The specification of SCR for $NO_x$ control on gas turbines at proposed natural gas compressor stations is a common practice. All eleven compressor drive gas turbines, including the Titan 130 gas turbine, included in the proposed Atlantic Coast Pipeline (ACP) will utilize SCR for $NO_x$ control.[7] The three compressor stations where these SCR-equipped gas turbines will be installed – sited in in West Virginia, Virginia, and North Carolina - will be located in attainment areas,[8] will not be Title V major sources,[9] and are therefore not subject to RACT. These compressor stations will be unmanned.[10] The erroneously high $NO_x$ control cost-effectiveness value presented by Metro Nashville for SCR in the RTC is belied by the fact that SCR has been selected as the gas turbine $NO_x$ control method at several proposed compressor stations in attainment areas in the same region of the country as the Joelton Compressor Station.

Metro Nashville's $NO_x$ RACT evaluation overlooked relevant SCR cost data developed by the EPA. The EPA published in March 2015 a cost estimate for SCR, oxidation catalyst (OxCat), and continuous emission monitors for a 21.7 MW gas turbine in combined heat and power (CHP) service.[11] The heat input and exhaust gas flowrate assumed by EPA for the 21.7 MW turbine match those of the Titan 250.[12,13]

The EPA cost estimate for SCR is based on multiple vendor quotations.[14] The EPA relied on vendor quotations in its March 2015 CHP document to estimate a total installed cost

[6] RTC, RACT Analysis, p. 6: "If we conservatively assume the turbine will operate in the 9 ppm range for 3 months of the year and the 15 ppm range for 9 months of the year . . ."
[7] Atlantic Coast Pipeline, LLC, Dominion Transmission, Inc. Supply Header Project, FERC Docket No. CP15-554-000 , Resource Report 9 Air and Noise Quality, September 2015, p. 9-24. See **Attachment A.**
[8] Ibid, p. 9-12.
[9] Ibid, p. 9-28.
[10] Farmville (VA) Herald, *No action taken on permit: Subcommittee created to look at station conditions*, October 25, 2016: http://www.farmvilleherald.com/2016/10/no-action-taken-on-permit-subcommittee-created-to-look-at-station-conditions/. "Kevin Zink, Dominion's director of operations for compressor stations and pipelines . . said the station (Buckingham Compressor Station) would use its own microwave communications system, using towers, to remote control the facility from another location, he said, with nine full-time positions. . . Zink said Dominion has many unmanned facilities." Powers Engineering assumes each of the three compressor stations will be operated in the same manner as Buckingham Compressor Station (Compressor Station No. 2).
[11] EPA Combined Heat and Power Partnership, Catalog of CHP Technologies - Section 3. Technology Characterization – Combustion Turbines, March 2015, p. 3-15: https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf.
[12] Ibid, Table 3-2, p. 3-6 and p. 3-7.
[13] Solar Turbines, Inc, *Industrial Gas Turbine Product Line and Performance* (brochure), 2016, p. 2. Titan 250 exhaust mass flow: 541,400 lb/hr. Titan 250 fuel heat input: lower heating value (LHV) 190.8 MMBtu/hr (estimated higher heating value = $1.1 \times$ LHV = 210 MMBtu/hr).
[14] EPA Combined Heat and Power Partnership, *Catalog of CHP Technologies - Section 3. Technology Characterization – Combustion Turbines,* March 2015, Table 3-5, p. 3-14, footnote 53.

of an SCR/oxidation catalyst/continuous emissions monitor package for the Titan 250 gas turbine of approximately $2,400,000.[15] This is approximately one-half the $4.7 million installed capital cost (per turbine) estimated by Metro Nashville for the Joelton gas turbines in its $NO_x$ RACT analysis.

The cost of the OxCat in the EPA cost estimate must be deducted to determine the cost of the SCR alone. The installed capital cost of the OxCat component of this control package is approximately $400,000 according to Solar Turbines, Inc.[16] When the $400,000 cost of the OxCat is deducted, the all-in cost for the SCR and continuous emission monitors is about $2,000,000. The only difference in the SCR design for a Titan 250 in a CHP application and a Titan 250 in a pipeline compressor application like Joelton is the addition of a low-cost tempering air fan in the compressor-drive application to maintain the exhaust gas temperature within the normal operating range of a standard SCR catalyst.[17]

The EPA capital cost estimate includes the installed cost of the continuous emissions monitoring package for the gas turbine. The cost of a $NO_x$ and carbon monoxide (CO) CEMS package is estimated at $250,000 for the two Joelton gas turbines based on an actual project consisting of two Solar Taurus turbines in Southern California.[18] When the installed cost of continuous emissions monitoring package is excluded, at an assumed installed cost of $125,000 per turbine, the total installed cost of the SCR estimated by EPA is $1.88 million. The $4.7 million installed capital cost (per turbine) estimated by Metro Nashville for SCR on the Joelton gas turbines in its $NO_x$ RACT analysis is about two-and-a-half times the $1.88 million SCR installed capital cost estimated by the EPA for the same turbine capacity.

### B. Metro Nashville's erroneous SCR cost assumptions drive its highly inflated SCR cost-effectiveness estimate.

Metro Nashville inflates several critical inputs to the SCR cost-effectiveness calculation in its $NO_x$ RACT analysis. Metro Nashville relied on the SCR vendor (Peerless-Aarding) identified by Solar Turbines, Inc. to provide inputs to the $NO_x$ cost-effectiveness calculation instead of conducting an independent review of SCR cost inputs. An

[15] Ibid, Table 3-5, p. 3-14. Equipment cost of SCR/OxCat/CEM, 21.7 MW turbine, 90% NOx control from 15 ppm to 1.5 ppm = $1,516,400. Ratio of CHP total installed cost to equipment cost = $30,879,300 ÷ $19,397,900 = 1.59. Therefore, total installed cost of SCR/OxCat/CEM = 1.59 × $1,512,400 = $2,404,716. See **Attachment B**.

[16] Telephone communication between B. Powers/Powers Engineering and J. Belmont/Solar Turbines, Inc. (Pittsburg office), July 12, 2016.

[17] E-mail communication between B. Powers/Powers Engineering and J. Harber/AHM Associates (Peerless Manufacturing representative), June 24, 2014. [18] E-mail communication between B. Powers/Powers Engineering and Q. Giuseppe/Syska Hennessy (CHP plant design firm) regarding installed cost of $NO_x$/CO continuous monitoring systems on two 5.8 MW Solar Taurus gas turbines, County of Orange Government Center, Santa Ana, California, December 5, 2016.

[18] E-mail communication between B. Powers/Powers Engineering and Q. Giuseppe/Syska Hennessy (CHP plant design firm) regarding installed cost of $NO_x$/CO continuous monitoring systems on two 5.8 MW Solar Taurus gas turbines, County of Orange Government Center, Santa Ana, California, December 5, 2016.

independent review would have made clear that the gas turbine manufacturer's provider of inputs to the SCR cost-effectiveness calculation was providing inputs that resulted in an erroneously high $NO_x$ control cost-effectiveness value for SCR.

EPA has developed two recent evaluations of the cost of SCR, the March 2015 evaluation of gas turbines in CHP applications and the July 2016 SCR chapter of the 7th Edition Control Cost Manual. The discrepancies between EPA 2015 and 2016 SCR cost assumptions and the assumptions used by Metro Nashville in its RTC $NO_x$ RACT analysis are listed in Table 3. The magnitude of the cost inflation by Metro Nashville is described in the right-hand column of Table 3.

***Table 3. Discrepancies between EPA 2015 CHP Plant Cost and 2016 Control Cost Manual 7th Edition, SCR,[19] and Metro Nashville SCR control cost-effectiveness calculations***

| Element | EPA basis | Metro Nashville basis | Magnitude of cost inflation by Metro Nashville |
|---|---|---|---|
| Capital cost | \$1.88 million (EPA March 2015 SCR in 21.7 MW CHP application, SCR only). | \$4.7 million (SCR cost calculation developed by Metro Nashville consultant using inputs from SCR vendor preferred by Titan 250 manufacturer.) | 2.5x higher capital cost of SCR |
| Capital recovery factor (CRF) | 7% interest, 30 years. CRF = 0.0806 (7th Ed., SCR, p.2-80) | 8% interest, 20 years. CRF = 0.10165 | 26% higher annualized capital cost of SCR. |
| SCR catalyst cost | \$160/ft$^3$ (7th Ed., SCR, p.2-80) | \$400/ft$^3$ | 2.5x higher SCR catalyst cost. |
| SCR catalyst life | 40,000 hours (5 years) in gas-fired service.[20] CRF at 7% interest, 5 years = 0.244.(7th Ed., SCR, p.2-75) | 3 years. CRF at 8% interest = 0.388 | 40% shorter catalyst life. |
| Annual catalyst replacement cost | \$25,415 /yr (7th Ed., SCR, p.2-80) | \$101,044/yr | 4x higher catalyst replacement cost |

[19] See 7th Edition, Chapter 2: Selective Catalytic Reduction, May 2016: https://www3.epa.gov/ttn/ecas/docs/SCRCostManualchapter7thEdition_2016.pdf.

[20] EPA 7th Edition, SCR, p. 2-75. "For oil- and gas-fired units, the SCR catalyst life is assumed to be 40,000 hours, and the catalyst life for some gas-fired units has been reported to be up to 60,000 hours."

| | | | |
|---|---|---|---|
| SCR $NO_x$ reduction | 90% (EPA, March 2015, CHP, p. 3-18) | 80% | EPA assumes additional 8.4 tpy of $NO_x$ removed by SCR |

**C. Using EPA assumptions and omitting Metro Nashville's erroneous assumptions shows that Metro overestimates the $NO_x$ cost-effectiveness of SCR on the Joelton gas turbines by a factor of three.**

Substituting accurate and current EPA assumptions for Metro Nashville's inflated assumptions demonstrates that the actual $NO_x$ cost-effectiveness of SCR on the Joelton gas turbines is under $5,000/ton. The actual cost-effectiveness of SCR on the Joelton gas turbines is approximately one-third the $NO_x$ control cost-effectiveness presented in Metro Nashville's RTC.

For example, Metro Nashville's analysis erroneously assumes that staff must be onsite at the Joelton facility solely to operate the SCR. However, SCR can be operated remotely at unmanned compressor stations using supervisory control and data acquisition (SCADA) technology.[21] Metro Nashville's assumption regarding staffing results in Metro Nashville applying an unsupported operating labor cost solely to support of the operation of SCR on the Joelton gas turbines. At a minimum, the only unique SCR parameter that must be remotely monitored is the ammonia reagent injection rate. Monitoring of this one parameter does not require onsite personnel. No operating cost should be assigned by Metro to SCR use at Joelton.

The effect of the correction of cost inputs to the Metro Nashville calculation of SCR cost-effectiveness for the Titan 250 gas turbines at Joelton is shown in **Attachment C.**

Use of accurate SCR cost inputs results in a SCR $NO_x$ control cost-effectiveness of $4,745/ton, not the $13,471/ton presented by Metro Nashville. Metro Nashville overestimates the $NO_x$ cost-effectiveness of SCR on the Joelton gas turbines by a factor of three in its RACT analysis included in the RTC.

Numerous states have established $NO_x$ RACT cost-effectiveness ceilings. A SCR $NO_x$ control cost-effectiveness of $4,745/ton is under the $NO_x$ RACT cost-effectiveness ceiling of $5,000/ton to $5,500/ton applied in Maryland, Ohio, and New York.[22] Metro

[21] Ozone Transport Commission, Technical Information:
Oil and Gas Sector Significant Stationary Sources of $NO_x$ Emissions – Final, October 17, 2012, p. 26.
"Another stated (industry) issue is that many compressor facilities are unmanned and that SCR installations have not been demonstrated in unmanned facilities. Other industry information indicates that while it may be true that there are currently few SCRs in unmanned facilities, with modern software based controls and supervisory control and data acquisition (SCADA) type communication technologies there does not appear to be any technical barrier to operating the SCR related controls and auxiliaries successfully from a remote location."
[22] Powers Engineering, *Review of Reasonableness of NOx Emission Limits for Two Titan Turbines at Proposed Joelton, Tennessee Compressor Station*, prepared for Southern Environmental Law Center, August 1, 2016, Table 8, p. 13. See RTC Document, pdf p. 488.

Nashville has a comprehensive technical and regulatory basis, as described in this comment letter, to establish SCR as $NO_x$ RACT for the Joelton gas turbines.

## III. CONCLUSION.

Should EPA concur with the proposed $NO_x$ limit of 9 ppm when the gas turbine(s) operate between 80 and 100 percent of full capacity, and 15 ppm when the gas turbine(s) operate between 40 and 80 percent of full capacity, the permit must address numerous deficiencies in the draft permit conditions. Principal among these additional requirements is the need for a $NO_x$ CEMS on each gas turbine. Numerous unmanned compressor stations utilize $NO_x$ CEMS on gas turbines. A $NO_x$ CEMS is necessary to demonstrate compliance with the proposed $NO_x$ limit, which can vary continuously depending on fuel flow and which cannot be verified solely by monitoring fuel flow.

However, the Metro Nashville draft air permit should have identified SCR as cost-reasonable $NO_x$ RACT for the Joelton gas turbines. The $NO_x$ cost-effectiveness of SCR is below the $NO_x$ RACT cost-effectiveness ceiling established in several other states, including Maryland, Ohio, and New York. SCR with a $NO_x$ outlet concentration of 2.5 ppm would be cost-effective and more protective than the current proposed $NO_x$ limit.

# Attachments

Attachment A

# ATLANTIC COAST PIPELINE, LLC
# ATLANTIC COAST PIPELINE

**Docket Nos. CP15-___-000**
**CP15-___-000**
**CP15-___-000**

**and**

# DOMINION TRANSMISSION, INC.
# SUPPLY HEADER PROJECT

**Docket No. CP15-___-000**

# Resource Report 9
# Air and Noise Quality

*Final*

**Prepared by**

NATURAL RESOURCE GROUP

an ERM Group company

**September 2015**

used only as emergency use engines. The emissions limits specified in Subpart JJJJ for emergency spark ignition engines greater than 130 hp for NOx, CO, and VOC are 2.0, 4.0, and 1.0 grams per hp-hour, respectively. Both engines have emissions guarantees that are at or below these limits.

All auxiliary generators at the ACP and SHP stations will be subject to NSPS notification and recordkeeping requirements, including records of notifications, maintenance, and documentation that the engines are certified to meet applicable emissions standards. If the engines are not certified by the manufacturer, then additional recordkeeping requirements apply.

**Subpart KKKK – Standards of Performance for Stationary Gas 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 NOx emissions limitations. All proposed turbines, except the Solar Centaur 40 turbine, fall within the "medium sized" (>50MMBtu/hr, < 850 MMBtu/hr) category for natural gas turbines. The Solar Centaur 40 turbine falls within the "small sized, mechanical drive" (< 50 MMBtu/hr) category for natural gas turbines. "Medium sized" turbines must meet a NOx limitation of 25 parts per million by volume (ppmv) at 15 percent oxygen ($O_2$), and "small sized, mechanical drive" turbines must meet a NOx limitation of 100 ppmv at 15 percent $O_2$ under the requirements of Subpart KKKK and will minimize emissions consistent with good air pollution control practices during startup, shutdown and malfunction.

Solar provides an emissions guarantee of 9 parts per million volume dry (ppmvd) NOx at 15 percent $O_2$ for SoLoNOx equipped units, except for the Solar Centaur 40 equipped with SoLoNOx, which has an emissions guarantee of 25 ppmvd NOx at 15 percent $O_2$. 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 installed at the new ACP compressor Stations to further reduce NOx emissions to 5 ppmvd at 15 percent $O_2$, except during periods of start-up and shutdown and periods with ambient temperatures below 0°F.

The ACP and SHP compressor stations plan 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 ensures compliance with the $SO_2$ standard due to the low sulfur content of pipeline quality natural gas.

# Catalog of CHP Technologies

## Section 3. Technology Characterization – Combustion Turbines

U.S. Environmental Protection Agency
Combined Heat and Power Partnership

March 2015

**Table 3-5. Estimated Capital Cost for Representative Gas Turbine CHP Systems[53]**

| Cost Component | System | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| Nominal Turbine Capacity (kW) | 3,510 | 7,520 | 10,680 | 21,730 | 45,607 |
| Net Power Output (kW) | 3,304 | 7,038 | 9,950 | 20,336 | 44,488 |
| **Equipment** | | | | | |
| Combustion Turbines | $2,869,400 | $4,646,000 | $7,084,400 | $12,242,500 | $23,164,910 |
| Electrical Equipment | $1,051,600 | $1,208,200 | $1,304,100 | $1,490,300 | $1,785,000 |
| Fuel System | $750,400 | $943,000 | $1,177,300 | $1,708,200 | $3,675,000 |
| Heat Recovery Steam Generators | $729,500 | $860,500 | $1,081,000 | $1,807,100 | $3,150,000 |
| SCR, CO, and CEMS | $688,700 | $943,200 | $983,500 | $1,516,400 | $2,625,000 |
| Building | $438,500 | $395,900 | $584,600 | $633,400 | $735,000 |
| Total Equipment | $6,528,100 | $8,996,800 | $12,214,900 | $19,397,900 | $35,134,910 |
| **Installation** | | | | | |
| Construction | $2,204,000 | $2,931,400 | $3,913,700 | $6,002,200 | $10,248,400 |
| Total Installed Capital | $8,732,100 | $11,928,200 | $16,128,600 | $25,400,100 | $45,383,310 |
| **Other Costs** | | | | | |
| Project/Construction Management | $678,100 | $802,700 | $1,011,600 | $1,350,900 | $2,306,600 |
| Shipping | $137,600 | $186,900 | $251,300 | $394,900 | $674,300 |
| Development Fees | $652,800 | $899,700 | $1,221,500 | $1,939,800 | $3,312,100 |
| Project Contingency | $400,700 | $496,000 | $618,500 | $894,200 | $1,526,800 |
| Project Financing | $238,500 | $322,100 | $432,700 | $899,400 | $2,303,500 |
| **Total Installed Cost** | | | | | |
| Total Plant Cost | $10,839,800 | $14,635,600 | $19,664,200 | $30,879,300 | $55,506,610 |
| Installed Cost, $/kW | $3,281 | $2,080 | $1,976 | $1,518 | $1,248 |

Source: Compiled by ICF from vendor-supplied data.

### 3.4.6 Maintenance

Non-fuel operation and maintenance (O&M) costs are presented in **Table 3-6**. These costs are based on gas turbine manufacturer estimates for service contracts, which consist of routine inspections and scheduled overhauls of the turbine generator set. Routine maintenance practices include on-line running maintenance, predictive maintenance, plotting trends, performance testing, fuel consumption, heat rate, vibration analysis, and preventive maintenance procedures. The O&M costs presented in **Table 3-6** include operating labor (distinguished between unmanned and 24 hour manned facilities) and total maintenance costs, including routine inspections and procedures and major overhauls.

---

[53] Combustion turbine costs are based on published specifications and package prices. Installation estimates are based on vendor cost estimation models and developer-supplied information.

**Table 3-8. Gas Turbine Emissions Characteristics**

| Emissions Characteristics | System | | | | |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 |
| Electricity Capacity (kW) | 3,304 | 7,038 | 9,950 | 20,336 | 44,488 |
| Electrical Efficiency (HHV) | 24.0% | 28.9% | 27.3% | 33.3% | 36.0% |
| **Emissions Before After-treatment** | | | | | |
| $NO_x$ (ppm) | 25 | 15 | 15 | 15 | 15 |
| $NO_x$ (lb/MWh) | 1.31 | 0.65 | 0.69 | 0.57 | 0.52 |
| CO (ppmv) | 50 | 25 | 25 | 25 | 25 |
| CO (lb/MWh) | 1.60 | 0.66 | 0.70 | 0.58 | 0.53 |
| NMHC (ppm) | 5 | 5 | 5 | 5 | 5 |
| NMHC (lb/MWh) | 0.09 | 0.08 | 0.08 | 0.07 | 0.06 |
| **Emissions with SCR/CO/CEMS** | | | | | |
| $NO_x$ (ppm) | 2.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| $NO_x$ (lb/MWh) | 0.09 | 0.05 | 0.05 | 0.05 | 0.05 |
| CO (ppmv) | 5.0 | 2.5 | 2.5 | 2.5 | 2.5 |
| CO (lb/MWh) | 0.11 | 0.05 | 0.05 | 0.05 | 0.05 |
| NMHC (ppm) | 4.3 | 4.3 | 4.3 | 4.3 | 2.0 |
| NMHC (lb/MWh) | 0.08 | 0.06 | 0.07 | 0.06 | 0.02 |
| **$CO_2$ Emissions** | | | | | |
| Generation $CO_2$ (lb/MWh) | 1,667 | 1,381 | 1,460 | 1,201 | 1,110 |
| Net $CO_2$ with CHP (lb/MWh) | 797 | 666 | 691 | 641 | 654 |

*Source: Compiled by ICF from vendor supplied data, includes heat recovery*

**Table 3-8** also shows the net $CO_2$ emissions after credit is taken for avoided natural gas boiler fuel. The net $CO_2$ emissions range from 641-797 lbs/MWh. A natural gas combined cycle power plant might have emissions in the 800-900 lb/MWh range whereas a coal power plant's $CO_2$ emissions would be over 2000 lb/MWh. Natural gas fired CHP from gas turbines provides savings against both alternatives.

### 3.5.2 Emissions Control Options

Emissions control technology for gas turbines has advanced dramatically over the last 20 years in response to technology forcing requirements that have continually lowered the acceptable emissions levels for nitrogen oxides ($NO_x$), carbon monoxide (CO), and volatile organic compounds (VOCs). When burning fuels other than natural gas, pollutants such as oxides of sulfur ($SO_x$) and particulate matter (PM) can be an issue. In general, $SO_x$ emissions are greater when heavy oils are fired in the turbine. $SO_x$ control is generally addressed by the type of fuel purchased, than by the gas turbine technology. Particulate matter is a marginally significant pollutant for gas turbines using liquid fuels. Ash and metallic additives in the fuel may contribute to PM in the exhaust.

A number of control options can be used to control emissions. Below are descriptions of these options.

# Attachment C

**RACT Analysis**
**Titan 250 Gas Turbine (NOx = 25 ppm) with SCR**

**Capital Cost Estimate**
**$NO_x$ Control**
**Basis: OAQPS Cost Control Manual (Sixth Ed.), USEPA Air Pollution Control Fact Sheets**

| Direct Costs | | Source |
|---|---|---|
| Purchased Equipment Cost | $ ~~2,100,000~~ | Manufacturer - Peerless |
| Ancillary Equipment Cost (User Input) | $ ~~355,000~~ | Manufacturer - Peerless |
| Equipment Cost "A" | $ 2,455,000 | |
| Instrumentation (0.10*A) | $ 245,500 | OAQPS (6th), Section 1, Chapter 2, Table 2.4 |
| Sales Taxes (0.03*A) | $ 73,650 | OAQPS (6th), Section 1, Chapter 2, Table 2.4 |
| Freight (0.05*A) | $ 122,750 | OAQPS (6th), Section 1, Chapter 2, Table 2.4 |
| Purchased Equipment Cost "B" | $ 2,896,900 | |
| **Direct Installation Costs** | | |
| Foundation & Supports (0.08*B) | $ 231,752 | OAQPS (6th), Incinerator or Adsorber |
| Handling & Erection (0.14*B) | $ 405,566 | OAQPS (6th), Incinerator or Adsorber |
| Electrical (0.04*B) | $ 115,876 | OAQPS (6th), Incinerator or Adsorber |
| Piping, Ductwork & Installation (0.02*B) | $ 57,938 | OAQPS (6th), Incinerator or Adsorber |
| Insulation for Ductwork (0.01*B) | $ 28,969 | OAQPS (6th), Incinerator or Adsorber |
| Painting (0.01*B) | $ 28,969 | OAQPS (6th), Incinerator or Adsorber |
| **Direct Installation Subtotal** | $ ~~869,070~~ | |
| Site Preparation (User Input) | $ - | |
| Facilities & Buildings (User Input) | $ - | |
| **Total Direct Cost** | $ ~~3,765,970~~ | |
| **Indirect Cost** | | |
| Engineering (0.10*B) | $ 289,690 | OAQPS (6th), General Accepted |
| Construction & Field Expenses (0.05*B) | $ 144,845 | OAQPS (6th), Incinerator or Adsorber |
| Contractor Fees (0.10*B) | $ 289,690 | OAQPS (6th), Generally Accepted |
| Start-up (0.02*B) | $ 57,938 | OAQPS (6th), Incinerator or Adsorber |
| Performance Test (0.01*B) | $ 28,969 | OAQPS (6th), Generally Accepted |
| Contingencies (0.03*B) | $ 86,907 | OAQPS (6th), Generally Accepted |
| **Total Indirect Cost** | $ ~~898,039~~ | |
| **Total Capital Investment** — EPA, March 2015, SCR TCI 21.7 MW gas turbine | $ ~~4,664,009~~ | $1,880,000 |

| Direct Annual Costs | | hr/shift | shift/day | day/yr | $/hr | | | Source |
|---|---|---|---|---|---|---|---|---|
| Operating Labor | | | | | | | | |
| unmanned station | ~~Operator~~ | 0.5 | 3 | 365 | 30 | $ ~~16,425~~ | $0 | S (6th), Section 1.2, Paragraph 2.5.5.2 |
| | ~~Supervisor(15% of Operator Cost)~~ | | | | | $ ~~2,464~~ | $0 | S (6th), Section 1.2, Paragraph 2.5.5.2 |
| | Operating Materials | | | | | $ - | | |
| Maintenance Labor | | 0.5 | 3 | 365 | 30 | $ 16,425 | | OAQPS (6th), Section 1.2, Paragraph 2.5.5.2 |
| Maintenance Materials | | 100% of Maintenance Labor | | | | $ 16,425 | | OAQPS (6th), Section 1.2, Paragraph 2.5.5.3 |
| Replacement Labor | | | | | | $ - | | |
| Parts Cost | | | | | | $ - | | |
| Utilities | | | | | | | | |
| | NG Usage (mmcf/yr) | | | | | 0.000 | | |
| | Fuel Cost ($/yr) | Based on $4.85/1000 cf | | | | $ - | | |
| | Electricity Usage (kwhr/yr) | | | | | 0.000 | | |
| | Electricity Cost ($/yr) | Based on 0.055$/KW-hr | | | | $ - | | |

| Catalyst Costs | | | | | Source |
|---|---|---|---|---|---|
| Catalyst Life (yrs) | ~~3~~ 5 | | | | ~~Manufacturer - Peerless~~ — EPA 7th Ed. Control Cost |
| Interest Rate (%) | ~~8%~~ 7% | ~~2.577~~ Capital Recovery | | | Assumed — EPA 7th Ed. Control Cost |
| Catalyst Replace: assume 30 $ft^3$ catalyst per MW, ~~$400/ft~~ | $160/ft3, EPA 7th Ed. | | $25,415 | ~~101,044~~ | ~~Manufacturer - Peerless~~ |
| Catalyst Dispose: $15/$ft^3$ * 30 $ft^3$ catalyst per MW | | | $ | 3,789 | Manufacturer - Peerless |
| Ammonia ($/ton): | 360 | (1:1 Molar Ratio) | $ | 10,658 | Manufacturer - Peerless |
| Ammonia Rate (lb/hr) | 6.7 | | | | Manufacturer - Peerless |
| $NH_3$ inject skid (blower, kw): | 12.4 | ($NH_3$/$H_2O$ pump, kw): | 24 $ | 38,264 | Manufacturer - Peerless |
| **Total Direct Costs** | | | $110,976 | ~~205,494~~ | |

| Indirect Annual Costs | | | | Source |
|---|---|---|---|---|
| Overhead (60% of total labor & materials) | | $19,710 | $ ~~31,043~~ | OAQPS (6th), Section 1.2, Paragraph 2.5.5.7 |
| Administrative (0.02*Total Capital Investment) | | $75,200, .04 x TCI | $ ~~93,280~~ | OAQPS (6th), Section 1.2, Paragraph 2.5.5.8 |
| Property Tax (0.01*Total Capital Investment) | | | $ ~~46,640~~ | OAQPS (6th), Section 1.2, Paragraph 2.5.5.8 |
| Insurance (0.01*Total Capital Investment) | 7%, 30 year life = 0.0806, EPA 7th Ed. | | $ ~~46,640~~ | OAQPS (6th), Section 1.2, Paragraph 2.5.5.8 |
| Capital Recovery | (based upon ~~8% & 20~~ year life: factor = ~~0.10165~~) | $151,528 | $ ~~474,097~~ | Assumed ~~8% and 20~~ year life |
| **Total Indirect Annual Cost** | | $246,438 | $ ~~691,700~~ | |

| | | | |
|---|---|---|---|
| | Total Annual Operating Cost= | $ ~~897,194~~ | $357,414 |
| | $NO_x$ Removed ton/yr | ~~66.60~~ | 75.3 |
| Blue Cells = Data Input Required | Cost Efficiency ($/ton removed) | $ ~~13,471.38~~ | $4,745 |

# Exhibit 6

**The Siting of New Proposed Nitrogen Oxide (NOx) Emission Sources in the Greater Nashville Region and Implications for Ozone NAAQS Compliance**

by: D. Howard Gebhart
Air Resource Specialists, Inc.
Fort Collins, CO

## Introduction and Background

The Nashville/Davidson County Metro Public Health Department, Division of Air Pollution Control (Metro) is currently considering permit applications for two large natural gas pipeline compressor stations to operate in Davidson County, Tennessee. One station, proposed by Tennessee Gas Pipeline (Joelton Compressor Station), would utilize new combustion turbines totaling 60,000 horsepower and a second station, proposed by Columbia Gulf Transmission (Cane Ridge Compressor Station), would utilize new combustion turbines totaling 41,000 horsepower. Combustion turbines are significant emitters of nitrogen oxides (NOx), a precursor to formation of ozone in the atmosphere.

The greater Nashville area is currently in compliance with the National Ambient Air Quality Standards (NAAQS) for ozone, although the margin of compliance is small. The NAAQS as defined by the U.S. Environmental Protection Agency (EPA) is 0.070 parts per million (ppm), defined as the annual fourth highest daily maximum 8-hour average concentration averaged over three years.[1] Using the Hendersonville, Tennessee monitor as the representative ozone monitoring site, the design value for Nashville as determined for monitored data over the 2013-2015 time period is 0.067 ppm. However, more than one ozone monitor in the greater Nashville area has measured an ozone design value above 0.070 ppm in the recent past. In fact, the Hendersonville monitor had an ozone design value in excess of the 0.070 ppm NAAQS in all four of the prior three year time periods, *i.e.*, 2009-2011, 2010-2012, 2011-2013, and 2012-2014.

Because of the small margin of compliance with the current 0.070 ppm NAAQS and the historical ozone measurements collected in the greater Nashville area that exceed 0.070 ppm, there is a reasonable basis for concern that the additional NOx emissions created by the proposed compressor stations could lead to increased ozone levels and threaten future attainment with the ozone NAAQS in Davidson County and the greater Nashville area.

## Ozone Monitoring in Greater Nashville

There are five monitoring stations for ozone located in the Nashville-Davidson-Murfreesboro-Franklin Metropolitan Statistical Area (MSA). Two stations are operated by Metro and three stations are operated by the Tennessee Department of Environmental Conservation (TDEC).

[1] The new NAAQS became effective on December 28, 2015. National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 206 (Oct. 26, 2015). *Federal Register: The Daily Journal of the United States*. Web. 17 January 2017. However, final designations, classifications, and nonattainment area SIP rules and guidance will not be released until October 2017. USEPA. Ozone NAAQS Timelines: Key Dates for Existing and Future Nonattainment Areas. Web. 17 January 2017. Available at: https://www.epa.gov/ozone-pollution/ozone-naaqs-timelines.

Ozone monitoring at all stations is conducted only during the "ozone season" (the Middle Tennessee ozone season is March 1 – October 31). No ozone measurements are collected during November, December, January, or February. Because the ozone NAAQS compliance is based on the fourth-highest daily 8-hour ozone measurement over the calendar year, the implicit assumption in the Nashville monitoring approach is that no high ozone values occur during the winter time period when ozone measurements are discontinued. In the author's view, if ozone monitoring continued throughout the year without interruption, then the monitoring data would provide for a more robust determination of NAAQS compliance. It is noted that some locations in the western United States measure their highest ozone levels during the winter months (*References 1 and 2*). Without a continuous 12-months measurement program for at least some Nashville MSA monitoring stations, the assumption that peak ozone does not occur in the fall/winter time period cannot be validated. The historical assumptions about seasonal variability in peak ozone could also be compromised as the ozone NAAQS becomes increasingly more stringent.

The Metro-operated stations are all located within Davidson County. One station is the East Health Site, located at 1015 Trinity Lane, northeast of downtown Nashville, but still within the urbanized region. This station has been in operation since 1972 and also supports monitoring for other pollutants besides ozone, *i.e.*, sulfur dioxide ($SO_2$) and nitrogen dioxide ($NO_2$). The second Metro station is located at the US Army Corps of Engineers J. Percy Priest Dam Campus east of the Nashville urban area (3711 Bell Road) and has operated since 1978. The J. Percy Priest Dam Station lies at the transition from the Nashville urbanized area to a more rural environment.

The TDEC ozone monitoring sites are located in areas surrounding the urbanized Nashville region, including Sumner County (the Hendersonville site), Williamson County (the Fairview site), and Wilson County (the Cedars site). **Figure 1** shows the location of the five greater Nashville area ozone monitors and also shows the location for the Tennessee Gas Pipeline (Joelton) and Columbia Gas Transmission (Cane Ridge) compressor stations.

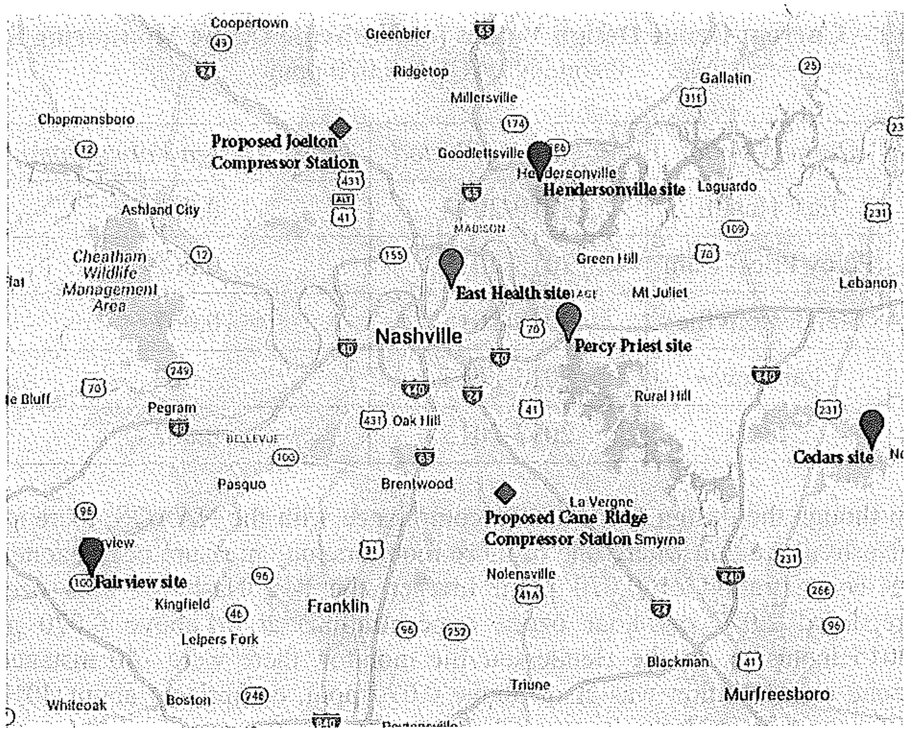



Figure 1: Network of ozone monitors for the Nashville MSA and compressor stations proposed in Davidson County. Proposed compressor stations are pictured as red diamonds, while the location of ozone monitors operated by Metro are blue pins and those operated by TDEC are purple pins

The current design values for each station in the Nashville ozone monitoring network are listed in **Table 1**. The ozone design values, which provide the ozone concentration compared to the NAAQS for determination of compliance, were calculated based on the fourth highest daily maximum 8-hour average ozone concentration averaged over the most recent three year monitoring period.

All data in **Table 1** are based on the three-year 2013-2015 monitoring period, except for the data at East Health. During a 2013 Technical Systems Audit conducted by EPA, it was determined that the inline filters had been relocated from the back of the continuous analyzers to the inlet of the sampling probe lines at this site. However, the new sampling configuration was not employed during the quality control checks for the analyzers and, as such, the data did not meet the specifications under 40 CFR Part 58, Appendix A, Sections 3.2.1.1 and 3.2.2.4. Based on the EPA audit, all data collected at East Health starting with September 2012 were invalidated. Given this audit finding, the 2010-2012 period is the most recent three year period with complete and valid data at the East Health ozone monitoring site.

**Table 1 – Current Ozone Design Values for Nashville Ozone Monitoring Stations**
Ozone NAAQS = 0.070 ppm

| *Ozone Monitor* | *Monitoring Period* | *Ozone Design Value (ppm)* |
|---|---|---|
| East Health | 2010-2012 | 0.069 |
| Percy Priest Dam | 2013-2015 | 0.065 |
| Hendersonville | 2013-2015 | 0.067 |
| Fairview | 2013-2015 | 0.062 |
| Cedars | 2013-2015 | 0.062 |

Even though the design value shows compliance with the NAAQS, there are occasional days in the Nashville region where one or more monitors may measure peak ozone levels above the NAAQS concentration of 0.070 ppm. In fact, the five Nashville area ozone monitors combined recorded 2,057 one-hour ozone concentrations at or above 0.070 ppm between 2010 and 2015 inclusive. At the Hendersonville monitor, there were 740 instances where the one-hour ozone concentration was at or above 0.070 ppm, comprising about 40% of the total occurrences for the greater Nashville area (*Reference 3*).

Of all of the Nashville area ozone monitors, the Hendersonville monitor is probably the most critical location. The Hendersonville monitoring site lies to the northeast of Nashville, and is generally "downwind" based on the prevailing southwesterly winds that dominate during the summertime ozone season. Emissions generated in the Nashville urban plume are simply more likely to be transported toward Hendersonville as opposed to the other ozone monitors. Excluding East Health where data quality problems bias the ozone design value, the Hendersonville monitor also has the highest design value of any monitor in the Nashville MSA.

The last five ozone design values at Hendersonville are shown in **Figure 2**. Note that in all time periods prior to the current 2013-2015 time period, the three year average ozone design value exceeded the NAAQS (0.070 ppm). In the 2010-2012 time period, the design value even approached 0.080 ppm. The historical ozone data at Hendersonville (and other Nashville monitoring sites) were influenced by a high ozone event that occurred over several clear, dry, calm days in 2012 (*Reference 4*). However, the apparent downward trend in the ozone design value is likely influenced to a greater degree by the lack of similar "worst-case" meteorology occurring since 2012 as opposed to emission reductions of ozone precursors. In fact, there is a reasonable expectation that the "worst-case" meteorology that was present in 2012 would likely recur at some time in the future.

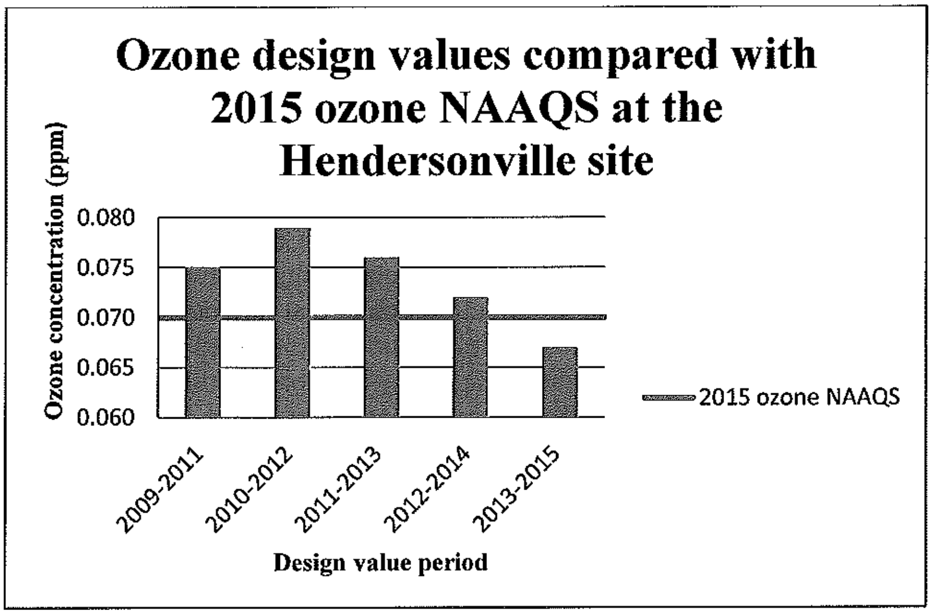



**Figure 2 – Historical Ozone Design Values at the Hendersonville, TN Monitor.**

## Implications of Increased NOx Emissions from Stationary Sources In and Around Nashville

Metro is considering permits that would allow for the construction and operation of two new NOx emission sources in Davidson County. The proposed increased NOx emissions at the Joelton Compressor Station total 167.4 tons per year (allowable emissions) and the proposed increased NOx emissions at the Cane Ridge compressor Station total 80.29 tons per year (allowable emissions). As proposed, both new sources would add about 248 tons per year to the NOx emissions budget in greater Nashville, an emissions increase almost equal to the 250 tpy "major source" threshold under the Prevention of Significant Deterioration (PSD) regulations.

NOx is one of the precursors to ozone formation. In fact, most areas with elevated ozone levels are believed to be "NOx-limited", meaning that the availability of NOx is the limiting factor in the ozone photochemistry. For NOx-limited locations, increases in regional NOx emissions would be expected to lead to increases in the ambient ozone levels.

Although elevated ozone readings tend to occur during the warmer summer months, temperature by itself does not directly influence the ozone chemistry in any meaningful way. In other words, assuming that all other parameters are the same, an increase or decrease in the ambient temperature, will not significantly influence the amount of ozone formation. The key meteorological parameter needed to promote ozone formation is the incoming solar radiation.

In a NOx-limited environment, new NOx emission sources (such as the new compressor stations proposed in the region) would also add to the NOx emissions budget and thus add to the potential to create ozone. In Nashville, all of the other ozone precursors are present in a surplus - the missing ingredient is sufficient NOx. On that basis, if additional NOx emissions are added, a reasonable expectation is that all of the additional NOx emissions can lead to more ozone. I have postulated that a 1% increase in NOx emissions would lead to a proportional 1% increase in ozone levels (this is called the 1-to-1 relationship). USEPA has also modeled hypothetical sources for ozone precursor emissions to assess the potential impact on ozone levels and these findings are consistent with the increases projected in greater Nashville when using the simple 1-to-1 relationship assumption (*Reference 5*). These new EPA modeling findings are discussed in more detail later in this report.

It is the increased NOx drives that ozone formation and not temperature. Changes in ambient temperature would not alter the 1-to-1 relationship between NOx emissions and ozone. Although temperature is not a direct variable that affects ozone formation, ozone formation is driven by the same atmospheric conditions that lead to warmer temperatures, *i.e.*, incoming radiation present in sunlight. Clear sunny days have more solar radiation compared to other days and it is the levels of solar radiation that effect ozone formation. Sunny days do occur year-round; for example, Nashville's percent of possible sun[2] in winter months ranges from 42% in December to 52% in March (*Reference 6*).[3] However, the summer also promotes higher levels of incoming solar radiation as the sun angle is more directly overhead. Also, on those days with higher incoming solar radiation (and greater ozone formation potential), the increased solar radiation acts to warm the atmosphere. So, high ozone days may be correlated with warmer temperatures, but temperature is not the main driver for the higher ozone levels. Instead, the same atmospheric conditions that promote ozone formation (clear sunny skies) are also the same conditions that would be expected to cause warmer temperatures.

**Table 2** shows the current NOx emissions budget for Davidson County and the relative increase in NOx that would be generated by the proposed new compressor station emissions (248 tpy NOx). The new compressor station emissions would generate a substantial increase (13%) in NOx emissions compared to other stationary fuel combustion sources in Davidson County. To put these emission increases in perspective, using EPA data where the NOx emissions from a passenger car driven 12,000 miles per year is 18.32 lb/year (*Reference 7*), the proposed NOx emissions increase from the Joelton facility (167 tpy) is equal to the NOx emissions generated by 18,231 automobiles. Likewise, the proposed NOx emissions increase from the Cane Ridge facility (80 tpy) would be the yearly equivalent of 8,734 automobiles. If both compressor stations were constructed, the resulting burden on Davidson County would equate to an increase in NOx emissions equal to approximately 27,000 automobiles.

[2] The total time sunshine reaches Nashville expressed as a percentage of the maximum amount possible if clear-sky conditions were prevalent from sunrise to sundown.
[3] NOAA National Centers for Environmental Information. Comparative Climatic Data. Datasets. Web. 17 January 2017. https://www.ncdc.noaa.gov/ghcn/comparative-climatic-data.

**Table 2 – Impact of New Compressor Station NOx Emissions on Davidson County NOx Budget**

| *Source Category* | *NOx Budget (ton/yr)* | *Percentage Increase* |
|---|---|---|
| Fuel Combustion Stationary Sources | 1629 | 13% |
| All Stationary Sources | 2448 | 9.2% |
| All NOx Sources (Stationary & Mobile) | 22653 | 1.1% |

If it is assumed that NOx increases lead to a proportional increase in ambient ozone levels (based on the presumption that ozone formation is NOx-limited), then the increase in ambient ozone levels associated with any increase in NOx emissions can be projected. A proportional 1.1% increase in ambient ozone at the Hendersonville monitor would increase the design value from 0.067 to 0.068 ppm. While the estimated ozone concentration remains under the NAAQS, the available compliance margin based on the Henderson design value is reduced by about one-third.

Also, the assumption that changes in ozone levels are proportional to the NOx emissions increase is based on an assumption that the new NOx emissions are well-mixed within the Nashville urban plume. However, this may not be the case. Because the increased NOx emissions would occur from concentrated point sources, there would likely be a NOx emissions plume transported downwind where the relative NOx concentrations may be significantly higher, compared to other sections of the Nashville urban plume. Thus, in a NOx-limited environment, there are likely pockets where a disproportional increase in ozone may occur that exceeds 1.1%. If one of these pockets should affect the Hendersonville monitor, the measured ozone increases may even be higher than the above projection and NAAQS compliance could be threatened.

The potential impact of higher ozone precursor emissions in multiple areas of the United States has also been modeled by EPA (*Reference 5*). EPA modeled hypothetical sources of ozone precursor emissions (NOx and VOC) at various locations in the United States and determined what effect such emissions might have on future ozone level as part of an effort to develop formal protocols for addressing new sources of ozone precursors in the new source review process. Based on these EPA modeling results, a new hypothetical source in Tennessee or Kentucky releasing an additional 500 tpy of ozone precursors was modeled to result in an increase in ambient ozone levels of approximately 3 parts per billion (ppb) or 0.03 ppm. In fact, EPA's conclusions were that new sources of ozone precursor emissions in and around Nashville would generate a larger response on ambient ozone levels comparted to most other areas of the United States. Given that the NAAQS compliance margin based on current data from the Hendersonville monitor is only 3 ppb, the EPA modeling data suggest that proposed emissions increase associated with the new compressor stations (almost 250 tpy) would consume about 50% of the current ozone NAAQS compliance margin.

Lastly, the various design values for Nashville area ozone monitors are based on the measurements over the 2013-2015 period, which does not appear to represent the "worst-case" meteorology. It is known that meteorological conditions conducive the very high ozone reading can and do occur in Nashville, with the most recent episode occurring over several days in 2012 (*Reference 4*). A repeat of the meteorological conditions that led to the 2012 ozone episode would most likely result in new ozone measurements above the 0.070 ppm NAAQS and the new NOx emission sources resulting from the recent compressor station permits would only exacerbate the problem.

**Conclusions and Recommendations**

Although the available data on ozone in the greater Nashville area indicate that the region complies with the 0.070 ppm NAAQS, the margin of compliance is small. However, there is no long-term historical record showing that Nashville can consistently meet the 0.070 ppm ozone NAAQS. All recent periods prior to the 2013-15 three-year data period have design values above the 0.070 ppm NAAQS at one or more ozone monitors. Given that almost no compliance margin exists, any repeat of the meteorological conditions that led to elevated ozone readings in 2012 would likely push Nashville into non-compliance with the ozone NAAQS.

Newly released EPA ozone modeling data also show that future ozone levels around Nashville are very sensitive to changes in levels for ozone precursor emissions. Compared to other areas of the United States, relatively small changes in ozone precursor emissions from new/modified sources around Nashville can elicit a much larger response in the ambient ozone levels. Extrapolating from new EPA modeling studies suggest that the two proposed compressor stations would generate sufficient NOx precursor emissions to reduce the ozone NAAQS compliance margin in Nashville by 50%, assuming no change in meteorological conditions from the 2013-2015 baseline period.

Given these findings, a more proactive approach to managing ozone precursor emissions of NOx and volatile organic compounds (VOCs) is appropriate. Given that Nashville appears to be "NOx-limited" like most other ozone regions, an emphasis on strategies that reduce NOx emissions is especially warranted.

**Specific Recommendations**

- Ozone monitoring in the Nashville MSA should be extended to a continuous 12-month program in order to be confident that the fourth-highest daily maximum concentrations are in fact being measured for comparison to the NAAQS. The ozone season monitoring currently performed in Nashville relies on an assumption that higher ozone levels do not occur during the fall and winter months, and this assumption has in fact been disproved in other regions of the United States.

- Permitting of new/modified emission sources that increase NOx should be more carefully managed as such sources would very likely lead to higher ozone levels in the urban plume downwind of Nashville and threaten NAAQS compliance. New source permitting in Davidson County and surrounding areas should include proactive strategies such as adopting selected provisions of non-attainment new source review (NNSR), *i.e.*, offsets for major new NOx emission sources. Other approaches would include more stringent NOx/VOC emission control requirements such as Best Available Control Technology (BACT) for even for non-PSD sources. Avoiding a future non-attainment designation in Nashville should be the preferred alternative rather than allowing for unmanaged increases in NOx precursor emissions that continue to threaten ozone compliance.

## References


1. Wyoming Department of Environmental Quality, 2016. Final Report – 2016 Upper Green River Ozone Study. Prepared by Meteorological Solutions, Inc.

2. Utah Department of Environmental Quality, Undated. Unita Basin Ozone Studies. Available at http://deq.utah.gov/locations/U/uintahbasin/ozone/strategies/ubos.htm.

3. US Environmental Protection Agency, Undated. AIRNOW - Ambient Air Quality Data. www.airnow.gov.

4. Bolton R. and J. Shipp, 2013. Update on Past, Present, and Future Ozone Levels in Tennessee. PowerPoint Presentation.

5. US Environmental Protection Agency, 2016. Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and PM2.5 under the PSD Permitting Program. US Environmental Protection Agency, Office of Air Quality Planning and Standards, December 2016 (DRAFT), EPA-454/R-16-006.

6. NOAA National Centers for Environmental Information. Comparative Climatic Data. Datasets. Web. 17 January 2017. https://www.ncdc.noaa.gov/ghcn/comparative-climatic-data.

7. US Environmental Protection Agency, 2008. Average Annual Emissions and Fuel Consumption for Gasoline-Fueled Passenger Cars and Light Trucks. US Environmental Protection Agency, Office of Transportation and Air Quality, EPA 420-F-08-024.