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TC Energy

June 24, 2025

Department of Ecology
Cashiering Unit
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Olympia, WA 98504-7611

Re: Gas Transmission Northwest, LLC (GTN)
Notice of Construction Application
Compressor Station 7

Gas Transmission Northwest, LLC (GTN) is submitting this Notification of Construction Application to the Washington State Department of Ecology's Air Quality Program for Compressor Station 7. The station is in Walla Walla County on Barstow Road, 10 miles south of Ayer Junction, near Starbuck, Washington, with coordinates of approximately Latitude: 46.535, and Longitude: -118.294.

Compressor Station 7 currently operates three (3) natural gas turbines (Units 7C/7D/7E) under the Notice of Construction - Approval Order No. 21AQ-E009, issued on January 27, 2021. This application proposes to allow for low temperature operating hours for the two (2) 22,605 hp Solar Titan 130 turbines (Units 7D/7E). Historical data for this area has shown that hours of low-temperature operation are needed, during the winter months, to be able to provide gas to the end-users. GTN is proposing to modify the operating modes for Units 7D/7E to allow for 200 hours of subzero temperature operating hours, in order to be able to provide gas to end-users during critical times of need.

Compressor Station 7 qualifies as an existing major stationary source under the New Source Review Program. With this submittal, Compressor Station 7 will qualify as a minor permitting action, with regards to NSR, and a PSD modification will not be triggered.

Should you have any questions or require additional information, please contact Nathan Chenaux at (832) 444-0051 or nathan_chenaux@tcenergy.com.

Sincerely,

Aczael Valdez

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cc: Andre Kruse, Washington Department of Ecology (electronic copy)

Compressor Station 7 (Starbuck)

Notification of Construction Application

PREPARED FOR

TC Energy

Gas Transmission Northwest LLC

DATE

24 June 2025

REFERENCE

0774376

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EXECUTIVE SUMMARY

Gas Transmission Northwest, LLC (GTN) is submitting this Notification of Construction Application to Washington State Department of Ecology's Air Quality Program for Compressor Station 7. The station is in Walla Walla County on Barstow Road, 10 miles south of Ayer Junction, near Starbuck, Washington, with coordinates of approximately Latitude: 46.535, and Longitude: -118.294.

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Compressor Station 7 is located in Walla Walla County, which is currently designated as attainment or unclassifiable for all pollutants for which National Ambient Air Quality Standards (NAAQS) have been promulgated.

1. FACILITY EQUIPMENT

This facility currently consists of the following equipment:

Emission Units

- 39,700 hp Cooper Rolls Coberra RB211 Natural Gas-fired Turbine (Unit 7C)
- 22,605 hp Solar Titan 130 (23,470 hp based on ISO) Natural Gas-fired Turbine (Unit 7D)
- 22,605 hp Solar Titan 130 (23,470 hp based on ISO) Natural Gas-fired Turbine (Unit 7E)
- 1,827 hp Caterpillar G3512 Natural Gas-fired Emergency Generator (Unit G2)

Insignificant Activities

- One (1) natural gas-fired fuel gas heater with a capacity of 2.00 MMBtu/hr
- Natural gas-fired space heaters (size varies) with a total capacity of 0.63 MMBtu/hr
- One (1) natural gas-fired space heater with a total capacity of 2.00 MMBtu/hr
- One (1) water heater with a total capacity of 0.04 MMBtu/hr

The sources listed as insignificant are due to their potential for low emissions.

Additional equipment at the facility consists of fugitive leaks, pipeline fluids tanks, lube oil tanks, blowdowns/venting, and pneumatic devices.

2. PROCESS DESCRIPTION

Compressor Station 7 is a natural gas transmission facility covered by Standard Industrial Classification (SIC) code 4922 (natural gas transmission), and has the potential to operate seven (7) days per week, twenty-four (24) hours per day. Compressor Station 7 is located in Walla Walla County, Washington. Walla Walla County is designated as attainment or unclassifiable for all pollutants for which National Ambient Air Quality Standards (NAAQS) have been promulgated.

Pipeline transmission of natural gas requires that the gas be compressed. Compressor Sation 7 will receive natural gas via pipeline from an upstream compressor station and compresses it using two existing turbines to increase pressure to transmit the gas via pipeline to a downstream station. Depending upon gas availability and demand for end users, the turbines may operate simultaneously, independently, or not at all. The turbines will fire only pipeline quality natural gas.

The proposed modified Solar Titan 130 turbines (Units 7D/7E) will be equipped with Solar's SoLoNOx dry low NOx combustor technology which reduces NOx emissions. Dry low NOx (DLN) emissions or lean-premix combustion reduces the conversion of atmospheric nitrogen to NOx by reducing the combustor's flame temperature. Since NOx formation rates are dependent on flame temperature, lowering this temperature is an effective strategy for reducing NOx emissions. Lean combustion is enhanced by premixing the fuel and combustor airflows upstream of the combustor primary zone. The SoLoNOx system is operational at turbine loads from approximately 50% to 100% of full load. During operation at low turbine loads and during turbine startup and shutdown, supplemental pilot fuel is fired for flame stability and results in NOx, CO, and VOC concentrations that are higher than during SoLoNOx operation. Estimated emissions during each of the operating modes are summarized in Appendix B. Units 7D/7E are expected to continuously operate; therefore, emission estimates are based on 8,760 operating hours per year. Combustion turbine power varies with atmospheric conditions such that maximum heat input, maximum fuel consumption, and associated emissions generally increase as ambient temperature decreases. For the purpose of this application, turbine emissions under normal operations have been characterized based on an ambient temperature of 0 °F. Additional hourly estimates are provided for lower temperatures.

Additionally, the turbines will be equipped with pilot active control logic (PACO) which is a computer-based technology that will enable the unit to operate during sub-zero operating conditions with reduced NOx, CO, and VOC emissions. PACO employs active oscillations feedback which, when needed, will increase pilot to reduce operations. GTN reviewed historical meteorological data from the region to estimate the worst-case number of hours under sub-zero (less than 0 °F, but greater than -20 °F) conditions. The annual hours of operation during sub-zero conditions were conservatively proposed to not exceed 200 hours per year. Engineering data from Solar was used as the basis for the emissions during these sub-zero temperature operations. Site-specific PACO emission data from Solar was used for the basis for the emissions during sub-zero temperature operations and is included in Appendix B.[1]

It has been conservatively estimated that the modified Solar Titan 130 turbines (Unit 7D/7E) will experience 150 startup and shutdown events annually. The duration of each startup and shutdown event is expected to be 10 minutes per event. Therefore, it is assumed that there will be approximately 50 hours of startup and shutdown event time when the unit may not be operating in SoLoNOx mode. Engineering data from Solar was used as the basis for the emissions during low load operations. Solar PIL 170 was used for the basis for the emissions during these startup and shutdown events and is included in Appendix B.

During turbine start-ups, natural gas may be vented as part of the start-up process. Emissions associated with engine shutdowns are primarily in the form of natural gas that is vented when the unit is opened for repair. The facility may conduct pipeline and vessel blowdowns prior to performing maintenance on station equipment or transmission pipeline segments adjacent to the facility.

In addition to the maintenance activities above, emissions may also be associated with routine operations such as calibrating equipment, changing orifice plates, deadweight testing and the changing of equipment filters.

[1] Solar Turbines SoLoNOx Dry Low Emissions Technology Literature

3. POTENTIAL TO EMIT

Table 3-1 below indicates the facility-wide emissions prior to the proposed modification (tons/year):

TABLE 3-1 PRE-MODIFICATION FACILITY-WIDE PTE

	PM / PM_{10} / $PM_{2.5}$[1] (tons/year)	**SO_2 (tons/year)**	**NO_x (tons/year)**	**VOC (tons/year)**	**CO (tons/year)**	**Total HAPs (tons/year)**
Total PTE excluding fugitives	14.65	5.79	329.07	23.74	275.22	3.22
Title V Major Thresholds	100	100	100	100	100	25
PSD Major Thresholds	250	250	250	250	250	-

[1] PM_{10} and $PM_{2.5}$ are considered a 'regulated air pollutant' under Part 70.

Table 3-2 below indicates the PTE for the proposed modification to the Solar Titan 130 combustion turbines (Unit 7D/7E) (tons/year):

TABLE 3-2 PTE FOR SOLAR TITAN 130 TURBINES UNITS 7D/7E

	NO_x (tons/year)	**CO (tons/year)**	**VOC (tons/year)**	**PM / PM_{10} / $PM_{2.5}$ (tons/year)**	**SO_2 (tons/year)**	**Total HAPs (tons/year)**
Unit 7D Currently Permitted	44.53	48.26	5.89	5.43	0.59	0.85
Unit 7D Modified	46.40	51.41	6.03	5.52	0.60	0.86
Unit 7E Currently Permitted	44.53	48.26	5.89	5.43	0.59	0.85
Unit 7E Modified	46.40	51.41	6.03	5.52	0.60	0.86
Units 7D/7E Combined Emission Delta	3.74	6.30	0.27	0.16	0.02	0.03

The original potential to emit, the changes due to this permit application, and the resulting potential to emit are shown in Table 3-3 below:

TABLE 3-3 SUMMARY OF PTE CHANGES

Pollutant	Permitted Facility PTE (tons/year)	Facility PTE after Proposed Changes (tons/year)	Emission Delta (tons/year)
NO_x	329.07	332.81	3.74
CO	275.22	281.53	6.30
VOC	23.74	24.01	0.27
PM / PM_{10} / $PM_{2.5}$	14.65	14.82	0.16
SO_2	5.79	5.81	0.02
Total HAPs	3.22	3.24	0.03
CO_2e	353,337.84	356,207.14	2,869.31

Table 3-3 above excludes fugitive emissions, as compressor stations are not one of the names source categories that include fugitive emissions. Fugitive emissions are presented in the detailed emissions calculations.

The updated potential emissions are based upon the proposed modifications discussed in this application to allow for hours of operation during subzero temperatures in order to be able to provide gas to end-users during critical times of need. The proposed operating conditions for Units 7D/7E are depicted in Table 3-4.

TABLE 3-4 UNITS 7D/7E COMBUSTION TURBINE OPERATING CONDITIONS

Operating Condition	Hours
Normal Operations (Temp ≥ 0° F)	8,510
Low Temperature Operations (Temp < 0° F ≥ -20° F) - PACO	200
Startup/Shutdown Operations (200 events per year)	50

Detailed emission calculations are provided in Appendix B.

3.1 PROPOSED COMPLIANCE APPROACHES

GTN suggests the following calculation methodology to show compliance with the emission limitations for Units 7D/7E:

In order to demonstrate compliance with the proposed emission limitations, GTN will monitor and record the monthly operating hours for each operating condition. Monthly emissions for each pollutant will be calculated using the following equation:

MEPx = NLPx * NL hrs + LTPx * LT hrs + SSPx * SS cycles

Where:

- MEPx is the monthly emissions for each pollutant
- NLPx is the unit emission rates (lb/hr) for pollutant X during normal load (NL) operation
- LTPx is the unit emission rates (lb/hr) for pollutant X during low-temperature (LT) operation
- SSPx is the unit emission rates (lb/cycle) for pollutant X during startup/shutdown (SS) operation

At the end of each month, the monthly emissions will be summed for the preceding 12 months to determine compliance with the annual emissions limits.

GTN is including a site specific monitoring plan with this application as Appendix G that was prepared for the Solar Titan 130's (Units 7D/7E) to sufficiently provide reasonable assurance with applicable NOx emission limitations. The monitoring plan specifies the monitoring approach, parameters to be monitored and associated indicators, data acquisition method and system, fuel flow monitoring, quality assurance and quality control procedures, instrument calibration, preventative maintenance, review, reporting and recordkeeping. GTN is proposing to utilize both the site-specific monitoring plan along with the 12 month rolling total proposed above as a means to demonstrate continuous compliance with emission limits.

3.2 APPROPRIATENESS FOR CONTIUNOUS EMISSION MONITORING SYSTEMS (CEMS)

As discussed previously, the purpose of this application is to provide gas to customers when it is needed most. Historical data for the area has shown that hours of low-temperature operation are needed during the winter months to provide gas to end-users in these times of critical demand. The use of PACO controls will allow units 7D/7E to operate at the mentioned low temperatures with reduced NOx, CO, and VOC emissions. There is some historical context surrounding the use of continuous emissions monitoring systems (CEMS). TC Energy feels that CEMS is overly burdensome and unnecessary for use in these turbines as it is not common in the midstream industry for turbines of this size, it is not protective of air quality, and it places unmanned sites such as the Starbuck location under significant staffing and economic strain.

GTN owns and operates a similar facility near Rosalia, Washington (Compressor Station 6), which includes a 19,500 hp (ISO) Solar Titan. GTN installed a CEMS on this unit per the state's request and ended up removing the unit due to overburdensome costs and labor. All parties agreed upon cessation of the CEMS that data effectively demonstrated compliance with the SOLAR emission guarantees and the applicable emission limits.

The site specific monitoring plan provided in Appendix G is believed to be sufficient for determining the compliance of the Starbuck station.

In conversations between Ecology and TC Energy outlined in the 2020 technical support document (TSD) for Starbuck, it was mentioned that "the majority of Turbines in the State of Washington have a CEMS for CO." While it is true that there are sites that do have a CEMS, TC Energy's research into the matter indicates a number of sites do not and there appears to be precedent to seek alternative compliance mechanisms. For example, the Avista Corporation's 2018 statement of basis for air operating permit 18AQ-E017 both falls under Ecology's jurisdiction and does not mention the use of a CEMS. Additional sites such as Northwest Pipeline LLC's Sumas compressor station discuss monitoring "NOx emissions in accordance with alternate monitoring program". Hence, it is believed that the details outlined in the site monitoring plan should suffice as alternative compliance.

Additionally, in the 2020 TSD provided by the Department of Ecology, there was concern expressed regarding the closeness to crossing PSD thresholds. However, it was stated that "although the CEMS is the preferred method to verify emissions, a decision was made to forego the installation of a CEMS and include additional testing to ensure emission limits in the permit were not exceeded." In lieu of a CEMS, TC Energy performed additional testing in very cold conditions and has shown that the emissions are well below permitted levels. Hence, the relative closeness to PSD thresholds was the consequence of conservative estimates and not representative of actual site conditions. Ecology should consider this data (see Appendix H) to mitigate concerns about triggering PSD. TC Energy believes this data, not previously available to Ecology, should provide relative certainty that the Starbuck facility is not in threat of violating PSD provisions.

Further, TC Energy does not operate any other CEMS in the Starbuck area. CEMS require specialized training, equipment, and daily calibration to function. Given the remote nature of the Starbuck site, reliably operating a CEMS would be challenging and labor intensive.

In summary, the use of a CEMS for these turbines is believed to be unnecessary and onerous. A CEMS is not commonly applied to turbines of this size in the midstream industry, it is not expected to be protective of air quality, and the site's location would make manned calibration and control difficult. TC Energy commits to working with Ecology to address concerns through the permitting process and requests that the proposed mechanism of compliance detailed in the site specific monitoring plan be deemed be sufficient to demonstrate compliance.

4. REGULATORY DISCUSSION

This section outlines the air quality rules that could be reasonably expected to apply to Compressor Station 7 and makes an applicability determination for each rule based on activities conducted at the site and the emissions of regulated air pollutants.

Washington Administrative Code (WAC) 173-400-110 requires the owner or operator to obtain a NOC permit to construct or modify any building, structure, facility or installation that:

- increases the amount of any air contaminant emitted by the source; or
- results in the emissions of any air contaminant not previously emitted.

An NOC permit must be issued prior to beginning construction or modifying the source (unless the activity is specifically exempt from the need to obtain a permit). The enclosed permit application forms are for a NOC to authorize construction of the proposed project and are included in Appendix A.

In addition, WAC 173-400-113 requires the following elements to be included with a NOC application:

- Federal and state regulatory review;
- Best Available Control Technology (BACT) analysis for all new equipment; and
- Ambient impacts analysis; including a review of any toxic pollutant emissions.

The regulatory requirements in reference to this application for Compressor Station 7 are described in detail in the section below:

- Federal Air Quality Regulations

Applicability of the following regulatory programs are addressed:

- Prevention of Significant Deterioration (PSD)
- Non-Attainment New Source Review (NNSR)
- Title V Operating Permit Requirements
- New Source Performance Standards (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Compliance Assurance Monitoring (CAM)

This summary review addresses potential applicable federal regulatory requirements for the proposed modification of the Solar Titan 130 combustion turbines. Walla Walla County is currently designated as attainment or unclassifiable for all pollutants for which National Ambient Air Quality Standards (NAAQS) have been promulgated.

4.1.1 40 CFR §52.21 PREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY

Compressor Station 7 has historically, most recently in 1998, been permitted as a New Source Review (NSR) Prevention of Significant Deterioration (PSD) facility. Since this permitting action, subsequent permitting actions have not triggered PSD major modification thresholds. Most recently, the Technical Support Document (September 2020) prepared by Washington State Department of Ecology clarifies, in the executive summary, that the 2020 permitting action was finalized such that PSD was not triggered.

Compressor Station 7 qualifies as an existing major stationary source under the New Source Review Program since the PTE emissions exceeds two-hundred and fifty (250) tons per year of Nitrogen Oxides and Carbon Monoxide. With this submittal, Compressor Station 7 will qualify as a minor permitting action, with regards to NSR, and a PSD modification will not be triggered.

40 CFR §52.21(b)(2)(i) defines "major modification" as any physical change in or change in the method of operation of a major stationary source which results in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(5) of this section); and a significant net emissions increase of that pollutant from the major stationary source.

Any significant emissions increase (as defined in paragraph (b)(4) of this section) from any emissions units or net emissions increase (as defined in paragraph (b)(3) of this section) at a major stationary source that is significant for VOCs or NO_x shall be considered significant for ozone.

40 CFR §52.21(b)(40) defines "significant" in reference to a net emission increase or the potential of a source to emit any of the following pollutants, at a rate of emissions that would equal or exceed any of the following rates in Table 4-1:

TABLE 4-1 PSD SIGNIFICANT RATES

Pollutant	Significant Emission Rate (tons/year)
CO	100
NO_x	40
SO_2	40
PM	25
PM_{10}	15
$PM_{2.5}$	10 (direct $PM_{2.5}$ emissions)

Pollutant	Significant Emission Rate (tons/year)
$PM_{2.5}$	40 (of SO_2 emissions)
$PM_{2.5}$	40 (of NO_x emissions)
Ozone	40 (of VOC or NO_x)
Lead	0.6
Fluorides	3
Sulfuric Acid Mist	7
Hydrogen Sulfide (H_2S)	10
Total Reduced Sulfur (including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10

40 CFR §52.21(a)(2) prescribes the determination as to whether a proposed project is a major modification for a regulated NSR pollutant. A project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases – a significant emissions increase and a significant net emissions increase.

For modifications to existing units, significant emissions are determined by applying either the Projected Actual Emissions (PAE) or Potential to Emit (PTE) to the Baseline Actual Emissions (BAE). As shown in table 4-2 below, the total increase of the PTE included with this permitting action is less than a significant emissions increase. Quantifying the baseline actual emissions from the past operations of units 7D and 7E is not necessary to demonstrate that project will not be deemed significant.

Table 4-2 below includes the emission increases associated with the proposed project.

TABLE 4-2 PROPOSED PROJECT EMISSION INCREASES

	NO_x (tons/year)	**CO (tons/year)**	**VOC (tons/year)**	**$PM_{10}/PM_{2.5}$ (tons/year)**	**SO_2 (tons/year)**
Solar Titan 130 (Unit 7D)	1.87	3.15	0.13	0.08	0.01
Solar Titan 130 (Unit 7E)	1.87	3.15	0.13	0.08	0.01
Total	**3.74**	**6.30**	**0.27**	**0.16**	**0.02**
Significant Level	40	40	40	15/10	100

This permitting action, qualifying as a standalone permitting action not subject to contemporaneous periods, does not qualify as a significant emissions increase and the PSD permitting process does not apply.

Alternative PSD Applicability

In the 2020 permitting action, netting was used to determine that the facility was not subject to PSD. Below is the supporting emission summary from the final PSD analysis included in the 10/29/2020 permitting application supplement and referenced in the final TSD (September 2020):

TABLE 4-3 PREVIOUS BASELINE ANALYSIS FACILTY EMISSIONS

Source	Capacity	Annual Emissions (tpy)							
		NO_x	CO	CO_2e	$PM_{10}/PM_{2.5}$	VOC	SO_2	CH_2O	Total HAP
Unit 7D Solar Titan 130 Turbine[3]	22,605 hp (0 °F)	44.53	48.26	96,418	5.43	5.89	0.59	0.58	0.85
Unit 7E Solar Titan 130 Turbine[3]	22,605 hp (0 °F)	44.53	48.26	96,418	5.43	5.89	0.59	0.58	0.85
IA - Fuel Gas Heater	2.00 MMBtu/hr	0.86	0.72	1,026	0.07	0.05	0.006	0.0006	0.02
IA - Space Heaters	0.63 MMBtu/hr	0.27	0.23	323.12	0.02	0.01	0.002	0.0002	0.005
AUX GEN2 Emergency Generator	13.05 MMBtu/hr	2.01	4.03	382.06	0.03	1.01	0.002	0.2618	0.236
Equipment Leaks (fugitive emissions)[1]				3,833		1.39			
Venting				15,193		5.52			
Proposed Facility PTE[2]		92.20	101.49	209,759	10.99	18.37	1.19	1.43	1.95
Unit 7B Cooper Rolls Coberra Avon	39,700 hp (59 °F)	56.53	14.49	20,684	1.17	2.70	0.50	0.13	0.18
Caterpillar G3412 Emergency Generator	737 hp	0.09	0.01	2.63	0.0002	0.003	0.00001	0.0012	0.002
Baseline Actual Emissions		56.62	14.50	20,687	1.17	2.70	0.50	0.13	0.18
PTE - Baseline Emissions		35.58	86.99	189,073	9.82	15.67	0.69	1.31	1.77
PSD Major Source Threshold		40	100	75,000	15/10	40	40	n/a	n/a
Trigger PSD Review?[4]		No	No	Yes	No	No	No	n/a	n/a

1. Fugitive emissions are not part of PSD applicability analysis.
2. Excludes fugitive emissions (compressor stations are not one of the named source categories that include fugitive emissions).
3. Turbine emissions based on 150 Start up / shut down cycles per year. The remainder of the hours per year are based on emissions at normal load (0°F).
4. A July 24, 2014 memorandum from the USEPA that stated that the USEPA will not apply or enforce regulations that would require a PSD permit where PSD would be applicable solely because of GHG emissions.

Ecology's TSD document cited that caution was taken in the permitting process to account for Station 7's close proximity to the PSD permitting program. This alternative applicability is provided to demonstrate that even an overly conservative applicability results in no PSD applicability, allowing for increased confidence from Ecology during this permitting process.

A permitting action is considered contemporaneous if the following occur:

- Change occurs within a period beginning 5 years before the date of construction is expected to commence
- Projects were reasonable foreseeable; and
- Project shared funding;

This permitting action is not evaluated as being contemporaneous because the project will not occur within 5 years, the PACO installation could not have been reasonably foreseeable, and the project is being funded separately. With that in mind, even evaluating the project as contemporaneous results in no change to the lack of PSD applicability of the project. As shown in Table 4-4 below, the project does not result in an exceedance of the significant threshold from an overly conservative approach of assuming these projects are contemporaneous.

TABLE 4-4 PTE INCREASE FROM PREVIOUS BASELINE EMISSIONS

Source	NO_x	CO	$CO2_e$	$PM_{10}/PM_{2.5}$	VOC	SO_2	CH_2O	Total HAP
Previous PTE-Baseline Emissions	35.58	86.99	189,073	9.82	15.67	0.69	1.31	1.77
New Facility PTE Increase	3.74	6.30	2,869	0.16	0.27	0.02	0.02	0.03
Baseline + Increase	**39.31**	**93.29**	**191,942**	**9.98**	**15.94**	**0.71**	**1.32**	**1.79**
Significant Level	40	100	75,000	15/10	40	40	N/A	N/A

PSD Applicability Summary

As shown in Tables 4-3 and 4-4 above, a significant emissions increase does not occur as a result of this project. A major modification does not occur with this project.

4.1.2 NON-ATTAINMENT NEW SOURCE REVIEW

NNSR applies to new major sources or major modifications at existing sources of pollutants where the source is located is not in attainment with the NAAQS. Walla Walla County is designated as attainment or unclassifiable for all pollutants for which NAAQS have been promulgated; therefore, this section is not applicable.

4.1.3 40 CFR §71 FEDERAL OPERATING PERMIT PROGRAMS

Compressor Station 7 is a major source under these regulations.

4.1.4 NEW SOURCE PERFORMANCE STANDARDS

4.1.4.1 40 CFR 60 SUBPART KKKK (STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES)

This regulation establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005.

The modified Solar Titan 130 turbines have a conservatively estimated heat input of 190.79 MMBtu/hr. Therefore, this unit is subject to this rule and will comply with the applicable requirements of this subpart. §60.4320 requires the turbine to meet the NO_x requirement in Table 1 of this rule. Since the turbines are a natural gas fired turbines between 50 and 850 MMBtu/hr, Table 1 requires the turbines to meet a NO_x limit of 25 ppm at 15% O_2 or 150 ng/J of useful output. To demonstrate compliance with this limit, §60.4400(a) requires both an initial (within 180 days of startup or 60 days of achieving full load operation) and annual (not to exceed 14 months from previous test) performance test.

The regulation also limits SO_2 emissions from the turbines. §60.4330(a)(2) allows the facility to meet this limit by burning fuel with a total potential SO_2 emissions of less than 0.06 lb/MMBtu. Additionally, §60.4365(a) exempts the permittee from monitoring fuel sulfur content if the source burns only pipeline quality natural gas that is covered by a purchase or transportation contract that limits sulfur to no more than 20 grains per 100 standard cubic feet. The permittee's tariff limits the sulfur content to no more than 20 grains per 100 standard cubic feet, therefore, the turbines are exempt from monitoring fuel sulfur content.

4.1.4.2 40 CFR 60 SUBPARTS OOOOA AND OOOOB (STANDARDS OF PERFORMANCE FOR CRUDE OIL AND NATURAL GAS FACILITIES)

The New Source Performance Standards (NSPS) for the oil and natural gas source category sets standards for both greenhouse gases (GHGs) and Volatile Organic Compounds (VOCs) under current 40 CFR 60 OOOOa (Standards of Performance for Crude Oil and Natural Gas Facilities for Which

Construction, Modification or Reconstruction Commenced After September 18, 2015 and On or Before December 6, 2022) and published 40 CFR 60 OOOOb (Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification or Reconstruction Commenced After December 6, 2022, effective May 7, 2024) regulations. These regulations include emission standards for each centrifugal compressor, reciprocating compressor, pneumatic controller**,** storage vessel, natural gas processing unit, natural gas sweetening unit, pneumatic pump, and collection of fugitive emission components at an affected facility.

Fugitive emissions from the components of the total facility will continue to be subject to the requirements of Subpart OOOOa per 40 CFR §60.5365a(j) following the Project.

There is no 'modification' associated with this permit application, therefore, 40 CFR 60 Subpart OOOOb does not apply.

4.1.5 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

National Emission Standards for Hazardous Air Pollutants (NESHAP) are promulgated under40 CFR Part 63 for specific processes and HAP emissions. Compressor Station 7 following the proposed project will have potential HAP emissions that are less than the major source threshold and will therefore be considered an area source of HAPs.

4.1.5.1 40 CFR 63 SUBPART YYYY (NESHAP FOR STATIONARY COMBUSTION TURBINES)

This regulation establishes national emission limitations and operating limitations for HAPs from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitation. Compressor Station 7 is a minor source of HAP emissions and is not subject to this regulation.

4.1.6 40 CFR §64 COMPLIANCE ASSURANCE MONITORING

Compliance Assurance Monitoring (CAM) is a requirement of 40 CFR 64 for emission control equipment. It is designed to ensure that the control devices are properly maintained and operated. CAM applies to emission units that have an emission limitation, uses the control device to comply with the emission limits in the permit, and has the potential to be a 40 CFR Part 70 source. The modified turbines (Unit 7D/7E) do not use add-on control devices, therefore, are not subject to CAM requirements.

4.2 WASHINGTON STATE AIR POLLUTION CONTROL RULES

In addition to federal air regulations, Ecology establishes regulations applicable at the emission unit level (source specific) and at the facility level. The rules also contain requirement related to the need for construction and/or operating permits.

4.2.1 EMISSION STANDARDS FOR AIR CONTAMINANTS

The federal standards of performance for new stationary sources (40 CFR 60), and federal standards for hazardous air pollutants (40 CFR 61 and 63) were adopted and incorporated by reference by Ecology in WAC 173-400-025 "Adoption of federal rules". Procedures are in place to ensure the facility complies with these standards.

4.2.2 VISIBLE EMISSIONS

GTN utilizes pipeline natural gas in all combustion sources at Compressor Station 7. This assures compliance with the opacity standards (not to exceed 20% for an aggregate of more than 3 minutes in any one hour) specified under WAC 173-400-040(2) "General Standards for Maximum Emissions, Visible Emissions". GTN does not expect visible emissions to the atmosphere from the proposed combustion sources to exceed the opacity limit. In case of excess emissions, GTN will follow the requirements specified in AOP condition 1.11 "Excess Emissions Due to an Emergency" or 1.12 "Unavoidable Excess Emissions".

4.2.3 PARTICULATE MATTER

There are no solid or liquid fuel firing combustion sources at Compressor Station 7 or proposed by this project. As indicated previously, GTN utilizes pipeline natural gas in all combustion sources at the station and will continue to do so after the Project. The clean burning nature of natural gas results in low emissions of PM. The facility will not exceed 0.1 grain/dscf of exhaust gas from general process units per WAC 173-400-060.

4.2.4 FUGITIVE DUST

GTN will comply with general fugitive dust requirements specified in WAC 173-400- 040(9) "General Standards for Maximum Emissions, Fugitive Dust". GTN will take reasonable precautions to prevent fugitive dust from becoming air borne and will maintain and operate sources of fugitive dust to minimize emissions.

5. AMBIENT AIR QUALITY ANALYSIS

Dispersion modeling is required for all NOC applications that include an increase in emissions. The air dispersion modeling includes all proposed sources only in accordance with Ecology guidelines. Additional discussion regarding the specifics of the air dispersion modeling analysis are provided in the modeling report in Appendix E.

6. TOXIC POLLUTANT EMISSIONS REVIEW

Washington State also maintains Washington Ambient Air Quality Standards (WAAQS) for five pollutants and Acceptable Source Impact Levels (ASIL) for 395 Toxic Air Pollutants, as listed in WAC 173-460-150. An evaluation of WAC 173-460-150 is provided below. The following steps are required to determine project's ambient air quality impacts:

1. Identify the air pollutants released from each emission unit.
2. Calculate the potential emissions from each emissions unit.
3. If the potential emissions are below the pollutant's respective de minimis value and/or Small Quantity Emission Rate (SQER), no additional impacts analyses is needed for that pollutant.
4. If the potential emissions are equal to or greater than the pollutant's respective de minimis value and/or SQER, you must:
    - model the impacts of emissions for the pollutant and
    - compare the impacts to the respective AAQS and/or ASIL.

Table 6-1 below outlines the potential air toxic emissions for the proposed project. Table 7-1 includes the de minimum values and SQERs. As shown in Table 7-1, the potential air toxic emissions from the project are above the de minimum values for all pollutants except toluene and xylene. A T-BACT analysis is provided below in Section 8 for the aforementioned pollutants. The potential air toxic emissions from the project are above SQERs for acetaldehyde, acrolein, benzene, ethylbenzene, formaldehyde, and propylene oxide; therefore, additional modeling is required for these pollutants. This has been included in the modeling report provided in Appendix E.

TABLE 6-1 TOXICS EMISSIONS

Pollutant	Turbine 7D (lb/hr)	Turbine 7D (lb/year)	Turbine 7E (lb/hr)	Turbine 7E (lb/year)	Total (lb/hr)	Total (lb/year)	Ave Period	SQER (lb/ave period)	Above SQER?	De Minimis (lb/ave period)	Above De Minimis
1,3-Butadiene	8.2E-5	0.72	8.2E-5	0.72	1.64E-4	1.44	Year	5.4	No	0.27	Yes
Acetaldehyde	7.63E-3	66.85	7.63E-3	66.85	1.53E-2	133.70	Year	60	Yes	3	Yes
Acrolein	1.22E-3	10.70	1.22E-3	10.70	2.44E-3	21.39	24-hour	0.03	Yes	0.001	Yes
Benzene	2.29E-3	20.06	2.29E-3	20.06	4.58E-3	40.11	Year	21	Yes	1	Yes
Ethylbenzene	6.11E-3	53.48	6.11E-3	53.48	1.22E-2	106.96	Year	65	Yes	3.2	Yes
Formaldehyde	1.35E-1	1,186.62	1.35E-1	1,186.62	2.71E-1	2,373.24	Year	27	Yes	1.4	Yes
Naphthalene	2.48E-4	2.17	2.48E-4	2.17	4.96E-4	4.35	Year	4.8	No	0.24	Yes

Pollutant	Turbine 7D (lb/hr)	Turbine 7D (lb/year)	Turbine 7E (lb/hr)	Turbine 7E (lb/year)	Total (lb/hr)	Total (lb/year)	Ave Period	SQER (lb/ave period)	Above SQER?	De Minimis (lb/ave period)	Above De Minimis
Propylene Oxide	5.53E-3	48.47	5.53E-3	48.47	1.11E-2	96.93	Year	44	Yes	2.2	Yes
Toluene	2.48E-2	217.27	2.48E-2	217.27	4.96E-2	434.54	24-hour	370	No	19	No
Xylene	1.22E-2	106.96	1.22E-2	106.96	2.44E-2	213.93	24-hour	16	No	0.82	No

7. BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

A BACT analysis is required under WAC 173-400-113(2) to be completed before the Ecology will issue a final air permit approving the project. GTN has updated the BACT analysis supporting the Notice of Construction - Approval Order No. 21AQ-E009, issued on January 27, 2021, to include additional information regarding the PACO technology, which is a computer-based technology that will enable the unit to operate during sub-zero operating conditions with reduced NOx, CO, and VOC emissions. The following section documents the BACT determination for the Project.

7.1 BACT DEFINITION

BACT is defined in 40 CFR 52.21(j) BACT as follows:

“an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each air pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…”

The following BACT has been determined using EPA’s top-down approach. Following the top-down approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached on the basis of environmental, energy, and economic impacts. The steps involved include:

- Step 1 - Identify applicable options;
- Step 2 - Eliminate technically infeasible options;
- Step 3 - Rank remaining alternatives by control effectiveness;
- Step 4 - Evaluate most effective controls; and
- Step 5 - Select BACT

7.2 CONTROL OF NO_X EMISSIONS

The operating temperatures within turbine burner systems result in the formation of NOx emissions. Thermal NOx and fuel NOx are the two primary NOx formation mechanisms in compressor turbines. Thermal NOx is formed by the dissociation of atmospheric nitrogen and oxygen in the turbine combustor and the subsequent formation of NOx. When fuels containing nitrogen are combusted this additional source of nitrogen results in fuel NOx formation. Thermal NOx is the dominant mechanism for NOx emissions for the proposed turbines because natural gas fuel contains little or no nitrogen. The formation rate of thermal NOx increases exponentially with an increase in temperature.

The following technologies were identified as potentially able to control NOx emissions from compressor turbines:

- Good Combustion Practices (GCPs);
- Dry Low NOx (DLN) Burner Technology;
- Selective Non-Catalytic Reduction (SNCR); and
- Selective Catalytic Reduction (SCR).

7.2.1 ELIMINATE TECHNICALLY INFEASIBLE ALTERNATIVES

1. Good Combustion Practices

Techniques that seek to influence the combustion process and, thereby, prevent the formation of a given pollutant, are referred to as "combustion controls." GCPs include combustion system design elements and operational strategies intended to control the amount and distribution of excess air in the combustion zone for enough oxygen to be present for complete combustion, while not creating high temperatures that promote the creation of NO_x.

GCPs are a technically feasible method of limiting NO_x emissions from the turbines and are considered a baseline control alternative. NO_x exhaust concentrations of 25 parts per million (ppm) (or less) may be achievable using this approach, depending on the turbine design and configuration.

2. Dry Low NOx Technology

DLN burners use an advanced combustion design to suppress NOx formation and/or promote CO burnout while firing natural gas. The technology can include a lower combustion temperature with lean mixtures of air and fuel, staged premix combustion, or decreased residence time. For turbines such as those proposed, DLN burners can achieve 15 ppm NOx without the addition of any further controls. As discussed earlier, GTN proposes a dry low-NOx combustion system (SoLoNOx) control for NOx.

3. Selective Non-Catalytic Reduction

In the SNCR process, ammonia is mixed with the exhaust from the combustion device, and the NO_x in the exhaust reacts with the introduced ammonia to form N_2 and water. The reagent, which can be anhydrous ammonia (NH_3), aqueous ammonia, or urea dissolved in water, is typically injected at the exit of the turbine to mix with the hot flue gases. The success of this process in reducing NO_x emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas. This must occur within a zone of the exhaust stream where the flue gas temperature is within a range typically from 1,600 to 2,200 degrees Fahrenheit (°F). In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. Within the temperature range, the reagent will react with NO_x to form N_2 and water (and CO_2 if urea is used as the reagent). The consequence of operating outside the optimum temperature range is additional NO_X generation or significant NH_3 emissions. At temperatures above that range, the reagent will be converted to NO_X. At temperatures less than that range, the reagent will not react with the NO_X and significant quantities of NH_3 will discharge from the stack (known as "ammonia slip").

The use of SNCR can achieve control efficiencies of up to 65 percent, with actual emission reductions varying based on inlet NO_x, and exhaust parameters such as temperature and total volumetric flow.[2] For this assessment, SNCR is technically infeasible due to low stack temperature. The stack temperature from the new turbine is below the range of 1,600 to 2,200°F required for SNCR use.

4. Selective Catalytic Reduction

The SCR process is similar to SNCR, in that a reagent (usually NH_3) reacts with NO_x to form N_2 and water, but a catalyst matrix is used to allow the reduction reaction to take place at lower temperatures (600 to 700ºF for SCR, as opposed to 1,600 to 2,200ºF for SNCR).

Depending on system design and the inlet NOx level, NOx removal of up to 70-90 percent is achievable at optimum theoretical conditions. Depending on the catalyst, NOx reduction occurs within a reaction window of 400 to 1100 degrees Fahrenheit. The design of the proposed turbines allows for catalyst installation in the optimum temperature zone.

SCR is commonly used in the utility-scale electric power sector for the control of NO_x emissions from gas-fired turbines and is considered technologically feasible for the proposed Solar Titan 130 turbines. SCR can achieve NO_x emission controls of up to 90 percent, depending on the inlet NO_x levels being controlled.[3] For this assessment, we assume SCR would be capable of achieving a 90 percent removal efficiency.

7.2.2 RANK REMAINING ALTERNATIVES BY EFFECTIVENESS

Effectiveness is defined by the ability of an emission reduction alternative to reduce the emission rate of a given pollutant or group of pollutants. The use of SCR as a NO_x control option is considered technologically feasible for this project. Since the use of DLN combustors employing good combustion practices has been selected as part of the design of the proposed turbine, the costs of

2 USEPA Cost Control Manual, Seventh Edition, Section 7, Chapter 1, "NOx Controls – Selective Non-Catalytic Reduction," pp.1-1 to 1-4

3 USEPA Cost Control Manual, Seventh Edition, Section 7, Chapter 2, "NOx Controls – Selective Catalytic Reduction," pp.1-1 to 1-4

these options are not evaluated. Therefore, the use of control technology (SCR) has been evaluated for its cost effectiveness. The results of this analysis are described below.

7.2.3 CONSIDERATION OF ECONOMIC, ENERGY, AND ENVIRONMENTAL FACTORS

This step of a BACT analysis involves consideration of economic, energy, and environmental factors starting with the emission reduction alternative identified in the previous step to be the most effective.

Based on the information presented above, the use of SCR is evaluated here. Economic factors were considered using cost effectiveness as the criterion, which is calculated as the annualized cost of the emission reduction alternative divided by the annual tons of pollutant reduced by the emission reduction alternative.

Direct and indirect capital and operating costs were estimated based on the control cost estimation methodology provided by the USEPA's Air Pollution Control Cost Manual. The calculated annual cost to use add-on control options, which includes the capital cost of the equipment and installation costs amortized over the life of the equipment, as well as annual operating costs, was estimated for SCR. These costs were then divided by the level of emission reduction below baseline levels achievable by SCR. These calculations and the resulting cost-per-ton cost effectiveness values are presented in Appendix F.

As seen in these calculations, the cost of SCR is anticipated to be $17,614 per ton of NO_x removed (in 2024 dollars).[4] In its 2016 guidance entitled "BACT and tBACT Cost-Effectiveness Thresholds[5]," Ecology lists the BACT cost effectiveness threshold range for NO_x emission control options as $10,000 to $12,000 per ton. Since the cost of the add-on control option is above the high end of this threshold range, the use of SCR is deemed to be not cost effective for this project.

7.2.4 PROPOSED BACT

Based on the analyses outlined above, BACT for NOx from the new turbine is proposed as 15 ppm in the exhaust, achievable with low-NOx burners employing good combustion control practices. The turbines are Solar Titan 100 turbines, equipped with Solar's proprietary dry-low NOx combustion technology, SoLoNOx®, capable of achieving the NOx emission rate determined to represent BACT. During sub-zero operating conditions PACO technology will be employed to reduce NOx emissions.

7.3 CONTROL OF CO EMISSIONS

CO emissions from any combustion process are formed due to incomplete combustion of the fuel. Typically, CO emissions from combustion sources depend on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. SoLoNOx used during

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4 Based on 2024 CEPCI value as the 2025 value is not yet available

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natural gas firing achieves low NOx emissions at high efficiency by optimizing the combustion to produce a lower flame temperature. CO emissions are also reduced through more thorough mixing of fuel and air in the proposed turbines, which promotes more complete combustion. Two types of CO control technologies will be discussed for the compressor turbines. The technologies available include the following:

- GCPs and
- Oxidation Catalyst.

7.3.1 ELIMINATE TECHNICALLY INFEASIBLE ALTERNATIVES

1. Good Combustion Practices

CO is formed due to incomplete combustion or inefficient combustion of the fuel. Improperly tuned turbines operating at off-design levels decrease combustion efficiency, increasing CO emissions. By controlling the combustion process carefully, the generation of CO emissions can be minimized.

2. Catalytic Oxidizer

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after it is formed in the combustion turbine. In the presence of a catalyst, CO will react with O_2 present in the turbine exhaust, converting it to CO_2. No supplementary reactant is used in conjunction with an oxidation catalyst.

Oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Oxidation of CO to CO_2 utilizes the excess oxygen present in the turbine exhaust; the activation energy required for the oxidation reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10} and sulfuric acid mist emissions.

CO catalytic oxidation reactors operate in a relatively narrow temperature range. At lower temperatures, CO conversion efficiency falls off rapidly. At higher temperatures, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the proper turbine exhaust point and proper operating temperature considering the temperature variations that are expected to occur across the unit's operating load range. Operation at part load or during start-up/shutdown will result in less than optimum temperatures and reduced control efficiency.

Catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation.

The use of an oxidation catalyst is technologically feasible for the proposed turbines. Oxidation catalysts can achieve CO concentrations as low as 2 ppm in the exhaust.

7.3.2 RANK REMAINING ALTERNATIVES BY EFFECTIVENESS

Effectiveness is defined by the ability of an emission reduction alternative to reduce the emission rate of a given pollutant or group of pollutants. The use of an oxidation catalyst is the most effective control option and has been further evaluated below for additional impacts compared to the use of good combustion practices.

7.3.3 CONSIDERATION OF ECONOMIC, ENERGY, AND ENVIRONMENTAL FACTORS

Based on the information presented above, the use of an oxidation catalyst is evaluated here. Economic factors were considered using cost effectiveness as the criterion, which is calculated as the annualized cost of the emission reduction alternative divided by the annual tons of pollutant reduced by the emission reduction alternative.

Direct and indirect capital and operating costs were estimated based on the control cost estimation methodology provided by the USEPA's Air Pollution Control Cost Manual. The calculated annual cost to use add-on control options, which includes the capital cost of the equipment and installation costs amortized over the life of the equipment, as well as annual operating costs, was estimated for each option. These costs were then divided by the level of emission reduction below baseline levels achievable by each option. These calculations and the resulting cost-per-ton cost effectiveness values are presented in Appendix F.

As seen in these calculations, the costs of an oxidation catalyst are anticipated to be $13,318 per ton to remove CO. In its 2016 guidance entitled "BACT and tBACT Cost-Effectiveness Thresholds,[6]" Ecology lists the BACT cost effectiveness threshold for CO emission control options as $5,000 per ton. Since the cost of an oxidation catalyst is above this threshold, the use of this option is deemed to be not cost effective for this project.

7.3.4 PROPOSED BACT

Based on the analysis outlined above, BACT for CO emissions from the new turbine is proposed to be the use of good combustion practices to achieve a design CO exhaust concentration of 25 ppm in the exhaust. During sub-zero operating conditions PACO technology will be employed to reduce CO emissions.

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7.4 CONTROL OF VOC AND TAP EMISSIONS

Similar to CO emissions, VOC and TAP emissions are formed in any combustion process due to incomplete combustion of the fuel. The VOCs may consist of a wide spectrum of volatile and semi-volatile organic compounds. By controlling the combustion process carefully, VOC emissions can be minimized.

The following alternatives have been identified for the reduction of VOC emissions, including volatile TAPs, from the new Solar Titan 130 turbines.

- GCPs
- Oxidation Catalyst

7.4.1 ELIMINATE TECHNICALLY INFEASIBLE ALTERNATIVES

1. Good Combustion Practices

Techniques that seek to influence the combustion process and, thereby, prevent the formation of a given pollutant, are referred to as "combustion controls." GCPs include combustion system design elements and operational strategies intended to control the amount and distribution of excess air in the combustion zone for enough oxygen to be present for complete combustion, which minimizes VOC and volatile TAP emissions in the exhaust.

GCPs are a technically feasible method of limiting VOC and volatile TAP emissions from the turbines and are considered a baseline control alternative. Based on information from Solar a VOC emission rate of 1.38 pound per hour and a HCHO emission rate of 0.14 pound per hour is considered feasible for this unit.

2. Oxidation Catalyst

An oxidation catalyst is a post-combustion technology that removes VOC and volatile TAPs from the exhaust gas stream after it is formed in the combustion turbine. This is the same technology discussed above for the control of CO emissions. In the presence of a catalyst, VOC and volatile TAPs will react with O_2 present in the turbine exhaust, converting it to CO_2 and water. No supplementary reactant is used in conjunction with an oxidation catalyst.

Oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Oxidation of VOC and volatile TAPs to CO_2 utilizes the excess O_2 present in the turbine exhaust; the activation energy required for the oxidation reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10} and sulfuric acid mist emissions.

Oxidation catalysts are commonly used for utility-scale and industrial-scale turbines (>25 MW). The proposed turbines are smaller (approximately 13 MW), and oxidation catalysts are less commonly used for turbines of this size due to their cost and negative impacts on system performance. In spite of this, the use of an oxidation catalyst is considered to be technologically feasible for the proposed turbines. Oxidation catalysts can achieve VOC concentrations as low as 1 ppm in the exhaust.

7.4.2 RANK REMAINING ALTERNATIVE BY EFFECTIVENESS

Effectiveness is defined by the ability of an emission reduction alternative to reduce the emission rate of a given pollutant or group of pollutants. The use of an oxidation catalyst is the most effective control option and has been further evaluated below for additional impacts compared to the use of good combustion practices.

7.4.3 CONSIDERATION OF ECONOMIC, ENERGY, AND ENVIRONMENTAL FACTORS

Based on the information presented above, the use of an oxidation catalyst is evaluated here. Economic factors were considered using cost effectiveness as the criterion, which is calculated as the annualized cost of the emission reduction alternative divided by the annual tons of pollutant reduced by the emission reduction alternative.

Direct and indirect capital and operating costs were estimated based on the control cost estimation methodology provided by the USEPA's Air Pollution Control Cost Manual. The calculated annual cost to use add-on control options, which includes the capital cost of the equipment and installation costs amortized over the life of the equipment, as well as annual operating costs, was estimated for each option. These costs were then divided by the level of emission reduction below baseline levels achievable by each option. These calculations and the resulting cost-per-ton cost effectiveness values are presented in Appendix F.

As seen in these calculations, the costs of an oxidation catalyst are anticipated to be $113,595 per ton to remove VOCs. In its 2016 guidance entitled "BACT and tBACT Cost-Effectiveness Thresholds7," Ecology lists the BACT cost effectiveness threshold for VOC emission control options as $10,000 to $12,000 per ton. Since the cost of an oxidation catalyst is above the high end of this range, the use of this option is deemed to be not cost effective for this project.

Additionally shown in the calculations appended, the cost effectiveness of installation of a catalytic oxidizer to remove volatile TAPs that exceed *de minimis* values (1,3-butadiene, acetaldehyde, acrolein, benzene, ethylbenzene, formaldehyde, naphthalene, and propylene oxide) results in anticipated cost of $797,499 per ton. When considering the sum of criteria pollutants (CO and VOC) in addition to the above-mentioned volatile TAPs, based on estimated equipment cost to install and abate emissions, the resulting cost effectiveness amounts to $11,745 per ton of emissions, still deemed not cost effective for this project.

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7.4.4 PROPOSED BACT

Based on the analysis outlined above, BACT for VOC and tBACT for volatile TAP emissions from the new turbine is proposed to be the use of good combustion practices to achieve a design VOC emission rate of 1.38 pound per hour and a design HCHO emission rate of 0.14 pound per hour. During sub-zero operating conditions PACO technology will be employed to reduce VOC emissions.

7.5 CONTROL OF PM EMISSIONS

Particulate matter (PM) emissions from combustion turbine generators are a combination of filterable (front-half) and condensable (back-half) particles. Filterable PM is formed from impurities contained in the fuels and from incomplete combustion. Condensable particulate emissions, which are to be aggregated with filterable PM when quantifying PM_{10} and $PM_{2.5}$ emission rates, are attributable primarily to the formation of sulfates and possibly organic compounds. Only the filterable fraction of PM is used to quantify PM emission rates.

When the NSPS for stationary combustion turbines (40 CFR 60, Subpart KKKK) were proposed in 2005, USEPA declined to establish emission limits on PM because "…particulate matter emissions are negligible with natural gas firing due to the low sulfur content of natural gas. Emissions of PM are only marginally significant with distillate oil firing because of the lower ash content…"[8].

Additionally, USEPA found that no combustion turbines permitted since 2003 utilized add-on controls. Proper combustion control and the use of pipeline quality natural gas is the only control option that has been achieved in practice for this category of emissions.

Add-on PM controls, such as electrostatic precipitators or baghouses, have never been applied to commercial natural gas-fired combustion turbines. The use of electrostatic precipitators and baghouses are considered technically infeasible, and do not represent a commercially available control technology.

7.5.1 ELIMINATE TECHNICALLY INFEASIBLE ALTERNATIVES

The only commercially available control option for limiting PM emissions from natural gas combustion is the use of pipeline quality natural gas.

7.5.2 RANK REMAINING ALTERNATIVES BY EFFECTIVENESS

Effectiveness is defined by the ability of an emission reduction alternative to reduce the emission rate of a given pollutant or group of pollutants. Only one control option has been identified: the use of pipeline quality natural gas as a fuel. Since this option is incorporated into the project design, no further evaluation of economic, energy, and environmental factors is necessary.

[8] EPA, 70 FR 8314, February 2005

7.5.3 PROPOSED BACT

Based on the analysis outlined above, BACT for PM emissions from the new turbine is proposed to be the use of pipeline quality natural gas as a fuel.

7.6 CONTROL OF SO_2 EMISSIONS

SO2 emissions are formed in combustion systems as a result of the oxidation of sulfur contained in the fuel. Control options therefore focus both on the use of low-sulfur fuels as a pollution prevention measure, or, where necessary, add-on controls to remove SO2 once it has been generated. The following subsections present the BACT assessment for SO2 emissions.

Natural gas is an inherently low-sulfur fuel. The sulfur present in pipeline quality natural gas is primarily the result of mercaptans added to the gas to give it an odor, for safety reasons.

Add-on SO2 controls, such as scrubbers, have never been applied to commercial natural gas-fired combustion turbines. The use of scrubbers are considered technically infeasible, and do not represent a commercially available control technology for emissions from a natural gas-fired turbine.

7.6.1 ELIMINATE TECHNICALLY INFEASIBLE ALTERNATIVES

The only commercially available control option for limiting SO_2 emissions from natural gas combustion is the use of pipeline quality natural gas.

7.6.2 RANK REMAINING ALTERNATIVES BY EFFECTIVENESS

Effectiveness is defined by the ability of an emission reduction alternative to reduce the emission rate of a given pollutant or group of pollutants. Only one control option has been identified: the use of pipeline quality natural gas as a fuel. Since this option is incorporated into the project design, no further evaluation of economic, energy, and environmental factors is necessary.

7.6.3 PROPOSED BACT

Based on the analysis outlined above, BACT for SO_2 emissions from the new turbine is proposed to be the use of pipeline quality natural gas as a fuel.

APPENDIX A NOTICE OF CONSTRUCTION

Notice of Construction Application

A notice of construction permit is required before installing a new source of air pollution or modifying an existing source of air pollution. This application applies to facilities in Ecology's jurisdiction. Submit this application for review of your project. For general information about completing the application, refer to Ecology Forms ECY 070-410a-g, "Instructions for Ecology's Notice of Construction Application."

Ecology offers up to two hours of free pre-application assistance. We encourage you to schedule a pre-application meeting with the contact person specified for the location of your proposal, below. If you use up your two hours of free pre-application assistance, we will continue to assist you after you submit Part 1 of the application and the application fee. You may schedule a meeting with us at any point in the process.

Upon completion of the application, please enclose a check for the initial fee and mail to:

Department of Ecology
Cashiering Unit
PO Box 47611
Olympia, WA 98504-7611

For Fiscal Office Use Only: 0299-3030404-B00-216--001--000404

Check the box for the location of your proposal. For assistance, call the appropriate office listed below:

Check box	Ecology Permitting Office	Contact
☐	**Chelan, Douglas, Kittitas, Klickitat, or Okanogan County** Ecology Central Regional Office (509) 575-2490	Lynnette Haller (509) 457-7126 lynnette.haller@ecy.wa.gov
☐	**Adams, Asotin, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Stevens, Walla Walla, or Whitman County** Ecology Eastern Regional Office (509) 329-3400	Karin Baldwin (509) 329-3452 karin.baldwin@ecy.wa.gov
☐	**San Juan County** Ecology Northwest Regional Office (206) 594-0000	David Adler (425) 649-7267 david.adler@ecy.wa.gov
☐	**For actions taken at Kraft and Sulfite Paper Mills and Aluminum Smelters Only** Ecology Industrial Section (360) 407-6900	James DeMay (360) 407-6868 james.demay@ecy.wa.gov
☐	**For actions taken on the US Department of Energy Hanford Reservation Only** Ecology Nuclear Waste Program (509) 372-7950	Lilyann Murphy (509) 372-7951 lilyann.murphy@ecy.wa.gov

Check the box below for the fee that applies to your application.

New project or equipment:

- ☐ **$1,904: Basic project** initial fee covers up to 16 hours of review.
- ☐ **$12,614: Complex project** initial fee covers up to 106 hours of review.

Change to an existing permit or equipment:

- ☐ **$357: Administrative or simple change** initial fee covers up to 3 hours of review. Ecology may determine your change is complex during the completeness review of your application. If you project is complex, you must pay the additional xxx before we will continue working on your application
- ☐ **$1,190: Complex** change initial fee covers up to 10 hours of review
- ☐ **$350flat fee**: Replace or alter control technology equipment under WAC 173-400-114. Ecology will contact you if we determine your change belongs in another fee category. You must pay the fee associated with that category before we will continue working on your application.

Read each statement below, then check the box next to it to acknowledge that you agree.

- ☐ The initial fee you submitted may not cover the cost of processing your application. Ecology will track the number of hours spent on your project. If the number of hours Ecology spends exceeds the hours included in your initial fee, Ecology will bill you $119 per hour for the extra time.
- ☐ You must include all information requested by this application. Ecology may not process your application if it does not include all the information requested.
- ☐ Submittal of this application allows Ecology staff to visit and inspect your facility.

Part 1: General Information

I. Project, Facility, and Company Information

1. Project Name: GTN Low Temperature
2. Facility Name: Compressor Station #7 - Starbuck
3. Facility Street Address:

   Latitude: 46.43505 N, 118.29367
4. Facility Legal Description: Natural Gas Compressor Station
5. Company Legal Name (if different from Facility Name):
   Gas Transmission Northwest, LLC
6. Company Mailing Address (street, city, state, zip)

   201 W. North River Dr., Suite 505, Spokane, WA 99201

II. Contact Information and Certification

1. Facility Contact Name (who will be onsite): Dan Maguire
2. Facility Contact Mailing Address (if different than Company Mailing Address:

   ____

3. Facility Contact Phone Number: 509-533-2832
4. Facility Contact E-mail: dan_maguire@tcenergy.com
5. Billing Contact Name (who should receive billing information):
   Same as above
6. Billing Contact Mailing Address (if different Company Mailing Address):
7. Billing contact Phone Number: ______
8. Billing Contact E-mail: ______
9. Consultant Name (optional – if 3rd party hired to complete application elements):
   Joe Gross
10. Consultant Organization/Company: Environmental Resources Management
11. Consultant Mailing Address (street, city, state, zip):
12. Consultant Phone Number: 504-617-0184
13. Consultant E-mail: Joe.Gross@erm.com
14. Responsible Official Name and Title (who is responsible for project policy or decision making):
    Aczael Valdez
15. Responsible Official Phone: 509-405-2046
16. Responsible Official E-mail: aczael_valdez@tcenergy.com
17. Responsible Official Certification and Signature:

    I certify that the information on this application is accurate and complete.

    Signature: Aczael Valdez Date: 6-3-25

Part 2: Technical Information

The Technical Information may be sent with this application form to the Cashiering Unit, or may be sent directly to the Ecology regional office with jurisdiction along with a copy of this application form.

For all sections, check the box next to each item as you complete it.

III. Project Description

- ☐ Written narrative describing your proposed project.
- ☐ Projected construction start and completion dates.
- ☐ Operating schedule and production rates.
- ☐ List of all major process equipment and manufacturer and maximum rated capacity.
- ☐ Process flow diagram with all emission points identified.
- ☐ Plan view site map.
- ☐ Manufacturer specification sheets for major process equipment components
- ☐ Manufacturer specification sheets for pollution control equipment.
- ☐ Fuel specifications, including type, consumption (per hour and per year) and percent sulfur.

IV. State Environmental Policy Act (SEPA) Compliance

Check the appropriate box below.

- ☐ SEPA review is complete. Include a copy of the final SEPA checklist and SEPA determination (e.g., DNS, MDNS, and EIS) with your application.
- ☐ SEPA review has not been conducted:
  - ☐ If review will be conducted by another agency, list the agency. You must provide a copy of the final SEPA checklist and SEPA determination before Ecology will issue your permit. Agency reviewing SEPA: ____
  - ☐ If the review will be conducted by Ecology, fill out a SEPA checklist and submit it with your application. You can find a SEPA checklist online at https://ecology.wa.gov/Regulations-Permits/SEPA/Environmental-review/SEPA-document-templates

V. Emissions Estimations of Criteria Pollutants

Does your project generate criteria air pollutant emissions? ☐ Yes ☐ No

If yes, please proved the following information regarding your criteria emissions in the application.

- ☐ The names of the criteria air pollutants emitted (i.e., NO_X, SO_2, CO, $PM_{2.5}$, PM_{10}, TSP, VOC, and Pb)
- ☐ Potential emissions of criteria air pollutants in tons per hour, tons per day, and tons per year (include calculations)
- ☐ If there will be any fugitive criteria pollutant emissions, clearly identify the pollutant and quantity

VI. Emissions Estimations of Toxic Air Pollutants

Does your project generate toxic air pollutant emissions? ☐ Yes ☐ No

If yes, please provide the following information regarding your toxic air pollutant emissions in your application.

- [ ] The names of the toxic air pollutants emitted (specified in WAC 173-460-150[1])
- [ ] Potential emissions of toxic air pollutants in pounds per hour, pounds per day, and pounds per year (include calculations)
- [ ] If there will be any fugitive toxic air pollutant emissions, clearly identify the pollutant and quantity

VII. Emission Standard Compliance

- [ ] Provide a list of all applicable new source performance standards, national emission standards for hazardous air pollutants, national emission standards for hazardous air pollutants for source categories, and emission standards adopted under Chapter 70A.15 RCW.

Does your project comply with all applicable standards identified? ☐ **Yes** ☐ **No**

VIII. Best Available Control Technology

- [ ] Provide a complete evaluation of Best Available Control Technology (BACT) for your proposal.

IX. Ambient Air Impacts Analyses

Please provide the following:

- [ ] Ambient air impacts analyses for Criteria Air Pollutants (including fugitive emissions)
- [ ] Ambient air impacts analyses for Toxic Air Pollutants (including fugitive emissions)
- [ ] Discharge point data for each point included in air impacts analyses (include only if modeling is required)
    - [ ] Exhaust height
    - [ ] Exhaust inside dimensions (ex. diameter or length and width)
    - [ ] Exhaust gas velocity or volumetric flow rate
    - [ ] Exhaust gas exit temperature
    - [ ] The volumetric flow rate
    - [ ] Description of the discharges (i.e., vertically or horizontally) and whether there are any obstructions (ex., raincap)
    - [ ] Identification of the emission unit(s) discharging from the point
    - [ ] The distance from the stack to the nearest property line
    - [ ] Emission unit building height, width, and length
    - [ ] Height of tallest building on-site or in the vicinity and the nearest distance of that building to the exhaust
    - [ ] Whether the facility is in an urban or rural location

Does your project cause or contribute to a violation of any ambient air quality standard or acceptable source impact level? ☐ **Yes** ☐ **No**

To request ADA accommodation, call Ecology at (360) 407-6800, 711 (relay service), or (877) 833-6341 (TTY)

[1] http://apps.leg.wa.gov/WAC/default.aspx?cite=173-460-150

APPENDIX B DETAILED EMISSIONS CALCULATIONS

Gas Transmission Northwest (GTN)
Compressor Station 7
Notice of Construction Application
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Table B-1. Facility Total PTE

Existing Source	Capacity	Annual Emissions (tpy)							
		NO_x	CO	CO_2e	$PM_{10}/PM_{2.5}$	VOC	SO_2	CH_2O	Total HAP
Unit 7C Cooper Rolls Coberra RB-211	39,700 hp (59 °F)	236.00	173.00	142,532	3.60	5.26	4.60	0.86	1.25
Unit 7D Solar Titan 130 Turbine[1]	22,605 hp (0 °F)	44.53	48.26	96,418	5.43	5.89	0.59	0.58	0.85
Unit 7E Solar Titan 130 Turbine[1]	22,605 hp (0 °F)	44.53	48.26	96,418	5.43	5.89	0.59	0.58	0.85
IA - Fuel Gas Heater	2.00 MMBtu/hr	0.86	0.72	1,026	0.07	0.05	0.006	0.0006	0.02
IA - Space Heaters	0.63 MMBtu/hr	0.27	0.23	323	0.02	0.01	0.002	0.0002	0.005
IA - Space Heater	2.00 MMBtu/hr	0.86	0.72	1025.78	0.07	0.05	0.01	0.001	0.02
IA - Water Heater	0.04 MMBtu/hr	0.02	0.01	20.52	0.00	0.001	0.0001	0.00001	0.0003
AUX GEN2 Caterpillar G3512 Emergency Generator	13.05 MMBtu/hr	2.01	4.03	382	0.03	1.01	0.002	0.2618	0.236
Equipment Leaks (fugitive emissions)				3,833		1.39			
Venting				15,193		5.52			
Pipeline Fluids Tank	150 gallons					0.002			
Lube Oil Tanks (2)	Varies gallons					0.06			
Existing Facility PTE[2]		329.07	275.22	353337.84	14.65	23.74	5.79	2.30	3.22
Modified Source									
Unit 7D Solar Titan 130 Turbine[3]	22,605 hp (0 °F)	46.40	51.41	97852.46	5.52	6.03	0.60	0.593	0.86
Unit 7E Solar Titan 130 Turbine[3]	22,605 hp (0 °F)	46.40	51.41	97852.46	5.52	6.027	0.5967	0.59331	0.8585
Modified Sources PTE		92.79	102.81	195704.91	11.03	12.05	1.19	1.19	1.72
Total Facility PTE (Existing + Proposed)[2]		332.81	281.53	356207.14	14.82	24.01	5.81	2.31	3.24
PTE Change (tons/year)		3.74	6.30	2869.31	0.16	0.27	0.02	0.02	0.03
PSD Major Source Threshold		250	250	n/a	250	250	250	n/a	n/a
Title V Threshold		100	100	100,000	100	100	100	10	25
Applicability		NSR Major Source	NSR Major Source	Title V	None, Natural Minor	None, Natural Minor	None, Natural Minor	None, Area Source	None, Area Source

1. Existing turbine emissions based on 150 Start up / shut down cycles per year.
2. Excludes fugitive emissions (compressor stations are not one of the named source categories that include fugitive emissions).
3. Turbine emissions based on 150 Start up / shut down cycles per year, 200 hours of very low temperature operating mode, and the remainder of the hours per year are based on emissions

Gas Transmission Northwest (GTN)
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Table B-2. PSD Analysis

Existing Source	Capacity	Annual Emissions (tpy)							
		NO_x	CO	CO_2e	$PM_{10}/PM_{2.5}$	VOC	SO_2	CH_2O	Total HAP
Unit 7C Cooper Rolls Coberra RB-211	39,700 hp (59 °F)	236.00	173.00	142,532	3.60	5.26	4.60	0.86	1.25
Unit 7D Solar Titan 130 Turbine[1]	22,605 hp (0 °F)	44.53	48.26	96,418	5.43	5.89	0.59	0.58	0.85
Unit 7E Solar Titan 130 Turbine[1]	22,605 hp (0 °F)	44.53	48.26	96,418	5.43	5.89	0.59	0.58	0.85
IA - Fuel Gas Heater	2.00 MMBtu/hr	0.86	0.72	1,026	0.07	0.05	0.006	0.0006	0.02
IA - Space Heaters	0.63 MMBtu/hr	0.27	0.23	323	0.02	0.01	0.002	0.0002	0.005
IA - Space Heater	2.00 MMBtu/hr	0.86	0.72	1025.78	0.07	0.05	0.01	0.001	0.02
IA - Water Heater	0.04 MMBtu/hr	0.02	0.01	20.52	0.00	0.001	0.0001	0.00001	0.0003
AUX GEN2 Caterpillar G3512 Emergency Generator	13.05 MMBtu/hr	2.01	4.03	382	0.03	1.01	0.002	0.2618	0.236
Equipment Leaks (fugitive emissions)				3,833		1.39			
Venting				15,193		5.52			
Pipeline Fluids Tank	150 gallons					0.002			
Lube Oil Tanks (2)	Varies gallons					0.06			
Existing Facility PTE[2]		329.07	275.22	353337.84	14.65	23.74	5.79	2.30	3.22
Modified Source									
Unit 7D Solar Titan 130 Turbine[3]	22,605 hp (0 °F)	46.40	51.41	97852.46	5.52	6.03	0.60	0.593	0.86
Unit 7E Solar Titan 130 Turbine[3]	22,605 hp (0 °F)	46.40	51.41	97852.46	5.52	6.027	0.5967	0.59331	0.8585
Modified Sources PTE		92.79	102.81	195704.91	11.03	12.05	1.19	1.19	1.72
Emissions Increase (tons/year)		3.74	6.30	2869.31	0.16	0.27	0.02	0.02	0.03
PSD Significant Emission Rate (SER)		40	100	75000	15/10	40	40	n/a	n/a
Trigger PSD Review?[4]		No	No	No	No	No	No	n/a	n/a

1. Fugitive emissions are not part of PSD applicability analysis.
2. Excludes fugitive emissions (compressor stations are not one of the named source categories that include fugitive emissions).
3. Turbine emissions based on 150 Start up / shut down cycles per year, 200 hours of very low temperature operating mode, and the remainder of the hours per year are based on emissions

Gas Transmission Northwest (GTN)
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Units 7D & 7E - Solar Titan 130 - Emission Rates

Emission Rates per Operating Mode

Operating Mode	Units	NO_x	CO	VOC
Normal Load (≤0 °F)[1]	lb/hr	10.19	10.34	1.18
Startup/ Shutdown[2]	lb/event	2.00	43.00	10.00
Very Low Temp (-20 °F ≤ T ≤ 0 °F)[3]	lb/hr	28.87	41.85	2.39

1. Based on data from Solar Titan 130 Compressor Set Predicted Emission Performance data sheet and the following concentrations:
   15 ppm NOx; 25 ppm CO; 5 ppm VOC
2. Based on data from Solar PIL170 for SoLoNOx Titan 130 23502S CS/MD Application Nominal Start-up and Shutdown, Natural Gas Fuel, Production Units with Enhanced Emissions Control.
3. Based on data from Solar for Titan 130 operations between 0 °F and ≥ -20 °F utilizing pilot active control logic (PACO).

Potential Annual Emissions Per Turbine

Operating Mode	Operating Time[1]		NO_x	CO	VOC
	Cycles	hr/yr	ton/yr	ton/yr	ton/yr
Normal Load (≤0 °F)		8510	43.36	44.00	5.04
Startup/ Shutdown	150	50	0.15	3.23	0.75
Very Low Temp (-20 oF ≤ T ≤ 0 oF)[2]		200	2.89	4.18	0.24
Total		8,760	46.40	51.41	6.03
Total (lb/hr)		8,760	10.59	11.74	1.38

1. Startup/Shutdown cycles based on 20 minute cycle time. Based on Startup/Shutdown event time of 10 minutes each as listed in Solar PIL 170 (Revision 5, June 13, 2012)

2. Based on data from Solar PIL167 for SoLoNOx Titan 130 PACO.

Emission Rates During Normal Operation (g/hp-hr)[1]

Emission Point ID / Model	NO_x	CO	VOC[2]	SO_2[3]	PM_{10} / $PM_{2.5}$	CH_2O
Solar Titan 130	0.177	0.180	0.021	*0.209*	*0.024*	*0.003*

1. Based on vendor performance data; values in italics based on AP-42 emission factors.
2. VOC is based on 20 percent of unburned hydrocarbons per Solar Product Information Letter 168.
3. Conservatively based on 20 grains sulfur per 100 standard cubic feet of natural gas for maximum short-term emissions.

Gas Transmission Northwest (GTN)
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Table B-3. Unit 7D Solar Titan 130 Turbine

Horsepower	22,605	hp (0 °F)
Brake Specific Fuel Consumption	7492	Btu/Bhp-hr (LHV, 0 °F)
Maximum Heat Input (at 0 °F)	171.88	MMBtu/hr (LHV, 0 °F)
	190.79	MMBtu/hr (HHV, 0 °F)[3]
Operating Hours	8760	hr/yr
Natural Gas Heat Content	1020	Btu/scf
Fuel Consumption	1638.52	MMscf/yr (based on 0 °F)

Pollutant	Emission Factor			Emission Rate		Emission Factor Reference
	ppmvd@15%O_2	lb/MMBtu		lb/hr[1]	ton/yr[2]	
NO_x	15.00			10.59	46.40	Vendor Data
CO	25.00			11.74	51.41	Vendor Data
CO_2e		117.1	HHV	22,341	97,852	40 CFR 98 Subpart C
PM_{10}		0.0066	HHV	1.26	5.52	AP-42 Table 3.1-2a (4/00)
$PM_{2.5}$		0.0066	HHV	1.26	5.52	AP-42 Table 3.1-2a (4/00)
VOC	5.00			1.38	6.03	Vendor Data (20% of UHC)[4]
SO_2 (Maximum Hourly)		0.0571	HHV	10.89		20 grains S / 100 scf
SO_2 (Average Annual)		0.000714	HHV		0.60	0.25 grains S / 100 scf
Formaldehyde		0.00071	HHV	0.14	0.59	AP-42 Table 3.1-3 (4/00)
Total HAPs		0.00103	HHV	0.20	0.86	AP-42 Table 3.1-3 (4/00)

1. Hourly emission rate based on average emissions over the year.
2. Annual emission rate based on combination of potential operating modes. The operating modes are 200 hours or subzero temperature (<0°F) and 150 startups and shutdowns per year. The remainder of the hours per year are based on emissions at normal load (0°F). All other pollutants based on horsepower and brake specific fuel consumption at 0°F.
3. Conservatively estimated based on vendor data. HHV heat input based on HHV=1.11*LHV
4. VOC based on 20% of vendor data for unburned hydrocarbon.

Gas Transmission Northwest (GTN)
Compressor Station 7
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Table B-3. Unit 7E Solar Titan 130 Turbine

Horsepower	22,605	hp (0 °F)
Brake Specific Fuel Consumption	7492	Btu/Bhp-hr (LHV, 0 °F)
Maximum Heat Input (at 0 °F)	171.88	MMBtu/hr (LHV, 0 °F)
	190.79	MMBtu/hr (HHV, 0 °F)[3]
Operating Hours	8760	hr/yr
Natural Gas Heat Content	1020	Btu/scf
Fuel Consumption	1638.52	MMscf/yr (based on 0 °F)

Pollutant	Emission Factor			Emission Rate		Emission Factor Reference
	ppmvd@15%O_2	lb/MMBtu		lb/hr[1]	ton/yr[2]	
NO_x	15.00			10.59	46.40	Vendor Data
CO	25.00			11.74	51.41	Vendor Data
CO_2e		117.1	HHV	22,341	97,852	40 CFR 98 Subpart C
PM_{10}		0.0066	HHV	1.26	5.52	AP-42 Table 3.1-2a (4/00)
$PM_{2.5}$		0.0066	HHV	1.26	5.52	AP-42 Table 3.1-2a (4/00)
VOC	5.00			1.38	6.03	Vendor Data (20% of UHC)[4]
SO_2 (Maximum Hourly)		0.0571	HHV	10.89		20 grains S / 100 scf
SO_2 (Average Annual)		0.000714	HHV		0.60	0.25 grains S / 100 scf
Formaldehyde		0.00071	HHV	0.14	0.59	AP-42 Table 3.1-3 (4/00)
Total HAPs		0.00103	HHV	0.20	0.86	AP-42 Table 3.1-3 (4/00)

1. Hourly emission rate based on average emissions over the year.
2. Annual emission rate based on combination of potential operating modes. The operating modes are 200 hours or subzero temperature (<0°F) and 150 startups and shutdowns per year. The remainder of the hours per year are based on emissions at normal load (0°F). All other pollutants based on horsepower and brake specific fuel consumption at 0°F.
3. Conservatively estimated based on vendor data. HHV heat input based on HHV=1.11*LHV
4. VOC based on 20% of vendor data for unburned hydrocarbon.

Solar Turbines Emissions Estimates

T130-23502S

Assumptions: pipeline gas, 1070' elevation, 4/6" inlet/outlet losses, with P/

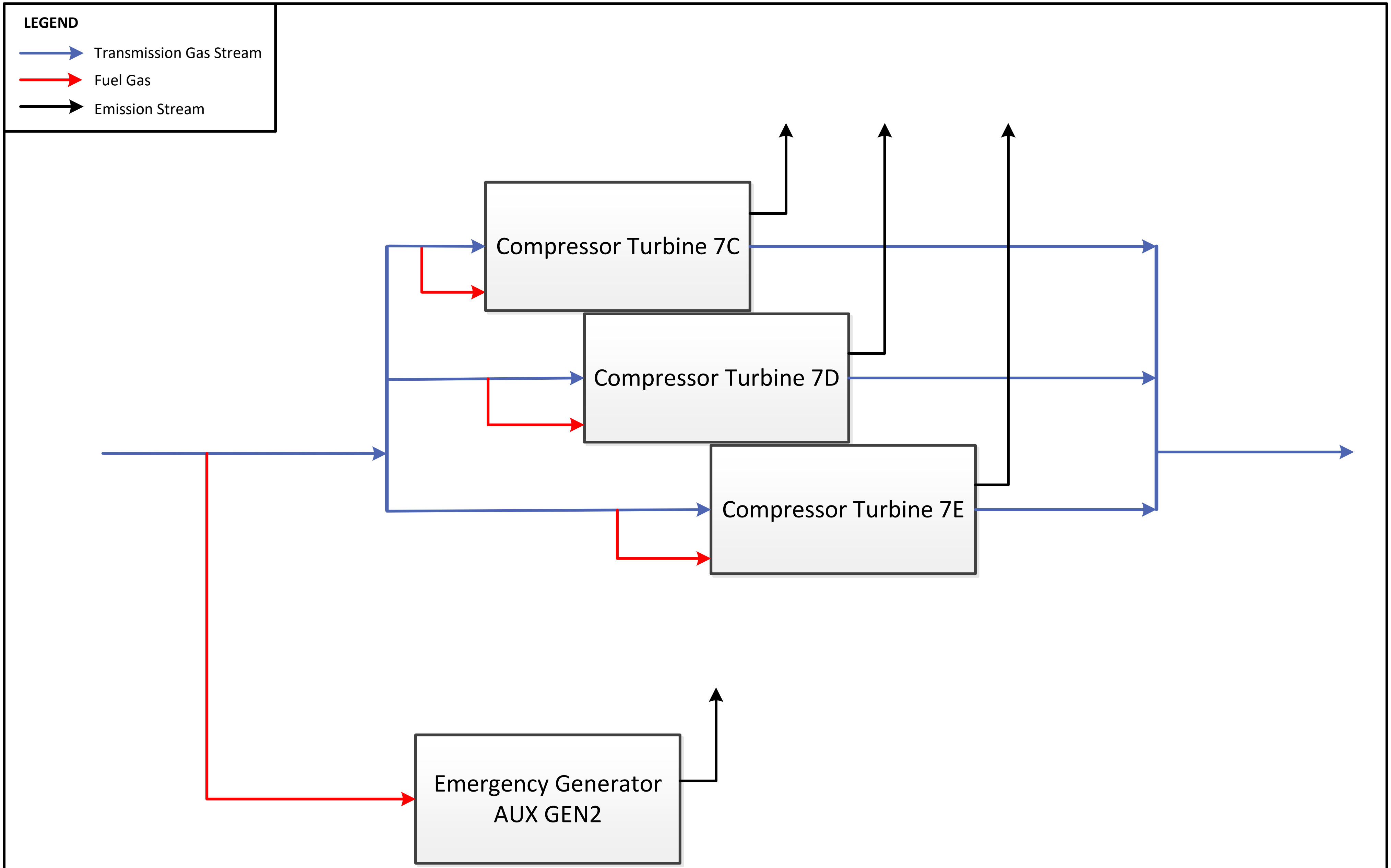
Load	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)
-20F						
40%	42	19.1	100	28.4	50	7.9
50%	42	20.9	100	30.3	50	8.7
75%	42	25.6	100	37.1	50	10.6
100%	42	28.9	100	41.8	50	12.0

Load	NOx (ppm)	NOx (lb/hr)	CO (ppm)	CO (lb/hr)	UHC (ppm)	UHC (lb/hr)
-5F						
40%	42	18.5	100	27.2	50	7.6
50%	42	20.5	100	29.8	50	8.5
75%	42	25.0	100	36.2	50	10.3
100%	42	28.2	100	40.8	50	11.7

APPENDIX C AREA MAP

Area Map
Gas Transmission Northwest, LLC- Compressor Station 7
46.535, -118.295
Starbuck, Washington

APPENDIX D PROCESS FLOW DIAGRAM



PROCESS FLOW DIAGRAM
Gas Transmission Northwest, LLC
Compressor Station 7

APPENDIX E AIR DISPERSION MODELING

Air Dispersion Modeling Report

Compressor Station 7; Starbuck, WA

PREPARED FOR

TC Energy

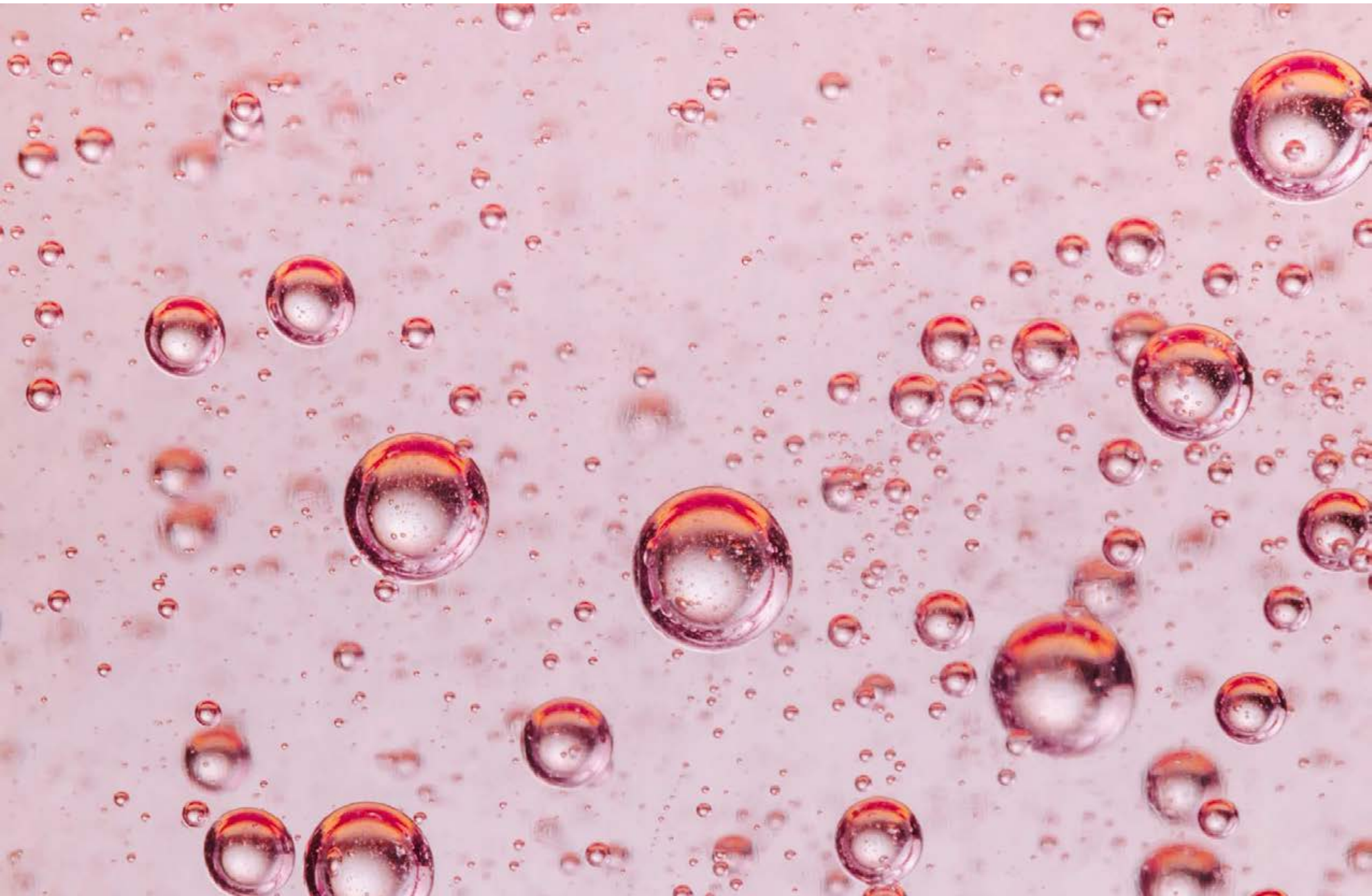
TC Energy; Gas Transmission Northwest, LLC

DATE

06 June 2025

REFERENCE

0774376



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ACRONYMS AND ABBREVIATIONS

Acronym	Description
ADAQM	Air Data Air Quality Monitors
AERMOD	American Meteorological Society/Environmental Protection Agency Regulatory Model
ARM2	Ambient Ratio Method
ASIL	Acceptable Source Impact Levels
ASOS	Automated Surface Observing System
AWL	Call sign for Walla Walla Regional Airport
BPIPPRM	Building Profile Input Program with PRIME algorithms
ERM	Environmental Resources Management
GEP	Good Engineering Practice
GTN	Gas Transmission Northwest, LLC
hr	Hour(s)
ISR	In-stack Ratio
K	Kelvin
lb	Pound(s)
m	meters
m/s	Meters per second
NAAQS	National Ambient Air Quality Standard
NED	National Elevation Database
NOC	Notice of Construction
NWS	National Weather Service
SIL	Significant Impact Level
SQER	Small Quantity Emission Rate
TAP	Toxic air pollutant
USEPA	United States Environmental Protection Agency
USGS	US Geological Survey
WDOE	Washington Department of Ecology
$\mu g/m^3$	Microgram per meter cubed

1. INTRODUCTION

This memorandum summarizes the air dispersion modeling analysis completed for Gas Transmissions Northwest LLC's (GTN) – Compressor Station 7 located in Starbuck, WA. As part of the Notice of Construction Application (NOC), the Washington State Department of Ecology (WDOE) requires a modeling analysis of the applicable criteria pollutants to demonstrate compliance with the National Ambient Air Quality Standard (NAAQS) and Washington's Ambient Air Quality Standards (WAAQS). The NAAQS analysis is to evaluate carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM_{10} and $PM_{2.5}$), and nitrogen oxides (NO_X) from the facility.

In addition, Washington State also maintains Acceptable Source Impact Levels (ASIL) for 395 Toxic Air Pollutants, as listed in WAC 173-460-150. An evaluation to determine if additional modeling is required for any toxic air pollutant (TAP) emitted as part of the project was completed in the enclosed permit application. The potential air toxic emissions from the project are above Small Quantity Emission Rate (SQER) for six TAPs: acetaldehyde, acrolein, benzene, ethylbenzene, formaldehyde and propylene. Therefore, additional modeling was required for these six TAPs. All other toxic air pollutants are below the respective SQERs as defined in WAC 173-460-150.

The following document outlines the proposed conventions and assumptions that were used to complete the required modeling analysis. This modeling report includes a summary of the project (Section 2); source emission rates and stack parameters (Section 3); an overview of the modeling methodology, meteorology and ambient background concentrations used in this analysis (Section 4); and presentation of the predicted both the criteria pollutant and TAP concentrations that demonstrate compliance with the respective WDOE standards (Section 5).

2. PROJECT DESCRIPTION

TC Energy owns and operates the GTN – Compressor Station 7 located in Starbuck, WA. The coordinates of the station are approximately Latitude: 46.535 N, and Longitude: 118.294 W. The station is in Walla Walla County at Barstow Road, 10 miles south of Ayer Junction, near Starbuck, Washington.

Compressor Station 7 currently operates three (3) natural gas turbines (Units 7C/7D/7E) under the Notice of Construction - Approval Order No. 21AQ-E009, issued on January 27, 2021. This application proposes to allow for low temperature operating hours for the two (2) 22,605 hp Solar Titan 130 turbines (Units 7D/7E). Historical data for this area has shown that hours of low-temperature operation are needed, during the winter months, to be able to provide gas to the end-users. GTN is proposing to modify the operating modes for Units 7D/7E to allow for 200 hours of subzero temperature operating hours, in order to be able to provide gas to end-users during critical times of need.

3. EMISSION SOURCES DESCRIPTION

Well-defined exhaust stacks are represented as “point” sources in the AERMOD model. Point sources are defined in the model by the emission rate and discharge parameters for stack height, stack temperature, exhaust flow rate, exit velocity, and stack diameter. Units 7D and 7E were explicitly modeled. Modeled emission rates were based on the calculated potential emissions for each unit modeled.

The fuel gas heater and eight space heaters are considered insignificant activities under WAC 173-401-503 and emit well below all thresholds listed in the previously mentioned rule. Additionally, the emergency generator AUX-GEN2 does not operate for more than 500 hours per year and is considered an intermittent source. Therefore, GTN is proposing to exclude these emission units from the modeling demonstration. The Unit 7D and 7E emission rates for short- and long-term criteria pollutants are shown in Tables 1. Table 2 shows a comparison of the TAP emission rates against their respective SQER. Table 3 outlines the stack parameters for the two modeled units.

TABLE 1 CRITERIA POLLUTANT SOURCE EMISSION RATES

Emission Source	Model ID	CO	NO_x		PM_{10} & $PM_{2.5}$		SO_2
		lb/hr	lb/hr	tpy	lb/hr	tpy	lb/hr
Turbine 7D	7D	41.8	28.9	46.4	1.3	5.5	10.9
Turbine 7E	7E	41.8	28.9	46.4	1.3	5.5	10.9

TABLE 2 TAP EMISSION RATE COMPARED AGAINST RESPECTIVE SQER

Pollutant	Proposed Turbine (7D)		Proposed Turbine (7E)		Total		Averaging period	SQER (lb/ave period)	Above SQER? *Modeling Required*
	lb/hr	lb/year	lb/hr	lb/year	lb/hr	lb/year			
Acetaldehyde	7.63E-03	66.85	7.63E-03	66.85	1.53E-02	133.70	Year	60.0	yes
Acrolein	1.22E-03	10.70	1.22E-03	10.70	2.44E-03	21.39	24-hour	0.03	yes
Benzene	2.29E-03	20.06	2.29E-03	20.06	4.58E-03	40.11	Year	21.0	yes
Ethylbenzene	6.11E-03	53.48	6.11E-03	53.48	1.22E-02	106.96	Year	65.0	yes
Formaldehyde	1.35E-01	1186.62	1.35E-01	1186.62	2.71E-01	2373.24	Year	27.0	yes
Propylene Oxide	5.53E-03	48.47	5.53E-03	48.47	1.11E-02	96.93	Year	44.0	yes

TABLE 3 EMISSION SOURCE PARAMETERS

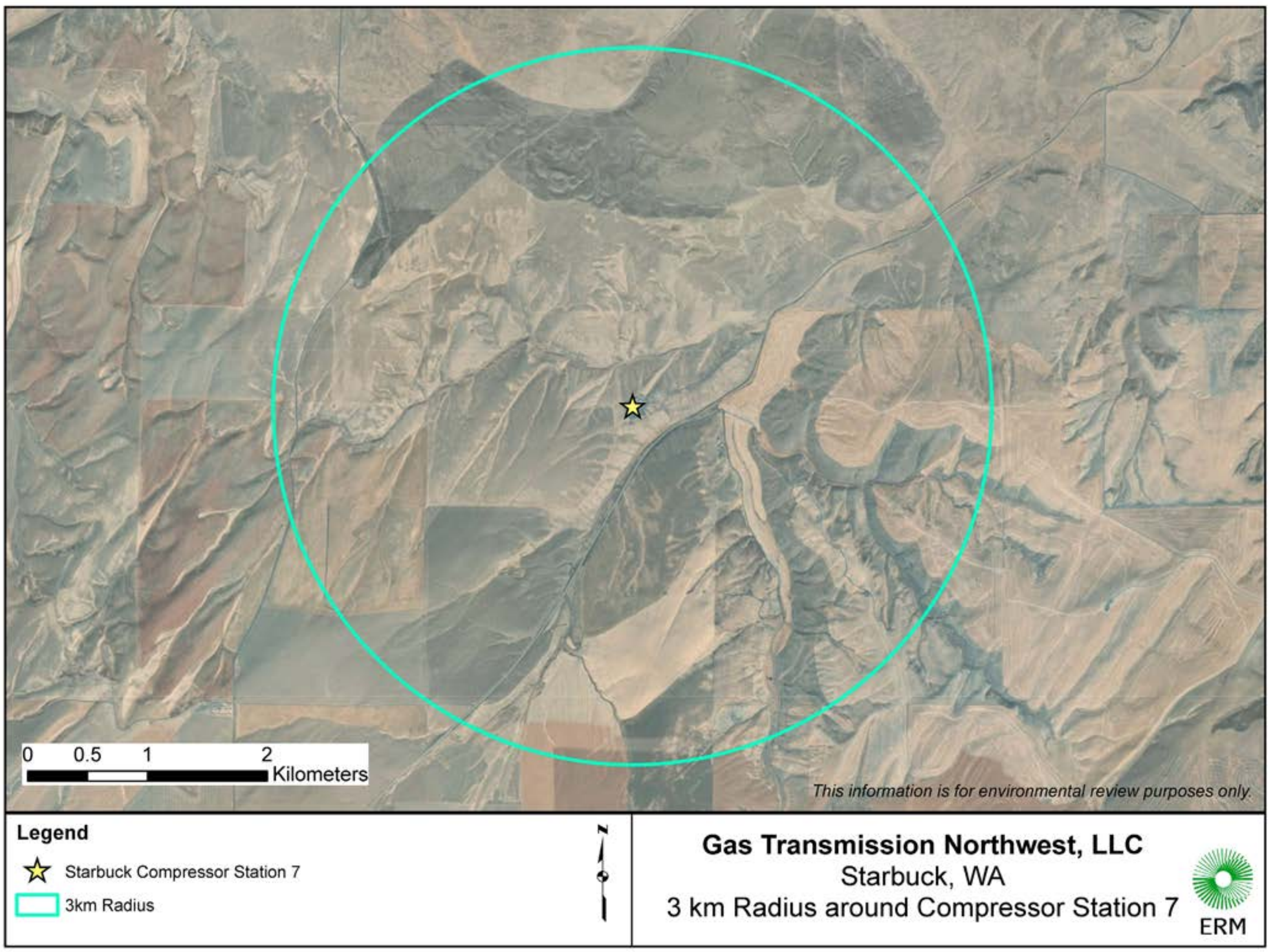
Emission Source	Model Source ID	Location and Elevation			Release Height (m)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)	Vertical or Capped?
		East (m)	North (m)	Base Elev. (m)					
Turbine 7D	7D	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Turbine 7E	7E	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

4. MODELING METHODOLOGY

4.1 DISPERSION MODEL OPTIONS

For this modeling analysis, the latest version (24142) of the Environmental Protection Agency (USEPA) regulatory air dispersion model[1] AERMOD was run with regulatory default options. Based on visual inspection of a 3 km radius around the GTN Compressor Station (Figure 1) the Starbuck facility was modeled using the rural dispersion option. Appendix B is the zoning map for Walla Walla County.

FIGURE 1 3 KM RADIUS AERIAL AROUND STARBUCK COMPRESSOR STATION 7



AERMOD's Ambient Ratio Method, version 2 (ARM2) was used to model NO_X emissions. ARM2 provides estimates of representative equilibrium ratios of NO_2 to NO_X concentrations based on measured ambient levels of NO_2 and NO_X derived from national data from the EPA's Air Quality System. Source-specific NO_2/NO_X in stack ratios (ISR) are unknown; therefore, ARM2 is an

[1] *Guideline on Air Quality Models,* 40 CFR 51, Appendix W (2024)

acceptable approach as opposed to the Tier III options. The ARM2 default maximum ISR value of 0.9 and the default minimum value of 0.5 were used.

4.2 GOOD ENGINEERING PRACTICE: BUILDING DOWNWASH

Section 123 of the Clean Air Act, as amended, required the US EPA to promulgate regulations to assure that the degree of emission limitation required for the control of any air pollutant is not affected by that portion of any stack height which exceeds Good Engineering Practice (GEP) or by any other dispersion technique.

The formula for GEP stack height is given as:

$$H_{GEP} = HB + 1.5LB$$

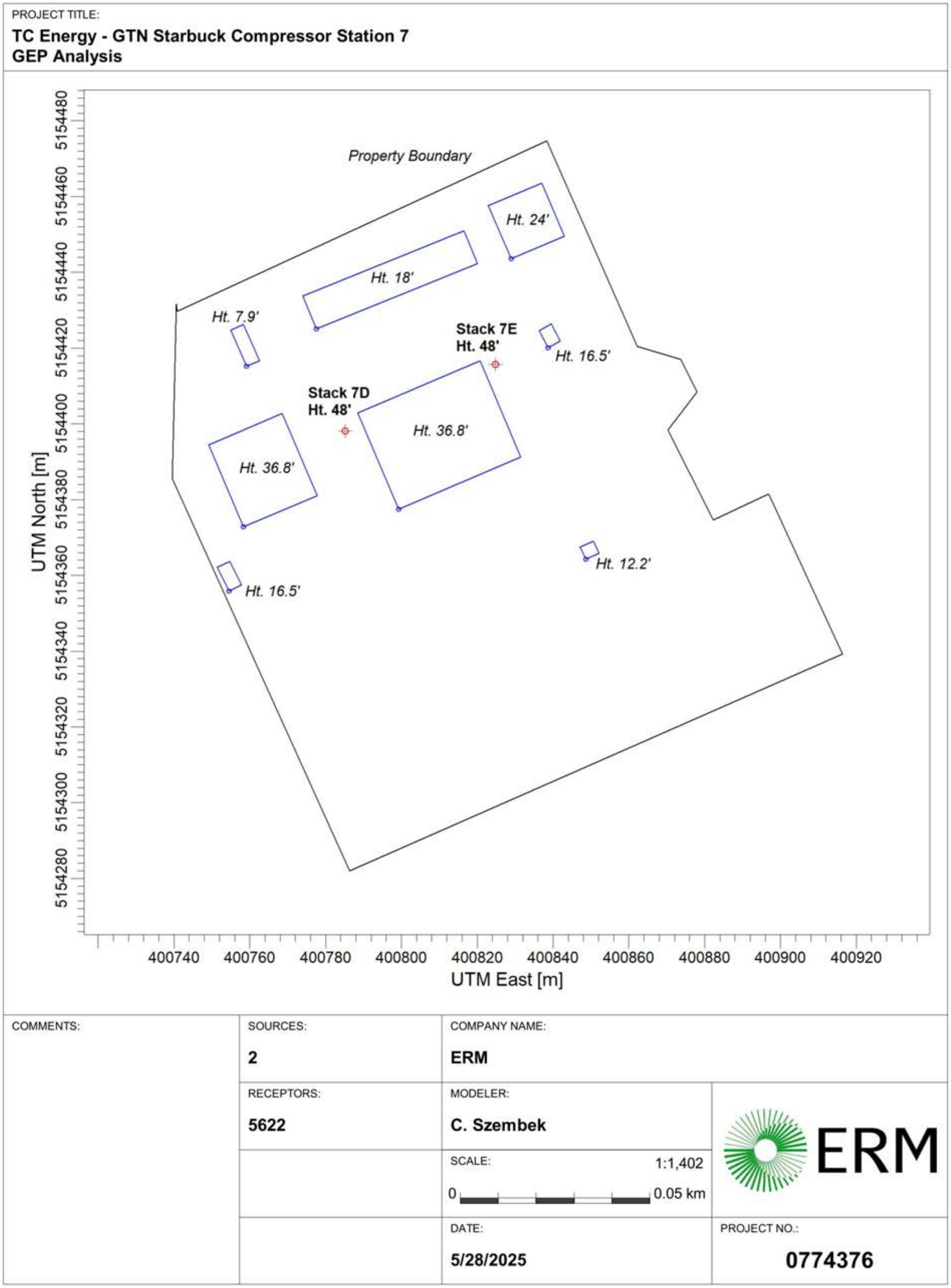
where:

- H_{GEP} = formula GEP stack height;
- H_B = the building's height above stack base; and
- L_B = the lesser of the building's height or maximum projected width.

If a stack height is greater than 65 meters, the modeled height of the stack cannot exceed the GEP formula height. None of the existing or proposed stack heights exceed the minimum GEP height of 65 meters, so the actual height was used in the modeling. However, the potential for downwash must be assessed since the stacks are also less than 2.5 times the height of the proposed surrounding structures.

To include the potential influence that buildings may have on the dispersion of pollutants from the stack, the US EPA Building Profile Input Program "PRIME" version (BPIPPRM) was used. BPIPPRM requires a geo-referenced depiction of the facility's buildings and stacks, storage tanks, and other nearby structures which may influence dispersion. The position and height of buildings relative to the stack positions must be evaluated to determine how it will influence dispersion for each wind direction. The BPIPPRM utility produces the necessary direction-specific dimensions that are subsequently used by AERMOD to account for building wake effects. UTM coordinates for the buildings and proposed stacks at the Starbuck Compressor Station 7 were identified using a geo-referenced mapping utility and incorporated into BPIPPRM. Figures 2 shows the location and heights of the modeled sources and buildings.

FIGURE 2 BUILDINGS AND SOURCES USED IN GEP ANALYSIS



4.3 MODEL RECEPTORS AND TERRAIN ELEVATIONS

A nested Cartesian grid of receptors was set with:

- 10-meter spacing along the fence line;
- 50-meter spacing out to 1 kilometer (km)
- 100-meter spacing out to 2 km;
- 250-meter spacing out to 5 km;
- 500-meter spacing out to 10 km

The nested grid was centered on the centroid of proposed emission sources. All receptor coordinates were referenced using the NAD83 datum (zone 11). Elevations were assigned to each receptor using the US EPA's AERMAP utility (version 24142), which extracts elevations from the United States Geological Survey (USGS) National Elevation Dataset (NED) data available for the area. In this evaluation, the 1/3-degree (approximately 10 m) resolution data in GeoTIFF format was used. Figures 3 and 4 show the far- and near-field receptors, respectively.

FIGURE 3 FAR-FIELD MODELING RECEPTORS

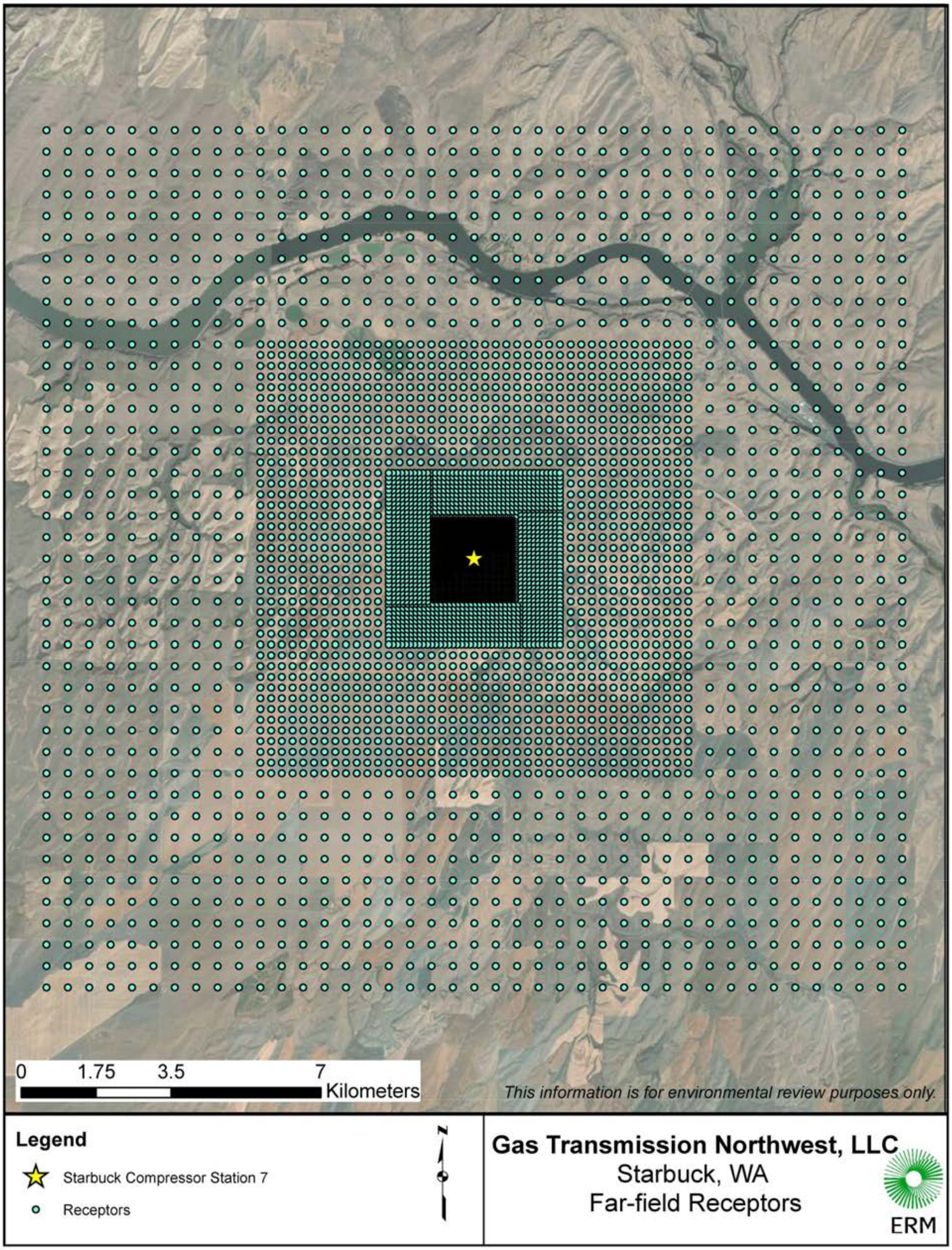
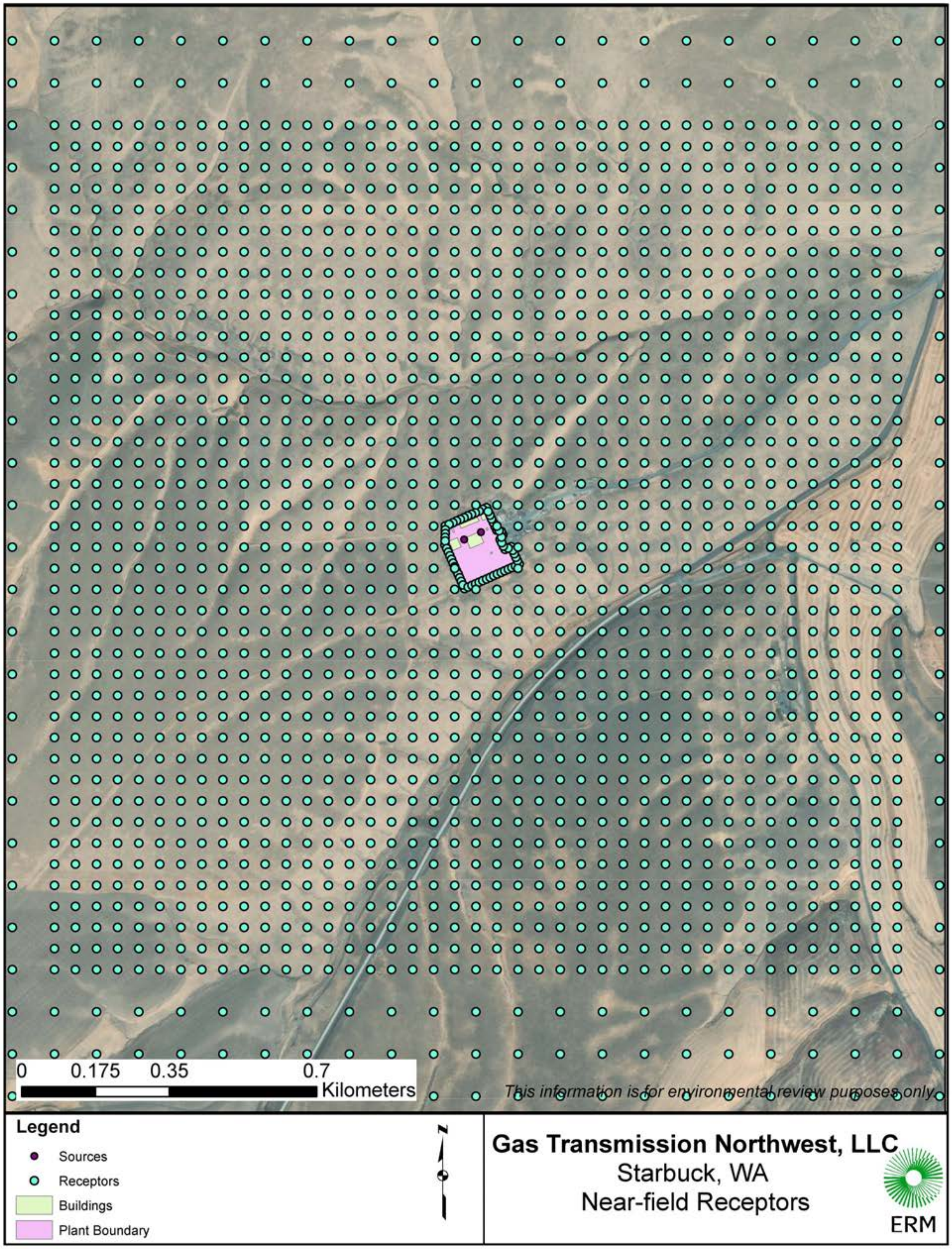


FIGURE 4 NEAR-FIELD RECEPTORS

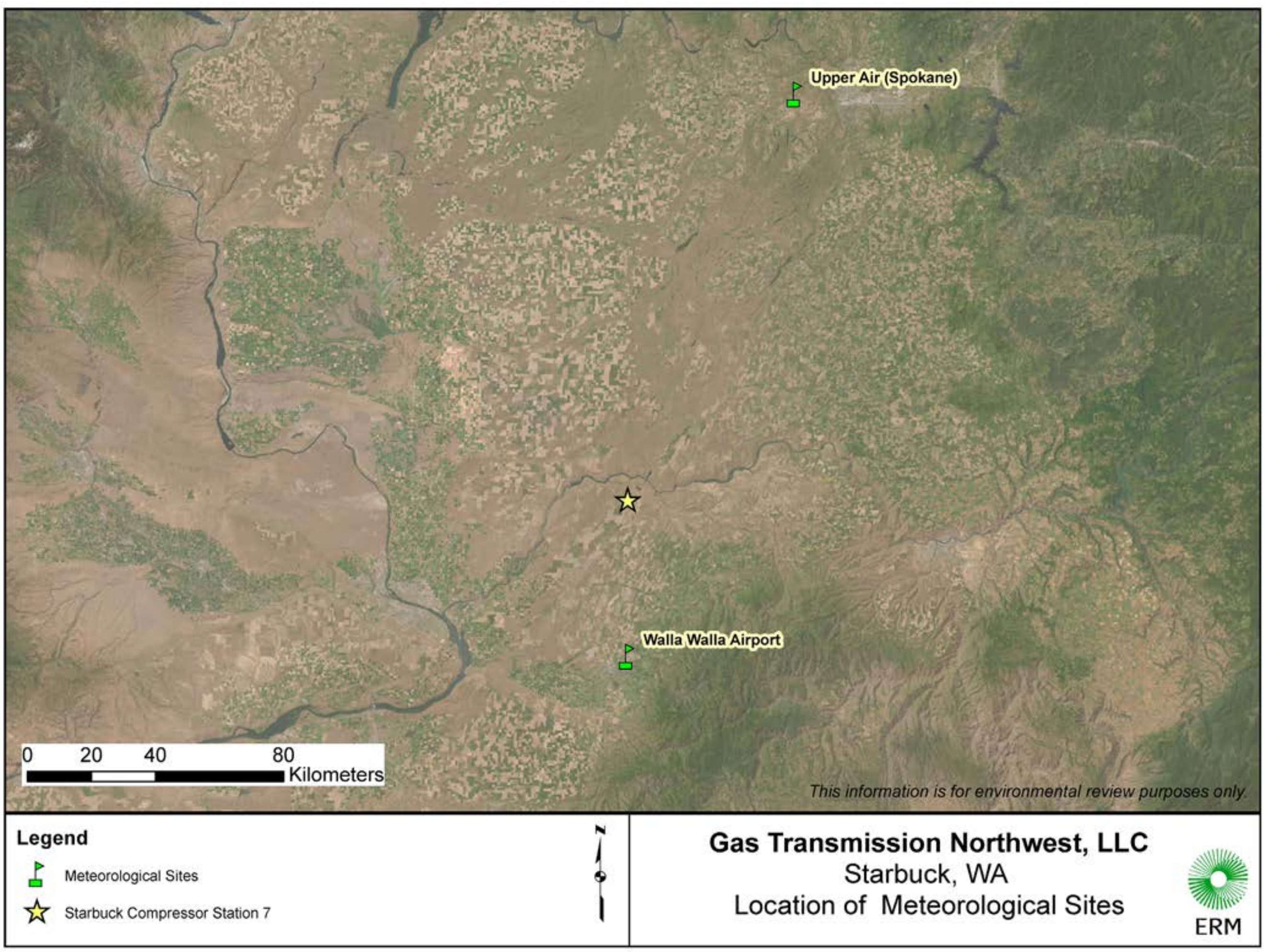


4.4 METEOROLOGY

For refined modeling analyses, USEPA guidelines specify the use of either one (1) year of on-site meteorological data, or five (5) years of representative, hourly National Weather Service (NWS) observations. Because no on-site data existed, NWS data was relied upon in this analysis for the most recent available calendar years of 2020 through 2024.

The meteorological data necessary for the AERMOD meteorological preprocessor AERMET (version 24142) was based on hourly surface observation data from the Walla Walla County Regional Airport (call sign ALW) and upper air sounding data from Spokane, WA (Figure 5). Meteorological sites were chosen based on the available data, the distance to the station, topography, and land use classification. Compressor Station 7 is primarily located in an area of flat terrain with some rolling hills. The station also has an elevation of approximately 1,085 feet. The Walla Walla County Regional Airport is approximately 50 km from Compressor Station 7 and has an elevation of 1,194 feet. It is also located in a rural area with relatively flat terrain. The Spokane station is located in a rural area, 132 km from Compressor Station 7 at approximately 2,385 feet. Based on the availability of data, surrounding topography, distance to the station, and land use classification, the Walla Walla Airport station and Spokane are most representative of Compressor Station 7.

FIGURE 5 LOCATION OF METEOROLOGICAL SITES

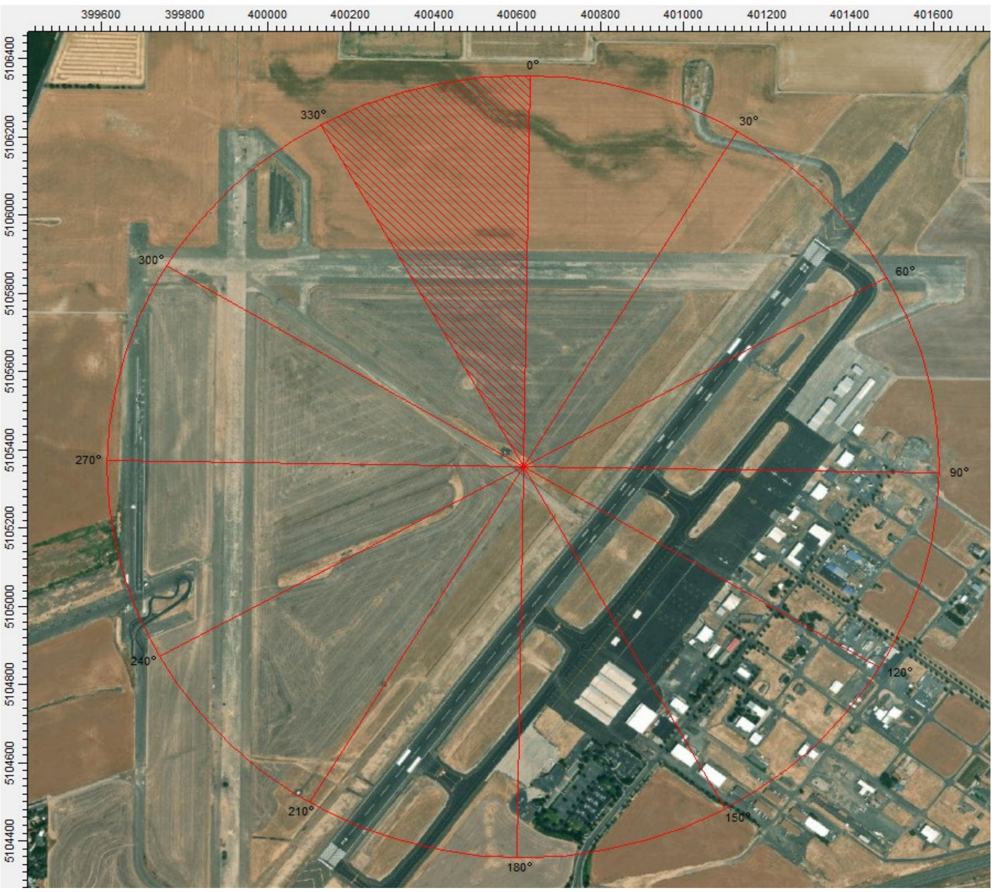


The surface parameters (surface roughness, Bowen Ratio, and albedo) for the Walla Walla County Regional Airport station were determined using AERSURFACE version 24142, which was run for dry, average, or wet conditions on a monthly basis for 12 evenly spaced sectors (Figure 6). The input land use, canopy, and impervious files were obtained from the 2021 National Land Use Cover Database[2]. As the project site is defined as an arid site, winter with snow is by default not considered. Monthly seasonal assignments and characterization were based on the following assumptions:

- Late Autumn/Winter without snow: December – February
- Winter with continuous snow: (not applicable for an arid site)
- Transitional spring: March – May
- Midsummer: June – August
- Autumn: September – November

The monthly surface moisture classifications for the meteorological period are shown in Table 4.

FIGURE 6 SECTOR DESIGNATION 1 KM AROUND WALLA WALLA AIRPORT ANEMOMETER



[2] 2021 National Land Use Cover Database. Files available for download at https://www.mrlc.gov/. Accessed February 2025.

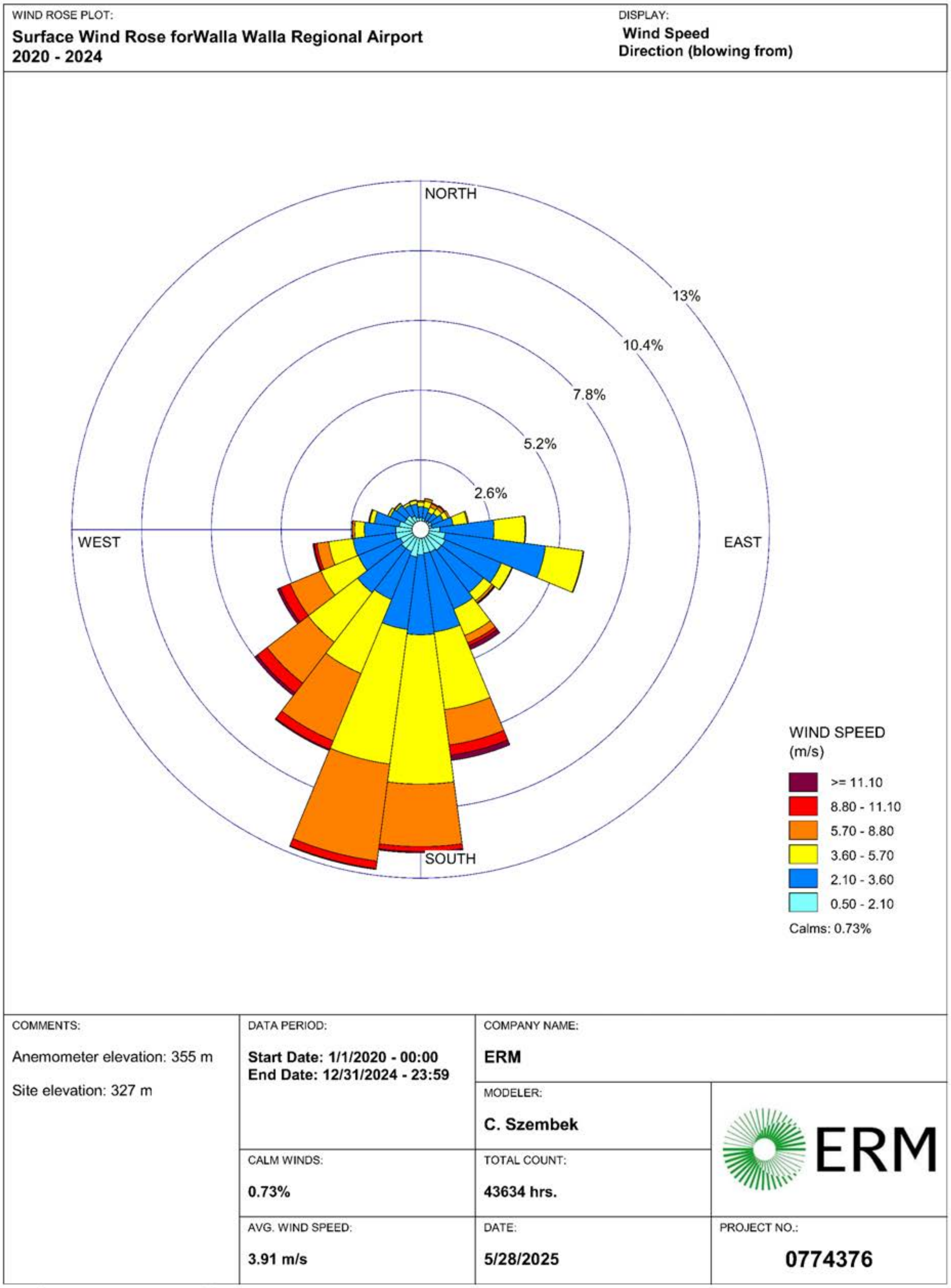
TABLE 4 2020 - 2024 SURFACE MOISTURE CLASSIFICATIONS

Month	Year				
	2020	**2021**	**2022**	**2023**	**2024**
Jan	Avg	Dry	Avg	Dry	Avg
Feb	Wet	Avg	Dry	Dry	Avg
Mar	Dry	Dry	Avg	Dry	Dry
Apr	Dry	Dry	Wet	Avg	Dry
May	Wet	Dry	Wet	Dry	Wet
Jun	Avg	Dry	Wet	Dry	Avg
Jul	Avg	Dry	Wet	Avg	Dry
Aug	Dry	Avg	Wet	Wet	Avg
Sep	Avg	Wet	Dry	Avg	Avg
Oct	Avg	Wet	Wet	Avg	Dry
Nov	Wet	Avg	Wet	Avg	Wet
Dec	Avg	Avg	Avg	Avg	Avg

Based on precipitation climatology from AWL for 1995 – 2025.

AREMINUTE (version 15272) was used to process 1-minute Automated Surface Observing System (ASOS) wind data to generate hourly average winds for input into AERMET. A wind rose of the surface winds at Walla Walla Airport is shown in Figure 7. A predominant flow from the south is shown. With no significant terrain between Walla Walla Regional Airport and Starbuck, WA, this pattern should also persist at the GTN Compressor Station 7.

FIGURE 7 SURFACE WIND ROSE FOR WALLA WALLA REGIONAL AIRPORT (2020 – 2024)



4.5 BACKGROUND CONCENTRATIONS FOR CRITERIA POLLUTANTS

For the purposes of demonstrating modeled compliance with ambient standards, "background" values are required to estimate the total impact of sources under review. The background value represents the emission concentration resulting from distance sources and smaller regional sources. The total ambient impact is estimated as the sum of the maximum modeled impact and the background value.

Background values were obtained via USEPA's Air Data Air Quality Monitors (ADAQM) website. Monitoring sites were chosen based on the available data, the distance to the project and topography (Figure 8). Table 5 displays the monitor (with ADAQM ID) and background design value for the latest three-year period (2022 – 2024) for each criteria pollutant.

FIGURE 8 LOCATION OF AMBIENT AIR MONITORS

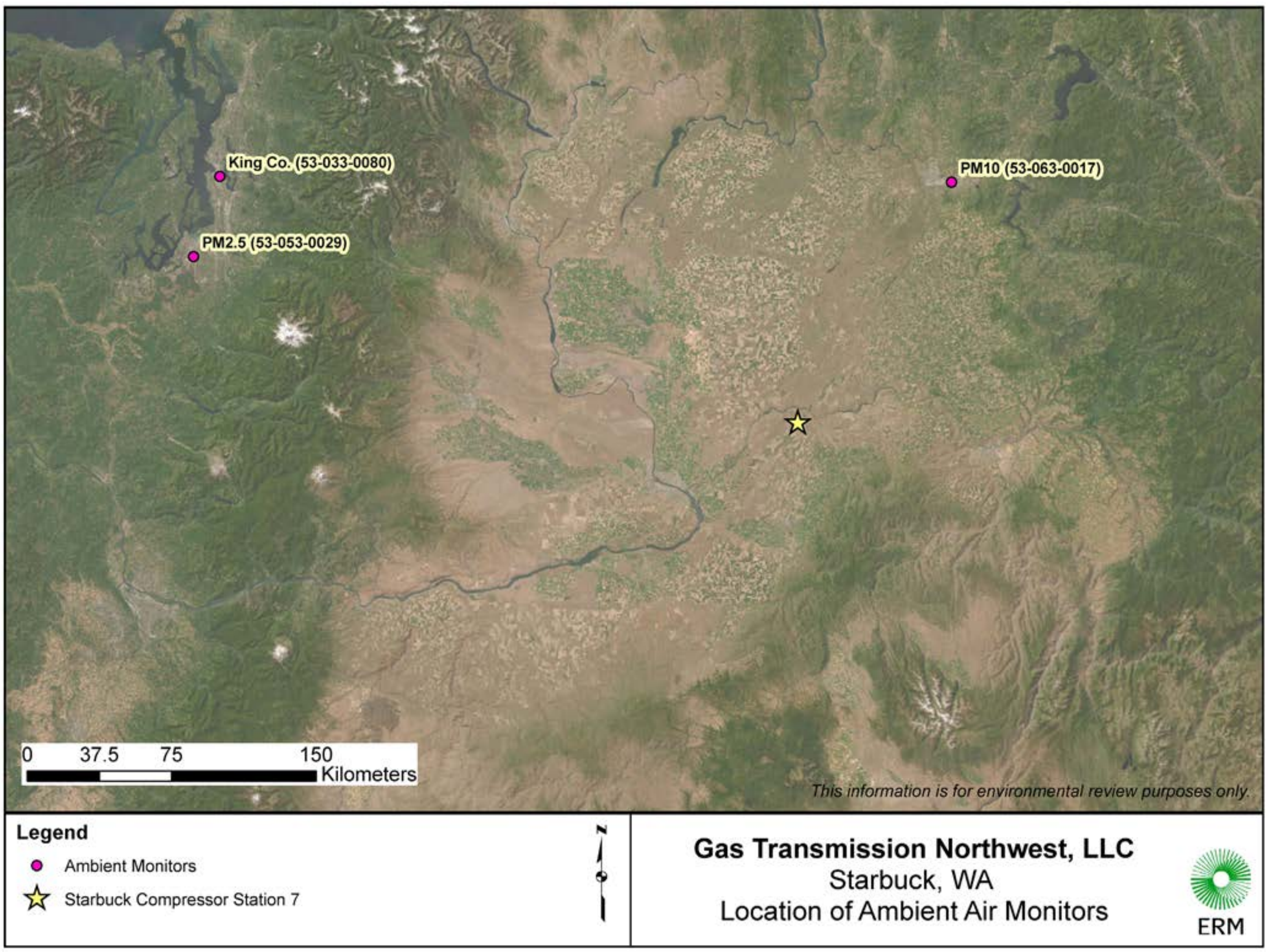


TABLE 5 AMBIENT BACKGROUND MONITORS AND 2020-2024 DESIGN VALUES

Pollutant	Monitor (AIRS ID)	Location from site		Avg. Period	Background Concentration (µg/m³)			Design Value (µg/m³)
		(km)	Direction		2022	2023	2024	
CO	King (53-033-0080)	325	WNW	1-hour	1773.9	1078.4	1013.7	1288.7
				8-hour	1704.6	909.1	795.5	1136.4
NO_2	King (53-033-0080)	325	WNW	1-hour	80.8	79.0	75.8	78.5
				Annual	19.2	17.6	16.5	17.7
PM10	Spokane (53-063-0017)	145	NE	24-hour	99.0	71.0	188.0	119.3
PM2.5	Tacoma (53-053-0029)	322	WNW	24-hour	38.1	28.5	19.0	28.5
				Annual	8.7	7.3	5.1	7.0
SO2	King (53-033-0080)	325	WNW	1-hour	8.9	6.8	5.2	7.0

5. MODELING RESULTS

AERMOD modeling of GTN's potential emissions from the proposed turbines at Starbuck Compressor Station 7 demonstrates compliance with the NAAQS for all pollutants and averaging periods. The predicted impacts for the criteria pollutants including background concentrations were compared to the NAAQS and are presented in Table 6. Table 7 presents the predicted impacts for the six TAPs modeled which are in compliance with their respective ASIL.

A modeling archive with all the files used in this modeling analysis is provided separately as an electronic archive.

TABLE 6 NAAQS ASSESSMENT OF MODELED PREDICTED IMPACTS OF CRITERIA POLLUTANTS

Pollutant	Averaging Time	Maximum AERMOD Predicted Concentrations (µg/m³)					Maximum Predicted Concentrations (µg/m3)	Background (µg/m³)	TOTAL (µg/m³)	NAAQS (µg/m³)	NAAQS Exceeded?	Percent of NAAQS
		2020	2021	2022	2023	2024						
CO	1 Hour[(a)]	199.5					199.46	1288.7	1488.1	40000	No	4%
	8 Hour[(a)]	95.9					95.94	1136.4	1232.3	10000	No	12%
NO_2	1 Hour[(b)]	39.8					39.77	78.5	118.3	188	No	63%
	Annual[(c)]	0.3	0.3	0.2	0.2	0.2	0.30	17.7	18.0	100	No	18%
$PM_{2.5}$	24 Hour[(d)]	0.2					0.23	28.5	28.8	35	No	82%
	Annual[(e)]	0.03					0.03	7.0	7.0	9	No	78%
PM_{10}	24 Hour[(f)]	0.8					0.80	119.3	120.1	150	No	80%
SO_2	1 Hour[(g)]	21.7					21.69	7.0	28.7	196	No	15%

[a] *Maximum high-2nd-high.*
[b] *5-year average of the 98th percentile of daily maxima.*
[c] *Maximum of yearly peak concentrations*
[d] *5-year average of 98th percentile*
[e] *Maximum 1st high*
[f] *5-year average of the 99th percentile of daily maxim*

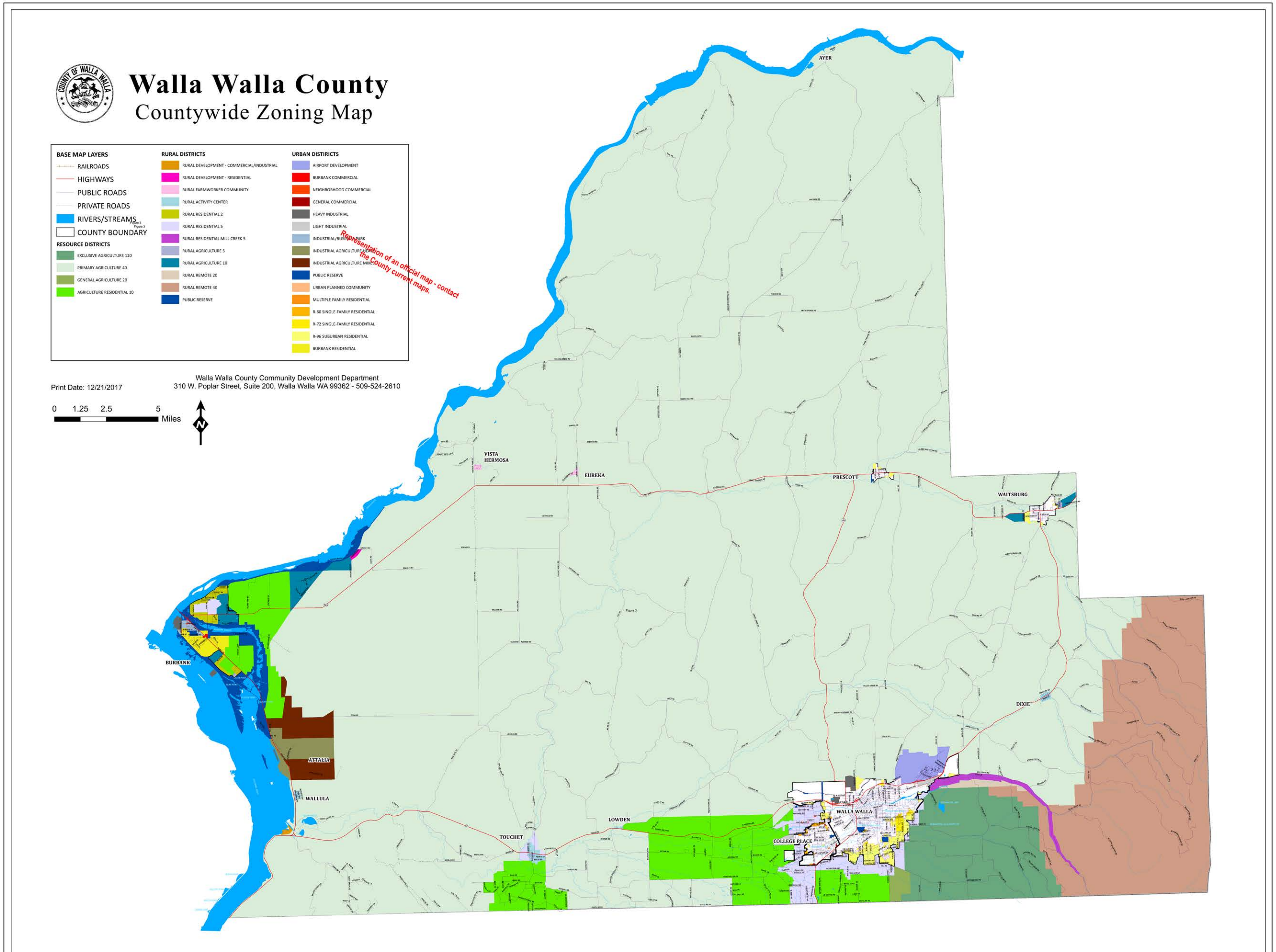
TABLE 7 TOXIC AIR POLLUTANTS PREDICTED IMPACTS

TAP	AERMOD µg/m³					MAX (µg/m³)	ASIL	
	2020	2021	2022	2023	2024		Avg. Period	µg/m3
Acetaldehyde	2.40E-04	2.00E-04	1.80E-04	1.80E-04	2.00E-04	2.40E-04	Annual	3.70E-01
Acrolein	1.59E-03					1.59E-03	24 hour	3.50E-01
Benzene	7.00E-05	6.00E-05	6.00E-05	5.00E-05	6.00E-05	7.00E-05	Annual	1.30E-01
Ethylbenzene	1.90E-04	1.60E-04	1.50E-04	1.50E-04	1.60E-04	1.90E-04	Annual	4.00E-01
Formaldehyde	4.25E-03	3.64E-03	3.27E-03	3.25E-03	3.52E-03	4.25E-03	Annual	1.70E-01
Propylene Oxide	1.70E-04	1.50E-04	1.30E-04	1.30E-04	1.40E-04	1.70E-04	Annual	2.70E-01

APPENDIX A MODELING ARCHIVE

SUBMITTED SEPARATELY AS AN ELECTRONIC ARCHIVE

APPENDIX B WALLA WALLA COUNTY ZONING MAP



APPENDIX F BACT CALCULATIONS

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf)		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_5_06_a	Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	Hourly mean wage $40.65/hr pipeline transport natural gas plant operator. May 2023 Hourly mean wage $45.32/hr for Washington State Gas Plant Operators NAICS 486200 - Pipeline Transportation of Natural Gas:	Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate	https://www.federalreserve.gov/releases/h15/ Bank prime loan rate - Feb 2025	Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	191	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 x 8760)/HHV =	1,638,549,412	scf/Year	
Actual Annual fuel consumption (Mactual) =		1,638,520,000	scf/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	0.82		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tscr/tplant) =	1.000	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	8760	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	90.0	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	9.17	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	40.16	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.13		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	3,370	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	3.37	/hour	
Residence Time	$1/V_{space}$	0.30	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.04		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.1	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3095	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	999.83	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	4	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	96	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	4	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	2.0	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	421	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	4	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	12	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	600	gallons (storage needed to store a 14 day reagent supply rounded to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0897

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = (0.1 x QB) for industrial boilers.	98.10	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$6,538,076	in 2024 dollars

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$0	in 2024 dollars
Reagent Preparation Cost (RPC) =	$0	in 2024 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2024 dollars
Balance of Plant Costs (BPC) =	$0	in 2024 dollars
Total Capital Investment (TCI) =	$0	in 2024 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$0 in 2024 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$0 in 2024 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2024 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$0 in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$118,755	in 2024 dollars
Indirect Annual Costs (IDAC) =	$588,638	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$707,393	in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$32,690	in 2024 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op}$ =	$4,213	in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$58,437	in 2024 dollars
Annual Catalyst Replacement Cost =	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	$23,415	in 2024 dollars
Direct Annual Cost =		$118,755	in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$2,173	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$586,465	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$588,638	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =		$707,393	per year in 2024 dollars
NOx Removed =		40.161	tons/year
Cost Effectiveness =	CE = TAC / Nox removed	$17,614	per ton of NOx removed in 2024 dollars

Parameter	Formula	Reference	Cost
Direct Capital Cost	DC		
Equipment Cost	EC	Vendor estimate	$ 1,000,000
Instrumentation	10% of EC	EPA Cost Manual	$ 100,000
Sales Tax	5% of EC	Estimated	$ 50,000
Freight	5% of EC	EPA Cost Manual	$ 50,000
Total Equipment Cost	TEC		**$ 1,200,000**
Direct Installation Cost	DI		
Foundation & Supports	8% of TEC	EPA Cost Manual	$ 96,000
Handling & Erection	14% of TEC	EPA Cost Manual	$ 168,000
Electrical	4% of TEC	EPA Cost Manual	$ 48,000
Piping	2% of TEC	EPA Cost Manual	$ 24,000
Insulation	1% of TEC	EPA Cost Manual	$ 12,000
Painting	1% of TEC	EPA Cost Manual	$ 12,000
Total Direct Installation	DI		**$ 360,000**
Site Preparation	as req.	assumed none required	$ -
Building	as req.	assumed none required	$ -
Total Direct Cost	DC = TEC + DI + SP + bldg	EPA Cost Manual	**$ 1,560,000**
Indirect Installation Cost	IC		
Engineering	10% of TEC	EPA Cost Manual	$ 120,000
Construction & field expenses	5% of TEC	EPA Cost Manual	$ 60,000
Start-up	2% of TEC	EPA Cost Manual	$ 24,000
Performance test	1% of TEC	EPA Cost Manual	$ 12,000
Total Installation Cost	IC		**$ 216,000**
Contractor fees	10%*(DC+IC)	EPA Cost Manual	$ 177,600
Contingencies	C = CF*(DC+IC)	CF = 10% factor used	$ 177,600
Total Capital Investment (TCI)	TCI = DC + IC + C + fees	EPA Cost Manual	**$ 2,131,200**
Direct Annual Cost	DAC		
Labor			
Operator	0.5hr/shift, 3 shifts/day, $30/hr, 365	EPA Cost Manual	$ 16,425
Supervisor	15% of Oper costs	EPA Cost Manual	$ 2,464
Maintenance			
Labor & Materials	1.5% of TCI	EPA Cost Manual	$ 31,968
Catalyst replacement cost	6 yr catalyst life	Vendor estimate	$ 116,667
Total Direct Annual Cost	DAC = Labor costs		**$ 50,857**
Indirect Annual Cost	IAC		
Capital Recovery Factor (CFR)	15yr equip life, 7% interest	EPA Cost Manual	0.1098
Capital Recovery	CR = CRF * TCI	EPA Cost Manual	$ 233,994
Property Tax	1% of TCI	EPA Cost Manual	$ 21,312
Insurance	1% of TCI	EPA Cost Manual	$ 21,312
General & Administrative	2% of TCI	EPA Cost Manual	$ 42,624
Overhead	80% of Labor costs	EPA Cost Manual	$ 40,685
Total Indirect Annual Cost	IAC		**$ 359,928**
Total Annualized Cost ($/yr)	TAC = DAC + IAC		**$ 410,784**
Cost Effectiveness			
Annual CO emissions (tons/yr)		facility estimate	51.41
CO Control efficiency		EPA Cost Manual	60%
Annual CO removed (tons/yr)			30.84
Cost Effectiveness ($/ton)			**$ 13,318**
Cost Effectiveness			
Annual VOC emissions (tons/yr)		facility estimate	6.03
VOC Control efficiency		EPA Cost Manual	60%
Annual VOC removed (tons/yr)			3.62
Cost Effectiveness ($/ton)			**$ 113,595**

APPENDIX G SITE-SPECIFIC MONITORING PLAN

ORIGIN ID:EIXA (832) 444-0051
NATHAN CHENAUX
TRANSCANADA PIPELINES LIMITED
700 LOUISIANA ST

HOUSTON, TX 77002
UNITED STATES US

SHIP DATE: 20MAR25
ACTWGT: 0.10 LB
CAD: 254528072/INET4535

BILL SENDER

TO DEPARTMENT OF ECOLOGY
AIR QUALITY PROGRAM
4601 N MONROE
STARBUCK MONITORING PLAN
SPOKANE WA 99205

(832) 444-0051 REF:
INV:
PO: DEPT:

58CJ3/5027/C6C4

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Gas Transmission Northwest, LLC
700 Louisiana Street, Suite 700, Houston, Texas, USA 77002
Tel: 832.444.0051
nathan_chenaux@tcenergy.com

TC Energy

March 20, 2025

Department of Ecology

Air Quality Program
4601 N Monroe
Spokane, WA 99205-1295

Re: Gas Transmission Northwest, LLC (GTN)
Compressor Station 7
Turbine Site Specific Monitoring Plan
Approval Order No. 21AQ-E009

GTN submits this natural gas-fired turbine site specific monitoring plan to the Department of Ecology's Air Quality Program (Ecology) for Gas Transmission Northwest's Starbuck, Washington facility (Compressor Station 7).

The site-specific monitoring plan was prepared for the Solar Titan 130's (Units 7D and E) to sufficiently provide reasonable assurance with applicable NOx emission limitations. The units are controlled via SoLoNOx. The monitoring plan specifies the monitoring approach, parameters to be monitored and associated indicators, data acquisition method and system, fuel flow monitoring, quality assurance and quality control procedures, instrument calibration, preventative maintenance, review, reporting and recordkeeping.

Should you have any questions or require additional information, please contact me at (832) 444-0051 or nathan_chenaux@tcenergy.com.

Sincerely,

Nathan Chenaux
Air Permitting, TC Energy

1. MONITORING PLAN

1.1 MONITORING APPROACH:

The rationale of this Monitoring Plan is to sufficiently provide a reasonable assurance of compliance with the applicable NOx emissions limit. The approach of this alternative monitoring plan is the following:

- Select representative turbine operational parameters.
- Establish indicator ranges for reasonable assurance of compliance based on manufacturer guarantee.
- Establish data collection method and averaging time.
- Establish QA/QC procedures.

1.2 PARAMETERS TO BE MONITORED:

- Inlet T1 Temperature (as measured at the inlet to the gas turbine)
- Fuel Rate
- Turbine Speed
- SoLoNOx Mode

1.3 PARAMETER MONITORING

Parameters are monitored per the operating indicators as specified in Tables 1 and 2 whenever the turbine is operating.

TABLE 1. PARAMETER INDICATOR SUMMARY

	Indicator No. 1	**Indicator No. 2**
Indicator	Turbine inlet combustion temperatures (T1).	Turbine SoLoNOx Mode status
Measurement Approach	Temperatures are measured using a thermocouple.	Programmable controller
Indicator Range	Turbine temperature shall range within manufacturer specifications.	SoLoNOx Mode status shows "run"
Data Representativeness	The measuring thermocouple are installed at the inlet of the turbine with a minimum accuracy of each temperature thermocouple of ±2.2°C (±4°F).	Alarm sound if the controller trips into standby
QA/QC Practices and Criteria	The accuracy of each thermocouple is checked as needed by calibration using a signal transmitter. The thermocouples are checked annually.	Controller and alarm sensor checked and calibrated when needed
Monitoring Frequency	Measured continuously using a DAS, where one-minute averages are recorded.	Monitored continuously using a DAS
Recordkeeping	Continuous data is recorded on and archived.	Paper records archived for at least 5 years
Averaging Period	Hourly block average	N/A

TABLE 2. PARAMATER INDICATOR SUMMARY

	Indicator No. 3	Indicator No. 4
Indicator	Turbine speed.	Turbine fuel rate.
Measurement Approach	Turbine speeds are measured in the unit control system.	Turbine fuel rates are measured using a flow meter.
Indicator Range	Turbine speeds shall range within manufacturer specifications.	Turbine fuel rates shall range within manufacturer specifications.
Data Representativeness	The speed sensor is checked at three points and calibrated per manufacturer specs if needed.	The measuring flow meter is installed with a minimum accuracy of 0.2%.
QA/QC Practices and Criteria	The accuracy of the speed monitor is checked annually using a frequency generator.	The accuracy of the flow meter is checked annually (or as needed) by calibration using a signal transmitter.
Monitoring Frequency	Measured continuously using a DAS, where one-minute averages are recorded.	Measured continuously using a DAS, where one-minute averages are recorded.
Recordkeeping	Continuous data is recorded on and archived.	Continuous data is recorded on and archived.
Averaging Period	Hourly block average.	Hourly block average.

1.4 DATA ACQUISITION METHOD

Turbine operating ranges are monitored on a continuous basis by the unit programmable logic controller (PLC), the control system for the gas turbine compressor package.

1.4.1 SOLONOX MODE MONITORING

The SoLoNOx Mode is monitored in two dedicated registers depending on the ambient temperature: SoLoNOx mode, and non-SoLoNOx mode.

1.4.2 FUEL FLOW MONITORING

The fuel monitoring system consists of three measured inputs:

- Actual fuel flow using the turbine flow meter, FF_{Actual}.
- Fuel temperature using a resistance temperature device, T_{Actual}.
- Fuel pressure using a fuel pressure transmitter, P_{Actual}

The turbine PLC uses the above values to calculate unit fuel flow at standard conditions using the below Equation:

$$Fuel\ Flow\ (STD) = \frac{P_{\mathrm{Actual}} * FF_{\mathrm{Actual}} * T_{\mathrm{STD}}}{T_{\mathrm{Actual}} * P_{\mathrm{STD}}}$$

where: T_{STD} = 528 R and P_{STD} = 14.7 psi

Only fired hours are calculated.

1.4.3 DATA ACQUISITION SYSTEM (DAS)

Collected data points are passed to the turbine PLC. The GTN Supervisory Control and Data Acquisition System (SCADA) and Plant Information System (PI) scans the turbine PLC on a periodic basis and collects the data points. SCADA and PI then store data, along with date and compressor unit identification.

1.5 QA/QC PROCEDURES

Quality assurance is a planned set of external activities to evaluate data quality. Examples of these QA activities, as delineated in this section are:

- Auditing quality control procedures.
- Developing procedures to ensure data quality.

Quality control is a planned set of internal activities that are conducted to ensure data accuracy and completeness. Activities include the use of:

- Automated data checking procedures.
- Technical reviews.
- Accuracy checks.
- Standardized procedures for emissions calculations.

Examples of these QC activities, as included in this section:

- Examination of data to identify errors or outliers.
- Comparing emissions results to previously developed or similar inventories to assess reasonableness.

1.6 QA/QC OBJECTIVES

The objective of the procedures listed below is to provide a consistent, orderly sequence of actions that will ensure all data collected and reported is meaningful, precise and accurate.

The use of these procedures will:

- Reduce errors in the collection of turbine parameters and emission calculations
- Improve overall data quality and completeness.

1.6.1 INSTRUMENT CALIBRATION AND ACCURACY VERIFICATION

This Monitoring Plan utilizes the turbine fuel meter, unit speed meter, inlet thermocouples, and the unit PLC to record fired hours including those in SoLoNOx Mode. The turbine monitoring system is calibrated in accordance with manufacturer's specification, sound engineering judgment, or when readings indicate a potential problem. Thermocouples, for both ambient air and fuel, are routinely checked for accuracy. All instrument calibration and accuracy verifications are performed to an approved set of procedures.

Record all calibrations, deficiencies/anomalies, and repairs in Computerized Maintenance Management System (CMMS) and schedule any additional maintenance in a timely manner.

1.6.2 PREVENTIVE MAINTENANCE ACTIVITIES

GTN performs preventative maintenance for thermocouples as necessary to ensure proper operation. When a calibration is not possible, the device is replaced. Proper operation is checked during calibration and whenever a malfunction is suspected.

1.7 PARAMETER REVIEW

Turbine operating parameters are reviewed on a regular basis. A review of the Monitoring Plan parameters is conducted monthly. The monthly data reports will be reviewed for "reasonableness." Any data unavailability, abnormalities, or adverse trends will be identified, and corrective actions initiated.

Other non-Monitoring Plan parameters are regularly reviewed by facility staff. Anomalous readings could indicate reduced unit performance. In some cases, anomalous readings could indicate the potential for an excess NOx emission event.

Where monitoring indicates the possibility of an excess of NOx emissions or of monitored parameters outside expected ranges, investigation, required corrections, and reporting will occur.

1.8 REPORTING

Reporting will be done as specified by Title V permit.

1.9 RECORD KEEPING

Records of data will be maintained per Title V permit.

APPENDIX H SOLAR TITAN 130 EMISSIONS TEST DATA

Solar Titan 130 Testing at GTN's Starbuck Facility

Unit 7D

Test Date	Parameter	Run 1	Run 2	Run 3	Average	Limit	[1]Manufacturer Guarantee
January 2022	NOx ppmvd @ 15% O2	8.2	8.3	12.1	**9.6**	15	**15**
	CO ppmvd @ 15% O2	3.1	0.0001	0.0001	**1.0**	25	**25**
March 2023	NOx ppmvd @ 15% O2	14.8	12.1	12.8	**13.2**	15	**15**
	CO ppmvd @ 15% O2	20.7	16.5	17.1	**18.1**	25	**25**
February 2024	NOx ppmvd @ 15% O2	9.4	5.5	4.7	**6.5**	15	**15**
	CO ppmvd @ 15% O2	9.5	6.9	6.8	**7.7**	25	**25**

Unit 7E

Test Date	Parameter	Run 1	Run 2	Run 3	Average	Limit	[1]Manufacturer Guarantee
January 2025	NOx ppmvd @ 15% O2	7.6	7.8	8.1	**7.8**	15	**15**
	CO ppmvd @ 15% O2	17.0	17.1	15.5	**16.5**	25	**25**

[1]Based on data from Solar Titan 130 Compressor Set Predicted Emission Performance data sheet at normal load

Solar Titan 130 Cold Weather Test Data at GTN's Athol Facility in Idaho

Date / time	sec Runtime	% O2	ppm CO	ppm NOx	ppm NO	ppm NO2	% CO2	ppm cCO	[1]PACO CO ppm Guarantee	ppm cNOx	[1]PACO NOx ppm Guarantee	% O2ref.	l/min Pump	°F Tamb	f^3/m Flow	Dilution factor	Fuel
1/12/2024 11:40:06 AM	0	15.88	3.0	4.9	4.5	0.4	2.81	3.5	100.0	5.8	42.0	15.0	0.00	11.5	6157.4	x1	Natural Gas
1/12/2024 11:40:07 AM	1	15.89	3.0	4.9	4.5	0.4	2.80	3.5	100.0	5.8	42.0	15.0	0.00	11.5	6157.4	x1	Natural Gas
1/12/2024 11:40:08 AM	2	15.94	3.0	6.1	5.7	0.4	2.78	3.6	100.0	7.3	42.0	15.0	1.10	10.8	2829.1	x1	Natural Gas
1/12/2024 11:40:09 AM	3	15.95	3.0	8.4	8.0	0.4	2.77	3.6	100.0	10.0	42.0	15.0	1.00	10.8	1997.0	x1	Natural Gas
1/12/2024 11:40:10 AM	4	15.91	3.0	18.5	18.1	0.4	2.79	3.5	100.0	21.9	42.0	15.0	1.00	10.8	1997.0	x1	Natural Gas
1/12/2024 11:40:11 AM	5	15.91	3.1	29.1	28.7	0.4	2.79	3.7	100.0	34.4	42.0	15.0	0.98	12.0	1997.0	x1	Natural Gas
1/12/2024 11:40:12 AM	6	15.93	3.2	29.1	28.7	0.4	2.78	3.8	100.0	34.5	42.0	15.0	0.98	12.0	1997.0	x1	Natural Gas
1/12/2024 11:40:13 AM	7	15.93	3.0	23.4	23.0	0.4	2.78	3.6	100.0	27.8	42.0	15.0	0.98	12.4	1997.0	x1	Natural Gas
1/12/2024 11:40:14 AM	8	15.93	3.0	13.6	13.3	0.3	2.78	3.6	100.0	16.2	42.0	15.0	0.99	11.5	3994.0	x1	Natural Gas
1/12/2024 11:40:15 AM	9	15.93	3.1	11.2	10.9	0.3	2.78	3.7	100.0	13.3	42.0	15.0	0.99	11.5	3994.0	x1	Natural Gas
1/12/2024 11:40:16 AM	10	15.92	3.3	10.0	9.7	0.3	2.79	3.9	100.0	11.8	42.0	15.0	0.98	11.3	3494.7	x1	Natural Gas
1/12/2024 11:40:17 AM	11	15.91	3.5	9.3	9.0	0.3	2.79	4.1	100.0	11.0	42.0	15.0	0.98	11.3	3494.7	x1	Natural Gas
1/12/2024 11:40:18 AM	12	15.91	3.7	9.0	8.7	0.3	2.79	4.4	100.0	10.6	42.0	15.0	0.99	10.9	3494.7	x1	Natural Gas
1/12/2024 11:40:19 AM	13	15.91	3.9	8.8	8.5	0.3	2.79	4.6	100.0	10.4	42.0	15.0	0.99	10.9	3494.7	x1	Natural Gas
1/12/2024 11:40:20 AM	14	15.91	4.1	8.8	8.5	0.3	2.79	4.8	100.0	10.4	42.0	15.0	0.99	10.4	3494.7	x1	Natural Gas
1/12/2024 11:40:21 AM	15	15.91	4.3	8.8	8.5	0.3	2.79	5.1	100.0	10.4	42.0	15.0	0.99	10.4	3494.7	x1	Natural Gas
1/12/2024 11:40:22 AM	16	15.90	4.4	8.7	8.4	0.3	2.80	5.2	100.0	10.3	42.0	15.0	0.99	10.4	3994.0	x1	Natural Gas
1/12/2024 11:40:23 AM	17	15.90	4.5	8.6	8.3	0.3	2.80	5.3	100.0	10.2	42.0	15.0	0.99	10.0	5658.2	x1	Natural Gas
1/12/2024 11:40:24 AM	18	15.90	4.6	8.5	8.2	0.3	2.80	5.4	100.0	10.0	42.0	15.0	0.99	10.0	5658.2	x1	Natural Gas
1/12/2024 11:40:25 AM	19	15.90	4.3	8.5	8.2	0.3	2.80	5.1	100.0	10.0	42.0	15.0	0.98	10.2	6323.8	x1	Natural Gas
1/12/2024 11:40:26 AM	20	15.90	4.0	8.5	8.2	0.3	2.80	4.7	100.0	10.0	42.0	15.0	0.98	10.0	5991.0	x1	Natural Gas
1/12/2024 11:40:27 AM	21	15.90	4.0	8.4	8.1	0.3	2.80	4.7	100.0	9.9	42.0	15.0	0.98	10.0	5991.0	x1	Natural Gas
1/12/2024 11:40:28 AM	22	15.90	4.1	8.4	8.1	0.3	2.80	4.8	100.0	9.9	42.0	15.0	0.98	10.0	5991.0	x1	Natural Gas
1/12/2024 11:40:29 AM	23	15.89	4.0	8.4	8.1	0.3	2.80	4.7	100.0	9.9	42.0	15.0	0.99	9.7	4992.5	x1	Natural Gas
1/12/2024 11:40:30 AM	24	15.89	4.1	8.4	8.1	0.3	2.80	4.8	100.0	9.9	42.0	15.0	0.99	9.5	4992.5	x1	Natural Gas
1/12/2024 11:40:31 AM	25	15.90	4.2	8.4	8.1	0.3	2.80	5.0	100.0	9.9	42.0	15.0	0.99	9.5	4992.5	x1	Natural Gas
1/12/2024 11:40:32 AM	26	15.90	4.2	8.4	8.1	0.3	2.80	5.0	100.0	9.9	42.0	15.0	0.98	9.1	5325.3	x1	Natural Gas
1/12/2024 11:40:33 AM	27	15.90	4.3	8.3	8.0	0.3	2.80	5.1	100.0	9.8	42.0	15.0	0.98	9.1	5325.3	x1	Natural Gas
1/12/2024 11:40:34 AM	28	15.90	4.3	8.3	8.0	0.3	2.80	5.1	100.0	9.8	42.0	15.0	0.98	9.0	4493.2	x1	Natural Gas
1/12/2024 11:40:35 AM	29	15.90	4.4	8.2	7.9	0.3	2.80	5.2	100.0	9.7	42.0	15.0	0.98	9.0	4493.2	x1	Natural Gas
1/12/2024 11:40:36 AM	30	15.90	4.5	8.2	7.9	0.3	2.80	5.3	100.0	9.7	42.0	15.0	0.99	9.1	5991.0	x1	Natural Gas
1/12/2024 11:40:37 AM	31	15.90	4.5	8.2	7.9	0.3	2.80	5.3	100.0	9.7	42.0	15.0	0.99	9.1	4992.5	x1	Natural Gas
1/12/2024 11:40:38 AM	32	15.90	4.6	8.2	7.9	0.3	2.80	5.4	100.0	9.7	42.0	15.0	0.99	9.1	4992.5	x1	Natural Gas
1/12/2024 11:40:39 AM	33	15.90	4.5	8.2	7.9	0.3	2.80	5.3	100.0	9.7	42.0	15.0	0.98	9.3	4992.5	x1	Natural Gas
1/12/2024 11:40:40 AM	34	15.90	4.7	8.2	7.9	0.3	2.80	5.5	100.0	9.7	42.0	15.0	0.98	9.3	4992.5	x1	Natural Gas
1/12/2024 11:40:41 AM	35	15.90	4.6	8.2	7.9	0.3	2.80	5.4	100.0	9.7	42.0	15.0	0.99	9.3	5325.3	x1	Natural Gas
1/12/2024 11:40:42 AM	36	15.90	4.7	8.1	7.8	0.3	2.80	5.5	100.0	9.6	42.0	15.0	0.99	9.3	4992.5	x1	Natural Gas
1/12/2024 11:40:43 AM	37	15.90	4.7	8.0	7.7	0.3	2.80	5.5	100.0	9.4	42.0	15.0	0.99	9.3	4992.5	x1	Natural Gas
1/12/2024 11:40:44 AM	38	15.90	4.5	8.0	7.7	0.3	2.80	5.3	100.0	9.4	42.0	15.0	0.98	9.0	5325.3	x1	Natural Gas
1/12/2024 11:40:45 AM	39	15.90	4.5	7.9	7.6	0.3	2.80	5.3	100.0	9.3	42.0	15.0	0.98	9.0	5325.3	x1	Natural Gas
1/12/2024 11:40:46 AM	40	15.90	4.5	7.9	7.6	0.3	2.80	5.3	100.0	9.3	42.0	15.0	0.99	8.8	5991.0	x1	Natural Gas
1/12/2024 11:40:47 AM	41	15.90	4.5	7.9	7.6	0.3	2.80	5.3	100.0	9.3	42.0	15.0	0.99	8.8	5991.0	x1	Natural Gas
1/12/2024 11:40:48 AM	42	15.90	4.4	7.9	7.6	0.3	2.80	5.2	100.0	9.3	42.0	15.0	0.99	8.8	4992.5	x1	Natural Gas
1/12/2024 11:40:49 AM	43	15.90	4.3	7.9	7.6	0.3	2.80	5.1	100.0	9.3	42.0	15.0	0.99	8.8	4992.5	x1	Natural Gas
1/12/2024 11:40:50 AM	44	15.90	4.3	8.0	7.6	0.4	2.80	5.1	100.0	9.4	42.0	15.0	0.98	9.1	3994.0	x1	Natural Gas
1/12/2024 11:40:51 AM	45	15.90	4.5	7.9	7.5	0.4	2.80	5.3	100.0	9.3	42.0	15.0	0.99	9.5	3494.7	x1	Natural Gas
1/12/2024 11:40:52 AM	46	15.91	4.5	8.0	7.6	0.4	2.79	5.3	100.0	9.5	42.0	15.0	0.99	9.5	3494.7	x1	Natural Gas
1/12/2024 11:40:53 AM	47	15.91	4.6	7.9	7.5	0.4	2.79	5.4	100.0	9.3	42.0	15.0	0.99	10.2	3994.0	x1	Natural Gas
1/12/2024 11:40:54 AM	48	15.90	4.3	7.9	7.5	0.4	2.80	5.1	100.0	9.3	42.0	15.0	0.99	10.2	3994.0	x1	Natural Gas
1/12/2024 11:40:55 AM	49	15.90	4.3	7.9	7.4	0.5	2.80	5.1	100.0	9.3	42.0	15.0	0.98	10.4	4992.5	x1	Natural Gas
1/12/2024 11:40:56 AM	50	15.90	4.2	7.9	7.4	0.5	2.80	5.0	100.0	9.3	42.0	15.0	0.99	10.4	4992.5	x1	Natural Gas
1/12/2024 11:40:57 AM	51	15.90	4.1	7.8	7.3	0.5	2.80	4.8	100.0	9.2	42.0	15.0	0.99	10.4	4992.5	x1	Natural Gas
1/12/2024 11:40:58 AM	52	15.89	4.0	7.8	7.3	0.5	2.80	4.7	100.0	9.2	42.0	15.0	0.98	9.9	5658.2	x1	Natural Gas
1/12/2024 11:40:59 AM	53	15.89	3.9	7.7	7.2	0.5	2.80	4.6	100.0	9.1	42.0	15.0	0.98	9.9	5658.2	x1	Natural Gas
1/12/2024 11:41:00 AM	54	15.90	4.0	7.7	7.2	0.5	2.80	4.7	100.0	9.1	42.0	15.0	0.99	9.9	4992.5	x1	Natural Gas
1/12/2024 11:41:01 AM	55	15.90	3.9	7.7	7.2	0.5	2.80	4.6	100.0	9.1	42.0	15.0	0.99	9.9	4992.5	x1	Natural Gas
1/12/2024 11:41:02 AM	56	15.90	4.0	7.7	7.2	0.5	2.80	4.7	100.0	9.1	42.0	15.0	0.98	9.7	5991.0	x1	Natural Gas

Solar Titan 130 Cold Weather Test Data at GTN's Athol Facility in Idaho

Date / time	sec Runtime	% O2	ppm CO	ppm NOx	ppm NO	ppm NO2	% CO2	ppm cCO	[1]PACO CO ppm Guarantee	ppm cNOx	[1]PACO NOx ppm Guarantee	% O2ref.	l/min Pump	°F Tamb	f^3/m Flow	Dilution factor	Fuel
1/12/2024 11:41:03 AM	57	15.90	3.8	7.5	7.0	0.5	2.80	4.5	100.0	8.9	42.0	15.0	0.98	9.5	5991.0	x1	Natural Gas
1/12/2024 11:41:04 AM	58	15.90	3.7	7.6	7.0	0.6	2.80	4.4	100.0	9.0	42.0	15.0	0.98	9.5	5991.0	x1	Natural Gas
1/12/2024 11:41:28 AM	0	15.90	3.1	4.8	4.1	0.7	2.80	3.7	100.0	5.7	42.0	15.0	1.15	9.0	5658.2	x1	Natural Gas
1/12/2024 11:41:29 AM	1	15.92	2.9	4.9	4.3	0.6	2.79	3.4	100.0	5.8	42.0	15.0	1.15	9.0	5658.2	x1	Natural Gas
1/12/2024 11:41:30 AM	2	15.99	2.9	5.6	5.0	0.6	2.75	3.5	100.0	6.7	42.0	15.0	1.05	9.9	5658.2	x1	Natural Gas
1/12/2024 11:41:31 AM	3	15.99	2.9	6.5	5.9	0.6	2.75	3.5	100.0	7.8	42.0	15.0	1.05	9.9	5658.2	x1	Natural Gas
1/12/2024 11:41:32 AM	4	15.94	3.0	7.3	6.6	0.7	2.77	3.6	100.0	8.7	42.0	15.0	0.99	9.3	5658.2	x1	Natural Gas
1/12/2024 11:41:33 AM	5	15.92	3.2	7.5	6.8	0.7	2.78	3.8	100.0	8.9	42.0	15.0	0.99	9.3	5658.2	x1	Natural Gas
1/12/2024 11:41:34 AM	6	15.92	3.3	7.5	6.7	0.8	2.79	3.9	100.0	8.9	42.0	15.0	0.99	9.5	5658.2	x1	Natural Gas
1/12/2024 11:41:35 AM	7	15.92	3.1	7.3	6.5	0.8	2.79	3.7	100.0	8.6	42.0	15.0	0.99	9.7	5658.2	x1	Natural Gas
1/12/2024 11:41:36 AM	8	15.91	3.2	7.3	6.4	0.9	2.79	3.8	100.0	8.6	42.0	15.0	0.99	9.7	5658.2	x1	Natural Gas
1/12/2024 11:41:37 AM	9	15.91	3.3	7.2	6.2	1.0	2.79	3.9	100.0	8.5	42.0	15.0	0.99	9.9	5991.0	x1	Natural Gas
1/12/2024 11:41:38 AM	10	15.91	3.3	7.1	6.1	1.0	2.79	3.9	100.0	8.4	42.0	15.0	0.99	9.9	5991.0	x1	Natural Gas
1/12/2024 11:41:39 AM	11	15.90	3.3	7.1	6.0	1.1	2.80	3.9	100.0	8.4	42.0	15.0	0.99	9.1	8154.4	x1	Natural Gas
1/12/2024 11:41:40 AM	12	15.90	3.1	7.2	6.0	1.2	2.80	3.7	100.0	8.5	42.0	15.0	0.99	9.1	8154.4	x1	Natural Gas
1/12/2024 11:41:41 AM	13	15.90	2.9	7.2	6.0	1.2	2.80	3.4	100.0	8.5	42.0	15.0	0.99	7.9	6989.5	x1	Natural Gas
1/12/2024 11:41:42 AM	14	15.91	3.0	7.2	5.9	1.3	2.79	3.5	100.0	8.5	42.0	15.0	0.98	7.9	6656.7	x1	Natural Gas
1/12/2024 11:41:43 AM	15	15.91	3.0	7.3	5.9	1.4	2.79	3.5	100.0	8.6	42.0	15.0	0.98	7.9	6656.7	x1	Natural Gas
1/12/2024 11:41:44 AM	16	15.91	3.3	7.2	5.8	1.4	2.79	3.9	100.0	8.5	42.0	15.0	0.99	8.2	6989.5	x1	Natural Gas
1/12/2024 11:41:45 AM	17	15.91	3.3	7.2	5.8	1.4	2.79	3.9	100.0	8.5	42.0	15.0	0.99	8.2	6989.5	x1	Natural Gas
1/12/2024 11:41:46 AM	18	15.91	3.3	7.2	5.8	1.4	2.79	3.9	100.0	8.5	42.0	15.0	0.98	8.4	5991.0	x1	Natural Gas
1/12/2024 11:41:47 AM	19	15.92	3.2	7.2	5.7	1.5	2.79	3.8	100.0	8.5	42.0	15.0	0.98	8.4	5991.0	x1	Natural Gas
1/12/2024 11:41:48 AM	20	15.92	3.2	7.2	5.7	1.5	2.79	3.8	100.0	8.5	42.0	15.0	0.99	8.8	6656.7	x1	Natural Gas
1/12/2024 11:41:49 AM	21	15.92	3.0	7.3	5.7	1.6	2.79	3.6	100.0	8.6	42.0	15.0	0.98	9.1	6656.7	x1	Natural Gas
1/12/2024 11:41:50 AM	22	15.92	3.1	7.3	5.7	1.6	2.79	3.7	100.0	8.6	42.0	15.0	0.98	9.1	6656.7	x1	Natural Gas
1/12/2024 11:41:51 AM	23	15.92	3.0	7.3	5.7	1.6	2.79	3.6	100.0	8.7	42.0	15.0	0.99	9.3	6323.8	x1	Natural Gas
1/12/2024 11:41:52 AM	24	15.92	3.0	7.3	5.7	1.6	2.79	3.6	100.0	8.6	42.0	15.0	0.98	9.7	6323.8	x1	Natural Gas
1/12/2024 11:41:53 AM	25	15.92	3.0	7.5	5.8	1.7	2.79	3.6	100.0	8.9	42.0	15.0	0.98	9.7	6323.8	x1	Natural Gas
1/12/2024 11:41:54 AM	26	15.92	2.8	7.5	5.8	1.7	2.79	3.3	100.0	8.9	42.0	15.0	0.98	9.7	6323.8	x1	Natural Gas
1/12/2024 11:41:55 AM	27	15.91	2.5	7.5	5.8	1.7	2.79	3.0	100.0	8.9	42.0	15.0	0.98	10.0	6323.8	x1	Natural Gas
1/12/2024 11:41:56 AM	28	15.91	2.4	7.5	5.8	1.7	2.80	2.8	100.0	8.9	42.0	15.0	0.99	10.0	6989.5	x1	Natural Gas
1/12/2024 11:41:57 AM	29	15.90	2.3	7.5	5.8	1.7	2.80	2.7	100.0	8.9	42.0	15.0	0.99	10.0	6989.5	x1	Natural Gas
1/12/2024 11:41:58 AM	30	15.90	2.5	7.5	5.8	1.7	2.80	3.0	100.0	8.9	42.0	15.0	0.98	10.0	6989.5	x1	Natural Gas
1/12/2024 11:41:59 AM	31	15.91	2.4	7.5	5.8	1.7	2.80	2.8	100.0	8.9	42.0	15.0	0.99	10.0	6656.7	x1	Natural Gas
1/12/2024 11:42:00 AM	32	15.91	2.6	7.6	5.8	1.8	2.80	3.1	100.0	9.0	42.0	15.0	0.99	10.0	6656.7	x1	Natural Gas
1/12/2024 11:42:01 AM	33	15.91	2.8	7.5	5.7	1.8	2.79	3.3	100.0	8.9	42.0	15.0	0.98	10.2	6656.7	x1	Natural Gas
1/12/2024 11:42:02 AM	34	15.91	2.6	7.5	5.7	1.8	2.79	3.1	100.0	8.9	42.0	15.0	0.98	10.2	6656.7	x1	Natural Gas
1/12/2024 11:42:03 AM	35	15.91	2.6	7.5	5.7	1.8	2.79	3.1	100.0	8.9	42.0	15.0	0.98	10.0	6989.5	x1	Natural Gas
1/12/2024 11:42:04 AM	36	15.91	2.6	7.4	5.6	1.8	2.79	3.1	100.0	8.7	42.0	15.0	0.98	10.0	6989.5	x1	Natural Gas
1/12/2024 11:42:05 AM	37	15.91	2.5	7.4	5.6	1.8	2.79	3.0	100.0	8.7	42.0	15.0	0.99	9.9	6989.5	x1	Natural Gas
1/12/2024 11:42:06 AM	38	15.91	2.7	7.5	5.7	1.8	2.79	3.2	100.0	8.9	42.0	15.0	0.99	9.9	6989.5	x1	Natural Gas
1/12/2024 11:42:07 AM	39	15.90	2.7	7.5	5.7	1.8	2.80	3.2	100.0	8.9	42.0	15.0	0.99	9.5	6656.7	x1	Natural Gas
1/12/2024 11:42:08 AM	40	15.90	2.7	7.5	5.7	1.8	2.80	3.2	100.0	8.8	42.0	15.0	0.98	9.3	6656.7	x1	Natural Gas
1/12/2024 11:42:09 AM	41	15.89	2.8	7.4	5.6	1.8	2.80	3.3	100.0	8.7	42.0	15.0	0.98	9.3	6656.7	x1	Natural Gas
1/12/2024 11:42:10 AM	42	15.89	2.9	7.5	5.6	1.9	2.80	3.4	100.0	8.8	42.0	15.0	0.98	9.5	6656.7	x1	Natural Gas
1/12/2024 11:42:11 AM	43	15.89	2.6	7.6	5.7	1.9	2.80	3.1	100.0	9.0	42.0	15.0	0.98	9.5	6656.7	x1	Natural Gas
1/12/2024 11:42:12 AM	44	15.89	2.6	7.6	5.7	1.9	2.80	3.1	100.0	9.0	42.0	15.0	0.98	9.0	6656.7	x1	Natural Gas
1/12/2024 11:42:13 AM	45	15.89	2.1	7.6	5.7	1.9	2.80	2.5	100.0	8.9	42.0	15.0	0.98	9.0	6656.7	x1	Natural Gas
1/12/2024 11:42:14 AM	46	15.89	2.3	7.4	5.5	1.9	2.81	2.7	100.0	8.7	42.0	15.0	0.99	9.0	6989.5	x1	Natural Gas
1/12/2024 11:42:15 AM	47	15.89	2.7	7.5	5.6	1.9	2.80	3.2	100.0	8.8	42.0	15.0	0.99	9.0	6989.5	x1	Natural Gas
1/12/2024 11:42:16 AM	48	15.90	2.4	7.5	5.6	1.9	2.80	2.8	100.0	8.8	42.0	15.0	0.99	9.0	6989.5	x1	Natural Gas
1/12/2024 11:42:17 AM	49	15.90	2.2	7.5	5.5	2.0	2.80	2.6	100.0	8.9	42.0	15.0	0.99	9.0	6989.5	x1	Natural Gas
1/12/2024 11:42:18 AM	50	15.90	2.3	7.4	5.5	1.9	2.80	2.7	100.0	8.7	42.0	15.0	0.99	9.0	6989.5	x1	Natural Gas
1/12/2024 11:42:19 AM	51	15.90	2.5	7.5	5.5	2.0	2.80	3.0	100.0	8.9	42.0	15.0	0.99	9.0	7488.7	x1	Natural Gas
1/12/2024 11:42:20 AM	52	15.90	2.6	7.5	5.5	2.0	2.80	3.1	100.0	8.9	42.0	15.0	0.99	9.0	7488.7	x1	Natural Gas
1/12/2024 11:42:21 AM	53	15.90	2.6	7.6	5.6	2.0	2.80	3.1	100.0	9.0	42.0	15.0	0.98	8.8	7322.3	x1	Natural Gas
1/12/2024 11:42:22 AM	54	15.90	2.6	7.6	5.6	2.0	2.80	3.1	100.0	9.0	42.0	15.0	0.98	8.8	7322.3	x1	Natural Gas

Solar Titan 130 Cold Weather Test Data at GTN's Athol Facility in Idaho

Date / time	sec Runtime	% O2	ppm CO	ppm NOx	ppm NO	ppm NO2	% CO2	ppm cCO	[1]PACO CO ppm Guarantee	ppm cNOx	[1]PACO NOx ppm Guarantee	% O2ref.	l/min Pump	°F Tamb	f³/m Flow	Dilution factor	Fuel
1/12/2024 11:42:23 AM	55	15.90	2.7	7.5	5.5	2.0	2.80	3.2	100.0	8.9	42.0	15.0	0.99	8.8	7322.3	x1	Natural Gas
1/12/2024 11:42:24 AM	56	15.90	2.5	7.5	5.5	2.0	2.80	3.0	100.0	8.9	42.0	15.0	0.99	8.8	6989.5	x1	Natural Gas
1/12/2024 11:42:25 AM	57	15.90	2.5	7.5	5.5	2.0	2.80	3.0	100.0	8.9	42.0	15.0	0.99	8.8	6989.5	x1	Natural Gas
1/12/2024 11:42:26 AM	58	15.90	2.6	7.6	5.6	2.0	2.80	3.1	100.0	9.0	42.0	15.0	0.99	9.0	7322.3	x1	Natural Gas
1/12/2024 11:42:27 AM	59	15.90	2.7	7.5	5.5	2.0	2.80	3.2	100.0	8.9	42.0	15.0	0.98	8.6	7322.3	x1	Natural Gas
1/12/2024 11:42:28 AM	60	15.90	2.7	7.5	5.5	2.0	2.80	3.2	100.0	8.9	42.0	15.0	0.98	8.6	7322.3	x1	Natural Gas
1/12/2024 11:42:29 AM	61	15.90	2.5	7.5	5.5	2.0	2.80	3.0	100.0	8.9	42.0	15.0	0.99	8.8	7488.7	x1	Natural Gas
1/12/2024 11:42:30 AM	62	15.90	2.4	7.5	5.5	2.0	2.80	2.8	100.0	8.9	42.0	15.0	0.99	8.8	7488.7	x1	Natural Gas
1/12/2024 11:42:31 AM	63	15.91	2.2	7.5	5.5	2.0	2.79	2.6	100.0	8.9	42.0	15.0	0.99	8.6	7488.7	x1	Natural Gas
1/12/2024 11:42:32 AM	64	15.91	2.3	7.5	5.5	2.0	2.79	2.7	100.0	8.9	42.0	15.0	0.99	8.6	7488.7	x1	Natural Gas
1/12/2024 11:42:33 AM	65	15.91	2.4	7.5	5.5	2.0	2.79	2.8	100.0	8.9	42.0	15.0	0.98	8.8	7821.6	x1	Natural Gas
1/12/2024 11:42:34 AM	66	15.91	2.4	7.5	5.5	2.0	2.79	2.8	100.0	8.9	42.0	15.0	0.98	8.8	7821.6	x1	Natural Gas
1/12/2024 11:42:35 AM	67	15.91	2.6	7.5	5.5	2.0	2.79	3.1	100.0	8.9	42.0	15.0	0.99	8.8	7488.7	x1	Natural Gas
1/12/2024 11:42:36 AM	68	15.91	2.5	7.6	5.6	2.0	2.79	3.0	100.0	9.0	42.0	15.0	0.98	9.1	7821.6	x1	Natural Gas
1/12/2024 11:42:37 AM	69	15.92	2.5	7.6	5.6	2.0	2.79	3.0	100.0	9.0	42.0	15.0	0.98	9.1	7821.6	x1	Natural Gas
1/12/2024 11:42:38 AM	70	16.16	2.4	7.7	5.7	2.0	2.65	3.0	100.0	9.6	42.0	15.0	0.98	9.1	7488.7	x1	Natural Gas
1/12/2024 11:42:39 AM	71	17.15	2.4	6.2	4.5	1.7	2.10	3.8	100.0	9.8	42.0	15.0	0.98	9.1	7488.7	x1	Natural Gas
1/12/2024 11:42:40 AM	72	17.15	2.3	5.9	4.5	1.4	2.10	3.6	100.0	9.3	42.0	15.0	0.98	9.5	8154.4	x1	Natural Gas
1/12/2024 11:42:41 AM	73	18.42	2.3	4.4	3.2	1.2	1.39	5.5	100.0	10.5	42.0	15.0	0.98	9.5	8154.4	x1	Natural Gas
1/12/2024 11:42:42 AM	74	19.40	2.2	3.0	2.0	1.0	0.84	8.7	100.0	11.8	42.0	15.0	0.99	10.0	7655.1	x1	Natural Gas

[1]Solar turbines emissions estimates for the T130 with PACO

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