CLASS I PERMIT RENEWAL APPLICATION
Arizona LNG

Needle Mountain Gas Plant
Topock, Arizona
ADEQ Class I Permit #66295

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1. EXECUTIVE SUMMARY

Arizona LNG provides natural gas transportation services for natural gas suppliers and end users throughout the Western United States. The Needle Mountain Gas Plant (NMGP), Standard Industrial Classification (SIC) code 1321, is an "end user" facility, owned by Arizona LNG and operated by Applied Natural Gas Fuels, Inc. (Applied) and its affiliate Arizona LNG (together, "Applied"). The NMGP is a Liquefied Natural Gas (LNG) processing facility in Topock, Mohave County, Arizona and currently operates under Arizona Department of Environmental Quality (ADEQ) Class I Air Quality Permit No. 66295.

ADEQ Class I Air Quality Permit No. 66295 was issued on October 18, 2017 and will expire in 5 years on October 17, 2022. Applied is submitting this permit renewal application to the ADEQ in order to maintain the authorization to operate the NMGP. Applied is proposing to maintain all elements and conditions of the current version of ADEQ Class I Permit No. 66295.

The NMGP currently operates two identical processing plants - First plant "Topock I" and second plant "Topock II" under the current permit no. 66295. The expansion of the NMGP with the second plant took place in 2014 which led to the requirement for a Class I permit. No new construction or modifications have been made to the facility since the original application was filed in was filed in August 2012. Therefore, the emissions considered in this application remain the same as in 2012. Table 1-1 contains the site-wide emissions from the NMGP.

Table 1-1. Summary of NMGP Site-Wide Emissions

Emission Unit	Site-Wide Annual Emissions (tpy)							
	PM10/ PM2.5	NOx	CO	VOC	SO2	H2S	Formaldehyde	CO2e
Solar Centaur Gas Turbine	7.88	202.44	41.08	4.73	22.51	-	1.08	44,039
Process Fugitives	-	-	-	34.59	-	-	-	436
Initial Start Up/Plant Purge	-	-	-	5.20	-	-	-	7,931
Engine Start-up Blowdown	-	-	-	0.56	-	-	-	857
Deriming	-	-	-	1.95	-	-	-	2,974
Amine Regenerator	-	-	-	-	-	0.99	-	6,336
Compressor Seal	-	-	-	113.88	-	-	-	356
Site-Wide Total Emissions	***7.88***	***202.44***	***41.08***	***160.91***	***22.51***	***0.99***	***1.08***	***62,929***
Non-Fugitive Total Emissions	***7.88***	***202.44***	***41.08***	***4.73***	***22.51***	***0.99***	***1.08***	***50,375***
Site-Wide Emissions Cap	***-***	***220.00***	***-***	***-***	***-***	***-***	***-***	***-***

The enclosed forms and documentation include all applicable ADEQ forms for the standard Class I Permit Application, supporting documentation for the information contained in the forms, and detailed emission calculation tables (Appendix A).

2. ADEQ STANDARD PERMIT APPLICATION FORM

SECTION 2.1

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

Air Quality Division

1110 West Washington • Phoenix, AZ 85007 • Phone: (602) 771-2338

STANDARD CLASS I PERMIT APPLICATION FORM

(As required by A.R.S. § 49-426, and Chapter 2, Article 3, Arizona Administrative Code)

1. Permit to be issued to (Business license name of organization that is to receive permit):

   Arizona LNG, L.L.C.

2. Mailing Address: 5499 West Needle Mountain Road

   City: Topock State: Arizona ZIP: 86436

3. Name (or names) of Owners/ Principals: Ed McKenna (President & CEO)

   Phone: (818)450-3652 Fax: _____ Email: EMcKenna@appliedlng.com

4. Name of Owner's Agent: _____

   Phone: _____ Fax: _____ Email: _____

5. Plant/Site Manager/ Contact Person and Title: _____

   Phone: (928)466-4449 Fax: _____ Email: JCovello@appliedlng.com

6. Plant Site Name: Needle Mountain LNG Plant

7. Plant Site Location Address: 5499 West Needle Mountain Road

   City: Topock County: Mohave County Zip Code: 86436

   Indian Reservation (if applicable, which one): N/A

   Latitude/ Longitude, Elevation: 34.726426, -114.463805 (elevation approx. 650 ft)

   Section/ Township/ Range: Section 36, NW 1/4, SW 1/4, Township 16 North, Range 21 West

8. General Nature of Business: Liquefied Natural Gas Services

9. Type of Organization:
   ☒ Corporation ☐ Individual Owner ☐ Partnership ☐ Government Entity (Government Facility Code----------)

   ☐ Other _____

8. Permit Application Basis: ☐ New Source ☐ Revision ☒ Renewal of Existing Permit
   (Check all that apply.)

   For renewal or modification, include existing permit number (and exp. date): 66295 (expires October 17, 2022)

   Date of Commencement of Construction or Modification: No new construction or modifications to the existing facility

   Primary Standard Industrial Classification Code: 1321

9. I certify that I have knowledge of the facts herein set forth, that the same are true, accurate and complete to the best of my knowledge and belief, and that all information not identified by me as confidential in nature shall be treated by ADEQ as public record. I also attest that I am in compliance with the applicable requirements of the Permit and will continue to comply with such requirements and any future requirements that become effective during the life of the Permit. I will present a certification of compliance to ADEQ no less than annually and more frequently if specified by ADEQ. I further state that I will assume responsibility for the construction, modification,

*Definitions for all terms that are **bolded and italicized** can be found starting on page 26*

or operation of the source in accordance with Arizona Administrative Code, Title 18, Chapter 2 and any permit issued thereof.

Signature of Responsible Official: _____

Official Title of Signer: Chief Executive Officer

Typed or Printed Name of Signer: Edward McKenna, Jr.

Date: April 14, 2022 Telephone Number: 818-450-3652

SECTION 2.2 - EMISSION SOURCES

PAGE_____OF _____
DATE _____

Estimated "Potential to Emit" per A.A.C. R18-2-101.
Review of applications and issuance of permits will be expedited by supplying all necessary information on this Table.

REGULATED AIR POLLUTANT DATA					EMISSION POINT DISCHARGE PARAMETERS									
EMISSION POINT [1]		CHEMICAL COMPOSITION OF TOTAL STREAM	AIR POLLUTANT EMISSION RATE		UTM COORDINATES OF EMISSION POINT [5]			STACK SOURCES [6]					NONPOINT	
NUMBER	NAME	REGULATED AIR POLLUTANT NAME [2]	#/ HR. [3]	TONS/ YEAR [4]	ZONE	EAST (Mtrs)	NORTH (Mtrs)	HEIGHT ABOVE GROUND (feet)	HEIGHT ABOVE STRUC. (feet)	EXIT DATA			SOURCES [7]	
										DIA (ft.)	VEL. (fps)	TEMP. (°F)	LENGTH (ft.)	WIDTH (ft.)
See Table A-18 in Appendix A														

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LEVEL_____feet
ADEQ STANDARD CONDITIONS ARE 293K AND 101.3 KILOPASCALS (A.A.C. R18-2-101)

****Submit emission calculations spreadsheet with your application****

General Instructions:

1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits, and Emissions Inventory Questionnaire. Include fugitive emissions. Limit emission point number to eight (8) character spaces. For each emission point use as many lines as necessary to list regulated air pollutant data. Typical emission point names are: heater, vent, boiler, tank, reactor, separator, baghouse, fugitive, etc. Abbreviations are O.K.

2. Components to be listed include regulated air pollutants as defined in A.A.C. R18-2-101. Examples of typical component names are: Carbon Monoxide (CO), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Volatile Organic Compounds (VOC), particulate matter (PM), particulate less than 10 microns (PM_{10}), etc. Abbreviations are O.K.

3. Pounds per hour (#/HR) is maximum potential emission rate expected by applicant.

4. Tons per year is annual maximum potential emission expected by applicant, which takes into account process operating schedule.

5. As a minimum applicant shall furnish a facility plot plan as described in the filing instructions. UTM coordinates are required only if the source is a major source or is required to perform refined modeling for the purposes of demonstrating compliance with ambient air quality guidelines.

6. Supply additional information as follows if appropriate:
   (a) Stack exit configuration other than a round vertical stack. Show length and width for a rectangular stack. Indicate if horizontal discharge with a note.
   (b) Stack's height above supporting or adjacent structures if structure is within 3 "stack height above the ground" of stack.

7. Dimensions of nonpoint sources as defined in A.A.C. R18-2-101.

SECTION 2.3 - EQUIPMENT LIST

The following table should include all equipment utilized at the facility, and should be completed with all the requested information. Be sure to notate the units (tons/hour, horsepower, etc.) when recording the Maximum Rated Capacity information, the Serial Number and/or the Equipment ID Number. The date of manufacture must be included in order to determine if portions of the facility are NSPS applicable. Make additional copies of this form if necessary.

Submit photographs of the faceplates for all engines listed below. If an engine is certified, please also include a copy of the engine certification with the application. For any newly added equipment, include a copy of the specification sheet. These documents will be used to verify equipment information and determine applicable regulations.

Type of Equipment	Maximum Rated Capacity [1]	Make	Model	Serial Number	Date of Manufacture	Equipment ID Number
See Table A-19 in Appendix A						

[1] For generator sets, enter the maximum rated capacity of the engine rather than the maximum rated capacity of the generator.

3. PERMIT PROCESSING FEE

In accordance with the ADEQ Permit Fee Schedule (effective November 1, 2021), Applied agrees to pay the $173 per hour permit processing fee required based on the total actual time spent processing the application by ADEQ.

4. PROCESS DESCRIPTION

The following provides a description of the emission generating activities at the NMGP, SIC code 1321.

4.1 Gas Treating

The inlet gas is initially passed through an inlet gas separator to remove any entrained material in the gas stream. The bulk of the carbon dioxide (CO_2) removal is accomplished by scrubbing the gas with an aqueous "lean" amine solution which reacts with the contained CO_2 and reduces the CO_2 content in the natural gas. The "rich" amine solution is then heated in the Rich/Lean Amine Exchanger with the lean solution leaving the Amine Regenerator and then flashed in the Amine Regenerator. Most of the absorbed CO_2 is released during the flash and the rest is stripped from the solution as it descends through the column. The stripping of the CO_2 is accomplished by steam produced by the Amine Regenerator Reboiler. The "lean" solution is returned to the top of the Amine Absorber to repeat the cycle after it is cooled in the Rich/Lean Amine Exchanger and the H. P. Lean Amine Cooler. The CO_2 and water contained in the Amine Regenerator overhead are cooled in the Amine Regenerator reflux condenser where most of the contained water is condensed and the CO_2 is vented to atmosphere.

4.2 Gas Dehydration

The gas saturated with water leaving the Amine Absorber is passed through molecular sieves in Gas Dehydrators to absorb any water in the gas stream. At any one time, only one of the two dehydrators in each natural gas processing unit will be in service; the other dehydrator will be in the regeneration cycle. The molecular sieves also serve to remove any residual CO_2. The inlet gas dehydration units are followed by filters which remove any molecular sieve dust that may be carried from the dehydrators in the gas stream.

Gas used in the regeneration of the molecular sieves is treated natural gas obtained from the exit of the gas dehydration units. A coil in the exhaust of the gas turbine driving the refrigerant gas compressor heats the regeneration gas. Following each heating cycle, the molecular sieve bed is cooled with dry regeneration gas and left in a standby mode ready for the next dehydration cycle.

4.3 Gas Liquefaction

Dry, CO_2 free gas from the dehydration process units is first cooled in one pass of the multi-pass, refrigerant exchangers. The two-phase stream flows to the Demethanizers where most of the condensed heavier hydrocarbons are stripped from the feed gas. The heavy components leave the bottom of the Demethanizers and are sent to the fuel gas system, and the tower overhead flows to the second pass of the refrigerant exchangers where it is totally condensed.

Cooling necessary to liquefy the natural gas is provided by a multi-component mixed refrigerant system. The refrigerant is compressed in the turbine driven refrigerant gas compressors and cooled in the refrigerant condensers. The cooled gas then flows through a third pass in the refrigerant exchangers where it is partially condensed. Condensed refrigerant is expanded to a low pressure and then returns to the refrigerant exchangers where it provides the necessary cooling of the other three passes. Vaporized refrigerant from the refrigerant exchangers returns to the refrigerant gas compressor to close the cycle.

4.4 Hot Oil System

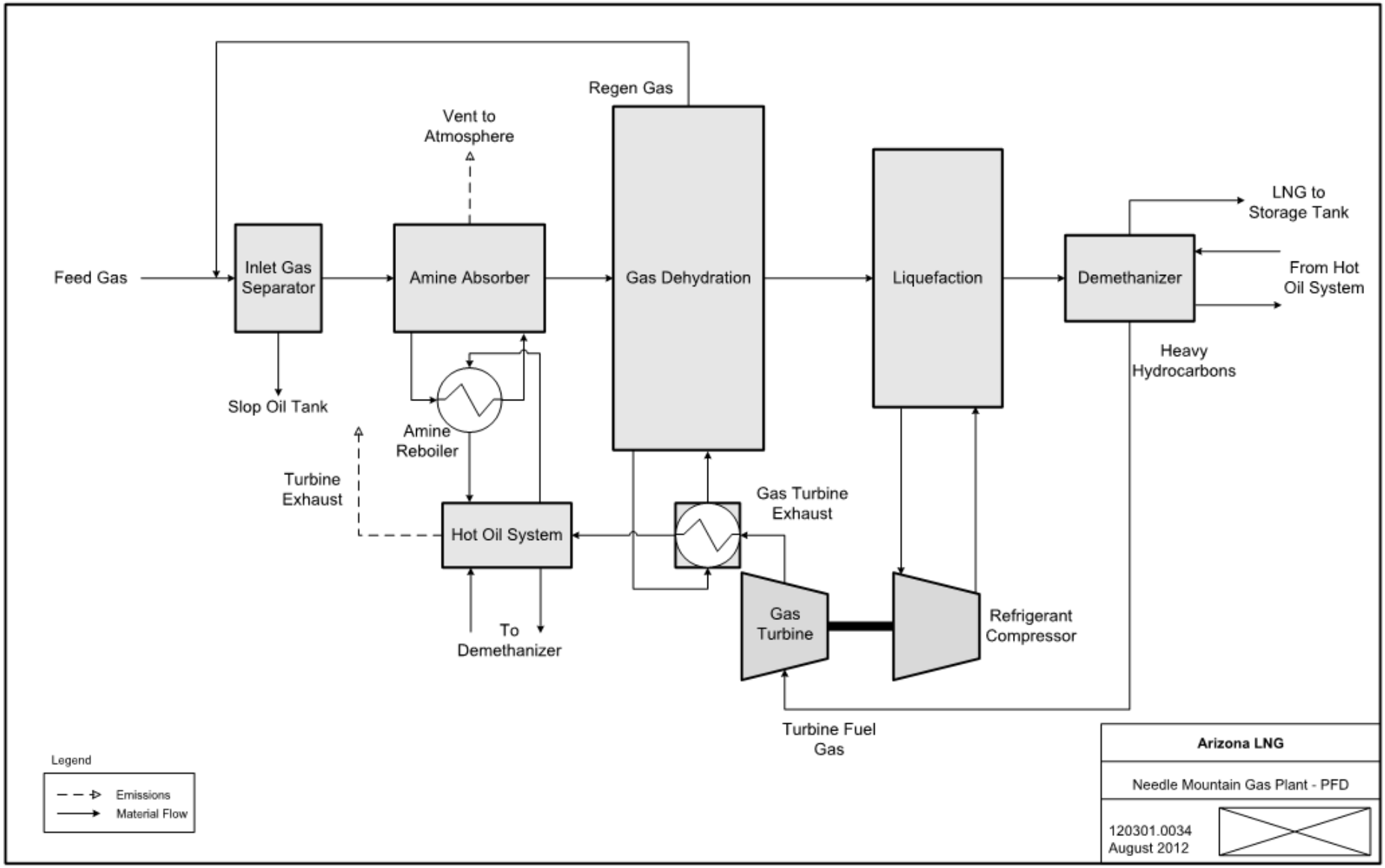
Heat for the amine regenerator reboilers and the demethanizers is supplied by a hot oil system. Oil from the hot oil surge drums is pumped through a coil in the gas turbines exhaust duct where it is heated to the required temperature. The hot oil then flows sequentially through the amine regenerator reboiler and the demethanizer reboiler and returns to the surge drum to repeat the cycle.

There are several small branch connections along the piping system within the NMGP. These branch connections allow for piping blowdowns to a small vent stack in case of pressure exceedance. Note that such releases are not part of "normal operation" and in accordance with R18-2-101.119.y, emissions from natural gas pressure regulator vents are considered trivial and may be omitted from permit applications.

Pipeline quality natural gas is burned at the NMGP for two gas turbines. A natural gas meter owned and operated by Applied measures the natural gas flow to the NMGP. Emissions from both plants at the facility would consist of fugitive emissions, emergency venting, and both complete and incomplete products of combustion.

The amount of LNG processed varies depending on customer demand. Therefore, Applied is seeking a permit that will allow full operation of the both turbines to meet maximum demand for LNG processing services. However, for those times when processing is not needed due to customer demand, the turbines will be shut down. Other factors may also require turbine shutdown.

5. PROCESS FLOW DIAGRAM


Regen Gas
Vent to Atmosphere
Feed Gas
Inlet Gas Separator
Amine Absorber
Gas Dehydration
Liquefaction
Demethanizer
LNG to Storage Tank
From Hot Oil System
Heavy Hydrocarbons
Slop Oil Tank
Amine Reboiler
Turbine Exhaust
Hot Oil System
Gas Turbine Exhaust
Gas Turbine
Refrigerant Compressor
To Demethanizer
Turbine Fuel Gas
Legend
Emissions
Material Flow
Arizona LNG
Needle Mountain Gas Plant - PFD
120301.0034
August 2012

The operations at the Needle Mountain Gas Plant may generate emissions of the following constituents:

- Particulate Matters (PM_{10} and $PM_{2.5}$)
- Nitrogen Oxides (NOx)
- Carbon Monoxide (CO)
- Sulfur Dioxide (SO_2)
- Hydrogen Sulfide (H_2S)
- Volatile Organic Compounds (VOC)
- Formaldehyde
- Greenhouse Gases (GHGs) [i.e., Carbon Dioxide (CO_2), Methane, (CH_4), and Nitrous Oxide (N_2O)]

The following sections contain a description of the methodology used to calculate emissions for the proposed operations. Detailed calculations are contained in Appendix A.

6.1 Combustion Turbine Emissions

Emissions are generated from the combustion of natural gas in the NMGP's combustion turbines. Combustion emissions for PM_{10}/$PM_{2.5}$, NOx, CO, VOC, SO_2, Formaldehyde, Total HAPs, and GHG in this permit application are calculated based on heat input rating, emission factors, as well as manufacturer's emission data.

6.1.1 Solar Centaur 40-T4700 Gas Turbines (Topock I and Topock II)

- PM_{10}/$PM_{2.5}$, and Formaldehyde, and Total HAPs emission factors acquired from Solar Turbines Product Information Letters (PIL) contained in Appendix B.
- CO and VOC emission factors based on manufacturer's emission estimation contained in Appendix B.
- NOx and SO_2 emission factors calculated based on 40 CFR Part 60 Subpart KKKK limitations.
- GHG emission factors acquired from 40 CFR Part 98 Subpart C, for natural gas combustion.

6.1.2 Calculation Methodology

The hourly and annual emission calculation equations for PM_{10}/$PM_{2.5}$, NOx, CO, VOC, SO_2, Formaldehyde, Total HAPs, and GHG are as follows. Detailed combustion turbine emissions are calculated and summarized in Appendix A.

Hourly emission rates are calculated using the following equation:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) \times \text{Heat Input}\left(\frac{\text{MMBtu}}{\text{hr}}\right)$$

Annual emissions are determined based on the following equation:

$$\text{Annual Emission Rate}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{8{,}760\ \text{hrs}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}}$$

Emissions of GHG pollutants are converted to the unit of "CO_2 equivalents" (CO_2e) using the Global Warming Potential (GWP) of CO_2, CH_4, and N_2O contained in 40 CFR Part 98 Subpart A.

6.2 Process Fugitives

Process fugitive emissions are calculated using emission factors of lbs of total hydrocarbon (THC)/hour obtained from EPA guidance for valves, relief valves, and flanges.[1] The compressor emission factor is obtained from manufacturer's data. The total numbers of piping components are divided into four stream types as follows:

- Process stream;
- Refrigerant loop;
- Demethanizer bottoms; and
- Fuel gas

Each of these streams has a different VOC, CO_2, and CH_4 content, which is determined by gas chromatograph analysis of the specified fluid type. The hourly and annual emissions are calculated as follows. Detailed emissions calculations are summarized in Appendix A.

Hourly emission rates are calculated using the following equation:

$$\begin{aligned}
&\text{Hourly VOC Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) = \\
&\left[\text{Valve Emission Factor}\left(\frac{\text{lb THC}}{\text{hr - valve}}\right) \times \text{No. of Valves} \times \text{Stream VOC Content in THC (wt\%)/100}\right] \\
&+\left[\text{Relief Valve Emission Factor}\left(\frac{\text{lb THC}}{\text{hr - valve}}\right) \times \text{No. of Relief Valves} \times \text{Stream VOC Content in THC (wt\%)/100}\right] \\
&+\left[\text{Flange Emission Factor}\left(\frac{\text{lb THC}}{\text{hr - flange}}\right) \times \text{No. of Flanges} \times \text{Stream VOC Content in THC (wt\%)/100}\right] \\
&+\left[\text{Compressor Emission Factor}\left(\frac{\text{lb THC}}{\text{hr - comp}}\right) \times \text{No. of Compressors} \times \text{Stream VOC Content in THC (wt\%)/100}\right]
\end{aligned}$$

Annual VOC emissions are determined based on the following equation:

$$\text{Annual VOC Emissions}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Hourly VOC Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) \times \left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

Emissions of GHG pollutants are calculated as shown below and converted to the unit of "CO_2 equivalents" (CO_2e) using the Global Warming Potential (GWP) of CO_2, CH_4, and N_2O contained in 40 CFR Part 98 Subpart A.

[1] Per Table 2-4 of EPA "*Protocol for Equipment Leak Emission Estimates*," EPA-453/R-95-017, November 1995.

Hourly GHG emission rates are calculated using the following equation:

$$\text{Hourly GHG Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) =$$
$$\left[\text{Valve Emission Factor}\left(\frac{\text{lb THC}}{\text{hr - valve}}\right) \times \text{No. of Valves} \times \left(\frac{\text{Stream GHG Content in Gas}}{\text{Stream VOC Content in Gas}}\right) \times \left(\frac{\text{Stream VOC Content in Gas}}{\text{Stream VOC Content in THC}}\right)\right]$$
$$+\left[\text{Relief Valve Emission Factor}\left(\frac{\text{lb THC}}{\text{hr - valve}}\right) \times \text{No. of Relief Valves} \times \left(\frac{\text{Stream GHG Content}}{\text{Stream THC Content}}\right)\right]$$
$$+\left[\text{Flange Emission Factor}\left(\frac{\text{lb THC}}{\text{hr - flange}}\right) \times \text{No. of Flanges} \times \left(\frac{\text{Stream GHG Content}}{\text{Stream THC Content}}\right)\right]$$
$$+\left[\text{Compressor Emission Factor}\left(\frac{\text{lb THC}}{\text{hr - comp}}\right) \times \text{No. of Compressors} \times \left(\frac{\text{Stream GHG Content}}{\text{Stream THC Content}}\right)\right] \times \text{GWP}$$

Annual GHG emissions are determined based on the following equation:

$$\text{Annual GHGEmissions}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Hourly GHGEmissions}\left(\frac{\text{lb}}{\text{hr}}\right) \times \left(\frac{8{,}760\ \text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

6.3 Initial Start Up/Plant Air Purge

In this mode of operation, air will be displaced with nitrogen. The turbine will be running at idle to provide heat for startup of the amine regenerator. Sufficient gas would be added to pressure up the amine absorber and dehydration unit with the line to the liquefaction units blocked in. Amine circulation would then be lined out with hot oil regulated to the regenerator and a minimum flow of gas would be circulated through the mole sieve regeneration loop.

It is conservatively assumed that two plant blowdowns are to be conducted per year for each unit. Each plant blowdown will have an average purge gas throughput of 2 MMscf/day for a period of 2 days. All purge gas used in this process will be vented into the air without control. The VOC, CO^2, and CH^4 content of the purge gas is determined by gas chromatograph analysis. The hourly and annual emissions are calculated as follows. Detailed emissions calculations are summarized in Appendix A.

Hourly emission rates are calculated using the following equation:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Purge Gas Throughput}\left(\frac{\text{MMscf}}{\text{day}}\right) \times \frac{1\ \text{day}}{24\ \text{hrs}} \times \frac{10^6\ \text{scf}}{\text{MMscf}} \div \text{Purge Gas Volume}\left(\frac{\text{scf}}{\text{Mol}}\right)$$
$$\times \text{Purge Gas Molecular Weight}\left(\frac{\text{lb}}{\text{Mol}}\right) \times \text{Content of Constituent in Purge Gas}\ (\text{wt\%})/100$$

Annual emissions are determined based on the following equation:

$$\text{Annual Emission Rate}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{24\ \text{hrs}}{\text{day}} \times \frac{2\ \text{days}}{\text{blowdown}} \times \frac{2\ \text{blowdowns}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}}$$

Emissions of GHG pollutants are converted to the unit of "CO_2 equivalents" (CO_2e) using the Global Warming Potential (GWP) of CO_2, CH_4, and N_2O contained in 40 CFR Part 98 Subpart A.

6.4 Engine Start Up Blowdown

The starting gas flow during turbine start-up is 2,400 scfm for an average of 3 minutes, which is then released in the low pressure vent stack. For a worst-case scenario reflecting maximum theoretical emissions, a total of 120 startups per engine will be used in the calculations. The VOC, CO_2, and CH_4 content of the starting gas is determined by gas chromatograph analysis. The hourly and annual emissions are calculated as follows. Detailed emissions calculations are summarized in Appendix A.

Hourly emission rates are calculated using the following equation:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Starting Gas Flow}\left(\frac{\text{scf}}{\text{min}}\right) \times \frac{3\text{ mins}}{\text{hr}} \div \text{Starting Gas Volume}\left(\frac{\text{scf}}{\text{Mol}}\right)$$
$$\times \text{Starting Gas Molecular Weight}\left(\frac{\text{lb}}{\text{Mol}}\right) \times \text{Content of Constituent in Starting Gas}\left(\text{wt\%}\right)/100$$

Annual emissions are determined based on the following equation:

$$\text{Annual Emission Rate}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{120\text{ Start-ups}}{\text{yr}} \times \frac{1\text{ ton}}{2{,}000\text{ lb}}$$

Emissions of GHG pollutants are converted to the unit of "CO_2 equivalents" (CO_2e) using the Global Warming Potential (GWP) of CO_2, CH_4, and N_2O contained in 40 CFR Part 98 Subpart A.

6.5 Defrosting the Liquefaction Plant (Derimming)

Cryogenic plants often require occasional defrosting and gradual heating to remove solids that accumulate in the piping. Deriming the NMGP would be achieved by blocking in the liquefaction units, operating the pretreatment facilities under a minimum flow recycle, and gradually heating the brazed aluminum heat exchanger with compressed refrigerant. A low flow of pretreated gas would sweep the liquefaction piping to a vent to remove CO_2, H_2O, and other substances that form low temperature solids.

Each unit should be able to perform up to 2 derimes per year. Maximum venting for a derime is estimated to be 36 hours of process gas, flowing at 1 MMscf/day. The VOC, CO_2, and CH_4 content of the venting gas is determined by gas chromatograph analysis. The hourly and annual emissions are calculated as follows. Detailed emissions calculations are summarized in Appendix A.

Hourly emission rates are calculated using the following equation:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Venting Gas Throughput}\left(\frac{\text{MMscf}}{\text{day}}\right) \times \frac{1\text{ day}}{24\text{ hrs}} \times \frac{10^6\text{ scf}}{\text{MMscf}} \div \text{Venting Gas Volume}\left(\frac{\text{scf}}{\text{Mol}}\right)$$
$$\times \text{Venting Gas Molecular Weight}\left(\frac{\text{lb}}{\text{Mol}}\right) \times \text{Content of Constituent in Venting Gas}\left(\text{wt\%}\right)/100$$

Annual emissions are determined based on the following equation:

$$\text{Annual Emission Rate}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{36\text{ hrs}}{\text{derime}} \times \frac{2\text{ derimes}}{\text{yr}} \times \frac{1\text{ ton}}{2{,}000\text{ lb}}$$

Emissions of GHG pollutants are converted to the unit of "CO_2 equivalents" (CO_2e) using the Global Warming Potential (GWP) of CO_2, CH_4, and N_2O contained in 40 CFR Part 98 Subpart A.

6.6 Amine Regenerators

Applied utilize amine units to treat the inlet gas at the NMGP. The CO_2 and H_2S are scrubbed out of the feed gas by "lean" amine and ends up as "rich" amine which must be regenerated. The volume of CO_2 vented from the Amine Regenerator overhead is conservatively estimated at a maximum of 2 volume percent of 7.60 MMscf/day for each liquefaction unit. The H_2S emissions are calculated based on the tariff limit of 0.25 grains/100 scf. The hourly and annual emissions are calculated as follows. Detailed emissions calculations are summarized in Appendix A.

6.6.1 CO_2 Emissions from Amine Regenerator

Hourly emission rates are calculated using the following equation:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Natural Gas Throughput}\left(\frac{\text{MMscf}}{\text{day}}\right) \times \frac{1\,\text{day}}{24\,\text{hrs}} \times \frac{10^6\,\text{scf}}{\text{MMscf}} \div \text{Natural Gas Volume}\left(\frac{\text{scf}}{\text{Mol}}\right)$$
$$\times \text{Natural Gas } CO_2 \text{ Content}(\text{vol\%})/100 \times CO_2 \text{ Molecular Weight}\left(\frac{\text{lb}}{\text{Mol}}\right)$$

Annual emissions are determined based on the following equation:

$$\text{Annual Emission Rate}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{8{,}760\ \text{hrs}}{\text{yr}} \times \frac{1\,\text{ton}}{2{,}000\ \text{lb}}$$

6.6.2 H_2S Emissions from Amine Regenerator

Hourly emission rates are calculated using the following equation:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Natural Gas Throughput}\left(\frac{\text{MMscf}}{\text{day}}\right) \times \frac{1\,\text{day}}{24\,\text{hrs}} \times \frac{10^6\,\text{scf}}{\text{MMscf}}$$
$$\times \text{Natural Gas Tariff Limit}\left(\frac{\text{gr } H_2S}{100\,\text{scf}}\right) \times \frac{1\,\text{lb}}{7{,}000\,\text{gr}}$$

Annual emissions are determined based on the following equation:

$$\text{Annual Emission Rate}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{8{,}760\ \text{hrs}}{\text{yr}} \times \frac{1\,\text{ton}}{2{,}000\ \text{lb}}$$

6.7 Compressor Seal Emissions

A small amount of CO_2 vent gas may be released through the compressor seals. A leakage rate of 3 scfm was assumed for each compressor. The VOC, CO_2, and CH_4 content of the vent gas is determined by gas chromatograph analysis. The hourly and annual emissions are calculated as follows. Detailed emissions calculations are summarized in Appendix A.

Hourly emission rates are calculated using the following equation:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Seal Vent Gas Flow}\left(\frac{\text{scf}}{\text{min}}\right) \text{x} \frac{60\ \text{min}}{\text{hr}}\ \text{x}\ \frac{34.63\ \text{lb}}{\text{lb} - \text{mol}} \text{x} \frac{1\ \text{lb} - \text{mol}}{385\ \text{scf}} \text{x}$$

$$\text{Concentration of Constituent in Venting Gas (wt\%)}/100$$

Annual emissions are determined based on the following equation:

$$\text{Annual Emission Rate}\left(\frac{\text{ton}}{\text{yr}}\right) = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \frac{8{,}760\ \text{hrs}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}}$$

Emissions of GHG pollutants are converted to the unit of "CO_2 equivalents" (CO2e) using the Global Warming Potential (GWP) of CO_2, CH_4, and N_2O contained in 40 CFR Part 98 Subpart A.

6.8 Site-Wide Emissions

The calculated site-wide emissions from the NMGP are summarized in Table 6-1. Detailed calculations are shown in Appendix A.

Table 6-1. Summary of NMGP Post-Change Site-Wide Emissions

Emission Unit	Site-Wide Annual Emissions (tpy)							
	PM10/ PM2.5	NOx	CO	VOC	SO2	H2S	Formaldehyde	CO2e
Solar Centaur Gas Turbine	7.88	202.44	41.08	4.73	22.51	-	1.08	44,039
Process Fugitives	-	-	-	34.59	-	-	-	436
Initial Start Up/Plant Purge	-	-	-	5.20	-	-	-	7,931
Engine Start-up Blowdown	-	-	-	0.56	-	-	-	857
Deriming	-	-	-	1.95	-	-	-	2,974
Amine Regenerator	-	-	-	-	-	0.99	-	6,336
Compressor Seal	-	-	-	113.88	-	-	-	356
Site-Wide Total Emissions	***7.88***	***202.44***	***41.08***	***160.91***	***22.51***	***0.99***	***1.08***	***62,929***
Non-Fugitive Total Emissions	***7.88***	***202.44***	***41.08***	***4.73***	***22.51***	***0.99***	***1.08***	***50,375***
Site-Wide Emissions Cap	***-***	***220.00***	***-***	***-***	***-***	***-***	***-***	***-***

7. AIR DISPERSION MODELING ANALYSIS

The following section describes the air dispersion modeling analysis conducted by Trinity Consultants in 2012 for the purpose of adding second plant - Topock II. The "proposed expansion" in this section simply means addition of Topock II plant which is currently in operation.

The NMGP is located in Mohave County, Arizona approximately 1.5 miles northeast of Topock, Arizona. An aerial photograph depicting the location of the NMGP is provided in Figure 7-1 below. As can be seen in the figure, the area surrounding the NMGP is rural.

Figure 6.8-1. Aerial Photograph of the NMGP

7.1 Modeling Approach

7.1.1 Dispersion Model Selection

This modeling analysis was conducted using the U.S. EPA AERSCREEN version 11126 model. AERSCREEN is a screening model used to produce "worst case" concentrations. Since AERSCREEN does not use fully developed meteorological and terrain data, the model produces conservative estimates when compared to the EPA's AERMOD modeling system.

7.1.2 Modeled Emission Sources

The proposed expansion at the NMGP includes the addition of a gas combustion turbine and other process units. The gas combustion turbine contributes to combustion emissions which may have an associated National Ambient Air Quality Standard (NAAQS). The other process units contribute to emissions of VOC, GHG, and H_2S which do not have an associated NAAQS. Therefore, this modeling analysis was performed for the emissions from the gas combustion turbine that have an associated NAAQS. The detailed parameters used in the modeling analysis are included in Appendix C.

7.1.3 General Modeling Methodology

In order to efficiently address multiple constituents in one modeling run using AERSCREEN, the modeling analysis was performed using the following procedure:

1. The proposed combustion turbine was assigned a unit emission rate of one lb/hr.
2. The 1-hour average maximum ground level concentration in micrograms per cubic meter ($\mu g/m^3$) per lb/hr ("maximum normalized impact") was obtained using AERSCREEN.
3. AERSCREEN provides the maximum concentrations for the other averaging periods (e.g., 3-hour, 8-hour, 24-hour, etc.). However, these concentrations are scaled from the 1-hour average concentration using the most conservative multiplying factors contained in EPA guidance as noted below:[2]
   - 3-Hour: 0.9
   - 8-Hour: 0.7
   - 24-Hour: 0.4
   - Annual: 0.08
4. The normalized impact was multiplied by the emission rate to obtain maximum concentration estimates in $\mu g/m^3$.
5. Per ADEQ modeling guidance for non-Prevention of Significant Deterioration (PSD) projects, background concentrations were obtained and added to the total maximum concentration for each constituent.
6. The concentrations from step 5 were used for comparison with the corresponding NAAQS values.

7.1.4 Background Concentrations

The proposed modification at NMGP does not trigger PSD review. Per the ADEQ modeling guidelines, for non-PSD sources, representative background concentrations were added to modeled impacts from the proposed project.[3] The total concentrations were then compared to the NAAQS. In addition, no regional sources were included in this modeling analysis since inclusion of regional sources in the non-PSD NAAQS is not required per the ADEQ modeling guidelines.[4]

The background concentrations used in the modeling analysis are summarized in Appendix C. In general, the concentrations were selected based on the proximity of the monitoring site to the location of the NMGP, as well as the date and completeness of the available monitoring data. In some cases, monitoring stations which were more representative of the NMGP location were selected over stations in closer proximity. For example, for $PM_{2.5}$, the Apache Junction Fire Station monitoring station was selected over closer stations located in Maricopa County. $PM_{2.5}$ background concentrations in Maricopa County were not considered to be representative for this modeling analysis for the following reasons:

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[2] Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised (Section 4.5.4), Report Number EPA-454/R-92-019.

[3] ADEQ, Air Dispersion Modeling Guidelines for Arizona Air Quality Permits, December, 2004.

[4] Ibid.

- The land use characteristics are significantly different between the NMGP site and Maricopa County.
- The traffic patterns are significantly different between the NMGP site and Maricopa County.
- The population density is significantly different between the NMGP site and Maricopa County.

7.2 Modeling Results

The maximum normalized impacts, obtained using AERSCREEN, are provided in Appendix C. Per ADEQ modeling guidelines, representative background concentrations were added to modeled impacts from the proposed facility.[5] Appendix C summarizes the total concentrations for comparison with the NAAQS. As represented in the table, the emissions from the proposed expansion at NMGP will not cause or contribute to a violation of the NAAQS.

[5] ADEQ, Air Dispersion Modeling Guidelines for Arizona Air Quality Permits, December, 2004.

The following sections summarize the potential state and federal regulatory requirements that may be applicable to the NMGP. NMGP proposes to maintain all regulatory applicability, including insignificant activities and sources, contained in the current ADEQ Class I Permit 56735.

8.1 Federal New Source Review and Title V Applicability

The NMGP is located in an area within Mohave County that is currently classified as an attainment area for all criteria pollutants.[6] Therefore, the applicable Federal NSR thresholds for the Prevention of Significant Deterioration (PSD) program are applicable. Note that the NMGP is not a "categorical source" contained in AAC R18-2-101.64.c. Therefore, only non-fugitive emissions are compared to applicable thresholds. A comparison of the potential non-fugitive emissions from the expanded NMGP and the Federal New Source Review and Title V thresholds is included in Table 7-1. As presented, potential emissions do not exceed any of the Federal NSR thresholds. However, the NOx emission exceeds the Title V thresholds. Therefore, the expanded NMGP becomes a Title V source and must maintain the ADEQ Class I permit as noted in this renewal application.

Table 7-1. Federal NSR and Title V Applicability

Pollutant	Potential Emissions (tpy)	PSD Major Source Threshold (tpy)	Title V Threshold (tpy)
$PM_{10}/PM_{2.5}$	7.88	250	100
CO	41.08	250	100
NOx	202.44	250	100
SO_2	22.51	250	100
VOC	4.78	250	100
Single HAP	1.08	-	10
Total HAPs	1.14	-	25
GHG	50,375	100,000	100,000

[6] Per the EPA Green book website, http://www.epa.gov/oar/oaqps/greenbk/

8.2 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

The Topock I and Topock II gas turbines at the NMGP are subject to the requirements of 40 CFR Part 60 Subpart KKKK (and exempt from the requirements of 40 CFR Part 60 Subpart GG). This regulation sets emission standards for NOx, and SO_2 for stationary combustion turbines and applies to turbines "constructed" after February 18, 2005. Per 40 CFR §60.4320, the emissions of NOx must meet the following limit:

> *A modified or reconstructed turbine with a heat input ≤ 50 MMBtu/hr must have an exhaust NO_x concentration less than 150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh).*

Applied will comply with the requirements of this section. Compliance will be demonstrated via stack testing.

Per 40 CFR §60.4330, the emissions of SO_2 must meet the following limit:

> *You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;*
>
> *You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.*

Applied will comply with the requirements of this section by utilizing pipeline quality natural gas that meets the sulfur content requirement.

Per 40 CFR §60.4333(a)

> *You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.*

Applied will comply with the requirements of this section.

Per 40 CFR §60.4340(a)

> *If you are not using water or steam injection to control NOx emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NOx emission limit for the turbine, you must resume annual performance tests.*

Applied will perform performance tests based on the frequency outlined in this section.

Per 40 CFR §60.4365

> *You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas … You must use one of the following sources of information to make the required demonstration:*

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less, … the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet, … has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas …

Applied operates under a Tariff approved by the Federal Energy Regulatory Commission that establishes specifications for sulfur content of natural gas received into the pipeline. A portion of the gas received from suppliers is used to fuel the various natural gas fired engines used throughout the pipeline system. Accordingly as specified in the delivery Tariff sheets, natural gas received from suppliers is limited to a total sulfur content of 0.75 grains/100 standard cubic feet. This amount is equivalent to approximately 0.0025 weight % sulfur. Therefore, under allowable operating conditions, the sulfur content of the pipeline quality natural gas burned by the NMGP would not exceed the limits specified above. Applied anticipates no changes to these Tariff limitations over the course of the permit term.

8.3 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting

The NMGP is subject to the GHG reporting requirements of 40 CFR Part 98 Subpart C since the aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 MMBtu/hr or greater and the facility is likely to emit 25,000 metric tons CO_2e or more per year in combined emissions from all stationary fuel combustion sources. As a result, the NMGP is subject to the following subparts under 40 CFR Part 98:

- 40 CFR Part 98 Subpart A – General Provision
- 40 CFR Part 98 Subpart C – General Stationary Fuel Combustion Sources

Note that the NMGP is not subject to the following 40 CFR Part 98 subparts:

- 40 CFR Part 98 Subpart W – Petroleum and Natural Gas Systems
  40 CFR §98.230 applies to the following industry segments:
  1) Offshore petroleum and natural gas production
     NMGP is not an offshore facility.
  2) Onshore petroleum and natural gas production
     Natural gas production means all equipment on a single well-pad or associated with a single well-pad used in the production, extraction, recovery, lifting, stabilization, separation or treating of natural gas. NMGP does not produce natural gas and is not part of this industry segment.
  3) Onshore natural gas processing
     Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures.[7]
     NMGP receives pipeline quality natural gas from supplier and is not part of this industry segment. In addition,
  4) Onshore natural gas transmission compression
     Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. NMGP does not utilize compressors to move natural gas and is not part of this industry segment.
  5) Underground natural gas storage
     NMGP does not store natural gas underground.

[7] Per 40 CFR Part 98 Subpart W, Background Technical Support Document, "in the processing facility, natural gas liquids and various other constituents from the raw gas are separated, resulting in "pipeline quality" gas that is compressed and injected into the transmission pipelines." Based on this definition, the NMGP is not a "natural gas processing" facility.

6) Liquefied natural gas (LNG) storage
   LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.
   NMGP does not utilize compressors to capture and re-liquefy boil-off-gas, re-condensers, or vaporization units. Therefore, NWGP is not part of this industry segment.
7) LNG import and export equipment
   NMGP does not import or export natural gas.
8) Natural gas distribution
   Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system.
   NMGP is not regulated as a separate operating company by a public utility commission or operated as an independent municipally-owned distribution system. Therefore, NWGP is not part of this industry segment.

Based on the above, the NMGP does not meet the definition of the source categories regulated under 40 CFR 60 Subpart W.

> 40 CFR Part 98 Subpart NN – Suppliers of Natural Gas and Natural Gas Liquids (NGLs)

Suppliers of natural gas and NGLs are defined as natural gas liquids fractionators and local natural gas distribution companies (LDCs), as follows:

- Natural gas liquids fractionators are installations that fractionate NGLs into their constituent liquid products (ethane, propane, normal butane, isobutane, or pentanes plus) for supply to downstream facilities.
- Local distribution companies are companies that own or operate distribution pipelines that physically deliver natural gas to end users and that are regulated as separate operating companies by state public utility commissions, or that operate as independent municipally owned distribution systems. Companies that operate interstate or intrastate pipelines are not part of this source category.

The NMGP is not a natural gas liquids fractionators or distribution company as defined above

The GHG emissions to be reported from the NMGP include CO_2, CH_4, and N_2O) emissions from the combustion of natural gas in the turbines.

9. COMPLIANCE CERTIFICATION

As required in AAC R18-2-304.H, I hereby certify that, based on the information provided after reasonable inquiry of Arizona LNG and Applied Natural Gas Fuels staff, the information contained in this submittal is true, accurate, and complete to the best of my knowledge.

Signature of Responsible Official: _____

Print Name: Edward McKenna, Jr.

Date of Signature: April 14, 2022

APPENDIX A. EMISSION CALCULATION WORKSHEETS

ARIZONA LNG - NEEDLE MOUNTAIN GAS PLANT
EMISSION CALCULATIONS

Table A-1. Combustion Turbine Emission Factors

Emission Unit	Unit Input Capacity [1, 2, 3]		Unit Output Capacity [2]	Emission Factors [4, 5, 6, 7, 8, 9]													
				$PM_{10}/PM_{2.5}$	NO_x			CO		VOC		SO_2	Formaldehyde	Total HAPs	CO_2	CH_4	N_2O
	(MMBtu/hr LHV)	(MMBtu/hr HHV)	(hp)	(lb/MMBtu HHV)	(ppmv)	(lb/hr) @165 ppmv	(lb/hr) @150 ppmv	(ppmv)	(lb/hr)	(ppmv)	(lb/hr)	(lb/MMBtu HHV)	(lb/MMBtu HHV)	(lb/MMBtu HHV)	(kg/MMBtu)	(kg/MMBtu)	(kg/MMBtu)
Solar Centaur 40-T4700 Gas Turbine - Topock I	38.93	42.83	4,079	0.021	150	25.42	23.11	-	4.69	-	0.54	0.060	0.00288	0.00305	53.06	0.001	0.0001
Solar Centaur 40-T4700 Gas Turbine - Topock II	38.93	42.83	4,079	0.021	150	25.42	23.11	-	4.69	-	0.54	0.060	0.00288	0.00305	53.06	0.001	0.0001

[1] Per Solar Turbine "Predicted Emission Performance" dated December 21, 2011, the nominal heat rate for T4700 turbine (@ 80 degree F) is: 9,545 Btu/hp-hr

[2] Turbine input/output capacities acquired from Solar Turbine "Predicted Emission Performance" dated December 21, 2011, per case #2 @80 degree F.

[3] Assuming fuel gas Higher Heating Value (HHV) is 10% higher than Lower Heating Value (LHV)

[4] $PM_{10}/PM_{2.5}$ emission factors per Solar Turbines Product Information Letter (PIL) 171 - Particulate Matter Emission Estimates

[5] NOx emission rate in lb/hr for the T4700 gas turbine per Solar Turbine "Predicted Emission Performance" dated December 21, 2011 @ 100 % load.
The referenced lb/hr emission rate was ratioed down to meet the 150 ppm NSPS Subpart KKKK limit for "Reconstructed" turbines.

[6] CO and VOC emission factors for the T4700 gas turbine per manufacturer's Emission Estimates (@ 80 degree F). VOC emissions are assumed equal to 20% of the unburned hydrocarbon (UHC) emission rate.

[7] SO_2 emission factors per fuel sulfur limit specified in NSPS Subpart KKKK - Standards of Performance for Stationary Combustion Turbines, July 6, 2006.

[8] Formaldehyde and Total HAPs emission factors per Solar Turbines Product Information Letter (PIL) 168 - Volatile Organic Compound, Sulfur Dioxide, and Formaldehyde Emission Estimates

[9] GHG emission factors acquired from Tables C-1 and C-2 of 40 CFR Part 98 Subpart C, for natural gas combustion.

Table A-2. Hourly Turbine Emissions

Emission Unit	Hourly Emission Rate (lb/hr)										
	$PM_{10}/PM_{2.5}$	NO_x	CO	VOC	SO_2	Formaldehyde	Total HAPs	CO_2	CH_4	N_2O	CO_2e [1]
Solar Centaur 40-T4700 Gas Turbine - Topock I	0.90	23.11	4.69	0.54	2.57	0.12	0.13	5,022	0.09	0.009	5,027
Solar Centaur 40-T4700 Gas Turbine - Topock II	0.90	23.11	4.69	0.54	2.57	0.12	0.13	5,022	0.09	0.009	5,027
Total Turbine Emissions	***1.80***	***46.22***	***9.38***	***1.08***	***5.14***	***0.25***	***0.26***	***10,044***	***0.19***	***0.02***	***10,054***

[1] Global warming potential values obtained from 40 CFR 98 Table A-1

CH_4 GWP = 25

N_2O GWP = 298

Table A-3. Annual Turbine Emissions

Emission Unit	Annual Emission Rate (tpy) [1]										
	$PM_{10}/PM_{2.5}$	NO_x	CO	VOC	SO_2	Formaldehyde	Total HAPs	CO_2	CH_4	N_2O	CO_2e [2]
Solar Centaur 40-T4700 Gas Turbine - Topock I	3.94	101.22	20.54	2.37	11.26	0.54	0.57	21,997	0.41	0.041	22,019
Solar Centaur 40-T4700 Gas Turbine - Topock II	3.94	101.22	20.54	2.37	11.26	0.54	0.57	21,997	0.41	0.041	22,019
Total Turbine Emissions	***7.88***	***202.44***	***41.08***	***4.73***	***22.51***	***1.08***	***1.14***	***43,993***	***0.83***	***0.08***	***44,039***

[1] Annual emissions are calculated based on continuous operation (8,760 hr/yr).

[2] Global warming potential values obtained from 40 CFR 98 Table A-1

CH_4 GWP = 25

N_2O GWP = 298

Table A-4. Fugitive Component Counts

Emission Unit	Component	Piping Component Count for Stream Number [1]				Emission Factors [2]
		1	2	3	4	
		Process Stream	Refrigerant Loop	Demethanizer Bottoms	Fuel Gas	(lb/hr/source THC)
Topock I	Valves	115	22	4	17	9.95E-03
	Relief Valves	10	4	0	1	1.94E-02
	Flanges	160	50	22	35	8.62E-04
	Compressor	0	2	0	0	2.01
Topock II	Valves	115	22	4	17	9.95E-03
	Relief Valves	10	4	0	1	1.94E-02
	Flanges	160	50	22	35	8.62E-04
	Compressor	0	2	0	0	2.01
VOC Weight % (THC Based) [3]		1.54%	88.88%	34.42%	15.59%	-
CO_2 to THC Ratio (Weight Based) [3]		4.44%	0.00%	0.00%	2.10%	-
CH_4 to THC Ratio (Weight Based) [3]		93.92%	11.12%	0.02%	53.04%	-

[1] Component counts acquired from the 1996 permit application.
[2] Emission factors for valves, relief valves, and flanges obtained from Table 2-4 of EPA "Protocol for Equipment Leak Emission Estimates," EPA-453/R-95-017, November 1995.
Emission factor for the compressor obtained from the compressor manufacturer.
[3] Per gas composition calculation contained in Table A-10 through Table A-13.

Table A-5. Hourly Fugitive VOC Emissions

Emission Unit	Component	Piping Component Fugitive Emissions (lb/hr THC)				Total Emissions			
		1	2	3	4	VOC	CO_2	CH_4	CO_2e [1]
		Process Stream	Refrigerant Loop	Demethanizer Bottoms	Fuel Gas	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Topock I	Valves	1.14	0.22	0.040	0.17	0.25	0.05	1.19	30
	Relief Valves	0.19	0.078	0	0.019	0.08	0.01	0.20	5
	Flanges	0.14	0.043	0.019	0.030	0.05	0.01	0.15	4
	Compressor	0	4.02	0	0	3.57	0.00	0.45	11
Topock II	Valves	1.14	0.22	0.040	0.17	0.25	0.05	1.19	30
	Relief Valves	0.19	0.078	0	0.019	0.08	0.01	0.20	5
	Flanges	0.14	0.043	0.019	0.030	0.05	0.01	0.15	4
	Compressor	0	4.02	0	0	3.57	0.00	0.45	11
Totals		***2.95***	***8.71***	***0.12***	***0.44***	***7.90***	***0.14***	***3.97***	***99***

[1] Global warming potential values obtained from 40 CFR 98 Table A-1
CH_4 GWP = 25

Table A-6. Annual Fugitive VOC Emissions

Emission Unit	Component	Piping Component Fugitive Emissions (tpy THC)				Total Emissions			
		1	2	3	4	VOC	CO_2	CH_4	CO_2e [1]
		Process Stream	Refrigerant Loop	Demethanizer Bottoms	Fuel Gas	(tpy)	(tpy)	(tpy)	(tpy)
Topock I	Valves	5.01	0.96	0.17	0.74	1.10	0.24	5.20	130
	Relief Valves	0.85	0.34	0	0.085	0.33	0.040	0.88	22
	Flanges	0.60	0.19	0.083	0.13	0.23	0.030	0.66	16
	Compressor	0	17.59	0	0	15.63	0.00	1.96	49
Topock II	Valves	5.01	0.96	0.17	0.74	1.10	0.24	5.20	130
	Relief Valves	0.85	0.34	0	0.085	0.33	0.040	0.88	22
	Flanges	0.60	0.19	0.083	0.13	0.23	0.030	0.66	16
	Compressor	0	17.59	0	0	15.63	0.00	1.96	49
Totals		***12.93***	***38.15***	***0.51***	***1.92***	***34.59***	***0.61***	***17.40***	***436***

[1] Global warming potential values obtained from 40 CFR 98 Table A-1
CH_4 GWP = 25

Table A-7. Initial Startup/Plant Air Purge Emissions

Emission Unit	Purge Gas Flowrate (MMscf/day)	Annual Operation (days/yr)	Process Gas MW [2] (lb/mole)	Process Gas Content (%) [2]			Emissions									
							Process Gas [1]		VOC		CO_2		CH_4		CO_2e [3]	
				VOC	CO_2	CH_4	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Amine Regenerator - Topock I	2	4	17.04	1.47	4.24	89.50	3,686	177	54.18	2.60	156.09	7.49	3,298.42	158.32	82,617	3,966
Amine Regenerator - Topock II	2	4	17.04	1.47	4.24	89.50	3,686	177	54.18	2.60	156.09	7.49	3,298.42	158.32	82,617	3,966
Total Amine Regenerator Startup Emissions									***108.37***	***5.20***	***312.17***	***14.98***	***6,596.84***	***316.65***	***165,233***	***7,931***

[1] Volume of purge gas is estimated using Ideal Gas Law at standard conditions

PV = nRT

P = 29.92 in Hg per R18-2-701.50
T = 527.67 R per R18-2-701.50
R = 21.85 in Hg . Ft3 / (lbmol.deg R)
V = 385 scf/mole

[2] Per gas composition calculation contained in Table A-10.

[3] Global warming potential values obtained from 40 CFR 98 Table A-1

CH_4 GWP = 25

Table A-8. Engine Startup Blowdown Emissions

Emission Unit	Starting Gas Flow Rate (scfm)	Startup Period (min)	Annual Startups (#/yr)	Process Gas MW [2] (lb/mole)	Process Gas Content (%) [2]			Emissions									
								Process Gas [1]		VOC		CO_2		CH_4		CO_2e [3]	
					VOC	CO_2	CH_4	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Solar Centaur 40-T4700 Gas Turbine - Topock I	2,400	3	120	17.04	1.47	4.24	89.50	318	19	4.68	0.28	13.49	0.81	284.98	17.10	7,138.07	428.28
Solar Centaur 40-T4700 Gas Turbine - Topock II	2,400	3	120	17.04	1.47	4.24	89.50	318	19	4.68	0.28	13.49	0.81	284.98	17.10	7,138.07	428.28
Total Engine Startup Emissions										***9.36***	***0.56***	***26.97***	***1.62***	***569.97***	***34.20***	***14,276.14***	***856.57***

[1] Volume of 1 mole blowdown gas at standard condition is: **385 scf/mole**

[2] Per gas composition calculation contained in Table A-10.

[3] Global warming potential values obtained from 40 CFR 98 Table A-1

CH_4 GWP = 25

Table A-9. Liquefaction Plant Defrosting (Deriming) Emissions

Emission Unit	Vent Gas Flowrate (MMscf/day)	Deriming Duration (hr)	Deriming Events (#/yr)	Process Gas MW [2] (lb/mole)	Process Gas Content (%) [2]			Emissions									
								Process Gas [1]		VOC		CO_2		CH_4		CO_2e [3]	
					VOC	CO_2	CH_4	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Cryogenic Plant - Existing	1	36	2	17.04	1.47	4.24	89.50	1,843	66	27.09	0.98	78.04	2.81	1,649.21	59.37	41,308.27	1,487.10
Cryogenic Plant - New	1	36	2	17.04	1.47	4.24	89.50	1,843	66	27.09	0.98	78.04	2.81	1,649.21	59.37	41,308.27	1,487.10
Total Deriming Emissions										***54.18***	***1.95***	***156.09***	***5.62***	***3,298.42***	***118.74***	***82,616.54***	***2,974.20***

[1] Volume of 1 mole blowdown gas at standard condition is: **385 scf/mole**

[2] Per gas composition calculation contained in Table A-10.

[3] Global warming potential values obtained from 40 CFR 98 Table A-1

CH_4 GWP = 25

Table A-10. Process Stream Gas Composition

Process Stream Gas Composition	Fuel Gas Mole Fraction [1] (FMF)	Molecular Weight (MW)	Fuel Gas Mass = FMF * MW (lb/mol)	VOC Weight % (NG Based)	CO_2 Weight % (NG Based)	CH_4 Weight % (NG Based)	THC Mass = FMF * MW (lb/mol)	VOC Weight % (THC Based)
N2	0.0029	28.01	0.081	-	-	-	-	-
CO2	0.0164	44.01	0.722	-	4.24	-	-	-
CH4	0.9509	16.04	15.252	-	-	89.50	15.252	-
C2H6	0.0245	30.07	0.737	-	-	-	0.737	-
C3H8	0.0044	44.10	0.194	1.14	-	-	0.194	1.19
iC4H10	0.0003	58.12	0.017	0.10	-	-	0.017	0.11
nC4H10	0.0004	58.12	0.023	0.14	-	-	0.023	0.14
iC5H12	0.0001	72.15	0.007	0.04	-	-	0.007	0.04
nC5H12	0.0000	72.15	0.000	0.00	-	-	0.000	0.00
C6H14	0.0001	86.18	0.009	0.05	-	-	0.009	0.05
Totals	***1.0000***		***17.04***	***1.47***	***4.24***	***89.50***	***16.24***	***1.54***

[1] Process stream gas mole fraction obtained from a gas chromatograph analysis of process stream gas contained in the 1996 permit application.

Table A-11. Refrigerant Loop Gas Composition

Refrigerant Loop Stream Gas Composition	Fuel Gas Mole Fraction [1] (FMF)	Molecular Weight (MW)	Fuel Gas Mass = FMF * MW (lb/mol)	VOC Weight % (NG Based)	CO_2 Weight % (NG Based)	CH_4 Weight % (NG Based)	THC Mass = FMF * MW (lb/mol)	VOC Weight % (THC Based)
N2	0.1200	28.01	3.361	-	-	-	-	-
CO2	0.0000	44.01	0.000	-	0.00	-	-	-
CH4	0.2200	16.04	3.529	-	-	10.05	3.529	-
Ethylene	0.3700	28.05	10.379	29.56	-	-	10.379	32.69
C3H8	0.0900	44.10	3.969	11.31	-	-	3.969	12.50
iC4H10	0.0400	58.12	2.325	6.62	-	-	2.325	7.32
nC4H10	0.0000	58.12	0.000	0.00	-	-	0.000	0.00
iC5H12	0.1600	72.15	11.544	32.88	-	-	11.544	36.36
nC5H12	0.0000	72.15	0.000	0.00	-	-	0.000	0.00
C6H14	0.0000	86.18	0.000	0.00	-	-	0.000	0.00
Totals	***1.0000***		***35.11***	***80.37***	***0.00***	***10.05***	***31.75***	***88.88***

[1] Refrigerant loop gas mole fraction obtained from a gas chromatograph analysis of the refrigerant contained in the 1996 permit application.

Table A-12. Demethanizer Bottoms Gas Composition

Demethanizer Bottoms Gas Composition	Fuel Gas Mole Fraction [1] (FMF)	Molecular Weight (MW)	Fuel Gas Mass = FMF * MW (lb/mol)	VOC Weight % (NG Based)	CO_2 Weight % (NG Based)	CH_4 Weight % (NG Based)	THC Mass = FMF * MW (lb/mol)	VOC Weight % (THC Based)
N2	0.0000	28.01	0.000	-	-	-	-	-
CO2	0.0000	44.01	0.000	-	0.00	-	-	-
CH4	0.0005	16.04	0.008	-	-	0.02	0.008	-
C2H6	0.7525	30.07	22.628	-	-	-	22.628	-
C3H8	0.1910	44.10	8.423	24.40	-	-	8.423	24.40
iC4H10	0.0215	58.12	1.250	3.62	-	-	1.250	3.62
nC4H10	0.0238	58.12	1.383	4.01	-	-	1.383	4.01
iC5H12	0.0034	72.15	0.245	0.71	-	-	0.245	0.71
nC5H12	0.0037	72.15	0.267	0.77	-	-	0.267	0.77
C6H14	0.0036	86.18	0.310	0.90	-	-	0.310	0.90
Totals	***1.0000***		***34.51***	***34.42***	***0.00***	***0.02***	***34.51***	***34.42***

[1] Demethanizer bottoms gas mole fraction obtained from a gas chromatograph analysis of the demethanizer bottoms gas contained in the 1996 permit application.

Table A-13. Fuel Gas Piping Stream Composition

Fuel Gas Piping Stream Composition	Fuel Gas Mole Fraction [1] (FMF)	Molecular Weight (MW)	Fuel Gas Mass = FMF * MW (lb/mol)	VOC Weight % (NG Based)	CO_2 Weight % (NG Based)	CH_4 Weight % (NG Based)	THC Mass = FMF * MW (lb/mol)	VOC Weight % (THC Based)
N2	0.0088	28.01	0.246	-	-	-	-	-
CO2	0.0100	44.01	0.440	-	2.03	-	-	-
CH4	0.6942	16.04	11.135	-	-	51.36	11.135	-
C2H6	0.2190	30.07	6.585	-	-	-	6.585	-
C3H8	0.0524	44.10	2.311	10.66	-	-	2.311	11.01
iC4H10	0.0060	58.12	0.349	1.61	-	-	0.349	1.66
nC4H10	0.0066	58.12	0.384	1.77	-	-	0.384	1.83
iC5H12	0.0010	72.15	0.072	0.33	-	-	0.072	0.34
nC5H12	0.0010	72.15	0.072	0.33	-	-	0.072	0.34
C6H14	0.0010	86.18	0.086	0.40	-	-	0.086	0.41
Totals	***1.0000***		***21.68***	***15.10***	***2.03***	***51.36***	***20.99***	***15.59***

[1] Fuel gas mole fraction obtained from a gas chromatograph analysis of natural gas contained in the 1996 permit application.

ARIZONA LNG - NEEDLE MOUNTAIN GAS PLANT
EMISSION CALCULATIONS

Table A-14. Amine Regenerator Emissions

Emission Unit	Natural Gas Flowrate [1] (MMscf/day)	Maximum CO_2 Content [2] (vol %)	Maximum H_2S Concentration [3] (grain/100 scf)	CO_2 Emissions [4, 5]		H_2S Emissions [5]	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)
Amine Regenerator - Topock I	7.6	2.0	0.25	723.32	3,168.15	0.11	0.50
Amine Regenerator - Topock II	7.6	2.0	0.25	723.32	3,168.15	0.11	0.50
Totals				***1,447***	***6,336***	***0.23***	***0.99***

[1] Maximum daily flowrate for each unit acquired from the 1996 permit application and assumes Topock II unit will have the same flowrate as the Topock I unit.

[2] Maximum CO_2 content per 1996 permit application.

[3] Maximum H_2S concentration based on tariff limit.

[4] Molecular weight of CO_2 gas is : 44.01 lb/mol

[5] Volume of 1 mole natural gas at standard condition is: 385 scf/mole

Table A-15. Compressor Seal Emissions

Emission Unit	Seal Vent Flowrate	Concentration [1]			Emissions							
		VOC	CO_2	CH_4	VOC [2, 3]		CO_2 [2, 3]		CH_4 [2, 3]		CO_2e [4]	
	(scfm)	(wt %)	(wt %)	(wt %)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Gas Compressor - Topock I	3	80.37	0.00	10.05	13.00	56.94	0.00	0.00	1.63	7.12	40.65	178.03
Gas Compressor - Topock II	3	80.37	0.00	10.05	13.00	56.94	0.00	0.00	1.63	7.12	40.65	178.03
Totals					***26.00***	***113.88***	***0.00***	***0.00***	***3.25***	***14.24***	***81.29***	***356.06***

[1] Refrigerant loop gas mole fraction obtained from a gas chromatograph analysis of the refrigerant contained in the 1996 permit application.

[2] Molecular weight of compressor seal gas is : 34.63 lb/lb-mol

[3] Volume of 1 mole blowdown gas at standard condition is: 385 scf/lb-mol

[4] Global warming potential values obtained from 40 CFR 98 Table A-1

CH_4 GWP = 25

ARIZONA LNG - NEEDLE MOUNTAIN GAS PLANT
EMISSION CALCULATIONS

Table A-16. Needle Mountain Gas Plant - Site-Wide Emissions Summary - Hourly

Emission Unit		Site-Wide Hourly Emissions (lb/hr)							
		$PM_{10}/PM_{2.5}$	**NO_x**	**CO**	**VOC**	**SO_2**	**H_2S**	**Formaldehyde**	**CO_2e**
Topock I	Solar Centaur Gas Turbine	0.90	23.11	4.69	0.54	2.57	-	0.12	5,027
	Process Fugitives	-	-	-	3.95	-	-	-	50
	Initial Start Up/Plant Purge	-	-	-	54.18	-	-	-	82,617
	Engine Start-up Blowdown	-	-	-	4.68	-	-	-	7,138
	Deriming	-	-	-	27.09	-	-	-	41,308
	Amine Regenerator	-	-	-	-	-	0.11	-	723
	Compressor Seal	-	-	-	13.00	-	-	-	40.65
	Totals	***0.90***	***23.11***	***4.69***	***103.45***	***2.57***	***0.11***	***0.12***	**136,904**
Topock II	Solar Centaur Gas Turbine	0.90	23.11	4.69	0.54	2.57	-	0.12	5,027
	Process Fugitives	-	-	-	3.95	-	-	-	50
	Initial Start Up/Plant Purge	-	-	-	54.18	-	-	-	82,617
	Engine Start-up Blowdown	-	-	-	4.68	-	-	-	7,138
	Deriming	-	-	-	27.09	-	-	-	41,308
	Amine Regenerator	-	-	-	-	-	0.11	-	723
	Compressor Seal	-	-	-	13.00	-	-	-	40.65
	Totals	***0.90***	***23.11***	***4.69***	***103.45***	***2.57***	***0.11***	***0.12***	**136,904**
Site-Wide Total Emissions		***1.80***	***46.22***	***9.38***	***206.89***	***5.14***	***0.23***	***0.25***	**273,808**

ARIZONA LNG - NEEDLE MOUNTAIN GAS PLANT
EMISSION CALCULATIONS

Table A-17. Needle Mountain Gas Plant - Site-Wide Emissions Summary - Annual

Emission Unit		Site-Wide Annual Emissions (tpy)							
		$PM_{10}/PM_{2.5}$	NO_x	CO	VOC	SO_2	H_2S	Formaldehyde	CO_2e
Topock I	Solar Centaur Gas Turbine	3.94	101.22	20.54	2.37	11.26	-	0.54	22,019
	Process Fugitives	-	-	-	17.29	-	-	-	218
	Initial Start Up/Plant Purge	-	-	-	2.60	-	-	-	3,966
	Engine Start-up Blowdown	-	-	-	0.28	-	-	-	428
	Deriming	-	-	-	0.98	-	-	-	1,487
	Amine Regenerator	-	-	-	-	-	0.50	-	3,168
	Compressor Seal	-	-	-	56.94	-	-	-	178.03
	Totals	***3.94***	***101.22***	***20.54***	***80.46***	***11.26***	***0.50***	***0.54***	**31,464**
Topock II	Solar Centaur Gas Turbine	3.94	101.22	20.54	2.37	11.26	-	0.54	22,019
	Process Fugitives	-	-	-	17.29	-	-	-	218
	Initial Start Up/Plant Purge	-	-	-	2.60	-	-	-	3,966
	Engine Start-up Blowdown	-	-	-	0.28	-	-	-	428
	Deriming	-	-	-	0.98	-	-	-	1,487
	Amine Regenerator	-	-	-	-	-	0.50	-	3,168
	Compressor Seal	-	-	-	56.94	-	-	-	178.03
	Totals	***3.94***	***101.22***	***20.54***	***80.46***	***11.26***	***0.50***	***0.54***	***31,464***
Site-Wide Total Emissions		***7.88***	***202.44***	***41.08***	***160.91***	***22.51***	***0.99***	***1.08***	***62,929***
Non-Fugitive Total Emissions		***7.88***	***202.44***	***41.08***	***4.73***	***22.51***	***0.99***	***1.08***	***50,375***
Proposed Site-Wide Emission Cap		***-***	***220.00***	***-***	***-***	***-***	***-***	***-***	***-***

Table A-18. Needle Mountain Gas Plant - Emission Sources

Regulated Air Pollutant Data					Emission Point Discharge Parameters									
Emission Point [1]		Chemical Composition of Total Stream	Air Pollutant Emissions Rate		UTM Coordinates of Emission Point [5]			Stack Sources [6]					Non Point	
Number	Name	Regulated Air Pollutant Name [2]	#/hr [3]	Tons/ year [4]	Zone	East (Mtrs)	North (Mtrs)	Height Above Ground (feet)	Height Above Struc (feet)	Exit Data			Sources [7]	
										Dia (ft)	Vel (fps)	Temp (°F)	Length (ft)	Width (ft)
ST-1	Solar Centaur 40 T4700	$PM_{10}/PM_{2.5}$	0.90	3.94	11	732,235	3,845,651	36.00	N/A	4	64.2	600	N/A	N/A
		NOx	23.11	101.22										
		CO	4.69	20.54										
		VOC	0.54	2.37										
		SO_2	2.57	11.26										
		Formaldehyde	0.12	0.54										
		CO_2e	5,027	22,019										
ST-1	Solar Centaur 40 T4700	$PM_{10}/PM_{2.5}$	0.90	3.94	11	732,235	3,845,651	36.00	N/A	4	64.2	600	N/A	N/A
		NOx	23.11	101.22										
		CO	4.69	20.54										
		VOC	0.54	2.37										
		SO_2	2.57	11.26										
		Formaldehyde	0.12	0.54										
		CO_2e	5,027	22,019										
FUG-1	Process Fugitives	VOC	3.95	17.29	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FUG-2	Process Fugitives	VOC	3.95	17.29	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
MSS-1	MSS Emissions	VOC	85.96	3.86	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		CO_2e	131,063	5,881										
MSS-2	MSS Emissions	VOC	85.96	3.86	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		CO_2e	131,063	5,881										
AR-1	Amine Regenerator	H_2S	0.11	0.50	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		CO_2e	723	3,168										
AR-2	Amine Regenerator	H_2S	0.11	0.50	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		CO_2e	723	3,168										
CS-1	Compressor Seal	VOC	13.00	56.94	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		CO_2e	40.65	178.03										
CS-2	Compressor Seal	VOC	13.00	56.94	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		CO_2e	40.65	178.03										

Ground Elevation of Facility Above Mean Sea Level ≈ 650 ft

Table A-19. Needle Mountain Gas Plant - Equipment List

Type of Equipment	Maximum Rated Capacity	Make	Model	Serial Number	Date of Manufacture/Install	Equipment ID Number
Gas Turbine	4,079 hp	Solar Centaur 40	T4700	OHL19-C0598	Dec-2019 / 19-Jan-2020	EC47RC-C8G00000
Gas Turbine	4,079 hp	Solar Centaur 40	T4700	OHD20-C6626	Apr-2020 / 03-May-2020	EC47RC-C8G00000

APPENDIX B. MANUFACTURER'S DOCUMENTATIONS

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer: *ALT LNG*	Model: CENTAUR 40-4700
	Package Type: CS/MD
Job ID: Arizona LNG predicted emissions	Match: HI-AMBIENT
Run By: Leo M Merk — Date Run: 21-Dec-11	Fuel System: GAS
Engine Performance Code: REV. 3.54 — Engine Performance Data: REV. 3.1	Fuel Type: SD NATURAL GAS

DATA FOR NOMINAL PERFORMANCE

Elevation	feet	200
Inlet Loss	in H2O	3.0
Exhaust Loss	in H2O	4.0
Accessory on GP Shaft	HP	14.0

		1	2	3
Engine Inlet Temperature	deg F	59.0	80.0	110.0
Relative Humidity	%	60.0	60.0	60.0
Driven Equipment Speed	RPM	15500	15500	15248
Specified Load	HP	FULL	FULL	FULL
Net Output Power	HP	4294	4079	3604
Fuel Flow	mmBtu/hr	40.43	38.93	36.11
Heat Rate	Btu/HP-hr	9415	9545	10020
Therm Eff	%	27.026	26.656	25.394
Engine Exhaust Flow	lbm/hr	148573	141637	129601
PT Exit Temperature	deg F	817	846	886
Exhaust Temperature	deg F	817	846	886

Fuel Gas Composition (Volume Percent)

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

Fuel Gas Properties

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

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

Solar Turbines

A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer: ALT LNG	Engine Model: CENTAUR 40-4700 CS/MD HI-AMBIENT
Job ID: Arizona LNG predicted emissions	
Inquiry Number: DN11-0017	Fuel Type: SD NATURAL GAS — Water Injection: NO
Run By: Leo M Merk — Date Run: 21-Dec-11	Engine Emissions Data: REV. 1.2

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 4294 HP 100.0% Load — Elev. 200 ft — Rel. Humidity 60.0% — Temperature 59.0 Deg. F			
PPMvd at 15% O2	165.00	50.00	50.00
ton/yr	116.41	21.48	12.30
lbm/MMBtu (Fuel LHV)	0.657	0.121	0.069
lbm/(MW-hr) (gas turbine shaft pwr)	8.30	1.53	0.88
lbm/hr	26.58	4.90	2.81
2 — 4079 HP 100.0% Load — Elev. 200 ft — Rel. Humidity 60.0% — Temperature 80.0 Deg. F			
PPMvd at 15% O2	165.00	50.00	50.00
ton/yr	111.36	20.54	11.77
lbm/MMBtu (Fuel LHV)	0.653	0.120	0.069
lbm/(MW-hr) (gas turbine shaft pwr)	8.36	1.54	0.88
lbm/hr	25.42	4.69	2.69
3 — 3604 HP 100.0% Load — Elev. 200 ft — Rel. Humidity 60.0% — Temperature 110.0 Deg. F			
PPMvd at 15% O2	165.00	50.00	50.00
ton/yr	101.19	18.67	10.69
lbm/MMBtu (Fuel LHV)	0.640	0.118	0.068
lbm/(MW-hr) (gas turbine shaft pwr)	8.60	1.59	0.91
lbm/hr	23.10	4.26	2.44

Notes

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

Particulate Matter Emission Estimates

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

Since particulate matter is a regulated pollutant, most air permitting agencies require customers to provide particulate matter emission estimates during the air permitting process. In addition, many air permit agencies require dispersion modeling analyses for particulate matter. More and more often, regulatory agencies are including a particulate matter compliance testing requirement in the air permit.

This document summarizes Solar's recommended $PM_{10/2.5}$ emission levels for our combustion turbines. The recommended levels are based on an analysis of emissions tests collected from customer sites.

Particulate Matter Definition

National Ambient Air Quality Standards (NAAQS) for particulate matter were first set in 1971. Total suspended particulate (TSP) was the first indicator used to represent suspended particles in the ambient air. Since July 1, 1987, the Environmental Protection Agency (EPA) has used the indicator PM_{10}, which includes only the particles with aerodynamic diameter smaller than 10 micrometers. PM_{10} (coarse particles) come from sources such as windblown dust from the desert or agricultural fields and dust kicked up on unpaved roads by vehicle traffic.

The EPA added a $PM_{2.5}$ ambient air standard in 1997. $PM_{2.5}$ includes particles with an aerodynamic diameter less than 2.5 micrometers. $PM_{2.5}$ (fine particles) are generally emitted from activities such as industrial and residential combustion and from vehicle exhaust. Fine particles are also formed in the atmosphere when gases such as sulfur dioxide, nitrogen oxides, and volatile organic compounds, emitted by combustion activities, are transformed by chemical reactions.

Nearly all particulate matter from gas turbine exhaust is less than one micrometer (micron) in diameter. Thus the emission rates of TSP, PM_{10}, and $PM_{2.5}$ from gas turbines are theoretically equivalent although source testing will show significant variation due to test method detection levels and processes.

TESTING FOR PARTICULATE MATTER

The turbine combustion process has little effect on the particulate matter generated and measured. The largest contributor to particulate matter emissions for gas and liquid fired combustion turbines is measurement technique and error. Other, minor contributing, sources of particulate matter emissions include carbon, ash, fuel-bound sulfur, artifact sulfate formation, compressor/lubricating oils, and inlet air.

Historical customer particulate matter source test data show that there is significant variability from test to test. The source test results support the common industry argument that particulate matter from natural gas fired combustion sources is difficult to measure accurately. The reference test methods for particulate matter were developed primarily for measuring emissions from coal-fired power plants and other major emitters of particulates. Particulate concentrations from gas turbine can be 100 to 10,000 times lower than the "traditional" particulate sources. The test methods were not developed or verified for low emission levels. There

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are interferences, insignificant at higher exhaust particulate matter concentrations that result in emissions greater than the actual emissions from gas turbines. New methods are being developed to address this problem.

Due to measurement and procedural errors, the measured results, in most cases, may not be representative of actual particulate matter emitted. There are many potential error sources in measuring particulate matter. Most of these have to do with contamination of the samples, material from the sampling apparatus getting into the samples, and general sloppiness in samples and analysis.

Recommended Particulate Matter Emission Factors

When necessary to support the air permitting process Solar recommends using a $PM_{10/2.5}$ emission factor of 0.021 lb/MMBtu fuel input (HHV) for natural gas. For landfill gas, the recommended emission factor is 0.03 lb/MMBtu fuel input (HHV). For liquid fuel, the recommended emission factor is 0.06 lb/MMBtu fuel input (HHV). The liquid fuel emission factor assumes fuel sulfur content is <500 ppm and ash content is <0.005% by wt.

The emission levels cited above are only for engine operation with the fuels listed. Other fuels many not yield similar results.

At this time, Solar does not recommend using AP-42 (EPA AP-42 "Compilation of Air Pollutant Emission Factors.") AP-42. While some source tests have had similar results to AP-42, others are higher.

Test Method Recommendation

For customers who conduct emission source tests for particulate matter, Solar recommends that EPA Methods 201/201A[1] be used to measure the “front half”. “Front half” represents filterable particulate matter.

EPA Method 202[2] (with nitrogen purge and field blanks) should be used to measure the “back half”. “Back half” measurements represent the condensable portion of particulate matter.

EPA Method 5[3], which measures the front and back halves may be substituted (e.g. where exhaust temperatures do not allow the use of Method 202).

Testing should include three test runs of 4 hours each.

Solar recommends using the aforementioned test methods until more representative test methods are developed and made commercially available.

References

[1] EPA Method 201, Determination of PM10 Emissions, Exhaust Gas Recycle Procedure. EPA Method 201A, Determination of PM10 Emissions, Constant Sampling Rate Procedure, 40 CFR 60, Part 60, Appendix A.

[2] EPA Method 202, Determination of Condensible Particulate Emissions from Stationary Sources, 40 CFR 60, Part 60, Appendix A.

[3] EPA Method 5, Determination of Particulate Emissions from Stationary Sources, 40 CFR 60, Part 60, Appendix

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Volatile Organic Compound, Sulfur Dioxide, and Formaldehyde Emission Estimates

Leslie Witherspoon
Solar Turbines Incorporated

PURPOSE

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

INTRODUCTION

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

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

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

Volatile Organic Compounds

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

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

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

Sulfur Dioxide

Sulfur dioxide emissions are produced by conversion of sulfur in the fuel to SO_2. Since Solar does not control the amount of sulfur in the fuel, we are unable to generically predict SO_2 emissions. Customers generally estimate SO_2 emissions with a mass balance calculation by assuming that any sulfur in the fuel will convert to SO_2. For reference, the typical mass balance equation is shown below.

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

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

As an alternative to a mass balance calculation, EPA's AP-42 document can be used. AP-42 (Table 3.1-2a, April 2000) suggests emission factors of 0.0034 lb/MMBtu for gas fuel (HHV*) and 0.033 lb/MMBtu for liquid fuel (HHV).

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

Formaldehyde

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

- Ambient temperature
- Humidity
- Atmospheric pressure
- Fuel quality
- Formaldehyde concentration in the ambient air
- Test method measurement variability
- Operational factors

The emission factor data in Table 1 is an excerpt from an EPA memo: "Revised HAP Emission Factors for Stationary Combustion Turbines, 8/22/03." The memo presents hazardous air pollutant (HAP) emission factor data in several categories including: mean, median, maximum, and minimum. The emission factors in the memo are a compilation of the HAP data EPA collected during the Maximum Achievable Control Technology (MACT) standard development process. The emission factor documentation shows there is a high degree of variability in formaldehyde emissions from gas turbines, depending on the manufacturer, rating size of equipment, combustor design, and testing events. To estimate formaldehyde emissions from gas turbines, users should use the emission factor(s) that best represent the gas turbines actual / planned operating profile. Refer to the memo for alternative emission factors.

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

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

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

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APPENDIX C. AERSCREEN MODELING ANALYSIS

ARIZONA LNG - NEEDLE MOUNTAIN GAS PLANT
MODELING ANALYSIS

Table C-1. Needle Mountain Gas Plant - Modeling Parameters [1]

Equipment	Stack					Distance to Property Line	Flow Rate
	Height (ft)	Diameter (in)	Velocity (ft/sec)	Temperature (°F)	Temperature Above Ambient (°F)	(ft)	(acfm)
Solar Centaur Gas Turbine	36.00	48.00	64.2	600	530	55	48,406

[1] Modeling Parameters per February 1996 standard permit application for Needle Mountain Gas Plant.

Table C-2. Needle Mountain Gas Plant - AERSCREEN Modeling Parameters

Parameter	Value
Topography	Rural
NO_2 Chemistry Modeling	None
Building Downwash	None
Terrain Height	Flat
Source Elevation	0 m (Default)
Minimum Temperature [1]	26 °F
Maximum Temperature [1]	111 °F
Wind Speed	0.5 m/s (Default)
Anemometer Height	10 m (Default)
Surface Characteristics	AERMET Seasonal Tables (Desert Shrubland, Dry)

[1] Minimum and maximum temperature obtained from wunderground.com for the time period of 10/6/2009 - 10/6/2010

Table C-3. Needle Mountain Gas Plant - Normalized Maximum Concentrations [1]

Equipment	Max Concentration ($\mu g/m^3$ per lb/hr)				
	1-Hour	3-Hour	8-Hour	24-Hour	Annual
Solar Centaur Gas Turbine	5.4	4.8	3.8	2.1	0.4

[1] 1-hour concentrations obtained from AERSCREEN using an emission rate of 1 lb/hr for each source

All other concentration are based off the 1-hour concentrations using the following conversion factors per ADEQ Modeling Guidelines

3- Hour: 0.9 24-Hour: 0.4

8-Hour: 0.7 Annual: 0.08

Property
Line

Table C-4. Modeled Concentration

Equipment	Maximum Impact ($\mu g/m^3$)								
	PM_{10}	$PM_{2.5}$		NOx	SO_2			CO	
	24-Hour	24-Hour	Annual	Annual	3-Hour	24-Hour	Annual	1-Hour	8-Hour
Solar Centaur Gas Turbine	2.1	2.1	0.4	2.7	13.2	5.9	1.2	26.8	18.8

Note - Please see update to Table C-4 on next page.

ARIZONA LNG - NEEDLE MOUNTAIN GAS PLANT
MODELING ANALYSIS

Update to Table C-4. Modeled Concentration - 1-hr NO_2

Equipment	Maximum Impact ($\mu g/m^3$)	
	NO_2	
	1-Hour (Tier 1)	1-Hour (Tier 2)
Solar Centaur Gas Turbine	124	99

Table C-5. Needle Mountain Gas Plant - Summary of Background Concentrations [1, 2, 3, 4]

Pollutant	Averaging Period	Selected Monitor Site			Distance Between Monitor Site & Facility (mile)	Selected Background Concentration ($\mu g/m^3$)
		EPA ID	County	ADEQ ID		
SO_2	3-hour	040278011	Yuma	Yuma Supersite	140	39.3
	24-hour	040278011	Yuma	Yuma Supersite	140	13.1
	Annual	040139997	Maricopa	JLG Supersite	160	6.6
NO_x	Annual	040133010	Maricopa	Greenwood	160	53.2
CO	1-hour	040130016	Maricopa	West Indian School	158	6,928
	8-hour	040130016	Maricopa	West Indian School	158	5,587
PM_{10}	24-hour	040151003	Mohave	Bullhead City	30	56.7
$PM_{2.5}$	24-hour	040270004	Yuma	Apache Junction Fire Station	192	13.1
	Annual	040270004	Yuma	Apache Junction Fire Station	192	6.6

[1] All background concentration values were obtained from EPA AirData.

[2] Per ADEQ Air Dispersion Modeling Guidelines for Arizona Air Quality Permits (December 2004), the average background concentration between 2006 and 2008 was selected for PM10.

[3] Per EPA memorandum "Modeling Procedures for Demonstrating Compliance with PM2.5 NAAQS" dated March 23, 2010, for annual averaging period, the 3-year average of the annual average PM2.5 concentrations were used as the background concentration; For 24-hour averaging period, the 3-year average of the 98th percentile 24-hour PM2.5 concentrations were used as the background concentration.

[4] Per ADEQ Air Dispersion Modeling Guidelines for Arizona Air Quality Permits (December 2004), the maximum background concentration between 2006 and 2008 was selected for pollutants other than PM10 and PM2.5.

Note - Please see update to Table C-5 on next page.

ARIZONA LNG - NEEDLE MOUNTAIN GAS PLANT
MODELING ANALYSIS

Update to Table C-5. Needle Mountain Gas Plant - Summary of Background Concentrations - 1-hr NO_2 [1]

Pollutant	Averaging Period	Selected Monitor Site			Selected Background Concentration ($\mu g/m^3$)
		EPA ID	County	Site ID	
NOx	1-hour	350290003	Luna	Deming	59

[5] Per email from Feng Mao (ADEQ_ to Eddie Al-Rayes (Trinity) on October 23, 2012, the Demin NM monitor station is relatively representative of the ambient NO_2 around the Needle Mountain Gas Plant site.

Table C-6. Needle Mountain Gas Plant - AERSCREEN Modeling Summary

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Modeled + Background ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Exceed NAAQS?
PM_{10}	24-Hour	2.1	56.7	59	150	No
$PM_{2.5}$	Annual	0.4	6.6	7.0	15	No
	24-Hour	2.1	13.1	15.2	35	No
SO_2	3-Hour	13.2	39.3	52.5	1,300	No
	24-Hour	5.9	13.1	19.0	365	No
	Annual	1.2	6.6	7.7	80	No
NOx	Annual	2.7	53.2	56	100	No
CO	8-Hour	18.8	5,587	5,606	10,000	No
	1-Hour	26.8	6,928	6,955	40,000	No

Note - Please see update to Table C-6 on next page.

ARIZONA LNG - NEEDLE MOUNTAIN GAS PLANT
MODELING ANALYSIS

Updates to Table C-6. Needle Mountain Gas Plant - AERSCREEN Modeling Summary - 1-hr NO_2

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Modeled + Background ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Exceed NAAQS?
NOx	1-hour	99	59	158	188	No

```
AERSCREEN 11126 / AERMOD  1110                                          04/25/12
                                                                        12:38:43

TITLE: Turbine


 ---------------------------------------------------------------------------
 ****************************  STACK PARAMETERS  ****************************
 ---------------------------------------------------------------------------

 SOURCE EMISSION RATE:            0.1260 g/s                 1.000 lb/hr
 STACK HEIGHT:                     10.97 meters              36.00 feet
 STACK INNER DIAMETER:             1.219 meters              48.00 inches
 PLUME EXIT TEMPERATURE:           294.4 K above ambient     530.0 Deg F above
ambient
 PLUME EXIT VELOCITY:             19.568 m/s                 64.20 ft/s
 STACK AIR FLOW RATE:              48406 ACFM
 RURAL OR URBAN:                   RURAL

 INITIAL PROBE DISTANCE =          5000. meters             16404. feet


 ---------------------------------------------------------------------------
 ************************  BUILDING DOWNWASH PARAMETERS  **********************
 ---------------------------------------------------------------------------

         NO BUILDING DOWNWASH HAS BEEN REQUESTED FOR THIS ANALYSIS


 **************************  PROBE ANALYSIS  **************************
                 25 meter receptor spacing: 5. meters - 5000. meters

     Zo       ROUGHNESS       1-HR CONC   DIST      TEMPORAL
     SECTOR     LENGTH         (ug/m3)     (m)       PERIOD
     ---------------------------------------------------------------------
      1*         0.300         5.358        75.0      SPR
 * = worst case flow sector


 ---------------------------------------------------------------------------
 **********************  MAKEMET METEOROLOGY PARAMETERS  *********************
 ---------------------------------------------------------------------------

 MIN/MAX TEMPERATURE:    269.8 / 317.0 (K)

 MINIMUM WIND SPEED:       0.5 m/s

 ANEMOMETER HEIGHT:     10.000 meters

 SURFACE CHARACTERISTICS INPUT: AERMET SEASONAL TABLES

 DOMINANT SURFACE PROFILE: Desert Shrubland
 DOMINANT CLIMATE TYPE:    Dry Conditions
 DOMINANT SEASON:          Spring

 ALBEDO:                  0.30
 BOWEN RATIO:             5.00
 ROUGHNESS LENGTH:       0.300 (meters)
```

METEOROLOGY CONDITIONS USED TO PREDICT OVERALL MAXIMUM IMPACT

YR	MO	DY	JDY	HR
10	05	28	28	01

H0	U*	W*	DT/DZ	ZICNV	ZIMCH	M-O LEN	Z0	BOWEN	ALBEDO	REF WS
-64.00	2.051	-9.000	0.020	-999.	4000.	8888.0	0.300	5.00	0.30	18.00

HT	REF TA	HT
10.0	317.0	2.0

ESTIMATED FINAL PLUME HEIGHT (non-downwash): 13.8 meters

METEOROLOGY CONDITIONS USED TO PREDICT AMBIENT BOUNDARY IMPACT

YR	MO	DY	JDY	HR
10	01	05	28	12

H0	U*	W*	DT/DZ	ZICNV	ZIMCH	M-O LEN	Z0	BOWEN	ALBEDO	REF WS
17.90	0.081	0.300	0.020	50.	53.	-2.5	0.150	10.00	0.45	0.50

HT	REF TA	HT
10.0	269.8	2.0

ESTIMATED FINAL PLUME HEIGHT (non-downwash): 152.3 meters

********** AERSCREEN AUTOMATED DISTANCES **********

OVERALL MAXIMUM CONCENTRATIONS BY DISTANCE

DIST (m)	MAXIMUM 1-HR CONC (ug/m3)	DIST (m)	MAXIMUM 1-HR CONC (ug/m3)
4.57	0.4401E-01	2525.00	0.5482
25.00	0.3910	2550.00	0.5449
50.00	2.384	2575.00	0.5417
75.00	5.358	2600.00	0.5384
100.00	4.951	2625.00	0.5353
125.00	4.499	2650.00	0.5321
150.00	3.974	2675.00	0.5290
175.00	3.501	2700.00	0.5259
200.00	3.313	2725.00	0.5229
225.00	3.051	2750.00	0.5199
250.00	2.765	2775.00	0.5169
275.00	2.487	2800.00	0.5139
300.00	2.233	2825.00	0.5110
325.00	2.006	2850.00	0.5081
350.00	1.852	2875.00	0.5052

375.00	1.771	2900.00	0.5024
400.00	1.684	2925.00	0.4996
425.00	1.595	2950.00	0.4968
450.00	1.508	2975.00	0.4941
475.00	1.424	3000.00	0.4913
500.00	1.343	3025.00	0.4887
525.00	1.268	3050.00	0.4860
550.00	1.202	3075.00	0.4834
575.00	1.149	3100.00	0.4807
600.00	1.098	3125.00	0.4782
625.00	1.050	3150.00	0.4756
650.00	1.004	3175.00	0.4731
675.00	0.9603	3200.00	0.4706
700.00	0.9190	3225.00	0.4681
725.00	0.8800	3250.00	0.4656
750.00	0.8431	3275.00	0.4632
775.00	0.8083	3300.00	0.4608
800.00	0.7961	3325.00	0.4584
825.00	0.8029	3350.00	0.4561
850.00	0.8082	3375.00	0.4538
875.00	0.8123	3400.00	0.4514
900.00	0.8157	3425.00	0.4492
925.00	0.8185	3450.00	0.4469
950.00	0.8203	3475.00	0.4447
975.00	0.8214	3500.00	0.4424
1000.00	0.8217	3525.00	0.4402
1025.00	0.8213	3550.00	0.4381
1050.00	0.8203	3575.00	0.4359
1075.00	0.8187	3600.00	0.4338
1100.00	0.8166	3625.00	0.4317
1125.00	0.8140	3650.00	0.4296
1150.00	0.8111	3675.00	0.4275
1175.00	0.8077	3700.00	0.4255
1200.00	0.8040	3725.00	0.4234
1225.00	0.8000	3750.00	0.4214
1250.00	0.7957	3775.00	0.4194
1275.00	0.7911	3800.00	0.4174
1300.00	0.7863	3825.00	0.4155
1325.00	0.7813	3850.00	0.4136
1350.00	0.7762	3875.00	0.4116
1375.00	0.7709	3900.00	0.4097
1400.00	0.7654	3925.00	0.4078
1425.00	0.7598	3950.00	0.4060
1450.00	0.7541	3975.00	0.4041
1475.00	0.7482	4000.00	0.4023
1500.00	0.7422	4025.00	0.4005
1525.00	0.7361	4050.00	0.3987
1550.00	0.7298	4075.00	0.3969
1575.00	0.7234	4100.00	0.3951
1600.00	0.7168	4125.00	0.3934
1625.00	0.7105	4150.00	0.3916
1650.00	0.7045	4175.00	0.3899
1675.00	0.6986	4200.00	0.3882
1700.00	0.6927	4225.00	0.3865
1725.00	0.6869	4250.00	0.3848
1750.00	0.6812	4275.00	0.3832
1775.00	0.6755	4300.00	0.3815
1800.00	0.6699	4325.00	0.3799
1825.00	0.6643	4350.00	0.3783
1850.00	0.6589	4375.00	0.3767
1875.00	0.6534	4400.00	0.3751
1900.00	0.6481	4425.00	0.3735
1925.00	0.6428	4450.00	0.3719

1950.00	0.6376	4475.00	0.3704
1975.00	0.6325	4500.00	0.3688
2000.00	0.6274	4525.00	0.3673
2025.00	0.6224	4550.00	0.3658
2050.00	0.6175	4575.00	0.3643
2075.00	0.6128	4600.00	0.3628
2100.00	0.6089	4625.00	0.3613
2125.00	0.6051	4650.00	0.3602
2150.00	0.6013	4675.00	0.3593
2175.00	0.5975	4700.00	0.3584
2200.00	0.5938	4725.00	0.3575
2225.00	0.5901	4750.00	0.3566
2250.00	0.5864	4775.00	0.3557
2275.00	0.5828	4800.00	0.3548
2300.00	0.5792	4825.00	0.3539
2325.00	0.5756	4850.00	0.3530
2350.00	0.5721	4875.00	0.3521
2375.00	0.5685	4900.00	0.3512
2400.00	0.5651	4925.00	0.3503
2425.00	0.5616	4950.00	0.3494
2450.00	0.5582	4975.00	0.3485
2475.00	0.5548	5000.00	0.3476
2500.00	0.5515		

********** AERSCREEN MAXIMUM IMPACT SUMMARY **********

CALCULATION PROCEDURE	MAXIMUM 1-HOUR CONC (ug/m3)	SCALED 3-HOUR CONC (ug/m3)	SCALED 8-HOUR CONC (ug/m3)	SCALED 24-HOUR CONC (ug/m3)	SCALED ANNUAL CONC (ug/m3)
FLAT TERRAIN	5.360	5.360	4.824	3.216	0.5360

DISTANCE FROM SOURCE 76.00 meters

IMPACT AT THE AMBIENT BOUNDARY	0.4401E-01	0.4401E-01	0.3961E-01	0.2641E-01	0.4401E-02

DISTANCE FROM SOURCE 4.57 meters