INDECK NILES, LLC • 600 NORTH BUFFALO GROVE ROAD • SUITE 300 • BUFFALO GROVE, ILLINOIS 60089
847/520-3212 • FAX: 847/520-9883

Rex Lane
EGLE – Air Quality Division
Kalamazoo District Office
7953 Adobe Road
Kalamazoo, Michigan 49009

December 5, 2022

RE: Initial Renewable Operating Permit (ROP) Application
Indeck Niles Energy Center – Indeck Niles, LLC (SRN: N6921)

Dear Mr. Lane:

Indeck Niles, LLC (Indeck) is submitting the enclosed Renewable Operating Permit (ROP) Application and supporting materials for our facility located at 2200 Progressive Drive in Niles, Cass County, Michigan. Indeck operates a natural gas combined-cycle combustion turbine facility that operates in accordance with Permit to Install (PTI) No. 75-16B. Indeck commenced operation as a major stationary source on December 28, 2021 at the commencement of trial operation of the combined-cycle CTG units EUCTGHRSG1 and 2.

Since issuance of 75-16B and commissioning of the facility, Indeck submitted a PTI application on October 18, 2022 to amend PTI No. 75-16B to incorporate reductions and minor changes to equipment capacities and regulatory requirements associated with ancillary equipment including EUAUXBOILER, EUFUELHTR1, EUFUELHTR2, and EUEMENGINE, including a correction to the nameplate capacity at EUEMENGINE. We also proposed the removal of equipment that was not installed at the facility, including the space heaters and fire pump engine. Upon issuance of the amended PTI, the equipment changes will be incorporated into the ROP application.

Source and Regulatory Overview

In accordance with Rule 211, Indeck is required to obtain a ROP as the facility has the potential to emit in excess of 100 tpy of NO_x, CO, PM_{10}, $PM_{2.5}$, SO_2 and VOC and is subject to the acid rain program codified as 40 CFR Part 72. Indeck is also considered a major stationary source in accordance with the Prevention of Significant Deterioration (PSD) regulations, as specified in State of Michigan Air Pollution Control Rule 1802. The plant is considered an area (i.e., minor) source of hazardous air pollutants (HAPs) since individual HAPs are less than 10 tons per year (tpy) and total aggregate HAPs are less than 25 tpy.

Indeck's equipment is subject to the following regulatory standards that have been incorporated into the PTI and/or will be listed in the ROP.

- New Source Performance Standards (NSPS) for Stationary Combustion Turbines – 40 CFR Part 60 Subpart KKKK
- NSPS for Electric Utility Generating Units (EGU) – 40 CFR Part 60 Subpart TTTT
- NSPS for Industrial-Commercial-Institutional Steam Generating Units – 40 CFR Part 60 Subparts Dc and Db
- NSPS for Stationary Compression Ignition Internal Combustion Engines – 40 CFR Part 60 Subpart IIII

- National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines – 40 CFR Part 63 Subparts A and ZZZZ
- Acid Rain Program – 40 CFR Part 72
- Continuous Emission Monitoring – 40 CFR Part 75
- Cross-State Air Pollution Rule (CSAPR) – 40 CFR Part 97

Since the facility is an area source of HAPs, there are not applicable requirements under the federal NESHAP for the auxiliary boiler or CTGs. Specifically, there are not applicable requirements under 40 CFR Part 63 Subpart JJJJJJ for the gas-fired auxiliary boiler or 40 CFR Part 63 Subpart YYYY for the combined-cycle natural gas-fired CTG/HRSG.

According to PTI No. 75-16B, Indeck is required to maintain a Malfunction Abatement Plan (MAP) and Startup, Shutdown, and Malfunction (SSM) Plan for FGCTGHRSG and EUAUXBOILER. Additionally, the CTG/HRSG trains are subject to an emission limit for VOC that is not exempt under 40 CFR §64.2(b)(1), use oxidation catalysts to achieve compliance with the VOC emission limit of 4 ppmvd at 15% O_2, and have potential pre-control emission of VOC greater than the major source threshold of 100 tons per year (tpy); therefore, Indeck is required to maintain a Compliance Assurance Monitoring (CAM) plan for VOC at the CTG/HRSGs. The facility plans are included as Appendix C.

The facility CTG/HRSGs are regulated in accordance with 40 CFR Part 72 Acid Rain Program. An initial application was submitted to U.S. EPA on [November 7, 2019] and a copy of this application is also enclosed in Appendix D.

This ROP Application is being submitted to satisfy the requirements of the State of Michigan Air Pollution Control Rule 210 that requires new major sources to submit an initial ROP application within 12 months after the source commences operation as a major source. As previously stated, Indeck commenced operation as a major stationary source on December 28, 2021 at the commencement of trial operation of the combined-cycle CTG units EUCTGHRSG1 and 2; an application is due by December 28, 2022. Indeck has prepared this ROP Application using EGLE's Initial ROP Application Forms (enclosed), along with the certification form (C-001), and additional supporting documents, including a copy of PTI No. 75-16B as Appendix A, facility potential emission calculations as Appendix B, facility plans as Appendix C, and the Acid Rain application as Appendix D.

If there are questions regarding this Initial ROP Application, please contact Mr. Tom Krysiak at 716-225-6478 or Ms. Chloe Palajac of NTH Consultants, Ltd. At 616-451-6243.

Sincerely,

Thomas Krysiak
EH&S Manager

Enclosures

cc: Mr. Michael DuBois, Indeck
Ms. Madison Mosher, Indeck
Mr. Michael Ferguson, Indeck
Mr. Ken Brenner, Indeck
Ms. Rachel Benaway, EGLE
Ms. Chloe Palajac, NTH

EGLE Michigan Department of Environment, Great Lakes, and Energy - Air Quality Division

RENEWABLE OPERATING PERMIT APPLICATION
C-001: CERTIFICATION

This information is required by Article II, Chapter 1, part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to provide this information may result in civil and/or criminal penalties. Please type or print clearly.

This form is completed and included as part of Renewable Operating Permit (ROP) initial and renewal applications, notifications of change, amendments, modifications, and additional information.

Form Type **C-001**	SRN N6921

Stationary Source Name Indeck Niles Energy Center	
City Niles	County Cass

SUBMITTAL CERTIFICATION INFORMATION

1. Type of Submittal *Check only one box.*

☒ Initial Application (Rule 210) ☐ Notification / Administrative Amendment / Modification (Rules 215/216)

☐ Renewal (Rule 210) ☐ Other, describe on AI-001

2. If this ROP has more than one Section, list the Section(s) that this Certification applies to _____

3. Submittal Media ☒ E-mail ☐ FTP ☐ Disk ☒ Paper

4. Operator's Additional Information ID - Create an Additional Information (AI) ID that is used to provide supplemental information on AI-001 regarding a submittal.

AI

CONTACT INFORMATION

Contact Name Mr. Thomas Krysiak	Title Environmental, Health & Safety Manager
Phone number 716-225-6478	E-mail address tkrysiak@indeckenergy.com

This form must be signed and dated by a Responsible Official.

Responsible Official Name Mr. Thomas Krysiak			Title Environmental, Health & Safety Manager	
Mailing address 1 Sheridan Drive				
City Tonawanda	State NY	ZIP Code 14150	County Erie	Country United States

As a Responsible Official, I certify that, based on information and belief formed after reasonable inquiry, the statements and information in this submittal are true, accurate and complete.

Thomas Krysiak 12/5/2022

Signature of Responsible Official Date

Michigan Department of Environment, Great Lakes, and Energy - Air Quality Division

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RENEWABLE OPERATING PERMIT INITIAL APPLICATION
ASC-001 APPLICATION SUBMITTAL AND CERTIFICATION

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

Source Name: Indeck Niles, LLC	SRN: N6921	Section Number (if applicable):

Identify the items that are included as part of your administratively complete application in the checklist below. For your application to be complete, it must include information necessary to evaluate the source and to determine all applicable requirements. Answer the compliance statements as they pertain to all the applicable requirements to which the source is subject. A Responsible Official must sign and date this form.

Listing of ROP Application Contents. See the initial application instructions for guidance regarding which forms and attachments are required for your source. Check the box for the items included with your application.

☒	Completed ROP Initial Application Forms (required)	☐	Copies of all Consent Orders/Consent Judgments
☐	MAERS Forms (to report emissions not previously submitted)	☐	Compliance Plan/Schedule of Compliance
☒	HAP/Criteria Pollutant Potential to Emit Calculations	☒	Acid Rain Initial Permit Application
☐	Stack information	☒	Cross-State Air Pollution Rule (CSAPR) Information
☒	Copies of all active Permit(s) to Install (required)	☒	Additional Information (AI-001) Forms
☒	Compliance Assurance Monitoring (CAM) Plan	☒	Paper copy of all documentation provided (required)
☒	Other Plans (e.g., Malfunction Abatement, Fugitive Dust, Operation and Maintenance, etc.)	☒	Electronic documents provided (optional)
☐	Confidential Information	☐	Other, explain:

Compliance Statement

This source is in compliance with **all** of its applicable requirements, including those contained in Permits to Install, this application and other applicable requirements that the source is subject to.	☐ Yes	☒ No
This source will continue to be in compliance with all of its applicable requirements, including those contained in Permits to Install, this application and other applicable requirements that the source is subject to.	☐ Yes	☒ No
This source will meet, in a timely manner, applicable requirements that become effective during the permit term.	☒ Yes	☐ No

The method(s) used to determine compliance for each applicable requirement is/are the method(s) specified in the existing Permits to Install, this application and all other applicable requirements that the source is subject to.

If any of the above are checked No, identify the emission unit(s) or flexible group(s) affected and the applicable requirement for which the source is or will be out of compliance at the time of issuance of the ROP on an AI-001 Form. Provide a compliance plan and schedule of compliance on an AI-001 Form.

Name and Title of the Responsible Official (Print or Type)

Thomas Krysiak, Environmental Health & Safety Manager

As a Responsible Official, I certify that, based on information and belief formed after reasonable inquiry, the statements and information in this application are true, accurate, and complete.

Thomas Krysiak | 12/5/2022

Signature of Responsible Official | **Date**

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RENEWABLE OPERATING PERMIT INITIAL APPLICATION
SI-001 SECTION INFORMATION

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

SECTION INFORMATION	
Section Name NA	
Section Description (Including address if different from Source address identified on the S-001 Form) NA	
Emission Units Included In This Section	
EU-CTGHRSG1	**EU-**
EU-CTGHRSG2	**EU-**
EU-AUXBOILER	**EU-**
EU-FUELHTR1	**EU-**
EU-FUELHTR2	**EU-**
EU-EMENGINE	**EU-**
EU-EMFUELTANK	**EU-**
EU-COLDCLEANER	**EU-**
EU-	**EU-**
EU-	**EU-**
EU-	**EU-**
EU-	**EU-**
EU-	**EU-**
EU-	**EU-**
EU-	**EU-**
EU-	**EU-**
EU-	**EU-**
EU-	**EU-**
EU-	**EU-**

☒ Check if an AI-001 Form is attached to provide more information for SI-001. Enter AI-001 Form ID: **AI-**001

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RENEWABLE OPERATING PERMIT INITIAL APPLICATION
S-001 STATIONARY SOURCE INFORMATION

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

SOURCE INFORMATION

SIC Code	NAICS Code
4911	221112

Source Name			
Indeck Niles Energy Center			
Street Address			
2200 Progressive Drive			
City	State	ZIP Code	County
Niles	MI	49120	Cass
Section/Town/Range (if street address not available)			
Source Description			
Natural gas combined-cycle power plant consisting of two (2) combustion turbine generators with duct-fired heat recovery steam generators, one (1) auxiliary boiler, two (2) fuel heaters, one (1) emergency generator and one (1) cold cleaner.			

OWNER INFORMATION

Owner Name				
Indeck Niles, LLC				
Mailing address (☐ check if same as source address)				
600 North Buffalo Grove Rd. Suite 300				
City	State	ZIP Code	County	Country
Buffalo Grove	IL	60089	Lake	U.S.

☐ Check if an AI-001 Form is attached to provide more information for S-001. Enter AI-001 Form ID: **AI-**

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RENEWABLE OPERATING PERMIT INITIAL APPLICATION FORM
S-002 CONTACT AND RESPONSIBLE OFFICIAL INFORMATION

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

At least one contact and one Responsible Official must be identified. Additional contacts and Responsible Officials may be included if necessary.

CONTACT INFORMATION

Contact 1 Name			Title	
Thomas Krysiak			Environmental, Health & Safety Manager	
Company Name & Mailing address (☐ check if same as source address) Indeck Niles, LLC				
City Tonawanda	State NY	ZIP Code 14150	County Erie	Country U.S.
Phone number 716-225-6478		E-mail address tkrysiak@indeckenergy.com		

Contact 2 Name (optional)			Title	
Madison Mosher			Compliance Manager	
Company Name & Mailing address (☐ check if same as source address) Indeck Niles, LLC				
City Niles	State MI	ZIP Code 49120	County Cass	Country U.S.
Phone number		E-mail address madison.mosher@picgroupinc.com		

RESPONSIBLE OFFICIAL INFORMATION

Responsible Official 1 Name			Title	
Thomas Krysiak			Environmental, Health & Safety Manager	
Company Name & Mailing address (☐ check if same as source address) Indeck Niles, LLC				
City Tonawanda	State NY	ZIP Code 14150	County Erie	Country U.S.
Phone number 716-225-6478		E-mail address tkrysiak@indeckenergy.com		

Responsible Official 2 Name (optional)			Title	
Michael Ferguson			Vice President of Operations	
Company Name & Mailing address (☐ check if same as source address) 600 North Buffalo Grove Road, Suite 300				
City Buffalo Grove	State IL	ZIP Code 60089	County Lake	Country USA
Phone number 847-520-3212		E-mail address mferguson@indeckenergy.com		

☐ Check if an AI-001 Form is attached to provide more information for S-002. Enter AI-001 Form ID: **AI-**

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RENEWABLE OPERATING PERMIT INITIAL APPLICATION
S-003 SOURCE REQUIREMENT INFORMATION

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

SOURCE REQUIREMENT INFORMATION

Answer the questions below for specific requirements or programs to which the source may be subject. Refer to the ROP Initial Application Instructions for additional information.

1.	Actual emissions and associated data from **all** emission units with applicable requirements are required to be reported in MAERS. Are there any emissions and associated data that have not been reported in MAERS for the most recent emissions reporting year? If Yes, identify the emission unit(s) that was/were not reported in MAERS on an AI-001 Form. Applicable MAERS form(s) for unreported emission units must be included with this application.	☐ Yes ☒ No
2.	Is this source subject to the federal regulations on ozone-depleting substances? (40 CFR Part 82)	☐ Yes ☒ No
3.	a. Is this source subject to the federal Chemical Accident Prevention Provisions? (Section 112(r) of the Clean Air Act Amendments, 40 CFR Part 68) If Yes, a Risk Management Plan (RMP) and periodic updates must be submitted to the USEPA.	☐ Yes ☒ No
	b. Has an updated RMP been submitted to the USEPA?	☐ Yes ☒ No
4.	Does the source belong to one of the source categories that require quantification of fugitive emissions? If Yes, identify the category on an AI-001 Form and include the fugitive emissions in the PTE calculations for the source. *See ROP Initial Application instructions.*	☒ Yes ☐ No
5.	Does this stationary source have the potential to emit (PTE) of 100 tons per year or more of any criteria pollutant (PM-10, PM 2.5, VOC, NOx, SO_2, CO, lead)? If Yes, include potential emission calculations for each identified pollutant on an AI-001 Form.	☒ Yes ☐ No
6.	Does this stationary source emit any hazardous air pollutants (HAPs) regulated by the federal Clean Air Act, Section 112? If Yes, include potential and actual emission calculations for HAPs, **including fugitive emissions** on an AI-001 Form.	☒ Yes ☐ No
7.	a. Are any emission units subject to Compliance Assurance Monitoring (CAM)? If Yes, identify the specific emission unit(s) and pollutant(s) subject to CAM on an AI-001 Form.	☒ Yes ☐ No
	b. Is a CAM plan included with this application on an AI-001 Form?	☒ Yes ☐ No
8.	Does the source have any active Consent Orders/Consent Judgments (CO/CJ)? If Yes, attach a copy of each CO/CJ on an AI-001 Form.	☐ Yes ☒ No
9.	Are any emission units subject to the federal Cross State Air Pollution Rule (CSAPR)? If Yes, identify the specific emission unit(s) subject to CSAPR on an AI-001 Form.	☒ Yes ☐ No
10.	a. Are any emission units subject to the federal Acid Rain Program? If Yes, identify the specific emission unit(s) subject to the Federal Acid Rain Program on an AI-001 Form.	☒ Yes ☐ No
	b. Is an Acid Rain Permit Application included with this application?	☒ Yes ☐ No
11.	Does the source have any required plans such as a malfunction abatement plan, fugitive dust plan, operation/maintenance plan, startup/shutdown plans or any other monitoring plan? If Yes, then the plan(s) must be submitted with this application on an AI-001 Form.	☒ Yes ☐ No
12.	Are there any specific requirements that the source proposes to be identified in the ROP as non-applicable? If Yes, then the requirement and justification must be submitted on an AI-001 Form.	☐ Yes ☒ No

☒ Check if an AI-001 Form is attached to provide more information for S-003. Enter AI-001 Form ID: **AI-**001

Michigan Department of Environment, Great Lakes, and Energy - Air Quality Division

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RENEWABLE OPERATING PERMIT INITIAL APPLICATION
EU-001 PERMIT TO INSTALL (PTI) EXEMPT EMISSION UNITS

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

Review all emission units at the source and answer the question below.

1. Does the source have any emission units that are required to be listed in the ROP application under R 336.1212(4) (Rule 212(4)) of the Michigan Air Pollution Control Rules, not including Rules 281(2)(h), 287(2)(c), and 290? ☐ Yes ☒ No

If Yes, identify the emission units in the table below. If No, go to the EU-002 Form.

Note: Emission units that are subject to process specific emission limitations or standards, even if identified in Rule 212, must be captured in either an EU-002 or EU-004 Form. Identical emission units may be grouped (e.g. PTI exempt Storage Tanks).

Emission Unit ID	**Emission Unit Description**	**PTI Exemption Rule Citation** [e.g. Rule 282(2)(b)(i)]	**Rule 212(4) Citation** [e.g. Rule 212(4)(c)]
EU-			
EU-			
EU-			
EU-			
EU-			
EU-			
EU-			
EU-			
EU-			

Comments:

☐ Check if an AI-001 Form is attached to provide more information for EU-001. Enter AI-001 Form ID: **AI-**

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RENEWABLE OPERATING PERMIT INITIAL APPLICATION
EU-002 EMISSION UNITS MEETING THE CRITERIA OF RULES 281(2)(h), 285(2)(r)(iv), 287(2)(c), OR 290

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

Review all emission units and applicable requirements at the source and provide the following information.

1. Does the source have any emission units which meet the criteria of Rules 281(2)(h), 285(2)(r)(iv), 287(2)(c), or 290. ☐ Yes ☒ No

   If Yes, identify the emission units in the table below. If No, go to the EU-003 Form.

Note: If several emission units were installed under the same rule above, provide a description of each and an installation date for each.

Origin of Applicable Requirements	**Emission Unit Description – *Provide Emission Unit ID and a description of Process Equipment, Control Devices and Monitoring Devices***	**Date Emission Unit was Installed/ Modified/ Reconstructed**
☐ Rule 281(2)(h) or 285(2)(r)(iv) cleaning operation	.	
☐ Rule 287(2)(c) surface coating line		
☐ Rule 290 process with limited emissions		

Comments:

☐ Check if an AI-001 Form is attached to provide more information for EU-002. Enter AI-001 Form ID: **AI-**

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RENEWABLE OPERATING PERMIT INITIAL APPLICATION
EU-003 EMISSION UNITS WITH PERMITS TO INSTALL

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

Review all emission units at the source and fill in the information in the following table for **all** emission units with Permits to Install (PTI). Any PTI(s) identified below must be attached to the application.

Permit to Install Number	Emission Unit ID	Description (*Include Process Equipment, Control Devices and Monitoring Devices*)	Date Emission Unit was Installed/ Modified/ Reconstructed
75-16B	**EU-**CTGHRSG1	A 3,651 MMBtu/hr natural gas-fired combustion turbine (CTG) coupled with a 71 MMBtu/hr heat recovery steam generator (HRSG) with DLNB, SCR, and oxidation catalyst.	
75-16B	**EU-**CTGHRSG2	A 3,651 MMBtu/hr natural gas-fired combustion turbine (CTG) coupled with a 71 MMBtu/hr heat recovery steam generator (HRSG) with DLNB, SCR, and oxidation catalyst.	
75-16B	**EU-**AUXBOILER	A natural gas-fired auxiliary boiler rated at 182 MMBtu/hr to facilitate startup of the CTG/HRSG equipped with LNB and FGR. [Note, installed capacity is 85 MMBtu/hr]	
75-16B	**EU-**FUELHTR1	A natural gas-fired 13.5 MMBtu/hr heat input fuel gas dew point heater for superheating the natural gas fuel above the hydrocarbon dew point temperature. [7.3 MMBtu/hr install]	
75-16B	**EU-**FUELHTR2	A natural gas-fired 13.5 MMBtu/hr heat input fuel gas dew point heater for superheating the natural gas fuel above the hydrocarbon dew point temperature.[7.3 MMBtu/hr install]	
75-16B	**EU-**EMENGINE	A 2,922 HP (2,179 kW) diesel-fueled emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. [2,923 HP (2,180 kW) install]	
75-16B	**EU-**EMFUELTANK	A 3,500 gallon closed-roof tank for purposes of storing ultra-low sulfur diesl fuel. This tank services the diesel-fueled emergency engine.	
75-16B	**EU-** COLDCLEANER	New closed-cover cold cleaner.	
	EU-		

1. Are you proposing changes to any emission unit names, descriptions or control devices in the PTIs listed above? If Yes, describe the proposed changes on an AI-001 Form. ☐ Yes ☒ No

2. Are you proposing additions or clarifications to any permit conditions? If Yes, describe the proposed changes on an AI-001 Form. ☐ Yes ☒ No

3. Are you proposing monitoring, testing, recordkeeping and/or reporting necessary to demonstrate compliance with any applicable requirements? If Yes, describe the proposed conditions on an AI-001 Form. ☐ Yes ☒ No

☒ Check if an AI-001 Form is attached to provide more information for EU-003. Enter AI-001 Form ID: **AI-**001

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RENEWABLE OPERATING PERMIT INITIAL APPLICATION
EU-004 OTHER EMISSION UNITS

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

Complete an EU-004 Form for **all** emission units with applicable requirements that have **not** been addressed on an EU-001, EU-002 or EU-003 Form. This would include grandfathered emission units or PTI exempt emission units subject to applicable requirements in the AQD Rules, and emission units subject to a MACT, NESHAP, NSPS, or other federal requirement.

1. Does the source have emission units with applicable requirements that have not been addressed on the EU-001, EU-002 and/or EU-003 Forms? ☐ Yes ☒ No

   If Yes, provide the required information below. Complete the AR-001 and/or AR-002 Form(s) to identify all applicable requirements and all monitoring, testing, recordkeeping and/or reporting to demonstrate compliance with the applicable requirements.

Emission Unit ID	Installation Date (MM/DD/YYYY)	Modification/Reconstruction Date(s) (MM/DD/YYYY)	SIC Code – *If different from S-001 Form*
EU-			
Emission Unit Description – *Include process equipment, control devices, monitoring devices, and all stacks/vents associated with this emission unit that have applicable requirements. Indicate which forms are used to describe/include the applicable requirements for this emission unit (AR-001 and/or AR-002 Forms)*.			

Emission Unit ID	Installation Date (MM/DD/YYYY)	Modification/Reconstruction Date(s) (MM/DD/YYYY)	SIC Code – *If different from S-001 Form*
EU-			
Emission Unit Description – *Include process equipment, control devices, monitoring devices, and all stacks/vents associated with this emission unit that have applicable requirements. Indicate which forms are used to describe/include the applicable requirements for this emission unit (AR-001 and/or AR-002 Forms)*.			

Emission Unit ID	Installation Date (MM/DD/YYYY)	Modification/Reconstruction Date(s) (MM/DD/YYYY)	SIC Code – *If different from S-001 Form*
EU-			
Emission Unit Description – *Include process equipment, control devices, monitoring devices, and all stacks/vents associated with this emission unit that have applicable requirements. Indicate which forms are used to describe/include the applicable requirements for this emission unit (AR-001 and/or AR-002 Forms)*.			

☐ Check if an AI-001 Form is attached to provide more information for EU-004. Enter AI-001 Form ID: **AI-**

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Michigan Department of Environment, Great Lakes, and Energy - Air Quality Division

RENEWABLE OPERATING PERMIT INITIAL APPLICATION
FG-001: FLEXIBLE GROUPS

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

Complete the FG-001 Form for all Emission Units (EUs) that you want to combine into a Flexible Group (FG). Create a descriptive ID for the FG and description, and list the IDs for the EUs to be included in the FG. See instructions for FG examples.

Flexible Group ID **FG-**CTGHRSG			
Flexible Group Description Two (2) combined-cycle natural gas-fired CTG with HRSG in a 2x1 configuration with a steam turbine generator. Each CTG/HRSG is equipped with DLNB, SCR, and oxidation catalyst.			
Emission Unit IDs			
EU-CTGHRSG1	**EU-**	**EU-**	**EU-**
EU-CTGHRSG2	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**
Flexible Group ID **FG-**FUELHTR			
Flexible Group Description Two (2) natural gas-fired fuel gas dew point heaters.			
Emission Unit IDs			
EU-FUELHTR1	**EU-**	**EU-**	**EU-**
EU-FUELHTR2	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**
EU-	**EU-**	**EU-**	**EU-**

☒ Check if an AI-001 Form is attached to provide more information for FG-001. Enter AI-001 Form ID: **AI-**001

Michigan Department of Environment, Great Lakes, and Energy - Air Quality Division

EGLE

RENEWABLE OPERATING PERMIT INITIAL APPLICATION
AR-001 APPLICABLE REQUIREMENTS FROM MACT, NESHAP OR NSPS

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Proposed Section Number (if applicable):

Answer the question below for emission units subject to a MACT, NESHAP or NSPS regulation and provide either an existing Permit to Install, an existing template table*, or a newly created table** that contains the applicable requirements for each subject emission unit with the application, including associated monitoring, testing, recordkeeping and reporting necessary to demonstrate compliance.

1. Is any emission unit subject to a Maximum Achievable Control Technology (MACT) standard in 40 CFR Part 63, National Emission Standard for Hazardous Air Pollutants (NESHAP) in 40 CFR Part 61, or New Source Performance Standard (NSPS) in 40 CFR Part 60? ☒ Yes ☐ No

   If yes, identify the emission units and applicable MACT, NESHAP or NSPS in the table below.

Note: If several emission units are subject to the same regulation, list all of the emission unit IDs together. Attach the applicable requirements (PTI, template table or newly created table) in the selected format to the application using an AI-001 Form.

MACT NESHAP or NSPS Subpart and Name	**Emission Unit ID –** *Provide the Emission Unit ID you created on the EU-003 or EU-004 Form*	**Applicable Requirements Attached in Which Format?**
40 CFR Part 60, Subpart KKKK 40 CFR Part 60, Subpart TTTT	EU-CTGHRSG1 EU-CTGHRSG2	☒ PTI No. 75-16B ☐ Template Table* ☐ Newly Created Table**
40 CFR Part 60, Subpart Db 40 CFR Part 63, Subpart JJJJJJ	EU-AUXBOILER	☒ PTI No. 75-16B ☐ Template Table* ☐ Newly Created Table**
40 CFR Part 60, Subpart IIII 40 CFR Part 63, Subparts A and ZZZZ	EUEMENGINE	☒ PTI No. 75-16B ☐ Template Table* ☐ Newly Created Table**
40 CFR Part 60, Subpart Dc	EUFUELHTR1 EUFUELHTR2	☒ PTI No. 75-16B ☐ Template Table* ☐ Newly Created Table**
		☐ PTI No. ☐ Template Table* ☐ Newly Created Table**

STREAMLINED REQUIREMENTS

2. Are you proposing to streamline any requirements? ☐ Yes ☒ No

   If yes, identify the streamlined and subsumed requirements and provide the EU ID and a justification for streamlining the applicable requirement on an AI-001 Form.

*MACT and NSPS template tables (available at the link below)

**Blank EU or FG template tables (available at the link below)

http://michigan.gov/air (select the Permits Tab, "Renewable Operating Permits(ROP)/Title V", then "ROP Forms & Templates")

☐ Check if an AI-001 Form is attached to provide more information for AR-001. Enter AI-001 Form ID: **AI-**

EGLE

RENEWABLE OPERATING PERMIT INITIAL APPLICATION
AR-002 OTHER APPLICABLE REQUIREMENTS

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

APPLICABLE REQUIREMENTS NOT INCLUDED IN A PTI, MACT, NESHAPS, NSPS, OR PERMIT EXEMPTION

Answer the questions below and create an EU table to identify terms and conditions for each emission unit identified on an EU-004 Form (other than MACT, NESHAP, or NSPS requirements). This would include emission units that are grandfathered or exempt from PTI requirements but subject to state rules, federal rules or consent orders/consent judgments. Blank EU template tables are available on the EGLE Internet at: http://michigan.gov/air (select the Permits Tab, "Renewable Operating Permits (ROP)/Title V", then "ROP Forms & Templates")

1. Is there an emission unit identified on an EU-004 Form that is subject to **emission limit(s)**? If Yes, fill out an EU table to identify the emission limit(s), and provide the EU ID and the source of the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No
2. Is there an emission unit identified on an EU-004 Form that is subject to **material limit(s)**? If Yes, fill out an EU table to identify the material limit(s), and provide the EU ID and the source of the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No
3. Is there an emission unit identified on an EU-004 Form that is subject to **process/operational restriction(s)**? If Yes, fill out an EU table to identify the process/operational restriction(s), and provide the EU ID and the source of the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No
4. Is there an emission unit identified on an EU-004 Form that is subject to **design/equipment parameter(s)**? If Yes, fill out an EU table to identify the design/equipment parameter(s), and provide the EU ID and the source of the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No

5.	Is there an emission unit identified on an EU-004 Form that is subject to **testing/sampling requirement(s)**? If Yes, fill out an EU table to identify the testing/sampling requirement(s), and provide the EU ID and the source of the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No
6.	Is there an emission unit identified on an EU-004 Form that is subject to **monitoring/recordkeeping requirement(s)**? If Yes, fill out an EU table to identify the monitoring/recordkeeping requirement(s), and provide the EU ID and the source of the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No
7.	Is there an emission unit identified on an EU-004 Form that is subject to **reporting requirement(s)**? If Yes, fill out an EU table to identify reporting requirement(s), and provide the EU ID and the source of the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No
8.	Is there an emission unit identified on an EU-004 Form that is subject to **stack/vent restriction(s)**? If Yes, fill out an EU table to identify stack/vent restriction(s), and provide the EU ID and the source of the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No
9.	Are there any other requirements that you would like to **add** for an emission unit identified on an EU-004 Form? If Yes, fill out an EU table to identify the requirements, and provide the EU ID and a justification for the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No
10.	Are you proposing to streamline any requirements? If Yes, identify the streamlined and subsumed requirements and the EU ID, and provide a justification for streamlining the applicable requirement below. Do not include requirements identified on an AR-001 Form.	☐ Yes ☒ No
☐	Check if an AI-001 Form is attached to provide more information for AR-002. Enter AI-001 Form ID: **AI-**	

EGLE

RENEWABLE OPERATING PERMIT INITIAL APPLICATION
AR-003 SOURCE-WIDE APPLICABLE REQUIREMENTS

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Refer to "Renewable Operating Permit Initial Application Instructions" for additional information to complete the application.

SRN: N6921	Section Number (if applicable):

Complete a Source-wide table for any conditions that apply to the entire source. A blank Source-wide template table is available on the EGLE Internet at:
http://michigan.gov/air (select the Permits Tab, "Renewable Operating Permits (ROP)/Title V", then "ROP Forms & Templates")

1. Are there any applicable requirements that apply to the entire source? If Yes, identify the conditions by utilizing a Source-wide template table and include all of the appropriate applicable requirements, including associated monitoring, testing, recordkeeping and reporting necessary to demonstrate compliance. Provide information regarding the applicable requirements in the comment field below.	☐ Yes ☒ No
Comments	
☐ Check if an AI-001 Form is attached to provide more information for AR-003. Enter AI-001 Form ID: **AI-**	

EGLE

RENEWABLE OPERATING PERMIT APPLICATION
AI-001: ADDITIONAL INFORMATION

This information is required by Article II, Chapter 1, Part 55 (Air Pollution Control) of P.A. 451 of 1994, as amended, and the Federal Clean Air Act of 1990. Failure to obtain a permit required by Part 55 may result in penalties and/or imprisonment. Please type or print clearly. Refer to instructions for additional information to complete this form.

	SRN: N6921	Section Number (if applicable):

1. Additional Information ID
AI-001

Additional Information

2. Is This Information Confidential? ☐ Yes ☒ No

ASC-001
EUEMENGINE was permitted at 2,922 horsepower (HP) (2,179 kilowatts (kW)) but installed with a nameplate capacity of 2,923 HP (2,180 kW). Indeck submitted a permit application on October 18, 2022 to amend PTI No. 75-16B to the correct nameplace of 2,923 HP (2,180 kW). Indeck will be in compliance with EUEMENGINE Special Condition IV.2 upon issuance of the amended PTI.

Section SI-001
Indeck did not install the following emisison units and can be removed from the permit: EUFPENGINE, EUFPFUELTANK, and FGSPACEHTRS. Instead, the facility is using electric-power equipment to power the fire pump and provide space heat.

Section S-003
1. Indeck will be submitting actual emissions and related information for the facility into MAERS starting reporting year 2022 by the deadline in March 2023.
4. Indeck is required to quantity fugitive emissions according to 116(n) as the facility is a fossil fuel-fired steam electric plant of more than 250,000,000 Btu per hour heat input. There are not fugitive emissions expected from the combustion of natural gas.
5&6. The facility has the PTE of 100 tpy or more for criteria pollutants and emits HAPs and is required to include PTE calculations as part of this initial renewable operating permit application. Potential emission calculations are included as Appendix B.
7. EUCTGHRSG1 and EUCTGHRSG2 are subject to CAM for the VOC limit of 4 ppmvd at 15% O2 as the units use an oxidation catalyst to achieve control and potential pre-control emission VOC emissions are greater than 100 tpy. The CTG/HRSG CAM plan is included in Appendix C.
9. CSAPR subject units according to 40 CFR Part 97 are EUCTGHRSG1 and EUCTGHRSG2 (CAMD Unit IDs: EUCT1 and EUCT2)
10. Acid Rain subject units are EUCTGHRSG1 and EUCTGHRSG2 (CAMD Unit IDs: EUCT1 and EUCT2). The acid rain permit application is included with this initial renewable operating permit application as Appendix D.

EU-003
Indeck submitted a PTI application on October 18, 2022 to update equipment capacities at emission units EUAUXBOILER, EUFUELHTR1, EUFUELHTR2, and EUEMENGINE to align with the emission units as installed. Upon issuance of the amended PTI, the changes will be incorproated into the ROP application.

FG-001
FGFUELTANK - One (1) closed roof tank for purposes of storing ultra-low sulfur diesel fuel (EUEMFUELTANK). Note that only one (1) of the two (2) diesel fuel tanks was installed. EUFPFUELTANK was not installed.
FGSPACEHTRS - Indeck did not install natural gas-fired space heaters, remove flexible group.
FGINITIALPROJECT - All of the equipment associated with the greenfield project, EUCTGHRSG1, EUCTGHRSG2, EUFUELHTR1, EUFUELHTR2, EUEMENGINE, EUEMFUELTANK, and EUCOLDCLEANER.
Indeck did not install EUFPENGINE, EUFPFUELTANK, and FGSPACEHTRS and is proposing to remove these emission units through this initial renewable operating permit application.

APPENDIX A

// ACTIVE PERMIT TO INSTALL

75-16B

MICHIGAN DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY
AIR QUALITY DIVISION

November 26, 2019

PERMIT TO INSTALL
75-16B

ISSUED TO
Indeck Niles, LLC

LOCATED AT
2200 Progressive Drive
Niles, Michigan

IN THE COUNTY OF
Cass

STATE REGISTRATION NUMBER
N6921

The Air Quality Division has approved this Permit to Install, pursuant to the delegation of authority from the Michigan Department of Environment, Great Lakes, and Energy. This permit is hereby issued in accordance with and subject to Section 5505(1) of Article II, Chapter I, Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended. Pursuant to Air Pollution Control Rule 336.1201(1), this permit constitutes the permittee's authority to install the identified emission unit(s) in accordance with all administrative rules of the Department and the attached conditions. Operation of the emission unit(s) identified in this Permit to Install is allowed pursuant to Rule 336.1201(6).

DATE OF RECEIPT OF ALL INFORMATION REQUIRED BY RULE 203: **August 20, 2019**	
DATE PERMIT TO INSTALL APPROVED: **November 26, 2019**	SIGNATURE: Mary Ann Dolehanty
DATE PERMIT VOIDED:	SIGNATURE:
DATE PERMIT REVOKED:	SIGNATURE:

PERMIT TO INSTALL

Table of Contents

COMMON ACRONYMS

AQD	Air Quality Division
BACT	Best Available Control Technology
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
COMS	Continuous Opacity Monitoring System
Department/department/EGLE	Michigan Department of Environment, Great Lakes, and Energy
EU	Emission Unit
FG	Flexible Group
GACS	Gallons of Applied Coating Solids
GC	General Condition
GHGs	Greenhouse Gases
HVLP	High Volume Low Pressure*
ID	Identification
IRSL	Initial Risk Screening Level
ITSL	Initial Threshold Screening Level
LAER	Lowest Achievable Emission Rate
MACT	Maximum Achievable Control Technology
MAERS	Michigan Air Emissions Reporting System
MAP	Malfunction Abatement Plan
MSDS	Material Safety Data Sheet
NA	Not Applicable
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standard for Hazardous Air Pollutants
NSPS	New Source Performance Standards
NSR	New Source Review
PS	Performance Specification
PSD	Prevention of Significant Deterioration
PTE	Permanent Total Enclosure
PTI	Permit to Install
RACT	Reasonable Available Control Technology
ROP	Renewable Operating Permit
SC	Special Condition
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SRN	State Registration Number
TBD	To Be Determined
TEQ	Toxicity Equivalence Quotient
USEPA/EPA	United States Environmental Protection Agency
VE	Visible Emissions

*For HVLP applicators, the pressure measured at the gun air cap shall not exceed 10 psig

POLLUTANT / MEASUREMENT ABBREVIATIONS

acfm	Actual cubic feet per minute
BTU	British Thermal Unit
°C	Degrees Celsius
CO	Carbon Monoxide
CO_2e	Carbon Dioxide Equivalent
dscf	Dry standard cubic foot
dscm	Dry standard cubic meter
°F	Degrees Fahrenheit
gr	Grains
HAP	Hazardous Air Pollutant
Hg	Mercury
hr	Hour
HP	Horsepower
H_2S	Hydrogen Sulfide
kW	Kilowatt
lb	Pound
m	Meter
mg	Milligram
mm	Millimeter
MM	Million
MW	Megawatts
NMOC	Non-Methane Organic Compounds
NO_x	Oxides of Nitrogen
ng	Nanogram
PM	Particulate Matter
PM10	Particulate Matter equal to or less than 10 microns in diameter
PM2.5	Particulate Matter equal to or less than 2.5 microns in diameter
pph	Pounds per hour
ppm	Parts per million
ppmv	Parts per million by volume
ppmw	Parts per million by weight
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
scf	Standard cubic feet
sec	Seconds
SO_2	Sulfur Dioxide
TAC	Toxic Air Contaminant
Temp	Temperature
THC	Total Hydrocarbons
tpy	Tons per year
µg	Microgram
µm	Micrometer or Micron
VOC	Volatile Organic Compounds
yr	Year

GENERAL CONDITIONS

1. The process or process equipment covered by this permit shall not be reconstructed, relocated, or modified, unless a Permit to Install authorizing such action is issued by the Department, except to the extent such action is exempt from the Permit to Install requirements by any applicable rule. **(R 336.1201(1))**

2. If the installation, construction, reconstruction, relocation, or modification of the equipment for which this permit has been approved has not commenced within 18 months, or has been interrupted for 18 months, this permit shall become void unless otherwise authorized by the Department. Furthermore, the permittee or the designated authorized agent shall notify the Department via the Supervisor, Permit Section, Air Quality Division, Michigan Department of Environment, Great Lakes, and Energy, P.O. Box 30260, Lansing, Michigan 48909-7760, if it is decided not to pursue the installation, construction, reconstruction, relocation, or modification of the equipment allowed by this Permit to Install. **(R 336.1201(4))**

3. If this Permit to Install is issued for a process or process equipment located at a stationary source that is not subject to the Renewable Operating Permit program requirements pursuant to Rule 210 (R 336.1210), operation of the process or process equipment is allowed by this permit if the equipment performs in accordance with the terms and conditions of this Permit to Install. **(R 336.1201(6)(b))**

4. The Department may, after notice and opportunity for a hearing, revoke this Permit to Install if evidence indicates the process or process equipment is not performing in accordance with the terms and conditions of this permit or is violating the Department's rules or the Clean Air Act. **(R 336.1201(8), Section 5510 of Act 451, PA 1994)**

5. The terms and conditions of this Permit to Install shall apply to any person or legal entity that now or hereafter owns or operates the process or process equipment at the location authorized by this Permit to Install. If the new owner or operator submits a written request to the Department pursuant to Rule 219 and the Department approves the request, this permit will be amended to reflect the change of ownership or operational control. The request must include all of the information required by subrules (1)(a), (b), and (c) of Rule 219 and shall be sent to the District Supervisor, Air Quality Division, Michigan Department of Environment, Great Lakes, and Energy. **(R 336.1219)**

6. Operation of this equipment shall not result in the emission of an air contaminant which causes injurious effects to human health or safety, animal life, plant life of significant economic value, or property, or which causes unreasonable interference with the comfortable enjoyment of life and property. **(R 336.1901)**

7. The permittee shall provide notice of an abnormal condition, start-up, shutdown, or malfunction that results in emissions of a hazardous or toxic air pollutant which continue for more than one hour in excess of any applicable standard or limitation, or emissions of any air contaminant continuing for more than two hours in excess of an applicable standard or limitation, as required in Rule 912, to the Department. The notice shall be provided not later than two business days after start-up, shutdown, or discovery of the abnormal condition or malfunction. Written reports, if required, must be filed with the Department within 10 days after the start-up or shutdown occurred, within 10 days after the abnormal conditions or malfunction has been corrected, or within 30 days of discovery of the abnormal condition or malfunction, whichever is first. The written reports shall include all of the information required in Rule 912(5). **(R 336.1912)**

8. Approval of this permit does not exempt the permittee from complying with any future applicable requirements which may be promulgated under Part 55 of 1994 PA 451, as amended or the Federal Clean Air Act.

9. Approval of this permit does not obviate the necessity of obtaining such permits or approvals from other units of government as required by law.

10. Operation of this equipment may be subject to other requirements of Part 55 of 1994 PA 451, as amended and the rules promulgated thereunder.

11. Except as provided in subrules (2) and (3) or unless the special conditions of the Permit to Install include an alternate opacity limit established pursuant to subrule (4) of Rule 301, the permittee shall not cause or permit to be discharged into the outer air from a process or process equipment a visible emission of density greater than the most stringent of the following. The grading of visible emissions shall be determined in accordance with Rule 303 (R 336.1303). **(R 336.1301)**
    a) A six-minute average of 20 percent opacity, except for one six-minute average per hour of not more than 27 percent opacity.
    b) A visible emission limit specified by an applicable federal new source performance standard.
    c) A visible emission limit specified as a condition of this Permit to Install.

12. Collected air contaminants shall be removed as necessary to maintain the equipment at the required operating efficiency. The collection and disposal of air contaminants shall be performed in a manner so as to minimize the introduction of contaminants to the outer air. Transport of collected air contaminants in Priority I and II areas requires the use of material handling methods specified in Rule 370(2). **(R 336.1370)**

13. The Department may require the permittee to conduct acceptable performance tests, at the permittee's expense, in accordance with Rule 1001 and Rule 1003, under any of the conditions listed in Rule 1001. **(R 336.2001)**

EMISSION UNIT SPECIAL CONDITIONS

EMISSION UNIT SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date / Modification Date	Flexible Group ID
EUCTGHRSG1	A 3,651 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 71 MMBTU/hr to provide heat for additional steam production. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with dry low NO_x burner (DLNB), selective catalytic reduction (SCR), and an oxidation catalyst.	TBD	FGCTGHRSG, FGINITIALPROJECT
EUCTGHRSG2	A 3,651 MMBTU/hr natural gas-fired combustion turbine generator (CTG) coupled with a heat recovery steam generator (HRSG). The HRSG is equipped with a natural gas-fired duct burner rated at 71 MMBTU/hr to provide heat for additional steam production. The HRSG is not capable of operating independently from the CTG. The CTG/HRSG is equipped with dry low NO_x burner (DLNB), selective catalytic reduction (SCR), and an oxidation catalyst.	TBD	FGCTGHRSG, FGINITIALPROJECT
EUAUXBOILER	A natural gas-fired auxiliary boiler rated at 182 MMBTU/hr to facilitate startup of the CTG/HRSG trains and to provide steam to the steam turbine generator seals. The auxiliary boiler is equipped with low NO_x burners (LNB) and flue gas recirculation (FGR).	TBD	FGINITIALPROJECT
EUFUELHTR1	A natural gas-fired 13.5 MMBTU/hr heat input fuel gas dew point heater for superheating the natural gas fuel above the hydrocarbon dew point temperature.	TBD	FGFUELHTR, FGINITIALPROJECT
EUFUELHTR2	A natural gas-fired 13.5 MMBTU/hr heat input fuel gas dew point heater for superheating the natural gas fuel above the hydrocarbon dew point temperature.	TBD	FGFUELHTR, FGINITIALPROJECT
EUEMENGINE	A 2,922 HP (2,179 kW) diesel-fueled emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder.	TBD	FGINITIALPROJECT
EUFPENGINE	A 260 brake HP diesel-fueled emergency fire pump engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The fire pump engine has an indicated HP of 300 on the nameplate.	TBD	FGINITIALPROJECT

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date / Modification Date	Flexible Group ID
EUEMFUELTANK	A 3,500 gallon closed-roof tank for purposes of storing ultra-low sulfur diesel fuel. This tank services the diesel-fueled emergency engine.	TBD	FGFUELTANK, FGINITIALPROJECT
EUFPFUELTANK	A 500 gallon closed-roof tank for purposes of storing ultra-low sulfur diesel fuel. This tank services the diesel-fueled emergency fire pump engine.	TBD	FGFUELTANK, FGINITIALPROJECT
EUCOLDCLEANER	New closed-cover cold cleaner.	TBD	FGINITIALPROJECT

Changes to the equipment described in this table are subject to the requirements of R 336.1201, except as allowed by R 336.1278 to R 336.1291.

EUAUXBOILER
EMISSION UNIT CONDITIONS

DESCRIPTION

A natural gas-fired auxiliary boiler rated at 182 MMBTU/hr to facilitate startup of the CTG/HRSG trains and to provide steam to the steam turbine generator seals. The auxiliary boiler is equipped with low NO_x burners (LNB) and flue gas recirculation (FGR).

Flexible Group ID: FGINITIALPROJECT

POLLUTION CONTROL EQUIPMENT

Low NO_x burners and flue gas recirculation for NO_x control.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring / Testing Method	Underlying Applicable Requirements
1. NO_x	0.04 lb/MMBTU	30-day rolling average time period	EUAUXBOILER	SC VI.2, SC VI.3, SC VI.10	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.44b(i)[A], 40 CFR 60.44b(l)(1)[A]
2. CO	0.04 lb/MMBTU	Hourly	EUAUXBOILER	SC V.1, SC VI.10	R 336.1205(1)(a) & (b), R 336.2804, R 336.2810
3. PM	0.005 lb/MMBTU	Hourly	EUAUXBOILER	SC V.1, SC VI.10	R 336.1331(1)(c), R 336.2810
4. PM10	1.36 pph	Hourly	EUAUXBOILER	SC V.2, SC VI.7, SC VI.10	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
5. PM2.5	1.36 pph	Hourly	EUAUXBOILER	SC V.2, SC VI.7, SC VI.10	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
6. SO_2	0.6 lb/MMscf	Based upon fuel receipt records.	EUAUXBOILER	SC VI.6, SC VI.8, SC VI.10	R 336.2803, R 336.2804, R 336.2810
7. VOC	0.004 lb/MMBTU	Hourly	EUAUXBOILER	SC V.1, SC VI.10	R 336.1205(1)(a) & (b), R 336.1702(a), R 336.2810

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring / Testing Method	Underlying Applicable Requirements
8. GHGs as CO_2e	93,346 tpy	12-month rolling time period as determined at the end of each calendar month.	EUAUXBOILER	SC VI.9, SC VI.10	R 336.1205(1)(a) & (b), 40 CFR 52.21(j)
[A] The emission limit as required in 40 CFR 60.44b(l)(1) is 0.20 lb/MMBTU at a high heat release rate. SC I.1 subsumes the NSPS emission limit.					

II. MATERIAL LIMIT(S)

1. The permittee shall burn only pipeline quality natural gas in EUAUXBOILER, with a sulfur content of 2,000 gr per MMscf or less. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60 Subpart Db, 40 CFR 63.11195(e))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Within 180 days of trial operation, the permittee shall submit, implement, and maintain a malfunction abatement plan (MAP) as described in Rule 911(2) for EUAUXBOILER. The MAP shall, at a minimum, specify the following:
   a) A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.
   b) An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.
   c) A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

   If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits. **(R 336.1205(1)(a) & (b), R 336.1910, R 336.1911, R 336.2803, R 336.2804, R 336.2810)**

2. The permittee shall not operate EUAUXBOILER unless an acceptable plan that describes how emissions will be minimized during all startups, shutdowns and malfunctions has been submitted to the AQD District Supervisor. The plan shall incorporate procedures recommended by the equipment manufacturer as well as incorporating standard industry practices. **(R 336.1911, R 336.1912, R 336.2810, 40 CFR 52.21(j))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The maximum design heat input capacity for EUAUXBOILER shall not exceed 182 MMBTU/hr on a fuel heat input basis. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR Part 60 Subpart Db)**

2. The permittee shall not operate EUAUXBOILER unless the low NO_x burners and flue gas recirculation system are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining the air pollution control equipment in accordance with the MAP required in SC III.1. **(R 336.1205(1)(a) & (b), R 336.1910, R 336.2803, R 336.2804, R 336.2810)**

3. The permittee shall install, calibrate, maintain and operate, in a satisfactory manner, a device to monitor and record the hourly and daily natural gas usage rate for EUAUXBOILER. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.49b(d))**

4. The permittee shall install, calibrate, maintain and operate in a satisfactory manner, devices to monitor and record the NO_x emissions, and oxygen (O_2), or carbon dioxide (CO_2), content of the exhaust gas from EUAUXBOILER on a continuous basis. The permittee shall install and operate the Continuous Emission Monitoring System (CEMS) to meet the timelines, requirements and reporting detailed in Appendix A. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.48b(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. Within 180 days after commencement of initial startup, the permittee shall verify CO, PM, and VOC emission rates from EUAUXBOILER by testing at owner's expense, in accordance with Department requirements. The permittee shall complete the required testing once every five years, thereafter, unless an alternate testing schedule is approved by the District Supervisor. Testing shall be performed using an approved EPA Method listed in:

Pollutant	Test Method Reference
PM	40 CFR Part 60, Appendix A; Part 10 of the Michigan Air Pollution Control Rules
CO	40 CFR Part 60, Appendix A
VOCs	40 CFR Part 60, Appendix A

An alternate method, or a modification to the approved EPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. Verification of emission rates includes the submittal of a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1205(1)(a) & (b), R 336.1331(1)(c), R 336.1702(a), R 336.2001, R 336.2003, R 336.2004, R 336.2803, R 336.2804, R 336.2810)**

2. Within 180 days after commencement of initial startup, the permittee shall verify PM10 and PM2.5 emission factors from EUAUXBOILER by testing at the owner's expense, in accordance with Department requirements. The permittee shall use the emission factors to demonstrate hourly compliance with SC I.4 and SC I.5. Testing shall be performed using an approved EPA Method listed in 40 CFR Part 51, Appendix M. An alternate method, or a modification to the approved EPA Method, may be specified in an AQD approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. Verification of emission rates includes the submittal of a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1205(1)(a) & (b), R 336.2001, R 336.2003, R 336.2004, R 336.2803, R 336.2804, R 336.2810)**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the 30th day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.44b(i), 40 CFR 60.49b(d), (g), & (w))**

2. The permittee shall continuously monitor and record, in a satisfactory manner, the NO_x emissions and the O_2, or CO_2, emissions from EUAUXBOILER. The permittee shall operate each Continuous Emission Monitoring System (CEMS) to meet the timelines, requirements and reporting detailed in Appendix A and shall use the CEMS data for determining compliance with SC I.1. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.48b(b))**

3. The permittee shall keep, in a satisfactory manner, daily and 30-day rolling average NO_x emission rate records for EUAUXBOILER, as required by SC I.1. The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.44b(i), 40 CFR 60.49b(g))**

4. The permittee shall keep hourly and daily natural gas usage records, in a format acceptable to the AQD District Supervisor, indicating the amount of natural gas used, in cubic feet, on a clock hour and calendar day bases and shall calculate and keep monthly natural gas usage records, in a format acceptable to the AQD District Supervisor, indicating the amount of natural gas used, in cubic feet, on a calendar month basis and a 12-month rolling time period basis. The records must indicate the total amount of natural gas used in EUAUXBOILER. The permittee shall keep all records on file at the facility and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.49b(d))**

5. The permittee shall calculate and keep, in a satisfactory manner, records of the monthly and 12-month rolling annual capacity factor for natural gas for EUAUXBOILER. The permittee shall keep all records on file and make them available to the Department upon request. **(40 CFR 60.49b(d))**

6. The permittee shall keep, in a satisfactory manner, records of the fuel receipts (such as a current, valid purchase contract, tariff sheet, or transportation contract) from the fuel supplier that certify that the natural gas meets the definition of natural gas defined in 40 CFR 60.41b and records indicating the sulfur content of the natural gas for EUAUXBOILER on file at the facility and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR Part 60 Subpart Db, 40 CFR 60.49b(r)(1))**

7. The permittee shall calculate and keep, in a satisfactory manner, records of hourly PM10 and PM2.5 mass emissions for EUAUXBOILER, as required by SC I.4 and SC I.5. The permittee shall keep all records on file and make them available to the Department upon request. The calculations shall be performed using a method approved by the AQD District Supervisor. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810)**

8. The permittee shall calculate and keep, in a satisfactory manner, records validating the SO_2 emission factor in SC I.6 based upon the most recent fuel receipts, required by SC VI.6, for EUAUXBOILER. The permittee shall keep all records on file and make them available to the Department upon request. The calculations shall be performed using a method approved by the AQD District Supervisor. **(R 336.2803, R 336.2804, R 336.2810)**

9. The permittee shall calculate and keep, in a satisfactory manner, records of monthly and 12-month rolling total CO_2e mass emissions for EUAUXBOILER, as required by SC I.8. The permittee shall keep all records on file and make them available to the Department upon request. The calculations shall be performed according to Appendix B or an alternate method approved by the District Supervisor. **(R 336.1205(1)(a) & (b), 40 CFR 52.21(j))**

10. The permittee shall maintain records of all information necessary for all notifications and reports as specified in these special conditions as well as that information necessary to demonstrate compliance with the emission limits of this permit. This information shall include, but shall not be limited to the following:
    a) Compliance tests and any testing required under the special conditions of this permit.
    b) Monitoring data.
    c) Verification of heat input capacity required to show compliance with SC IV.1.
    d) Identification, type and the amounts of fuel combusted in EUAUXBOILER on an hourly basis, calendar day basis, and calendar month basis.

e) All records required by 40 CFR 60.7 and 60.49b.
f) All calculations or documents necessary to show compliance with the limits contained in this permit.

All of the above information shall be stored in a format acceptable to the Air Quality Division and shall be consistent with the requirements of 40 CFR 60.7(f). The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1331(1)(c), R 336.1702(a), R 336.1912, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.7(f), 40 CFR Part 60 Subpart Db)**

VII. REPORTING

1. The permittee shall provide written notification of construction and operation to comply with the federal Standards of Performance for New Stationary Sources, 40 CFR 60.7. The permittee shall submit the notification(s) to the AQD District Supervisor within the time frames specified in 40 CFR 60.7. **(40 CFR 60.7(a))**

2. The permittee shall provide written notification of the actual date of initial startup to comply with the federal Standards of Performance for New Stationary Sources, 40 CFR 60.49b(a). The notification shall include:
   a) The design heat input capacity of EUAUXBOILER and identification of the fuels to be combusted in EUAUXBOILER.
   b) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired.

   The permittee shall submit this notification to the AQD District Supervisor within 15 days after initial startup occurs. **(R 336.1201(7)(a), 40 CFR 60.7(a)(3), 40 CFR 60.49b(a))**

3. The permittee shall submit all reports required by the federal Standards of Performance for New Stationary Sources, 40 CFR 60.49b, as applicable. The permittee shall submit these reports to the AQD District Supervisor within the time frames specified in 40 CFR 60.49b and/or 40 CFR 60.7. **(40 CFR 60.7, 40 CFR 60.49b(b), (h) & (i))**

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Diameter / Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVAUXBOILER	48	85	R 336.1225, R 336.2803, R 336.2804

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and Db, as they apply to EUAUXBOILER. **(40 CFR Part 60 Subparts A & Db)**

EUEMENGINE
EMISSION UNIT CONDITIONS

DESCRIPTION

A 2,922 HP (2,179 kilowatts (kW)) diesel-fueled emergency engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder.

Flexible Group ID: FGINITIALPROJECT

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring / Testing Method	Underlying Applicable Requirements
1. NMHC[B]+NO_x	6.4 g/kW-hr[C]	Hourly	EUEMENGINE	SC V.1, SC VI.2, SC VI.3	R 336.1702(a), R 336.2803, R 336.2804, R 336.2810[D], 40 CFR 60.4205(b), 40 CFR 60.4202(a)(2), Table 1 of 40 CFR 89.112
2. CO	3.5 g/kW-hr[C]	Hourly	EUEMENGINE	SC V.1, SC VI.2, SC VI.3	R 336.2804, R 336.2810, 40 CFR 60.4205(b), 40 CFR 60.4202(a)(2), Table 1 of 40 CFR 89.112
3. PM	0.20 g/kW-hr[C]	Hourly	EUEMENGINE	SC V.1, SC VI.2, SC VI.3	R 336.1331(1)(c), R 336.2810, 40 CFR 60.4205(b), 40 CFR 60.4202(a)(2), Table 1 of 40 CFR 89.112
4. PM10	1.58 pph	Hourly	EUEMENGINE	SC VI.5	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
5. PM2.5	1.58 pph	Hourly	EUEMENGINE	SC VI.5	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
6. GHGs as CO_2e	928 tpy	12-month rolling time period as determined at the end of each calendar month.	EUEMENGINE	SC VI.6	R 336.1205(1)(a) & (b), 40 CFR 52.21(j)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring / Testing Method	Underlying Applicable Requirements

[B] NMHC = nonmethane hydrocarbon
[C] These emission limits are for certified engines; if testing becomes required to demonstrate compliance, then the tested values must be compared to the Not to Exceed (NTE) requirements determined through 40 CFR 60.4212(c).
[D] The NMHC+NO_x emission limit is a combined NO_x and VOC BACT limit for PSD review. Note that in PSD regulations, VOCs include formaldehyde, regardless of the NSPS-designated testing method.

II. MATERIAL LIMIT(S)

1. The permittee shall burn only diesel fuel in EUEMENGINE with the maximum sulfur content of 15 ppm (0.0015 percent) by weight, and a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.4207(b), 40 CFR 80.510(b))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUEMENGINE for more than 4 hours per day, except during emergency conditions and required stack testing in SC V.1, and not more than 500 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. The 4 hours and the 500 hours includes the hours for the purpose of necessary maintenance checks and readiness testing as described in SC III.2. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

2. The permittee may operate EUEMENGINE for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUEMENGINE may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing. Except as provided in 40 CFR 60.4211(f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 60.4211(f))**

3. If the permittee purchased a certified engine, according to procedures specified in 40 CFR Part 60 Subpart IIII, for the same model year and maximum engine power, the permittee shall meet the following requirements for EUEMENGINE:
   a) Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;
   b) Change only those emission-related settings that are permitted by the manufacturer; and
   c) Meet the requirements as specified in 40 CFR 89, 94, and/or 1068, as they apply to EUEMENGINE.

   If the permittee does not install, configure, operate, and maintain EUEMENGINE according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the engine may be considered an uncertified engine. **(40 CFR 60.4211(a) & (c), R 336.2810, 40 CFR 52.21(j))**

4. If the permittee purchased an uncertified engine or a certified engine operating in an uncertified manner, the permittee shall keep a maintenance plan for EUEMENGINE and shall, to the extent practicable, maintain and operate engine in a manner consistent with good air pollution control practice for minimizing emissions. **(40 CFR 60.4211(g)(3), R 336.2810, 40 CFR 52.21(j))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUEMENGINE with a non-resettable hours meter to track the operating hours. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.4209(a))**

2. The maximum rated power output of EUEMENGINE shall not exceed a nameplate capacity of 2,179 kW (2,922 HP). **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

3. The permittee shall monitor, in a satisfactory manner, the diesel fuel usage for EUEMENGINE on a continuous basis. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. If EUEMENGINE is not installed, configured, operated, and maintained according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance as follows:
   a) Conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.
   b) If a performance test is required, the performance tests shall be conducted according to 40 CFR 60.4212.
   c) Conduct subsequent performance testing every 8,760 hours of engine operation or every 3 years, whichever comes first, thereafter, to demonstrate compliance with the applicable emission standards.
   d) If a performance test is required, the test plan and complete report must describe how the NMHC+NO_x verification meets the requirements of 40 CFR Part 60 Subpart IIII and of PSD BACT.

   No less than 30 days prior to testing, a complete test plan shall be submitted to the AQD. Verification of emission rates includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test. **(R 336.1331(1)(c), R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.4211(g)(3), 40 CFR 60.4212)**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the 30th day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.4211, 40 CFR 60.4214)**

2. The permittee shall keep, in a satisfactory manner, the following records for EUEMENGINE:
   a) For certified engine: The permittee shall keep records of the manufacturer certification documentation.
   b) For uncertified engine: The permittee shall keep records of testing required in SC V.1.

   The permittee shall keep all records on file and make them available to the Department upon request. **(40 CFR 60.4211)**

3. The permittee shall keep, in a satisfactory manner, the following records of maintenance activity for EUEMENGINE:
   a) For certified engine: The permittee shall keep records of the manufacturer's emission-related written instructions, and records demonstrating that the engine has been maintained according to those instructions, as specified in SC III.3.

b) For uncertified engine: The permittee shall keep records of a maintenance plan, as required by SC III.4, and maintenance activities.

The permittee shall keep all records on file and make them available to the Department upon request. **(40 CFR 60.4211)**

4. The permittee shall keep, in a satisfactory manner, records of the diesel fuel usage for EUEMENGINE on an hourly, monthly, and 12-month rolling time period basis. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

5. The permittee shall calculate and keep, in a satisfactory manner, records of hourly PM10 and PM2.5 mass emissions for EUEMENGINE, as required by SC I.4 and SC I.5. The permittee shall keep all records on file and make them available to the Department upon request. The calculations shall be performed using a method approved by the AQD District Supervisor. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810)**

6. The permittee shall calculate and keep, in a satisfactory manner, records of monthly and 12-month rolling total CO_2e mass emissions for EUEMENGINE, as required by SC I.6. The permittee shall keep all records on file and make them available to the Department upon request. The calculations shall be performed according to Appendix B or an alternate method approved by the District Supervisor. **(R 336.1205(1)(a) & (b), 40 CFR 52.21(j))**

7. The permittee shall monitor and record the total hours of operation for EUEMENGINE on an hourly, daily, monthly, and 12-month rolling time period basis, and the hours of operation during emergency and non-emergency service that are recorded through the non-resettable hours meter for EUEMENGINE, on a calendar year basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUEMENGINE, including what classified the operation as emergency and how many hours are spent for non-emergency operation. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.4211, 40 CFR 60.4214)**

8. The permittee shall keep, in a satisfactory manner, fuel supplier certification records or fuel sample test data, for each delivery of diesel fuel oil used in EUEMENGINE, demonstrating that the fuel meets the requirement of 40 CFR 80.510(b), as specified in SC II.1. The certification or test data shall include the name of the oil supplier or laboratory, the sulfur content, and cetane index or aromatic content of the fuel oil. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.4207(b), 40 CFR 80.510(b))**

VII. REPORTING

1. Within 30 days after completion of the installation, construction, reconstruction, relocation, or modification authorized by this Permit to Install, the permittee or the authorized agent pursuant to Rule 204, shall notify the AQD District Supervisor, in writing, of the completion of the activity. Completion of the installation, construction, reconstruction, relocation, or modification is considered to occur not later than commencement of trial operation of EUEMENGINE. **(R 336.1201(7)(a))**

2. The permittee shall submit a notification specifying whether EUEMENGINE will be operated in a certified or an uncertified manner to the AQD District Supervisor, in writing, within 30 days following the initial startup of the engine and within 30 days of switching the manner of operation. **(R 336.1201(3))**

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Diameter / Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVEMENGINE	21.6	40	R 336.1225, R 336.2803, R 336.2804

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subpart A and Subpart IIII, as they apply to EUEMENGINE. **(40 CFR Part 60 Subparts A & IIII, 40 CFR 63.6590)**

2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR, Part 63, Subpart A and Subpart ZZZZ, as they apply to EUEMENGINE, upon startup. **(40 CFR Part 63 Subparts A and ZZZZ, 40 CFR 63.6595)**

EUFPENGINE
EMISSION UNIT CONDITIONS

DESCRIPTION

A 260 brake HP diesel-fueled emergency fire pump engine with a model year of 2011 or later, and a displacement of <10 liters/cylinder. The fire pump engine has an indicated HP of 300 on the nameplate.

Flexible Group ID: FGINITIALPROJECT

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring / Testing Method	Underlying Applicable Requirements
1. NMHC[B]+NO_x	3.0 g/bhp-hr	Hourly	EUFPENGINE	SC V.1, SC VI.2, SC VI.3	R 336.1702(a), R 336.2803, R 336.2804, R 336.2810[D], 40 CFR 60.4205(c), Table 4 of 40 CFR Part 60 Subpart IIII
2. CO	2.6 g/bhp-hr	Hourly	EUFPENGINE	SC V.1, SC VI.2, SC VI.3	R 336.2804, R 336.2810, 40 CFR 60.4205(c), Table 4 of 40 CFR Part 60 Subpart IIII
3. PM	0.15 g/bhp-hr	Hourly	EUFPENGINE	SC V.1, SC VI.2, SC VI.3	R 336.1331(1)(c), R 336.2810, 40 CFR 60.4205(c), Table 4 of 40 CFR Part 60 Subpart IIII
4. PM10	0.57 pph	Hourly	EUFPENGINE	SC VI.5	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
5. PM2.5	0.57 pph	Hourly	EUFPENGINE	SC VI.5	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
6. GHGs as CO_2e	13.58 tpy	12-month rolling time period as determined at the end of each calendar month.	EUFPENGINE	SC VI.6	R 336.1205(1)(a) & (b), 40 CFR 52.21(j)

[B] NMHC = nonmethane hydrocarbon
[D] The NMHC+NO_x emission limit is a combined NO_x and VOC BACT limit for PSD review. Note that in PSD regulations, VOCs include formaldehyde, regardless of the NSPS-designated testing method.

II. MATERIAL LIMIT(S)

1. The permittee shall burn only diesel fuel in EUFPENGINE with the maximum sulfur content of 15 ppm (0.0015 percent) by weight, and a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.4207(b), 40 CFR 80.510(b))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUFPENGINE for more than 1 hour per day, except during emergency conditions and required stack testing in SC V.1, and not more than 100 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. The 1 hours and the 100 hours includes the hours for the purpose of necessary maintenance checks and readiness testing as described in SC III.2. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

2. The permittee may operate EUFPENGINE for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUFPENGINE may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing. Except as provided in 40 CFR 60.4211(f)(3)(i), the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 60.4211(f))**

3. If the permittee purchased a certified engine, according to procedures specified in 40 CFR Part 60 Subpart IIII, for the same model year and maximum engine power, the permittee shall meet the following requirements for EUFPENGINE:
   a) Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;
   b) Change only those emission-related settings that are permitted by the manufacturer; and
   c) Meet the requirements as specified in 40 CFR 89, 94, and/or 1068, as they apply to EUFPENGINE.

   If the permittee does not install, configure, operate, and maintain EUFPENGINE according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the engine may be considered an uncertified engine. **(40 CFR 60.4211(a) & (c), R 336.2810, 40 CFR 52.21(j))**

4. If the permittee purchased an uncertified engine or a certified engine operating in an uncertified manner, the permittee shall keep a maintenance plan for EUFPENGINE and shall, to the extent practicable, maintain and operate engine in a manner consistent with good air pollution control practice for minimizing emissions. **(40 CFR 60.4211(g)(2), R 336.2810, 40 CFR 52.21(j))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUFPENGINE with a non-resettable hours meter to track the operating hours. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.4209(a))**

2. The maximum rated power input of EUFPENGINE shall not exceed 260 brake HP. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), Table 4 of 40 CFR Part 60 Subpart IIII)**

3. The permittee shall monitor, in a satisfactory manner, the diesel fuel usage for EUFPENGINE on a continuous basis. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. If EUFPENGINE is not installed, configured, operated, and maintained according to the manufacturer's emission-related written instructions, or the permittee changes emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance as follows:
   a) Conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.
   b) If a performance test is required, the performance tests shall be conducted according to 40 CFR 60.4212.
   c) If a performance test is required, the test plan and complete report must describe how the $NMHC+NO_x$ verification meets the requirements of 40 CFR Part 60 Subpart IIII and of PSD BACT.

   No less than 30 days prior to testing, a complete test plan shall be submitted to the AQD. Verification of emission rates includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test. **(R 336.1331(1)(c), R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.4211(g)(2), 40 CFR 60.4212)**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the 30th day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.4211, 40 CFR 60.4214)**

2. The permittee shall keep, in a satisfactory manner, the following records for EUFPENGINE:
   a) For certified engine: The permittee shall keep records of the manufacturer certification documentation.
   b) For uncertified engine: The permittee shall keep records of testing required in SC V.1.

   The permittee shall keep all records on file and make them available to the Department upon request. **(40 CFR 60.4211)**

3. The permittee shall keep, in a satisfactory manner, the following records of maintenance activity for EUFPENGINE:
   a) For certified engine: The permittee shall keep records of the manufacturer's emission-related written instructions, and records demonstrating that the engine has been maintained according to those instructions, as specified in SC III.3.
   b) For uncertified engine: The permittee shall keep records of a maintenance plan, as required by SC III.4, and maintenance activities.

   The permittee shall keep all records on file and make them available to the Department upon request. **(40 CFR 60.4211)**

4. The permittee shall keep, in a satisfactory manner, records of the diesel fuel usage for EUFPENGINE on an hourly, monthly, and 12-month rolling time period basis. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

5. The permittee shall calculate and keep, in a satisfactory manner, records of hourly PM10 and PM2.5 mass emissions for EUFPENGINE, as required by SC I.4 and SC I.5. The permittee shall keep all records on file and make them available to the Department upon request. The calculations shall be performed using a method approved by the AQD District Supervisor. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810)**

6. The permittee shall calculate and keep, in a satisfactory manner, records of monthly and 12-month rolling total CO_2e mass emissions for EUFPENGINE, as required by SC I.6. The permittee shall keep all records on file and make them available to the Department upon request. The calculations shall be performed according to Appendix B or an alternate method approved by the District Supervisor. **(R 336.1205(1)(a) & (b), 40 CFR 52.21(j))**

7. The permittee shall monitor and record the total hours of operation for EUFPENGINE on an hourly, daily, monthly, and 12-month rolling time period basis, and the hours of operation during emergency and non-emergency service that are recorded through the non-resettable hours meter for EUFPENGINE, on a calendar year basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUFPENGINE, including what classified the operation as emergency and how many hours are spent for non-emergency operation. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.4211, 40 CFR 60.4214)**

8. The permittee shall keep, in a satisfactory manner, fuel supplier certification records or fuel sample test data, for each delivery of diesel fuel oil used in EUFPENGINE, demonstrating that the fuel meets the requirement of 40 CFR 80.510(b), as specified in SC II.1. The certification or test data shall include the name of the oil supplier or laboratory, the sulfur content, and cetane index or aromatic content of the fuel oil. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.4207(b), 40 CFR 80.510(b))**

9. The permittee shall keep manufacturer documentation showing the brake HP for EUFPENGINE. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 228.2810, 40 CFR 52.21(j), Table 4 of 40 CFR Part 60 Subpart IIII)**

VII. REPORTING

1. Within 30 days after completion of the installation, construction, reconstruction, relocation, or modification authorized by this Permit to Install, the permittee or the authorized agent pursuant to Rule 204, shall notify the AQD District Supervisor, in writing, of the completion of the activity. Completion of the installation, construction, reconstruction, relocation, or modification is considered to occur not later than commencement of trial operation of EUFPENGINE. **(R 336.1201(7)(a))**

2. The permittee shall submit a notification specifying whether EUFPENGINE will be operated in a certified or an uncertified manner to the AQD District Supervisor, in writing, within 30 days following the initial startup of the engine and within 30 days of switching the manner of operation. **(R 336.1201(3))**

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Diameter / Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVFPENGINE[E]	6	10	R 336.1225, R 336.2803, R 336.2804
[E] This stack has a horizontal discharge.			

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subpart A and Subpart IIII, as they apply to EUFPENGINE. **(40 CFR Part 60 Subparts A & IIII, 40 CFR 63.6590)**

2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR, Part 63, Subpart A and Subpart ZZZZ, as they apply to EUFPENGINE, upon startup. **(40 CFR Part 63 Subparts A and ZZZZ, 40 CFR 63.6595)**

EUCOLDCLEANER
EMISSION UNIT CONDITIONS

DESCRIPTION

New closed-cover cold cleaner.

Flexible Group ID: FGINITIALPROJECT

POLLUTION CONTROL EQUIPMENT

Closed cover when not in use.

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

1. The permittee shall not use cleaning solvents containing more than five percent by weight of the following halogenated compounds: methylene chloride, perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, carbon tetrachloride, chloroform, or any combination thereof. **(R 336.1225, R 336.1702(a))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Cleaned parts shall be drained for no less than 15 seconds or until dripping ceases. **(R 336.1225, R 336.1702(a), R 336.1707(3)(b))**

2. The permittee shall perform routine maintenance on each cold cleaner as recommended by the manufacturer. **(R 336.1225, R 336.1702(a))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The cold cleaner must meet one of the following design requirements: **(R 336.1225, R 336.1702(a))**
   a. The air/vapor interface of the cold cleaner is no more than ten square feet.
   b. The cold cleaner is used for cleaning metal parts and the emissions are released to the general in-plant environment.

2. The cold cleaner shall be equipped with a device for draining cleaned parts. **(R 336.1225, R 336.1702(a), R 336.1707(3)(b))**

3. The cold cleaner shall be equipped with a cover and the cover shall be closed whenever parts are not being handled in the cold cleaner. **(R 336.1205, R 336.1224, R 336.1225, R 336.1702(a), R 336.1707(3)(a), R 336.1910, R 336.2810)**

4. The cover of a new cold cleaner shall be mechanically assisted if the Reid vapor pressure of the solvent is more than 0.3 psia or if the solvent is agitated or heated. **(R 336.1225, R 336.1702(a), R 336.1707(3)(a))**

5. If the Reid vapor pressure of any solvent used in a new cold cleaner is greater than 0.6 psia; or, if any solvent used in a new cold cleaner is heated above 120 degrees Fahrenheit, then the cold cleaner must comply with at least one of the following provisions: **(R 336.1225, R 336.1702(a), R 336.1707(2)(a), (b), & (c))**
   a) The cold cleaner must be designed such that the ratio of the freeboard height to the width of the cleaner is equal to or greater than 0.7.

b) The solvent bath must be covered with water if the solvent is insoluble and has a specific gravity of more than 1.0.
c) The cold cleaner must be controlled by a carbon adsorption system, condensation system, or other method of equivalent control approved by the AQD.

V. TESTING/SAMPLING
Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

NA

VI. MONITORING/RECORDKEEPING
Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. For each new cold cleaner in which the solvent is heated, the solvent temperature shall be monitored and recorded at least once each calendar week during routine operating conditions. **(R 336.1225, R 336.1707)**

2. The permittee shall maintain the following information on file for each cold cleaner: **(R 336.1225, R 336.1702(a), R 336.1707(2))**
   a) A serial number, model number, or other unique identifier for each cold cleaner.
   b) The date the unit was installed, manufactured or that it commenced operation.
   c) The air/vapor interface area.
   d) The Reid vapor pressure of each solvent used.
   e) If applicable, the option chosen to comply with SC IV.5.

3. The permittee shall maintain written operating procedures for each cold cleaner. These written procedures shall be posted in an accessible, conspicuous location near each cold cleaner. **(R 336.1910, R 336.1707(4))**

4. As noted in Rule 707(3)(c), if applicable, an initial demonstration that the waste solvent is a safety hazard shall be made prior to storage in non-closed containers. If the waste solvent is a safety hazard and is stored in non-closed containers, verification that the waste solvent is disposed of so that not more than 20 percent, by weight, is allowed to evaporate into the atmosphere shall be made on a monthly basis. **(R 336.1225, R 336.1702(a), R 336.1707(3)(c))**

VII. REPORTING

NA

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

NA

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

FLEXIBLE GROUP SPECIAL CONDITIONS

FLEXIBLE GROUP SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Flexible Group ID	Flexible Group Description	Associated Emission Unit IDs
FGCTGHRSG	Two (2) combined-cycle natural gas-fired CTG with HRSG in a 2x1 configuration with a steam turbine generator. Each CTG/HRSG is equipped with dry low NO_x burners (DLNB), selective catalytic reduction (SCR), and an oxidation catalyst.	EUCTGHRSG1, EUCTGHRSG2
FGFUELHTR	Two (2) natural gas-fired fuel gas dew point heaters.	EUFUELHTR1, EUFUELHTR2
FGFUELTANK	Two (2) closed-roof tanks for purposes of storing ultra-low sulfur diesel fuel.	EUEMFUELTANK, EUFPFUELTANK
FGSPACEHTRS*	Up to 44 natural gas-fired space heaters and air makeup units with a combined rating of 10 MMBTU/hr or less to provide building heating and ventilation.	NA
FGINITIALPROJECT	All of the equipment associated with the greenfield project.	EUCTGHRSG1, EUCTGHRSG2, EUAUXBOILER, EUFUELHTR1, EUFUELHTR2, EUEMENGINE, EUFPENGINE, EUEMFUELTANK, EUFPFUELTANK, EUCOLDCLEANER, FGSPACEHTRS
*This flexible group is also contained within the FGINITIALPROJECT flexible group.		

FGCTGHRSG
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Two (2) combined-cycle natural gas-fired CTG with HRSG in a 2x1 configuration with a steam turbine generator. Each CTG/HRSG is equipped with dry low NO_x burners (DLNB), selective catalytic reduction (SCR), and an oxidation catalyst.

Emission Unit: EUCTGHRSG1, EUCTGHRSG2

POLLUTION CONTROL EQUIPMENT

DLNB and SCR for NO_x control for each CTG/HRSG unit. An oxidation catalyst for CO and VOC control for each CTG/HRSG unit.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring / Testing Method	Underlying Applicable Requirements
1. NO_x	2 ppmvd at 15% O_2 (each unit)[F]	24-hour rolling average as determined each operating hour, except during startup and shutdown	EUCTGHRSG1, EUCTGHRSG2	SC VI.2, SC VI.3	R 336.1205(1)(a) & (b), R 336.2810
2. NO_x	15 ppm at 15% O_2 (each unit)[F]	30-day rolling average as determined each operating day	EUCTGHRSG1, EUCTGHRSG2	SC VI.2, SC VI.3	40 CFR 60.4320(a), Table 1 of 40 CFR Part 60 Subpart KKKK[G]
3. NO_x	27.4 pph (each unit)[F]	24-hour rolling average as determined each operating hour, except during startup and shutdown	EUCTGHRSG1, EUCTGHRSG2	SC VI.2, SC VI.3	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
4. NO_x	286 pph (each unit)[H]	Operating hour during startup or shutdown[H]	EUCTGHRSG1, EUCTGHRSG2	SC VI.2, SC VI.3, SC VI.11	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
5. CO	4 ppmvd at 15% O_2 (each unit)[F]	24-hour rolling average as determined each operating hour, except during startup and shutdown	EUCTGHRSG1, EUCTGHRSG2	SC VI.2, SC VI.4	R 336.1205(1)(a) & (b), R 336.2810

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring / Testing Method	Underlying Applicable Requirements
6. CO	24.7 pph (each unit)[F]	24-hour rolling average as determined each operating hour, except during startup and shutdown	EUCTGHRSG1, EUCTGHRSG2	SC VI.2, SC VI.4	R 336.1205(1)(a) & (b), R 336.2804, R 336.2810
7. CO	3,537 pph (each unit)[H]	Operating hour during startup or shutdown[H]	EUCTGHRSG1, EUCTGHRSG2	SC VI.2, SC VI.4, SC VI.11	R 336.1205(1)(a) & (b), R 336.2804, R 336.2810
8. PM	9.9 pph (each unit)	Hourly	EUCTGHRSG1, EUCTGHRSG2	SC V.1, SC VI.11	R 336.1205(1)(a) & (b), R 336.1331(1)(c), R 336.2810
9. PM10	19.8 pph (each unit)	Hourly	EUCTGHRSG1, EUCTGHRSG2	SC V.1, SC VI.11	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
10. PM2.5	19.8 pph (each unit)	Hourly	EUCTGHRSG1, EUCTGHRSG2	SC V.1, SC VI.11	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
11. SO_2	11.7 pph (each unit)	Hourly	EUCTGHRSG1, EUCTGHRSG2	SC V.1, SC VI.11	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
12. SO_2	0.060 lb/MMBTU	Hourly	EUCTGHRSG1, EUCTGHRSG2	SC VI.11	40 CFR 60.4330
13. VOC	4 ppmvd at 15% O_2 (each unit)[F]	Hourly	EUCTGHRSG1, EUCTGHRSG2	SC V.1, SC VI.11	R 336.1205(1)(a) & (b), R 336.1702(a), R 336.2810
14. Sulfuric acid mist (H_2SO_4)	4.6 pph (each unit)	Hourly	EUCTGHRSG1, EUCTGHRSG2	SC V.1, SC VI.11	R 336.1205(1)(a) & (b), R 336.2810
15. GHGs as CO_2e	1,911,481 tpy (each unit)	12-month rolling time period as determined at the end of each calendar month.	EUCTGHRSG1, EUCTGHRSG2	SC VI.5, SC VI.6, SC VI.11	R 336.1205(1)(a) & (b), 40 CFR 52.21(j)
16. CO_2	802 lb/MWh	12-operating month rolling average basis as determined at the end of each operating calendar month.[I]	EUCTGHRSG1, EUCTGHRSG2	SC VI.6, SC VI.11	R 336.1205(1)(a) & (b), 40 CFR 52.21(j), 40 CFR 60.5520(a)[J], Table 2 of 40 CFR Part 60 Subpart TTTT[J]

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring / Testing Method	Underlying Applicable Requirements
17. Formaldehyde	9.3 tpy	12-month rolling time period as determined at the end of each calendar month.	FGCTGHRSG	SC V.2, SC VI.10, SC VI.11	R 336.1205(1), R 336.1224, R 336.1225

ppmvd = parts per million by volume at 15 percent oxygen (O_2) and on a dry gas basis
lb/MWh = pound per megawatt hour
[F] Does not include startup and shutdown.
[G] Table 1 of 40 CFR Part 60 Subpart KKKK also allows 96 ppm at 15 percent O_2 when the turbines are operating at less than 75 percent of peak load and at temperatures less than 0°F.
[H] Startup is defined as the period of time from initiation of the combustion process (flame-on) from shutdown status and continues until steady state operation (loads greater than a demonstrated percent of design capacity) is achieved. Shutdown is defined as that period of time from the lowering of the turbine output below the demonstrated steady state level, with the intent to shut down, until the point at which the fuel flow to the combustor is terminated. The demonstrated percent of design capacity, or demonstrated steady state level, shall be described in the plan required in SC III.2.
[I] Compliance is determined monthly at the end of the initial and each subsequent 12-operating-month period. The first month of the initial compliance period is defined in 40 CFR 60.5525(c)(1)(i).
[J] The emission limit as required in 40 CFR 60.5520(a) and Table 2 of 40 CFR Part 60 Subpart TTTT is 1,000 lb CO_2/MWh. SC I.14 subsumes the NSPS emission limit.

II. MATERIAL LIMIT(S)

1. The permittee shall only burn pipeline quality natural gas in any unit in FGCTGHRSG. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1702(a), R 336.2810, 40 CFR 52.21(j), 40 CFR 60.4330)**

2. The pipeline quality natural gas shall not have a total sulfur content in excess of 20 gr of sulfur per 100 scf. **(40 CFR 60.4365)**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Within 180 days of trial operation, the permittee shall submit, implement, and maintain a malfunction abatement plan (MAP) as described in Rule 911(2) for EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG. The MAP shall, at a minimum, specify the following:
   a) A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.
   b) An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.
   c) A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.
   d) Identification of the source, and operating variables and ranges for varying loads, shall be monitored and recorded. The normal operating range of these variables and a description of the method of monitoring shall be maintained.
   e) The procedure that will be followed to address a test result that is higher than the emission factor listed in SC V.2.

   If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 90 days after such an event occurs. The permittee shall also amend the MAP within 90 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1702(a), R 336.1910, R 336.1911, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

2. The permittee shall not operate any unit in FGCTGHRSG unless the AQD District Supervisor has approved a plan that describes how emissions will be minimized during startup and shutdown. The plan shall incorporate procedures recommended by the equipment manufacturer as well as incorporating standard industry practices, and shall describe the demonstrated percent of design capacity, or demonstrated steady state level. Unless notified by the District Supervisor within 30 business days after plan submittal, the plan shall be deemed approved. **(R 336.1911, R 336.1912, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.4333(a))**

3. The total hours for startup and shutdown for each CTG/HRSG train in FGCTGHRSG shall not exceed 500 hours per 12-month rolling time period as determined at the end of each calendar month. **(R 336.2803, R 336.2804, R 336.2810)**

4. The permittee shall operate and maintain EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. **(40 CFR 60.4333(a), 40 CFR 60.5525(b))**

5. The permittee shall prepare a monitoring plan to quantify the hourly CO_2 mass emission rate (tons/hr), in accordance with the applicable provisions in 40 CFR 75.53(g) and (h). The electronic portion of the monitoring plan must be submitted using the ECMPS Client Tool and must be in place prior to reporting emissions data and/or the results of monitoring system certification tests under this subpart. The monitoring plan must be updated as necessary. Monitoring plan submittals must be made by the Designated Representative (DR), the Alternate DR, or a delegated agent of the DR (see 40 CFR 60.5555(c)). **(40 CFR 60.5535(a), 40 CFR 60.5535(d)(1))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The maximum design heat input capacity for each turbine in FGCTGHRSG shall not exceed, on a fuel heat input basis, 3,651 MMBTU/hr and the design heat input capacity for each duct burner in FGCTGHRSG shall not exceed, on a fuel heat input basis, 71 MMBTU/hr. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

2. The permittee shall not operate EUCTGHRSG1 or EUCTGHRSG2 of FGCTGHRSG unless each respective dry low NO_x burners, selective catalytic reduction, and oxidation catalyst are installed, maintained, and operated in a satisfactory manner, for each CTG/HRSG. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for FGCTGHRSG as required in SC III.1. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.1910, R 336.2803, R 336.2804, R 336.2810)**

3. The permittee shall install, calibrate, maintain and operate in a satisfactory manner, devices to monitor and record the NO_x emissions and oxygen (O_2), or carbon dioxide (CO_2), content of the exhaust gas from both EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG on a continuous basis. The permittee shall install and operate the Continuous Emission Monitoring System (CEMS) to meet the timelines, requirements and reporting detailed in Appendix A. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.4340(b)(1), 40 CFR 60.4345, 40 CFR Part 75)**

4. The permittee shall install, calibrate, maintain and operate in a satisfactory manner a device to monitor and record the CO emissions and oxygen (O_2), or carbon dioxide (CO_2), content of the exhaust gas from both EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG on a continuous basis. The permittee shall install and operate the Continuous Emission Monitoring System (CEMS) to meet the timelines, requirements and reporting detailed in Appendix A. **(R 336.1205(1)(a) & (b), R 336.2804, R 336.2810, 40 CFR Part 75)**

5. The permittee shall install, calibrate, maintain and operate in a satisfactory manner a device to monitor and record the natural gas flow rate for EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG on a continuous basis. The device shall be operated in accordance with 40 CFR 60.4345(c). **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.4345)**

6. The permittee shall install, calibrate, maintain and operate in a satisfactory manner a sufficient number of watt meters to continuously measure and record the hourly gross electric output from EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG. **(R 336.1205(1)(a) & (b), 40 CFR 52.21(j), 40 CFR 60.5535(d)(1))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. Within 180 days after commencement of initial startup, the permittee shall verify PM, PM10, PM2.5, SO_2, VOC, and H_2SO_4 emission rates from EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG at maximum routine operating conditions, by testing at the owner's expense, in accordance with Department requirements. The permittee must complete the required testing once every five years of operation, thereafter. Upon approval of the AQD District Supervisor, subsequent testing may be conducted upon EUCTGHRSG1 or EUCTGHRSG2 as a representative unit. However, the permittee shall not test the same representative unit in subsequent tests unless approved or requested by the AQD District Supervisor. Testing shall be performed using an approved EPA Method listed in:

Pollutant	**Test Method Reference**
PM	40 CFR Part 60, Appendix A; Part 10 of the Michigan Air Pollution Control Rules
PM10 / PM2.5	40 CFR Part 51, Appendix M
SO_2	40 CFR Part 60, Appendix A
VOCs	40 CFR Part 60, Appendix A
H_2SO_4	40 CFR Part 60, Appendix A

An alternate method, or a modification to the approved EPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. Verification of emission rates includes the submittal of a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1205(1)(a) & (b), R 336.1331(1)(c), R 336.1702(a), R 336.2001, R 336.2003, R 336.2004, R 336.2803, R 336.2804, R 336.2810)**

2. The permittee shall conduct testing to verify the formaldehyde emission factor from EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG at maximum routine operating conditions, by testing at the owner's expense, in accordance with Department requirements, according to the following schedule:
   a) An initial test within 180 days after commencement of initial startup.
   b) Subsequent tests shall be performed once per year for a period of two years to develop a baseline data set consisting of three separate test reports (the initial test and two subsequent tests).
   c) Each subsequent test after the baseline data set is developed shall be performed once per year.
   d) After the baseline data set is developed, if two consecutive test results are less than 75 percent of the base emission factor, then the subsequent test may be performed once every three years. The emission factor and threshold are below:

Base Emission Factor Annual Timeframe (ppmvd at 15% O_2 on a dry gas basis)	Emission Factor 75% Threshold 3-Year Timeframe (ppmvd at 15% O_2 on a dry gas basis)	Emission Factor 55% Threshold 5-Year Timeframe (ppmvd at 15% O_2 on a dry gas basis)
0.160	0.120	0.088

   e) If a test results in an emission factor at or above the 75 percent threshold, then the subsequent tests shall revert back to an annual timeframe as described in SC V.2(c).
   f) After the baseline data set is developed, if two consecutive test results are less than 55 percent of the base emission factor, then the subsequent test may be performed once every five years. The emission factor and threshold are above.

g) If a test results in an emission factor at or above the 55 percent threshold, then the subsequent tests shall revert back to once every three years if below the 75 percent threshold as described in SC V.2(d) or an annual timeframe as described in SC V.2(c).
h) If a test results in an emission factor above the listed base emission factor, then procedures shall be enacted to address future emissions according to the MAP required in SC III.1.

Upon approval of the AQD District Supervisor, subsequent testing may be conducted upon EUCTGHRSG1 or EUCTGHRSG2 as a representative unit. However, the permittee shall not test the same representative unit in subsequent tests unless approved or requested by the AQD District Supervisor. Testing shall be performed using an approved EPA Method listed in 40 CFR Part 63, Appendix A. An alternate method, or a modification to the approved EPA Method, may be specified in an AQD approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1205(1), R 336.1224, R 336.1225, R 336.2001, R 336.2003, R 336.2004)**

VI. <u>MONITORING/RECORDKEEPING</u>

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the 30th day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.5540(a) & (b), 40 CFR 60.5560)**

2. The permittee shall continuously monitor and record, in a satisfactory manner, the NO_x and CO emissions and the O_2, or CO_2, emissions from EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG. The permittee shall operate each CEMS to meet the timelines, requirements and reporting detailed in Appendix A and shall use the CEMS data for determining compliance with SC I.1, SC I.2, SC I.3, SC I.4, SC I.5, SC I.6, and SC I.7. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.4345)**

3. The permittee shall calculate and keep, in a satisfactory manner, hourly and 24-hour rolling average NO_x concentration and mass emission records, and 30-day rolling average NO_x concentration records for EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG, as required by SC I.1, SC I.2, SC I.3, and SC I.4. The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 60.4345)**

4. The permittee shall calculate and keep, in a satisfactory manner, hourly and 24-hour rolling average CO concentration and mass emission records for EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG, as required by SC I.5, SC I.6, and SC I.7. The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), R 336.2804, R 336.2810)**

5. The permittee shall monitor and record, in a satisfactory manner, the natural gas usage for EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG on a monthly basis. The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

6. The permittee shall calculate and keep, in a satisfactory manner, records of monthly and 12-month rolling total CO_2e mass emissions for EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG, as required by SC I.15. The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), 40 CFR 52.21(j))**

7. The permittee shall determine the hourly CO_2 mass emissions and hourly gross energy output for both EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG according to 40 CFR 60.5535(b) or (c) and 40 CFR 60.5540(a). The permittee shall keep records of the determined values for hourly CO_2 mass emissions and hourly gross energy output for both EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG. **(40 CFR 60.5535(c), 40 CFR 60.5540(a), 40 CFR 60.5560)**

8. The permittee shall calculate and keep, in a satisfactory manner, records of the monthly and initial and each subsequent 12-operating-month calculation required by SC I.16 according to the procedures described in 40 CFR 60.5540: **(R 336.1205(1)(a) & (b), 40 CFR 52.21(j), 40 CFR 60.5540(a) & (b), 40 CFR 60.5560)**
   a) Total data is determined by summing valid operating hours for either CO_2 mass emissions or gross energy output.
   b) To determine compliance with SC I.16, the total CO_2 mass emissions for each unit, EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG, shall be divided by the total gross energy output value of the same unit, EUCTGHRSG1 or EUCTGHRSG2 of FGCTGHRSG.
   c) The final calculated value shall be rounded to two significant figures if the calculated value is less than 1,000 and to three significant figures if the calculated value is greater than 1,000.

9. The permittee shall keep, in a satisfactory manner, a record of the monthly and 12-month rolling total hours of startup and shutdown for each CTG/HRSG train in FGCTGHRSG. The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.2803, R 336.2804, R 336.2810)**

10. The permittee shall calculate and keep, in a satisfactory manner, records of monthly and 12-month rolling total formaldehyde mass emissions for FGCTGHRSG, as required by SC I.17. The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.1205(1), R 336.1224, R 336.1225)**

11. The permittee shall maintain records of all information necessary for all notifications and reports as specified in these special conditions as well as that information necessary to demonstrate compliance with the emission limits of this permit for FGCTGHRSG. This information shall include, but shall not be limited to the following:
    a) Compliance tests and any testing required under the special conditions of this permit.
    b) Monitoring data.
    c) Total sulfur content and potential sulfur emissions, as applicable, of the natural gas as required by 40 CFR 60.4365(a) or (b).
    d) Verification of heat input capacity.
    e) Identification, type, and amount of fuel combusted on a calendar month basis.
    f) Gross energy output on a calendar month basis.
    g) All records required by 40 CFR 60.7.
    h) Records of the duration of all dates and times of startup and shutdown events.
    i) All calculations necessary to show compliance with the limits contained in this permit.
    j) All records related to, or as required by, the MAP and the startup and shutdown plan.

    All of the above information shall be stored in a format acceptable to the AQD District Supervisor and shall be consistent with the requirements of 40 CFR 60.7(f). **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1331(1)(c), R 336.1702(a), R 336.1912, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.7(f), 40 CFR 60.4345, 40 CFR 60.4365, 40 CFR 60.5525(b), 40 CFR 60.5560)**

VII. <u>REPORTING</u>

1. Within 30 days after completion of the installation, construction, reconstruction, relocation, or modification authorized by this Permit to Install, the permittee or the authorized agent pursuant to Rule 204, shall notify the AQD District Supervisor, in writing, of the completion of the activity. Completion of the installation, construction, reconstruction, relocation, or modification is considered to occur not later than commencement of trial operation of EUCTGHRSG1 or EUCTGHRSG2. **(R 336.1201(7)(a))**

2. The permittee shall provide written notification of the date construction commences and the actual date of initial startup of each unit in FGTURBINES, in accordance with 40 CFR 60.7. The permittee shall submit the notification(s) to the AQD District Supervisor within the time frames specified in 40 CFR 60.7 and 40 CFR 60.19, where applicable. **(40 CFR 60.7(a), 40 CFR 60.5550(a))**

3. The permittee shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c) and with 40 CFR 60.4375 and 40 CFR 4380. The reports shall be postmarked by the 30th day following the end of each 6-month period. **(40 CFR 60.7(c), 40 CFR 60.4375(a), 40 CFR 60.4380, 40 CFR 60.4395)**

4. The permittee shall prepare and submit the notifications specified in 40 CFR 60.19, as applicable, and 40 CFR 75.61, as applicable, for each unit, EUCTGHRSG1 and EUCTGHRSG2 of FGCTGHRSG. **(40 CFR 60.5550(a) & (b))**

5. The permittee shall submit electronic quarterly reports as follows: **(40 CFR 60.5555(a) & (b))**
   a) After each unit has accumulated the first 12-operating months, the permittee shall submit a report for the calendar quarter that includes the twelfth operating month no later than 30 days after the end of that quarter.
   b) Thereafter, the permittee shall submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.
   c) Each quarterly report shall include the information specified in 40 CFR 60.5555(a)(2).
   d) The final quarterly report of each calendar year shall include the information specified in 40 CFR 60.5555(a)(3).
   e) All electronic reports shall be submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

6. The permittee shall meet all applicable reporting requirements and submit reports as required under 40 CFR Part 75 Subpart G in accordance with 40 CFR 75.64(a), which is also listed in 40 CFR 60.5555(c)(3)(i). **(40 CFR 60.5555(c)(1) & (3)(i))**

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Diameter / Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVCTGHRSG1	264	170	R 336.1225, R 336.2803, R 336.2804
2. SVCTGHRSG2	264	170	R 336.1225, R 336.2803, R 336.2804

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and KKKK, as they apply to each unit in FGCTGHRSG. **(40 CFR Part 60 Subparts A and KKKK)**

2. The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and TTTT, as they apply to each unit in FGCTGHRSG. **(40 CFR Part 60 Subparts A and TTTT)**

FGFUELHTR
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Two (2) natural gas-fired fuel gas dew point heaters.

Emission Unit: EUFUELHTR1, EUFUELHTR2

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring / Testing Method	Underlying Applicable Requirements
1. NO_x	1.32 pph (each unit)	Hourly	EUFUELHTR1, EUFUELHTR2	SC VI.3, SC VI.6	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
2. CO	1.11 pph (each unit)	Hourly	EUFUELHTR1, EUFUELHTR2	SC VI.3, SC VI.6	R 336.1205(1)(a) & (b), R 336.2804, R 336.2810
3. PM	0.002 lb/MMBTU (each unit)	Hourly	EUFUELHTR1, EUFUELHTR2	SC V.1 SC VI.4, SC VI.6	R 336.1331(1)(c), R 336.2810
4. PM10	0.10 pph (each unit)	Hourly	EUFUELHTR1, EUFUELHTR2	SC VI.3, SC VI.6	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
5. PM2.5	0.10 pph (each unit)	Hourly	EUFUELHTR1, EUFUELHTR2	SC VI.3, SC VI.6	R 336.1205(1)(a) & (b), R 336.2803, R 336.2804, R 336.2810
6. VOC	0.07 pph (each unit)	Hourly	EUFUELHTR1, EUFUELHTR2	SC VI.3, SC VI.6	R 336.1205(1)(a) & (b), R 336.1702(a), R 336.2810
7. GHGs as CO_2e	13,848 tpy	12-month rolling time period as determined at the end of each calendar month.	FGFUELHTR	SC VI.5, SC VI.6	R 336.1205(1)(a) & (b), 40 CFR 52.21(j)

II. MATERIAL LIMIT(S)

1. The permittee shall burn only pipeline quality natural gas in either unit of FGFUELHTR, with a sulfur content of 2,000 gr per MMscf or less. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60 Subpart Dc, 40 CFR 63.11195(e))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

NA

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The maximum design heat input capacity for each unit in FGFUELHTR shall not exceed 13.5 MMBTU per hour on a fuel heat input basis. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR Part 60 Subpart Dc)**

2. The permittee shall install, calibrate, maintain and operate, in a satisfactory manner, a device to monitor and record the hourly and monthly natural gas usage rate for each unit in FGFUELHTR. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.48c(g))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. Within 365 days after commencement of initial startup, the permittee shall verify PM emission rates from a single unit of FGFUELHTR, at maximum routine operation, by testing at the owner's expense, in accordance with Department requirements. Within 730 days after commencement of initial startup, the permittee shall verify PM emission rates from the other unit of FGFUELHTR, at maximum routine operation, by testing at the owner's expense, in accordance with Department requirements. Upon request by the AQD District Supervisor, the permittee shall verify the PM emission rates through subsequent testing of one or both units of FGFUELHTR. The permittee shall not test the same representative unit in subsequent tests unless approved or requested by the AQD District Supervisor. Testing shall be performed using an approved EPA Method listed in 40 CFR Part 60, Appendix A and Part 10 of the Michigan Air Pollution Control Rules. An alternate method, or a modification to the approved EPA Method, may be specified in an AQD approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. Verification of emission rates includes the submittal of a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1331(1)(c), R 336.2001, R 336.2003, R 336.2004, R 336.2810)**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the 30th day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.44b(i), 40 CFR 60.48c(j) & (g))**

2. The permittee shall keep hourly and monthly natural gas usage records, in a format acceptable to the AQD District Supervisor, indicating the amount of natural gas used, in cubic feet, on a clock hour basis for each unit in FGFUELHTR, and shall calculate and keep monthly natural gas usage records, in a format acceptable to the AQD District Supervisor, indicating the amount of natural gas used, in cubic feet, on a calendar month basis for each unit in FGFUELHTR and a 12-month rolling time period basis for FGFUELHTR. The permittee shall keep all records on file at the facility and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.48c(g))**

3. The permittee shall calculate and keep, in a satisfactory manner, records of hourly NO_x, CO, PM10, PM2.5, and VOC mass emissions for each unit in FGFUELHTR, as required by SC I.1, SC I.2, SC I.4, SC I.5, and SC I.6. The permittee shall keep all records on file and make them available to the Department upon request. The calculations shall be performed using a method approved by the AQD District Supervisor. **(R 336.1205(1)(a) & (b), R 336.1702(a), R 336.2803, R 336.2804, R 336.2810)**

4. The permittee shall keep, in a satisfactory manner, test reports for any unit in FGFUELHTR required by SC V.1 on file at the facility. The permittee shall make the records available to the Department upon request. **(R 336.1331(1)(c), R 336.2001, R 336.2003, R 336.2004, R 336.2810)**

5. The permittee shall calculate and keep, in a satisfactory manner, records of monthly and 12-month rolling total CO_2e mass emissions for FGFUELHTR, as required by SC I.7. The permittee shall keep all records on file and make them available to the Department upon request. The calculations shall be performed according to Appendix B or an alternate method approved by the District Supervisor. **(R 336.1205(1)(a) & (b), 40 CFR 52.21(j))**

6. The permittee shall maintain records of all information necessary for all notifications and reports as specified in these special conditions as well as that information necessary to demonstrate compliance with the emission limits of this permit. This information shall include, but shall not be limited to the following:
   a) Compliance tests and any testing required under the special conditions of this permit.
   b) Monitoring data.
   c) Verification of heat input capacity required to show compliance with SC IV.1.
   d) Identification, type and the amounts of fuel combusted in each unit in FGFUELHTR on a calendar month basis.
   e) Sulfur content of the fuel combusted in each unit in FGFUELHTR.
   f) All records required by 40 CFR 60.7 and 60.48c.
   g) All calculations or documents necessary to show compliance with the limits contained in this permit.

   All of the above information shall be stored in a format acceptable to the Air Quality Division and shall be consistent with the requirements of 40 CFR 60.7. The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1331(1)(c), R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j), 40 CFR 60.7, 40 CFR Part 60 Subpart Dc)**

VII. REPORTING

1. The permittee shall provide written notification of the date construction commences and actual startup of each unit in FGFUELHTR, in accordance with 40 CFR 60.7 and 60.48c. The notification shall include the design heat input, an identification of the fuels to be combusted, and the annual capacity factor for each unit in FGFUELHTR. The permittee shall submit this notification to the AQD District Supervisor within the time frames specified in 40 CFR 60.7. **(40 CFR 60.7, 40 CFR 60.48c)**

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Diameter / Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVFUELHTR1	19	30	R 336.1225, R 336.2803, R 336.2804
2. SVFUELHTR2	19	30	R 336.1225, R 336.2803, R 336.2804

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60 Subparts A and Dc, as they apply to each unit in FGFUELHTR. **(40 CFR Part 60 Subparts A & Dc)**

FGFUELTANK
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Two (2) closed-roof tanks for purposes of storing ultra-low sulfur diesel fuel.

Emission Unit: EUEMFUELTANK, EUFPFUELTANK

POLLUTION CONTROL EQUIPMENT

Conservation vent valves for VOC control.

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

1. The permittee shall only store ultra-low sulfur diesel fuel in either tank of FGFUELTANK. **(R 336.1205, R 336.1224, R 336.1225, R 336.1702(a), R 336.2810)**

III. PROCESS/OPERATIONAL RESTRICTION(S)

NA

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall install, maintain and operate in a satisfactory manner, conservation vent valves on FGFUELTANK. **(R 336.1205, R 336.1224, R 336.1225, R 336.1702(a), R 336.1910, R 336.2810)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. The permittee shall keep, in a satisfactory manner, fuel supplier certification records demonstrating that the fuel stored in the tank is ultra-low sulfur diesel. The permittee shall make the records available to the Department upon request. **(R 336.1205, R 336.1224, R 336.1225, R 336.1702(a), R 336.2810)**

2. The permittee shall keep, in a satisfactory manner, documentation of the design of the tanks demonstrating that the tanks have conservation vent valves. The permittee shall make the records available to the Department upon request. **(R 336.1205, R 336.1224, R 336.1225, R 336.1702(a), R 336.1910, R 336.2810)**

VII. REPORTING

NA

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

NA

FGSPACEHTRS
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Up to 44 natural gas-fired space heaters and air makeup units with a combined rating of 10 MMBTU/hr or less to provide building heating and ventilation.

Emission Unit: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

1. The permittee shall burn only pipeline quality natural gas in FGSPACEHTRS. **(R 336.1205(1)(a) & (b), R 336.1224, R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

NA

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The maximum combined design heat input capacity for FGSPACEHTRS shall not exceed 10 MMBTU per hour on a fuel heat input basis. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(j))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

1. The permittee shall keep manufacturer documentation showing the maximum heat input for each space heater in FGSPACEHTRS. **(R 336.1205(1)(a) & (b), R 336.1225, R 336.2803, R 336.2804, R 228.2810, 40 CFR 52.21(j))**

VII. REPORTING

NA

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

NA

FGINITIALPROJECT
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

All of the equipment associated with the greenfield project.

Emission Units and Flexible Group: EUCTGHRSG1, EUCTGHRSG2, EUAUXBOILER, EUFUELHTR1, EUFUELHTR2, EUEMENGINE, EUFPENGINE, EUEMFUELTANK, EUFPFUELTANK, EUCOLDCLEANER, FGSPACEHTRS

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

NA

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1201(3))**

NA

VII. REPORTING

NA

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall only construct and install the equipment associated with FGINITIALPROJECT in Cass County. **(R 336.1201, R 336.2802, R 336.2902)**

2. The permittee shall demarcate the County line between Berrien and Cass Counties. **(R 336.1201, R 336.2802, R 336.2902)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

APPENDIX A
Continuous Emission Monitoring System (CEMS) Requirements

1. Within 30 calendar days after commencement of initial start-up, the permittee shall submit two copies of a Monitoring Plan to the AQD, for review and approval. The Monitoring Plan shall include drawings or specifications showing proposed locations and descriptions of the required CEMS.

2. Within 150 calendar days after commencement of initial start-up, the permittee shall submit two copies of a complete test plan for the CEMS to the AQD for approval.

3. Within 180 calendar days after commencement of initial start-up, the permittee shall complete the installation and testing of the CEMS.

4. Within 60 days of completion of testing, the permittee shall submit to the AQD two copies of the final report demonstrating the CEMS complies with the requirements of the corresponding Performance Specifications (PS) in the following table:

Pollutant	Applicable PS
NO_x	2
O_2 & CO_2	3
CO	4

5. The span value shall be 2.0 times the lowest emission standard or as specified in the federal regulations.

6. The CEMS shall be installed, calibrated, maintained, and operated in accordance with the procedures set forth in 40 CFR 60.13 and the PS, listed in the table above, of Appendix B to 40 CFR Part 60.

7. Each calendar quarter, the permittee shall perform the Quality Assurance Procedures of the CEMS set forth in Appendix F of 40 CFR Part 60. Within 30 days following the end of each calendar quarter, the permittee shall submit the results to the AQD in the format of the data assessment report (Figure 1, Appendix F).

8. In accordance with 40 CFR 60.7(c) and (d), the permittee shall submit two copies of an excess emission report (EER) and summary report in an acceptable format to the AQD, within 30 days following the end of each calendar quarter. The Summary Report shall follow the format of Figure 1 in 40 CFR 60.7(d). The EER shall include the following information:
   a) A report of each exceedance above the limits specified in the conditions of this permit. This includes the date, time, magnitude, cause and corrective actions of all occurrences during the reporting period.
   b) A report of all periods of CEMS downtime and corrective action.
   c) A report of the total operating time of EUAUXBOILER, EUCTGHRSG1, or EUCTGHRSG2 during the reporting period.
   d) A report of any periods that the CEMS exceeds the instrument range.
   e) If no exceedances or CEMS downtime occurred during the reporting period, the permittee shall report that fact.

The permittee shall keep all monitoring data on file for a period of at least five years and make them available to the AQD upon request.

APPENDIX B
CO_2e Emission Calculations

For EUAUXBOILER and FGFUELHTR:

CO_2e emissions (tons/month) = [(Fuel Usage (MMscf/month) x Higher Heating Value (MMBTU/MMscf)) x (CO_2 EF (kg/MMBTU) x CO_2 GWP + CH_4 EF (kg/MMBTU) x CH_4 GWP + N_2O EF (kg/MMBTU) x N_2O GWP)] x 2.20462 (lb/kg) x 1/2000 (ton/lb)

Where:
Fuel Usage (MMscf/month) = monthly fuel usage data from fuel flow meter
Heat Content (MMBTU/MMscf) = standard value in AP-42 for natural gas or supplier data, if available
CO_2 EF (kg/MMBTU) = emission factors from 40 CFR Part 98, Subpart C, Table C-1 (December 9, 2016)
CH_4 EF (kg/MMBTU) = emission factors from 40 CFR Part 98, Subpart C, Table C-2 (December 9, 2016)
N_2O EF (kg/MMBTU) = emission factors from 40 CFR Part 98, Subpart C, Table C-2 (December 9, 2016)
CO_2 GWP = global warming potential from 40 CFR Part 98, Subpart A, Table A-1 (January 1, 2014)
CH_4 GWP = global warming potential from 40 CFR Part 98, Subpart A, Table A-1 (January 1, 2014)
N_2O GWP = global warming potential from 40 CFR Part 98, Subpart A, Table A-1 (January 1, 2014)

For EUEMENGINE and EUFPENGINE:

CO_2e emissions (tons/month) = [(Fuel Usage (gallons/month) x Higher Heating Value (MMBTU/gallons)) x (CO_2 EF (kg/MMBTU) x CO_2 GWP + CH_4 EF (kg/MMBTU) x CH_4 GWP + N_2O EF (kg/MMBTU) x N_2O GWP)] x 1/2000 (ton/lb)

Where:
Fuel Usage (gallons/month) = monthly fuel usage data
Heat Content (MMBTU/gallons) = standard value in AP-42 for natural gas or supplier data, if available
CO_2 EF (kg/MMBTU) = emission factors from 40 CFR Part 98, Subpart C, Table C-1 (December 9, 2016)
CH_4 EF (kg/MMBTU) = emission factors from 40 CFR Part 98, Subpart C, Table C-2 (December 9, 2016)
N_2O EF (kg/MMBTU) = emission factors from 40 CFR Part 98, Subpart C, Table C-2 (December 9, 2016)
CO_2 GWP = global warming potential from 40 CFR Part 98, Subpart A, Table A-1 (January 1, 2014)
CH_4 GWP = global warming potential from 40 CFR Part 98, Subpart A, Table A-1 (January 1, 2014)
N_2O GWP = global warming potential from 40 CFR Part 98, Subpart A, Table A-1 (January 1, 2014)

For EUCTGHRSG1 and EUCTGHRSG2:

If not utilizing a CO_2 CEMS:

CO_2 emissions (tons/month) = CO_2 EF (scf/MMBTU) x Fuel Usage (MMscf/month) x Higher Heating Value (MMBTU/MMscf) x CO_2 MW (lb/lb-mol) x CO_2 GWP / molar volume (scf/lb-mol)

Where:
CO_2 EF (scf/MMBTU) = carbon based F-factor for natural gas according to the methodology from equation G-4 of Appendix G to Part 75
Fuel Usage (MMscf/month) = monthly fuel usage data from fuel flow meter
Heat Content (MMBTU/MMscf) = standard value in AP-42 for natural gas or supplier data, if available
CO_2 MW (lb/lb-mol) = 44 [C = 6; O = 8; 6 + (8 x 2) = 22]
CO_2 GWP = global warming potential from 40 CFR Part 98, Subpart A, Table A-1 (January 1, 2014)
Molar volume (scf/lb-mol) = 385

CO_2e emissions (tons/month) = CO_2 emissions (tons/month) + [((Fuel Usage (MMscf/month) x Higher Heating Value (MMBTU/MMscf)) x (CH_4 EF (kg/MMBTU) x CH_4 GWP + N_2O EF (kg/MMBTU) x N_2O GWP)) x 2.20462 (lb/kg) x 1/2000 (ton/lb)]

Where:
Fuel Usage (MMscf/month) = monthly fuel usage data from fuel flow meter
Heat Content (MMBTU/MMscf) = standard value in AP-42 for natural gas or supplier data, if available
CH_4 EF (kg/MMBTU) = emission factors from 40 CFR Part 98, Subpart C, Table C-2 (December 9, 2016)
N_2O EF (kg/MMBTU) = emission factors from 40 CFR Part 98, Subpart C, Table C-2 (December 9, 2016)
CH_4 GWP = global warming potential from 40 CFR Part 98, Subpart A, Table A-1 (January 1, 2014)
N_2O GWP = global warming potential from 40 CFR Part 98, Subpart A, Table A-1 (January 1, 2014)

APPENDIX B

// SUPPLEMENTAL INFORMATION

EMISSION CALCULATIONS

Table 1-1. Combined Cycle (CTG/HRSG) Maximum Potential Steady State Emissions

Specifications Per Unit	Combustion Turbine Heat Input (MMBtu/hr)	Duct Burner Heat Input (MMBtu/hr)	CTG/HRSG Exhaust Flow Rate (scf/hr)	Operation (hr/yr)	Natural Gas Heating Value (Btu/scf)
Annual Average Scenario	3,597	71	81,350,546	8,760	1,020
Maximum Hourly Scenario	3,651	71	85,285,405		

Criteria Pollutants and GHGs	Per Combustion Turbine Generator (CTG)				Per Duct Fired Heat Recovery Steam Generating (HRSG)				Per CTG/HRSG Train				Two (2) CTG/HRSG Trains	
	Emission Factor	Emission Factor Units	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Emission Factor	Emission Factor Units	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Emission Factor	Emission Factor Units	Hourly Emissions (lb/hr)	Annual Emissions (tpy)	Total Hourly Emissions (lb/hr)	Total Annual Emissions (tpy)
NO_x [1,2]									2	ppm	27.4	118	54.8	237
CO [1,3]									4	ppm	24.7	108	49.4	216
PM, filterable [1]											9.9	43.4	19.8	86.7
PM_{10}, filterable & condensable [1]											19.8	86.7	39.6	173
$PM_{2.5}$, filterable & condensable [1]											19.8	86.7	39.6	173
SO_2 [1]											11.7	51.3	23.4	103
Pb [4]					0.0005	lb/MMscf	3.48E-05	1.52E-04			3.48E-05	1.52E-04	6.96E-05	3.05E-04
VOC, as methane [1]									4	ppm	14.1	59	28.2	118
CO_2 [1]	1,040	scf/MMBtu	433,947	1,872,578	1,040	scf/MMBtu	8,439	36,962			442,386	1,909,540	884,773	3,819,080
CH_4 [5]	1.0E-03	kg/MMBtu	8.05	34.7	1.0E-03	kg/MMBtu	0.16	0.69			8.2	35.4	16.41	70.8
N_2O [5]	1.0E-04	kg/MMBtu	0.80	3.47	1.0E-04	kg/MMBtu	0.02	0.07			0.82	3.5	1.64	7.1
CO_2e [6]				1,874,481				37,000			442,836	1,911,481	885,672	3,822,962

[1] Emissions of NO_x, CO, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, and CO_2 are based on equipment manufacturer data, current permit limits/permit calculation methodology or BACT. A safety factor is applied to SO_2 to account for variation between vendor information and generic AP-42 emission factor. Annual emissions are based on continuous operation at 8,760 hours/year.

[2] Hourly and annual mass emissions of NO_x are based on the F-factor methodology.

[3] Hourly and annual mass emissions for VOC are calculated with the following equation: "(ppm x MW (lb/lb-mol) x exhaust (dscf/hr)) / (10^6 x 386.5 (scf air/lb-mole air))".

[4] Emissions of Pb are based on AP-42 Ch.1.4, Table 1.4-2. Annual emissions are based on continuous operation at 8,760 hours/year.

[5] Emissions of CH_4 and N_2O are based on 40 CFR Part 98, Table C-1 and Table C-2. Annual emissions are based on continuous operation at 8,760 hours/year.

[6] Emissions of CO_2e are calculated using the global warming potentials according to Table A-1 of 40 CFR Part 98 and the following equation: "(1 x CO_2) + (25 x CH_4) + (298 x N_2O)"

Table 1-2a. Hourly Combined Cycle (CTG/HRSG) Startup/Shutdown Emissions [1]

Pollutant	Startup Emissions (lb/event, 2 Trains)	Startup Duration (minutes/event)	Shutdown Emissions (lb/event, 2 Trains)	Shutdown Duration (minutes/event)	Hourly Startup Emissions (lb/hr, 2 Trains) [2]	Hourly Shutdown Emissions (lb/hr, 2 Trains) [2]	Hourly Startup Emissions (lb/hr, per Train) [2]	Hourly Shutdown Emissions (lb/hr, per Train) [2]	Annual Startup/Shutdown Hours (hours/year, per Train) [2]
NO_x	525	55.0	44.2	18.0	573	147	286	74	500
CO	2,006	38.0	1,474	12.5	3,168	7,074	1,584	3,537	500
VOC	931	38.0	694	12.5	1,469	3,329	735	1,665	500

[1] Startup/shutdown emissions are based on the worst-case emission rate presented in PTI Application No. 75-16B.

[2] Hourly startup and shutdown emissions represent the absolute worst-case 1-minute rate of any startup or shutdown events, over a 60-minute (1 hour) period. This is conservative because the startup and shutdown events are less than 60 minutes.

Table 1-2b. Annual Project Emissions with Startup and Shutdown

Pollutant	CTG/HRSG Annual Startup and Shutdown Emissions (tpy, 2 Trains) [1]	CTG/HRSG Annual Baseload Emissions based on 8,260 hr/yr (tpy, 2 Trains) [2]	Ancillary Equipment PTE (tpy)	Total Project PTE with Startup/Shutdown Emissions (tpy)
NO_x	117	223	29	369
CO	1,034	204	24	1,262
VOC	482	82	2	567

[1] Calculated for 2 CTG/HRSG trains based on the startup/shutdown data from Table 1-2a above for the maximum annual startup/shutdown time of 500 hours/year.

[2] Calculated for CTG/HRSGs based on emission rates from Table 1-1, assuming remaining non-startup/shutdown hours per year (e.g., 8,260 hours/year for CO) are steady-state operation.

Table 1-3. Fuel Gas Dew Point Heater Emissions

Specifications							
Hourly heat input (MMBtu/hr)	7.3						
Operation (hr/yr)	8,760						
Natural Gas Heating Value (Btu/scf)	1,020						
Number of Units [1]	2						
Criteria Pollutants and GHGs	**Emission Factor**	**Emission Factor Units**	**Emission Factor Basis**	**Hourly Emissions (One unit) (lb/hr) [2]**	**Annual Emissions (One unit) (tpy) [3]**	**Hourly Emissions (Two units) (lb/hr) [2]**	**Annual Emissions (Two units) (tpy) [3]**
NO_x	100	lb/MMscf	AP-42 Ch.1.4, Table 1.4-1	0.72	3.13	1.43	6.27
CO	84	lb/MMscf	AP-42 Ch.1.4, Table 1.4-1	0.60	2.63	1.20	5.27
PM, filterable	3.8	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2 with safety factor	0.03	1.19E-01	5.44E-02	0.24
PM_{10}, filterable & condensable	7.6	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2	0.05	0.24	0.11	0.48
$PM_{2.5}$, filterable & condensable	7.6	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2	0.05	0.24	0.11	0.48
SO_2	0.6	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2	4.29E-03	1.88E-02	8.59E-03	3.76E-02
Pb	0.0005	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2	3.58E-06	1.57E-05	7.16E-06	3.13E-05
VOC	5.5	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2	3.94E-02	0.17	7.87E-02	0.34
CO_2	53.06	kg/MMBtu	40 CFR Part 98, Table C-1	854	3,740	1,708	7,480
CH_4	1.0E-03	kg/MMBtu	40 CFR Part 98, Table C-2	1.61E-02	7.05E-02	3.22E-02	0.14
N_2O	1.0E-04	kg/MMBtu	40 CFR Part 98, Table C-2	1.61E-03	7.05E-03	3.22E-03	1.41E-02
CO_2e					3,744		7,488

[1] Both fuel gas heaters may operate concurrently.

[2] Hourly emission rates are based on the maximum capacity of the fuel heaters.

[3] Annual emission rates are based on continuous operation at 8,760 hours/year.

Table 1-4. Auxiliary Boiler Emissions

Specifications					
Hourly heat input (MMBtu/hr)	85				
Operation (hr/yr)	8,760				
Natural Gas Heating Value (Btu/scf)	1,020				
Criteria Pollutants and GHGs	**Emission Factor**	**Emission Factor Units**	**Emission Factor Basis**	**Emissions (lb/hr) [1]**	**Emissions (tpy) [2]**
NO_x	0.04	lb/MMBtu	Vendor	3.40	14.89
CO	0.04	lb/MMBtu	Vendor	3.40	14.89
PM, filterable	0.005	lb/MMBtu	Vendor	0.43	1.86
PM_{10}, filterable & condensable	7.6	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2	0.63	2.77
$PM_{2.5}$, filterable & condensable	7.6	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2	0.63	2.77
SO_2	0.6	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2	5.00E-02	0.22
Pb	0.0005	lb/MMscf	AP-42 Ch.1.4, Table 1.4-2	4.17E-05	1.83E-04
VOC	0.004	lb/MMBtu	Vendor	0.34	1.49
CO_2	53.06	kg/MMBtu	40 CFR Part 98, Table C-1	9,943	43,551
CH_4	1.0E-03	kg/MMBtu	40 CFR Part 98, Table C-2	0.19	0.82
N_2O	1.0E-04	kg/MMBtu	40 CFR Part 98, Table C-2	1.87E-02	8.21E-02
CO_2e					43,596

[1] Hourly emission rates are based on the maximum capacity of the auxiliary boiler.

[2] Annual emission rates are based on continuous operation at 8,760 hours/year.

Table 1-5. Emergency Diesel RICE Potential Emissions

Specifications					
Hourly heat input (MMBtu/hr)	22.68				
Operation (hr/yr)	500				
Horsepower (hp)	2,923				
Criteria Pollutants and GHGs	**Emission Factor**	**Emission Factor Units**	**Emission Factor Basis**	**Emissions (lb/hr)** [1]	**Emissions (tpy)** [2]
NO_x	4.8	g/bhp-hr	NSPS IIII (converted to g/bhp-hr)	30.75	7.69
CO	2.6	g/bhp-hr	NSPS IIII (converted to g/bhp-hr)	16.82	4.20
PM, filterable	0.15	g/bhp-hr	NSPS IIII (converted to g/bhp-hr)	0.96	0.24
PM_{10}, filterable & condensable	0.0697	lb/MMBtu	AP-42 Ch. 3.4, Table 3.4-2	1.58	0.40
$PM_{2.5}$, filterable & condensable	0.0697	lb/MMBtu	AP-42 Ch. 3.4, Table 3.4-2	1.58	0.40
SO_2	1.21E-05	lb/hp-hr	AP-42 Ch. 3.4, Table 3.4-1 and 0.0015% Sulfur	3.55E-02	8.87E-03
VOC (TNMOC)	6.42E-04	lb/hp-hr	AP-42 Ch. 3.4, Table 3.4-1 and footnote f (91% of TOC is nonmethane)	1.88	0.47
CO_2	73.96	kg/MMBtu	40 CFR Part 98, Table C-1	3,698	925
CH_4	3.0E-03	kg/MMBtu	40 CFR Part 98, Table C-2	0.15	3.75E-02
N_2O	6.0E-04	kg/MMBtu	40 CFR Part 98, Table C-2	3.00E-02	7.50E-03
CO_2e					928

[1] Hourly emission rates are based on the maximum capacity of the emergency diesel RICE.
[2] Annual emission rates for the emergency diesel RICE are based on intermittent operation at 500 hours/year.

Table 1-6. Emergency Diesel Fire Pump RICE Potential Emissions

Specifications					
Hourly heat input (MMBtu/hr)	0				
Operation (hr/yr)	0				
Horsepower (hp)	0				
Criteria Pollutants and GHGs	**Emission Factor**	**Emission Factor Units**	**Emission Factor Basis**	**Emissions (lb/hr)**	**Emissions (tpy)**
NO_x	3	g/bhp-hr	NSPS IIII	0	0
CO	2.6	g/bhp-hr	NSPS IIII	0	0
PM, filterable	0.15	g/bhp-hr	NSPS IIII	0	0
PM_{10}, filterable & condensable	2.20E-03	lb/hp-hr	AP-42 Ch. 3.3, Table 3.3-1	0	0
$PM_{2.5}$, filterable & condensable	2.20E-03	lb/hp-hr	AP-42 Ch. 3.3, Table 3.3-1	0	0
SO_2	2.05E-03	lb/hp-hr	AP-42 Ch. 3.3, Table 3.3-1	0	0
VOC (as TOC)	2.47E-03	lb/hp-hr	AP-42 Ch. 3.3, Table 3.3-1	0	0
CO_2	73.96	kg/MMBtu	40 CFR Part 98, Table C-1	0	0
CH_4	3.0E-03	kg/MMBtu	40 CFR Part 98, Table C-2	0	0
N_2O	6.0E-04	kg/MMBtu	40 CFR Part 98, Table C-2	0	0
CO_2e					0

Table 1-7. Circuit Breaker SF_6 Fugitive Emissions

GHGs	SF_6 at Full Charge (lbs)	Number of Breakers	Annual Leak Rate (%)	Emissions (lb/hr)	Emissions (tpy)
SF_6 (Generator Circuit Breakers)	24.2	3	0.5	4.14E-05	1.82E-04
SF_6 (HV Power Circuit Breakers)	550	11	0.5	3.45E-03	1.51E-02
Total CO_2e [1]					349

[1] Emissions of CO_2e are calculated using the global warming potential of 22,800 for SF_6 according to Table A-1 of 40 CFR Part 98

Table 1-8. TAC/HAP Potential Emission Estimates (Part 1 of 2)

Hazardous Air Pollutants	CAS	Emission Factor		Combustion Turbine		Duct Burner		CTG/HRSG (1)		CTG/HRSG (2)		Fuel Gas Dew Point Heater		Auxiliary Boiler	
		Stationary Internal Combustion Sources AP-42 Ch.3.1, Table 3.1-3	External Combustion Sources AP-42 Ch. 1.4, Table 1.4-3 and Table 1.4-4	Emission Rates Per Unit		Emission Rates Per Unit		Emission Rates per Train		Total Emission Rates (2 Trains)		Emission Rates (2 Heaters)		Emission Rates	
		(lb/MMBtu)	(lb/MM scf)	(lb/hr) [1,2]	(tpy) [2,3]	(lb/hr) [1,2]	(tpy) [2,3]	(lb/hr) [1,2]	(tpy) [2,3]	(lb/hr) [1,2]	(tpy) [2,3]	(lb/hr) [1,4]	(tpy) [3,4]	(lb/hr) [1]	(tpy) [3]
Acetaldehyde	75070	4.0E-05		7.3E-02	3.2E-01			7.3E-02	3.2E-01	1.5E-01	6.3E-01				
Acrolein	107028	6.4E-06		1.2E-02	5.0E-02			1.2E-02	5.0E-02	2.3E-02	1.0E-01				
Arsenic	7440382		2.0E-04			1.4E-05	6.1E-05	1.4E-05	6.1E-05	2.8E-05	1.2E-04	2.9E-06	1.3E-05	1.7E-05	7.3E-05
Benzene	71432	1.2E-05	2.1E-03	2.2E-02	9.5E-02	7.3E-05	3.2E-04	2.2E-02	9.5E-02	4.4E-02	1.9E-01	3.0E-05	1.3E-04	1.8E-04	7.7E-04
Beryllium	7440417		1.2E-05			8.4E-07	3.7E-06	8.4E-07	3.7E-06	1.7E-06	7.3E-06	1.7E-07	7.5E-07	1.0E-06	4.4E-06
1,3 - Butadiene	106990	4.3E-07		7.8E-04	3.4E-03			7.8E-04	3.4E-03	1.6E-03	6.8E-03				
Cadmium	7440439		1.1E-03			7.7E-05	3.4E-04	7.7E-05	3.4E-04	1.5E-04	6.7E-04	1.6E-05	6.9E-05	9.2E-05	4.0E-04
Chromium, total	7440473		1.4E-03			9.7E-05	4.3E-04	9.7E-05	4.3E-04	1.9E-04	8.5E-04	2.0E-05	8.8E-05	1.2E-04	5.1E-04
Cobalt	7440484		8.4E-05			5.8E-06	2.6E-05	5.8E-06	2.6E-05	1.2E-05	5.1E-05	1.2E-06	5.3E-06	7.0E-06	3.1E-05
Dichlorobenzene	106467		1.2E-03			4.2E-05	1.8E-04	4.2E-05	1.8E-04	8.4E-05	3.7E-04	1.7E-05	7.5E-05	1.0E-04	4.4E-04
Ethylbenzene	100414	3.2E-05		5.8E-02	2.5E-01			5.8E-02	2.5E-01	1.2E-01	5.0E-01				
Formaldehyde [5]	50000		7.5E-02					1.1E+00	4.7E+00	2.1E+00	9.3E+00	1.1E-03	4.7E-03	6.3E-03	2.7E-02
Hexane	110543		1.8E+00			6.3E-02	2.7E-01	6.3E-02	2.7E-01	1.3E-01	5.5E-01	2.6E-02	1.1E-01	1.5E-01	6.6E-01
Manganese	7439965		3.8E-04			2.6E-05	1.2E-04	2.6E-05	1.2E-04	5.3E-05	2.3E-04	5.4E-06	2.4E-05	3.2E-05	1.4E-04
Mercury	7439976		2.6E-04			1.8E-05	7.9E-05	1.8E-05	7.9E-05	3.6E-05	1.6E-04	3.7E-06	1.6E-05	2.2E-05	9.5E-05
Nickel	7440020		2.1E-03			1.5E-04	6.4E-04	1.5E-04	6.4E-04	2.9E-04	1.3E-03	3.0E-05	1.3E-04	1.8E-04	7.7E-04
Selenium	7782492		2.4E-05			1.7E-06	7.3E-06	1.7E-06	7.3E-06	3.3E-06	1.5E-05	3.4E-07	1.5E-06	2.0E-06	8.8E-06
Toluene	108883	1.3E-04	3.4E-03	2.4E-01	1.0E+00	1.2E-04	5.2E-04	2.4E-01	1.0E+00	4.7E-01	2.0E+00	4.9E-05	2.1E-04	2.8E-04	1.2E-03
Xylenes	1330207	6.4E-05		1.2E-01	5.0E-01			1.2E-01	5.0E-01	2.3E-01	1.0E+00				
Polycyclic Organic Matter (POMs)															
2-Methylnaphthalene	91576		2.4E-05			8.4E-07	3.7E-06	8.4E-07	3.7E-06	1.7E-06	7.3E-06	3.4E-07	1.5E-06	2.0E-06	8.8E-06
3-Methylcholanthrene	56495		1.8E-06			6.3E-08	2.7E-07	6.3E-08	2.7E-07	1.3E-07	5.5E-07	2.6E-08	1.1E-07	1.5E-07	6.6E-07
7,12-Dimethylbenz(a)anthracene	57976		1.6E-05			5.6E-07	2.4E-06	5.6E-07	2.4E-06	1.1E-06	4.9E-06	2.3E-07	1.0E-06	1.3E-06	5.8E-06
Acenaphthene	83329		1.8E-06			6.3E-08	2.7E-07	6.3E-08	2.7E-07	1.3E-07	5.5E-07	2.6E-08	1.1E-07	1.5E-07	6.6E-07
Acenaphthylene	208968		1.8E-06			6.3E-08	2.7E-07	6.3E-08	2.7E-07	1.3E-07	5.5E-07	2.6E-08	1.1E-07	1.5E-07	6.6E-07
Anthracene	120127		2.4E-06			8.4E-08	3.7E-07	8.4E-08	3.7E-07	1.7E-07	7.3E-07	3.4E-08	1.5E-07	2.0E-07	8.8E-07
Benz(a)anthracene	56553		1.8E-06			6.3E-08	2.7E-07	6.3E-08	2.7E-07	1.3E-07	5.5E-07	2.6E-08	1.1E-07	1.5E-07	6.6E-07
Benzo(a)pyrene	50328		1.2E-06			4.2E-08	1.8E-07	4.2E-08	1.8E-07	8.4E-08	3.7E-07	1.7E-08	7.5E-08	1.0E-07	4.4E-07
Benzo(b)fluoranthene	205992		1.8E-06			6.3E-08	2.7E-07	6.3E-08	2.7E-07	1.3E-07	5.5E-07	2.6E-08	1.1E-07	1.5E-07	6.6E-07
Benzo(g,h,i)perylene	191242		1.2E-06			4.2E-08	1.8E-07	4.2E-08	1.8E-07	8.4E-08	3.7E-07	1.7E-08	7.5E-08	1.0E-07	4.4E-07
Benzo(k)fluoranthene	205823		1.8E-06			6.3E-08	2.7E-07	6.3E-08	2.7E-07	1.3E-07	5.5E-07	2.6E-08	1.1E-07	1.5E-07	6.6E-07
Chrysene	218019		1.8E-06			6.3E-08	2.7E-07	6.3E-08	2.7E-07	1.3E-07	5.5E-07	2.6E-08	1.1E-07	1.5E-07	6.6E-07
Dibenz(a,h)anthracene	53703		1.2E-06			4.2E-08	1.8E-07	4.2E-08	1.8E-07	8.4E-08	3.7E-07	1.7E-08	7.5E-08	1.0E-07	4.4E-07
Fluoranthene	206440		3.0E-06			1.0E-07	4.6E-07	1.0E-07	4.6E-07	2.1E-07	9.1E-07	4.3E-08	1.9E-07	2.5E-07	1.1E-06
Fluorene	86737		2.8E-06			9.7E-08	4.3E-07	9.7E-08	4.3E-07	1.9E-07	8.5E-07	4.0E-08	1.8E-07	2.3E-07	1.0E-06
Indeno(1,2,3,c,d)pyrene	193395		1.8E-06			6.3E-08	2.7E-07	6.3E-08	2.7E-07	1.3E-07	5.5E-07	2.6E-08	1.1E-07	1.5E-07	6.6E-07
Naphthalene	91203	1.3E-06	6.1E-04	2.4E-03	1.0E-02	2.1E-05	9.3E-05	2.4E-03	1.0E-02	4.8E-03	2.1E-02	8.7E-06	3.8E-05	5.1E-05	2.2E-04
PAH	several isomers	2.2E-06		4.0E-03	1.7E-02			4.0E-03	1.7E-02	8.0E-03	3.5E-02				
Phenanthrene	85018		1.7E-05			5.9E-07	2.6E-06	5.9E-07	2.6E-06	1.2E-06	5.2E-06	2.4E-07	1.1E-06	1.4E-06	6.2E-06
Propylene Oxide	75569	2.9E-05		5.3E-02	2.3E-01			5.3E-02	2.3E-01	1.1E-01	4.6E-01				
Pyrene	129000		5.0E-06			1.7E-07	7.6E-07	1.7E-07	7.6E-07	3.5E-07	1.5E-06	7.2E-08	3.1E-07	4.2E-07	1.8E-06
Maximum Single HAP (Formaldehyde)					0		0		4.65		9.30		4.7E-03		2.7E-02
Aggregate HAPs					2.50		0.28		7.43		14.85		0.12		0.69
Non-HAP Toxic Air Contaminants	**CAS**														
Ammonia [6]	7664417							28.2	124	56.4	247				
Barium	7440393		4.4E-03			3.1E-04	1.3E-03	3.1E-04	1.3E-03	6.1E-04	2.7E-03	6.3E-05	2.8E-04	3.67E-04	1.6E-03
Butane	106978		2.1E+00			1.5E-01	6.4E-01	1.5E-01	6.4E-01	2.9E-01	1.3E+00	3.0E-02	1.3E-01	1.75E-01	7.7E-01
Copper	7440508		8.5E-04			5.9E-05	2.6E-04	5.9E-05	2.6E-04	1.2E-04	5.2E-04	1.2E-05	5.3E-05	7.08E-05	3.1E-04
Molybdenum	7439987		1.1E-03			7.7E-05	3.4E-04	7.7E-05	3.4E-04	1.5E-04	6.7E-04	1.6E-05	6.9E-05	9.17E-05	4.0E-04
Pentane	109660		2.6E+00			9.0E-02	4.0E-01	9.0E-02	4.0E-01	1.8E-01	7.9E-01	3.7E-02	1.6E-01	2.17E-01	9.5E-01
Sulfuric Acid Mist [7]	7664939							4.6	20.1	9.2	40.2				
Vanadium	7440622		2.3E-03			1.6E-04	7.0E-04	1.6E-04	7.0E-04	3.2E-04	1.4E-03	3.3E-05	1.4E-04	1.92E-04	8.4E-04
Zinc	7440666		2.9E-02			2.0E-03	8.8E-03	2.0E-03	8.8E-03	4.0E-03	1.8E-02	4.2E-04	1.8E-03	2.42E-03	1.1E-02

[1] Hourly emission rates are based on the maximum capacities of the equipment.

[2] CTG/HRSG trains will be controlled with oxidation catalysts. Therefore, 50% control is assumed for VOC HAPs/TACs.

[3] Annual emission rates are based on continuous operation at 8,760 hours/year.

[4] Fuel gas dew point heaters potential emission estimates reflect operation of both fuel gas heaters at maximum heat input capacity for 8,760 hours/year.

[5] Formaldehyde emissions from the CTG/HRSG trains are based on the current permit limit of 9.3 tpy.

[6] Ammonia emissions from the CTG/HRSG trains based on equipment manufacturer data.

[7] Sulfuric acid mist emissions from the CTG/HRSG trains are based on equipment manufacturer data (and is the current permit limit), which conservatively assumes all SO_3 combines with water to from sulfur mist (although some SO_3 may form other chemical species).

Table 1-8. TAC/HAP Potential Emission Estimates (Part 2 of 2)

Hazardous Air Pollutants	CAS	Emission Factor: Stationary Internal Combustion Sources AP-42 Ch.3.4, Table 3.4-3 and 3.4-4 (lb/MMBtu)	Emission Factor: Stationary Internal Combustion Sources AP-42 Ch.3.3, Table 3.3-2 (lb/MMBtu)	Emergency Diesel RICE Emission Rates (lb/hr) [1]	Emergency Diesel RICE Emission Rates (tpy) [2]	Emergency Diesel Fire Pump RICE Emission Rates (lb/hr) [1]	Emergency Diesel Fire Pump RICE Emission Rates (tpy) [2]
Acetaldehyde	75070	2.52E-05	7.67E-04	5.7E-04	1.4E-04	0	0
Acrolein	107028	7.88E-06	9.25E-05	1.8E-04	4.5E-05	0	0
Benzene	71432	7.76E-04	9.33E-04	1.8E-02	4.4E-03	0	0
1,3 - Butadiene	106990		3.91E-05			0	0
Formaldehyde	50000	7.89E-05	1.18E-03	1.8E-03	4.5E-04	0	0
Toluene	108883	2.81E-04	4.09E-04	6.4E-03	1.6E-03	0	0
Xylenes	1330207	1.93E-04	2.85E-04	4.4E-03	1.1E-03	0	0
Polycyclic Organic Matter (POMs)							
Acenaphthene	83329	4.68E-06	1.42E-06	1.1E-04	2.7E-05	0	0
Acenaphthylene	208968	9.23E-06	5.06E-06	2.1E-04	5.2E-05	0	0
Anthracene	120127	1.23E-06	1.87E-06	2.8E-05	7.0E-06	0	0
Benz(a)anthracene	56553	6.22E-07	1.68E-06	1.4E-05	3.5E-06	0	0
Benzo(a)pyrene	50328	2.57E-07	1.88E-07	5.8E-06	1.5E-06	0	0
Benzo(b)fluoranthene	205992	1.11E-06	9.91E-08	2.5E-05	6.3E-06	0	0
Benzo(g,h,i)perylene	191242	5.56E-07	4.89E-07	1.3E-05	3.2E-06	0	0
Benzo(k)fluoranthene	205823	2.18E-07	1.55E-07	4.9E-06	1.2E-06	0	0
Chrysene	218019	1.53E-06	3.53E-07	3.5E-05	8.7E-06	0	0
Dibenz(a,h)anthracene	53703	3.46E-07	5.83E-07	7.8E-06	2.0E-06	0	0
Fluoranthene	206440	4.03E-06	7.61E-06	9.1E-05	2.3E-05	0	0
Fluorene	86737	1.28E-05	2.92E-05	2.9E-04	7.3E-05	0	0
Indeno(1,2,3,c,d)pyrene	193395	4.14E-07	3.75E-07	9.4E-06	2.3E-06	0	0
Naphthalene	91203	1.30E-04	8.48E-05	2.9E-03	7.4E-04	0	0
PAH	several isomers	2.12E-04	1.68E-04	4.8E-03	1.2E-03	0	0
Phenanthrene	85018	4.08E-05	2.94E-05	9.3E-04	2.3E-04	0	0
Pyrene	129000	3.71E-06	4.78E-06	8.4E-05	2.1E-05	0	0
Maximum Single HAP (Formaldehyde)					4.5E-04		0
Aggregate HAPs					8.9E-03		0
Non-HAP Toxic Air Contaminants							
Propylene (Propene)	115071	2.79E-03	2.58E-03	6.33E-02	1.58E-02	0	0

[1] Hourly emission rates are based on the maximum capacity of the emergency diesel RICE.

[2] Annual emission rates for the emergency diesel RICE are based on intermittent operation at 500 hours/year.

APPENDIX C

// REFERENCED FACILITY PLANS

COMPLIANCE ASSURANCE MONITORING PLAN

Indeck Niles Energy Center

For Two (2) Natural Gas-Fired Combustion Turbines

2200 Progressive Drive
Niles, Michigan

NTH Project No. 74-210317-03
November 22, 2022

NTH Consultants, Ltd.
3300 Eagle Run Dr NE, Suite 202
Grand Rapids, MI 49525

TABLE OF CONTENTS

1.0 INTRODUCTION

Indeck Niles, LLC (Indeck) operates a natural gas-fired combined-cycle (NGCC) power plant at the Indeck Niles Energy Center located at 2200 Progressive Drive in Niles, Cass County, Michigan. The NGCC plant consists of two (2) combustion turbine generators (CTGs) equipped with heat recovery steam generators (HRSGs) for generation of electricity and various ancillary equipment including an auxiliary boiler, fuel gas dew-point heaters, and an emergency diesel-fired generator.

The CTG/HRSG trains, rated at 3,651 Million British thermal units per hour (MMBtu/hr) each, are equipped with dry low NO_x burners (DLNB), selective catalytic reduction (SCR), and oxidation catalysts. Aqueous ammonia is used in the SCR system to reduce nitrogen oxides (NO_x) in the combustion turbine exhaust gas and duct burner. The CTG/HRSG utilize oxidation catalysts to reduce carbon monoxide (CO) and volatile organic compound (VOC) emissions.

Indeck is required to implement and maintain a Compliance Assurance Monitoring (CAM) Plan in accordance with 40 CFR Part 64. 40 CFR Part 64 specifies that a CAM Plan be implemented for emission units meeting applicability criteria under 40 CFR §64.2(a). The CTG/HRSG trains meet CAM criteria for emissions of volatile organic compounds (VOCs) and are controlled by oxidation catalysts; therefore, CAM requirements apply for the VOC limit of 4 ppmvd at 15% O_2 listed as special condition (SC) I.13 under flexible group "FGCTGHRSG" in the air permit.

CAM does not apply for NO_x and CO as the CTG/HRSG are already subject to continuous monitoring of emissions through other regulatory requirements and are exempt from CAM since continuous compliance measures would already be in place.

This document and its referenced manuals constitute Indeck's CAM Plan for the CTG/HRSG trains. The referenced manuals are maintained on-site and electronically at the Indeck Niles Energy Center.

1.1 CAM Applicability

CAM is used to determine that a control technology is properly maintained and that it continues to achieve the level necessary to meet associated emission limits or standards. CAM establishes specific monitoring parameters that are indicative of unit performance. Units that are already subject to continuous monitoring of emissions through other regulatory requirements are exempt from CAM since continuous compliance measures would already be in place.

Pursuant to 40 CFR §64.2(a), Compliance Assurance Monitoring (CAM) applies to pollutant-specific emission units at major sources required to obtain a Title V (i.e., ROP) permit, if the emission unit and associated limit meet the following criteria:

1. Subject to an emission limitation or standard that is not exempt pursuant to 40 CFR §64.2(a);
2. Uses a control device to achieve compliance with such emission limitation or standard; and
3. Has potential pre-control emissions of the applicable regulated air pollutant that exceed or are equivalent to the major source threshold.

CAM applies to the VOC emission limit of 4 ppmvd at 15% O_2 at each CTG/HRSG train as listed in FGCTGHRSG SC I.13 of the air permit and is not exempt under 40 CFR §64.2(b)(1). Each CTG/HRSG train is equipped with an oxidation catalyst to control emissions of VOCs, and pre-control emissions of VOCs exceeds 100 tons per year. The CAM Plan provides parameters indicative of oxidation catalyst performance at routine frequency for reasonable assurance of compliance with the VOC limit. The CTG/HRSG trains are equipped with CEMS for monitoring NO_x and CO emissions, therefore, CAM does not apply for NO_x and CO pursuant 40 CFR §64.2(b)(1)(vi).

2.0 COMPLIANCE ASSURANCE MONITORING PLAN

The following sections outline monitoring parameters used to maintain the VOC emission limit and CAM monitoring requirements for the oxidation catalyst control system on each CTG/HRSG.

2.1 Control Technology

The oxidation catalysts contain precious metals (such as platinum, palladium, or rhodium) to treat exhaust gas from the CTG/HRSGs for control of VOC emissions, as well as CO emissions. The precious metal(s) catalyze the oxidation reaction of hydrocarbons (VOCs) and CO with available oxygen to convert the compounds to carbon dioxide and water vapor. With the use of the oxidation catalyst, each CTG/HRSG train can achieve an emission rate of 4 ppmvd VOC at 15% O_2 (FGCTGHRSG SC I.13).

2.2 Monitoring Approach and Performance Criteria

Emissions of VOCs and CO are formed as result of incomplete combustion; increased emissions of CO typically occur in conjunction with increased emissions of VOCs. Catalytic oxidation is used at FGCTGHRSG to reduce the emissions of CO and VOC resulting from the incomplete combustion of natural gas at the turbines. The emissions of CO, as measured by the CEMS, will be monitored to provide reasonable assurance of compliance with the VOC emission limit, as described below and in Table 2-1.

Table 2-1: Oxidation Catalyst Monitoring and Performance Criteria

Parameter	CAM Criteria
Indicator	CO emissions monitored continuously at the CTH/HRSG train
Indicator Range	An excursion is defined as a 24-hour average, excluding startup and shutdown, where CO emissions exceed 4 ppmvd at 15% O_2. Excursions trigger an inspection, corrective action, and the cause must be investigated.
Data Representativeness	The oxidation catalyst is necessary to achieve reduction of CO and VOC emissions resulting from incomplete combustion. CO emissions data are indicative of oxidation catalyst performance.
QA/QC Practices and Criteria	The CO CEMS will be maintained according to the requirements of Appendix A of the air permit.
Monitoring Frequency	Continuously, excluding startup and shutdown
Data Collection	CO concentration is obtained as an hourly average, reported to the data acquisition and handling system

Upon detecting an excursion or exceedance as outlined by performance indicators in Table 2-1, Indeck will investigate the cause and initiate corrective action to the oxidation catalyst, if needed, as expeditiously as practicable and in accordance with good air pollution control practices for minimizing emissions.

2.3 Justification of Monitoring Approach and Performance Criteria

The emissions of VOCs and CO are formed as a result of incomplete combustion; increased emissions of CO typically occur in conjunction with increased emissions of VOCs. Incomplete combustion of the carbon-containing compounds within natural gas produce hydrocarbons (such as VOCs) and CO, contained in the exhaust gas. Oxidation catalysts contain precious metals to catalyze the oxidation reaction of carbon-containing compounds within the exhaust gas with available oxygen, producing water vapor and carbon dioxide.

The CO emissions (after the oxidation catalyst) are continuously monitored using CEMS. Pursuant to 40 CFR §64.3(a)(1), direct or predicted emissions may be used as indicators of performance for emission controls. Emissions of CO will be used as an indicator of oxidation catalyst performance for reasonable assurance of compliance with the VOC limit (4 ppmvd @ 15% O_2 pursuant to the air permit).

3.0 RECORDKEEPING AND REPORTING REQUIREMENTS

Pursuant to 40 CFR §64.9, Indeck maintains records of monitoring data, monitor performance data, corrective actions taken when parameters are out of range, and other supporting information required to provide reasonable assurance of compliance with the VOC emission limit (such as data used to document the adequacy of monitoring, or records of monitoring, maintenance, or corrective actions).

Pursuant to 40 CFR §64.9(a), Indeck will submit semiannual CAM reports of monitoring and deviations. Each CAM report will include summary information on the number, duration, and cause of excursions or exceedances, as applicable, and the corrective action(s) taken. The report will summarize the number, duration, and cause for monitor downtime incidents. When there are no excursions, exceedances, or downtime events in the reporting period, the CAM report will include a statement that no excursions, exceedances, or downtime events occurred.

4.0 PLAN REVISION HISTORY

A current copy of the CAM plan will be maintained electronically and onsite at Indeck Niles Energy Center. Previous versions will be kept on file and available for at least five (5) years from the date of revision. Table 4-1 contains a list of revisions of this document.

Table 4-1. Plan Revision History

Revision No.	Date	Revised By	Comments
Original	11/21/2022	N/A	Initial Draft

APPENDIX A

// PREVENTATIVE AND OPERATOR'S MAINTENANCE SCHEDULE (SUGGESTED)

PREVENTIVE MAINTENANCE

While operating the boiler, if anything happens where obvious damage may occur by continuing to operate, load should be reduced, and the unit taken out of service as soon as possible. Inspection should be made to assess the problem. If there are questions about the condition of the unit, contact the **INDECK** Service Department.

Problems which may arise during the operation of a boiler can be separated into two (2) categories: The first is "Operational Problems", the second is "Maintenance Problems". In this section, the second category will be dealt with. Keep in mind the basic axiom that preventive maintenance is the best tool towards avoiding problems that ultimately cause untimely shut down and loss of production.

REFRACTORY

Routine maintenance is normal with any refractory construction. When the boiler is subjected to cyclic operation, (fired and shut down frequently) the maintenance of the refractory increases. Since refractory is not ductile, any shock load can crack it. When cracking of the castable walls occurs, hot gases can seep into the wall and either destroy the backing insulation or overheat the casing. Once the backing insulation is destroyed, the casing becomes exposed to the flame temperature. Spalling, when a fragment of the refractory breaks loose, is not abnormal. Spalling can be tolerated, provided the loss of material is not over half of the thickness of the original pour.

Spalling should be patched with a compatible mortar at the next outage of the unit. Cracks in the refractory should be stuffed with high temperature ceramic fibre felt, but never patched with mortar. If high casing temperatures do arise, the boiler should be brought OFF-line as soon as possible for internal inspection and repair. A reputable refractory firm or the **INDECK** Service department should be consulted before any extensive refractory work is attempted.

TUBES

Another routine maintenance problem is soot build up on the gas side of tube surfaces. As has been discussed earlier in this manual, soot or carbon build up can impede thermal transfer and is due to high soot build up, the most likely cause is the burning rate, or the air-fuel ratio is out of proportion. At every outage, if possible, check the water side of the tubes for scale build up. If a scale deposit is formed on the tube surfaces, heat cannot pass effectively into the water. The scale causes the steel tube to become overheated and they could blister or swell to a point of rupturing. Preventing scale build up requires close cooperation with a reputable water treatment laboratory, and close surveillance of the feedwater system. To remove this scale, build up from the tube surface, a mechanical tube cleaner can be used, but chemical cleaning has been found to be more effective. If the chemical cleaning is done, it must be closely supervised and it is advisable to hire professional personnel since the process, if done incorrectly, can cause irreparable damage to the tube metal.

COMBUSTION EQUIPMENT

The main component of the combustion equipment which requires maintenance, is the burner. This component will be covered in the "Burner Operating and Instruction" manual. The valves in the fuel system require routine maintenance, such as stem packing.

WATER COLUMN AND AUXILIARY FLOAT TYPE LEVEL CUT-OFF

The water column and water gauge glass should be blown down at the beginning of each shift. The three times a day schedule will insure two things: first, the sludge or sediment will not have a chance to accumulate in the column or glass. Any accumulation can cause an erroneous level indication. Second, the boiler attendant, by observing blowdown and return of liquid to glass, will be assured of proper actuation of one of the most important safety devices of the unit.

When the boiler is out of service for the annual inspection, dismantling the water column, gauge glass, etc. and clean the internals thoroughly.

OPERATOR'S MAINTENANCE

A conscientious maintenance program should be applied. The following list is by way of suggestion.

1. **Each shift**
   a) Check fuel pressures and temperatures at burner. Inspect flame pattern through burner and rear wall observation ports.
   b) Blowdown water column and gauge glass.
   c) Operate sootblowers. (The sootblowing sequence must follow the internal boiler gas flow).
   d) Check operation of continuous blowdown.

2. **Daily**
   a) Clean fuel strainers or filters.

3. **Weekly**
   a) Clean lens of scanner.

4. **Periodically**
   a) Clean and inspect inside of furnace for deterioration of refractory or insulation.
   b) Clean atomizing tip on oil gun.
   c) Remove pilot assembly for cleaning and resetting of spark gap.

Preventative Maintenance Schedule

PURPOSE AND SCOPE

The information presented provides guidance to those individuals responsible for maintenance of boiler plant equipment.

Preventive maintenance is the systematic and periodic inspection and servicing required for keeping equipment in proper operating condition. The life of the boiler plant equipment depends largely upon its maintenance. Boiler life is consistently higher in a well maintained plant than in a poorly maintained one.

The plant supervisor has the ultimate responsibility for boiler plant equipment, its proper operation, and the scheduling and performance of preventive maintenance. The plant supervisor should assign to themselves responsibility for all inspection and servicing required for plant safety. They will assign other operating or maintenance personnel the responsibility for maintenance of specific pieces of equipment, as required by the preventive maintenance plan. Some items listed for a daily inspection by an assigned individual also require hourly inspections by the operating personnel. These hourly inspections do not relieve the assigned operator of his responsibility to inspect, service, and record the equipment condition.

Inspection is the first step in a preventive maintenance program. The early detection of problems can greatly simplify maintenance, reduce the amount of damage, and prolong equipment life. The key to an effective inspection is a complete understanding of the equipments operating characteristics. The operator should know the condition, sound, temperature, pressure, speed, vibration, and performance characteristics of each piece of equipment in the plant and particularly those for which he/she is assigned responsibility. Any change in normal characteristics should be immediately reported, recorded, investigated, and corrected.

Preventive maintenance programs are effective only if careful, accurate, and complete records are kept. Each time a piece of equipment is inspected a record should be made detailing any noticeable change in normal characteristics. Each time a piece of equipment is worked upon, a detailed record should be made describing the work and type of work whether the work was a repair or preventative maintenance. It may also be helpful to record any useful manual references, the frequency of the same task, and the time required to complete the task.

SCHEDULING AND USE OF THE INFORMATION

The following sections provide suggested preventive maintenance schedules for the boiler plant equipment. The subparagraph designates the frequency for preventive maintenance: daily, weekly, monthly, quarterly, semiannually, and annually. The second subparagraph numbers are numbered consecutively and can be used as index numbers in the records. The lists or inspection and work presented here should not be considered to be complete. Review the manufacturer's operating and maintenance instructions and add additional required items as needed. Review the applicable ASME Code and the National Board Inspection Code published by the National Board of Boiler and Pressure Vessels Inspectors, for additional requirements and suggestions. Other equipment may be found which is not discussed in this section. Such equipment should be researched with the manufacturer and appropriate records prepared. The frequency suggested here is based on good practice and experience. Modify the suggested frequency to best match local conditions and experience.

I BOILERS

The successful operation and maintenance of a boiler is greatly dependent on the operation and maintenance of its auxiliaries. Boiler operation and boiler preventive maintenance both involve the inspection of the boiler operating conditions.

A. Daily

(1) Check the following conditions and take action as required

(a) Water level.

(b) Water pressure or water temperature stability.

(c) Flue gas temperature at two loads, compared to clean boiler temperatures.

(d) Flue gas oxygen or carbon dioxide levels at two loads, compared with baseline data.

(e) Water or steam leaks.

(f) Air leaks in casing & ducts.

(g) Blowdown gauge glass

(h) Blowdown & test low water cut-off.

(2) Take water samples and perform necessary tests. Adjust internal treatment and continuous blowdown.

(3) Blowdown boilers through the bottom blowdown connection to remove sludge.

(4) Clean boiler exterior

(5) WATER COLUMNS

(a) Blowdown and inspect all water columns, gage glasses, level indicators, and level alarm devices for leaks, correct operation, correct level indication: and adequate lighting. Repair leaks immediately.

(b) Check to see that valves between boiler and gage glass are free and operational.

(c) When provided, test high and low automatic alarm to ensure that it is in perfect order. Repair when faulty.

(6) SAFETY VALVES

(a) Check for steam leakage indicating damaged seat, defective parts or lodged scale. Correct immediately such faults as leaking, simmering or chattering.

(b) Check supports and anchors of discharge pipe.

(c) Check the drain line from safety valve outlet to insure that it is open and will function when needed.

(7) Inspect boiler piping, valves and fitting for leaks.

B. Monthly

(1) Lever test all safety valves. Check each safety valve by raising the valve off the seat by listing the lever. Keep the valve wide open for at last 10 seconds to blow dirt and scale clean from the seat. Close the valve by suddenly releasing the lever.

(2) Inspect all boiler drain valves for proper opening and closing.

(3) Inspect boiler room floor drains for proper function.

(4) Inspect all safety controls for such problems as dirty switch contacts, defective diaphragms or sensing elements, loose wires, dirty flame scanner lens or flame rod. Clean or repair immediately.

C. Quarterly

One of the quarterly inspections should be timed to coincide with the annual inspection by the Authorized Inspector.

(1) Internally and externally inspect the boiler. Reference semi-annual and annual procedures.

D. Semi-Annually

Semi-annually or as required an external inspection of the boiler by an Authorized Inspector is required. With the boiler operating, inspect for the following:

(1) Any evidence of steam or water leakage.

(2) Pressure gage accuracy and function.

(3) Safety or safety relief valves.

(4) Water level gage function.
(5) Pressure controls function.
(6) Low water fuel cutoff and level control function.
(7) Steam, water and blowdown piping for leakage, vibration, proper rating, and freedom to expand.
(5) Review the boiler log, maintenance records, and water treatment records to ensure that regular and adequate tests have been made.

E. Annually

Boiler inspections are to be made in accordance with Rule for Inspection in Section VII of the ASME Boiler and Pressure Vessel Code. An Authorized Inspector is required.

(1) Inspect the boiler for the following:
   (a) Water side of tubes and boiler for corrosion, grooving and cracks.
   (b) All manholes, manways, internals and connections to the boiler for cracks, corrosion, erosion and clean passages.
   (c) Tube sheets, tube ends and drums for signs of thinning, leaking, corrosion or cracks.
   (d) Boiler supports and setting for freedom of expansion.
   (e) Fire side of tubes for bulging, blistering , leaks, corrosion or erosion.
   (f) Settling for cracks, settlement, loose bricks, refractory spalling and leakage.

Safety valves and their connections and piping. Test the safety valves. Before and after the annual steam generator inspection and overhaul, test the operation of all safety valves. Testing is also required whenever the spring or blow back ring has been reset or adjusted.

II BURNERS

A1. Oil Burners

a. Daily

(1) Inspect for the following hourly:
   (a) Oil, steam, or air leaks. Repair immediately.
   (b) Unburned oil deposits and overheating of burner parts.
   (c) Burner flame for proper shape, color and stability.
   (d) Proper operating pressures and temperatures.
   (e) Check gas, oil, steam pressure readings to make sure conditions are normal.
   (f) Check lens of scanner & check flame failure cut-out.

b. Annually

(1) Inspect all air register and burner parts for freedom of movement, warpage, and wear. Repair and/or replace as required. Adjust all parts for proper operation. The services of a burner/Indeck
technician may be required.
(2) Check/replace atomizer tips or nozzles that have been in normal service with new tips or nozzles.
(3) Calibrate burner pressure and temperature gages.
(4) Check/remove and clean the oil atomizer.
(5) Check ignition electrode/pilot for proper gap/flame, adjust if necessary.
(6) Inspect flame view lens ports, clean if necessary.
(7) For electric ignition systems, test and record voltage readings on each side of the ignition transformer.
(8) Visually inspect all control linkages and components for proper operation, lubricate moving parts, if necessary.

A2. Oil Handling Equipment

a. Daily

(1) Inspect for the following:

(a) Oil, Steam water, or air leaks. Repair immediately.
(b) Proper operation of traps, controls, and instrumentation.
(c) Proper operating pressures, temperatures, and levels.
(2) Clean equipment as required.
(3) Establish a schedule for cleaning strainers.
(4) Inspect and maintain pumps.

b. Annually
(1) Inspect and clean tanks internally and externally. Inspect carefully for corrosion, erosion, pitting, plugged tubes, damaged baffles, sludge deposits, water accumulations, and scale deposits.
(2) Inspect for damage to protective coatings or paint. Repair or repaint as required.
(3) Test relief valve settings and operation.
(4) Clean, inspect, and calibrate all controls and instrumentation.

B. Gas Burners
a. Daily: Inspect for the following hourly:
(1) Gas or air leaks. Repair immediately.
(2) Proper gas and air pressures.
(3) Burner flame for proper shape, color, and stability.
(4) Overheating or binding of burner parts.
(5) Flame scanner, check flame signal strength.

b. Annually:
(1) Inspect all burner parts for freedom of movement, warpage and wear. Inspect gas nozzles. Repair or replace as required. Adjust all parts for proper operation. The services of a burner serviceman may be required.
(2) Calibrate burner pressure gages.
(3) Check ignition electrode/pilot for proper gap/flame, adjust if necessary.
(4) Inspect flame view ports, clean if necessary.
(5) Electric ignition systems, test and record voltage readings on each side of the ignition transformer.

III FUEL RACK

a. Daily:
(1) Inspect natural gas and oil, isolation and control valves, air intake damper and damper drive linkages, adjust if necessary.
(2) Inspect for air, oil, gas and water leaks. Repair immediately.
(3) Blow down compressed air drip legs and filters.

b. Monthly:
Inspect all fuel solenoid valves, full closure and proper operation.
Test valve settings and operation.

c. Quarterly:
Clean and inspect all fuel oil strainers.
Check actuator motor for proper operation.
Inspect, and calibrate all controls and instrumentation. Inspect boiler fuel piping, valves, gaskets and fitting for leaks. Inspect and replace as necessary.

d. Annually:
Inspect and test all fuel gas isolation valves to confirm proper fuel isolation and venting.
Check/confirm that fuel gas is vented to a safe location away form people, equipment and flame source, etc.

IV COMBUSTION CONTROLS

a. Daily:

(1) Inspect for stable and proper operation.

(2) Clean exterior of controls cabinet.

b. Monthly:

Replace or clean all system filters. Check boiler set points align with service and operation records.

c. Semi-Annually:

(1) Perform hard drive maintenance requirements as outlined in Indeck's "Standard maintenance for HMIs"

d. Annually:

(1) Inspect and completely clean all control devices. Replace any worn, corroded, or damaged parts.

(2) Test for correct calibration on instruments. Adjust as required.

(3) Obtain the assistance of a fully trained Indeck technician as required to calibrate, clean and adjust the controls.

(4) The Indeck technician should tune the boiler for operation on the primary fuel. A combustion gas analyzer should be used to check burner efficiency at 25%, 50%, 75%, and 100%. Firing rate.

(5) Other observations should be made during boiler tune-up such as fuel/air ration, flame color/spread, opacity, stack temperatures, and 02/NOx/CO/CO2 concentrations.

(6) Check/test burner control panel/system for the following indication lights/safety devices/alarms; flame failure, high/low gas/oil pressure, air switch and alarms on HMI.

V OPERATIONAL TESTING OF BOILER SAFETY DEVICES:

a. Monthly

(1) Low- water cutoff (slow drain) [Low water flow for hot water boilers]

(2) Fire each boiler & the pilot on the alternate fuel for 1 hour (if applicable)

(3) Low-water cutoff trip switch [Low water flow trip switch for hot water boilers]

(4) Auxiliary low-water cut-off (slow drain)

(5) Auxiliary low-water cut-off trip switch

(6) Steam safety valves (accumulation test at high fire

(7) Steam safety valves (raise boiler pressure until valve pops)

(8) Low-water cutoff bypass switch

b. Semi-Annually

(1) High-water alarm

(2) Low-water alarm

(3) High-steam pressure cut-out (recycle)

(4) High-steam pressure cut-out (non-recycle)

(5) Flame scanner

(6) Check gas vent for leaks

(7) High-gas fuel pressure cut-off

(8) Low-gas fuel pressure cut-off

(9) Gas fuel safety shut off valves proof of closure

(10) Leak test gas fuel safety shut off valves

(11) High-fuel oil temperature cut-off (heated fuel)

(12) Low-fuel oil temperature cut-off (heated fuel)

(13) Low-atomizing pressure for fuel oil

(14) High-fuel oil pressure cut-off

(15) Low-fuel oil pressure cut-off
(16) Fuel oil safety shut off valves proof of closure
(17) Leak test fuel oil safety shut off valves
(18) Check operation of Liquid Petroleum Gas pilot
(19) Low-pilot gas pressure cut-out
(20) Forced draft fan motor interlock
(21) Forced draft fan damper limit switches
(22) Boiler outlet damper limit switches
(23) Purge air flow interlock
(24) VIV damper limit switches
(25) High water cutout switch
(29) Main flame out; i.e., time to close valves
(30) Ignition flame out; i.e., it is time to close valves
(31) Minimum igniter flame test
(32) Scanner not sensing ignition spark
(33) Low-oxygen alarm and/or cut-out

VI FEEDWATER/DRUM LEVEL CONTROLS

a. Daily:
   (1) Inspect for water leaks. Repair immediately.
   (2) Observe operation of feed-water control valve. Report and repair any malfunction immediately.

b. Annually:
   (1) During the boiler overhaul, or more often, if necessary, clean and inspect all control components. Look for signs of corrosion, erosion, or wear and for deposits, leaks, and defective parts. Repair as required.
   (2) Check settings, adjustments, and operation of all components.

VII INSTRUMENTATION

a. Daily:
   (1) Inspect for leaks. Repair immediately.
   (2) Check for proper operation. Report any malfunction. Only trained personnel should place in service, remove from service, calibrate, or maintain instruments.
   (3) Inspect for undue vibration, broken glass, lighting, and readability.

b. Annually:
   Once a year, or more often if necessary, make a thorough inspection of all instruments and gages for corrosion, deposits, or other defects. Inspect carefully for the following:
   (1) Ruptured or distorted pressure parts.
   (2) Incorrect calibrations or adjustments.
   (3) Badly worn pins or bushings.
   (4) Damaged or burned thermocouple wire insulation.
   (5) Leaking or damaged diaphragms, bellow and gaskets.
   (6) Mercury separations in thermometers.
   (7) Loose pointers.
   (8) Broken balance-arm screws.
   (9) Plugged piping or tubing.
   (11)Broken or damaged adjustment assemblies.
   (10)Defective mechanism or electric motor operation.

VIII ECONOMIZERS

a. Daily:

Inspect for leaks in piping, valves, packings, gasketed joints, manway openings, casing, etc., make repairs as required.

b. Monthly:

Check the following under identical load conditions:

(1) Water pressure drop through the economizer.
(2) Draft losses across the economizer.
(3) Gas temperature drop across the economizer. An increase in draft loss and a decrease in gas temperature drop normally indicates a fouling condition.

c. Annually:

During the annual boiler overhaul, clean and inspect the economizer.

(1) Externally look for signs of overheating, leakage, wear, or corrosion in pressure parts. Check the baffles and tubes in the area of soot blowers for signs of abrasion caused by steam cutting. Check the elements of the soot blower.
(2) Internally look for corrosion, erosion, scale, sludge deposits, or oil in tubes and headers.

IX ELECTRIC MOTORS

a. Daily:

(1) Inspect for the flowing:
  (a) Cleanliness.
  (b) Overheating.
  (c) Hot bearings.
  (e) Unusual noise or vibration.
  (f) Establish lubrication and motor maintenance in accordance with manufacturers recommendations.

b. Quarterly:

Perform vibration tests of bearings and collect data to create baseline for future comparison.

c. Annually:

(1) Check for loose or broken cooling fan blades.
(2) Check coupling alignment.

X. FORCED DRAFT FANS

a. Daily:

(1) Inspect for the following:
  (a) Abnormal noises.
  (b) Abnormal vibration.
  (c) Overheating of drive.
  (d) Abnormal bearing temperature.
  (e) Condition of oil/grease and bearing oil level.
  (f) Proper flow and temperature of bearing-cooling water (if required)
  (g) Freedom of damper motion.
(2) Establish lubrication requirements and schedule in accordance with manufacturers recommendations.
(3) Check that actuators are secured/anchored correctly.
(4) Confirm that damper positoners are operating correctly.

b. Monthly:

(1) Inspect entire unit for unusual noise and/or vibration, insure that it is in good working order.
(2) Check the damper linkages are properly connected and operating.
(3) Inspect ductwork flexible connectors for abnormalities and leaks.
(4) Inspect gaskets around access doors.
(5) Lubricate fan bearings and motors, as necessary.
(6) Lubricate all moving parts/connections, as necessary.
(7) Operate dampers over the full modulation range, verify proper operation and position.

c. Quarterly:
   (1) Check: alignment of shaft and coupling; inspect coupling.
   (2) Check condition of foundation and tightness of bearing, actuators, fan and foundation bolts.
   (3) Inspect bearings, perform vibration testing and collect data to create baseline for future comparison.
   (4) Check access doors for tightness.
   (5) Inspect unit for unusual noise and/or vibration, ensure that it is in good working order.
   (6) If unit is not running or an identified problem requires the unit to be serviced, perform ALL Non-Critical Tasks listed below.
   (7) Inspect fan and motor assemble for proper alignment.
   (8) Provide lubrication, if necessary.
   (9) Check for bearing vibration, record levels at each bearing.

d. Semi-Annually:
   Inspect the following:
   (1) All pneumatic/electrical connections, tighten if necessary.
   (2) All fan wiring for deterioration.
   (3) Motor-shaft coupling connection and ensure tightness.
   (4) Controls and cycle actuators to ensure proper operation.
   (5) Verify that dampers open and close fully.
   (6) Inspect all linkages and ensure proper positioning.

e. Annually:
   Annually, or more often if required, inspect and performs the following maintenance work:
   (1) Complete by overhaul bearings.
   (2) Inspect all gauges and meters, ensure they are functional, replace if necessary.
   (3) Inspect all fan wiring for deterioration.
   (4) Check damper linkage, set screws and blade adjustment for proper tightness.
   (5) Inspect damper collar set screws and weld connection on shaft. Ensure tightness.
   (6) Ensure tightness of all electrical connections.
   (7) Inspect motor starter/control center.
   (8) Ensure that overload settings are proper.
   (9) Verify correct operation of starter.
   (10) Inspect electrical contact surfaces for pitting or wear.
   (11) Inspect fan assembly.

<u>XI STEAM TRAPS</u>

Establish a comprehensive and coordinated maintenance and inspection program for all steam traps, strainers, and separators. As a minimum, the following must be done for central boiler plants.

a. Daily: Inspect the traps, strainers, and separators for the following:
   (1) Piping leaks. Repair as necessary.
   (2) Correct operation.
   (3) Abnormal pressure drop across strainers.
   (4) Unusual accumulations of foreign matter in strainer baskets.
   (5) Unusual and excessive discharge of condensate and oil from separators.
   (6) Damage to insulation at traps. Repair as necessary.

b. Monthly:
   (1) Blowdown steam trap to eliminate dirt accumulations.
   (2) Open the air vents on float traps to vent accumulated air.
   (3) Test traps for correct operation.

c. Annually:
   (1) Completely disassemble all steam traps and inspect them carefully for the following:
      (a) Cracked, corroded, broken, loose, or worn parts.

    (b) Excessive wear, grooving, and wire drawing of valves and seats.
    (c) Defective bellow, buckets, or floats.
  (2) Replace or repair all defective gaskets, linkages, and orifices.
  (3) Reassemble and test for proper operation.

XII DUCTWORK, EXPANSION JOINTS, DAMPERS, STACK, LADDER AND PLATFORMS

a. Daily: Inspect for possible defects, leaks, damage or settlement in foundation. Report promptly any such observation.

b. Quarterly:
  (1) Make a more thorough examination of the ductwork, expansion joints, dampers & stack to look for cracks, corrosion, loose hangers, damaged lightning rod and connectors, loose parts, etc.
  (2) Check dampers to ensure free movement.

c. Semi-Annually: Carefully examine supports for corrosion, cracking, or movement of anchor blocks. Check for corrosion of ladder and platforms.

d. Annually: Inspect equipment internally and externally. Inspect lightning rod tips and ground connections. Paint.

XII AIR HEATERS

a. Daily:
  (1) Inspect the air heater for gas or air leaks in duct, casing, gasketed joints, etc.
  (2) Inspect for abnormal air or gas temperatures.

b. Monthly: Check the following under identical load conditions:
  (1) Air and gas side draft losses.
  (2) Gas temperature drop through the air heater.

c. Annually:
  (1) During the boiler overhaul, clean and inspect the air heater. Look for indication of corrosion, erosion, leakage, and wear.

XIII DEARATING HEATERS AND DEARATORS

a. Daily:
  (1) Check for correct operation of relief valve, steam pressure reducing valve, overflow, controls, alarms and steam pressure and temperature indicator. Report any malfunctions immediately.
  (2) Inspect for steam and water leaks. Repair immediately.
  (3) Check vent for proper operation.
  (4) Check tank and water temperatures.

b. Annually: Once a year, or more often under sever service conditions, clean the unit and inspect the following:
  (1) Spray valves for corrosion, erosion, scaling and proper seating.
  (2) Water discharge nozzles for clogging, corrosion, and wear.
  (3) Trays (on tray type units). Remove and inspect for corrosion, warping, and scaling.

c. Quarterly: Inspect for the following:
  (1) Compressor valves for wear, dirt and improper seating.
  (2) Operation of all safety valves.
  (3) Cleanliness of air intake filter.
  (4) Tightness of cylinder head bolts and gaskets.

d. Annually:
  (1) Check cylinders for wear, scoring corrosion and dirt.
  (2) Inspect pistons and rings for leakage, wear, scoring, security to the piston rod and head clearances.

IX CENTERIFUGAL PUMPS

a. Daily: Inspect for the following hourly.
   (1) Abnormal vibration and noise.
   (2) Abnormal pressure and flow conditions.
   (3) Excessive or inadequate packing leakage.
   (4) Hot bearings.
   (5) Hot stuffing box.

b. Semi-Annually:
   (1) Check alignment of pump and driver with the unit at stand-still and normal operating temperature.
   (2) Check shaft sleeves for scoring.
   (3) Replace packing if required.
   (4) Drain the oil from oil-lubricated bearings, flush, and refill with clean oil.
   (5) Check grease-lubricated bearings. Do not overgrease the bearings. When adding grease, remove drain plug or use a safety fitting to prevent overgreasing.
   (7) Check pump bearing vibration, bearing record vibration levels at each bearing.

a. Daily: Check for the following:
   (1) Shaft for scoring, corrosion, or wear at seals, alignment and coupling connection.
   (2) Calibrate pressure gages, thermometers, and flowmeters.
   (3) Suction and discharge strainers for cleanliness.

XV CENTERIFUGAL PUMPS

b. Daily:
   (1) Inspect for the following:
      (a) Unusual noise or vibration.
      (b) Abnormal temperature and pressure of compressed air, cooling water, or lubricating oil.
      (c) Proper operation of unloader.
      (d) Hot bearings and stuffing box.
      (e) Correct lubricating oil level and oil consistency.
   (2) Establish lubrication requirements and schedule in accordance with manufacturers recommendations.

ATTACHMENT B

// AUXILIARY BOILER SPARE PARTS LIST

CRITICAL BOILER SPARE PARTS

BOILER STEAM PRESSURE INDICATOR	85-1379SS-04L- XSG
MANWAY GASKET	S-2000
BOILER SAFETY VALVE SET(a}425PSI	1811KB-0-6Xl-22
BOILER SAFETY VALVE SET@437PSI	1811KB-0-6Xl-22
MANHOLE GASKET	14"x18"
WATER COLUMN PROBE	W0450-EA6
ECONOMIZER FLUE GAS INLET/ OULET RTD	R1T185H483-H4D1809T3-SL- 8HN31,I
FRESH AIR DAMPER POSITION ER	D400
IVC DAMPER POSITION ER	D400
FEEDWATER CONTROL VALVE POSITION ER	DVC6200
UV FLAME SCANNER	ProFlame-120
WATER LEVEL GAUGE GLASS	DSS000-191H-1
IGNITER ROD ASSEMBLY	041-002-0010
LWCO BY PASS PUSH BUTTON	800T-AR2AP
3/ 4^{11} & 1-1/ 2^{11} & 3^{11} AUTOMATED GAS VALVE MECHANICAL SWITCH	QX2VB02SDM
OXYGEN ANALYZER PROBE	ZR22G-B-070-S-C-N-E-T-T-E- A/FA/SCT
OBSERVATION PORT GASKET	2-5/ 8^{11} OD x 2^{11} ID x l / l 6^{11}THK.
ONSERVATION PORT GLASS	Q-2-1/2BGOP
15 PSI GAS PRESSURE GAUGE	45-1279-SS-04L- 15#
60 PSI GAS PRESSURE GAUGE	45-1279-SS-04L-60#
100 PSI GAS PRESSURE GAUGE	45-1279-SS-04L-100#
200 PSI INSTRUMENT AIR PRESSURE GAUGE	45-1279-SS-04L-200#
AIR FLOW SWITCH, 3.0-11.0" w.c.	1950G-10-B-120- NA
RECIRCULATION ISO BALL VALVE ACTUATOR	VPVL400SR45BD
RECIRCULATION ISO BALL VALVE LIMIT SWITCH	QX2VB02NDM
RECIRCULATION ISO BALL VALVE VACC. SOLENOID	EF8551A001MS
FGR & STACK DAMPER POSITION ER	D400
STEAM RTD	OP20040-0300- 125-304
STEAM SECTION/WATE R STORAGE TEMP. GAUGE	50EL60090-XC4-50/300
3" VACUUM BREAKER	DFT8037-51
VESSEL/STEAM PRESSURE GAUGE/ 60#	45-1279SSH-04LO- XLLC4-0/60#
WATER LEVEL GAUGE CUSHION GASKET	#9 NON ASBESTOS
WATER GAUGE VALVE	SG854
WATER GAUGE VALVE NIPPLE PACKING	SG854-5
WATER GAUGE VALVE STEM PACKING	SG854-4
WATER LEVEL GAUGE	FG409
WATER LEVEL GAUGE MICA GASKET	#9 MICA
WATER LEVEL GAUGE SEALING GASKET	#9 GRAFOIL
WATER PRESSURE GAUGE/ 100#	45-1279SSH-04LO- XLLC4-0/100#
FGR DAMPER ACTUATOR	VPVL-400DA
STACK DAMPER ACTUATOR	VPVL-600SR6

SPARE PARTS FOR BOILER FEED WATER PUMPS

GASKET	4000
SPIRAL WOUND GASKET	4113
O-RING	4120.1
O-RING	4120.2
O-RING	4120.5
O-RING	4120.6
O-RING	4120.9
O-RING	4120.1
O-RING	4120.11
O-RING	4120.M3
BEARING SHELL	3700.1
BEARING SHELL	3700.2
THRUST BEARINGS SEGMENT / BEARING SEGEMENT CARRIER	3870.1/3921.1
THRUST BEARINGS SEGMENT / BEARING SEGEMENT CARRIER	3870.2/3921.2
MECHANICAL SEAL	4330
CASING WEAR RING	5020.1
CASING WEAR RING	5020.2
IMPELLER WAER RING	5030.1
IMPELLER WAER RING	5030.2
BALANCE SEAT	6020
BALANCE PISTON	6030
COUPLING	8400
OIL PUMP	6320
LABYRINTH RING	4230.1-3
THROTTLE BUSHING	5420
SHAFT NUT	9210
SNAP RING	9320
LOU ELECTRIC HEATER (LUBE OIL UNIT)	6
LOU THERMOCOUPLE (LUBE OIL UNIT)	7
LOU AUX LUBE OIL PUMP (LUBE OIL UNIT)	12
COUPLING HOUSEBELL (LUBE OIL UNIT)	0
AUX LUBE OIL MOTOR (LUBE OIL UNIT)	13
LOU SAFETY VALVE (LUBE OIL UNIT)	15
LOU COOLER GASKETS (LUBE OIL UNIT)	16
LOU FILTER CARTRIDGE (LUBE OIL UNIT)	19
LOU THEROMCOUPLE (LUBE OIL UNIT)	27

ATTACHMENT C

// COMBUSTION CONTROL SYSTEM (CCS) CONTROL NARRATIVE

Combustion Control System (CCS)
Control Narrative
(REV. 2)

FOR

Indeck Power Equipment Company

PROJECT:

Indeck Niles Energy Center

One (1) – 68,500 lb/hr. Packaged Water Tube Boiler

(1) - One GB-V Low NOx Burner

with Natural Gas Pilot

Zeeco PO #: 124204

Zeeco SO & Doc. #: 42575-6231

Rev.	By	Checked	Date	Description
0	PC	NN	1/13/20	Original issue
1	PC	NN	3/2/20	Customer Comments
2	PC	NN	3/13/20	Customer Comments
3				
4				

Contents

GENERAL INFORMATION

This CCS Narrative is focused around a 68,500 lb./hr. boiler. Natural Gas fired package boiler where Zeeco will be providing:

- One (1) – Zeeco GB Low NOx Gas Burner
- One (1) – Zeeco ZA2 Class 3 Natural Gas Pilot

The boiler burner will be operated using Natural Gas. The Burner Management System (BMS) and Combustion Control System (CCS) are by others. This CCS Narrative is for reference only.

WARNING: The burner system shall be designed utilizing the most current engineering practices for operating fired equipment. This equipment shall only be operated by individuals who have been trained with fired equipment operations and are knowledgeable of safety systems. As with any fired device, operation of this equipment by non-qualified personnel may result in equipment damage, bodily harm, and/or death.

CAUTION: Please read the entire contents of this document in conjunction with electrical drawings and any other supporting documentation prior to the installation, commissioning, and start-up of the Burner. Please direct any questions or comments to the project manager at Zeeco for clarification. A complete understanding of the installation is required for safe and successful burner start-up and operation.

REFFERENCE DOCUMENTS

Document Number	Title
42575-C041A-500	Zeeco P&ID – Index Sheet
42575-C041A-501	Zeeco P&ID – Gas Fuel Skid
42575-C041A-502	Zeeco P&ID –Windbox Instrument and Piping
G3363-400 to 404	Customer Boiler P&IDs (by others)
G3363-511	Customer BMS/CCS Electrical Schematics (by others)
42575-C042A-100 (Index)	Zeeco BMS/CCS Junction Box Electrical Schematics
42575-6130	Zeeco BMS/CCS Master I/O List

BURNER MANAGEMENT SYSTEM (BMS)

The Burner Management System (BMS) is the control system that will provide safe startup and stopping of the single (1) GB Natural Gas fueled burner for the boiler while meeting the current NFPA 85 2019 standards. The BMS shall be implemented utilizing a PLC based control system. The basic requirements of the Burner Management System (BMS) are:

- Safely light-off of the burner(s) and annunciate any combustion instability to the Operators for remedial action.

- Properly sequence the field and burner control elements to ensure that the proper operation event sequencing is followed. Some of these events are purging, Pilot trial-for-ignition, burner Main trial-for-ignition.
- Automatically initiate burner shutdown should any abnormal condition(s) occur leading to the accumulation of any unburned fuel.

  For further information, please see BMS Sequence of Operation (Zeeco Doc. No. 42575_6230)

COMBUSTION CONTROL SYSTEM (CCS)

- The Combustion Control System (CCS) shall provide burner combustion control and supply various hardwired safety and alarm interlocks to the Burner Management System (BMS) for safe operation of the boiler burner(s). The actual CCS design and implementation is not by Zeeco and shall be supplied by Indeck. This narrative is provided only as a general recommendation based on the equipment provided by Zeeco. Network communication between the BMS and CCS/DCS shall be specified and selected by the owner.

- The Combustion Control System (CCS) will be programmed to automatically and efficiently control the fuel/air ratio to the boiler burner to maintain a constant output of steam pressure to the customers system. A boiler load change will result in a change in the steam pressure triggering the CCS to automatically adjust the fuel/air ratio to compensate for the pressure change by either increasing or decreasing boiler firing rate.

- The Combustion Control System (CCS) is designed for fully-metered, cross-limited control with O2 trim. To maintain an air-rich flame on load changes, the air flow setpoint is “cross-limited” with the total measured fuel flow and will increase before fuel on load increases and decrease after fuel on load decreases. Airflow will never drop below the fuel flow value. Likewise, the fuel flow setpoint is “cross-limited” with the total measured Air Flow and will increase after air flow on load increases and decrease before air flow on load decreases always maintaining an air-rich environment and never allowing fuel to lead the air flow.

- The Combustion Control System shall also provide for 3-element feed water control. The CCS shall measure the water level in the steam drum, feed water flow rate, and the exiting steam flowrate to calculate how to adjust the feed water entering the boiler. Typically, this method is used from 20% load and above, with a single element control scheme used below 20% load (that single element being water level).

BOILER DEMAND/FIRING RATE

- The signal controlling the boiler demand/firing rate should come:
  - Steam Pressure Transmitter on the Steam Drum *default
    or Header Steam Pressure (in Local mode)
  - Plant Master Remote analog input signal (Remote mode) with Bias
  - Manual operator entered demand from the HMI (Manual Mode).

The Boiler Master controller tracks fuel flow and automatically calculates required bias value when between current demand and customers plant master signal for transitioning into Remote mode.
Demand bias can be removed by the operator incrementally at the HMI or bias control can also be used to add or subtract load from the boiler.

- Boiler Master Controller - (Manual Mode):
  The Boiler Master controller will be forced into Manual mode if any of the following occur:
  1. BCS is not Released-to-Modulate/No burners firing. (Boiler demand is 0%)
  2. Fuel controller is in Manual.
  3. Airflow controller is in manual (forcing Fuel Controller to Manual)
  4. In Local Mode and Steam Drum Pressure Transmitter signal goes Bad Quality.
  5. In Remote Mode and Plant Master Analog Input Signal goes Bad Quality.
  - With Fuel and Air controllers in Manual, Boiler Master will track fuel flow value.
  - With Fuel and Air controllers in Auto, Boiler demand will follow the manually entered controller output value.
  - For bump less transfer to Manual, the manual setpoint will track the current boiler master output while in Auto-Local or Remote.

- Boiler Master Controller - (Auto Local Mode – (Steam Drum Pressure Control):
  Local Mode is selected to allow the Boiler Master controller to modulate the boiler demand by using the Steam Drum Pressure Transmitter and an operator entered steam pressure control setpoint.

  The Boiler Master controller can be placed into Local mode if the following are true:
  1. Fuel controller is in Auto mode.
  2. Steam Drum Pressure Transmitter signal is not Bad Quality.
  - For bump less transfer to Auto Local mode, the steam pressure setpoint will track the boiler master drum pressure while in Manual.

- Boiler Master Controller - (Remote Mode – Remote Plant Master Control):
  Remote Mode is selected to allow the Boiler Master demand to be controlled directly from a remote Plant Master Analog Input Signal. (4-20mA = 0-100% demand)

  The Boiler Master controller can be placed into Remote mode if the following are true:
  1. Fuel and Air controllers are in Auto mode.
  2. Plant Master Analog Input Signal is not Bad Quality.
  3. Plant Master Bias is within +/- 20%. (Bias = Current BM demand % - PM demand %)

  - Once in Remote mode, the current demand Bias value can be reduced incrementally to zero so current boiler master demand matches the remote plant master signal. The operator can also use the bias to add or subtract load from the boiler locally.

AIR & FUEL CHARACTERIZATION

- Characterizers will be provided for Combustion Air Flow and Fuel Flow inputs.
- Characterizers convert the field flow transmitter signals to a 0-100% MCR signal to be used by the CCS individual cross limited PID control loops for Air and Fuel flow.

COMBUSTION AIR FLOW CONTROL

- The CCS controls Air Flow via a Combustion Air Flow PID controller with Auto/Manual function.
- In Auto, the PID controller output will increase or decrease the Combustion Air Flow in response to the current firing rate demand. F(X) = Y, Air Demand (X), Damper Position(Y)
- Combustion Air Flow will be characterized per fuel, temperature compensated and trimmed to satisfy O2 requirements.
- The PID controller air flow setpoint uses the higher of the firing rate demand vs. the characterized fuel flow (High limit select) assuring an air-rich flame.
- Air flow will lead the fuel flow on an increasing demand and will never be less than the fuel flow on a decreasing demand. (cross-limiting)
- In Manual, the Air Flow PID controller output can be manually adjusted by the operator with no lead/lag cross-limited controls.
- Air Flow control PID output signal is used to position the Air Control Dampers as needed to maintain the current Air Flow setpoint for overall control of the combustion airflow via individual f(x) positioning curves.
- Upon start of the boiler, the Combustion Airflow controller in will be in Manual. The operator will need to place the controller in Auto.
- The Combustion Airflow controller will be forced into manual if any of the following occur:
  - Air Flow Meter signal is Bad Quality
  - Any Air Control Damper(s) Bad Quality signal
  - No Burner in Service/Released to Modulate

NATURAL GAS FUEL FLOW CONTROL

- The CCS controls the fuel flow control via a Natural Gas PID controller with Auto/Manual function.
- In Auto, the PID controller output will increase or decrease the Fuel Flow in response to the firing rate demand but never greater than the Air Flow. (cross-limiting)

- The PID controller setpoint uses the lower of the firing rate demand vs. the temperature compensated air flow trimmed for O2 assuring that the fuel flow is always lower than the air flow resulting in an air-rich flame.

- The Air Flow will lead the fuel flow on an increasing demand and will never be less than the fuel flow on a decreasing demand.

- In Manual, the PID controller output can be manually adjusted by the operator with no lead/lag cross-limited controls.

- Natural Gas Flow control PID output signal is used to position the Gas Flow Control Valve (FCV) as needed to maintain the current Natural Gas Flow setpoint.

- Upon startup of the boiler, the fuel controller will be in Manual. The operator will need to place the Fuel controller in Auto only once the Air controller has been placed in Auto

- The Natural Gas Fuel Controller will be put in manual if any of the following occur:
    - Air Flow Controller in Manual
    - Natural Gas Flow Meter FT Bad Quality signal
    - Natural Gas Flow Control Valve FCV Bad Quality signal
    - No Burner in Service/Released to Modulate (BMS-HWIR-4)

OXYGEN TRIM CONTROL

- The CCS will incorporate Flue gas oxygen trim control in addition to the fully metered cross-limited fuel/air ratio controls.

- O2 Trim provides a +/- 15% trim factor which is applied to the Air Flow control process variable in Auto only to control the excess O2% in the flue gas and increase boiler efficiency.

- The CCS controls the O2 trim control via an O2 Trim PID controller with Auto/Manual function.

- In Auto, the O2 trim PID controller will trim the Air Flow Process Variable, limited to +/- 15% at boiler demands greater than 25% and below this trim is null.

- When measured flue gas O2 increases above setpoint, the O2 Trim PID controller output will increase and cause a slight positive trim of the Combustion Air Flow Process variable causing the Air Flow controller output to reduce the air flow and thus the flue gas O2.

- When measured flue gas O2 decreases below setpoint, the O2 Trim PID controller output will decrease and cause a slight negative trim of the Combustion Air Flow Process variable causing the Air Flow controller output to increase the air flow and thus the flue gas O2.

- O2 Trim controller will be placed in Manual if any of the following occur:
    - Airflow control in manual
    - Fuel controller in manual
    - Flue Gas Oxygen Meter bad quality

- In manual the O2 trim will be forced to null value (0% trim).

- Automatic O2 trim may only be implemented when both Combustion Air Flow and Fuel control are in automatic modes.

- In Auto, O2 trimming should only occur at boiler demands equal to or greater than 25%. Below this point the O2 trim will be null.

- Since the O2% setpoint is a function of demand and not adjustable, a setpoint bias is made available to the operator. The bias is a constant value in the range of -.5% to .5% O2

BOILER DRUM LEVEL CONTROL

- The Steam Drum level control shall utilize both single-element control and three-element level control.

- The CCS controls the steam drum level via a Drum Level PID controller with Auto/Manual function.

SINGLE-ELEMENT DRUM LEVEL CONTROL

- The Single Element - Drum Level Control PID controller will be put into manual if any of the following occur:
  - Drum Level Transmitter bad quality
  - Feedwater FCV bad quality

- Single-element control will be forced if any of the following occur:
  - Feedwater Flow Meter bad quality
  - Steam Flow Meter bad quality
  - Low Steam Load (<20%)
  - Single Element Lock mode is active (from HMI pushbutton)

- Single-element PID control utilizes only the steam drum level transmitter for control.
- Single-element PID Drum Level control can be locked if selected on the HMI.
- When the steam flow increases to a set value, typically 25% steam flow, the CCS will switch control over to three-element control unless the controller has been forced into single element.
- While in single-element control the drum level control PID output signal is used to position the Feedwater Flow Control valve to maintain a set drum level.

THREE-ELEMENT DRUM LEVEL CONTROL

- Three-element level control utilizes three elements for control, drum level, steam flow, and feed water flow as process variables.
- When the steam load increases to the single-element to three-element set value, (>=25%) the CCS will switch from single-element control to three-element control.

- Three-element control will be activated at a higher steam flow rate at about 25% increasing. and return to single-element control at steam flow rate decrease to about 20%.
- Three-element drum level control is used for more finite control and to compensate for the shrink and swell conditions, which occur in the steam drum at higher steam flow rates.
- The steam flow signal, corrected by drum level, becomes the setpoint signal for the feed water control loop increasing and decreasing the feed water flow as needed.
- When the steam load decreases to the three-element to single-element set value, (<=20%) the CCS will switch control back to single-element control.

FURNACE PRESSURE/DRAFT CONTROL

- CCS shall control the Stack damper via a Draft Controller PID controller with Auto/Manual function.

- In Auto, the PID controller will modulate the Stack Damper to maintain a stack pressure setpoint. The pressure transmitter will act as the process variable for the control loop.

- A "Low Fire" request from the BMS will force the Draft PID control variable (CV) to a set value of X% (T.B.D. during commissioning) to position the Stack Damper accordingly.

- A "Purge" request from the BMS will force the Draft PID control variable (CV) to a set value of 100% to position the Stack Damper to fully open position for purge.

- In Manual the stack damper is manually controlled by the operator through the workstations or local HMI. And may be fully closed to keep heat in boiler after shutdown. Stack damper cannot be closed for light off or during boiler operation.

- Furnace Draft Controller - (Manual Mode):
  The Stack/Furnace Draft controller can be placed into Manual mode if any of the following occur:
  1. Draft Controller is placed in Manual Mode.
  2. Pressure Transmitter signal goes Bad Quality.
  3. Stack damper command signal goes Bad Quality
  - In Manual, the Draft controller output can be manually adjusted by the operator.
  - For bumpless transfer to Manual, the manual control output will track the current Draft controller output while in Auto.

- Furnace Draft Controller - (Auto Mode):
  At boiler startup, the FGR Flow controller should be placed in Auto when the following are true:
  1. Draft controller has been placed in Auto.
  2. Draft controller is not being forced to Manual mode.
  3. Since the Draft Controller Pressure Setpoint is a function of boiler demand and not adjustable, a setpoint bias is made available to the operator. (-.5 to +.5 In H2O)

- In Auto, the PID controller output will open or close the Stack damper to maintain the Draft Controller pressure setpoint. A controller output low limit setpoint will prevent the draft controller from driving the Stack damper fully closed during operation to avoid tripping the boiler.

FLUE GAS RECIRCULATION (FGR)

- Flue Gas Recirculation (FGR) is used as a NOx reduction tool. The amount of FGR induced into the burner windbox is based on the position of the FGR damper. The amount of FGR will be adjusted at commissioning to provide best NOx reduction and will be set by prepositioning the FGR damper based on load tests.
- The FGR Damper Position will adjust the amount of FGR in the combustion air and be based on the current fuel flow.
- The FGR Damper will be adjusted via an f(x) characterizer to control the amount of FGR in the combustion air and be based on current fuel flow.
- Since FGR damper position is a function of boiler demand and not adjustable, a setpoint bias is made available to the operator -2% to 2%.

BMS-CCS INTERFACE

The following hard-wired discrete interface signals from the BMS to CCS are used for CCS control:

- Master Fuel Trip – CCS notified that BMS has been tripped/shutdown burner. Proceed to perform a 15-Second Post Purge Timer where the air settings are left in their last position until the end of the timer. After the timer elapses, the CCS shall return the Air control dampers to their respective Low Fire positions.

- Purge Request – CCS to position the Air control Dampers (Combustion Air Inlet & VIV Damper, FGR Damper and Stack Damper) to their fully opened positions or as required to reach purge air flow rate to satisfy BMS for purging of the boiler.

- Low Fire Request - CCS to position the Air control Damper (Combustion Air Inlet) to their low-fire/light-off position or as required for successful light-off of the burner by the BMS. Fuel flow control valves will also be positioned to their low-fire/light-off positions to satisfy BMS for light-off of the burner.

- Release to Modulate – CCS is fully released to modulate the air flow and the selected fuel flow control valves (Gas or Oil) to follow the boiler demand. BMS has successfully lit off the burner on selected fuel.

- Post Purge Active/Timing – A 15 second post-purge timer has been started in the BMS logic after burner has tripped or normal stopped. Signal is active on while this timer is timing in BMS and signals the CCS to maintain the Air control Dampers (Combustion Air Inlet & VIV, FGR and Stack Dampers) at their last operating positions and hold until this post-purge signal is turned off. (Post Purge timer done.)

The CCS has a hardwired signal to the BMS that will cause a boiler trip if lost. It is detailed below:

- CCS Interlock Trip – BMS operating limit which will trip the BMS upon loss of this signal. Possible causes to lose this signal are CCS processor failure, high-high fuel %, low-low O2%, and FCV or Damper High-High position deviations.

- Note: All the above listed interface signals are detailed further on the 42575-6230 BMS Sequence of Operations document.

STARTUP, SHUTDOWN AND MALFUNCTION PLAN
MALFUNCTION ABATEMENT PLAN

Indeck Niles Energy Center

For Two (2) Natural Gas-Fired Combustion Turbines

2200 Progressive Drive
Niles, Michigan

NTH Project No. 74-210317-03
November 14, 2022

NTH Consultants, Ltd.
3300 Eagle Run Dr NE, Suite 202
Grand Rapids, MI 49525

TABLE OF CONTENTS

1.0 INTRODUCTION

Indeck Niles, LLC (Indeck) operates a natural gas-fired combined-cycle (NGCC) power plant at the Indeck Niles Energy Center located at 2200 Progressive Drive in Niles, Cass County, Michigan. The NGCC plant consists of two (2) combustion turbine generators (CTGs) equipped with heat recovery steam generators (HRSGs) for generation of electricity and various ancillary equipment including an auxiliary boiler, fuel dew-point heaters, and an emergency diesel-fired generator.

The CTG/HRSG trains, each rated at 3,651 Million British thermal units per hour (MMBtu/hr), are equipped with dry low NO_x burners (DLNB), selective catalytic reduction (SCR), and oxidation catalysts for emissions control. Aqueous ammonia is used in the SCR system to reduce nitrogen oxides (NO_x) in the combustion CTG/HRSG exhaust.

Indeck is required to implement and maintain a Malfunction Abatement Plan (MAP) and Startup, Shutdown, and Malfunction (SSM) Plan for the CTG/HRSG trains that describes the practices and procedures pertaining to the operation and maintenance of the CTG/HRSG and combustion controls, corrective procedures during a malfunction, operating variables, and how emissions will be minimized during startups and shutdowns in accordance with R 336.1911 and 336.1912 of the Michigan Air Pollution Control Rules.

This document and its referenced manuals constitute Indeck's SSM Plan (Section 2.0) and MAP (Section 3.0) for the CTG/HRSG trains. The referenced manuals are maintained on-site and electronically at the Indeck Niles Energy Center.

2.0 STARTUP, SHUTDOWN AND MALFUNCTION PLAN

Indeck is required to prepare a SSM plan for the CTG/HRSG trains pursuant to the air permit and Michigan Air Pollution Control Rule R 336.1912. The SSM Plan details procedures for operating and maintaining the CTG/HRSG trains during periods of startup and shutdown in a manner consistent with good air pollution control practices. Malfunction requirements for the CTG/HRSG trains and control equipment are addressed in Section 3.0 of this plan.

Indeck will operate and maintain the CTG/HRSG trains, DLNB, SCR system, and oxidation catalysts in a manner consistent with safety and good air pollution control practices during startups and shutdowns. Indeck is prepared to correct abnormal conditions during startups and shutdowns as soon as it is safe and practicable to do so, in order to minimize excess emissions. This SSM Plan will be followed to minimize emissions during these events. In accordance with the air permit, the total hours for startup and shutdown for each CTG/HRSG train will not exceed 500 hours per 12-month rolling time period as determined at the end of each calendar month.

Suggested startup and shutdown procedures are included in the *2020 – NEC – GE – 88.15.02.002-RE-0012-001 Plant Startup and Operating Philosophy (T210)* and *GEK121243_E Unit Operation HA Gas Turbine* manuals. These manuals are included as Attachments A and B of this plan, respectively. The latest versions of documents referenced in this plan will be maintained electronically at Indeck Niles Energy Center.

2.1 Startup Procedures

The CTG/HRSG operator will minimize the time spent at idle during startup of the CTG/HRSG trains while maintaining appropriate and safe loading of the CTG/HRSG trains. The CTG/HRSG trains will be operated in a manner consistent with good air pollution control practices.

According to the air permit:

> *Startup is defined as the period of time from initiation of the combustion process (flame-on) from shutdown status and continues until steady state operation (loads greater than a demonstrated percent of design capacity) is achieved.*

Pursuant to FGCTGHRSG Special Condition III.2, the demonstrated "percent of design capacity or demonstrated steady state level" specified in the startup definition above is required to be described in the SSM Plan as the end of the startup period. The demonstrated percent of design capacity or demonstrated steady state level is achieved at Minimum Emission Compliance Load (MECL). MECL is met when CTG/HRSG trains exceed 140 MW and NO_x

concentration is less than 4 ppm (as measured by CEMS to serve as an indicator of SCR operation).

As detailed in Section 3.4 of the 2020 – NEC – GE – 88.15.02.002-RE-0012-001 Plant Startup and Operating Philosophy (T210), included as Attachment A, upon startup, unless a different load is requested, the unit will load to the Spinning Reserve load point. The Spinning Reserve load point is slightly greater than no load, approximately 25 megawatts (MW). An exhaust gas temperature of 1,050°F, minimum pressure of 15 psig, and minimum fuel gas temperature of 120°F are required in order to ramp the CTGs to their MECL at 8.33% per minute. Normal startup and loading operations are further described in Section 3.3 of this plan.

Indeck will follow the suggested startup procedures and instructions described in *2020 – NEC – GE – 88.15.02.002-RE-0012-001 Plant Startup* and *Operating Philosophy (T210)* included as Attachment A and *GEK121243_E Unit Operation HA Gas Turbine* manuals included as Attachment B. Indeck will verify that the DLNB, SCR, oxidation catalyst and the associated aqueous ammonia system are operating within acceptable ranges and the CTG/HRSG trains are achieving the MECL, as specified. Suggested startup procedures for the SCR system are included in the *SCR Control Philosophy* manual (pages 11 – 13) of Attachment C. The oxidation catalyst for CO and VOC reduction is passive and requires no control function during startup.

2.2 Shutdown Procedures

According to the air permit:

> *Shutdown is defined as that period of time from the lowering of the turbine output below the demonstrated steady state level, with the intent to shut down until the point at which the fuel flow to the combustor is terminated.*

As described in Section I of the *GEK121243_E Unit Operation HA Gas Turbine* manual (Attachment B), shutdown is initiated by selecting STOP on the Human Machine Interface (HMI) Main Startup Display. The HMI is a personal computer that directly interfaces to the turbine control panel. The control system will follow automatically through generator unloading, generator breaker opening, turbine speed reduction, fuel shutoff at part speed, and initiation of the cool down sequence. Further, Section 5.0 of *2020 – NEC – GE – 88.15.02.002-RE-0012-001 Plant Startup* and *Operating Philosophy (T210)* (Attachment A) includes the suggested steps and parameters for shutdown of the CTG/HRSG. Typically, the objectives of a normal shutdown procedure are to maintain the steam turbine temperature and HRSG pressure as high as practical to facilitate a subsequent startup while minimizing HRSG and steam turbine stress. For a typical shutdown, the gas turbines are unloaded at designated shutdown rate (8.33%/min) towards MECL before steam turbine shutdown is initiated.

Upon normal shutdown order, the gas turbine load is reduced further until a reverse power situation is detected at which time the gas turbine generator breaker opens. When the generator breaker opening is detected, the gas turbine fuel flow is reduced to a minimum value enough to maintain flame, but not turbine speed. The gas turbine then decelerates. When the gas turbine transitions through approximately 25% speed, the fuel is completely shut off. The purpose of this "fired shutdown" operation is to reduce the thermal fatigue duty imposed on the hot gas path parts. After fuel shutoff, the gas turbine continues to coast down to turning gear speed where turning gear is engaged.

Indeck will follow the suggested shutdown procedures and instructions described in the *2020 – NEC – GE – 88.15.02.002-RE-0012-001 Plant Startup and Operating Philosophy (T210)* manual and *GEK121243_E Unit Operation HA Gas Turbine* manual, included as Attachments A and B, respectively. Suggested shutdown procedures for the SCR are described in the *SCR Control Philosophy* manual included as Attachment C.

3.0 MALFUNCTION ABATEMENT PLAN

Indeck is required to prepare a MAP for the CTG/HRSG trains pursuant to the air permit and Michigan Air Pollution Control Rule R 336.1911. The MAP details procedures for operating and maintaining the CTG/HRSG trains and control equipment (e.g., the DLNB, SCR system, oxidation catalyst), and is comprised of information regarding prevention, detection, and correction of malfunctions that may occur at the CTG/HRSG trains. The MAP describes implementation of preventative maintenance, and, should a malfunction occur, the MAP references procedures for correcting these incidents.

The MAP serves to provide the following information as required by Rule 911(2):

a) A complete preventative maintenance program, including identification of supervisory personnel responsible for overseeing the inspection maintenance and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs and identification of the major replacement parts that shall be maintained in inventory for quick replacement.
b) An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.
c) A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.
d) Identification of the source, and operating variables and ranges for varying load, shall be monitored and recorded. The normal operating range of these variables and a description of the method of monitoring shall be maintained.
e) The procedure that will be followed to address a test result that is higher than the emission factor listed in SC V.2 of the air permit.

3.1 Preventative Maintenance Procedures

This section outlines components of Indeck's preventative maintenance program and applicable documents for maintaining the CTG/HRSG trains and associated DLNB, SCR system, and oxidation catalysts.

3.1.1 Supervisory Personnel

Supervisory personnel responsible for preventative maintenance, including inspections, maintenance, and repair of the CTG/HRSG trains include:

Operations & Maintenance (O&M) Manager – Responsible for overseeing CTG/HRSG inspections, maintenance and corrective procedures/repairs.

Compliance Manager – Responsible for compliance demonstrations, reporting abnormal conditions and malfunctions, and recordkeeping.

Other personnel may be tasked with implementing the requirements of this plan, including inspections, routine maintenance, and repair, along with overall operations of the CTG/HRSGs and maintenance of combustion controls.

Suggested preventative maintenance procedures and schedules for the CTG/HRSG trains and associated equipment are included in *G.E. Master Comprehensive Equipment Manual GEK 134793* (this document is maintained electronically / on-site).

Recommended maintenance procedures and schedules for the SCR and oxidation catalyst are identified in the *SCR Control Philosophy* manual included as Attachment C.

3.1.2 Frequency of Repairs and Items to Be Inspected

Equipment repairs will be conducted as necessary, as suggested in *GEK121243_E Unit Operation HA Gas Turbine*. A list of parts to be inspected, descriptions of maintenance tasks, and specific inspection schedules for the CTG/HRSG trains and associated equipment are provided in the *G.E. Master Comprehensive Equipment Manual GEK 134793* (this document is maintained electronically / on-site) and for the SCR and oxidation catalyst in the *SCR Control Philosophy* manual included as Attachment C.

Records of inspections as well as maintenance events, including date and time of repairs will be documented electronically in the work order system (Maximo) and on-site in the eLogger system at Indeck Niles Energy Center.

3.1.3 Replacement Parts

Indeck maintains major replacements parts for the CTG/HRSG and associated equipment at the facility for quick replacement. If a spare part for the system is not available when needed, the CTG/HRSG will be shut down (when deemed necessary to maintain emission compliance) until the part or system can be installed or repaired. CTG/HRSG spare parts inventory tracking will be maintained in Maximo CMMS and physical part inventory will be maintained on site.

3.2 CTG/HRSG Operating Variables

Indeck will operate and maintain the CTG/HRSG, including the DLNB, SCR system, and oxidation catalysts, in a manner consistent with the safety and good air pollution control practices during malfunctions and abnormal conditions. Indeck will not operate the CTG/HRSG unless the DLNB, SCR system, and oxidation catalysts are installed, maintained, and operated in accordance with this MAP.

Control Room Operators will monitor operation, issue commands, and manage alarms for the CTG/HRSGs using the Human Machine Interface (HMI), a personal computer that directly interfaces to the turbine control panel. Normal operating variables for the CTG/HRSGs and components are included in the *2020 – NEC – GE - 88.15.02.002-RE-0012-001 Plant Startup and Operating Philosophy (T210)* and *GEK121243_E Unit Operation HA Gas Turbine* manuals included as Attachment A and B.

Normal operating variables for the CTG/HRSGs are summarized in Table 3-2. CTG/HRSG operators will monitor the NO_x and CO emissions rate using Continuous Emissions Monitoring System (CEMS) to ensure the CTG/HRSG trains are in compliance with the air permit and as an indicator of proper operation of the CTG/HRSGs and control equipment.

Table 3-2. CTG/HRSG Operating Variables

Monitored Variable	Normal Operating Range
CTG Exhaust Gas Temperature (°F)	1,050 - 1,250 °F
Fuel Gas Temperature (°F)	120 °F
HRSG Pressure (psig)	15 - 30 psig
Maximum Steam Outlet Temperature (°F)	1,085 °F
Maximum Overall Vibration Velocity (in/sec)	1.0 in (2.54 cm)
Maximum Rotor Temperature (°F)	185 °F
Maximum Stator Temperature (°F)	140 °F
HRSG Exhaust Temperature (°F)	65 - 80 °F*
Flame Out Speed (%)	94%

*If, during steady state and loading/unloading operation, there has been an increase in exhaust temperatures above the normal 65°F to 80°F, the thermocouples in the exhaust plenum should be examined. The thermocouples will be inspected for debris and checked that they are radially oriented relative to the turbine.

3.3 Control Equipment Operating Variables

The CTG/HRSG trains are each equipped with DLNB and SCR (for reducing/controlling NO_x emissions) and an oxidation catalyst (for controlling CO and VOC emissions). Indeck will maintain the DLNB, SCR system, and oxidation catalysts in accordance with the *SCR Control Philosophy* manual, included as Attachment C, and *2020 – NEC – CON – PSD Aqueous Ammonia 20026168-MSD-AQA-001.A.IFOR.A.01* manual, included as Attachment D. Indeck will not operate the CTG/HRSG train unless the respective DLNB, SCR, and oxidation catalyst are installed, maintained, and operated in accordance with this MAP.

Indeck will monitor the operating variables of the DLNB, SCR, and oxidation catalysts as described in the *SCR Control Philosophy* manual and as listed in Table 3-4 below. Variables to be monitored according to the SCR Control Philosophy manual include:

- Pressure drop across the catalyst, and
- Flue gas temperatures at the SCR inlet.

Table 3-4. Catalyst Operating Variables

Monitored Variable	Normal Operating Range
NO_x Emission Limit (ppmvd)[1]	< 2 ppmvd at 15% O_2
CO Emission Limit (ppmvd)[1]	< 4 ppmvd at 15% O_2
Flue Gas Temperature, SCR inlet (°F)	665 – 679 °F
dP Across Catalyst (in wc)	2.32 – 2.34 (in wc)
Ammonia Flow Rate (lb/hr)	282 – 845 lb/hr
Ammonia Supply Pressure (psig)	60- 80 psig

[1] 24-hour rolling average as determined each operating hour, except during startup and shutdown.

3.3.1 Response to Malfunction

While operating the CTG/HRSG, if an event happens where obvious damage may occur by continuing to operate, load should be reduced, and the unit taken out of service as soon as practicable. In the event of a malfunction of the CTG/HRSG or control equipment causing an exceedance of an emission limitation, Indeck will document and maintain records of the abnormal conditions. Indeck plant operators will notify the *Compliance Manager* and document the date of the malfunction, the duration of the malfunction, the type of malfunction, and the corrective action(s) taken. If shutdown of the CTG/HRSG is necessary, the CTG/HRSG will be shut down as described in Section 2.2. If the CTG/HRSG cannot be shut down safely or circumstances prevent the CTG/HRSG from being shut down, Indeck will document the reasons for continuing operation.

Corrective actions will be implemented in the event of a malfunction, in accordance with the *2020 – NEC – GE – 88.15.02.002-RE-0012-001 Plant Startup and Operating Philosophy (T210)* manual included as Attachment A, *GEK121243_E Unit Operation HA Gas Turbine* manual included as Attachment B, or other operational requirements. Records of corrective actions will be documented and maintained electronically in the work order system (Maximo) and on-site in the eLogger system. Corrective actions will be taken to resolve issues as soon as it is safe and practicable to do so.

3.3.2 Fugitive Emissions

A fugitive emissions condition would be considered the release of any air emissions from unintended release points for that emissions unit. In the event of a fugitive emissions condition being discovered, employees will report the area of concern to the Control Room Operator. The Control Room Operator will document the problem. If the condition can be readily corrected (leak stopped), the operator will attempt to do so if it can be done is a safe manner. If the fugitive emissions leak is determined to be a significant safety or environmental hazard, the unit will be shut down as described in Section 2.2.

If the fugitive emissions condition cannot be readily corrected and an immediate shut down of the related unit is not required, Plant Management will be informed of the situation. Plant Management will assess and determine the amount of emissions being released at the fugitive emissions point and will determine what repairs will need to be completed to correct the problem. If it is decided that Michigan EGLE needs to be informed of the situation, an email notification will be sent, including an estimate of the environmental impact of the condition, the proposed plan to repair or correct the condition and any other supporting documentation (i.e., photos, videos, drawings…) deemed relative. The plant will comply with any recommended, immediate, or long-term actions provided by Michigan EGLE, including immediate shut down of the unit and/or providing periodic updates to the Department.

If it is determined the fugitive emissions condition is minimal and the unit will continue with operations, the fugitive emissions condition will be inspected as often as deemed necessary with these results being documented. Once repairs have been completed, continue to monitor the area to ensure the repairs are successful until determined that extra inspections are no longer needed.

3.4 Formaldehyde Emission Factor

In accordance with the air permit, Indeck is required to conduct testing to verify the formaldehyde emission factor for the CTG/HRSG trains at maximum operating conditions. The formaldehyde emission factor and thresholds used to determine emissions testing frequency are listed in Table 3-4.

Table 3-4. CTG/HRSG Formaldehyde Tested Factor

Base Emission Factor Annual Timeframe (ppmvd at 15% O_2 on a dry gas basis)	Emission Factor 75% Threshold 3-Year Timeframe (ppmvd at 15% O_2 on a dry gas basis)	Emission Factor 55% Threshold 5-Year Timeframe (ppmvd at 15% O_2 on a gas basis)
0.160	0.120	0.088

After the baseline data set is developed (i.e., after Indeck conducts formaldehyde emissions testing 180 days after startup and once per year for the following two years – three (3) tests total), the default subsequent testing frequency is annual (once per year).

Following the initial baseline data set testing, if two (2) consecutive emissions test results are below 75 percent of the base emission factor, subsequent emissions testing may be conducted once per three (3) years; if two (2) consecutive emissions test results are below 55 percent of the base emission factor, subsequent emissions testing may be conducted once every five (5) years. If the subsequent emissions test result after a 3-year or 5-year test is at or above 55 percent the subsequent testing shall revert to every three (3) years if below 75 percent (i.e., if the result is between 55 and 75 percent) or once per year if the result is greater than 75 percent of the base emission factor.

If a test results in an emission factor above the listed base emission factor of 0.160 ppmv at 15% O_2, Indeck will implement procedures to address future emissions in accordance with MAP requirements in Section 3.0.

4.0 RECORDKEEPING AND REPORTING REQUIREMENTS

Indeck will maintain this MAP and SSM plan at the Indeck Niles Energy Center. Records associated with the plan will be maintained for a period of at least five (5) years.

Indeck will maintain the following records related to the MAP and SSM plan:

- Records of maintenance events, including the date and time of occurrence;
- Records of actions taken during periods of malfunction to minimize emissions including corrective actions to restore malfunctioning equipment to its normal or usual manner of operation;
- Records of the occurrence and duration of each malfunction or abnormal operating condition of the CTG/HRSG train, DLNB, SCR, and oxidation catalysts; and
- Records explaining the reasoning of continuance of CTG/HRSG train operation if the CTG/HRSG train(s) cannot be shut down safely during a malfunction or abnormal operating condition.

In the event that there is an exceedance of an applicable emission standard in the current permit as a result of a malfunction, abnormal condition, startup or shutdown, the Compliance Manager will provide notice and submit a written report to the AQD District Office, as required by R 336.1912, as described below.

If there is evidence of an air contaminant above a permitted emission limit for more than two (2) consecutive hours, prompt notice and a written report will be provided to the AQD, as follows.

- Prompt notice will be provided to the AQD District Office by reasonable means, such as electronic, by telephone, or oral communication as soon as possible, but not later than two (2) business days after the startup, shutdown, or abnormal condition or malfunction is discovered.

- Indeck will submit a written report within 10 days after a startup or shutdown occurrence, or after correction of the abnormal condition or malfunction, or within 30 days of the abnormal condition or malfunction being discovered.

Written reports will contain the following information:

- Time and date, duration, and probable cause of the abnormal condition, startup, shutdown, or malfunction.
- Identification of the CTG/HRSG equipment or control equipment that experienced the abnormal condition, startup, shutdown, or malfunction, and where it is known or reasonably possible to estimate, the magnitude of emissions in excess of the permitted emission limits.
- Description of measures taken and air pollution control practices followed to minimize emissions.
- Summary of actions taken to correct and prevent the recurrence of the abnormal condition or malfunction and the time taken to correct the malfunction.

5.0 PLAN REVISION HISTORY

The MAP and SSM plan may be revised to address revision requests required by the Michigan Department of Environment, Great Lakes, and Energy (EGLE) or due to the following:

- To incorporate new equipment installed;
- To address a revision request from the AQD District Supervisor;
- To address a malfunction event that occurs and is not addressed or that is inadequately addressed by the plan.

If an event described above occurs that requires Indeck to revise this MAP and SSM plan, Indeck will submit a revised MAP and SSM plan within 45 days of such event. A current copy of the MAP and SSM plan will be maintained electronically and onsite at Indeck Niles Energy Center. Previous versions will be kept on file and available for at least five (5) years from the date of revision. Table 5-1 contains a list of revisions of this document.

Table 5-1. Plan Revision History

Revision No.	Date	Revised By	Comments
Original	June 22, 2022	N/A	Initial Draft
001	November 14, 2022	Thomas Krysiak, Madison Mosher	Addition of Section 3.3.2 Fugitive Emissions

ATTACHMENT A

// 2020-NEC-GE-88.15.02.002-RE-0012-001

PLANT STARTUP AND OPERATING PHILOSOPHY (T210)

Plant Startup and Operating Philosophy (T210)

Project Title

Indeck Niles Energy Center
2x1 7HA.02 Multi-Shaft Combined Cycle Power Plant
Customer: Kiewit Power Constructors (Project No. 20026168)
End User: Indeck Niles, LLC
Niles, Michigan, USA
GE IPS No. 1362026
Equipment Scope: Balance of Plant (BOP)

Cross checked

Department	Name	Date	Signature

Revision History

Rev.	Revision Date	Created by	Checked by	Approved by	Brief Description
	Description current Revision				

Replaces	Customer Code	Project Document Code IDN/00/E/001b---001/DO/004	
Responsible Dept. PE-SMS	Created by F. BERTHELOT	Checked by O. CORYDON	Approved by J. Farrow — Format DIN A4
GE POWER Gas Power Systems	Document Type DO	Document Status Released	
	Document Title Plant Startup and Operating Philosophy (T210)	Identification Number 1GP027202	
		Rev. A — Date 2020-06-26 — Lang. en — Sheet 1/20	

GBM Gas Master Doc Temp (ZZZ)

Non-Public

Released

Drawing Revision Status

Rev	Issue Date	Description
A	June. 26th, 2020	First official issue based on draft versions sent to customer in January and June 2020.

Released

Table of Contents:

Released

1.0 INTRODUCTION

Indeck Niles Energy Center is a combined cycle unit consisting of two 7HA.02 gas turbines (GT) and their associated HRSG supplying steam to one steam turbine (ST). Each HRSG is equipped with supplementary firing and selective catalytic reduction system (SCR).

The GE supplied equipment is provided with dedicated controller:

- GE Mark VIe GT controller for each gas turbine and its generator,
- GE Mark VIe ST controller for the steam turbine with its generator,
- GE Mark VIe HRSG controllers for each HRSG with its associated terminal attemperators and steam bypass stations and referenced as Bottoming Cycle Controller (BCC).

Overall coordination of the control of plant operation will be part of the Distributed Controlled System (referenced as BOP DCS) which is supplied by the Customer.

The purpose of this document is to provide the necessary information for the elaboration of the plant control and operating philosophy.
It provides a general description of GE typical start-up, on load operation and shutdown of the combined-cycle unit, as well as a description of the control philosophy of the GE supplied equipment which is part of the steam cycle: HRSGs, terminal attemperators and steam bypass stations.
It also tries to identify the interfaces needed between the GE supplied controllers and the Customer BOP DCS to enable proper operation of the combined-cycle unit from the DCS consoles according to the overall plant control philosophy as defined by the Customer.

Based on the provided information, the customer is responsible for the design of the plant operation (startup and shutdown sequences, plant on load operation, contingency operation) with the necessary interfaces between controllers and will provide final corresponding description.

2.0 HRSG AND GE STEAM SYSTEMS CONTROL PHILOSOPHY

To facilitate automatic plant operation from the DCS consoles with minimal local operator interventions and to provide the operator with a good view throughout the progress of an automated start/stop of the plant, the control of the HRSGs and GE Steam systems will be hierarchized into the following levels:

- the drive control level as the lowest degree of automation,
- the group control level used to control functional systems (e.g. HRSG HP system),
- the sequence control level used to ensure the overall coordination of the start and shutdown of the HRSGs systems and GE Steam systems.

Consequently, the HRSGs and the GE Steam systems will be organized in the following groups:

- $HRSG_{1A/1B}$ blowdown group,
- $HRSG_{1A/1B}$ LP economizer recirculation group,
- $HRSG_{1A/1B}$ LP group,
- $HRSG_{1A/1B}$ IP group,
- $HRSG_{1A/1B}$ IP Steam to auxiliary steam header group,
- $HRSG_{1A/1B}$ reheater group,
- $HRSG_{1A/1B}$ HP group,
- $HRSG_{1A/1B}$ selective catalytic reduction group,

- HRSG$_{1A/1B}$ supplementary firing group,
- HRSG$_{1A/1B}$ outlet stack damper group,
- Unit$_{1A/1B}$ HP terminal attemperator group,
- Unit$_{1A/1B}$ HRH terminal attemperator group,
- Unit$_{1A/1B}$ HP steam bypass group,
- Unit$_{1A/1B}$ HRH steam bypass group.

Details about the content of above functional groups can be found in GE document "IDN-00-E-001b---001-DO-002-en-A-List of Functional Groups (T201)".

3.0 COMBINED CYCLE UNIT NORMAL STARTUP

Indeck Niles is provided with the GE Rapid Response Lite (RRL) technology that allows during startup to load the gas turbines independent of steam turbine startup temperature requirements. While the gas turbines are loaded according plant startup program, the HP and HRH steam temperatures are controlled using terminal attemperators installed at HRSGs HP superheater & reheater outlet to meet optimum steam temperature throughout steam turbine acceleration and loading. This way to start provides benefit in the form of fast dispatch capability and of low startup emissions.

The combined cycle unit can also be started using the "conventional start" mode, without the use of the terminal attemperators. In that case, the gas turbine(s) shall be parked at low load (~15% of gas turbine base load) while adjusting exhaust gas temperature to match the steam turbine startup requirements for HP and HRH steam temperature. Once HP & HRH steam temperatures are closed to nominal values, the steam turbine controller releases gas turbine(s) loading up to base load at controlled rate.
To be noted that this way to start will result in higher startup emissions and shall not be considered as the normal way to start, but as a back-up way in case terminal attemperator(s) would not be available.

Because there are two gas turbine/HRSG units, the operator must do some selections to define the way the combined-cycle will be started. In particular, he must:

- Select the number of gas turbine/HRSG units to be started by selecting the start of unit 1A or unit 1B or units 1A & 1B,
- Choose to start the units simultaneously or in sequenced order,
- Define the lead unit and eventually enter the time delay between the units start,

Depending on the plant startup automation concept, the operator may have to choose the start mode (Rapid Response Lite start or Conventional start). However, default startup mode should be Rapid Response Lite.

<u>Considering above, the following description applies for a combined cycle start in Rapid Response Lite mode, with auxiliary steam.</u>

3.1 Typical Pre-start Ready Conditions

To ensure a successful start of the combined cycle unit, the unit shall be in a "Normal Shutdown" state, which can be summed up by: the gas turbine and the steam turbine are turning gear speed and the condenser is at atmospheric pressure.

This "Normal Shutdown" state can be characterized by the following conditions:

- The air compressors are operating in auto,
- The gas turbine and steam turbine are at their turning gear speed,
- The lube/lift oil systems are ON,
- The hydraulic oil systems are ON,
- The generators stator cooling systems are ON,
- The generators hydrogen systems are ON,
- The seal oil systems are ON,
- The closed cooling water system is ON, with at least one closed cooling water pump running and the fin fan coolers fans in auto,
- The potable and service water systems are ON,
- The demineralized water system is ON,
- The HP drains tank system and LP drains tank system are ON,
- The plant drains system is ON,
- The waste water system is ON,
- The cycle chemical feed system is ON,
- The Ammonia injection & storage system (for SCR operation) is ON,
- The steam and water sample panel is in service,
- The fuel gas system is ON,
- The auxiliary boiler is in auto and ready to supply auxiliary steam.

During regular plant operation, the turbines are usually kept at turning gear speed during the shutdown period until next restart. The unit is normally in the "Normal Shutdown" state prior to start-up. Operator actions are then limited to verifications and eventually to the remote start of some systems using control screen pushbuttons, like the start of the auxiliary boiler.
For an extended shutdown (for instance for maintenance or local intervention), the turbines are usually stopped and most of the systems listed above are stopped as well. The operator will then have to restore the pre-start ready conditions and may have to do some local actions and verifications in the field to ensure the proper line up of the systems.

To assist the operator in establishing the pre-start ready conditions (to be defined by the Customer), a prestart checks list can be displayed on BOP DCS screen to inform about the actual status of BOP systems. If a system is not in a ready state, the operator will be informed and will take the appropriate actions to turn it ON.

3.2 Condenser Vacuum Raising

When the pre-start ready conditions are satisfied, the operator can proceed with the typical condenser vacuum raising sequence by starting the following functional systems:

- The condensate makeup and dump system,
- The condensate system,
- The auxiliary steam system,
- The steam turbine gland exhauster system,
- The steam turbine steam seal system,
- The air-cooled condenser and air removal system.

Depending on the level of plant automatization (by Customer), this sequence can be accomplished by the operator at group level, or automatically by the startup sequencer.

It can be summarized by the following automatic actions:

- The condensate make-up valves or dump valve open as needed to control the condensate receiver tank level within allowable range.
- Provided that the condensate receiver tank level is above the low-level alarm value and the condensate pumps discharge pressure is above a minimum threshold indicating that the condensate piping is pressurized, the lead condensate pump is automatically started. The condensate minimum flow control valve is immediately released to modulate and open to control a minimum flow downstream of the gland steam condenser. The lag condensate pump is in standby, ready to run upon an increase of condensate water flow demand or low condensate pumps common discharge pressure.
- The auxiliary steam system is conditioned thanks to the supply of auxiliary steam from the auxiliary boiler and the opening of the drain and warmup valves. The steam turbine controller is instructed to turn on the gland exhauster system and the steam seal system. Electrical superheater is turned ON to heat sealing steam at the temperature reference determined as a function of steam turbine average rotor temperature. When auxiliary steam conditions upstream of the steam seal feed valve are correct, the steam turbine controller release the opening of the valves to control steam seal manifold pressure. When sealing steam is applied satisfactory to the steam turbine, the closure of the close the vacuum breaker valve can be ordered to the steam turbine controller. The air evacuation unit is put in operation to evacuate the air-cooled condenser and to obtain the pressure required for start-up. Sparging steam supply is initiated as required to the condensate receiver tank.

At the completion of above sequence, the unit can be said in the following state: "Normal Shutdown with vacuum ON" which can be characterized by: at least one condensate pump is running with minimum flow control valve in auto, the steam turbine sealing steam system is operating satisfactory, condenser air evacuation is in progress and the condensate receiver tank level is automatically controlled at proper level.

3.3 HRSGs Systems & BOP Steam Systems Start

When the condenser vacuum raising sequence is completed and all associated permissives are met, the startup of the plant can go on with the start of HRSGs systems and BOP steam systems.

When "BOP is ready for HRSG start", the BOP DCS will proceed with the startup sequence of the HRSG(s) systems and associated GE Steam systems. When sequenced gas turbine/HRSG units start is selected by the operator, the BOP DCS can delay the startup of the lag HRSG, based on the predetermined time interval between the startup of the two gas turbines.

BOP DCS will send AUTO and ON orders first to the following HRSG functional groups:

- HRSG blowdown group (if not already ON),
- HRSG LP system group,

When Unit$_{1A/1B}$ boiler feedwater group is confirmed ON and ready for startup (i.e. valves and pump are in auto and the boiler feedwater pump is running), the BOP DCS will go on with the start of the following HRSG and GE steam systems:

- HRSG IP System group,

- HRSG IP to auxiliary steam header group (if not already ON),
- HRSG reheater system group,
- HRSG HP system group,
- HP terminal attemperator system group,
- HRH terminal attemperator system group,
- HP steam bypass system group,
- HRH steam bypass system group,
- HRSG LP economizer recirculation system group,
- HRSG selective catalytic reduction system group, provided the Ammonia storage and transfer system is in ready condition (at least one Ammonia forwarding pump is in service and Ammonia storage tank level is OK),
- HRSG supplementary firing system group,
- HRSG outlet stack damper group.

In the meantime, the BOP HRSG blowdown group, the BOP steam piping systems (HP steam piping system, HRH steam piping system, CRH steam piping system and LP steam piping system) shall be started and confirmed to be in ready condition for gas turbine startup.

At the completion of the HRSGs systems and BOP steam systems startup sequence, the HRSGs, the terminal attemperator systems, the steam piping systems and the bypass systems are normally properly configured to manage HRSG steam production. All valves are in auto and at proper position for startup. The HRSGs economizers have been vented and filled. The HP feedwater pump is running with its recirculation valve in auto. The HRSGs drum water levels are controlled at their startup water levels. The HRSG outlet stack damper is open. The steam isolation valves of the lead HRSG are open, those of the lag HRSG are closed.

Additionally, the BOP DCS has instructed the gas turbine control to implement the gas turbine ready to start checks. The gas turbine control will perform a series of functional checks to verify that all gas turbine systems are energized and in the correct state for starting. The gas turbine permissives to start include a start permissive from HRSG/BOP equipment (called "customer permissive"). This customer permissive will be created in the BOP DCS and consists in a list of some HRSG/BOP equipment permissives to inform that the steam cycle is ready for steam production. This customer permissive is sent by BOP DCS as a signal to gas turbine control.

At the completion of the gas turbine ready to start checks sequence and when all permissives to start are met, the gas turbine controller provides to the BOP DCS a signal to inform that the gas turbine/HRSG unit is ready to start.

3.4 Gas Turbines Start and Initial Loading

3.4.1 Gas Turbines Rolloff and Acceleration to Full Speed

When the BOP DCS gets confirmation from gas turbine controllers that both gas turbines are ready to start, the operator or the startup sequencer can order the start of the gas turbines.

When simultaneous start of the gas turbine/HRSG units has been selected, a start order is sent to each gas turbine controller. Otherwise, the start order to the lag gas turbine unit will be delayed by the predetermined time interval.

When the GT controller receives the start command, the Load Commutating Inverter (LCI) begins operating to produce torque through the generator in motoring mode to ensure gas turbine acceleration from turning gear speed. The turning gear automatically disengages when the gas turbine rotor speed exceeds turning gear speed.

When the HRSG purge has been performed during the unit shutdown sequence upon operator's decision and the "HRSG purge credit" status is still valid at the time of start-up, the gas turbine acceleration will proceed from turning gear roll off directly to firing speed without a speed hold for HRSG purging.

The "HRSG purge credit" status inside the GT controller is a combination of three conditions:

- "HRSG purge credit" valid (managed by GT controller itself)
- and "duct burner purge credit" valid (signal sent by burner management system to GT controller)
- and "SCR system purge complete" valid (signal sent by BCC to GT controller).

When "HRSG purge credit" status is lost (meaning that the HRSG purge has not been performed during the unit shutdown or the duct burner purge credit status has been lost or the SCR system purge has not been established), the gas turbine is accelerated to purge speed by the LCI. After a predetermined time interval monitored by the gas turbine, the purge is terminated. The LCI output is turned off and the unit goes to the firing speed.

At firing speed, the LCI output is regulated by the LCI controls to maintain a steady speed during gas turbine firing.

After successful gas turbine ignition, the LCI is set to full output capability. The gas turbine varies fuel flow based on the acceleration program section of the gas turbine controller and the gas turbine accelerates towards full speed.

As the unit accelerates and nears full speed, the LCI is turned off. The generator is transferred to generating mode.

3.4.2 Gas Turbine Synchronization

When the gas turbine is at full speed no load, the auto synchronizing equipment performs speed, voltage and phase matching and issues a breaker close command. When the generator breaker closes the gas turbine control applies a step load and the gas turbine immediately loads to its minimum load or spinning reserve (typically 15% (*) of gas turbine base load).

3.4.3 Gas Turbine Loading to Minimum Emission Compliance Load (MECL)

When the HRSG is in a cold condition, a stress hold is required to mitigate HRSG thermal stress during its warm-up. Also, it will require some time to get IP feedwater at enough temperature to heat the fuel gas at 120F in the fuel gas performance heater. For these two reasons, the gas turbine will be parked at spinning reserve for a while (typically 30 minutes (*)) at reduced exhaust temperature. The gas turbine temperature matching logic needs to be activated to lower the gas turbine exhaust temperature by opening the gas turbine variable guide vanes (VGVs) from their initial position to the position which gives the target exhaust gas temperature of 1050F (*).

After this hold period dictated by HRSG stress mitigation and minimum fuel gas temperature requirement, the gas turbine VGVs are returned to normal spinning reserve load position and the gas turbine is released for further loading to MECL.

When the residual pressure in HP drum and the residual HP superheater midwall temperature allow it, the gas turbine is immediately ramped to MECL at 8.33% per minute, provided the fuel gas temperature is at or above 120F.

Once at MECL, the gas turbine(s) will be kept at this load until the steam turbine is started.

3.5 Steam Systems Pressurization and Warm-up

Upon gas turbines start, hot exhaust gas passes through the HRSGs. Steam generation starts in the HRSG evaporators and pressures begin to build in the HRSG steam systems. Typically, when the HRSGs are cold, we observe first HP steam production while IP/LP steam production is delayed.

If the HRSG is depressurized at startup, the HRSG steam systems are at atmospheric pressure and it is necessary to vent them to remove bulk non-condensables. The HRSG superheaters vent valves then automatically open once the pressure is slightly above atmospheric pressure and will close when minimum pressure is reached in the systems (15-30 psig (*)).

During the warm-up period, the HRSG steam drain valves and the steam pipes drain valves open as necessary to expel condensate that forms when steam is in contact with cold piping walls.
The steam pipes drain system is also used to ensure a steam flow circulation through the whole steam systems up to the steam turbine admission valves to help the warming up of the steam piping systems.

Selective Catalytic Reduction (SCR) control will be automatically initiated by the BCC during gas turbine / HRSG startup. The system will control NH_3 injection (for reducing nitrogen oxides NO_x in the exhaust gas) based upon selected setpoint mode.

Gas turbine control has initiated automatically gas fuel heating control. The fuel temperature control valve previously open at minimum position has been released for control once gas turbine is fired. The valve then opens further to raise the fuel temperature to the setpoint determined based on IP Economizer outlet water temperature.

3.6 Steam Bypass Operation

As steam generation increases and pressures increase in the HRSGs, the steam bypass pressure control in BCC is activated and the bypass valves open and modulate to stabilize the pressures at the startup pressure setpoints. The produced steam is pressure reduced and attemperated in the steam bypass stations before being discharging into the cold reheat section of each HRSG for the HP steam and into the air-cooled condenser for the hot reheat steam.
The LP steam production is minimized by fully or partly bypassing the LP economizer and the excess is discharged to the atmosphere thanks to the LP startup sky vents.

Bypass operation of the lead HRSG(s) in above manner and in conjunction with steam piping drainage shall enable the warm-up of the whole steam piping system up to the steam turbine HP and reheat admission valves. It will last until the HP and HRH steam flow conditions required for steam turbine start (steam purity condition included) exist upstream of the HP and IP turbine inlet valves.

During this time, the HRSG IP steam back-pressure control valve control the IP drum pressure increase to minimum (floor) pressure by modulating the IP steam flow admitted into the cold reheat piping.

3.7 Steam Temperature Matching – Terminal Attemperation

To maintain thermal stresses within admissible limits and to minimize expenditure of steam turbine life during the start, the steam turbine requires enough HP/HRH steam flow production at a temperature determined by average rotor temperature prior to start.

While the gas turbines are maintained at MECL, the HRSG terminal attemperators are used to perform steam temperature matching and get the required HP/HRH steam temperatures.

When there is enough HP/HRH steam production, HP/HRH steam terminal attemperators are permitted to operate. Water flow to the terminal attemperators is then ramped up to lower the steam temperature to the target value calculated by the steam turbine controller and sent to the BCCs. When the target temperature is reached, the steam temperature stops changing until the steam turbine is started and further temperature increase is ordered by steam turbine control.

3.8 On Hold for Steam Purity Acknowledgment

Steam turbine start requires the steam purity to be within allowable limits. Depending on the shutdown period duration and startup conditions, it will require some time to achieve the proper steam purity. The operator will have to check and acknowledge the steam purity condition before allowing steam admission into the steam turbine.

3.9 Steam turbine Acceleration and Initial Loading

After the operator validates the steam purity condition in BOP DCS, the operator or the startup sequencer can proceed with the start of the steam turbine.

We will need to work on this section a bit. There are isolation MOVs on the steam lines upstream of the STG MCVs. These need to be opened by the operator. This can be incorporated into the master reset or ST ready to start logic.

The BOP DCS will first send a master reset order to the steam turbine controller and waits for the “ST ready to start” signal issued in return by ST controller to BOP DCS when all steam turbine permissives to start are met. The steam turbine permissive includes a plant permissive that will be elaborated in BOP DCS and sent to ST controller. This plant permissive shall mainly consist in checking that there is enough HP and HRH steam production for steam turbine roll off and transfer to HP flow mode.

Once BOP DCS gets confirmation that the steam turbine is ready to start, it sends a start order to ST controller upon the demand of the operator or the startup sequencer.

When the start command is received, the steam turbine startup speed/load control regulates the opening of the steam turbine reheat control valves (RCVs) to maintain turbine acceleration or hold at constant speed in accordance with the startup program as established by the prestart turbine temperature measurements.

Depending on rotor temperature and rotor stress, the HP evacuation valve is opened to limit HP turbine windage.

The steam turbine generator is automatically synchronized when it achieves rated speed and loaded to minimum load of about 10% (*). Depending on startup program, the steam turbine speed/load control may hold the steam turbine at this minimum load for a while before releasing steam turbine further loading at allowable rate.

As soon as all permissives are satisfied, steam turbine control system initiates the transfer to HP flow mode by opening the main control valve (MCV) at proper position. Purpose is to minimize the duration of reheat-only flow mode operation and prevent negative effects on alignment, differential expansion and stress.

After HP flow is established, the HP evacuation valve is gradually closed (if opened) as the steam flow increases to the HP turbine.

During this phase, the HP and HRH steam bypass pressure control valves are still in charge of controlling the HP/HRH steam pressure and then close as the produced steam is progressively admitted into the steam turbine.

When steam turbine stress control allows the increase of HP and HRH steam temperatures, the water flow to the terminal attemperators is reduced to control the steam temperature to the setpoint value sent by steam turbine control to the BCC(s). This steam temperature increase is moderated to keep steam turbine thermal stress within the allowable values.

The steam turbine continues to load by opening the MCV and RCVs turbine valves at the maximum rate determined by the steam turbine stress control, until consuming all the available steam produced with the gas turbine(s) at MECL.

Typically, when all the HP steam production of the HRSG (s) on line with the steam turbine is passing through the steam turbine (i.e. HP steam bypass pressure control valve(s) at minimum opening position), the steam turbine is placed in inlet pressure control (IPC).

Thus, when the conditions of the lead unit(s) are considered appropriate for selecting steam turbine IPC mode and when ST controller confirms that the steam turbine is ready for IPC, the BOP DCS instructs steam turbine controller to transfer the steam turbine to pressure control mode. When the steam turbine is confirmed in IPC control, the HP steam bypass pressure set point is adjusted to a delta pressure above the HP steam header operating pressure, to make the steam bypass pressure control valve to fully close. The HP steam bypass control is then placed in tracking mode. In the same way, the set point of the HRH steam bypass is adjusted to place its control in tracking mode.

3.10 HRSGs Blending

times

Depending on the way the plant is started (gas turbines started simultaneously or in sequenced order), the blending of the HRSG can happen at different time in the plant startup sequence. It can happen prior steam turbine start, or after steam turbine start and, in this case, before or after the steam turbine is in IPC.

In any case, to enable the coupling of the lag HRSG, the HP/HRH steam temperatures and pressures of the lag HRSG shall be controlled at proper values to match the HP/HRH steam headers conditions. Steam temperatures will be equalized thanks to terminal attemperators control using the steam temperature reference signal sent by ST controller as temperature set point. The HP/HRH steam pressures will be equalized by setting the steam bypass pressure set point of the lag HRSG to the common header pressure.

We will need to work on this section a bit. We currently have no automatic blending. Once steam conditions are met, the isolation MOVs on the steam lines upstream of the STG MCVs need to be opened by the operator.

When HP/HRH steam temperatures and pressures of the lag HRSG match the HP/HRH steam headers conditions, the blending of the HRSGs can be initiated, provided the operator has acknowledged the steam purity condition of the lag HRSG in BOP DCS. Depending on the plant level automatization, blending of the HRSGs can be performed automatically in the BOP DCS (*either programmed as a subsequence or in the logic of the main header isolation valves themselves*). When capability of automatic blending is present, the operator should have the possibility to manually trigger HRSGs blending and when using the main startup sequencer, he should be able to hold and release its execution. HRSGs blending is performed by first the opening of the CRH and HRH steam isolation valves of the lag HRSG and after the opening of the HP steam isolation valve.

When HRSGs blending is accomplished when the steam turbine is operating in IPC, the HP steam is diverting to the common HP steam header by ramping the HP steam bypass valve closed at a controlled rate. The additional HP steam of the lag HRSG into the steam turbine makes the HP and HRH natural steam pressures to increase thus making the HRH steam bypass valve of the lag HRSG to close.

In the same way, when LP steam temperature and pressure of the lag HRSG match the LP steam header conditions and steam purity conditions are acceptable, the blending of the HRSGs LP steam system can be initiated.

3.11 Steam Turbine LP Steam Admission

Usually LP steam admission is initiated after the steam turbine is in IPC. There shall be enough LP steam production with satisfactory superheat and the draining and warming of the LP steam line up to the LP admission stop valve shall have completed.

When above conditions are met, the BOP DCS will instruct steam turbine control to proceed with LP steam admission. When the steam turbine control deems the steam turbine ready for LP admission, then the LP injection stop valve opens and the LP injection control valve is ramped open to admit LP steam.

3.12 Gas Turbine and Steam Turbine Final Loading and Steam Temperature Normalization

When the steam turbine is in IPC and the HRSGs are coupled, the final loading of the gas turbines and steam turbine can be completed to bring the combined cycle unit at the entered target output. The gas turbines load will be increased at maximum loading rate of 8.33%/min to achieve the target MW output, unless steam turbine control provides some loading limitation due to rotor thermal stress or differential expansion.

With further gas turbines loading, the HRSGs steam production increases making the steam pressures to increase in proportion. The HRSGs IP steam back-pressure control valve will fully open (if not already) and allow the IP steam pressure to slide with steam production increase above the floor pressure. In case the IP pressure would decrease, the valve will reclose to control the pressure decreasing rate.

The steam turbine goes on loading in proportion to the steam flow increase. The water flow to the HP and HRH attemperators will be ramped down to allow the increase of HP/HRH steam temperatures at a rate determined by steam turbine control to limit thermal stress within the allowable values. When water injection control valves are at minimum position (meaning that HP/HRH steam temperatures are near or at rated values), the control valves are stepped shut, the water injection shutoff valves are closed and the terminal attemperators are disabled from further opening until the steam turbine is shut down and subsequently made ready for the next startup.

4.0 COMBINED CYCLE UNIT ON-LOAD OPERATION

Combined Cycle unit on-load operation can be performed typically using one of the two following modes:

Base load mode: the gas turbines operate at maximum power output, which will vary according to the atmospheric conditions.

Plant load control mode: the gas turbines operate at the load needed to meet the combine-cycle unit target output given by the operator or communicated by the dispatching. This mode of operation allows to automatically adjust the plant load between MECL and base load to satisfy the MW output demand.

When both gas turbine/HRSG units are operating in parallel in plant load control mode, the gas turbines are usually set at the same load.

Selection of plant operating mode and the associated control logics are by Customer in BOP DCS.

During on-load operation, the steam turbine operates in IPC mode, with HP and IP inlet control valves wide open. The steam pressures then slide with the HRSG steam production resulting from the gas turbines load variations and duct burners load. The HP steam pressure is let to slide from maximum continuous pressure to the minimum (floor) pressure set point. When the HP steam pressure will fall below floor pressure set point, the steam turbine main control valve will throttle to maintain minimum pressure. The LP injection control valve will control LP steam admission in the same way.

Released

The HP and HRH steam bypass pressure control valves, as well as the LP start-up sky vents remain closed with their pressure set point set slightly above the actual steam pressures, thus ready to open in case of overpressure detection, or in the event of turbine trip or load rejection.

The HP and HRH steam outlet temperatures are controlled by HRSG interstage attemperation to the maximum value of 1085F (*). Terminal attemperation is disabled.

4.1 HRSG Unfired Mode of Operation

In HRSG unfired mode of operation, the combined-cycle unit load can vary through variations of the gas turbines load at a load change rate of 8.33%/min within MECL and base load range.

Depending on the MW output demand, the operator will decide to shut down one gas turbine to operate the unit at low loads.

4.2 HRSG Fired Mode of Operation

Supplementary firing mode shall be used only after the steam turbine has completed startup and stabilized metal temperatures, stress and differential expansion.

Therefore, duct burner operation will be permitted when the gas turbine load is above 90% (*) of base load and there is enough HP steam flow and all duct burner system permissives are met. The BCC will send a signal to BOP DCS to inform the operator that HRSG fired mode of operation is allowed.

When the unit MW output demand cannot be satisfied with both gas turbines at base load and the steam turbine in service, the operator will initiate duct burner operation by giving a start command to the HRSG duct burner from the BCC console. This signal is relayed from the BCC to the burner management system, which will handle a safe duct burner startup.

We will need to work on this section a bit. This logic has not been developed in DCS yet. Do we want to add hardwired signals for this?

If the combined cycle unit is operating in plant load control mode, the BOP DCS can automatically calculate based on the plant MW output demand the duct burner load set point to be sent to each burner management system. The duct burner firing rate is then ramped on at maximum rate dictated by the HRSG design to achieve the MW output demand, provided there is no limiting process parameter.

If the combined cycle unit is operating in base load mode, the operator will have to manually increase and decrease duct burners load to satisfy the plant MW output demand.

To disable HRSG fired mode of operation, the operator will issue a duct burner stop command from the BCC console, which will be relayed to the burner management system. If not already done by the operator, the BCC will first reduce supplementary firing by ramping down the load set point. Then the BCC will send a normal stop command to the burner management system to perform the shutdown of the system.

4.3 Selective Catalytic Reduction Operation

The Selective Catalytic Reduction (SCR) control is active to control NH_3 injection to meet the NO_x emissions guaranteed level.

4.4 Inlet Air Evaporative Cooling

Inlet air media type evaporative cooling, by removing heat from the air (lowering its dry bulb temperature) and increasing its water vapor content (air density), increases the mass flow and gas turbine output. The evaporative cooler can be used once the gas turbine is at base load (evaporative cooler start permissive). Thus, evaporative cooling, controlled by the gas turbine controller, will generally only be on when the unit is operating during warm ambient temperatures and low humidity.

Depending on ambient air conditions, the operator will then decide whether to switch-on or off the evaporative cooler for the gas turbine, via the gas turbine control screen.

5.0 COMBINED CYCLE UNIT SHUTDOWN

5.1 General

Purpose of a normal shutdown sequence is to bring the unit from the on-load operating condition back to the "Normal Shutdown" state (see section 3.1). However, the operator can also decide to keep the air-cooled condenser under vacuum and maintain steam turbine sealing during the shutdown period. In that case, the unit is parked at an intermediate case that could be named "Normal Shutdown with Vacuum ON".

In any case, the operator shall ensure that sealing steam can be applied to the steam turbine until air cooled condenser vacuum is broken and then he shall ensure the supply of external auxiliary steam (from the auxiliary boiler) at proper time.

Typically, the objectives of a normal shutdown procedure are to maintain the steam turbine temperature and HRSG pressure as high as practical to facilitate a subsequent startup while minimizing HRSG and steam turbine stress.

5.2 HRSG Duct Burner Shutdown

Prior to initiate the plant shutdown sequence, the operator shall put an end to supplementary firing mode. The operator can do it in different ways:

- Either first gradually reducing the duct burner load by using the plant load set point or the duct burner manual load set point, and then selecting duct burner stop command from the BCC console.
- Or simply selecting duct burner stop command from the BCC console.

When the operator has selected a normal shutdown with purge credit, it is necessary to perform a duct burner purge credit sequence to allow the burner management system to extend a purge credit status to the GT controller. This sequence consists in a gas valves proving leak test sequence. Provided the duct burner had a normal shutdown, the sequence will be executed upon reception of the Purge credit start command from the BCC. When both the igniter gas and main gas have successfully completed the leak test sequence, a duct burner purge credit status is sent by the burner management system to the GT controller.

5.3 Gas Turbines Unloading

When supplementary firing is shutdown, the shutdown sequence can be initiated by the operator from the BOP DCS.

Typically, the gas turbines are unloading at designated shutdown rate (8.33%/min) towards MECL before steam turbine shutdown is initiated. This will be accomplished by the BOP DCS through a MW setpoint signal to the gas turbine controller. Gas turbines unloading can be simultaneous or staggered.

5.4 Lag Gas Turbine/HRSG Shutdown

When the lag gas turbine is at MECL, the lag gas turbine/HRSG shutdown sequence can be initiated by the automatic shutdown sequence or by the operator.

Not currently automatic in DCS logic. Operator has to open the MOVs.

The lag HRSG is first taken offline by closing the steam isolation valves and directing steam to the air-cooled condenser via the HP and HRH bypass systems by reactivation of the bypass pressure control. LP steam is discharged to atmosphere via the LP sky vent, as necessary.

Not currently automatic in DCS logic. Operator has to open the MOVs.

Like for HRSG blending, the HRSGs uncoupling can be performed automatically in the BOP DCS (*either programmed as a subsequence or in the logic of the main header isolation valves themselves*). When capability of automatic uncoupling is present, the operator should have the possibility to manually trigger HRSGs uncoupling and when using the main shutdown sequencer, he should be able to hold and release its execution.

Once the lag HRSG is offline, a normal shutdown order can be sent from the BOP DCS to the GT controller.

5.4.1 Gas Turbine Shutdown

Upon normal shutdown order, the gas turbine load is reduced further until a reverse power situation is detected at which time the gas turbine generator breaker opens. When the generator breaker opening is detected, the gas turbine fuel flow is reduced to a minimum value enough to maintain flame, but not turbine speed. The gas turbine then decelerates. When the gas turbine transitions through approximately 25% (*) speed, the fuel is completely shut off. The purpose of this "fired shutdown" operation is to reduce the thermal fatigue duty imposed on the hot gas path parts. After fuel shutoff, the gas turbine continues to coast down to turning gear speed where turning gear is engaged.

When the operator has selected a normal shutdown with purge credit, it is necessary to get the duct burner purge credit status from burner management system, as well as to perform a SCR purge sequence prior the HRSG purge sequence is initiated by the GT controller during gas turbine deceleration after flame out.

Thus, when the gas turbine receives the shutdown order, the BCC will send a Purge credit start command to the burner management system to execute the burner purge credit sequence and to extend the duct burner purge credit status to the GT controller.

Not currently programmed in DCS

Additionally, the BOP DCS will send a “SCR purge credit request” signal to the BCC once all following conditions are meet:

- normal shutdown selected by the operator,
- and purge credit selected by the operator,
- and gas turbine in shutdown process,
- and GT generator breaker (52G) open.

When the SCR purge sequence is successfully completed, the BCC sends the signal “SCR system purge complete” to the GT controller.

This signal combined with the “duct burner purge credit” status will be used by the GT control system as permissive to allow the HRSG purge sequence during gas turbine deceleration.

Consequently, if purge credit is selected and provided “duct burner purge credit” and “SCR system purge complete” signals are present, the gas turbine control system will initiate the purge credit sequence after gas turbine flame out. The sequence consists of first to sweep with compressed air the gas turbine fuel system in order to evacuate the fuel gas present, then to establish a pressure block within the cavity between the fuel gas stop valve and the control valves and after to execute an immediate HRSG purge with the use of the compressor flow during final deceleration. If purge credit status is maintained during all the plant shutdown period, the next plant startup will be executed without HRSG purging and will result in a reduced plant startup time.

5.4.2 HRSG Systems and BOP Steam Systems Shutdown

After the gas turbine has been on turning gear for a while, the automatic shutdown sequence or the operator can order the shutdown sequence of the lag HRSG systems and associated GE Steam systems. The BOP DCS will then send OFF orders to the functional groups. The HRSG outlet stack damper will be closed.

5.5 Steam Turbine Shutdown, Bypass Pressure Control Reactivation

With the gas turbines unloading to MECL and the lag HRSG uncoupling, the steam turbine has unloaded in proportion to steam flow diminution while full steam temperature was maintained.

BOP DCS will then issue a stop command to ST controller to initiate the automatic shutdown of the steam turbine. The steam turbine inlet pressure control mode is then deactivated, and the steam turbine HP and IP inlet control valves are ramped closed at a controlled rate. HP & HRH pressures control is transferred to the steam bypass of the lead HRSG by setting the set point at the operating pressure. The HP & HRH pressure control pressure control valves thus open and divert steam production into the air-cooled condenser.

In the meantime, the lead HRSG LP sky vent pressure set point is lowered to make the LP sky vent control valve to open and divert LP steam into the atmosphere, thus causing the LP admission valve to close.

At minimum load, the steam turbine is tripped. The closing of the turbine inlet valves causes a reverse power situation and the generator breaker opens. The steam turbine-generator then coasts down and will be automatically placed on turning gear operation when it reaches turning gear speed.

5.6 Lead Gas Turbine/HRSG Shutdown

When the BOP DCS gets confirmation from ST controller that the steam turbine inlet valves are fully closed, the plant shutdown sequence can go on with the shutdown of the lead gas turbine/HRSG.

BOP DCS sends a normal shutdown order to the lead GT controller and the shutdown of the lead gas turbine/HRSG will proceed in the same manner as the lag one.

5.7 Condenser Vacuum Breaking

When both gas turbines and the steam turbine are at turning gear speed, and the shutdown sequence of the HRSGs and the steam systems is completed, the combined cycle unit can be said in the following state: “Normal Shutdown with vacuum ON”.

The boiler feedwater pump groups can be switched off by the automatic shutdown sequence or upon the operator’s decision.

For an overnight shutdown, the condenser air removal system, the steam turbine gland sealing system, the unit auxiliary steam system, the condensate system and the condensate make-up and dump system may be kept in operation to maintain vacuum in the air-cooled condenser with external auxiliary steam. In that case, the operator shall ensure that the auxiliary boiler will be ready to provide the auxiliary steam needs at the proper time.

For an extended shutdown, the operator will normally decide to break vacuum in the air-cooled condenser.

The automatic shutdown sequence or the operator will then order to turn off the air-cooled condenser system and the air removal system. The vacuum breaker valve is ordered to open.

When the air-cooled condenser pressure is near atmospheric pressure, the automatic shutdown sequence or the operator instruct ST controller to turn off steam seals system. Once steam turbine seal system is off, an OFF order can be sent to the auxiliary steam system group to put an end to steam supply to the auxiliary steam header. Then the shutdown sequencer or the operator can instruct ST controller to turn off the gland exhauster system.

After that, the shutdown sequence can continue with the shutdown of the condensate system group and the condensate make up and dump system group; the condensate pumps are stopped, the condensate pumps minimum flow control valve, as well as the condensate make-up and dump control valves are no more released to modulate.

These actions normally complete the fully shutdown sequence of the combined-cycle unit by bringing it back to the steady state "Normal shutdown, Vacuum OFF".

6.0 CONTINGENCY OPERATIONS

Contingency operations include load rejection, trip of the gas turbines, trip of the HRSGs, trip of the duct burners and trip of the steam turbine.

The plant control system shall include logic that automatically protects the equipment from exposure to damaging conditions. This protective logic is applied to protect component parts as well as integrated systems, when little time is available for the operator to take corrective action.

For details of the protective actions related to the HRSG and Water/Steam cycle, please refer to the document T204 "HRSG and WSC Protective Loops Requirements" #1GP026560.

6.1 Gas Turbine Trip

The main consequence of a gas turbine trip order is the immediate closing of the gas turbine fuel valves, the trip of the duct burner (if in operation). The steam production of the tripped gas turbine/HRSG is diverted from the common steam headers by the closing of the steam isolation valves. The HP and HRH steam bypass valves will open to divert steam to the air-cooled condenser and will control the steam pressures to avoid safety valves lifting during the transient. The LP sky vent will act in the same manner.

The steam turbine remains in operation with steam from the remaining gas turbine/HRSG.

Should the last gas turbine trip, the steam turbine is tripped.

"two" or "too"?

6.2 HRSG Trip

The action of one HRSG protection (for instance a $\boxed{\text{two}}$ high HP steam temperature) is the trip of the duct burner (if in operation) and the trip of the gas turbine. The steam production of the tripped gas turbine/HRSG is diverted from the common steam headers by the closing of the steam isolation valves. The HP and HRH steam bypass valves will open to divert steam to the air-cooled condenser and will control the steam pressures to avoid safety valves lifting during the transient. The LP sky vent will act in the same manner.

The steam turbine remains in operation with steam from the remaining gas turbine/HRSG.

Should the last gas turbine/HRSG trip, the steam turbine is tripped.

6.3 Duct Burner Trip

The action of one duct burner protection (for instance a too low fuel gas supply pressure) is the trip of the duct burner. The gas turbine/HRSG will remain in operation at existing load.

6.4 Steam Turbine Trip

The action of one steam turbine protection is the trip of the steam turbine with immediate closing of the turbine inlet valves and the trip of the duct burner (if in operation). The gas turbines are kept in operation. The steam bypass valves open to divert steam to the air-cooled condenser and will control the steam pressures to avoid safety valves lifting during the transient The LP sky vents will act in the same manner.

The operator will then decide to continue with gas turbines operation only (unless the air-cooled condenser is not available to receive steam) or to shut down the gas turbines.

In case the fault has disappeared while the gas turbines are still operating, the operator may decide to restart the steam turbine. The restart of the steam turbine will be possible only manually. To obtain all steam turbine permissives to start, the operator may have to adjust the gas turbine(s) load so that HP & HRH steam is produced at suitable temperature and pressure.

6.5 Gas Turbine Load Rejection

In the event of gas turbine generator breaker (52G) opening due to an electrical fault, the gas turbine load is immediately reduced to full speed no load, the duct burner (if in operation) is immediately tripped and the associated HRSG steam isolation valves are closed.

The steam turbine remains in operation with steam from the remaining gas turbine/HRSG.

Should the last gas turbine experience same event, the steam turbine is tripped to prevent cold steam from entering the steam turbine and damaging the turbine.

6.6 Steam Turbine Load Rejection

In the event of steam turbine line breaker (52L) opening due to an electrical fault, the steam turbine is tripped. The duct burner (if in operation) is immediately tripped. The gas turbines are kept in operation. The steam bypass valves open to divert steam to the air-cooled condenser and will control the steam pressures to avoid safety valves lifting during the transient The LP sky vents will act in the same manner.

The operator will then decide to continue with gas turbines operation only or to shut down the gas turbine.

In case the fault has disappeared while the gas turbines are still operating, the operator may decide to restart the steam turbine. The restart of the steam turbine will be possible only manually. To obtain all steam turbine permissives to start, the operator may have to adjust the gas turbine(s) load so that HP & HRH steam is produced at suitable temperature and pressure.

6.7 Unit Load Rejection and House Load Operation

Should a failure of the high voltage grid occurs causing all line breakers (52L) to open, the steam turbine and the duct burner are tripped, and the load of gas turbines is suddenly reduced to meet the combined cycle unit auxiliaries' load. The operator may then decide to stop one gas turbine.

ATTACHMENT B

// GEK121243_E UNIT OPERATION HA GAS TURBINE

GEK121243 E
May 2020

GE Power

Unit Operation - Turbine (Gas)
HA

The following notices will be found throughout this publication. It is important that the significance of each is thoroughly understood by those using this document. The definitions are as follows:

NOTE

Highlights an essential element of a procedure to ensure correctness

CAUTION

Indicates a potentially hazardous situation, which, if not avoided, could result in minor or moderate injury or equipment damage

*****WARNING*****

INDICATES A POTENTIALLY HAZARDOUS SITUATION, WHICH, IF NOT AVOIDED, COULD RESULT IN DEATH OR SERIOUS INJURY

*****DANGER*****

INDICATES AN IMMINENTLY HAZARDOUS SITUATION, WHICH, IF NOT AVOIDED WILL RESULT IN DEATH OR SERIOUS INJURY

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I. REFERENCE DATA AND PRECAUTIONS

A. Operator Responsibility

It is essential that the turbine operators be familiar with the information contained in the following operations documentation in the O&M manual. Review the Operation Tab, the Piping Schematic drawings including the Device Summary, the Turbine Control Application Software control sequence program and the Controller System Guide Users' Manual. The operator must also be aware of the power plant devices, which are tied into the gas turbine mechanically and electrically and could affect normal operation.

No starts should be attempted whether on a new turbine or a newly overhauled turbine until the following conditions have been met:

Requirements listed under CHECKS PRIOR TO OPERATION have been met.

Control systems have been functionally checked for proper operation before restarting.

All GENERAL OPERATING PRECAUTIONS have been noted.

It is extremely important that gas turbine operators establish proper operating practices. We emphasize adherence to the following:

1. Respond to Annunciator /Alarm Indicators

Investigate and correct the cause of the abnormal condition. This is particularly true for the protection systems such as low oil pressure, overtemperature, vibration, overspeed etc.

2. Check of Control Systems

After any type of control maintenance is completed, whether repair or replacement of parts, functionally check control systems for proper operation. This should be done prior to restart of the turbine. It should not be assumed that reassembly, "as taken apart" is adequate without the functional test.

3. Monitor Exhaust

Monitor exhaust temperature and exhaust temperature spreads during all phases of startup.

B. Turbine Controller Unauthorized Access and Modifications

Unauthorized access and modifications, (e.g., forcing logic signals to customer gas turbine controllers) can create hazardous conditions for personnel and equipment. Customers are advised to implement physical or software access procedures to the gas turbine controllers to prevent unauthorized access and subsequent possible hazardous conditions.

MARK*[1]VIe ToolboxST provides various 'Access Rights.' Reference GEH 6700: *ToolboxST User Guide For Mark VIe Control* for details.

[1] *MARK is a registered trademark of General Electric

Privilege-level passwords are provided that allow the ability to force logic signals. It is intended that logic forcing only be used for off-line software checkout procedures, while the unit is shut down, and in conjunction with proper lockout / tag-out procedures.

NOTE

Customer personnel shall not force logic signals to circumvent control and protection functions.

The customer is responsible for password-protecting privilege levels or access rights within the Mark*VIe to limit access to control settings and logic forcing to qualified personnel only.

C. General Operating Precautions

1. Temperature Limits

Monitoring the exhaust temperature spread information is useful to understand the degradation of hardware components over time. Sudden shifts in this spread pattern can also indicate developing or actual hardware problems. It is important to define a "baseline value" of exhaust temperature spread with which to compare future data.

This baseline data is established during steady state operation after each of the following conditions:

Initial startup of unit

Before and after a planned shut-down

Before and after planned maintenance

It is important, when evaluating the magnitude of the exhaust temperature spread, to consider both the magnitude of the spread as well as the change of the spread over time. Consult the Control Constant Report and Control Software for further information on the maximum allowable temperature spreads and wheelspace temperature operating limits.

The 1st forward wheelspace thermocouple is listed in the Device Summary. A bad thermocouple may cause a "Turbine Wheelspace Temperature Differential" alert. The faulty thermocouple should be replaced at the earliest convenience.

Table 1 lists potential faults that cause high wheelspace temperature.

CAUTION

Wheelspace temperatures are read on the operators interface. Temperatures in excess of alarm level values are potentially harmful to turbine hot-gas-path and rotor parts over a prolonged period of time.

Excessive temperatures are annunciated but will not cause the turbine to trip. High wheelspace temperature readings must be reported to General Electric Company technical representative as soon as possible.

1. Restriction in cooling air lines, most often cooling and sealing air valves left improperly isolated after a water wash
2. Wear of turbine seals
3. Excessive distortion of the turbine stator
4. Improper positioning of thermocouple
5. Malfunctioning combustion system
6. Leakage in external piping
7. Excessive distortion of exhaust inner diffuser

Table 1. Potential Faults that may cause High Wheelspace Temperature

Wheelspace temperatures should be very closely monitored on initial startup. If a check of the external cooling air circuits reveals no explanation for consistently high temperatures, a General Electric Company technical representative should be contacted as soon as possible.

If the turbine is overloaded to such an extent that turbine temperature operational boundaries are not followed due to equipment malfunction or improper setting of the temperature control boundaries, the maximum allowable turbine inlet temperature and/or the maximum allowable exhaust temperature will be exceeded. This will necessitate more frequent and/or more extensive maintenance, and might result in failure of the turbine parts.

CAUTION

Overtemperature can damage the turbine hot gas path parts.

2. Pressure Limits

Lube oil pressure in the bearing feed header is maintained by a mechanical pressure regulating valve. A low-bearing header pressure alarm is generated if the pressure in the header drops below the low limit. The turbine will trip if the pressure at the Generator #2 bearing drops below the low-low limit. Refer to the unit specific control specification to verify actual values.

For Single Shaft Steam and Gas (SS STAG) applications the Lube oil control and trip resides in the steam turbine controller and can be monitored via the steam turbine screens.

3. Vibration Limits

NOTE

The maximum overall vibration velocity of the gas turbine should **never** exceed 1.0 inch (2.54 cm) per second in either the vertical or horizontal direction.

Corrective action should be initiated when the vibration levels at steady state exceed 0.5 inch (1.27 cm) per second as indicated on the control system HMI. This level of vibration will initiate an alarm.

4. Load Limit, Overloading of Gas Turbine, Facts Involved and Policy

The maximum load capability of the gas turbine is given in the control specification. For the upper limits of generator capability, refer to the Reactive Capability Curve found in the Generator Tab of the O&M manual.

It is General Electric Company practice to design gas turbines with margins of safety that can meet the contract commitments and secure long life and trouble-free operation.

General Electric Company designs these machines with margins on turbine blade thermal and dynamic stresses, compressor and turbine wheel stresses, generator ventilation, coolers, etc. in order to secure maximum trouble-free operation because of the importance of reliability of these turbines to our customers and to the electrical generation industry.

CAUTION

It is not recommended to run these machines beyond the load limits. Such operation encroaches upon the design margins of the machines with a consequent reduction in reliability and increased need for maintenance. Accordingly, any malfunction that occurs as a result of operation beyond contract limits cannot be the responsibility of General Electric Company.

a. AIEE Standards

Per the AIEE Standards, it is permitted to operate generators at temperature rises below 185°F (85°C) for the rotor and 140°F (60°C) for the stator; however this does not mean that the generator can be properly run with full safety up to these values by overloading beyond the nameplate rating.

These standards were primarily set up for the protection of insulation from thermal deterioration on small machines. The imbedded temperature detectors of the stator register a lower temperature than the copper windings because of the temperature drop through the insulation from the copper to the outside of the insulation, where the temperature detectors are located.

b. Variable Conditions

There are also conditions of conductor expansion, insulation stress, etc., which impose limitations. These factors have been anticipated in the “Vee” curves and reactive capability curves, which indicate recommended values consistent with good operating practice. The “Vee” curves and reactive capability curves form part of the operating instructions for the generator and it is considered unwise to exceed the values given.

c. Adhering to set limits

Gas turbines are mechanically designed so that (within proscribed limits), advantage can be taken of the increased capability over nameplate rating, which is available at lower ambient temperatures (because of increased air density), without exceeding the maximum allowable turbine inlet temperature.

The load limit of the gas turbine-generator must not be exceeded, even when the ambient temperature is lower than that at which the load limit of the gas turbine is reached. Under these conditions, the gas turbine will operate at this load with a lower turbine inlet temperature and the design stresses on the load coupling and turbine shaft will not be exceeded.

5. Fire Protection System Operating Precautions

When the fire protection system is actuated, the media discharge system will actuate, as well as the following:

The turbine will trip

An audible alarm will sound

The alarm message will be displayed on the HMI

The ventilation openings in the compartments will be closed by a pressure-operated latch, gravity, or both

All ventilation fans will shut down by electrical interlocks

This audible alarm may be silenced by clicking on the alarm SILENCE target. The alarm message can be cleared from the ALARM list on the HMI, after the ACKNOWLEDGE target and the ALARM RESET target are actuated, but only after the situation causing the alarm has been corrected.

The fire protection system must be recharged and reset before it can automatically react to another fire. Reset must be made after each activation of the fire protection system, including an initial discharge that is followed by an extended discharge period of the fire protection media. Fire protection system reset is accomplished by resetting the pressure switch located on the fire protection system.

Ventilation dampers, automatically closed by a signal received from the fire protection system, must be reopened manually in all compartments before restarting the turbine.

CAUTION

Failure to reopen/relatch compartment ventilation dampers will severely shorten the service life of major accessory equipment, due to compartment over temperature. Failure to reopen the load-coupling compartment dampers will materially reduce the performance of the generator.

6. Combustion System Operating Precautions

The gas turbine control implements many automatic protective features with respect to the combustion system. These protection systems should be reviewed in order to understand what they indicate about unit hardware as well as to ensure that the components of these systems are maintained in proper functioning order. This will reduce distortions of the control and protection functions and the number of unnecessary turbine trips.

a. Automatic protective functions

1) Exhaust Spread Monitor

Purpose is to detect full or partial flameout and trip fuel system. Indicates hardware deterioration or abnormal operation.

2) Combustion Dynamics Runback

Purpose is to protect against hardware fatigue due to elevated dynamics

3) Hazardous Gas Detection System

Purpose is to detect potentially hazardous gas leakage, shutdown or trip fuel system

4) Valve Faults

To protect system from excess fuel introduction. This may be related to the P2 or gas control valves having faulted positions or communication issues.

b. Operator protective expectations

1) Ensure that after any unit hardware change or significant fuel system work, the unit is properly tuned prior to standard operation

2) Monitor emissions, take action on abnormal emissions levels

3) Monitoring combustion dynamics, take action at elevated levels

4) Ensure accuracy of all control transmitters, take action on abnormal readings.

5) Ensure integrity of exhaust spread monitor (do not jumper exhaust thermocouples). Keep the number of nonoperational exhaust thermocouples to a maximum of two but no more than one of any three adjacent thermocouples.

6) Ensure proper operation of startup or dew point fuel heaters - liquid carryover into the gas fuel system often results in combustion component damage

7) Ensure that gas system conditioning equipment is properly maintained and liquids properly drained

8) Liquid fuel drain system properly operating on dual fuel units

CAUTION

Operation of the gas turbine with a single faulty thermocouple should not be neglected, as even one faulty thermocouple will increase the risk of an invalid “combustion alarm” and/or “Trip”. The unit does not have to be shut down just for replacement of a single faulty thermocouple. However, every effort should be made to replace the faulty thermocouples when the machine is down for any reason.

CAUTION

If, during operation, there has been an increase in exhaust temperature spread above the normal 65°F to 80°F (18.3°C to 26.6°C) during steady state operation and loading/unloading, the thermocouples in the exhaust plenum should be examined. If they are coated with ash, the ash should be removed. Radiation shields should also be checked.

If they are not radially oriented relative to the turbine, they should be repositioned per the appropriate drawing. If the thermocouples are coated with ash, or if the radiation shields are not properly oriented, a correct temperature reading will not be obtained.

If neither of the above conditions exists and there is no other explanation for the temperature spread, consult General Electric Company Installation and Service Engineering representative.

*****WARNING*****

OPERATING A TURBINE WITH NON-OPERATIONAL EXHAUST THERMOCOUPLES INCREASES THE RISK OF TURBINE OVER-FIRING AND PREVENTS DIAGNOSIS OF COMBUSTION PROBLEMS BY USE OF TEMPERATURE DIFFERENTIAL READINGS.

7. **Radio transmissions**

The use of radio transmitting devices, such as hand-held radios, arc welders, unsuppressed relays, contactors, or brake coils in the vicinity of electronic equipment is not recommended. Prohibiting use of such devices near electronic equipment will ensure that Electromagnetic Interference (EMI) noise does not impact normal operation. Please refer to Mark VIe System Guide (GEH-6721) for recommended Control Room operating environment.

II. PREPARATIONS FOR NORMAL LOAD OPERATION

A. Standby Power Requirements

Standby power insures the immediate startup capability of particular turbine equipment and related control systems when the start signal is given. Standby power is shown in MLI 0444 and is required for:

Component	**Notes**
Lube oil heaters	When used in conjunction with the lube oil pumps, heat and circulate turbine lube oil at low ambient temperatures is required to maintain proper oil viscosity.
Lube oil pumps	Auxiliary pump should be run at periodic intervals to prevent rust formation in the lube oil system.
H2 Monitor	Necessary for unit environmental protection and should not be turned off, except for maintenance work on that particular function / system.

Generator heating	Necessary for unit environmental protection and should not be turned off, except for maintenance work on that particular function / system.
Compartment heating (Humidity/Freeze Protection).	Necessary for unit environmental protection and should not be turned off, except for maintenance work on that particular function / system.
Control compartment air conditioner	Operation of control compartment air conditioner during periods of high ambient temperature to maintain electrical equipment within design temperature limits. Necessary for unit environmental protection and should not be turned off, except for maintenance work on that particular function / system.
Control panel heating	Necessary for unit environmental protection and should not be turned off, except for maintenance work on that particular function / system.
Battery charging	Necessary for unit environmental protection and should not be turned off, except for maintenance work on that particular function / system.
Hazardous Gas Monitoring	Necessary for protection of personnel and equipment.
Seal Oil Pumps	Necessary for protection of equipment.
Lift Oil	Necessary for protection of equipment.
Turning Gear	Necessary for protection of equipment.

Table 2. Standby Power Requirements

B. Checks Prior to Operation

The following checks are to be made before attempting to operate a new turbine or an overhauled turbine. It is assumed that the turbine has been assembled correctly, is in alignment and that calibration of the Turbine Control System has taken plance. A standby inspection of the turbine should be performed with the lube oil pump operating and emphasis on the following areas:

1. Check that all piping and turbine connections are securely fastened and that all blinds have been removed. Most tube fittings incorporate a stop collar, which insures proper torqueing of the fittings at initial fitting make up and at reassembly.

2. Inlet and exhaust plenums and associated ducting are clean and rid of all foreign objects. All access doors are secure. Reference GEK111332: *Operation and Maintenance Recommendations for Gas Turbine Inlet Ducts and Plenums* for further Operation and Maintenance Recommendations.

3. Inlet filter house integrity should be verified to ensure correct installation and proper sealing to minimize the risk of unfiltered air and/or water entering the gas turbine. Reference GEK111330: *O&M Recommendations for Gas Turbine Inlet Air Filter Compartments* for further Operation and Maintenance Recommendations.

4. Where fuel, air or lube oil filters have been replaced check that all covers are intact and tight.

5. Verify that the lube oil tank is within the operating level and if the tank has been drained that it has been refilled with the recommended quality and quantity of lube oil. If lube oil flushing has been conducted verify that all filters have been replaced and any blinds if used, removed.

6. Check operation of auxiliary and emergency equipment, such as lube oil pumps, water pumps, fuel forwarding pumps, etc. Check for obvious leakage, abnormal vibration (maximum 3 mils), noise or overheating.

7. Check lube oil piping for obvious leakage. Also using provided oil flow sights, check visually that oil is flowing from the bearing drains. The turbine should not be started unless flow is visible at each flow sight.

8. Check condition of all thermocouples and/or resistance temperature detectors (RTDs) on the HMI. Reading should be approximately ambient temperature.

9. Check spark plugs for proper arcing, refer to Combustion I&M manual, prior to final installation to avoid wasting gasket materials.

*****WARNING*****

DO NOT TEST SPARK PLUGS WHERE EXPLOSIVE ATMOSPHERE IS PRESENT.

10. Check HMI Alarm and Diagnostics.

11. Devices requiring manual lubrication are to be properly serviced.

12. Determine that the cooling water system has been properly flushed and filled with the recommended coolant.

    a. Any fine powdery rust, which might form in the piping during a short period of exposure to atmosphere, can be tolerated.

    b. If there is evidence of scaly rust, the cooling system should be power flushed until all scale is removed.

    c. If it is necessary to use a chemical cleaner, most automobile cooling system cleaners are acceptable and will not damage the carbon and rubber parts of the pump mechanical seals or rubber parts in the piping.

Refer to GEI 41004: *Cooling Water Recommendations for Combustion Gas Turbine Closed Cooling Systems* included under tab titled Fluid Specifications. Note the following regarding antifreeze.

CAUTION

Do not change type of antifreeze without first flushing the cooling system very thoroughly. Inhibitors used may not be compatible and can cause formation of gums, in addition to destroying effectiveness as an inhibitor. Consult the antifreeze vendor for specific recommendations

Maintaining the water system refill ensures that the water system piping, primarily pumps and flexible couplings, do not leak. It is wise not to add any corrosion inhibitors until after the water system is found to be leak free.

Water Leaks and abnormal flow rates can compromise the operability of the cooling water system and can pose a significant hazard to the compressor rotor and stator components when leaks are in the turbine compartment. This applies not only to the cooling water system but to the water wash system and where applicable the water injection systems also.

The following inspections should be performed:

1) Verify that piping and tubing are properly supported and that there is no rubbing or abrading.

2) Check for any damage, wear, loose fittings, interference, fretting, or anything else that may lead to leaks or system malfunctions.

Closely monitor the water level in expansion tanks. Any significant drops in the water level will indicate a leak in the cooling water system. When inspecting the water wash aft manifold, ensure the water wash nozzle fittings are installed and properly tightened. Visually inspect for damage to the tubing and fittings.

When inspecting the water injection system on base piping and manifold, ensure the flow proportioning valves or check valves are installed properly on the tubing or flex hoses connecting the manifold to the end cover. Visually inspect all tubing and flex hoses for damage at weld points and check valve and end-cover connection points.

13. The Load Commutator Inverter (LCI) should be calibrated and tested per GEH-6192.

14. Check the Cooling and Sealing Air Piping against the assembly drawing and piping schematic, to ensure that all orifice plates are of designated size and in designated positions.

15. At this time all annunciated ground faults should be cleared. It is recommended that units not be operated when a ground fault is indicated. Immediate action should be taken to locate all grounds and correct the problems.

C. Checks during Start Up and Initial Operation

The following is a list of important checks to be made on a new or newly overhauled turbine with the TURBINE CONTROL MODE in different states. The Control Specifications drawing should be reviewed prior to operating the turbine.

When a unit has been overhauled those parts or components that have been removed and taken apart for inspection/repair should be critically monitored during unit startup and operation. This inspection should include: leakage check, vibration, unusual noise, overheating, and lubrication.

1. **Limited Crank Mode**

   Limited crank will bypass plant ready to start permissive to begin operating at crank speed. Limited crank will not give a ready to fire permissive and is intended to be used for maintenance conditions when cranking is required.

   Listen for rubbing noises in the turbine compartment, especially in the load tunnel area. A sound-scope or some other listening type device is suggested. Shut down and investigate if unusual noise occurs.

   Check for unusual vibration.

   Inspect for water system leakage.

2. **Crank Mode**

   Listen for rubbing noises in the turbine compartment, especially in the load tunnel area. A sound-scope or some other listening type device is suggested. Shut down and investigate if unusual noise occurs.

   Check for unusual vibration.

   Inspect for water system leakage.

3. **Automatic and Manual Mode**

   Automatic mode means the turbine controls will automatically control operation. Selecting automatic mode prior to start up means the unit will automatically select purge speed, firing speed, and full speed no load. Once breaker is closed in automatic mode the gas turbine will use the predefined load rate and a megawatt target to determine the load.

   Manual mode allows the operator to control speed-load independently through raise\lower control. It is not recommended to use manual mode for startup of the gas turbine.

On initial startup of a new unit, if the unit has not been run through the GE Full Speed No Load (FSNL) Factory Test, the green rotor run-in procedure found under MLI 0234 must be adhered to. If the unit was run in the factory these structural checks have already been performed and standard installation procedures apply.

*****WARNING*****

KEEP COMPARTMENT DOORS CLOSED DURING ENGINE OPERATION, ENGINE STARTUP AND SHUTDOWN, AS WELL AS ENGINE COOLDOWN PERIODS.

a. Turbine Compartment

Check the entire fuel system and the area immediately around the fuel nozzle for leaks upon reaching FSNL or immediately after a shutdown. Check for leaks at the following points:

1) Fuel piping/tubing to fuel nozzles

2) Gas manifold and associated piping

b. Liquid Fuel Module (when used)

1) Bleed fuel oil filters, if appropriate, to remove trapped air.

2) Flow divider

3) Fuel and water pumps

4) Filter covers and drains

5) Bulk head Floor Swagelock connections

CAUTION

Elimination of fuel leakage in the turbine compartment is of extreme importance as a fire preventive measure.

*****WARNING*****

DUE TO THE COMPLEXITY OF GAS TURBINE FUEL SYSTEMS, IT IS IMPERATIVE FOR PLANT PERSONNEL TO EXERCISE EXTREME CAUTION IN AND NEAR ANY TURBINE COMPARTMENT, FUEL HANDLING SYSTEM, OR ANY OTHER ENCLOSURES OR AREAS CONTAINING FUEL PIPING OR FUEL SYSTEM COMPONENTS.

DO NOT ENTER THE TURBINE COMPARTMENT <u>UNLESS ABSOLUTELY NECESSARY</u>.

IF IT IS NECESSARY TO ENTER THE COMPARTMENT, EXERCISE EXTREME CAUTION WHEN OPENING AND ENTERING THE COMPARTMENT. BE AWARE OF THE POSSIBILITY OF FUEL LEAKS, AND BE PREPARED TO SHUT DOWN THE TURBINE AND TAKE IMMEDIATE ACTION IF A LEAK IS DISCOVERED.

AT ANY TIME, IF/WHEN ENTERING THE TURBINE COMPARTMENT OR WHEN IN THE VICINITY OF THE FUEL HANDLING SYSTEM OR OTHER LOCATIONS WITH FUEL PIPING, FUEL SYSTEM COMPONENTS OR FUEL SYSTEM CONNECTIONS, TAKE THE FOLLOWING STEPS:

1. **Conduct an environmental evaluation of the turbine compartment, fuel handling system, or other area with particular attention to all locations where fuel piping, connections, components exist.**

2. **Follow applicable procedures for leak testing if fuel leaks are discovered, exit the area quickly. Shut the turbine down and take appropriate actions to eliminate all leaks.**
3. **Require personnel entering the turbine compartment to be fitted with appropriate personal protective equipment, such as**
   a. **hardhats,**
   b. **safety glasses,**
   c. **safety protection,**
   d. **harness/manline (optional, depending on space constraints),**
   e. **heat resistant & flame retardant coveralls, and**
   f. **gloves.**
4. **Designate an attendant to maintain visual contact with personnel inside the turbine compartment, and radio communication with the control room operator.**

*****WARNING*****

DURING THE FIRST START-UP AFTER A DISASSEMBLY, VISUALLY CHECK ALL CONNECTIONS FOR FUEL LEAKS.

PREFERABLY CHECK THE FITTINGS DURING THE WARM-UP PERIOD WHEN PRESSURES ARE LOW.

VISUALLY INSPECT THE FITTINGS AGAIN AT FULL SPEED, NO LOAD, AND AT FULL LOAD.

DO NOT ATTEMPT TO CORRECT LEAKAGE PROBLEMS BY TIGHTENING FITTINGS AND/OR BOLTING WHILE LINES ARE FULLY PRESSURIZED.

NOTE THE AFFECTED AREA AND, DEPENDING ON THE SEVERITY OF LEAK(S), REPAIR AT NEXT SHUTDOWN, OR IF IMMEDIATE REPAIR IS REQUIRED, SHUT UNIT DOWN IMMEDIATELY.

ATTEMPTS TO CORRECT LEAKAGE PROBLEM ON PRESSURIZED LINES COULD LEAD TO SUDDEN AND COMPLETE FAILURE OF COMPONENT AND RESULTING DAMAGE TO EQUIPMENT AND PERSONNEL INJURY.

c. Monitor FLAME status on the HMI to verify all flame detectors are correctly indicating flame.

d. Monitor the turbine control system readings on the HMI for unusual exhaust thermocouple temperature, wheelspace temperature, lube oil drain temperature, highest to lowest exhaust temperature spreads and “hot spots” i.e. combustion chamber(s) burning hotter than all the others. Record these values for future reference.

e. For all startups turbine and generator vibration monitoring is required using the unit’s proximity probes and velocity seismic sensors.

f. Listen for unusual noises and rubbing.

g. Utilize a planned shutdown to test the Electronic Trip System.

h. Monitor HMI display data for proper operation.

D. General

The following instructions pertain to the operation of a gas turbine unit designed for generator drive application. These instructions are based on use of Mark* VIe turbine control panels.

Functional description of the HMI Overview Display follows; however, panel installation, calibration, and maintenance are not included.

As described below, the procedure assumes that the turbine is in the cooldown or standby mode ready for normal operation with AC and DC power available for all pumps, motors, heaters, and controls and all annunciator drops are cleared.

E. Start-Up

1. General

Startup of a single turbine/generator unit may be accomplished either locally or remotely.

To transfer turbine control from the control compartment to remotely located equipment, select CABLE REMOTE on the HMI Overview Display. The turbine may then be started, automatically synchronized, and loaded by the remote equipment.

The following description lists operator, control system and machine actions or events in starting the gas turbine. Reference the section “Control Equipment" for description of turbine panel devices. The following assumes that the unit is in a ready to start condition.

2. Starting Procedure

a. The HMI Overview will indicate speed, temperature, various conditions etc. Check that there are no faults or alarms. Use the Start Permissive on the Controls HMI Overview and correct any start up issues.

b. On the HMI Overview Turbine Control Mode should be set to “Auto” and the Start Status should display “Ready to Start”.

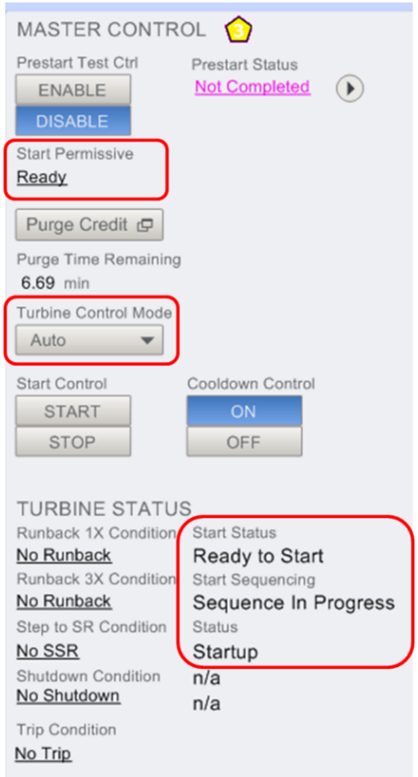

Figure 1. Example HMI Overview for Start Up

c. Select “START” and confirm the selection.

1) Unit auxiliaries will be started including a motor driven lube oil pump used to establish lube oil pressure. During this period, a test of the emergency lube oil pump is completed. If this test fails the start will be inhibited.

2) When permissives are satisfied, the master protective logic (L4) will be satisfied. The HMI Turbine Status will change.

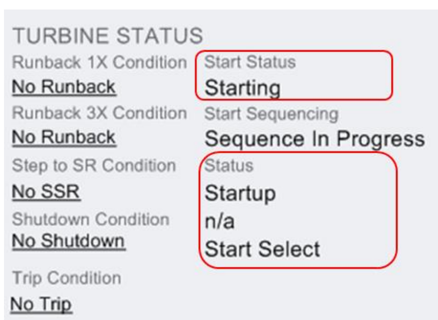

Figure 2. Example HMI Turbine Status After Start Initiated

3) The turbine shaft will begin to rotate on turning gear. When the unit reaches approximately 6 rpm, the starting device will be energized and accelerate the unit. The HMI display will change.

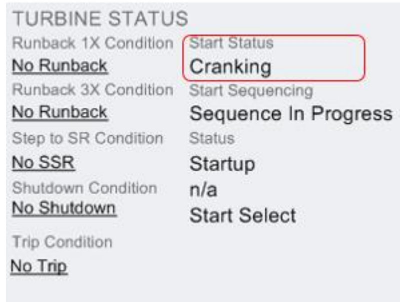

Figure 3. Example HMI Turbine Status Cranking

4) The starting device will crank the gas turbine at purge speed for a period of time determined by the setting of the purge timer. See Control Specifications-Settings Drawing for purge timer settings.

5) FSR will be set to firing value. (FSR, Fuel Stroke Reference, is the electrical signal that determines the amount of fuel delivered to the turbine combustion system.) Ignition sequence is initiated. The HMI display will change.

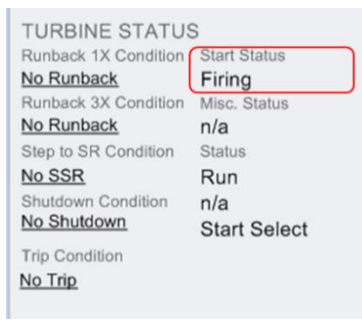

Figure 4. Example HMI Turbine Status Firing

6) When flame is established, the HMI display will indicate flame based on the status of the flame detectors.

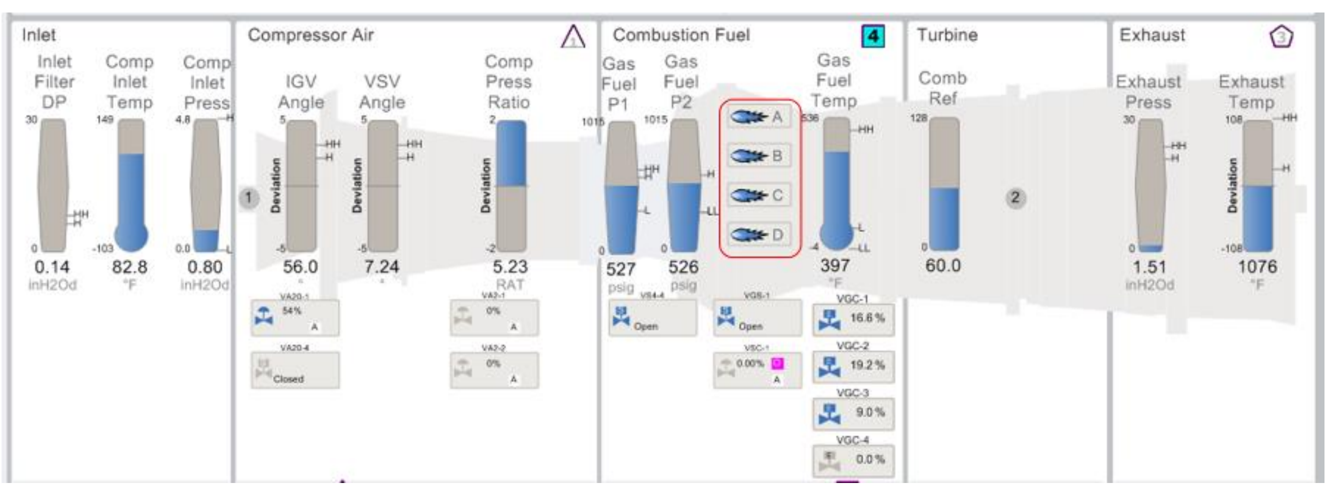

Figure 5. Example Flame Detectors on HMI

7) If the turbine fails to ignite on gas fuel, the unit returns to purge speed for an auto re-purge cycle.

After the auto re-purge cycle is complete the turbine holds at firing speed until the operator selects STOP or START from the operator interface. A STOP selection initiates a normal shutdown and a START selection initiates a second attempt to ignite. If a failure to ignite occurs a second time the turbine returns to purge speed and completes auto re-purge cycle followed by a turbine trip.

NOTE

Auto re-purge is not permitted on liquid fuel.

8) At the end of the warm-up period, with flame established, FSR will begin increasing. The HMI display will change.

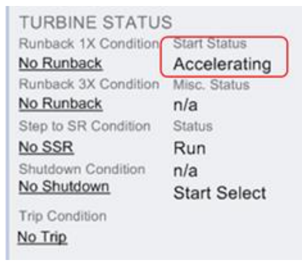

Figure 6. Example HMI Turbine Status Accelerating

9) The turbine will continue to accelerate. When it reaches 91% speed, the starting device will disengage.

10) When the turbine reaches operating speed (95%), Generator field flashing is initiated. If the synchronizing is not selected on the HMI, as the turbine reaches operating speed the HMI display will change.

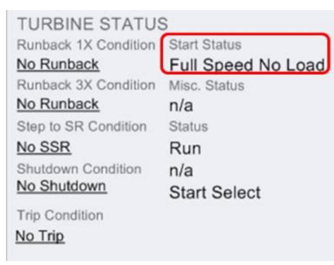

Figure 7. Example HMI Turbine Status FSNL

11) If Auto-Synch is selected on the HMI automatic synchronizing is initiated. The HMI will change.

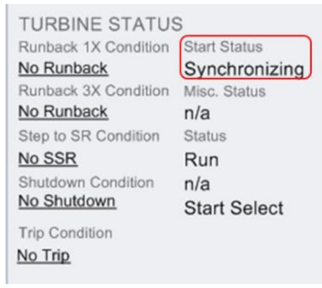

Figure 8. Example HMI Turbine Status Synchronizing

12) The turbine speed is matched to the system and when the proper phase relationship is achieved the generator breaker will close. The machine will load to Spinning Reserve unless a load control point BASE, PEAK or PRESELECTED LOAD has been selected.

13) The HMI will change once the unit has reached this load point.

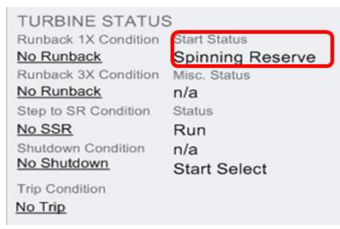

Figure 9. Example HMI Turbine Status Spinning Reserve

F. Synchronizing

When a gas turbine-driven synchronous generator is connected into a power transmission system, the phase angle of the generator going on-line must correspond to the phase angle of the existing line voltage at the moment of its introduction into the system. This is called synchronizing.

CAUTION

Before initiating synchronization procedures, be sure that all synchronization equipment is functioning properly, and that the phase sequence of the incoming unit corresponds to the existing line phase sequence and the potential transformers are connected correctly to proper phases. Initial synchronization and checkout after performing maintenance to synchronizing equipment should be performed with the breaker racked out.

NOTE

Only one lube oil, hydraulic oil (if applicable), and no seal oil motors are allowed to be running for synchronization.

1. Manual Synchronization

a. Select AUTO on the HMI Overview Display and apply the change.

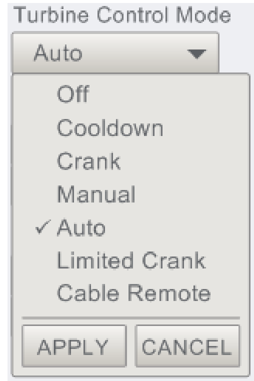

Figure 10. Example Turbine Control Mode HMI Selections

b. Select the START button and Confirm the selection on the HMI Overview Display. This will start the turbine and accelerate it to full speed as previously described.

Figure 11. Example Start\Stop Turbine Push Buttons

c. Select Manual on the Synchronization (left) or Overview (right) HMI Display. The graphic below shows the selection option that is identical and located on two different screens for operator preference.

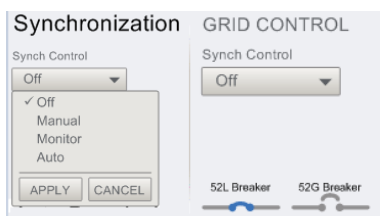

Figure 12. Example Synchronization Control HMI Selections

d. Compare the generator voltage with the bus-line voltage. These values are located on the HMI Synchronization display

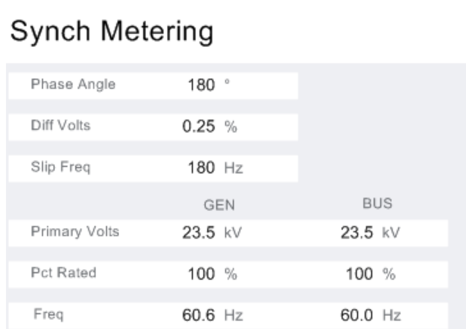

Figure 13. Example Synch Metering HMI Display

e. Make any necessary voltage adjustment by operating the RAISE- LOWER buttons on the HMI display until the generator voltage equals the bus-line voltage.

f. Compare the generator and line frequency on the synchroscope (located on the Synchronization HMI display). If the pointer is rotating counterclockwise, the generator frequency is lower than the line frequency and should be raised by increasing the turbine/generator speed.

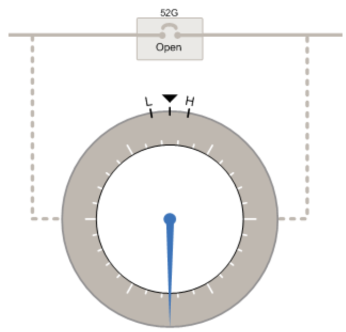

Figure 14. Example Synchoscope HMI Graphic

g. Adjust the speed until the synchroscope rotates clockwise at approximately five seconds per revolution or slower.

h. The generator circuit breaker "close" signal should be given when it reaches a point approximately one minute before the 12 o'clock position. This allows for a time lag for the breaker contacts to close after receiving the close signal.

2. Automatic Synchronization

a. Select Auto on the HMI Overview or Synchronization screens. Selecting auto before starting the turbine will allow the turbine to synchronize as soon as conditions match. It is possible to select auto synchronization anytime during the start up.

b. Select START and Confirm the selection on the HMI Main Startup Display. This will start the turbine and accelerate it to full speed as previously described. At this point the HMI will indicate RUN STATUS, FULL SPEED NO LOAD.

c. Select 'AUTO SYNCH' on the HMI Synchronization display.

d. The control system will match generator voltage to line voltage, synchronize the generator to the line frequency, and load the generator to the spinning reserve value.

e. If a synch fails for any reason, it may be necessary to either select START on the HMI Main Startup Display or select RE-SYNC on the HMI synchronization display to reset the sequence.

Once the generator has been connected to the power system, the turbine fuel flow may be increased to pick up load, and the generator excitation may be adjusted to obtain the desired kvar value.

*****WARNING*****

FAILURE TO SYNCHRONIZE PROPERLY MAY RESULT IN EQUIPMENT DAMAGE AND/OR FAILURE, OR THE CREATION OF CIRCUMSTANCES WHICH COULD RESULT IN THE AUTOMATIC

REMOVAL OF GENERATING CAPACITY FROM THE POWER SYSTEM.

In those cases where out-of-phase breaker closures are not serious enough to cause immediate equipment failure or system disruption, cumulative damage may result to the on-coming generator. Repeated occurrences of out-of-phase breaker closures can eventually result in generator failure because of the stresses created at the time of closure.

Out-of-phase breaker closure of a magnitude sufficient to cause either immediate or cumulative equipment damage mentioned above will usually result in annunciator drops to notify the operator of the problem. The following alarms have been displayed at various occurrences of known generator breaker mal-closures:

High vibration trip

Loss of excitation

Various AC under voltage drops

Out-of-phase breaker closure will result in abnormal generator noise and vibration at the time of closure. If there is reason to suspect such breaker mal-closure, the equipment should be immediately inspected to determine the cause of the mal-closure and for any damage to the generator.

G. Normal Load Operation

1. Manual Loading

Manual loading is accomplished by clicking on the SPEED/LOAD RAISE/LOWER targets on the HMI Main Startup Display.

Manual loading beyond the selected temperature control point BASE or PEAK (if applicable) is not possible. The manual loading rate is shown in the Control Specification-Settings Drawing.

2. Automatic Loading

On startup if no load point is selected, the unit will load to the SPINNING RESERVE load point. The SPINNING RESERVE load point is slightly greater than no load, around 25 MW unless requested to be different by the customer during the initial GT design phase.

An intermediate load point, PRE-SELECTED load or External Load setpoint, and temperature control load points BASE or PEAK (if applicable) can be selected any time after a start signal has been given. The selection will be displayed on the HMI. The unit will load to the selected load point. PRESELECTED LOAD is a load point greater than SPINNING RESERVE and less than BASE or the PEAK LIMIT (if applicable) if selected. The auto-loading rate is shown in Control Specification Settings is typically 8.3% of ISO day base load as the rated output/minute. Note that this is rated output. Control Specification setting is % of load set point.

H. DLN System Operation

1. General

Dry Low NO_x control systems regulate the distribution of fuel delivered to multi-nozzle combustors located around the gas turbine. These systems stage the fuel through multiple modes of operation to attain low emissions at base load.

2. Gas Fuel Operation

Each DLN combustion system operates in a series of modes to achieve desired operation at various loads. This is done with multiple control valves.

For DLN 2.6+ units with Axial Fuel Staging (AFS) refer to GEK121376: *Dry Low NOx 2.6+ with AFS Systems Operation* for more information on mode sequences and valve configurations.

3. Liquid Fuel Operation

The Pressure Atomized Liquid Fuel System (XAA) is engineered to provide liquid fuel and water as a mixture into the combustor. This system uses pressure atomization to atomize the fuel and water stream.

For 7HA.01 and 7HA.02 refer to GEK121590: *Pressure Atomized Liquid Fuel System Operation 7HA* for more information on mode sequences and valve configurations.

For 9HA.01 with DLN 2.6+ refer to GEK121611: *Pressure Atomized Liquid Fuel System Operation 9HA.01* for more information on mode sequences and valve configurations.

4. Inlet Guide Vane Operation (IGV)

a. DLN combustion systems are sensitive to changes in fuel to air ratio. DLN combustors are designed according to the airflow regulation scheme used with IGV Temperature Control.

b. As the gas turbine is loaded, the IGVs should remain at a fixed minimum value from full speed no load until the gas turbine exhaust temperature increases to the isotherm limit.

c. At this point, the IGVs will begin to open to maintain the appropriate temperature control boundary, until they reach their maximum open limit.

d. The Variable Stator Vanes (VSV) work in conjunction with the IGVs to control airflow through the gas turbine compressor. The reference to the VSV actuator is a function of IGV angle and Gas Turbine Corrected Speed.

5. Inlet Bleed Heat

Inlet heating via compressor bleed typically provides three primary functions:

a. Serve as compressor protection by increasing flow and decreasing pressure when required

b. Heat the inlet and front of compressor to prevent ice formation due to increased pressure drop across the reduced IGV angle.

c. Prevent compressor airflow from entering the combustor, maintaining a favorable temperature for premix operation

I. Shutdown, Cooldown and Restart

1. Normal Shutdown

Normal shutdown is initiated by selecting STOP on the HMI Main Startup Display. The control system will follow automatically through generator unloading, generator breaker opening, turbine speed reduction, fuel shutoff at part speed and initiation of the cool down sequence.

2. Emergency Shutdown

Emergency shutdown is initiated by depressing the EMERGENCY STOP pushbutton, located on the turbine control panel or remotely located at the operator station. The EMERGENCY STOP button will disable the turning gear and cool down sequence. Unless this is intended, the button should be released (unlatched) during coast down.

CAUTION

In the event of an emergency shutdown in which internal damage of any rotating equipment is suspected, do not turn the rotor after shutdown. Maintain lube oil pump operation, since lack of circulating lube oil following a hot shutdown will result in rising bearing temperatures which can result in damaged bearing surfaces. If the malfunction that caused the shutdown can be quickly repaired, or if a check reveals no internal damage affecting the rotating parts, recommence the cooldown cycle.

3. Cool down

The HMI Main Startup Display contains COOLDOWN CONTROL. Upon unit shutdown, either normal or emergency, the unit will automatically select cooldown control ON. Cooldown control will maintain the unit operating on turning gear with the lube oil and lift oil pumps running; however, cooldown control cannot be selected OFF for a minimum of 24 hours from shutdown. Selecting cooldown control OFF will disable the turning gear. Once the unit reaches ZERO speed, the lift oil and lube oil pumps will be de-energized and the seal oil pump will enable for units with hydrogen filled generators.

Proper cool down operation of the gas turbine is critical for avoiding high vibrations on unit restart, to control the unit clearances to avoid a compressor or turbine rub that would reduce overall unit performance, and to control the rotor stresses to achieve maximum rotor life.

The standard cooldown practice after a normal fired shutdown or unit trip from any load should be rotation by unit turning gear until all turbine wheelspace temperatures are < 150 °F as measured while unit at turning gear speed. At this condition the unit can be removed from turning gear by selecting cooldown control OFF. GER 3620 indicates the recommend turning gear practices when the unit is left idle prior to startup and for extended durations.

If required, the cooldown cycle may be accelerated using the starting device; in which case it will be operated at cranking speed. The same 150 °F requirement for removal of all rotation applies. but note that this temperate is to be measured and verified while the unit is at turning gear speed, not at cranking condition.

CAUTION

Opening up the turbine compartment doors or the lagging panels should not be done as a means to accelerate cooldown period. The compartment is engineered to provide specific cooling paths around the turbine to ensure uniform cooling. Disrupting this cooling path will result in uneven cooling of the outer casings resulting in excessive stress and uneven clearances.

4. Guidelines for Idle Rotor with Hot Unit

If there is a normal fired shutdown or trip, and the rotor achieves an idle state with no rotation when the wheel space temperatures are within range then following guidelines apply. The time limitation threshold is displayed on the Overview HMI screen, as shown in Figure 15, where the example shown is 20 minutes and wheelspaces threshold below 112°C. The values shown are to highlight the information on the HMI.

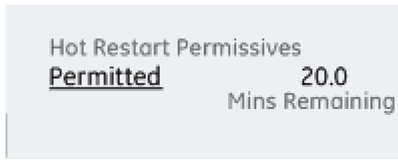

Figure 15. Hot Restart Permissive on Overview HMI

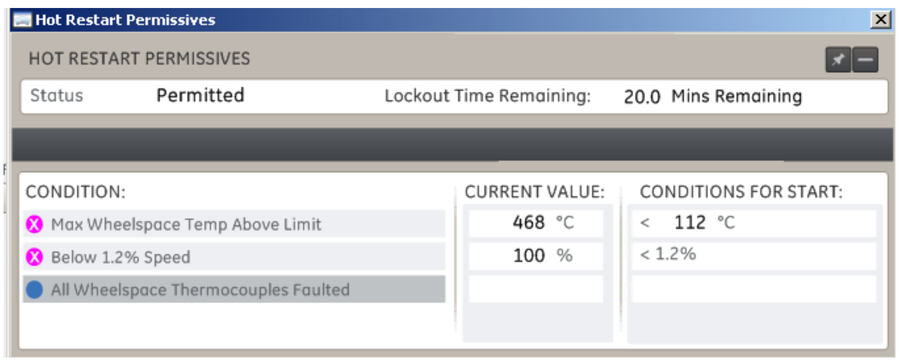

Figure 16. Example Hot Restart Permissive (Wheelspace and Time Limit)

NOTE

Wheelspace permissive temperature and time limit varies frame to frame. Check the Control Settings for the specific value.

a. If turning, cranking, or unit re-start is established within the time limit or less from a rotor idle condition, no rotor bowing is presumed to have occurred and no additional operational requirements are necessary.

b. If turning, cranking, or unit re-start cannot be established within the time limit or less from a rotor idle condition then it is presumed that rotor bowing has occurred. The below bowed rotor startup procedure requirements should be followed.

c. Bowed Rotor startup procedure

1) Bump check the unit rotor to ensure that it spins freely and to listen for any signs of rubs. If free spinning operation cannot be achieved or if rubs are detected return the rotor to idle and contact a GE technical service advisor for further instruction.

2) If the rotor freely spins and no rubs are detected, establish normal turning gear operation.

3) Maintain turning gear operation for a minimum of 8 hours

4) During subsequent start, monitor vibration and proximity sensors while the unit is at purge condition. If seismic vibration readings are greater than 0.1 in/sec for either GT bearing or proximity readings are above 0.8 mil, the start should be aborted.

5) If readings exceed above level and start is aborted, continue rotation on crank or turning gear. In this condition the unit should be cooled until wheel spaces are below wheelspace permissive as noted above before brought to idle or re-start is attempted.

NOTE

Wheelspace permissive temperature and time limit varies frame to frame. Check the Control Settings for the specific value.

CAUTION

If, during turning operation, the gas turbine rotor seizes, the turbine should be shut down and remain idle for at least 30 hours, or until the rotor is free. The turbine may be rotated at any time during the 30-hour period if it is free; however, audible checks should be made for rubs.

5. Unit Re-Start

NOTE

The following guidelines apply for normal unit operation. Initial commissioning of a new unit or new rotor requires adherence to a rotor start or "green" rotor run-in procedure. See addition details in Section II.C.3

When the gas turbine is hot, cranking and purging operation result in forced cooling of the turbine components. This forced cooling has an adverse impact on the unit clearances. The clearance design of the gas turbine allows for a period of cranking or purging operation while the unit is hot to allow for a unit re-start. Continued forced cooling beyond the time limit will result in an initial condition that could lead to a rub if a startup is initiated.

The following gas turbine re-start conditions should be adhered to. The below guidelines assume that a normal or emergency shutdown has taken place followed by normal cooldown rotation in which the rotor does not achieve an idle state.

a. Gas turbine start is allowed any time as long as all wheel space temperatures are below the wheelspace lock out measured while unit on turning gear. Reference control settings and\or HMI as shown in Figure 16.

b. If any of the unit wheel space temperatures are above wheelspace lock out temperature, purge and cranking time will be accrued against the time limitation. Reference control settings and\or HMI as shown in Figure 15 and Figure 16.

c. If total crank + purge time exceeds the time limitation and the unit does not achieve ignition, ignition will be locked out and unit will proceed with crank operation.

d. The total purge + crank time counter will be re-set to 0 when all wheel space temperatures are below wheelspace limit measured on turning gear OR after 1 hour of gas turbine operation at any condition at or greater than Full Speed No Load (FSNL).

NOTE

Wheelspace permissive temperature and time limit varies frame to frame. Check the Control Settings for the specific value.

J. Special Operations

1. Fuel Transfer (Gas-Distillate Option)

Fuel transfer is initiated using the Fuel Selection Buttons on the Main Startup Display of the HMI. When transferring from one fuel to the other, there is a delay before the transfer begins called the pre-fill time. Units with liquid fuel re-circulations systems will have a short pre-fill. For the gas-to-distillate transfer, the delay allows for filling the liquid fuel lines. For the distillate-to-gas transfer, the delay allows time for the speed ratio valve (and gas control valve) to modulate the inter volume gas pressure before the transfer begins.

2. Automatic Fuel Transfer On Low Gas Pressure (Gas-Distillate Option)

If available, in the event of low fuel gas pressure the turbine will attempt to transfer to liquid fuel. The transfer will occur with no delay for line filling. The success of a liquid fuel transfer depends on the operating conditions of the liquid fuel system. To return to gas fuel operation after an automatic transfer, manually reselect gas fuel.

This options is not available on all units.

3. Testing the Emergency DC Lube Pump

The DC emergency pump may be tested using the test pushbutton on the motor starter.

4. Annual Trip Test (previous overspeed test)

GE has removed the annual requirement to operate and trip the unit at 110% speed for all multi-shaft Heavy Duty Gas Turbines that utilize a MKV, MKVE, MKVI or MKVIe electronic overspeed trip circuit. GE still maintains an annual recommendation to perform a test of the MKV, MKVe, MKVI or MKVIe trip circuits themselves. This test is performed though the Fired Shutdown Trip Test.

a. Testing Requirements for the Fired Shutdown Trip Test:

The Fired Shutdown Trip Test should be performed on an annual basis or on the first shutdown opportunity if the unit is continuously operated for greater then a year.

NOTE

Maintenance that calls into doubt any portion of the Trip Protection System should be tested, at the earliest possible convenience after the outage in which the modifications took place.

CAUTION

> **__Under no circumstance__** may a test be run to test the emergency overspeed. (Intentionally failing the first line of defense to test the second line)
>
> The unit should never be run if either of the two lines of defense is known to be nonoperational.

b. Fired Shut Down Trip Test Procedure

1) From the Overspeed Test Display, operator initiates Fired Shutdown (Stop button).

2) Unit starts to shut down.

3) Prior to flame-out (see below) while flame is still detected, Operator initiates Fired Shutdown OST- Start button. It is recommended to do this 5-10% above design flame-out speed.

4) Design flame-out speed on gas fuel varies by frame, and is typically 30-55% depending on configuration and whether exhaust purge credit applies. Flame-out speed on liquid fuel is currently 94% for all HA frames.

5) System automatically checks the following during any OS trip event and will alarm if the results are not as expected:

   All Emergency Trip Relays (ETRs)/ Primary (PTRs) confirmed open

   Trip Header de-pressurized (for units with hydraulic valves)

   All valves closed

5. Temperature Matching

Temperature matching is used when the gas turbine exhaust temperature is to be controlled to bring on a steam turbine. From the Temperature Matching Control Screen, the operator must select temperature matching "ON."

Once selected, the turbine has to be loaded/unloaded to the matching window. Once the unit is in the matching window, temperature matching begins. The gas turbine typically receives a temperature matching reference from either the plant or steam turbine controller.

The gas turbine will control the exhaust temperature to the reference by modulating the IGVs. The IGVs will open to reduce the exhaust temperature and close to increase the exhaust temperature. If the reference is higher than the exhaust temperature and the IGVs are at their minimum position, the gas turbine will increase load to meet the reference.

Compliance to emissions and frequency response are not required to be maintained while in temperature matching mode.

6. Water Washing System Operation

a. General

Off-line Water washing should be scheduled during a normal shutdown, if possible. This will allow enough time for the internal machine temperature to drop to the required levels for the washing. Maintaining the unit at crank speed can shorten the time required to cool the machine. During this cooling of the turbine, the wash water is to be heated to the proper level.

The period between off-line water washes can be extended via frequent on-line washing. When the compressor is suspected of being heavily fouled, an off-line wash should be performed. The on-line compressor wash system allows an operator to water wash the turbine compressor without having to shut down the turbine.

b. Mandatory Precautions for Off-Line Water Wash

NOTE

Before water washing the compressor, inspect the inlet plenum and gas turbine bellmouth for large accumulations of atmospheric contaminants, which could be washed into the compressor. These deposits can be removed by washing with a garden hose.

Before off-line water washing of the compressor the turbine blading temperature must be low enough so that the water does not cause thermal shock.

To reduce this difference, the wash water may be heated and the turbine kept on crank until the wheel space temperatures drop to an acceptable level. The wheel space temperatures are displayed in the control room on the HMI.

CAUTION

The differential temperature between the wash water and the inter-stage wheel space temperature must not be greater than the wheelspace lockout limit to prevent thermal shock to the hot gas parts. Wheelspace permissive temperature varies frame to frame. Check the Control Settings for the specific value.

*****WARNING*****

THE WATER WASH OPERATION INVOLVES WATER UNDER HIGH PRESSURE.

CAUTION MUST BE EXERCISED TO ENSURE THE PROPER POSITIONING OF ALL VALVES DURING THIS OPERATION.

SINCE THE WATER MAY ALSO BE HOT, NECESSARY PRECAUTIONS SHOULD BE TAKEN IN HANDLING VALVES, PIPES, AND POTENTIALLY HOT SURFACES.

c. Compressor Water Washing Methods

For methods of Compressor Washing, water quality specifications and further recommendations refer to GEK121135: *7HA Gas Turbine Compressor Washing* or GEK121499: *9HA Gas Turbine Compressor Washing* in Unit Service Manual.

7. Unit Operation After Failure to Fire on Liquid Fuel

After every failure to fire on oil, an automatic unit TRIP will be issued. This trip will hold true until the unit has been below 2% speed for 2 minutes.

Once this trip condition is cleared a re-start command can be issued (provided other startup permissives are met). This operation allows excess liquid fuel to drain from liners.

III. DESCRIPTION OF PANELS AND TERMS

A. Turbine Control Panel (TCP)

The turbine control panel contains the hardware and software required to operate the turbine. A front elevation view of the panel can be seen in the Hardware Description of the applicable GEH-6721.

B. EMERGENCY STOP (5E)

This red pushbutton is located on the front of the TCP. Operation of this pushbutton immediately shuts off turbine fuel and locks out the turning gear mechanism. The turbine will come to a complete stop if left depressed.

C. Human Machine Interface (HMI)

The HMI is a personal computer that directly interfaces to the turbine control panel. This is the primary operator station. All operator commands can be issued from the HMI. Alarm management can be performed and turbine parameters can be monitored. With the proper password, turbine software editing can also be accomplished.

All Mode Select, Master Control and Auxiliary Control selections are the SELECT/CONFIRM type, which means that the target must first be selected and then also confirmed in order to actuate that command.

1. Main Startup Display

Mode Select, Master Control and Auxiliary Control selections can be made from the startup display. Mode Select Options and Master Control Options are detailed in Table 2.

MODE SELECT OPTIONS	
OFF	Inhibits a start signal.
CRANK	With crank selected, a start signal will bring the machine to crank speed.
LIMITED CRANK	Same as crank, except doesn't need plant permissives and cannot fire
AUTO	With AUTO selected, a START signal will bring the machine to operating speed. Changing selections from FIRE to AUTO will allow the machine to accelerate to operating speed.
CABLE REMOTE	With REMOTE selected, control for the unit is transferred to the remote control equipment.
COOLDOWN	Cooldown ON & OFF selection is used to put the turbine on turning gear speed or stop the turbine from rotating for possible maintenance activities.

MASTER CONTROL OPTIONS	
START	A START selection will cause the unit to start. With AUTO selected, the unit will load to FULL SPEED NO LOAD.
STOP	A STOP selection will cause the unit to initiate a normal shutdown. If the unit generator breaker is closed, the unit will unload at the standard rate, automatically open the breaker and continue to decelerate to a flameout and cooldown condition
LOAD CONTROL SELECTIONS (MADE FROM STARTUP)	
PRESEL.	Select the preselected load point.
BASE LIMIT (Optional with PEAK)	Limits preselected load to the nominal base load control curve.
BASE	Select base temperature control load point.
PEAK (Optional)	Select peak temperature control load point.

Table 3. Mode Select & Master Control Options

2. Master Reset Target

Selecting the Master reset target resets the Master Reset Lockout function. This target must be selected so that the unit can be restarted following a trip.

D. Definition of Terms

Spinning Reserve	The minimum load control point based on generator output. The spinning reserve magnitude in MWs is 25 MW.
Preselected Load	A load control point based on generator output. The preselected load point is adjustable within a range designated in the Control Specification. The preselected load point is normally set below the base load point. If the unit has peak load capability (optional), the operator can select to limit preselected load control by either the base limit or peak limit. If base limit is selected, the output will be limited to the nominal base load control curve. If peak limit is selected, the output can be controlled anywhere between nominal base load control curve and the peak limit.
Baseload	This is the normal maximum loading for continuous turbine operation.
Peak Load (Optional)	This is the maximum allowable output permitted for relatively long-duration, emergency power requirement situations consistent with acceptable turbine parts life. Peak Load operation will accrue factored fired hours at a rate greater than nominal. Refer to GER 3620 for peak operation maintenance implications.

Table 4. Definitions & Terms

E. Supervisory Remote Equipment

Supervisory equipment is normally functionally the same as the equipment described in the cable connected master panel. However, it may differ somewhat in metering and indications. Refer to the supervisory manufacturer's instruction manual for details.

F. Annunciator System

Alarms are displayed on the HMI operator screens. Before clearing an alarm, action should be taken to determine the cause and perform the necessary corrective action.

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ATTACHMENT C

// SCR CONTROL PHILOSOPHY MANUAL

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SCR Control Philosphy

SIGNATURES		DATE (dd-mmm-yyyy)
PREPARED BY	DSQ	05-Mar-2020
CHECKED BY	DSQ	05-Mar-2020
APPROVED BY	HAS	05-Mar-2020

GE Power

GENERAL ELECTRIC COMPANY
GENERAL ELECTRIC INTERNATIONAL, INC.
POWER PLANT SYSTEMS

-
EQUIPMENT SCOPE: HRSG

SIZE **A**	CAGE CODE	**NONE**	DWG NO	
SCALE	**NONE**	PA#	SHEET	**1 of 29**

Class II (Internal)
GE Proprietary Information

ENVIRO kinetics Keeping Pace With The World	Client: GE Gas Power Systems Indeck Niles, MI EKI Job#: 214319	*101 S Milliken Ave* *Ontario, CA 91761* *Phone: (909) 621-7599* *Fax: (909) 621-7899*

Control Philosophy
Doc No: 214319-303

0	3/5/2020	Issued for Approval	DSQ	DSQ	HAS
REV	**DATE**	**DESCRIPTION**	**MADE BY**	**CHECKED BY**	**APPROVED BY**

TABLE OF CONTENTS

INTRODUCTION

This manual presents general information on the function, construction, control, operation, and maintenance of the EnviroKinetics CO/SCR (Selective Catalytic Reduction) conversion system at the Indeck Niles Energy Center power plant. This is not a comprehensive manual and should be used in conjunction with other equipment manuals. When interfacing with existing equipment, those respective manuals should be consulted as well.

BACKGROUND

With the increased use of fossil fuels to generate electricity, Federal and Local Governments have imposed regulations to limit carbon monoxide (CO) and nitrogen oxide (NOx) emissions from combustion equipment. Carbon monoxide is an odorless, colorless, and toxic gas. Because it is impossible to see, taste, or smell, exposure to this toxic fume can kill. On the other hand, the nitrogen contained in fossil fuels combines with oxygen during combustion to create NOx. If released to the atmosphere, the NOx (NO, NO_2) combine with available oxygen and water to form nitric acid (HNO_3). The nitric acid returns to the earth in the form of acid rain, which is harmful to our environment. The Indeck Niles Energy Center power plant utilizes EnviroKinetics CO/SCR conversion system to reduce CO and NOx in the flue gas.

OPERATING THEORY

The CO/SCR conversion system is designed to convert CO and NOx emissions to environmentally compatible compounds through chemical reaction. This is broken down into two processes: CO conversion and NOx reduction; VOC destruction also occurs in the process.

CO Conversion and VOC Destruction

The CO reacts with oxygen in the exhaust gas in the presence of an oxidation catalyst and converts to CO_2 as follows:

$$2\ CO + O_2 \rightarrow 2\ CO_2$$

There is no control of the CO conversion rate. In addition to the CO conversion, VOC's (volatile organic compounds) are broken down in the same oxidation catalyst. The reaction for propane is as follows:

$$C_3H_8 + 5O_2 \rightarrow 3CO_2 + 4H_2O$$

Other VOC's are also present that will be oxidized in a similar manner, using available oxygen in the flue gas to complete the reaction. A high temperature is required for a high conversion rate. For this, the catalyst is placed in a higher temperature zone than that of the SCR catalysts where NOx reduction takes place.

NOx Reduction

The flue gas contains nitrogen oxides (NOx) that form during fuel combustion. These nitrogen oxides can be converted to nitrogen gas and water vapor using ammonia and a catalyst. Ammonia (NH_3) is injected into the flue gas upstream of the catalyst through a special injection grid designed to promote even ammonia distribution and mixing with the flue gas. The ammonia acts as a reducing agent as the flue gas passes through the catalyst. The NOx (NO, NO_2) contained in the flue gas is converted into $N_2$and H_2O.

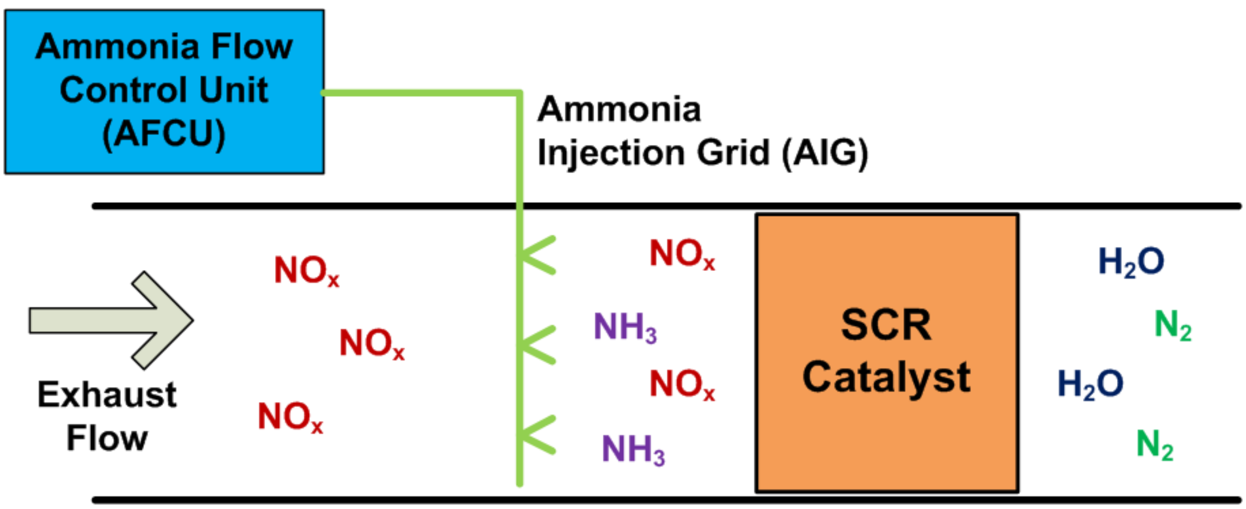
The fundamental NOx chemical reactions are:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$

$$NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O$$

Ammonia (NH_3) is introduced into the flue gas upstream of the reactor through an injection grid. The grid is designed to control the flow of ammonia to each region of the reactor to ensure that the ratio of NH_3 and NOx is uniform at the catalyst inlet.



Manual Objectives

This manual is divided into multiple sections. The content and objectives of each section are described below.

Equipment Description

This section gives an overview of system flow paths and describes each component and its function in the system, describing the SCR system and its function. It should be noted that the oxidation catalyst for CO and VOC reduction is passive and requires no control function. The SCR for NOx reduction, on the other hand, is monitored and controlled by the injection of ammonia at varying process conditions. This section and beyond will discuss more specifically about the SCR part of the system.

The objectives of this section are to:

- list the major components of the SCR system
- describe the function of the SCR components

Control and Operation

This section explains major control loops and the start-up and shutdown sequences. It describes the theory of the major control loops, lists alarm and interlock points, and describes start-up and shutdown sequences.

The objectives of this section are to:

- describe the theory of operation of major control loops
- list the alarm and interlock points and operating parameters for the system controls
- describe the start-up and shutdown sequences for the system

Maintenance

This section gives information on preventive maintenance of the major system components. It also explains how operating data can be used to recognize system malfunctions before they cause outages.

The objectives of this section are to:

- identify the routine operations and inspections necessary for proper maintenance of the SCR and NH_3 vaporization systems
- describe the required operating data necessary for the SCR system
- describe the procedure for preparing the catalyst samples for a catalyst efficiency test

Troubleshooting

This section describes the trouble shooting procedures for the SCR. It identifies potential operating problems with the system and describes their remedies.

The objectives of this section are to:

- list possible operating problems, which may occur during operation of the SCR and NH_3 vaporization systems
- describe remedies for system operating problems

Major Component Design Information

This section reviews the design details of the major equipment installed in the SCR and NH_3 vaporization systems. This information can be used to assist with operation, troubleshooting, and maintenance of the system.

Safety

This section will be used to review the safety requirements for personnel and equipment associated with the SCR and NH_3 systems. It describes the safety precautions necessary for operation of the system.

The objectives of this section are to:

- list the dangers associated with the handling and use of aqueous ammonia
- describe the possible operation conditions which can harm the catalyst
- describe the general operating practices and precautions necessary when working on or around the SCR and ammonia storage equipment

EQUIPMENT DESCRIPTION

DESIGN CONDITIONS

Item	Units	Design Conditions	Design Conditions	Design Conditions
Case Number		Guarantee Case 1	Guarantee Case 2	Guarantee Case 3
Unit Type		HRSG	HRSG	HRSG
Number of Units		One (1)	One (1)	One (1)
Unit Fuel Type		Natural Gas	Natual Gas	Natural Gas
Duct Firing		No	Yes	No
Flue Gas				
Flue Gas Flow Rate	lb/hr	5,809,200	5,664,813	5,788,600
Flue Gas Temperature	°F	665	679	674
Composition				
O2	% vol	11.32	10.77	11.52
N2	% vol	74.55	72.86	74.79
CO2	% vol	4.47	4.50	4.40
H2O	% vol	8.77	11.00	8.40
Ar	% vol	0.89	0.87	0.89
Flue Gas Emissions				
Inlet NOx	ppmv @ 15% O2 dry	32.00	32.13	32.00
Inlet CO	ppmv @ 15% O2 dry	6.29	6.56	6.41
Performance Requirements				
Outlet NOx	ppmv @ 15% O2 dry	2.00	2.00	2.00
Outlet CO	ppmv @ 15% O2 dry	3.00	3.00	3.00
dP Across SCR & CO System	inwc	2.33	2.32	2.34
Ammonia Supply				
Ammonia Type		19% Aqueous	19% Aqueous	19% Aqueous
Supply Condition		Liquid	Liquid	Liquid
Ammonia Flow Rate	lb/hr [Min|Norm|Max]	282 | 839 | 845	282 | 839 | 845	282 | 839 | 845
Ammonia Supply Pressure	psig [Min|Norm|Max]	60 | 75 | 80	60 | 75 | 80	60 | 75 | 80

FLUE GAS FLOW PATH

Flue gas enters the reactor over a range of temperatures from 544°F to 684°F. The flue gas travels through the AIG and static mixers that are designed to provide optimal distribution of ammonia throughout the reactor cross section. The ammonia-laden flue gas arrives at the catalyst where the NOx reacts with ammonia as it passes through the catalyst. Additional heat is recovered from the flue gas before being discharged to the stack. Instruments used for monitoring flue gas conditions include a differential pressure transmitter for monitoring pressure drop across the catalyst and thermocouples at the SCR inlet for monitoring flue gas temperature.

AMMONIA FLOW CONTROL SYSTEM

The reaction chemistry of the SCR requires flow control of the ammonia reagent. This is achieved by the Ammonia Flow Control Unit (AFCU) skid. The AFCU supplies a mixture of ammonia vapor and circulated hot flue gas to the ammonia injection grid (AIG). The AFCU skid is shop-assembled, pre-piped, and pre-wired. The skid is operated and controlled by the plant control system.

The AFCU has particular features that need to be noted.

- Strainer on the aqueous ammonia to remove any suspended solids. When the system is online, check the instrument 1A-PDI-AQA802 to note any pressure differential across the strainer. Clean out the strainer from any blockage in the event of alarm that is triggered by its pressure switch 1A-PDSH-AQA802.
- The block valves, 1A-YV-AQA830 & 1A-YV-AQA831, on the aqueous ammonia line allows for isolation of the ammonia for various functions and to stop ammonia injection at conditions referenced on the Cause and Effect.
- The flow of ammonia is set by a combined feed-forward of turbine conditions and the feedback of NOx at the stack. This calculated value provides a set point for the ammonia flow controller, FC-921. This controller has a split-range output to two control valves. One control valve, 1A-FCV-AQA821A, operates at low range of ammonia flow for start-up purposes, and the other, 1A-FCV-AQA821B, opens during higher demand.
- A vaporizer tower, packed with heat and mass transfer media, provides for efficient vaporization of the aqueous ammonia into vapor. Flue gas flows vertically up through the media with the aqueous ammonia sprayed down into the media. The flow and temperature of the circulated flue gas is enough to vaporize all of the ammonia required for the SCR operation.
- Two 100% hot-gas recirculation fans have been provided on the skid that siphon hot flue gas from the HRSG ducting for use in vaporizing the aqueous ammonia. These fans are provided with automated, ANSI class II dampers on their suction and discharge connections. These automated dampers are for maintenance purposes only and need to remain open during operation to keep the stand-by fan in a “ready-to-start” condition as automatic and remote fan switch over can occur during unit operations. A backdraft damper is provided on each fan discharge. This intentionally allows some hot-gas to leak back into the fan housing to keep the stand-by fan warm and ready for operation.
- Variable Frequency Drives (VFD’s) for each of the dilution air fans allows for the fan speed to be modulated to avoid excess gas velocity in the vaporizer (flooding) and to maintain the offline fan’s impeller at 10% speed after a trip.

Ammonia is delivered to the AFCU, strained, and metered by a flow meter that provides a feedback signal to the ammonia flow control valve. The amount of ammonia required is determined by feedback from a NOx analyzer, CTP-, on the stack.

Ammonia is injected into the hot flue gas stream in the vaporizer where it is completely vaporized. A differential pressure gage on the vaporizer, 1A-PDI-FLG844, can be used to determine the pressure inside the vaporizer tank.

Liquid accumulation in the bottom of the tower, as indicated by the level switch, 1A-LSH-FLG851, indicates incomplete vaporization from over-injection or inadequate gas circulation. In the event of flooding, the VFD shall be used to reduce the dilution fan speed to allow the vaporizer to recover.

AMMONIA SUPPLY

The aqueous ammonia liquid is fed to the AFCU via the ammonia supply line.

Reagent-grade 19% by weight aqueous ammonia of the following specification is required for this system:

Property	Requirement
Ammonia Assay	19%
Appearance	Colorless and free of suspended matter or sediment
Residue After Ignition	< 0.002% weight
Total Non-Volatile Matter	< 0.05% weight
Halides	< 0.5 ppmw
Alkali Metals	< 1.0 ppmw
Total Sulfur	< 2.0 ppmw
Phosphates	< 2.0 ppmw
Iron	< 0.2 ppmw
Heavy Metals	< 0.5 ppmw
Makeup Solution	Demineralized or deionized water

MAJOR COMPONENTS

The SCR system can be divided into three major components:

1. SCR Catalytic Reactor and Ductwork
2. Ammonia Supply System
3. Aqueous Ammonia Vaporization System

SCR REACTOR

The SCR reactor utilizes one fixed catalyst bed, horizontal flow reactor. The reactor assembly consists of a reinforced casing with structural supports designed for internal pressure, seismic loading, wind loading, catalyst loading, and thermal stress (design by others). The reactor housing has inside dimensions of approximately 84'-5 3/8"ft tall and 29'-6 9/16"ft wide and is constructed of carbon steel plate. The reactor is insulated internally. An access opening for catalyst loading and removal is located at the roof.

SCR CATALYST

The catalyst used for this reactor is highly reactive to NOx. The catalyst units are preassembled into catalyst modules for ease of shipment and installation.

The total installed catalyst bed consists of 54 catalyst modules with a single layer cross-sectional arrangement of 3 modules wide by 18 modules high. The catalyst bed is arranged for horizontal flow. There are 2 different catalyst modules that are similar in sizes with the dimension of approximately 14ft W x 3ft H x 2ft D. The catalyst should be kept as dry as possible during installation, storage or actual operation. Catalyst wetting will result in a permanent decrease in catalyst activity and may void the catalyst warranty

WARNING: The presence of some elements at some level of concentration on the surface of the catalyst can poison the catalyst and cause permanent deterioration. For this reason, care should be taken to avoid introducing the following compounds and elements into the flue gas stream ahead of the SCR.

Sodium	Platinum
Potassium	Palladium
Halogen Compounds	Rhodium
Arsenic	Ruthenium
Silicon	Osmium
Iridium	

Catalyst Samples

Catalyst can be sampled periodically to monitor catalyst performance. Umicore has provided sample coupons for this purpose and are distributed throughout the catalyst bed. If a program is to be established, it is recommended that the catalyst coupons be tested at twelve month intervals to assure that the catalyst is performing as expected and to help predict expected catalyst life and replacement time. If testing shows an unusually high deactivation rate, a consequent investigation can determine the cause and prevent premature replacement of catalyst.

Ammonia Injection Grid

There is one ammonia-air injection grid, originating at the vaporizer discharge on the AFCU. The ammonia-air injection system is located upstream of the SCR and consists of a feed line that is external to the ductwork, with a grid of injection pipes containing injection orifices located inside the ductwork (AIG). One-hundred and eight (108) 3” SCH 10 horizontal lances supply ammonia-air mixture to form the grid. The lances are grouped externally with nine (9) sub-headers, each with a balancing valve and flow indication. While these valves are intended to remain fully open, they may be used to balance or adjust the ammonia distribution. A differential pressure gauge 1A-PDI-FLG869 may be used to measure the flow on each sub-header. These sub-headers are, in turn, connected to the main header originating at the AFCU vaporizer.

Control and Operation

The NOx level at the stack is measured continuously by a CEMS analyzer, CTP-, with the measured NOx level used by the SCR control system to determine a set-point for the ammonia flow controller. Aqueous ammonia liquid is delivered to the control skid, where it is injected into the vaporizer at the discharge of the dilution fans. These fan supply hot flue gas that is used to dilute the ammonia so that it can be properly distributed in the ammonia injection grid (AIG) upstream of the catalyst. The ammonia injection grid is used to disperse the ammonia-air mixture across the catalyst face.

The ammonia injection should only be operated when the temperature of the flue gas entering the SCR catalyst is above 350 °F. The plant control system is programmed to close the isolation valves, 1A-YV-AQA830 & 1A-YV-AQA831 (located at the skid), and close the actuated ammonia valves, 1A-FCV-AQA821A & 1A-FCV-AQA821B (located at the skid), if the temperature of the system drops below this.

Commissioning

It is imperative that the system be completely free of construction debris and any surface preservatives prior to start up. This should be done as follows prior to catalyst loading:

1) Follow the startup procedure as indicated below.
2) Start the HRSG and bring up to temperature. The entire system must be blown clean and free of debris, including the ammonia injection ducting, prior to catalyst loading.
3) Cool the system in preparation for catalyst loading.
4) Ensure that the aqueous ammonia injection system is flushed and free of scale and construction debris.

Note: The ammonia system contains very small orifices and MUST be clean prior to placing in operation.

Pre-start

1) Drains Closed/Spectacle Blinds Open: Ensure all drain valves are shut. These are identified on the AFCU skid along the Ammonia Line, Instrument Air Line, Service Air Line, Vaporizer, and Fans. All Spectacle Blinds, found on the Fans and Vaporizer outlet, must be open.
2) When placed in service, fans must be checked for proper alignment and tested for vibration. Consult the fan OEM manual for allowable value of mis-alignment and/or vibration. If fans have been idle for more than 6 months, bearing must be checked for rusting. Failure to document alignment, vibration, and bearing condition will void the warranty on the fans.
3) Instruments in Normal Operating Configuration: Instruments must be checked for their configurations. Verify that the set points are in accordance to the Instrument Data Sheet (document 214319-105).
4) Valve Line-Up is Checked and Ready for Operation: Check to make sure all manual valves are set for operation.
5) Motor Contractors are in “Ready” Status.
6) Alarms and Interlocks are Cleared.

STARTUP

Note: Please also refer to the Catalyst Manufacturer's Operating Manual.

1) SCR Start: Upon receiving a signal from the plant control system that the turbine is ready to start, the following will happen:
   a) The ammonia dilution fans 1A-FLG-FAN-01A (Fan A) and 1A-FLG-FAN-01B (Fan B) will start at 10% output as controlled by the VFD's. The fans may also be manually started and stopped in the plant control system.
   b) Confirmation of ammonia dilution fan start must be received to allow the sequence to proceed.
   c) The gas turbine will come online and the system will monitor the temperature of the SCR Flue Gas as measured by the two temperature indicators 1A-TI-HEH837 and 1A-TI-HEH838.
   d) Flow to the vaporizer will be confirmed by flow transmitter 1A-FIT-FLG822, and the vaporizer start-up electric heater will be brought online once the temperature of the dilution air is above 300°F as verified by the Heater Control Panel Temperature feedback 1A-TE-FLG813.
2) When the temperature of the flue gas entering the SCR catalyst, as measured by the three temperature transmitters, TT, is above 350°F and the vaporizer outlet temperature as measured by, 1A-TT-FLG814A/ -B/ -C, is above 250°F, the following sequence will proceed:
   a) Ammonia block valves 1A-YV-AQA830 & 1A-YV-AQA831 will open.
   b) Ammonia control valves 1A-FCV-AQA821A & 1A-FCV-AQA821B will open and the ammonia injection rate will begin a ramp sequence to bring the ammonia flow up to the initial set-point that's defined by the flow controller FC-921. The flow controller imposes the set point based on the values given by the outlet NOx analyzer, CTP-, the flue gas analyzer, and exhaust flow.
3) Once the ammonia flow rate reaches the initial set-point value, the plant control system will switch ammonia flow control to automatic modulating control.
4) As the flue gas temperature entering the start-up electric heater increases, the start-up heater will reduce its output. When the temperature of the flue gas entering the SCR catalyst reaches the normal operating temperature, the electric heater will shut off, allowing the hot recirculated gas to vaporize the ammonia unassisted.

DURING OPERATION

1) With controllers in automatic, expect the following:
   a. Ammonia will be injected based on turbine load and NOx reading feedback from the NOx analyzer, CTP-. Atomizing air flow will then remain continuous.
   b. Alarm points will be monitored for process parameters, signaling the operator for action if necessary.
   c. The actuated valves on the fans are to remain open during normal operation to allow the offline fan to remain in a hot standby mode. Fans are to be alternated on a weekly basis to minimize shaft deflection of the offline fan.
   d. Balancing valves on the sub-headers, once positioned for proper distribution, should not need to be adjusted.

Shutdown

1) As the HRSG system shuts down, ammonia demand will be reduced. The control system will reduce ammonia injection as required. Once either of the temperature of flue gas entering the SCR catalyst or the vaporizer drops below 350°F or 250°F, respectively, ammonia injection will be stopped.
2) Continue running the ammonia dilution fans until the turbine is fully shut down to purge ammonia and flue gas combustibles from the system. Reverse the VFD start-up ramp described above to gradually bring the fans down to idle before shutting off.

Maintenance

The system shall be operated and maintained under a planned program of periodic inspection with the accompanying repair and replacement of parts needed to achieve the maximum availability and reliability of the system.

The inspection results and maintenance records should be compiled and be accessible at all times. Results of these inspections are used to determine the necessity for equipment repair or replacement.

Catalyst Maintenance

- Catalyst protection must be practiced constantly by maintenance personnel when inspecting or servicing the reactor. Do not physically touch or step on the catalyst directly during work inside the reactor as catalyst damage may occur. Temporary scaffolding and footplates are required to avoid the contact of any direct acting loads onto the catalyst modules or elements. As a precaution, a shield shall be installed over the catalyst layer to protect the catalyst during maintenance work.
- The catalyst must not be exposed to water or other moisture throughout all operating and storage conditions to prevent catalyst deterioration. This problem can be easily prevented by careful work and a daily check of the SCR system. All open inspection ports are to be shielded from the rain.
- Should rain enter through a cracked duct or open access door, dry the catalyst as soon as possible. Flue gas water vapor during startup, shutdown and normal operations is not a concern. Never wash the catalyst with water.

Equipment Maintenance

Periodic maintenance of the equipment will keep the equipment in excellent condition and in service for its intended use. All equipment shall be inspected and maintained in accordance with the manufacturer's instructions. Development of the practical maintenance program is to be based on the site and plant conditions.

Recommended Maintenance Schedule

The following table is a recommended maintenance schedule based on typical operation. Detailed maintenance procedures for each piece of equipment are available in the manufacturer's data books.

WARNING: Review all recommended safety practices before performing maintenance on any piece of equipment.

#	Equipment	Check Points	During Operation	While Offline	Interval					
					Every Shift	Daily	Weekly	Monthly	Yearly	Other
1	Ductwork	Inspection for gas leakage	X					X		
2		Check for abnormal vibration	X					X		
3		Check for signs of color change	X				X			
4	Ammonia Injection Grid	Check for plugging due to foreign matter inside of nozzles		X					X	
5		Check for deformation or corrosion		X					X	
6	SCR Reactor	Inspect for gas leakage	X		X					
7		Check for catalyst layer shifting		X					X	
8		Check for corrosion		X					X	
9		Check for dust adhesion to catalyst and clean (if necessary)		X					X	
10		Check for deformation or movement of sealing device		X					X	
11		Check total sealing system		X					X	
12		Check for deformation or distortion of structures		X					X	
13	Catalyst (Visual Check)	Check for deformation of module and catalyst elements		X					X	
14		Check for dust accumulation and blockage		X					X	

#	Equipment	Check Points	During Operation	While Offline	Interval					
					Every Shift	Daily	Weekly	Monthly	Yearly	Other
15		Check catalyst for dust erosion		X					X	
16	Ammonia Header	Confirmation of correct flow at header by pressure drop	X		X					
17	Vaporizer	Check for gas leakage	X			X				
18		Check for blockage	X	X						X
19	Dilution Air Fans	Check for sound or vibration at blower and motor	X			X				
20		Application of grease		X						X
21		Overhaul fan		X						X
22	Control Valve, Shut-Off Valve	Confirm valves are function properly	X		X					
23		Check pressure and temperature settings	X		X					
24		Check for leakage	X		X					
25		Check or replace gland packings		X					X	
27	Pressure Switches	Visual check for electrical sparking		X		X				
28		Check electrical terminals torque and tightness		X					X	
29		Measure insulation		X					X	
30		Verify set-point		X						X
31	Control Panels	Confirmation of annunciator and indicator lamps	X			X				
32		Check electrical wires for wear	X			X				
33		Check and clean panel internals		X					X	
34		Check electrical terminals torque and tightness		X					X	
35		Logic sequence test		X					X	
36	Manual Process Controllers	Check electrical terminals torque and tightness		X					X	
37		Check and clean instruments		X					X	
38		Confirm behavior of control loops		X					X	
39	Thermocouples	Remove adhered material	X	X						X

#	Equipment	Check Points	During Operation	While Offline	Interval					
					Every Shift	Daily	Weekly	Monthly	Yearly	Other
40	Transmitters	Calibration test		X						X
41	Pressure Gauges	Confirmation of indicated values	X	X						X
42		Calibration test	X	X						X
43		Check for damage		X			X			
44	Piping	Check for leakage	X				X			
45		Check for fouling	X				X			
46		Check for vibration	X				X			
47	Ammonia Strainer	Check differential pressure	X	X			X			
48		Clean out blockage		X						X

WARNING: Before entering into and working inside the SCR reactor or ductwork, verify the following conditions in addition to any plant-specific requirements:

- Inside temperature must be lower than 104 °F.
- Oxygen concentration in flue duct must be higher than 20%.
- Plant is shut down and locked out to prevent restart.
- The valves on the lines for ammonia, nitrogen, combustible gases and other hazardous fluids are to be closed and locked out.
- The ammonia line must be completely purged.
- Depressurize all equipment and piping to atmospheric pressure before opening them.
- During maintenance work, FRESH AIR shall be continuously ventilated by a fan or other suitable equipment.
- Before starting any repair work and especially when using open flames, use a combustible gas detector to confirm that no combustible gases are present in the work area.
- Always work in pairs with one remaining as an observer outside of the work/inspection area(s).

When performing work on electrical equipment, follow the instructions below to prevent electric shock and/or damage to the equipment.

- <u>OPEN</u> the circuit breaker for electrical equipment completely and place a safety tag in a safe, noticeable location.

- CONFIRM that the electrical power supply is absolutely isolated by using a circuit tester.
- CONNECT the earth wire firmly to the ground to prevent electric shocks.

NOTICE: Do not perform maintenance on instruments such as transmitters, analyzers or controllers without reading and understanding the instruction manuals. Otherwise, personal injury or damage to the instruments may result.

Prior to starting the maintenance work on the ammonia injection system, DEPRESSURIZE and PURGE the system using nitrogen or fresh air to secure safe conditions.

If any repairs are necessary on the pressurized section and/or high temperature service section, ISOLATE the system or STOP OPERATION to reduce the internal pressure to an ATMOSPHERIC level and to bring the plant temperature down to a SAFE level (120°F) before initiating repairs.

For fire explosion prevention, fire-fighting equipment shall be readily available near the equipment being repaired. The equipment shall be properly grounded to release static electricity before starting work.

Performance Evaluation

Although catalyst deterioration has been taken into account in the design, it has been found that catalyst activity deteriorates gradually with operation time. Initial deterioration that occurs within the first few thousand operating hours after the first start-up is somewhat more rapid.

The cause of deterioration cannot be quantitatively determined due to several causes, such as:

- Decrease of catalyst specific surface area due to sintering in elevated temperatures
- Effects of catalyst poisons which are usually contained in flue gas

The impact of each factor is very small. Regardless, the deterioration rate will not change abruptly as long as the operating conditions are constant.

The expected efficiency of the SCR system should be evaluated based upon the daily operating data, periodic performance tests, and examination of the catalyst samples.

The following methods can be used to evaluate catalyst performance and estimate remaining catalyst life:

- Evaluation of operating data
- Periodic system efficiency tests
- Analysis of catalyst samples

Evaluation of Operation Data

Evaluation of system performance is to be done by tracking key operating data on a regular basis. The operating data at the design conditions are preferable for calculation of system efficiency. Any abnormal occurrences (ex. process upsets or unit trips) should be recorded.

The following key operating data should be recorded on half-hourly (minimum) intervals. This data should be stored and readily accessible throughout the warranty period.

Parameter	Metric Units	Imperial Units
Fuel Flow Rate	kg/hr or NM3/hr	lb/hr or ft3/min
Gas Flow Rate Entering the SCR	kg/hr or NM3/hr	lb/hr or ft3/min
O2 Concentration at Reactor Inlet	% volume, dry	% volume, dry
NOx Mass Flow at Reactor Inlet	kg/hr	lb/hr
Outlet NOx Setpoint	mg/NM3 or ppmvdc	ppmvdc
Calculated NOx Reduction	%	%

Total Catalyst Operating Hours	hours	hours
NOx Concentration at Reactor Inlet	mg/NM3 or ppmvdc	ppmvdc
NOx Concentration at Stack	mg/NM3 or ppmvdc	ppmvdc
NH_3 Flow Rate	kg/hr	lb/hr
Flue Gas Temperature at Reactor Inlet	°C	°F
Dilution Air Flow for NH_3 Injection	kg/hr or NM3/hr	lb/hr or ft3/min
Differential Pressure Across Catalyst	kPa	inH2O
Ammonia Vaporizer Outlet Temperature	°C	°F

Periodic Efficiency Test

It is recommended to carry out system efficiency testing every 3,000 operating hours. The tendency of efficiency change with operating time should be reviewed along with a complete evaluation of operating data. Any abnormal trends or problems should be investigated.

Analysis of Catalyst Samples

Periodic testing can be performed on catalyst samples to help predict remaining catalyst life and replacement time.

This periodic testing enables the supplier to more accurately define the extent of catalyst deterioration during actual operation and to determine the required reactivation procedures.

TROUBLESHOOTING

Problem	Potential Cause	Remedy
Low De-NOx Removal	Not enough ammonia flow	Check for ammonia leakage
	Flow control is 100%	Check ammonia supply pressure Check for piping and atomizer fouling and manual valve opening Check ammonia flow meter and associated controllers Check for ammonia strainer blockage
	Outlet NOx set-point too high	Adjust outlet NOx set-point to the correct value Check for ammonia leakage
	Catalyst deterioration	Increase NH_3 injection flow Take sample catalysts and send them to a testing laboratory with historical operating data to evaluate deterioration
	Poor ammonia distribution	Check for ammonia injection pipe and nozzle fouling
	O2 analyzer giving incorrect signal	Check analyzer calibration Check for fouling or leakage of gas sampling tubes Check service air pressure
Repeated tripping of AFCU ammonia block valve	Low ammonia-air mixture	Check flue gas temperature Check dilution air temperature Check ammonia-air mixture temperature

High SCR pressure differential	Material collection at catalyst inlet	Remove material on catalyst surface Check exhaust gas flow rate

Catalyst Trouble

In case of suspected catalyst damage, contact EnviroKinetics immediately with detailed information and operating data relating to the damage. Catalyst samples shall be removed and sent to a catalyst testing laboratory to investigate the properties of the damaged catalyst. EnviroKinetics or the catalyst manufacturer will make recommendations based on the results of the catalyst sample analysis and operating data.

Catalyst Wetting

If water enters through a cracked duct or open access holes during system operation, maintenance, or storage, dry the catalyst immediately. Drying will occur naturally if the unit is in operation and the flue gas temperature is above 120°F.

Catalyst Sintering

Sintering refers to the swelling and subsequent deformation of the catalyst structure.

This can ultimately lead to a reduction in the available surface area. Sintering is a slow process that occurs naturally even at normal operating temperatures. At higher temperatures, the sintering process is accelerated and can speed up the rate of deterioration.

Major Component Design Information

NOTE: All quantities are on a per unit basis unless otherwise indicated.

Reactor

Manufacturer	EnviroKinetics, Inc.
Quantity	1
Flow Direction Through Catalyst	Horizontal
Materials of Construction:	
Reactor Casing	Carbon Steel (by others)
Catalyst Support Structure	Carbon Steel

Catalyst

Manufacturer	Umicore
Model	Horizontal Flow
Formulation	Vanadium, Titanium, Tungsten
Catalyst Volume	4,587 ft^3
Number of Modules	54
Layers	1

Ammonia Injection Grid (AIG)

Manufacturer	EnviroKinetics, Inc.
Quantity	One (1)
Number of Lances	108

Ammonia Flow Control Unit (AFCU)

Dilution Air Blowers

Manufacturer	Air Pro Fan
Quantity (Operating)	One (1)
Quantity (Spare)	One (1)
Type	Radial
Flow Rate, ACFM	8,000
Static Pressure Rise, inwc	36.6

Vaporizer

Manufacturer	EnviroKinetics
Atomizer	Bete Fog Nozzle
Type	Packed Tower

Ammonia Control Valve

Manufacturer	Fisher (Emerson)
Quantity	2
Type	Actuated Globe Valves

AMMONIA BLOCK VALVE

Manufacturer	AT Controls Triac
Quantity	2
Type	On/Off Valve

AMMONIA FLOW METER

Manufacturer	Micro Motion
Quantity	1
Type	Coriolis Meter

Instrument Air BLOCK VALVE

Manufacturer	AT Controls Triac
Quantity	1
Type	On/Off Valve

SAFETY

WARNING: Never remove any interlocks during operation and maintenance for personal safety and protection of equipment. Do not change a set point value for interlocks or alarms without authorization from the supplier.

WARNING: Maintain the volumetric concentration of ammonia (NH_3) in air at less than 13%. Failure to adhere to this may result in explosion**.**

WARNING: Ammonia is used in the SCR system. Contact with ammonia vapor or liquid causes strong irritation to the skin, eyes, and respiratory tract.

1) Personnel and equipment safety are the main consideration in operating the SCR De-NOx system.
2) If there is ever any doubt about safety and safe operating conditions, the operator must take appropriate steps to return the SCR De-NOx system to a known safe condition immediately even if it causes the plant to trip.
3) Protective clothing and equipment appropriate to the job is highly recommended
4) Never directly touch hot equipment, hot piping or rotating equipment. The use of gloves and protective clothing is highly recommended.
5) If flue gas leakage or ammonia leakage is discovered:
   a) Indicate the danger with caution plates and safety ropes to isolate personnel from the area,
   b) Extinguish all open flames.
   c) Never ignite any flames in the leakage area.
6) During a cold start-up of the HRSG, prior to ammonia injection, verify that the flue gas temperature reaches the minimum operation temperature at the outlet of the SCR reactor or stack, where flue gas temperature raises lower than the inlet.

MAINTENANCE SAFETY

Before entering into and working inside the system, verify the following conditions:

- Inside temperature must be lower than 104°F.
- Oxygen concentration in flue duct must be higher than 20%.
- Plant is shut down and locked out to prevent restart.
- The valves on the lines for ammonia, nitrogen, combustible gases and other hazardous fluids are to be closed and locked out.
- The ammonia line must be completely purged.
- Depressurize all equipment and piping to atmospheric pressure before opening them.
- During maintenance work, FRESH AIR shall be continuously ventilated by a fan or other suitable equipment.
- Before starting any repair work and especially when using open flames, use a combustible gas detector to confirm that no combustible gases are present in the work area.
- Always work in pairs with one remaining as an observer outside of the work/inspection area(s).

When performing work on electrical equipment, follow the instructions below to prevent electric shock and/or damage to the equipment.

- OPEN the circuit breaker for electrical equipment completely and place a safety tag in a safe, noticeable location.
- CONFIRM that the electrical power supply is absolutely isolated by using a circuit tester.
- CONNECT the earth wire firmly to the ground to prevent electric shocks.

NOTICE: Do not perform maintenance on instruments such as transmitters, analyzers or controllers without reading and understanding the instruction manuals. Otherwise, personal injury or damage to the instruments may result.

Prior to starting the maintenance work on the ammonia injection system, DEPRESSURIZE and PURGE the system using nitrogen or fresh air to secure safe conditions.

If any repairs are necessary on the pressurized section and/or high temperature service section, ISOLATE the system or STOP OPERATION to reduce the internal pressure to an ATMOSPHERIC level and to bring the plant temperature down to a SAFE level (120°F) before initiating repairs.

For fire explosion prevention, fire-fighting equipment shall be readily available near the equipment being repaired. The equipment shall be properly grounded to release static electricity before starting work.

HANDLING AMMONIA

At a minimum, the following standard and requirements, shall be applicable for handling of ammonia:

- ANSI K61.1 -1989
- OSHA
- Ammonia Supplier's Material Safety Data Sheet

Use approved gloves, goggles and full-face mask, whenever handling ammonia.

AMMONIA LEAKAGE

An ammonia analyzer is installed on the AFCU skid and has a set-point at 50 ppm. In the case of known or suspected ammonia (NH_3) leakage, proceed as follows:

- Stay upwind, Sniff, don't breathe deeply when approaching the area.
- Always use a gas mask or similar equipment when approaching the area.
- Extinguish all cigarettes, open flames and spark/ignition around ammonia unit.
- Use placards for notice.

The most likely locations for ammonia leakage are around the ammonia storage area, ammonia flow control station, and ammonia supply piping.

First Aid

NOTE: CONSULT A PHYSICIAN OR EMERGENCY SERVICES IN ALL CASES OF AMMONIA EXPOSURE.

Large volumes of fresh water constitute the basic first aid treatment for ammonia burns. Flush at least 15 minutes.

SKIN CONTACT

Immediately flood with water. Remove affected clothing. Re-flood and leave affected skin open to air.

EYE CONTACT

Immediately flood eye with abundance of fresh water for at least 15 minutes and repeat it.

MOUTH AND THROAT CONTACT

Rinse, gargle and drink large quantities of water or lemonade.

VAPOR CONTACT WITH LUNGS

Move to fresh air. Avoid violent and unskilled artificial respiration.

INTERNAL CONTACT

Neutralize ammonia with abundance of diluted vinegar, lemon juice or apple juice. Follow with raw eggs, cream or olive oil to protect tissues.

ATTACHMENT D

// 2020 - NEC - CON - PSD AQUEOUS AMMONIA 20026168-MSD-AQA-001.A.IFOR.A.01

PLANT SYSTEM DESCRIPTION
SECTION 24 (MSD-24)
AQUEOUS AMMONIA

INDECK NILES ENERGY CENTER
NILES, MICHIGAN

KIEWIT PROJECT NO. 20026168

ISSUED: NOVEMBER 13, 2020

REVISION A – ISSUED FOR REVIEW

Corporate Office: 8950 Renner Boulevard
Lenexa • Kansas 66219 • USA
PHN 913-928-7000

SECTION 24: AQUEOUS AMMONIA SYSTEM

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23. AQUEOUS AMMONIA SYSTEM

23.1 INTRODUCTION

The purpose of this section is to provide a general understanding of the Aqueous Ammonia System (AQA) operation by tracing flow paths, identifying and describing major components, and locating and describing the system instrumentation controls.

23.2 SYSTEM PURPOSE

The Aqueous Ammonia System provides 19.5% by weight ammonia to the Unit 1A/B Ammonia Flow Control Skids (1A/1B-AQA-SKD-01) for use in the Selective Catalytic Reduction (SCR) System. The SCR system is designed to reduce nitrogen oxides (NOx) in the combustion turbine exhaust gas and duct burner. Ammonia (NH3) is sprayed onto the catalyst and reacts with NOx in the gas stream producing nitrogen and water, thereby eliminating harmful emissions.

Loss of ammonia flow during combustion turbine operation is undesirable and will cause the NOx discharge to the atmosphere to exceed permit limits. As this is an environmental system, it is critical to maintain a high level of availability to maintain emissions compliance.

23.3 SYSTEM OVERVIEW

23.3.1 Primary System Flowpath

The 19.5% aqueous ammonia is delivered by truck, and unloaded via the Aqueous Ammonia Truck Unloading Station. The aqueous ammonia truck unloading station transfers aqueous ammonia from the tanker truck to the Aqueous Ammonia Storage Tank (1Z-AQA-TNK-01), which returns the vapor back to the truck during fill in order to maintain the correct pressure inside of the truck's tank. The ammonia storage tank level can be monitored using the local level gauge (1Z-LG-AQA100) and/or remotely using the level indicating transmitter (1Z-LIT-AQA100). During the tank filling process, the Aqueous Ammonia Storage Tank and Forwarding Pump Containment Sump (1Z-AQA-SMP-01) captures and contains any ammonia spills that may occur. An aqueous ammonia leak detection and high vapor level station is included at the unloading station in order to alert the operators of any hazardous conditions.

The Aqueous Ammonia Forwarding Pumps (1Z-AQA-PMP-01A/B), located on the Aqueous Ammonia Forwarding Pumps Skid (1Z-AQA-SKD-01), take suction from the Aqueous Ammonia Storage Tank and discharge via a common underground header to each Unit 1A/B Ammonia Flow Control Skid (1A/B-AQA-SKD-01). Using exhaust gas upstream of the CO/VOC catalyst, the ammonia flow control skid vaporizes and dilutes the aqueous ammonia. Injection into the exhaust gas stream of the combustion turbine is via an injection grid upstream of the SCR catalyst.

23.3.2 System Interfaces

The Aqueous Ammonia System also interfaces with the following:

a. HRSG System - Aqueous ammonia is provided to the two HRSG Unit 1A/B Ammonia Flow Control Skids for delivery to the Heat Recovery Steam Generator (HRSG) SCR system.
b. Instrument Air System (INA) – Instrument air provides motive energy for the control valves provided in the Aqueous Ammonia System.

23.4 MAJOR COMPONENTS AND SUBSYSTEMS

23.4.1 Aqueous Ammonia Storage Tank

The Aqueous Ammonia Storage Tank (1Z-AQA-TNK-01) receives and stores the aqueous ammonia. The tank instrumentation monitors the level (1Z-LIT-AQA100) and pressure (1Z-PIT-AQA101) within the tank and transmits this information to the DCS. A PSV (1Z-PSV-AQA103) is included on the tank for over-pressure protection. A vacuum breaker (1Z-VBK-AQA100) is also included on the tank if needed to bring the tank to atmospheric conditions. The Aqueous Ammonia Storage Tank is located outdoors.

a. Aqueous Ammonia Storage Tank

Equipment Designation:	1Z-AQA-TNK-01
Manufacturer:	Dixie Southern
Type:	Horizontal / Cylindrical
Shell Material:	Carbon Steel
Design Pressure:	50 psig
Design Temperature:	115°F
Capacity:	30,000 gpm
Dimensions:	10’-0” Dia x 63’-3” Long

23.4.2 Aqueous Ammonia Forwarding Pumps Skid

The Aqueous Ammonia Forwarding Pumps Skid (1Z-AQA-SKD-01) contains two by 100% capacity positive displacement Aqueous Ammonia Forwarding Pumps (1Z-AQA-PMP-01A/B) that transfer the aqueous ammonia from the aqueous ammonia storage tank to the ammonia injection skids. The motor is being provided with VFD.

a. Aqueous Ammonia Forwarding Pumps

Equipment Designations:	1Z-AQA-PMP-01A 1Z-AQA-PMP-01B
Manufacturer:	PULSAFEEDER
Type:	Positive Displacement
Capacity:	2.2 - 6.9 gpm
Head (pressure):	100 psig

b. Aqueous Ammonia Forwarding Pump Motors

Equipment Designations:	1Z-AQA-MPM-01A 1Z-AQA-MPM-01B
Manufacturer:	Teco Westinghouse
Type:	TBD
Speed:	1800 rpm
Size:	2 hp
Electrical Requirements:	480 VAC, 3 phase, 60 Hz

23.4.3 Unit 1A/B Aqueous Ammonia Flow Control Skid

The skid consists of Ammonia Dilution Fans (1A/1B-FLG-FAN-01A/B), Vaporizer Heater (1A/1B-FLG-HTR-01), Vaporizers (1A/1B-FLG-VPR-01), piping and valves to deliver diluted ammonia to the balancing valves located at the HRSG, downstream of the CO/VOC catalyst.

a. Vaporizer Heater

Equipment Designations:	1A-FLG-HTR-01 1B-FLG-HTR-01
Manufacturer:	Thermon
Type:	Duct Heater
Capacity:	300 kW

b. Ammonia Dilution Fan

Equipment Designations:	1A-FLG-FAN-01A/B 1B-FLG-FAN-01A/B
Manufacturer:	Air Pro
Type:	Centrifugal
Capacity:	8,000 ACFM
Static Pressure Rise:	32” WC

c. Vaporizers

Equipment Designations:	1A-FLG-VPR-01 1B-FLG-VPR-01
Manufacturer:	Lantec
Type:	LMTP 70

23.5 NORMAL PROCESS OPERATING RANGES AND SETPOINTS

Refer to Control Narrative in Appendix B.

23.6 REFERENCES

23.6.1 Manuals and Documents

a. Water Treatment System 94.03.72 Comprehensive Equipment Manual (LATER)
b. GE HRSG 94.03.32.100 Comprehensive Equipment Manual (LATER)
c. Piping Specialties 94.03.56.100 Comprehensive Equipment Manual (LATER)
d. Shop Fabricated Tanks 94.03.66.125.01 Comprehensive Equipment Manual (LATER)
e. Pressure Safety Valves 94.03.68.175 Comprehensive Equipment Manual (LATER)

23.6.2 Piping and Instrumentation Diagrams (P&IDs)

Refer to P&IDs in Appendix A.

a. Aqueous Ammonia System
Drawing No. 20026168-PD-780
Drawing No. 20026168-PD-781

23.6.3 Control Narrative - Refer to Appendix B.
23.6.4 DCS Graphics - Refer to Appendix C.
23.6.5 Instrument Index/List - Refer to Appendix D.
23.6.6 Line List - Refer to Appendix E.
23.6.7 Piping Specialties List - Refer to Appendix F.
23.6.8 Valve List - Refer to Appendix G.
23.6.9 Equipment List - Refer to Appendix H.

23.7 PRE-OPERATIONAL CHECKS

23.7.1 Precautions and Limitations

The following precautions and limitations apply specifically to the Aqueous Ammonia System. In addition to the items listed below, it is expected that the Operator exercises common sense, safety considerations, and industry acceptable techniques when operating plant equipment.

a. All rotating equipment guards and safety devices should be installed.
b. All electrical and mechanical LOTO (lock out tag out) tags are released and the equipment is in a safe condition to operate.
c. All bearings are properly lubricated and bearing oil levels are normal.
d. All essential instrumentation is properly calibrated and instrument readings in the control room correspond to local instruments. All essential instrumentation should be available and ready for service.
e. Review and comply with all requirements stated in the equipment Operation and Maintenance Manuals prior to operation of the equipment.

23.7.2 Pre-requisites

a. The Operator shall verify all system alarms are cleared and no alarms are out of the scan. Verify the system valve lineup is in accordance with details below.
b. The Aqueous Ammonia Storage Tank shall be above the ‘Low’ level prior to starting the Aqueous Ammonia Forwarding Pumps.

c. Verify that the Instrument Air System is operational and air is available.

23.7.3 Valve Line-ups (Manual Valves)

NOTE:

a. All instrumentation root valves are OPEN unless otherwise stated.
b. All vent, drain, and blowdown valves are CLOSED unless otherwise stated.
c. Valves, indicated as such on the PID, shall be locked in the OPEN or CLOSED position.
d. All air supply isolation valves to control valves, control panels, and equipment skids are OPEN unless otherwise stated.
e. All furnished valves are in AUTO, OPEN, or CLOSED as determined by the supplier.
f. Non-operational valves such as check valves or pressure regulators are not listed in the lineup, but shall be in proper working order.

Operator is to verify the following valves are OPEN:

Valve Tag	Description
1A-VAQA100	UNIT A ACFU SKID INLET ISOLATION VALVE
1B-VAQA200	UNIT B ACFU SKID INLET ISOLATION VALVE
1Z-VAQA115	AMMONIA FORWARDING PUMPS SUCTION ISOLATION

Operator is to verify the following valves are CLOSED:

Valve Tag	Description
1Z-VAQA101	AMMONIA TANK FILL LINE ISOLATION
1Z-VAQA103	AMMONIA TANK FILL LINE ISOLATION
1Z-VAQA105	AMMONIA TANK VAPOR LINE ISOLATION
1Z-VAQA107	AMMONIA TANK VAPOR LINE ISOLATION
1Z-VAQA109	AMMONIA TANK DRAIN

23.8 OPERATING THEORY

The below information is provided as a resource for the generic startup, operation and shutdown of the Aqueous Ammonia System and is not intended to be a detailed operating procedure. The below procedure assumes the system is adequately commissioned and ready for operation.

For complete system operation, maintenance, and operating requirements, refer to the GE provided Operation and Maintenance Manuals in addition to the GE provided Facility Training Material.

23.8.1 Startup

a. Verify that the system prerequisites are met as outlined in Section 24.7.2.
b. Follow the pump starting procedures outlined in the Water Treatment System Comprehensive Equipment Manual (LATER).

c. Place the AQA system in AUTO or HAND operating mode. If HAND operating mode is selected, the Operator is required to initiate the steps of controls provided by the PLC.
d. Verify all pumps and systems are in a stable condition.

23.8.2 Normal Operation

a. One Aqueous Ammonia Forwarding Pump is running and the other pump is in Auto standby.
b. The Aqueous Ammonia Storage Tank level and pressure should be in a non-alarm state. Equipment operating parameters, should be monitored to ensure the parameters remain within the normal operating range.

23.8.3 Normal Shutdown

a. Verify aqueous ammonia is no longer needed by the HRSG or the cycle chemical feed system.
b. Follow the shutdown procedure of the pump outlined in the Water Treatment System Comprehensive Equipment Manual (LATER).
c. Place the DCS Manual/Auto for aqueous ammonia forwarding pump to Manual-Off.
d. Verify that the system equipment has shutdown correctly, and that the operating equipment has de-energized.

23.8.4 Abnormal Operating Modes

a. Two Pumps Running – Spare/standby pumps can be initiated manually from the PLC while in HAND mode. Note that this mode of operating is abnormal and signals that the interfacing system or piece of equipment is not operating properly. Operating in this mode is not recommended for long durations.
b. Pump Trip – If the primary pump trips, the standby pump will auto start and become the primary pump. The cause of the trip shall be investigated and corrected as soon as possible.
c. Leak Detection Alarm – A horn and strobe located at the unloading area alert personnel in the area and the control room via the DCS of ammonia leaks.

COMPLIANCE ASSURANCE MONITORING PLAN

Indeck Niles Energy Park

For Two (2) Natural Gas-Fired Combustion Turbines

2200 Progressive Drive
Niles, Michigan

NTH Project No. 74-210317-03
November 22, 2022

NTH Consultants, Ltd.
3300 Eagle Run Dr NE, Suite 202
Grand Rapids, MI 49525

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1.0 INTRODUCTION

Indeck Niles, LLC (Indeck) operates a natural gas-fired combined-cycle (NGCC) power plant at the Indeck Niles Energy Center located at 2200 Progressive Drive in Niles, Cass County, Michigan. The NGCC plant consists of two (2) combustion turbine generators (CTGs) equipped with heat recovery steam generators (HRSGs) for generation of electricity and various ancillary equipment including an auxiliary boiler, fuel gas dew-point heaters, and an emergency diesel-fired generator.

The CTG/HRSG trains, rated at 3,651 Million British thermal units per hour (MMBtu/hr) each, are equipped with dry low NO_x burners (DLNB), selective catalytic reduction (SCR), and oxidation catalysts. Aqueous ammonia is used in the SCR system to reduce nitrogen oxides (NO_x) in the combustion turbine exhaust gas and duct burner. The CTG/HRSG utilize oxidation catalysts to reduce carbon monoxide (CO) and volatile organic compound (VOC) emissions.

Indeck is required to implement and maintain a Compliance Assurance Monitoring (CAM) Plan in accordance with 40 CFR Part 64. 40 CFR Part 64 specifies that a CAM Plan be implemented for emission units meeting applicability criteria under 40 CFR §64.2(a). The CTG/HRSG trains meet CAM criteria for emissions of volatile organic compounds (VOCs) and are controlled by oxidation catalysts; therefore, CAM requirements apply for the VOC limit of 4 ppmvd at 15% O_2 listed as special condition (SC) I.13 under flexible group “FGCTGHRSG” in the air permit.

CAM does not apply for NO_x and CO as the CTG/HRSG are already subject to continuous monitoring of emissions through other regulatory requirements and are exempt from CAM since continuous compliance measures would already be in place.

This document and its referenced manuals constitute Indeck’s CAM Plan for the CTG/HRSG trains. The referenced manuals are maintained on-site and electronically at the Indeck Niles Energy Center.

1.1 CAM Applicability

CAM is used to determine that a control technology is properly maintained and that it continues to achieve the level necessary to meet associated emission limits or standards. CAM establishes specific monitoring parameters that are indicative of unit performance. Units that are already subject to continuous monitoring of emissions through other regulatory requirements are exempt from CAM since continuous compliance measures would already be in place.

Pursuant to 40 CFR §64.2(a), Compliance Assurance Monitoring (CAM) applies to pollutant-specific emission units at major sources required to obtain a Title V (i.e., ROP) permit, if the emission unit and associated limit meet the following criteria:

1. Subject to an emission limitation or standard that is not exempt pursuant to 40 CFR §64.2(a);
2. Uses a control device to achieve compliance with such emission limitation or standard; and
3. Has potential pre-control emissions of the applicable regulated air pollutant that exceed or are equivalent to the major source threshold.

CAM applies to the VOC emission limit of 4 ppmvd at 15% O_2 at each CTG/HRSG train as listed in FGCTGHRSG SC I.13 of the air permit and is not exempt under 40 CFR §64.2(b)(1). Each CTG/HRSG train is equipped with an oxidation catalyst to control emissions of VOCs, and pre-control emissions of VOCs exceeds 100 tons per year. The CAM Plan provides parameters indicative of oxidation catalyst performance at routine frequency for reasonable assurance of compliance with the VOC limit. The CTG/HRSG trains are equipped with CEMS for monitoring NO_x and CO emissions, therefore, CAM does not apply for NO_x and CO pursuant 40 CFR §64.2(b)(1)(vi).

2.0 COMPLIANCE ASSURANCE MONITORING PLAN

The following sections outline monitoring parameters used to maintain the VOC emission limit and CAM monitoring requirements for the oxidation catalyst control system on each CTG/HRSG.

2.1 Control Technology

The oxidation catalysts contain precious metals (such as platinum, palladium, or rhodium) to treat exhaust gas from the CTG/HRSGs for control of VOC emissions, as well as CO emissions. The precious metal(s) catalyze the oxidation reaction of hydrocarbons (VOCs) and CO with available oxygen to convert the compounds to carbon dioxide and water vapor. With the use of the oxidation catalyst, each CTG/HRSG train can achieve an emission rate of 4 ppmvd VOC at 15% O_2 (FGCTGHRSG SC I.13).

2.2 Monitoring Approach and Performance Criteria

Emissions of VOCs and CO are formed as result of incomplete combustion; increased emissions of CO typically occur in conjunction with increased emissions of VOCs. Catalytic oxidation is used at FGCTGHRSG to reduce the emissions of CO and VOC resulting from the incomplete combustion of natural gas at the turbines. The emissions of CO, as measured by the CEMS, will be monitored to provide reasonable assurance of compliance with the VOC emission limit, as described below and in Table 2-1.

Table 2-1: Oxidation Catalyst Monitoring and Performance Criteria

Parameter	CAM Criteria
Indicator	CO emissions monitored continuously at the CTH/HRSG train
Indicator Range	An excursion is defined as a 24-hour average, excluding startup and shutdown, where CO emissions exceed 4 ppmvd at 15% O_2. Excursions trigger an inspection, corrective action, and the cause must be investigated.
Data Representativeness	The oxidation catalyst is necessary to achieve reduction of CO and VOC emissions resulting from incomplete combustion. CO emissions data are indicative of oxidation catalyst performance.
QA/QC Practices and Criteria	The CO CEMS will be maintained according to the requirements of Appendix A of the air permit.
Monitoring Frequency	Continuously, excluding startup and shutdown
Data Collection	CO concentration is obtained as an hourly average, reported to the data acquisition and handling system

Upon detecting an excursion or exceedance as outlined by performance indicators in Table 2-1, Indeck will investigate the cause and initiate corrective action to the oxidation catalyst, if needed, as expeditiously as practicable and in accordance with good air pollution control practices for minimizing emissions.

2.3 Justification of Monitoring Approach and Performance Criteria

The emissions of VOCs and CO are formed as a result of incomplete combustion; increased emissions of CO typically occur in conjunction with increased emissions of VOCs. Incomplete combustion of the carbon-containing compounds within natural gas produce hydrocarbons (such as VOCs) and CO, contained in the exhaust gas. Oxidation catalysts contain precious metals to catalyze the oxidation reaction of carbon-containing compounds within the exhaust gas with available oxygen, producing water vapor and carbon dioxide.

The CO emissions (after the oxidation catalyst) are continuously monitored using CEMS. Pursuant to 40 CFR §64.3(a)(1), direct or predicted emissions may be used as indicators of performance for emission controls. Emissions of CO will be used as an indicator of oxidation catalyst performance for reasonable assurance of compliance with the VOC limit (4 ppmvd @ 15% O_2 pursuant to the air permit).

3.0 RECORDKEEPING AND REPORTING REQUIREMENTS

Pursuant to 40 CFR §64.9, Indeck maintains records of monitoring data, monitor performance data, corrective actions taken when parameters are out of range, and other supporting information required to provide reasonable assurance of compliance with the VOC emission limit (such as data used to document the adequacy of monitoring, or records of monitoring, maintenance, or corrective actions).

Pursuant to 40 CFR §64.9(a), Indeck will submit semiannual CAM reports of monitoring and deviations. Each CAM report will include summary information on the number, duration, and cause of excursions or exceedances, as applicable, and the corrective action(s) taken. The report will summarize the number, duration, and cause for monitor downtime incidents. When there are no excursions, exceedances, or downtime events in the reporting period, the CAM report will include a statement that no excursions, exceedances, or downtime events occurred.

4.0 PLAN REVISION HISTORY

A current copy of the CAM plan will be maintained electronically and onsite at Indeck Niles Energy Center. Previous versions will be kept on file and available for at least five (5) years from the date of revision. Table 4-1 contains a list of revisions of this document.

Table 4-1. Plan Revision History

Revision No.	Date	Revised By	Comments
Original	11/21/2022	N/A	Initial Draft

APPENDIX D

// ACID RAIN PERMIT APPLICATION

INDECK®

November 7, 2019

Mr. Rex Lane
State of Michigan Department of Environment, Great Lakes and Energy
Air Quality Division
Kalamazoo District Office
7953 Adobe Road
Kalamazoo, MI 49009

Dear Mr. Lane:

Please find attached the Acid Rain Permit Application for the Indeck Niles Energy Center. This proposed power facility is to be located in the City of Niles, Michigan, Cass County, Michigan. The facility will utilize two gas turbines in combined cycle to produce approximately 1000 megawatts. Concurrent with this submittal, Indeck Niles is also providing a copy of this submittal to Mr. Brian Carley at EGLE AQD Jackson District.

I trust these submissions satisfy our requirements at this time. If you have any questions or comments, feel free to contact us.

Sincerely,

INDECK NILES, LLC

Mike DuBois
Vice President

cc: J. Schneider
K. Inns

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 12/31/2021

EPA

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: [X] new [ ] revised [ ] for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Indeck Niles Energy Center	MI	55460

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
EUCTHRSG1	Yes
EUCTHRSG2	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Indeck Niles Energy Center
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
- (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
- (ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:
- (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
- (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
- (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
- (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
- (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
- (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Indeck Niles Energy Center
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
   (i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
   (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
   (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
   (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Indeck Niles Energy Center
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Certification

Read the certification statement, sign, and date.

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Michael J DuBois	
Signature MICHAEL J. DUBOIS	Date 11/6/19