Grays Harbor Energy Center Fact Sheet

Grays Harbor Energy, LLC

No. EFSEC/2001-01, Amendment 5

1. Background

A. Facility Description

Grays Harbor Energy, LLC (GHE) owns and operates an electricity generation facility located at 401 Keys Road in Elma, Grays Harbor County, Washington. The facility is referred to as the Grays Harbor Energy Center (GHEC). GHEC is currently capable of generating up to 650 megawatts(MW) of electricity from a combined-cycle power plant comprised of two combustion turbines, each equipped with a duct burner and heat recovery steam generator and a single steam turbine and bank of cooling towers shared in common. GHEC also operates an auxiliary boiler, a diesel emergency generator, and an emergency fire water pump.

B. Project Description

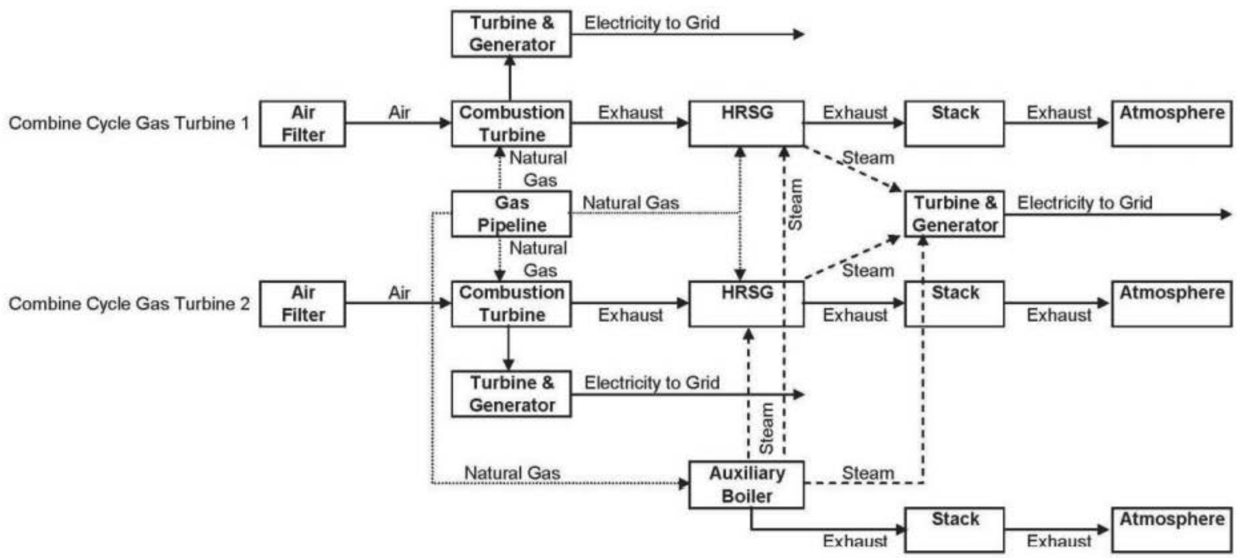
The Energy Facility Site Evaluation Council (EFSEC) has the authority to issue both Prevention of Significant Deterioration (PSD) and minor air permits. On August 18, 2020, EFSEC received an application to install General Electric (GE) combustion turbine (CGT) upgrades, which include the Advanced Gas Path (AGP) upgrade. This is an upgrade package for components of the CGT that will allow for more efficient combustion of natural gas within the turbines and increased turbine capacity. Since the modification only involves the CGT units (CGT01 & CGT02), this application does not include discussion of the other emission units at the site.

The AGP package is an upgrade over the standard equipment in the Frame 7FA.03 turbine. According to GE's technical documents, the 7FA AGP program utilizes 7FA.04 Hot Gas Path (HGP) technology, incorporating cooling and sealing enhancements and advanced materials to allow efficient operation at increased firing temperatures.

Together with the low D/P DLN 2.6 combustor and model-based controls architecture, the AGP upgrade delivers improved output and heat rate while maintaining base load emissions levels. AGP includes a complete set of 7FA.04 design HGP components, to include first, second, and third stage nozzles, buckets, and shrouds. A new support ring for the first stage nozzle (S1N) is also included. Technological enhancements included in the AGP upgrade revolve around application of advanced materials used in Aviation engines as well as optimization of secondary cooling and sealing flows. Additionally, 3D aerodynamic design methodology has been applied to the first stage nozzle and bucket to further enhance efficiency. Finally, design enhancements have been incorporated to address known FA HGP distress modes.

The Low Pressure Drop (dP/P) Combustor provides increased power output and decreased heat rate by reducing the overall pressure drop across the combustor through the use of newly designed combustion liners and flow sleeves. By reducing the overall combustion system pressure drop, the advanced liners and flow sleeves effectively improve combustion efficiency. The new design incorporates axial flow sleeve air injection for improved dynamic pressure recovery and new liner physical features for more uniform and low-loss heat transfer. The newly designed aerodynamic flow sleeve design enhances cooling efficiency across the liner and increases combustor inlet air pressure recovery. Hence, pressure losses through each combustor chamber are reduced.

The process flow diagram of the CGT/HRSG provided in the application is shown below.



GHE is not requesting any change in emission limits because the minor increase in heat input to the two turbines can be accommodated within the current criteria pollutant emission limits. The original emissions concentration and lb/hr emission limits were established based on turbine levels 1,671 MMBtu/hr at 59°F temperature conditions. The modification and low temperature operations will result in over 2,011 MMBtu/hr (14°F) to the combustion turbine. Therefore, short-term lb/hr limit emissions limit will control the operations. EFSEC does not expect the units to operate at 1,671 mmBtu/hr or lower in the future, therefore it is unlikely the concentration limits will be exceeded before the lb/hr limits.

C. Emission Units Capacity Discussion

The project will increase the nominal capacity of each individual CGT increases to 181.2 MW at 100 percent load and 59°F, from the currently capacity of 175 MW at 100 percent load and 59°F. There is no change in the rated capacity of the duct burner or the steam turbine. Based on GE performance data at 100 percent load and 59°F, the heat rate will improve (decrease) by approximately 2.3 percent. The applicant anticipates that the units will run more hours and have less start-up and shutdowns. Steam rate to the turbine will increase by approximately seven percent while the output in megawatt will increase by approximately one percent.

Table 1. Turbine Data

	CGT01		CGT02	
	mmBtu/hr	**MW**	**mmBtu/hr**	**MW**
Permitted (prior to upgrade) @ 59°F	1,671	175	1,671	175
Design	NA	175	NA	175
Historical maximum (unadjusted for temperature)	1,835	187	1,835	188
Post project @ 59°F	1,823	181.2	1,823	181.2
Post project/historical max	0.994	0.969	0.994	0.964

Table 2. GE Performance Design Data for each CGT+HRSG/ Duct Burner

	Pre Project	Post Project	
Max Heat Input Rate, mmBtu/hr @ HHV	At 59°F	At 59°F	At 14°F
Turbine	1735	1823	2,011
Duct Burner	505	505	505
Total	2240	2328	2,516
Max Output Rate, MW			
Combustion Turbine	175	181.2	206
Steam Turbine	300	300	300
Total	650	662.4	718
Lb CO_2/MW	820	822	822

Table 3. Heat Recovery Steam Generation Units (HSGUs) /Duct Burners Data

	Permitted	Design	Historical Maximum	Future	Change over Historical
#1 Duct Burner MMBtu/hr	505	494	504.9	---	---
#1 Steam rate, klb/hr	---	835	781	835	1.069
#2 Duct Burner MMBtu/hr	505	494	497.3	---	---
#2 Steam rate	---	835	790	835	1.057
Steam Turbine MW	300	300	296	300	1.014

Table 4. Electrical Generation Unit

	Permitted	Design	Historical Maximum	Future	Change over historical
mmBtu/hr	4352	NA	4695.4	4,656	0.992
MW	650	650	671	662.4	0.987

D. Permitting History:

On August 7, 2009, Grays Harbor Energy, LLC requested a fourth amendment to the approval. Amendment 4 established emissions limits during start-up and shutdown and rectifies issues with the approval identified in both the development of the Air Operating Permit for the facility and because of the first year of operation of the facility.

1. The total project consisted of the following major components which is consistent with the original permit and Amendments 1 through 3 unless noted:
    - Two General Electric combustion gas turbines (GE 7FA); each turbine having a maximum rating of 1,671 million British thermal units per hour (MMBtu/hr), and each turbine will have a supplementary duct burner with a maximum rating of 505 MMBtu/hr.
    - Two heat recovery steam generators (HRSG).
    - One steam turbine generator (STG) rated at 300 MW.
    - One auxiliary boiler rated at 29.3 MMBtu/hr.
    - One cooling tower system.
    - One emergency backup diesel generator (Manufactured in 2002, 400 KW).
    - One diesel engine-driven fire water pump (Manufactured on 10/25/2001, 300 BHP)
2. Below are from prior determinations.
3. BACT as required under WAC 173-400-113(2), and toxic best available control technology (T-BACT) as required under WAC 173-460-040(4), will be used for the control of all air pollutants which will be emitted by the proposed project. The following table lists the plant-wide allowable emissions and BACT based on Amendment 4 requirements.

Pollutant	Plant-Wide Potential to Emit, tpy	Best Available Control Technology			
		CGTs	**Auxiliary Boiler**	**Diesel-Fired Emergency Equipment**	**Cooling Tower**
NO_X	246.5	Selective Catalytic Reduction plus low NO_X burners (Turbine & HSRG)	Flue gas recirculation and low NO_X burners	Limited to emergency uses as defined by 40 CFR 63 Subpart ZZZZ	Not applicable
CO	146.1	Good combustion practice	Good combustion practice		Not applicable
SO_2	29.2*	Natural gas fuel		Use only on-road specification diesel oil	Not applicable
H_2SO_4	19.0	Natural gas fuel			Not applicable
VOCs	74.6	Natural gas fuel and good combustion practice		Limited to emergency uses as defined by 40 CFR 63 Subpart ZZZZ	Not applicable
PM and PM_{10}	203	Natural gas fuel and good combustion practice			Drift eliminator with less than 0.001% loss of the recirculating water
NH_3	141	5 ppm ammonia slip limitation	Not applicable		
∗ Based on an annual average natural gas total sulfur content of 0.5 grains/100 scf.					

4. Allowable emissions, from the emissions units, will not cause or contribute to air pollution in violation of:

   4.1. Any state or national ambient air quality standard.

   4.2. Any applicable PSD increment.

   The following table indicates the maximum Class I and Class II increment consumed by this project (Amendment 4 and earlier determinations):

Pollutant		Maximum Ambient Class II Area Impact Concentration (μg/m^3)	Class II Area Allowable Increment (μg/m^3)	Maximum Ambient Class I Area Impact Concentration (μg/m^3)	Class I Area Allowable Increment (μg/m^3)
PM_{10}*	24-hr	4.86	17	0.23	8
	Annual	0.91	30	0.01	4
Nitrogen dioxide (NO_2)*	Annual	0.898	25	0.008	2.5
SO_2	3-hr	13.54	20	0.26	25
	24-hr	3.5	91	0.032	5
	Annual	0.29	512	0.001	2
* Evaluated at a higher emission rate than proposed to be permitted. See attached Fact Sheet for the Nov. 2001 approval and application materials for details.					

5. Ambient Impact Analysis indicates that there will be no significant impacts resulting from pollutant deposition on soils and vegetation in either of the closest Class I areas, Olympic and Mt. Rainier National Parks. The permitted turbine project will have deposition levels significantly below the National Park Service's level of concern.

6. Ambient air quality analysis indicates that there will be no adverse impacts resulting from pollutant deposition in the Class II areas surrounding the project site.

7. Ambient Impact Analysis indicates that degradation of regional visibility or vistas from Olympic National Park due to the GHEC project is acceptable to the National Park Service based on an emission limitation of 2.0 ppm NO_X, 24-hr average on the CGTs (17.4 lb/hr, 24-hr rolling average).

8. No significant effect on industrial, commercial, or residential growth in the Elma area is anticipated due to the project.

9. As reflected in the Third Amendment Order, for the third amendment, EFSEC concluded that:

   9.1. The request for the third amendment was timely and complete (September 30, 2005).

   9.2. BACT:

      9.2.1. Based on comparable permit actions since 2002, EFSEC concluded that BACT for VOC emissions from the auxiliary boiler using good combustion practice was

0.0055 lb carbon/MMBtu (one-hour average). This determination is not changed in Amendment 5.

9.2.2. For all other anticipated pollutants from the gas combustion turbines, heat recovery steam generators, auxiliary boiler, and cooling tower system BACT was the same as determined in Amendment 2. This determination is not changed in Amendment 5.

2. Project Emission

The applicant indicated that all increases in emissions were below the significant emission rate therefore this was a minor modification of the PSD permit. Based on projected versus baseline emissions, the applicability shows that the project could trigger major modification for PM, PM_{10}, $PM_{2.5}$, and greenhouse gas (GHG). However, the applicant excludes the emissions that could have been accommodated during the baseline period and also unrelated to the upgrade under 40 CFR 52.21(4)(ii)(c) to demonstrate that all increases in emissions were below the significant emission rate therefore this was a minor modification of the PSD permit.

A. PSD Applicability (Major Modification)

Tpy	PM	PM_{10}	$PM_{2.5}$	NO_x	CO	SO_2	VOC	CO_2e
Baseline	55.53	55.53	55.53	91.05	11.84	5.17	3.04	1,292,285
Projected	83.76	83.76	83.76	128.08	16.41	7.69	5.85	1,885,289
Delta – projected	**28.23**	**28.23**	**28.23**	**37.03**	4.57	2.52	2.81	**593,004**
CA	93.60	93.60	93.6	130.68	19.80	13.92	4.92	2,177,478
Delta – CA	-9.84	-9.84	-9.84	-2.6	-3.39	-6.23	0.93	-292,189
SER	25	15	10	40	100	40	40	75,000
CA = Could have accommodated SER = Significant Emission Rate								

Baseline emission:

Table 5. Baseline Emission and Period

Pollutant	BAE (ton/yr)	Baseline Period
PM	55.53	5/18 -4/20
PM_{10}	55.53	5/18 -4/20
$PM_{2.5}$	55.53	5/18 - 4/20
NO_X	91.05	5/17 - 4/19
CO	11.84	5/16 - 4/18

Pollutant	BAE (ton/yr)	Baseline Period
SO_2	5.17	5/18 - 4/20
VOC	3.04	5/18 - 4/20
CO_2e	1,292,285	2/18 - 1/20

PM emission testing has been conducted 2009, 2014, and 2019. The main differences in the emission test were the length of the test, which were 240, 180, and 60 minutes, respectively. The overall emission rate per million BTU heat input were, 0.0053, 0.0024, and 0.0076, respectively. GHEC recalculated the PM emissions based on an average of the three years 0.0053 lb PM/MMBtu/hr for Unit 1.

Table 6. Baseline Emission Factors

	CGT1		CGT2	
	Baseline EF (lb/mmBtu)		Baseline EF (lb/mmBtu)	
Pollutant	Normal	SUSD	Normal	SUSD
PM	0.0053	0.0053	0.0049	0.0049
PM_{10}	0.0053	0.0053	0.0049	0.0049
$PM_{2.5}$	0.0053	0.0053	0.0049	0.0049
NO_X	0.0069	0.1272	0.0073	0.1229
CO	0.0007	0.0445	0.0004	0.0353
SO_2	0.0005	0.0004	0.0005	0.0004
VOC	0.0004	0.0004	0.0002	0.0002
CO_2e	118.98	118.98	118.98	118.98

Table 7. Start-up and Shutdown Baseline Heat Input

	CGT1	CGT2
	Baseline Heat Input (mmBtu)	Baseline Heat Input (mmBtu)
Pollutant	SUSD	SUSD
PM	266,691	189,748
PM_{10}	266,691	189,748
$PM_{2.5}$	266,691	189,748
NO_X	348,570	280,860
CO	334,303	258,388

	CGT1	CGT2
	Baseline Heat Input (mmBtu)	Baseline Heat Input (mmBtu)
Pollutant	SUSD	SUSD
SO_2	266,691	189,748
VOC	266,691	189,748
CO_2e	279,836	232,180

Table 8. Projected Emission Factors (lb/mmBtu)

	Normal	SUSD
PM	0.0053	0.0053
PM_{10}	0.0053	0.0053
$PM_{2.5}$	0.0053	0.0053
NO_X	0.0073	0.1272
CO	0.0007	0.0445
SO_2	0.0005	0.0004
VOC	0.0004	0.0004
CO_2e	118.98	118.98

Table 9. Scenario 2 – Projected Operations with AGP Upgrade

	Projected Heat Input (mmBtu/yr)		
Year	Total	Normal	SUSD
2022	30,530,288	30,305,888	224,400
2023	31,691,290	31,477,090	214,200
2024	31,691,290	31,477,090	214,200
2025	31,691,290	31,477,090	214,200
2026	31,691,290	31,477,090	214,200
2027	31,691,290	31,477,090	214,200
2028	31,691,290	31,477,090	214,200
2029	31,691,290	31,477,090	214,200

Based on the application, EFSEC has determined that this change will require changes to the permit to accommodate the new equipment but will not trigger major modification per the PSD regulations. Therefore this review will not update the best available control technology review or modeling for PSD. Because this action does not trigger major PSD permitting, GHG review is not required. The original permit was issued prior to the greenhouse gas regulations therefore no current (GHG) requirements. Therefore, this permit will not add any GHG requirements. The applicant has submitted regulatory review for GHG requirements, which will be reviewed in this document, but will be incorporated into the air operating permit. This change does trigger minor permitting under state law for air toxics.

B. Minor NSR Criteria Pollutant Emission Increase

While the fuel to the combustion turbine will increase, GHEC has requested that all the permit limits remain the same. Therefore, state minor source permitting is not triggered for criteria pollutant.

C. Toxic Air Pollutants (TAPs) Emission Increase

The TAPs emission increase per Table 22 of the application is shown below.

Pollutant	CAS	De minimis Standard		Emission Increase (CT1 + CT2)		Exempt From 173-460 Analysis?
		Threshold	Unit	lb/hr	lb/standard unit	
Acetaldehyde	75-07-0	3.00E+00	lb/year	1.22E-02	1.07E+02	NO
Acrolein	107-02-8	1.30E-03	lb/24-hr	1.95E-03	4.67E-02	NO
Ammonia	7664-41-7	1.90E+00	lb/24-hr	0.00E+00	0.00E+00	YES
Arsenic & Compounds NOS	7440-38-2	2.50E-03	lb/year	0.00E+00	0.00E+00	YES
Benz(a)anthracene	56-55-3	4.50E-02	lb/year	0.00E+00	0.00E+00	YES
Benzene	71-43-2	1.00E+00	lb/year	3.65E-03	3.20E+01	NO
Benzo(a)pyrene	50-32-8	8.20E-03	lb/year	0.00E+00	0.00E+00	YES
Benzo(b)fluoranthene	205-99-2	4.50E-02	lb/year	0.00E+00	0.00E+00	YES
Benzo(k)fluoranthene	207-08-9	4.50E-02	lb/year	0.00E+00	0.00E+00	YES
Beryllium & Compounds NOS	N/A	3.40E-03	lb/year	0.00E+00	0.00E+00	YES
1,3-Butadiene	106-99-0	2.70E-01	lb/year	1.31E-04	1.15E+00	NO
Cadmium & Compounds NOS	7440-43-9	1.90E-03	lb/year	0.00E+00	0.00E+00	YES
Chromium(VI) & Compounds NOS	7440-43-9	3.30E-05	lb/year	0.00E+00	0.00E+00	YES
Chrysene	218-01-9	4.50E-01	lb/year	0.00E+00	0.00E+00	YES
Cobalt & Compounds NOS	7440-48-4	3.70E-04	lb/24-hr	0.00E+00	0.00E+00	YES
Copper & Compounds NOS	7440-50-8	9.30E-03	lb/1-hr	0.00E+00	0.00E+00	YES
Dibenzo(a,h)anthracene	53-70-3	4.10E-03	lb/year	0.00E+00	0.00E+00	YES
7,12-Dimethylbenz(a)anthracene	57-97-6	6.90E-05	lb/year	0.00E+00	0.00E+00	YES
Ethylbenzene	100-41-4	3.20E+00	lb/year	9.73E-03	8.52E+01	NO
Formaldehyde	50-00-0	1.40E+00	lb/year	3.24E-02	2.84E+02	NO
Hexane	110-54-3	2.60E+00	lb/24-hr	0.00E+00	0.00E+00	YES
Indeno(1,2,3-cd)pyrene	193-39-5	4.50E-02	lb/year	0.00E+00	0.00E+00	YES
Lead & Compounds NOS	N/A	1.00E+01	lb/year	0.00E+00	0.00E+00	YES
Manganese & Compounds NOS	7439-96-5	1.10E-03	lb/24-hr	0.00E+00	0.00E+00	YES
Mercury	7439-97-6	1.10E-04	lb/24-hr	0.00E+00	0.00E+00	YES
3-Methylcholanthrene	56-49-5	7.80E-04	lb/year	0.00E+00	0.00E+00	YES
Naphthalene	91-20-3	2.40E-01	lb/year	3.95E-04	3.46E+00	NO
Nickel & Compounds NOS	7440-02-0	3.10E-02	lb/year	0.00E+00	0.00E+00	YES
Propylene Oxide	75-56-9	2.20E+00	lb/year	8.82E-03	7.72E+01	NO
Selenium & Compounds NOS	7782-49-2	7.40E-02	lb/24-hr	0.00E+00	0.00E+00	YES
Toluene	108-88-3	1.90E+01	lb/24-hr	3.95E-02	9.00E-01	YES
Vanadium	7440-62-2	3.70E-04	lb/24-hr	0.00E+00	0.00E+00	YES
Xylenes	1330-20-7	8.20E-01	lb/24-hr	1.95E-02	4.67E-01	YES

3. BACT Review

A. BACT for Criteria Pollutants

GHEC requested that all emission limits for the existing two turbines stay the same and this change is not a major modification. Therefore, this permit change does not trigger criteria pollutants BACT review.

B. BACT for Toxic Air Pollutants (tBACT)

The current PSD permit does not establish any TAP emissions limit pursuant to Chapter 173-460 WAC other than ammonia. Therefore, GHEC calculated hourly TAP increases by subtracting the current PTE from the new PTE after AGP upgrades are made. The same emissions factor was used for each TAP for both pre and post upgrade emissions. Therefore, the TAP increases accounted for are the increases due to the increase in the maximum design heat rate of the turbines. Hourly TAP increases were then adjusted for the proper TAP averaging period. For a 24-hour standard, the hourly increase was multiplied by 24. For an annual standard, the hourly increase was multiplied by 8,760. EFSEC estimated the change from maximum hourly rate to actual annual emissions to be a factor of six. If all calculations were adjusted, no additional review would be triggered.

EFSEC reviewed GHEC's TAP emissions calculations and concluded that adjustments to the calculations are needed to be consistent with Chapter 173-460 WAC. Specifically, for TAPs with annual average ASILs, current PTE for each TAP must be replaced with past actual annual emissions to calculate annual TAP increases. However, making this adjustment to the calculations does not change the outcome.

Also, EFSEC determined that a formaldehyde emission limit of 91 parts per billion (ppb) at 15-percent O_2 is required, except during turbine start-up to assure TAP emissions are controlled to levels reviewed and approved through this minor modification. This is the emission limit in National Emissions Standard for Hazardous Air Pollutants (NESHAP), Subpart YYYY for stationary combustion turbine.

This determination is based on the following reasons:

- GHE's combustion turbines belong to the same affected unit category covered by NESHAP, Subpart YYYY.
- In developing the emission limit, CAA requires NESHAP to reflect the maximum degree of reduction in emissions of Hazardous Air Pollutant (HAP) that is achievable.
- Formaldehyde is one of the major TAPs emitted from combustion turbine exhaust, can be considered a surrogate of how well TAPs are being controlled.

To demonstrate compliance with the formaldehyde emission limit, initial compliance testing will be required followed by compliance testing every two years thereafter. If GHE conducted test at the inlet of CO catalyst and showed that the unit is not relying on the control to meet the formaldehyde emission limit, then the subsequent testing frequency is every 5 years. The compliance testing is not require to fire the duct burner at representative maximum heat input rate. If GHEC chooses not to test at representative maximum heater input rate for the duct burners they will need to determine what the combine emissions from the turbine and duct burner for emission inventory purposes.

In addition to maintaining proper combustion in the turbines and duct burners, GHE's units rely on an oxidation catalyst for after combustion control of CO and TAPs emission. Oxidation catalyst performance degrades over time and must be monitored through testing to determine when it should be replaced or regenerated. Historical data from GHEC shows a 75 percent increase in CO emission rate in the last 10 years indicating the oxidation catalyst performance has significantly degraded over time. Catalyst degradation due to PM blinding (catalyst coated by PM) over time could explain the significant increase in CO emissions.

Annual formaldehyde emissions will be calculated based on the 0.25 lb/hr rate (prior to source test) when each turbine is operating with the carbon monoxide catalyst temperature is over 500F and uncontrolled 12 lb/hr rate when the turbine is operating with the carbon monoxide catalyst temperature is 500°F or less. This is based on VOC start-up emissions of 730 pounds per two hours and normal operation VOC emissions of 7.7 lb/hr compared to formaldehyde emissions of 0.25 lb/hr. This results in approximately 12 lb/hr of formaldehyde emissions during start-up. GHEC estimated future startup at 264 hour combined based on 210,800 mmBtu/yr fuel. The resulting emissions would be 1.6 tpy of formaldehyde emissions from startup. Historical combine startup have been 592,691 mmBtu/yr of fuel. The resulting emissions would be 4.5 tpy of formaldehyde emissions from startup.

4. Tier I Impact Review for Toxic Air Pollutant

The increase in TAP emissions due to additional natural gas consumption triggers review per Chapter 173-460 WAC. Based on TAP emissions increases and modeling results provided by GHEC in their application, TAP emissions increases pass a Tier 1 analysis as required per WAC 173-460-080. All TAP increases calculated by GHEC and provided in their application were based on 59°F operating temperature. The following table shows estimated worst-case ambient impacts of those TAPs requiring modeling lower than their respective acceptable source impact level (ASILs). EFSEC estimated the change from maximum hourly rate to actual annual emissions to be a factor of six. If all calculations were adjusted, no additional review would be triggered. This result demonstrates TAP emissions increases are sufficiently low to protect human health and safety and satisfies the ambient impact review requirements of the Air Toxics Rule.

Table 10. Toxic Air Pollutants – Dispersion Modeling Analysis

		ASIL ug/M3	ASIL ug/M3	(CGT1+CGT2)	(CGT1+CGT2)	
Pollutant	**CAS**	**Threshold**	**Avg. Time**	**ug/m3**	**Lb/hr**	**<ASIL**
Acetaldehyde	75-07-0	3.70E-01	Year	2.25E-04	1.22E-02	Yes
Acrolein	107-02-8	3.50E-01	24-hr	2.16E-04	1.95E-03	Yes
Benzene	71-43-2	1.30E-01	Year	6.76E-05	3.65E-03	Yes
Ethylbenzene	100-41-4	4.00E-01	Year	1.80E-04	9.73E-03	Yes
Formaldehyde	50-00-0	1.70E-01	Year	6.00E-04	3.24E-02	Yes
Propylene Oxide	75-56-9	2.70E-01	Year	1.63E-04	8.82E-03	Yes

5. NSPS, NESHAP, and WAC Rule Applicability

A. NSPS, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

Both CGT01and CGT02 are existing stationary combustion turbines. This subpart applies if the owner or operator commenced construction, modification, or reconstruction after February 18, 2005.

According to the applicant, this upgrade is not a "reconstruction" because the cost of the upgrade is below 50 percent of the fixed capital cost to construct a new turbine.

GHEC stated this does not apply based on NO_X emissions will decrease based on additional ammonia injection and sulfur dioxide emissions will not change based on one significant figure. EFSEC determine that there will be an increase in fuel used and therefore an increase in emissions of SO_2 from 0.836 lb/hr to 0.912 lb/hr. Modifications are defined as physical changes or changes in the method of operation of an emissions unit that results in an emissions increase. Therefore, EFSEC finds the AGP project triggers applicability of NSPS Subpart KKKK as a "modification." This finding is based on 40 CFR 60.4305 which states, "If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. **Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine**. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners."

Therefore, the requirements of Subpart KKKK will be added to the Title V permit conditions and superseded NSPS Subparts will be removed.

"Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc of this part." Therefore, GHEC's AOP will need to be revised to excise these standards and their associated monitoring requirements.

"For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NOX emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H)."

EFSEC concludes that the facility is subject to NSPS KKKK but is not including it in the requirements for the PSD permit. The current emission limits are more stringent than the standard. Therefore, the facility should document this during the start-up notification. EFSEC will incorporate this requirement into the Title V permit.

B. NSPS, Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

GHE estimates that the upgrade will increase the CO_2 emissions by approximately 9.1 percent. Based on 40 CFR 60.5509(b)(7), this project could avoid being subject to NSPS, Subpart TTTT if the modification resulted in an hourly increase in CO_2 emissions (lb/hr) of 10 percent or less (rounded to two significant figures). Based on data from the last five years, the maximum heat input recorded for CT1 was 1,835.4 mmBtu/hr, and for CT2 it was 1,857.8 mmBtu/hr.

To assure the 10 percent increase in CO_2 threshold is not crossed, EFSEC will monitoring to confirm that the project will not trigger NSPS Subpart TTTT.

C. NESHAP, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

This Subpart applies if the sites have the potential to emit any single HAP at a rate of 10 tons or more per year or any combination of HAP at a rate of 25 tons or more per year.

Based on emissions rates provided by GHEC in their application, HAP emissions from the HRSG stack at PTE are less than the thresholds distinguishing a major source of HAP emissions. However, there are some uncertainties with the accuracy of formaldehyde emission rate estimation. GHEC used an emission factor from AP-42 to estimate the formaldehyde and assumed that the oxidation catalyst provides additional 85 percent reduction. However, GHEC has not measured the control efficiency of the carbon monoxide catalyst in the past.

Without assuming the 85 percent reduction from the oxidation catalyst, EFSEC estimates that the formaldehyde is emitted at greater than 10 tpy. Mint Farms power plant has reported over 7.5 tpy of formaldehyde for one turbine similar to the GHEC two turbine plant in the past.

The CTs are equipped with selective catalytic reduction control and the CO oxidation catalysts. Neither of these catalyst systems has been replaced since the original operation. Based on 2009 and 2019 emission test, ammonia addition rate compared to natural gas combustion has increased by approximately 10 percent. During the same period, carbon monoxide hourly emissions have gone up 75 percent. Therefore, it is unlikely the carbon monoxide catalyst is controlling formaldehyde emissions by 85 percent. Also, using CO as a surrogate indicator for formaldehyde emissions, the 75 percent increase in CO emission rate in the last 10 years would indicate that oxidation catalyst performance has degraded significantly. Also, because the catalyst is not up to temperature during start-up, it is unlikely that the 85 percent reduction could be achieved during start-up even with a well performing catalyst until optimal catalyst operating temperatures are achieved.

Therefore, EFSEC will add the following limits and requirements to the permit to assure tBACT control of formaldehyde and other HAPs is maintained and GHEC remains a minor source of HAP emissions: Formaldehyde emissions limits at MACT YYYY levels, 91 ppb, every 2 years formaldehyde emission testing, and continuous monitor temperature prior to the catalyst to insure that the site is maintain the stated emission reductions.

D. WAC 463-80-030 – Greenhouse Gas Mitigation

The rule applies to new fossil-fueled thermal electric generation facilities with station generating capability of 350 MW or more after July 1, 2004. GHEC site is an existing facility per WAC 463-80-030.

The upgrade, which is a modification, could trigger mitigation of the increase of CO_2 emission when:

a. Increase by CO_2 emission by 15 percent or more.

The CO_2 emission will increase by 9.1 percent at 59°F and 100 percent load after the project. Therefore, the upgrade could avoid the mitigation as required by the rule.

However, the facility has a mitigation plan, which was required by EFSEC as a part of an amendment of the site certification agreement and EFSEC Resolution 298. In the 2003 Mitigation Plan, the facility capacity was 630 MW in 2001. Annual GHG emissions were estimated at 2,200,000 tpy. The plan required that 337,405 tons of greenhouse gases emissions be mitigated. A 2008 Mitigation Plan summary letter indicated that the facility capacity was 635 MW. Annual GHG emissions were estimated at 2,391,480 tpy and identified 514,103 tons of GHG emissions to be mitigated. GHEC requested the opportunity of a lump sum payment to represent seven years of yearly payment at a discounted rate.

GHEC's mitigation plan only addresses 635 MW of capacity while the permitted capacity is 650 MW. The project will increase megawatts capacity to 662.4 MW, even though the future expected megawatts generation from the combustion turbine is less than the historical maximum. Excess CO_2 emissions and the increased generating capacity of 662.4 MW resulting from this project will be incorporated in the mitigation calculations per the 2003 mitigation plan upon start-up.

E. WAC 463-85 – Greenhouse Gas Emissions Performance Standard and Sequestration Plans and Programs for Baseload Electric Generating Facilities

WAC 463-85-110 defines "upgrade" as any modification made for the primary purpose of increasing the electric generation capacity of a baseload electric generation facility or unit. However, an upgrade does not include "installation, replacement, or modification of equipment that improves the heat rate of the facility." GHEC believes that this exemption applies.

"Upgrade" means any modification made for the primary purpose of increasing the electric generation capacity of a baseload electric generation facility or unit. Upgrade does not include:

(a) Routine or necessary maintenance;

(b) Installation of emission control equipment;

(c) Installation, replacement, or modification of equipment that improves the heat rate of the facility; or

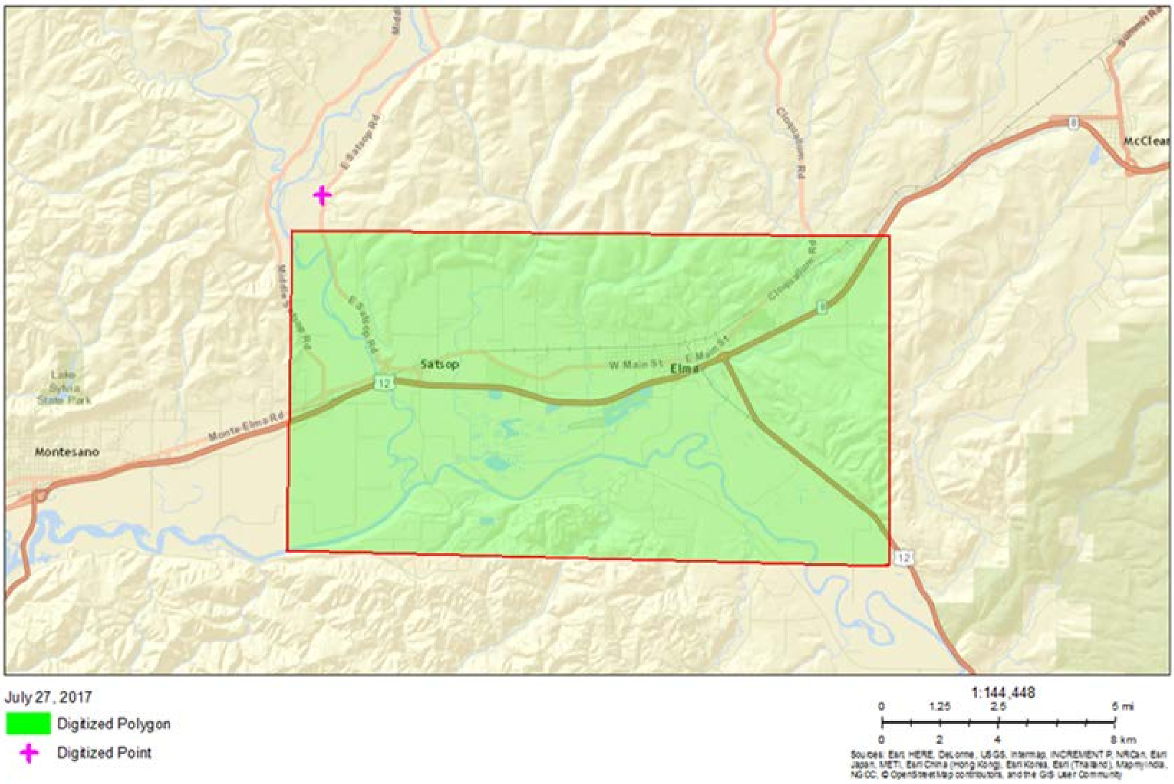
(d) Installation, replacement, or modification of equipment for the primary purpose of maintaining reliable generation output capability that does not increase the heat input or fuel usage as specified in existing generation air quality permits as of July 22, 2007, but may result in incidental increases in generation capacity.

Based on permitted (4,352 MMBtu/hr) to future (4,695.4 MMBtu/hr) heat input change (59°F) to the EGU there would be resultant an increase in fuel of seven percent below the trigger level.

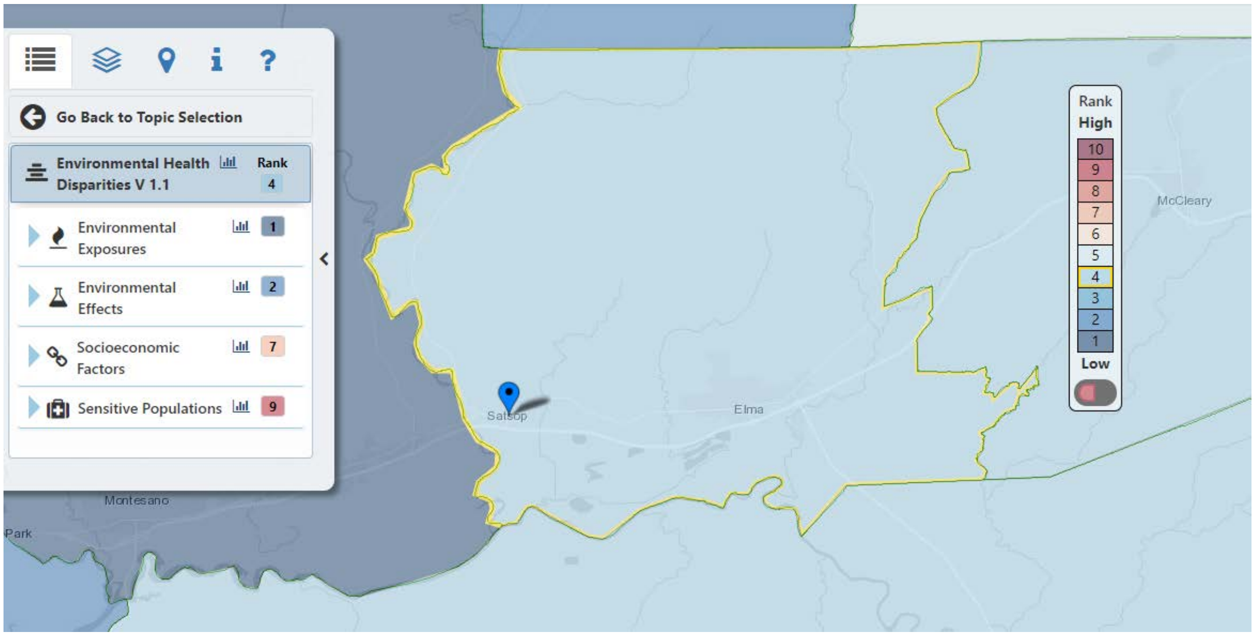
6. Environmental Justice

EPA defines Environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EFSEC conducts EJ review to ensure no group of people bears a disproportionate share of the negative environmental consequences as the result of the permitting action. Further, EFSEC strives to effectively and meaningfully engage the affected community in the permitting action, and to ensure compliance with Title VI obligations.

The initial step in this review is to identify any affected populations or communities of concern. EFSEC used EPA's environmental justice screening and mapping tool EJSCREEN. The area of the map shown below, which includes a total of 42 square miles (Elma/Satsop Area) was selected for the analysis.



The EJSCREEN American Community Survey (ACS) report estimates that approximately 12 percent of the population in the area consists of minorities, with approximately two percent of the total population speaking English “less than well.” A copy of the ACS report with more detailed information will be filed as part of the supporting documentation for the project. Both of these demographic indicators are below the initial 80th percentile in the state on the EJSCREEN Standard Report. The potentially affected population is the 79th percentile in the State for population with less than high school education. A review of the Washington Tracking Network Environmental Health Disparities Index indicates the population in the census tract, that approximately includes the study area, is in the 30th percentile overall in the state, the 90th percentile unemployment, and the 80th percentile for No High School Diploma.



1. The National Ambient Air Quality Standards (NAAQS) analysis indicates that the project is protective of the community as a whole and no other review is needed. Data indicate that the population speaking English less than very well is below the Title VI threshold of five percent or 1,000 people. EFSEC is not expecting any communication barrier to posting notice on the legal page of the predominant newspaper in the Elma area. If additional outreach materials are developed, EFSEC will ensure these are accessible, use plain language, and limit highly technical content. EFSEC also determines that an enhanced outreach effort is not needed due to the nature and scope of this project.

2. This permit amendment modifies a PSD permit originally issued before various newer NAAQS were established and appropriate Significate Impact Levels (SIL). This permit amendment does not increase PSD emissions, therefore, a new BACT and ambient analysis is not required. The NAAQS that apply are the NAAQS that were in effect on original permit date of November 2, 2001.

3. On June 29, 2017, EFSEC was given full delegation of the PSD program by EPA.

7. State Environmental Policy Act

Under Washington State rules, a final PSD permit shall not be issued for a project until the applicant has demonstrated that State Environmental Policy Act (SEPA) review has been completed for the project. Energy Facility Site Evaluation Council (EFSEC) is the lead agency for SEPA for this project. EFSEC issued a SEPA addendum on November 17, 2020, which addends the existing National Environmental Policy Act (NEPA) Environmental impact statement (EIS) for this project. Therefore, no additional action is required. EFSEC concludes that the applicant has adequately demonstrated compliance with SEPA requirements.

8. Changes to the Permit Conditions

1. Subject to NSPS KKKK: Dropped NSPS Da and GG requirements
2. All VOC lb/hr limits changed from as carbon (3*12) to a propane (44) resulting in an adjustment of 1.22. This is not a change in allowable emissions but will result in more accurate emission estimates.
3. Added clarification to the test requirements for a minimum of 3 hours per test run during the PM test unless otherwise approved in advance by EFSEC.
4. Added Formaldehyde limits consistent with WAC 173-460.
5. Added formaldehyde testing every 2 years, which uses the same test methods as the NESHAP YYYY. If GHE shows the unit is not relying on control to meet the limit, the minimum testing frequency is every 5 years.
6. Added clarification that maximum expected rate for the turbine would be in the winter months and requiring an initial emissions test during these months.
7. Added inlet temperature monitoring prior to the carbon monoxide catalyst to confirm adequate destruction.

9. Public Involvement

This PSD permitting action is subject to a minimum 30-day public comment period under WAC 173-400-740. A newspaper public notice announcing the public comment period was published in the Olympian on Thursday, December 17, 2020, and in the XXXX on December 17, 2020. In accordance with WAC 173-400-740(2)(a), application materials, and other related information were made available for public inspection at two locations:

EFSEC
621 Woodland Square Loop SE
P.O. Box 43172
Olympia, WA 98504-3172

The permit documents were posted on EFSEC's website:

https://www.efsec.wa.gov/energy-facilities/grays-harbor-energy-center

The public comment period closed on January 19, 2020.

Americans with Disabilities Act (ADA) – To request ADA accommodation or materials in a format for the visually impaired, call Joan Owens at (360) 664-1920 (Voice), or (TTD) (877) 210-5963.

10. Agency Contact

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Acronyms and Abbreviations

BACT	Best Available Control Technology
CFR	Code of Federal Regulations
CEMS	Continuous Emissions Monitoring System
CO	carbon monoxide
Ecology	Washington Department of Ecology
EFSEC	Energy Facility Site Evaluation Council
EPA	United States Environmental Protection Agency
FR	Federal Register
gal	gallon(s)
Gr/dscf	grains/dry standard cubic feet
H_2SO_4	sulfuric acid mist
km	kilometers
kW	kilowatt
lb	pound(s)
lb/hr	pound(s) per hour
NAAQS	National Ambient Air Quality Standard
NH_3	ammonia
NO_X	nitrogen oxides
NSR	New Source Review
O&M	Operations and Maintenance
PM	particulate matter
PM_{10}	particulate matter less than 10 micrometers in diameter
$PM_{2.5}$	particulate matter less than 2.5 micrometers in diameter
ppm	parts per million
ppmv	parts per million by volume

ppmvd	parts per million by volume on a dry basis
PSD	Prevention of Significant Deterioration of Air Quality
SCR	selective catalytic reduction
tpy	tons per year
WAC	Washington Administrative Code