ENERGY FACILITY SITE EVALUATION COUNCIL
P.O. BOX 47250
OLYMPIA, WASHINGTON 98504-7250

IN THE MATTER OF:	**]**	**NO. EFSEC/2001-01, AMENDMENT 4**
	]	
Grays Harbor Energy Center	**]**	**PROPOSED**
Grays Harbor Energy, LLC	**]**	**APPROVAL OF THE PREVENTION**
Electrical Generating Facility	**]**	**OF SIGNIFICANT DETERIORATION**
Elma, Washington	**]**	**(PSD) AND NOTICE OF CONSTRUCTION**

This amendment supersedes air quality PSD and NOC approval EFSEC 2001-01, Amendment 3 dated April 3, 2006. Pursuant to the Energy Facility Site Evaluation Council (EFSEC) Permit Regulations for Air Pollution Sources, Chapter 463-78 Washington Administrative Code (WAC), regulation for air permit applications WAC 463-60-536, the Washington Department of Ecology (Ecology) regulations for new source review WAC 173-400-110 and Chapter 173-460 WAC; and based upon the Notices of Construction Application (NOC), submitted by Duke Energy Grays Harbor, LLC., and Energy Northwest; the Administrative Order on Consent, Docket No. CAA-10-2001-0097, between the Satsop Combustion Turbine (Satsop CT) Project and the U.S. Environmental Protection Agency, Region 10, dated March 30, 2001; the request for second extension submitted by Grays Harbor Energy LLC, dated August 31, 2005; the request for modifications to Amendment 3 from Grays Harbor Energy LLC, dated August 7, 2009, amended Dec. 30 2010, and March 25, 2010, and the technical analysis performed by Ecology for EFSEC, EFSEC now finds the following:

FINDINGS

1. Duke Energy Grays Harbor, LLC, and Energy Northwest (jointly "Duke Energy") applied to construct the Satsop Combustion Turbine Project located near Elma, Washington. EFSEC previously approved the construction of this project (a.k.a. Satsop Phase I), which is designed to produce a maximum of 650 megawatt (MW) of electrical power. This project received final approval on November 2, 2001 (No. EFSEC/2001-01).

2. Amendment 1 was approved on January 2, 2003. Amendment 1 modified the operating requirements and emission limitations in the original approval, added equipment as part of the project, and removed certain operational restrictions.

3. Amendment 2 was approved on October 19, 2004. Amendment 2 authorized a delay in continuous construction to not later than January 20, 2006, and modified the monitoring requirements and BACT emission limitations based on recently available information. Amendment 2 did not change or add any emission units that were either proposed for installation or already installed at the facility. In approving Amendment 2, EFSEC concluded that:

3.1. The request for the second amendment was timely and complete (April 10, 2004).

3.2. Best Available Control Technologies (BACT) for all anticipated pollutants had not changed from the amendment 1 permit determination.

3.3. Interim source growth did not affect conclusions from the original permit analysis regarding air quality impact of this project.

4. On February 23, 2005, EFSEC approved transfer of ownership of the Satsop CT Project from Duke Energy and Energy Northwest to Grays Harbor Energy, LLC.

5. On August 31, 2005, Grays Harbor Energy, LLC requested a third amendment. Amendment 3 authorized a second delay in continuous construction to not later than July 20, 2007, and makes several administrative corrections to errors in Amendment 2. After January 20, 2006, the sum of all delays in continuous construction may not exceed 18 months.

6. 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 as a result of the first year of operation of the facility.

7. The total project is proposed to consist 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).

   Each gas turbine/duct burner/HRSG unit is defined as a combined cycle gas turbine (CGT). Each CGT has its own exhaust stack. These components are configured in a “power island” comprised of CGT 1 and CGT 2 and sharing one common steam turbine. Each CGT can operate independently with the steam turbine.

8. The project is subject to permitting requirements under WAC 173-400-700 as a fossil fuel fired steam electric generator, one of 28 listed industries that becomes a “major source,” when

emitting more than 100 tons per year (tpy) of any regulated pollutant. The Grays Harbor Energy Center CT Project has the potential to emit PSD significant quantities of nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), particulate matter (PM), particulate matter less than 10 micrometers (PM_{10}), and volatile organic compounds (VOCs).

9. The project is subject to permitting under the requirements of WAC 463-78-005(1) and 005(4) (adopting by reference Chapters 173-400 and 173-460 WAC, respectively) for ammonia (NH_3). Emissions of NO_x are reduced by the addition of NH_3. NH3 emission are limited in the permit to protect the NOx catalyst and minimize NH_3 emissions (air toxic and visibility regulations).

10. The combustion turbines, duct burners, and auxiliary boilers will only use natural gas. The fuel for the diesel engines powering the emergency generator and emergency fire water pump is to be on-road specification diesel fuel.

11. The site is within an area that is in attainment with all National Ambient Air Quality Standards (NAAQS) and state air quality standards. The site is approximately 60 kilometers from the nearest Class I area, Olympic National Park.

12. The project is subject to new source review requirements under Chapter 463-78 WAC, which adopts by reference Chapter 173-400 WAC and Chapter 173-460 WAC. The facility is also subject to emission limitation, monitoring and reporting requirements in 40 CFR 60 Subpart Da (applicable to the duct burners), Dc (applicable to the auxiliary boiler), and GG (applicable to the combustion turbines). Chapter 173-400 WAC, 40 CFR 60 Appendices A, B, and F, 40 CFR 75; and gas fuel monitoring requirements under 40 CFR Part 75 Appendix D are applicable to both the turbines and associated HRSGs.

13. 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 control technologies based on Amendment 4 requirements.

<table>
<tr><th rowspan="2">Pollutant</th><th rowspan="2">Plant-Wide Potential to Emit, tpy</th><th colspan="4">Best Available Control Technology</th></tr>
<tr><th>CGTs</th><th>Auxiliary Boiler</th><th>Diesel-Fired Emergency Equipment</th><th>Cooling Tower</th></tr>
<tr><td>NO_X</td><td>246.5</td><td>Selective Catalytic Reduction plus low NO_X burners (Turbine & HSRG)</td><td>Flue gas recirculation and low NO_X burners</td><td rowspan="2">Limited to emergency uses as defined by 40 CFR 63 Subpart ZZZZ</td><td>Not applicable</td></tr>
<tr><td>CO</td><td>146.1</td><td>Good combustion practice</td><td>Good combustion practice</td><td>Not applicable</td></tr>
<tr><td>SO_2</td><td>29.2*</td><td colspan="2">Natural gas fuel</td><td rowspan="2">Use only on-road specification diesel oil</td><td>Not applicable</td></tr>
<tr><td>H_2SO_4</td><td>19.0</td><td colspan="2">Natural gas fuel</td><td>Not applicable</td></tr>
</table>

Pollutant	Plant-Wide Potential to Emit, tpy	Best Available Control Technology			
		CGTs	Auxiliary Boiler	Diesel-Fired Emergency Equipment	Cooling Tower
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.					

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

14.1. Any state or national ambient air quality standard.

14.2. Any applicable PSD increment.

The following table indicates the maximum Class I and Class II increment consumed by this project:

Pollutant		Maximum Ambient Class II Area Impact Concentration (μg/m³)	Class II Area Allowable Increment (μg/m³)	Maximum Ambient Class I Area Impact Concentration (μg/m³)	Class I Area Allowable Increment (μg/m³)
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.					

14.3. Ammonia is the significant toxic air pollutant emitted by this facility. The emissions of ammonia and all other toxic air pollutants from this facility will not exceed an acceptable source impact level established under WAC 173-460-150 and 160 (effective Feb. 14, 1994.

15. 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.

16. 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.

17. Ambient Impact Analysis indicates that degradation of regional visibility or vistas from Olympic National Park due to the Grays Harbor Energy Center project is acceptable to the National Park Service based on an emission limitation of 2.0 ppm NOx, 24-hr average on the CGTs.

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

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

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

    19.2. BACT:

        19.2.1. 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/MMBtu (one-hour average). This determination is not changed in Amendment 4.

        19.2.2. 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 4.

    19.3. Interim source growth did not affect conclusions from the original permit analysis regarding air quality impact of this project.

20. For the fourth amendment, EFSEC concludes that:

    20.1. The request was deemed administratively complete on April 1, 2010.

20.2. No requested change results in an increase in an annual emission rate.

20.3. The sulfur monitoring is adjusted to match actual operating conditions and availability of fuel supplier information. The ability to determine compliance is not affected by the changes.

20.4. The allowable time for combustion turbine cold start-up is lengthened from four hours per turbine to 300 minutes per turbine in response to actual meteorological conditions at the Grays Harbor Energy Center site compared to the design meteorological conditions used by the prior owner/permittee, and in response to a review of the start-up procedures provided by the turbine manufacturer in its operation and maintenance manual. The climate for the site is colder than anticipated by the design conditions, so the turbines require a longer time to start up the gas and steam turbines compared to the design temperature. Both the actual start-up conditions and actual site design characteristics that affect start-up were unavailable during initial permitting.

20.5. For the CGTs, a Carbon monoxide BACT limit of 3.0 ppmdv @15% 0_2, on a 1-hour average was established in the original PSD permit based on the application of good combustion practice. The CO limit applicable to the CGTs was revised to 2.0 ppmdv @15% 0_2, on a 1-hour average to comply with EPA Region 10 Administrative Order on Consent, No.-CAA-10-2001-0097, dated March 2001.

20.6. EFSEC and Grays Harbor Energy agree that the CGTs are subject to emission limitation, monitoring and reporting requirements in 40 CFR 60 Subpart GG.

20.7. The requirement to comply with normal operation emissions limits during start-up and shutdown for NO_X CO and VOC is replaced with added start-up and shutdown emissions limits. Cold, warm, and hot start-ups and shutdown are defined.

20.8. For the emergency backup diesel generator and diesel engine-driven fire water pump, BACT constitutes the use of on-road diesel as 500 ppm sulfur defined in the Federal Code of Regulations (2007 to 2014) and limitation contained in 40 CFR 63, subpart ZZZZ.

21. EFSEC finds that all requirements for new source review (NSR) and PSD are satisfied and that as approved below, the emissions units comply with all applicable federal new source performance standards. Approval of the PSD and NOC application is granted subject to the following conditions:

APPROVAL CONDITIONS

1. This amendment supersedes air quality PSD approval EFSEC 2001-01, Amendment 3 dated April 3, 2006.

2. The CGTs (each consisting of a GE 7FA combustion turbine and its associated duct burner and HRSG) and auxiliary boiler are limited to the use of natural gas.

3. The diesel emergency generator shall:

   3.1. Use only on-road specification diesel oil with 500 ppm or less sulfur content.

   3.2. Not exceed 500 hours per any 12 consecutive months of operating time.

4. The emergency fire water pump engine shall use only on-road specification diesel oil with 500 ppm or less sulfur content.

5. Emissions from CGT1 or CGT2 exhaust stack shall not exceed the following, except during start-up and shutdown (CGT over-speed protection testing), when they must meet the requirements in Condition 11:

   5.1. Nitrogen oxide (NO_X) emissions:

      5.1.1. 21.7 pounds/hour (lb/hr), 1-hour (1-hr) average.

      5.1.2. 17.4 lb/hr, 24-hr rolling average.

      5.1.3. 2.5 parts per million by volume, dry (ppm), 1-hr average, corrected to 15% oxygen (O_2).

      5.1.4. 2.0 ppm, 24-hr rolling average, corrected to 15% O_2.

      5.1.5. Initial compliance with the limits in Conditions 5.1.1 and 5.1.3 shall be determined in accordance with 40 CFR Subpart GG and EPA Reference Method 20, except that the instrument span shall be set between zero and 25 ppm.

      5.1.6. Ongoing compliance with all limits in Condition 5.1 shall be indicated by continuous emission monitors for NO_X and O_2. The continuous emission monitoring system (CEMS) and flow measurement to determine lb/hr emissions shall meet the requirements of Approval Conditions 18.1 and 18.6.

   5.2. Carbon monoxide (CO) emissions:

      5.2.1. 2.0 ppm, corrected to 15% O_2, 1-hr average.

5.2.2. 10.6 lb/hr, 1-hr average.

5.2.3. EPA Reference Method 10 shall determine initial compliance for each CGT, or an equivalent method agreed to in advance by EFSEC. The span and linearity calibration gas concentrations in Method 10 are to be modified as appropriate to the CO concentration limits specified in this condition.

5.2.4. Ongoing compliance shall be indicated through use of a continuous emission monitor meeting the requirements of Approval and flow measurement to determine lb/hr emissions shall meet the requirements of Approval Conditions 18.3 and 18.6.

5.3. Sulfur dioxide emissions:

5.3.1. 19.8 lb/hr, 1-hr average.

5.3.2. 3.3 lb/hr, rolling annual-average of emissions determined monthly when the CGTs operate.

5.3.3. Compliance with the limit in Condition 5.3.1 shall be determined based on stack testing using EPA Reference Method 6c, or an equivalent method approved in advance by EFSEC.

5.3.4. Compliance shall be determined for each CGT through stack testing once per calendar quarter for the first year of commercial operation, and thereafter at 5-year intervals.

5.3.5. Ongoing compliance with both limits in Condition 5.3 shall be determined monthly by calculating the hourly average SO_2 emission rates from each CGT in pounds per hour for all hours of operation during the previous month, and the average emission rate in lb/hr over the previous 12-consecutive month period.

5.3.6. The following emission rates shall be calculated based on the actual quantity of natural gas used by each CGT and sulfur content of natural gas consumed by each CGT:

5.3.6.1. SO_2 rates shall be determined per protocols and test methods described in Appendix D to 40 CFR Part 75, <u>Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units</u>.

5.3.6.2. The quantity of SO_2 converted to H_2SO_4 shall be subtracted from SO_2 emissions rates for compliance determination purposes. The quantity of SO_2 converted to H_2SO_4 shall be based on the unit specific conversion rate of potential SO_2 to H_2SO_4 determined per Condition 5.4.2 below.

5.3.6.3. The hourly rate of natural gas burned shall be continuously monitored per the methods in 40 CFR Part 75, Appendix D, Section 2.1.

5.3.6.4. Sulfur content of natural gas shall be determined at least once per calendar month by sampling the natural gas burned and analyzing samples for total sulfur content per the method specified in 40 CFR Part 75, Appendix D for high variability, non-pipeline quality natural gas. Any other analysis method listed in 40 CFR Part 75, Appendix D may be used after the use is approved by EFSEC. Valid sulfur test results from the previous month, or an average of valid sulfur data approved by EFSEC may be used when monthly sampling and analysis of the natural gas is inconclusive or results in invalid data.

5.3.7. Grays Harbor Energy, LLC shall record monthly and report to EFSEC on a quarterly basis the quantity and average sulfur content of the natural gas burned at the facility, and purchase records and vendor's reports of total sulfur content in the natural gas delivered.

5.4. Sulfuric acid mist emissions:

5.4.1. 2.17 lb H_2SO_4/hr, rolling annual average calculated monthly.

5.4.2. Hourly H_2SO_4 rates and the unit-specific ratios of H_2SO_4 to SO_2 shall be determined for each CGT based on stack testing using EPA Reference Method 8, or an equivalent method approved by EFSEC. Stack testing shall be performed once per calendar quarter for the first year of commercial operation at each exhaust stack, and thereafter at 5-year intervals.

5.4.3. Unit-specific ratios of H_2SO_4 to SO_2 shall be used as conversion factors to apportion the calculated potential SO_2 emissions into sulfuric acid mist emissions and SO_2 emissions.

5.4.4. Compliance with the limit in Condition 5.4.1 shall be determined monthly by calculating the average H_2SO_4 emission rate over all hours of operation during the previous month and 12 consecutive month periods based on the quantity and sulfur content of natural gas used by each CGT per Condition 5.3.6 above.

5.5. Volatile organic compound (VOC) emissions:

5.5.1. 6.3 lb/hr, 1-hr average, reported as carbon equivalent.

5.5.2. 2.8 ppm, 1-hr average, reported as carbon equivalent at 15% O_2.

5.5.3. Use of EPA Reference Method 19 and EPA Reference Method 25A, 25B, or South Coast Air Quality Management District Method 25.3, shall determine initial compliance for each CGT or an equivalent method agreed to in advance by EFSEC. After the initial three years of tests on each CGT stack have been completed, each CGT stack shall be tested at 5-year intervals.

5.5.4. Ongoing compliance shall be monitored by calculating hourly VOC emissions rates using:

5.5.4.1. Hours of operation.

5.5.4.2. Fuel flow to each CGT.

5.5.4.3. Application of an emission factor for VOCs derived from the most recent stack testing of the installed CGT.

5.5.4.4. Emission testing of each CGT using one of the methods listed in Approval Condition 5.5.3 is required.

5.6. Particulate matter and particulate matter less than or equal to 10 micrometers (aerodynamic diameter) (PM_{10}) emissions:

5.6.1. 22.6 lb/hr of filterable plus condensable PM_{10}.

5.6.2. Use of EPA Reference Method 19 and Methods 5, 201, or 201A, plus Reference Method 202, or an equivalent PM_{10} test method approved by EFSEC shall be used to determine initial compliance for each CGT exhaust stack with the limit in Condition 5.6.1. Use of EPA Reference Method 5 assumes all filterable particulate is PM_{10}. Use of EPA Reference Method 201 or 201A assumes that the mass of filterable PM is equal to the mass of filterable PM_{10}. If Method 201 or 201A is used, the mass of particulate retained in the cyclone shall be determined and reported.

5.6.3. The results of the filterable and condensable particulate analyses shall be reported as total particulate, filterable particulate, and condensable particulate.

5.6.4. After the initial three years of tests on each CGT stack have been completed, each CGT stack shall be tested at 5-year intervals.

5.7. Ammonia (free NH_3 and combined measured as NH_3) emissions:

5.7.1. 5.0 ppm, 24-hr average corrected to 15% O_2.

5.7.2. 16.1 lb/hr, 24-hr average.

5.7.3. Initial compliance for each CGT shall be indicated by Bay Area Air Quality Management District Source Test Procedure ST-1B, "Ammonia, Integrated

Sampling;" EPA Conditional Test Method 027; or an equivalent method approved in advance by EFSEC.

5.7.4. Compliance shall be determined through use of a CEMS, which meets the requirements of Approval Condition 18.2 or Grays Harbor Energy, LLC may propose alternative means for continuous assessment and reporting of NH_3 emissions for approval by EFSEC. Any proposed alternative NH_3 reporting shall be, at a minimum, equivalent to a CEMS meeting the requirements of Approval Condition 18.2 and 18.6.

5.7.5. The SCR catalyst system treating the exhaust from one CGT shall be repaired, replaced, or have additional catalyst bed installed at the next scheduled outage, following a calendar month when the average ammonia slip cannot be maintained at or below 4.5 ppm, corrected to 15% oxygen, based on the actual operating hours of the CGT. No month with less than 200 hours of actual operation (excluding start-up and shutdown hours) shall be used for this evaluation. The outage to repair, replace, or install additional catalyst to the SCR system shall be no later than 12 months after the month the ammonia slip exceeds the 4.5 ppm criteria given above in this condition.

5.8. Opacity at each CGT exhaust stack:

5.8.1. Is not allowed to exceed a 6-minute average opacity of five percent.

5.8.2. Shall be determined by use of EPA Reference Method 9 or an equivalent method approved in advanced by EFSEC.

5.8.3. Ongoing compliance with the opacity limit in Condition 5.8.1 shall be monitored once per day (or weekly if Condition 5.8.3.3 is satisfied) as follows:

5.8.3.1. A certified opacity reader shall read and record the opacity of each operating unit during daylight hours per 5.8.3 frequency, or

5.8.3.2. Opacity shall be monitored using a Continuous Opacity Monitoring system on each CGT as an alternative to EPA Reference Method 9 readings. If installed, the continuous opacity monitor must be installed in the exhaust stack at a location meeting the requirements of Approval Condition 18.4.

5.8.3.3. If readings from daily monitoring are less than the opacity limit in Condition 5.8.1 for the last calendar month, the manual opacity monitoring frequency is reduced to weekly. Readings above the opacity limit in Condition 5.8.1 will require daily manual opacity readings for at least 30 days.

6. The auxiliary boiler exhaust stack emissions are not to exceed the following:

6.1. NO_X emissions:

6.1.1. 1.03 lb/hr, 1-hr average.

6.1.2. 30 ppm at 3% O_2, 1-hr average

6.1.3. Initial compliance shall be determined in accordance with 40 CFR 60, Appendix A, Reference Method 7E and Method 19.

6.1.4. Compliance shall be determined through periodic stack tests performed at 5-year intervals after the initial compliance test. Upon written request by EFSEC, GHE shall perform emissions testing using the method in Condition 6.1.3.

6.2. CO emissions:

6.2.1. 50.0 ppm, corrected to 3% O_2, 1-hr average.

6.2.2. 1.07 lb/hr, 1-hr average.

6.2.3. EPA Reference Method 10 and Method 19 or an equivalent method agreed to in advance by the EFSEC shall determine initial compliance. The span and linearity calibration gas concentrations in Method 10 shall be appropriate to the CO concentration limits specified in this condition.

6.2.4. Compliance shall be determined through periodic stack tests performed at 5-year intervals after the initial compliance test. Upon written request by EFSEC, GHE shall perform emissions testing using the method in Condition 6.2.3.

6.3. SO_2 emissions:

6.3.1. 0.07 lb/hr annual average, calculated monthly.

6.3.2. One ppm at 3% $O_{2,}$ 1-hr average.

6.3.3. EPA Reference Method 8 shall determine initial compliance with the limit in Condition 6.3.2 for the auxiliary boiler, or an equivalent method approved in advance by EFSEC.

6.3.4. Ongoing compliance with the limit in Condition 6.3.1 shall be determined by mass-balance calculations utilizing the:

6.3.4.1. Monthly Fuel consumption records for the auxiliary boiler, and

6.3.4.2. Sulfur content of the natural gas per Condition 5.3.6.4.

6.4. VOC emissions:

6.4.1. 0.16 lb/hr, 1-hr average, reported as carbon equivalent.

6.4.2. EPA Reference Method 19 and Method 25A or 25B or an equivalent method agreed to in advance by EFSEC shall determine initial compliance for the auxiliary boiler.

6.4.3. Ongoing compliance shall be determined through periodic stack tests, using one of the above referenced methods, at 5-year intervals after the initial compliance test. Upon written request by EFSEC, GHE shall perform emissions testing using methods in Condition 6.4.2.

6.5. PM_{10} emissions:

6.5.1. 0.292 lb/hr, hourly average.

6.5.2. 0.005 gr/dscf, 1-hr average, at 3% O_2.

6.5.3. Initial compliance with the limits in Condition 6.5 for the auxiliary boiler exhaust stack shall be determined by EPA Reference Method 19, Method 202 and either Reference Method 5, 201, or 201A, or an equivalent method agreed to in advance by EFSEC. Use of EPA Reference Method 5 assumes all particulate has an aerodynamic diameter less than 10 microns. Use of EPA Reference Method 201 or 201A assumes that the mass of filterable PM is equal to the mass of filterable PM_{10}.

6.5.4. The results of the filterable and condensable particulate analyses shall be reported as total particulate, filterable particulate, and condensable particulate.

6.5.5. Compliance shall be determined through periodic stack tests, using the above specified methods, taken at 5-year intervals after the initial compliance test. Upon written request by EFSEC, GHE shall perform emissions testing using the methods in Condition 6.5.3.

6.6. Opacity at the auxiliary boiler exhaust stack:

6.6.1. Is not allowed to exceed a 6-minute average opacity of five percent.

6.6.2. Shall be determined using EPA Reference Method 9 or an equivalent method approved in advance by EFSEC.

6.6.3. Ongoing compliance with the opacity limit in Condition 6.6.1 shall be monitored as follows:

6.6.3.1. An opacity reader shall survey the boiler stack daily to determine if any opacity is present. If opacity is not observed over the course of a week, the frequency for surveying the boiler stack may change to monthly. If the survey detects visible emissions, then the company must investigate the cause of the emissions and repair the problem or take EPA Method 9 observations for determining compliance.

7. The diesel generator engine shall meet the following requirements:

7.1. The engine shall comply with the requirements in 40 CFR Part 63, Subpart ZZZZ.

7.1.1. The facility shall maintain engine operation and maintenance records verifying the engine has been operated, maintained, and repaired in a manner consistent with the manufacturer's emission-related specifications. A copy of the manufacturer's recommendations for maintaining the engine shall be kept on-site and made available upon request.

7.2. The engine shall be operated only during routine maintenance, testing, and periods when electricity is not available from the power grid. Maintenance and testing shall not exceed 50 hours per any 12 consecutive month period.

7.3. The engine shall burn only diesel fuel, biodiesel, or a mixture of both. In any case, the fuel used shall have a maximum sulfur content that does not exceed 500 ppm by weight. A fuel certification from the fuel supplier may be used to demonstrate compliance with this requirement.

7.4. The engine shall be equipped with an operable, non-resetting hour meter.

7.5. Visible emissions from the engine shall not exceed an average of ten percent (10%) opacity during any 6-minute period except cold start-up, as determined in accordance with EPA Method 9 (Title 40 CFR, Part 60, Appendix A Method 9). Unless defined by the engine manufacturer, "cold start" as used in this condition shall be defined as the period beginning when the engine is started and ending when the temperature of the engine coolant reaches 150°F.

7.5.1. Initial compliance with the limit in Condition 7.5 shall be determined based on EPA Method 9 readings.

7.5.2. Weekly a qualified opacity reader shall survey and record if opacity is present from the engine whenever the engine is operated for testing and after the engine achieves normal operating temperature. If opacity is observed then Method 9 readings shall be performed during the next time the engine is started. The Survey frequency can be reduced to monthly once four readings without opacity are observed.

7.6. Visible emissions of ten percent (10%) opacity or more shall trigger prompt (within a week) action to initiate maintenance and/or repair the engine and eliminate opacity exceeding this standard. Maintenance and repair actions shall be documented and available for inspection.

8. The emergency fire water pump engine:

8.1. The engine must comply with requirements in 40 CFR 63 Subpart ZZZZ.

8.1.1. The facility shall maintain engine operation and maintenance records verifying the engine has been operated, maintained, and repaired in a manner consistent with the manufacturer's emission-related specifications. A copy of the manufacturer's recommendations for maintaining the engine shall be kept on-site and made available upon request.

8.2. The engine shall be operated only during routine maintenance, testing, and periods when electricity is not available from the power grid. Maintenance and testing shall not exceed 50 hours per any 12 consecutive month period.

8.3. The engine shall burn only diesel fuel, biodiesel, or a mixture of both. In any case, the fuel used shall have a maximum sulfur content that does not exceed 500 ppm by weight. A fuel certification from the fuel supplier may be used to demonstrate compliance with this requirement.

8.4. The engine shall be equipped with an operable, non-resetting hour meter.

9. The emissions from the cooling tower are not to exceed:

9.1. 24.5 lb/day PM_{10}, annual average.

9.2. 4.5 tpy PM_{10}, rolling total, calculated monthly.

9.3. Initial compliance shall be determined by:

9.3.1. An affirmative report by the cooling tower drift eliminator manufacturer, based on an on-site inspection of the completed installation, that its product has been installed in accordance with its specifications accompanied by the results of a test or analysis of the cooling tower drift eliminator material indicating that the material has a drift loss of less than 0.001% of the recirculating water flow rate. The required test could be performed on a full size mist eliminator module under laboratory conditions that match the worst case operations scenario of the actual cooling tower.

9.4. Compliance is determined by using the following formula:

$$Q \times C \times DL \times 60 \times 8.34 / 1000000 = D$$

Where: Q = Monthly average recirculation rate in gallons per minute
C = Monthly average total dissolved solids concentration in parts per million by weight (ppmw)
D = PM_{10} emission rate in lb/hr.
DL = the drift loss rate in gallon lost/gallon of recirculating cooling water

9.5. Calculate the PM_{10} emissions from the cooling tower once each month. The monthly calculations shall use the formula in Condition 9.4 above. The monthly average recirculating water flow rate for each month shall be used for “Q” in the formula. The monthly average recirculating water flow rate should be at or below the design recirculating water flow rate of 175,000 gpm. The monthly average total dissolved solids content measured or calculated during the month shall be used for “C” in the formula.

9.6. Prior to operation of the cooling tower, Grays Harbor Energy, LLC shall submit to EFSEC, a report describing the manufacturer’s recommendations for installing, operating, and testing the drift eliminators.

10. Annual Emissions.

10.1. Annual emissions, calculated as a rolling 12-month average, shall not exceed the limits in the following table. These limits apply to total emissions over each 12 consecutive month period and include emissions from all units during start-up, shutdown and periods of malfunction.

Pollutant	CGT 1 and 2 Individually tpy	Auxiliary Boiler tpy	Cooling Tower tpy
NO_X	121.7*	1.3	---
CO	71.6*	1.3	---
SO_2	14.5	0.088	---
H_2SO_4	9.5	---	---
PM/PM_{10}	99.0†	0.4	4.5
VOC	37.5*	0.6	---
NH_3	70.5	---	---

∗ Includes the emissions from start-up and shutdown events of the CGTs and diesel generators. CGT start-up emissions are equally apportioned between the two turbines.
† PM and PM_{10} conservatively assumed to be equal.

10.2. Rolling 12-month total emissions shall be calculated monthly based on the total monthly emissions from each permitted unit summed for the preceding 12 months. The actual emissions shall be based on CEMS, where installed, mass balance and emission factor calculations for SO_2 and H_2SO_4, and emission factors for other pollutants and emission units where CEMs are not installed.

11. Start-up and shutdown of CGTs 1 and 2 (including CGT over-speed protection testing).

11.1. Each CGT is limited to two start-ups per calendar day. This limitation does not apply during the period between initial firing of a combustion turbine for testing purposes and the start-up condition specified in Approval Condition 13.

11.2. A start-up begins when fuel is first fired in the combustion turbine, and ends when the earlier of one of these events occurs:

11.2.1. The operating temperatures of the oxidation and SCR catalysts serving an operating CGT reach 500°F and 525°F, respectively and when the associated combustion turbine achieves operational Mode 6, or

11.2.2. One of the following time limits has been reached, as applicable:

11.2.2.1. Three hundred minutes have elapsed since fuel was first introduced to the applicable turbine on a cold start-up. A cold start-up is any start-up occurring after the applicable turbine has not operated for 48 hours or more.

11.2.2.2. One hundred eighty minutes have elapsed since fuel was first introduced to the applicable turbine on a warm start-up. A warm start-up is any start-up occurring after the applicable turbine has not operated between 8 and 48 hours.

11.2.2.3. One hundred twenty minutes have elapsed since fuel was first introduced to the applicable turbine on a hot start-up. A hot start-up is any start-up occurring after the applicable turbine has not operated for 8 hours or less.

11.2.2.4. Once per year it is estimated that each CGT will need to be tested to confirm that the over-speed protection is functioning properly (less than 90 minutes). Each test will account for one start-up.

11.3. The Shutdown is defined as the period beginning when the combustion turbine leaves operational Mode 6 and ends when fuel is no longer being introduced to any burner. The turbine manufacturer defines operational Mode 6 as the low emission mode during which all six of the burner nozzles are burning a lean premixed gas steady-state operation. Duration of a planned shutdown period shall not exceed 30 minutes per occurrence.

11.4. During start-up, ammonia injection shall begin no later than when the SCR reaches an operating temperature of 525°F.

11.5. During a start-up and associated shutdown of a CGT, the combined emissions shall not exceed the following:

Pollutant	Emission Limit Per Turbine Per Start-Up/Shutdown
NO_X	900 lb
CO	500 lb
VOCs	600 lb

11.5.1. Ongoing compliance with the NOx limits in Condition 11.5 shall be indicated by continuous emission monitors for NO_X and O_2. The continuous emission monitoring system (CEMS) and flow measurement to determine NOx lb/hr emissions shall meet the requirements of Approval Conditions 18.1 and 18.6.

11.5.2. Ongoing compliance with the CO limits in condition 11.5 shall be indicated by continuous emission monitor for CO and O_2. The CEMS and flow measurement to determine CO lb/hr emissions shall meet the requirements of Approval Conditions 18.3 and 18.6.

11.6. To account for VOC emissions during start-up and shutdown when determining monthly or annual emissions, VOC emissions shall be calculated using a VOC emission factor of 177 lb/startup/shutdown/CGT. The emission factor accounts for combined VOC emissions during start-up and shutdown.

12. Within 180 days after formal, initial start-up of each combustion turbine, auxiliary boiler, and installation of the diesel generators, Grays Harbor Energy, LLC shall conduct the initial performance tests for NO_X, ammonia, SO_2, opacity, VOC, CO, PM_{10}, and H_2SO_4 noted above. An independent testing firm shall perform the initial performance testing. A test plan shall be submitted to EFSEC for approval at least 30 days prior to the testing.

13. The initial compliance testing, CEM system performance testing, and testing for other, non-acid rain program purposes must occur by the earlier of the following dates:

13.1. The earliest date that electrical power is offered for sale (not test generation) from a CGT and its associated steam turbine, or

13.2. One hundred eighty days after the first CGT in the power island has been synchronized to the electrical distribution grid.

14. Grays Harbor Energy, LLC shall notify EFSEC in writing at least 30 days prior to:

14.1. Initial start-up of any permitted emissions unit for operational testing and manufacturers certification purposes.

14.2. Formal, initial start-up defined in Approval Condition 13.

14.3. The date any emissions testing required by this permit shall be performed when the time between tests is specified to be longer than 30 days.

14.4. The date(s) CEMS performance testing or Relative Accuracy Test Audits will be performed.

15. Sampling ports and platforms shall be provided on each CGT stack, after the final pollution control device. The ports shall meet the requirements of 40 CFR, Part 60, Appendix A, Method 20. Upon request by EFSEC for emissions testing, sampling ports and platforms shall be installed on diesel engines as appropriate. Sampling ports and platforms shall meet the requirements of 40 CFR Part 60, Appendix A, Method 1.

16. Adequate permanent and safe access to the test ports shall be provided. Other arrangements may be acceptable if approved by EFSEC prior to installation.

17. Operating Records for Emissions Units:

17.1. Unless otherwise specified above, operating records shall contain information necessary to determine the operational status of the equipment.

17.2. Specific parameters and acceptable ranges of those parameters shall be specified in the Operation and Maintenance Manual.

17.2.1. Example operating record information includes, but is not limited to:

17.2.1.1. Fuel heat and sulfur content.

17.2.1.2. Fuel consumption during the period (hourly, monthly, etc.).

17.2.1.3. Unit operating parameters:

17.2.1.3.1. Exhaust temperature.

17.2.1.3.2. Percent oxygen.

17.2.1.3.3. Output rate (lb of steam/hr, kW output, etc.).

17.2.1.3.4. Operating hours during the reporting period and cumulative for the year.

17.2.1.3.5. For each combustion turbine, unit start-up and shutdown information.

17.2.1.3.5.1. Start-up day and time.

17.2.1.3.5.2. Time Mode 6 attained.

17.2.1.3.5.3. Error codes during start-up and their effect on start-up.

17.2.1.3.5.4. Ammonia flow as registered on an ammonia flow meter.

17.2.1.3.6. For the auxiliary boiler, start-up and shutdown information.

17.2.1.3.6.1. Start-up day and time.

17.2.1.3.6.2. Shutdown day and time.

18. Continuous Emission Monitoring Systems (CEMS):

18.1. CEMS for NO_X and O_2 compliance shall meet the requirements contained in 40 CFR 75, Emissions Monitoring.

18.2. CEMS for ammonia shall meet the requirements contained in 40 CFR, Part 63, Appendix A, Reference Method 301, Validation Protocol, and 40 CFR, Part 60, Appendix F, Quality Assurance Procedures, or other EFSEC-approved performance specifications and quality assurance procedures.

18.3. CEMS for CO shall meet the requirements contained in 40 CFR, Part 60, Appendix B, Performance Specification 4 or 4A, and in 40 CFR, Part 60, Appendix F, Quality Assurance Procedures.

18.4. Continuous Opacity Monitoring Systems shall meet the requirements contained in 40 CFR Part 60, Appendix B, Performance Specification 1 and in 40 CFR, Part 60, Appendix F, Quality Assurance Procedures.

18.5. Continuous emission and opacity monitors must meet the requirements of 40 CFR 60.13, except that the term "applicable subpart" as used in 40 CFR 60.13 means this permit. Monitors shall be capable of determining emissions during start-up, shutdown, and periods of malfunction.

18.6. Stack flows for calculating mass emissions must be determined in accordance with the following. Natural gas combusted in the CGT's and boiler must be sampled and analyzed based on the sampling and analysis frequencies established in the requirements of Approval Condition 5.3.6.4 for composition using Universal Oil Products (UOP) Laboratory Test Method 539-97 "Gas Analysis by Gas Chromatography" or equivalent. The gas composition must be used to determine the heat content of the gas in terms of British thermal unit, high heat value, per standard cubic foot (Btu/scf) and to determine the EPA Method 19 Fd factor for the gas. An alternative method to EPA Method 19 can be used to determine the Fd factor if pre-approved by EFSEC.

19. Relative Accuracy Test Audits (RATA) for NO_X and CO Continuous Emission Monitoring Systems:

    19.1. RATA testing is to be performed at the calendar year/calendar quarter frequency required by the quality assurance procedures referenced in Condition 18, except as provided for in Conditions 19.2 and 19.3.

    19.2. The testing shall be based on "QA operating quarters" as that term is defined in 40 CFR 72.2.

    19.3. A RATA is to be performed for all pollutants measured by CEMs as required by 40 CFR Part 75, Appendix B, Section 2.3, including the minimum frequency of once every eight calendar quarters.

    19.4. A test plan shall be prepared and submitted to EFSEC and Olympic Regional Clean Air Agency (ORCAA) for review at least 30 days prior to the RATA test. The test plan shall cover all pollutants required to be monitored during that RATA test. The test plan shall include the proposed dates of the testing. The permittee must revise the test plan to address comments provided by EFSEC or ORCAA.

    19.5. A report of the results of the RATA and other emission testing shall be submitted to EFSEC and ORCAA within 45 days of completing the test.

20. CEMS and process data shall be submitted quarterly, in written form (or electronic if permitted by the EFSEC) within 30 days of the end of each calendar quarter to EFSEC and ORCAA.

21. The format of the reporting described in Approval Condition 20 shall match that required by EPA for demonstrating compliance with the Title IV Acid Rain program reporting requirements. Pollutants not covered by that format shall be reported in a format approved by EFSEC that shall include at least the following:

    21.1. Process or control equipment operating parameters.

    21.2. The hourly maximum and average concentration, in the units of the standards, for each pollutant monitored.

    21.3. The duration and nature of any monitor downtime.

    21.4. Results of any monitor audits or accuracy checks.

    21.5. Results of any required stack tests.

    21.6. Results of any other stack tests performed after the initial performance test.

21.7. The above data shall be retained at the Grays Harbor Energy Center for a period of at least five years.

22. For each occurrence of monitored emissions in excess of the limits in this permit, the quarterly emissions report (per Approval Conditions 20 and 21) shall include the following:

22.1. For parameters subject to monitoring and reporting under the Title IV, Acid Rain program, the reporting requirements in that program shall govern excess emissions report content.

22.2. For all other pollutants:

22.2.1. The time of the occurrence.

22.2.2. Magnitude of the emission or process parameters excess.

22.2.3. The duration of the excess.

22.2.4. The probable cause.

22.2.5. Corrective actions taken or planned.

22.2.6. Any other agency contacted.

23. Grays Harbor Energy, LLC shall have on-site, and shall follow, an Operating and Maintenance manual, and an equipment Start-up, Shutdown, and Malfunction Procedures manual for all equipment that has the potential to affect emissions to the atmosphere. Copies of the manuals shall be available to EFSEC or ORCAA at the facility. Emissions that result from a failure to follow the requirements of the manuals may be considered evidence that emission violations have occurred. The above manuals must be reviewed annually and updated as needed. EFSEC and ORCAA shall be notified whenever the manual is updated.

23.1. The Operating and Maintenance manual should contain equipment-specific operating parameter and maintenance information.

23.2. The Start-up, Shutdown, and the Malfunction manual shall contain information on the proper procedures, and sequencing of actions for plant operations staff to follow in order to safely, efficiently start and stop the various equipment at the station under all reasonably ascertainable normal and abnormal start-up and shutdown situations.

24. Any activity, which is undertaken by Grays Harbor Energy, LLC, or others, in a manner, which is inconsistent with the application and this determination, shall be subject to enforcement under applicable regulations. Specific elements in the application to be followed are the structure locations and sizes depicted on site plans, emitting and process equipment specifications, and

emitting equipment stack height and diameters used for demonstrating compliance with ambient air quality impacts.

25. Nothing in this determination shall be construed so as to relieve Grays Harbor Energy, LLC of its obligations under any state, local, or federal laws or regulations.

26. At all times, Grays Harbor Energy, LLC must maintain and operate the emission units covered by this permit, including all associated emission control equipment and work practices, in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operation and maintenance procedures are being used shall be based on information available to EFSEC or ORCAA. This information may include, but is not limited to, monitoring results, opacity observations, operating and maintenance procedures, all operation and maintenance records, and site inspections.

27. Access to the source by EFSEC or ORCAA, shall be permitted upon request for the purpose of compliance assurance inspections. Failure to allow access is grounds for action under the Washington Clean Air Act.

Prepared by:

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Scott M. Inloes, P.E. Air Quality Program Washington Department of Ecology	Date

Approved by:

______________________________	____________________
Kathleen Drew Energy Facility Site Evaluation Council	Date