STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL (EFSEC)

TECHNICAL SUPPORT DOCUMENT AND STATEMENT OF BASIS

GRAYS HARBOR ENERGY CENTER, LLC

June 17, 2020

PERMIT #:	**EFSEC/94-1 AOP - Initial**
PREPARTED FOR:	**Grays Harbor Energy, LLC** **401 Keys Road** **Elma, WA 98541-9149**
PLANT SITE:	**Grays Harbor Energy Center** **401 Keys Road** **Elma, WA 98541-9149**
PERMIT ENGINEER:	**Mark V. Goodin – ORCAA Professional Engineer**
REVIEWED BY:	**Sonia E. Bumpus – EFSEC Manager**

ENERGY FACILITY SITE EVALUATION COUNCIL
621 Woodland Square Loop SE
P.O. Box 43172
Lacey, Washington 98503-3172
Telephone: (360) 664-1345

TABLE OF CONTENTS

1. DISCLAIMER

Information contained in this Technical Support Document is for purposes of background information only and is not enforceable. Applicable requirements including emission limits and monitoring, recordkeeping and reporting requirements are contained in the associated Air Operating Permit (AOP) for the Grays Harbor Energy Center, permit EFSEC/94-1 AOP, which was issued by the Energy Facility Site Evaluation Council (EFSEC) on June 17, 2020.

2. GENERAL INFORMATION

2.1 Table 1: Administrative Information and Contact Information

Company Name	Grays Harbor Energy, LLC (GHE)
Facility/Source Name	Grays Harbor Energy Center (GHEC)
AOP Permit No.	EFSEC/94-1 AOP - Initial
Mailing Address	Grays Harbor Energy, LLC 401 Keys Road Elma, WA 98541-9149
Site Address	Grays Harbor Energy, LLC 401 Keys Road Elma, WA 98541-9149
Facility/Plant/Environmental Manager	Eric Pace Plant Engineer (360) 482-4353 (ext 224)
Responsible Official	Chris Sherin Plant Manager
Unified Business Identification Number	602 082 646
Standard Industrial Classification (SIC) Code	4911
Attainment Area Status	Unclassified for all criteria pollutants.
Permitting Authority	The Washington Energy Facility Site Evaluation Council (EFSEC) is the permitting authority for the GHEC. EFSEC implements an Air Operating Permit program through Chapter 463-78 WAC, which adopts by reference the Washington Operating Permits Regulations under Chapter 173-401 WAC.
Enforcement Manager	Sonia E. Bumpus – EFSEC Manager (360) 664-1363
Compliance Contractor	Olympic Region Clean Air Agency (ORCAA) (360) 539-7610
Permit Engineer	Mark V. Goodin – ORCAA Engineer Manager (360) 539-7610 ext 108
Compliance Supervisor	Robert Moody – Compliance Manager (360) 539-7610 ext 106

2.2 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 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. Commercial operation of GHEC began on April 25, 2008.

2.3 Basis for Title V Applicability

Facilities with a potential to emit (PTE) at or above the “major source” thresholds defined in WAC 173-401-200(19) are required to operate under an Air Operating Permit (AOP) issued through an approved Washington State AOP program, according to Title V of the federal Clean Air Act. GHEC has the potential to emit several regulated air pollutants above their major source thresholds. In addition, GHEC is an affected source under Title IV (Acid Deposition Control) of the federal Clean Air Act, which independently triggers the requirement to obtain a Title V AOP.

EFSEC received delegation from EPA Region 10 on August 13, 2001 to implement an AOP program for electric power generating plants in Washington State with capacities exceeding 350 MW. EFSEC implements their AOP program through Chapter 463-78 WAC, which adopts by reference the Washington Operating Permits Regulations under Chapter 173-401 WAC.

Because GHEC is capable of generating up to 650 MW of electricity and is a “major source” as defined in WAC 173-401-200(19), GHEC is required to operate under an AOP issued by EFSEC.

2.4 Preconstruction Permitting

EFSEC is responsible for issuing pre-construction permits to electric power generating plants in Washington with capacities exceeding 350 MW, including Notice of Construction (NOC) permits and Prevention of Significant Deterioration (PSD) permits. Both types of permits have been issued to GHEC by EFSEC.

EFSEC issued the initial PSD approval to the previous owner of the facility (Duke Energy) in 2001 and approved transfer of the PSD permit to GHE in April 2005. The PSD permit for GHEC has been amended four separate times since it was originally issued in 2001. The following list summarizes the PSD permitting history of the facility:

1. Original PSD Approval (EFSEC/2001-01, approved November 2, 2001) – Includes both PSD and minor NOC permits to construct the GHEC;
2. Amendment 1 (EFSEC/2001-01 Amendment 1, January 2, 2003) - Approved modified operating requirements and emission limitations, added equipment as part of the project and removed certain operational restrictions;

3. Amendment 2 (EFSEC/2001-01 Amendment 2, October 19, 2004) - Approved a delay in continuous construction to no later than January 20, 2006 and modified the monitoring requirements and BACT emission limitations based on recently available information;
4. Amendment 3 (EFSEC/2001-01 Amendment 3, approved April 3, 2006) - Approved a second delay in continuous construction to no later than July 20, 2007 and made several administrative corrections; and,
5. Amendment 4 (EFSEC/2001-01 Amendment 4, approved June 28, 2018) corrected certain minor errors in the permit and adopted specific emissions limits for startup and shutdown operations.

2.5 Regulatory History

The regulatory history of GHEC is fairly complicated due to:

1. Delays in starting and completing construction of the facility; and,
2. Delays in securing approval of Amendment 4 by Region 10 of the U.S. Environmental Protection Agency (EPA).

Start of construction and construction delays necessitated the need for permit extensions. In addition, construction delays triggered the need to re-permit the facility because effective versions of applicable regulations, which depend on when an affected facility begins construction, required re-evaluation.

PSD Amendment 4 is the effective pre-construction air permit for GHEC. Approval of PSD Amendment 4 was significantly delayed in order to address issues raised by EPA regarding startup/shutdown emissions limits and other technical permit issues. These issues were resolved in 2018 and PSD Amendment 4 was issued September 29, 2018. Table 2 summarizes the permitting history for GHEC.

2.6 Table 2: Permitting History

1995	Construction Authorized - EFSEC authorizes construction and operation
1996	Original PSD Approval - Site Certification Agreement (SCA) with PSD (EFSEC 95-01)
March 1998	Permit extension
September 1999	Permit extension
April 2001	Re-Application - Duke submitted a new PSD application for project
June 2001	EPA Consent Order - Administrative Order on Consent issued by EPA allowing start of construction prior to issuance of the new PSD approval.
September 1, 2001	Start of Construction – authorized by EFSEC

November 2, 2001	PSD Approval - (EFSEC/2001-01)
January 2, 2003	PSD Amendment 1 (EFSEC/2001-01 Amendment 1) - EFSEC approves Amendment 1, which modified operating requirements and emission limitations in the original approval, added equipment as part of the project and removed certain operational restrictions.
October 19, 2004	PSD Amendment 2 (EFSEC/2001-01 Amendment 2) - approved by EFSEC authorizing a delay in continuous construction to not later than January 20, 2006 and modifying 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.
February 23, 2005	Transfer of Ownership - to Grays Harbor Energy LLC approved by EFSEC.
April 3, 2006	Amendment 3 (EFSEC/2001-01 Amendment 3) - approved by EFSEC authorizing a second delay in continuous construction to not later than July 20, 2007 and making several administrative corrections to errors in Amendment 2.
April 25, 2008	Start of Commercial Operation.
April 24, 2009	Date Complete Title V Application Submitted
August 7, 2009	Application for PSD Amendment 4 was submitted to EFSEC
September 29, 2018	Amendment 4 (EFSEC/2001-01 Amendment 4) - requested by GHE in 2009 to: 1. Rectify issues with the PSD permit identified during development of the Air Operating Permit for the facility; 2. Add specific startup/shutdown emissions limits; and, 3. Rectify permit issued raised by EPA.
December 18, 2019	Draft AOP - issued for public comment
March 16, 2020	Proposed AOP – submitted to EPA for review
June 17, 2020	Final AOP - issued by EFSEC

2.7 Effective Versions of Applicable Requirements

Effective versions of each applicable requirement in the AOP for GHEC are the versions that were effective on the date the AOP. The two key dates for determining the effective versions of applicable air requirements are the date GHEC commenced continuous construction (January 20, 2006) and the date the complete AOP application for GHEC was received by EFSEC (April 24, 2009).

However, an additional layer of complexity regarding effective versions of applicable requirements in GHEC's AOP is due to the fact that EFSEC adopts by reference in their own regulations the applicable state and federal air regulations. This rule adoption approach is referred to as "adoption-by-reference" (ABR). EFSEC's rules under WAC 463-78-005 ABR all state air regulations relevant to electricity power generating facilities. Therefore, the adoption date of EFSEC's WAC 463-78-005 is a key date that determines the latest version of applicable state air regulations. The current effective version of EFSEC's WAC 463-78-005 is the July 27, 2015 version. This version adopts by reference:

- The November 25, 2018 version of Chapter 173-400 WAC (WA General Regulations for Air Pollution Sources);
- The September 16, 2018 version of Chapter 173-401 WAC (WA AOP Regulations);
- The March 1, 2005 version of Chapter 173-406 WAC (WA Acid Rain Regulation);
- The June 20, 2009 version of Chapter 173-460 WAC (WA Controls for New Sources of Toxic Air Pollutants); and,
- The January 1, 2011 version of Chapter 173-441 WAC (Reporting of Emissions of Greenhouse Gases).

Likewise, EFSEC's rules under WAC 463-78-115 ABR federal Standards of Performance for New Stationary Sources (NSPS) relevant to electricity power generating facilities. Therefore, the adoption date of EFSEC's WAC 463-78-115 is a key date that determines the latest version of applicable federal NSPS. The current effective version of EFSEC's WAC 463-78-115 is the August 27, 2015 version. This version ABR relevant NSPS in effect on July 1, 2014.

2.8 AOP Enforcement

Terms and conditions in the AOP apply continuously and are enforceable by EFSEC. Each condition in the AOP cites both the regulatory origin and authority for each permit condition. Any disputes regarding the exact language of an applicable requirement listed in GHEC's AOP should be settled by consulting the regulation cited in the regulatory origin of the condition.

2.9 AOP Enforcement Contractor

Through a Memorandum of Agreement (MOA) signed by EFSEC on November 20, 2007, Olympic Region Clean Air Agency (ORCAA) was given the contract to serve as the air compliance /permitting contractor under EFSEC. Through this agreement, ORCAA is tasked with performing all air-related compliance monitoring and Title V permitting duties for GHEC on behalf of EFSEC. Under EFSEC's oversight and direction, ORCAA performs such tasks as annual inspections, source testing oversight, review of monitoring reports, responding to complaints, drafting the AOP and reporting findings to EFSEC. While ORCAA serves as the compliance/permitting contractor, EFSEC remains the regulatory authority over GHEC. This means that ORCAA reports findings directly to EFSEC who then may act on the findings at their discretion. Only EFSEC can issue Notices of Violation (NOVs) and penalties for non-compliance.

2.10 Owner and Operator

GHE is the current owner and operator of the GHEC and is the entity responsible for complying with the AOP. Ownership of the facility was transferred from the former owners, Duke Energy and Energy Northwest to GHE on February 23, 2005. GHE, a subsidiary of Invenergy, is a private company categorized under Electric Power Generation, and is located in Elma, WA. The parent company, Invenergy and its affiliates develop, own and operate large-scale renewable and other clean energy generation facilities in North America and Europe. Invenergy specializes in developing and operating clean power sources of energy such as combined cycle power plants that operate using natural gas.

2.11 GHEC Responsible Official

AOP regulations under Chapter 173-401 WAC require a "Responsible Official" certify any submittals regarding compliance with the AOP as being true, accurate and complete based on their belief formed after reasonable inquiry. To form a reasonable belief of the truth, accuracy, and completeness of a compliance certification or other AOP-related submittal, the Responsible Official needs to understand the significance of the submittal with respect to assuring compliance with the AOP. The Responsible Official must have a basic understanding of the Title V permitting program, an understanding of the deviations being reported, how permit deviations are determined and the role of credible evidence in certifying compliance.

AOP compliance-related submittals covers practically every report and submittal associated with an AOP, such as deviation reports, malfunction reports, periodic monitoring reports, test reports, quarterly reports and annual compliance certifications. The AOP as written for GHEC does allow for "batch-wise" certification of routine compliance reports. This is facilitated by condition P21, which states:

> *"Provided, however, where a report is sent more frequently than once every six months, the responsible official's certification need only be submitted once every six months, covering all required reporting since the date of the last certification."*

This allows the Responsible Official to batch-wise certify retroactively all reports submitted since the last certification.

According to WAC 173-401-200(29), the responsible official means one of the following:

a) For a corporation: A president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than two hundred fifty persons or have gross annual sales or expenditures exceeding forty-three million in 1992 dollars; or
(ii) The delegation of authority to such representative is approved in advance by the permitting authority;

b) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;
c) For a municipality, state, federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a regional administrator of EPA); or
d) For affected sources:
(i) The designated representative in so far as actions, standards, requirements, or prohibitions under Title IV of the FCAA or the regulations promulgated thereunder and in effect on April 7, 1993 are concerned; and
(ii) The designated representative for any other purposes under 40 C.F.R. Part 70.

Because GHEC is subject to an acid rain permit under Title IV of the federal Clean Air Act, the definitions under "d" apply. Therefore, for GHEC, the Responsible Official and "Designative Representative" for the Acid Rain Permit should be the same person.

3. FACILITY DESCRIPTION

3.1 General Overview

GHEC is an electricity production facility occupying approximately 20 acres within the Satsop Redevelopment Park in Grays Harbor County, which is approximately four miles southwest of Elma, Washington. The facility consists of a combined-cycle electric power generating plant including two General Electric natural gas-fired combustion turbine generators (GE 7FA), operated in a "2-x-1" combined cycle gas turbine configuration with one steam turbine (GE D11) shared in common. The steam turbine is part of a steam power cycle that generates additional electric power from the waste heat in the exhaust of the combustion turbines. Each turbine is followed by a duct burner and a heat recovery steam generator (HRSG) to generate the steam used by the steam turbine. The steam turbine itself is not a direct source of air emissions, but requires operation of duct burners, heat recovery steam generators (HRSGs) and a cooling tower. The duct burners and the cooling towers are sources of air emissions themselves. GHEC also includes an auxiliary natural gas fired boiler, a diesel-fired emergency generator and a diesel-fired water pump.

3.2 Fuel

All combustion equipment except the diesel-fired emergency generator and diesel-fired water pump are fueled by natural gas received from the Williams Co.'s., Northwest Pipeline. The natural gas is sampled monthly by GHE and analyzed to determine its sulfur and heat content.

The diesel fuel allowed for use in the emergency generator and fire water pump engines is non-road specification diesel fuel with a maximum sulfur content of 15 ppm.

3.3 Combined Cycle Gas Turbines (CGT1 & CGT2)

Description

The combustion turbine generators are identical GE 7FA units and are each rated at maximum power generating capacity of 175 MW. Each combustion turbine has a design maximum heat-rate of 1,671 million British thermal units per hour (MMBtu/hr). Each combustion turbine is equipped with a heat recovery steam generator (HRSG) which has a duct burner. Each duct burner has a design maximum heat-rate of 505 MMBtu/hr.

In this Technical Support Document and the associated AOP, each combustion turbine, duct burner and HRSG combination is referred to as a “Combined–Cycle Gas Turbine Unit” or CGT unit. Each CGT unit has a separate exhaust stack. The western-most CGT is designated as CGT1 and the eastern-most CGT is designated as CGT2.

The combustion turbines take in filtered air that is compressed in the compressor stage of the turbine and then mixed with natural gas. The compressed fuel and air mixture is then burned in the combustion chamber of the turbine where it is expanded through a series of turbines to convert the energy to mechanical rotating shaft power. This mechanical energy is then used to run the compressor section of the turbine and to directly power the electric generator.

High temperature exhaust produced by each combustion turbine is augmented with supplemental heat from its duct burner to generate high pressure steam in its connected HRSG. Each HRSG produces steam that is used by the steam turbine to generate power in a standard steam power cycle.

Each CGT exhaust through its own exhaust stack at a height of 180 feet above ground level. Exhaust stacks are each equipped with a caged ladder and stack testing platform that provide a permanent and safe access to stack testing ports. The testing ports conform to the requirements of 40 CFR, Part 60, Appendix A, Method 20.

Air emissions from the CGTs result from combustion of natural gas both in the combustion turbines and duct burners. Natural gas is the only fuel combusted. Air pollutant emissions from the CGTs include nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM_{10}), sulfur dioxide (SO_2), volatile organic compounds (VOCs), sulfuric acid mist (H_2SO_4), ammonia (NH_3) and several Hazardous Air Pollutants (HAPs). Actual as well as potential emissions rates are described in section 4 of this TSD below.

CGT NO_x Control and Monitoring

The combustion turbines incorporate “Advanced, Dry Low NO_x” combustor technology. This technology is guaranteed by the manufacturer to reduce NO_x emissions from the combustion turbines to 9 ppm. It accomplishes NO_x reduction by maintaining a “lean” premix of fuel to air, staging the combustion into three-stages and utilizing a central diffusion flame for overall flame stabilization. The lean, premixed technology burns a lean fuel-to-air mixture for a lower peak combustion flame temperature, which results in lower “thermal NO_x” formation. The combustion turbines operate with just one of the lean premixed stages and the diffusion pilot at lower loads, and additional stages at higher loads. This provides efficient combustion and lower temperatures throughout the combustor-loading regime.

The duct burners also incorporate low NO_x combustor technology. This burner technology is capable of maintaining NO_x emissions below 10 ppmvd at 15% oxygen.

The typical NO_x emission concentration from each CGT is in the 3 to 9 ppm range. NOx from each CGT is further treated by separate selective catalytic reduction (SCR) units downstream of each HRSG. The SCR units are capable of maintaining NO_x concentrations to less than 3 ppm during steady state operation of the CGTs.

SCR is a post-combustion NO_x control technology where ammonia (NH_3) is injected into the flue gas upstream of a vanadium oxide catalytic reactor. The catalyst bed operates most efficiently at temperatures between 600 and 800°F, which match the temperature range typically found within HRSG units. On the catalyst surface, the NH_3 reacts with NO_x to form molecular nitrogen and water. The process uses approximately 1 – 1.3 moles of NH_3 per mole of NO_x reduced. The rate of NH_3 injection is automatically controlled based on the amount of “NH_3 slip,” which is the concentration of unreacted NH_3 downstream of the SCR units. NH_3 slip is continuously monitored.

The primary variable affecting SCR performance is temperature. If operating below the optimum temperature range, the catalyst activity is reduced, allowing unreacted NH_3 to slip through into the exhaust stream. If operating above the optimum temperature range, NH_3 is oxidized, forming additional NO_x. In addition, the catalyst may suffer thermal stress damage. Temperature of the catalyst beds as well as NO_x concentrations are required to be continuously monitored in order to maintain NO_x rates below the permitted limits.

An aqueous solution of NH_3 is used as the source for NH_3 in order to minimize impacts of possible spills or the unlikely event of rupture of an NH_3 tank. The solution is approximately 19% NH_3 as received and used. The rate of NH_3 solution injection is automatically regulated based on the NH_3 slip rate, which is continuously monitored. NH_3 slip is limited to 5 ppm on a 24-hour average basis. The NH_3 pump is controlled to maintain NH_3 slip between 1 and 3 ppm.

Per the PSD permit, NO_x emission concentrations and rates from the CGTs are required to be continuously monitored. As such, both CGTs are equipped with continuous emissions monitoring systems (CEMS) for both NO_x and O_2. The CEMSs for NO_x and O_2 are subject to the requirements contained in 40 CFR Part 75, Continuous Emission Monitoring, which contains the continuous emissions monitoring requirements for facilities subject to the Acid Rain program. Because 40 CFR Part 75 establishes the monitoring requirements for all pollutants and parameters required to be monitored under the acid Rain program (NO_x, O_2, SO_2, CO_2, volumetric flow, and opacity), and for different types of combustion units, much of it is not applicable to GHEC. For this reason, 40 CFR Part 75 is incorporated by reference in the permit.

On a real-time basis, GHEC can verify compliance with any of the short-term NO_x limits from the NO_x CEMS. In addition, the NO_x CEMS triggers an alarm to notify the operator when concentrations approach any short-term limit. NO_x and O_2 concentrations measured by the CEMS are used to determine the NO_x concentrations in terms of parts per million by volume at 15%O_2, which is the metric of the CGT emissions concentration limits. For pollutant mass rate (PMR) limits, measured NO_x concentrations are coupled with the natural gas combustion rate measured by the fuel monitoring system and a Fuel Factor (Fd) measured monthly to calculate the NO_x PMR in terms of pounds per hour.

The natural gas combustion rate is monitored continuously by separate fuel flow meters on each CGT and Duct Burner (DB) in terms of cubic feet per hour. Cubic feet per hour of natural gas combusted by each unit is multiplied by the Fd (measured monthly) to compute the exhaust gas flowrate for each unit in terms of dry standard cubic feet per hour at 15% O_2. This result is then multiplied by the concentration to compute the NO_x PMR as shown in the following equation.

Pollution Mass Rate Calculation Method

$$PMRx = (NG)(HHV)(Fd)(Cx)(MW_{pollutant})/[(1000)(Molar\ Volume_{stp}]$$

Where:

- *PMRx = The calculated pollutant mass rate of pollutant "x" in terms of pound per hour (lbs/hr).*
- *NG = The actual amount of natural gas combusted by the unit over the hour per condition M6(a) in terms of dry standard cubic feet of natural gas (dscfng/hr).*
- *HHV = The Higher Heat Value of the natural gas determined for the month per condition M6(b)(i) in terms of million Btu per dry standard cubic feet of natural gas (MMBtu/$dscf_{ng}$).*
- *Fd = The dry basis fuel factor determined for the month per condition M6(b)(ii) in terms of dry standard cubic feet of exhaust per million Btu of natural gas combusted ($dscf_{exhaust}$/MMBtu)*
- *Cx = The average concentration of pollutant "x" monitored by CEMS over the hour in terms of parts per million by volume, dry (ppmvd), uncorrected.*

CGT CO Control and Monitoring

The dry low NO_x combustors in the CGTs also minimize the formation of CO. Minimizing NO_x is usually at the expense of higher CO emissions, however, the "Advanced, Dry Low NO_x" combustor technology is able to optimize the combustors to minimize emissions of both pollutants. The dry low NO_x combustors are expected to maintain a CO emission rate well below 9 ppm. In addition to CO control through the dry low NO_x combustors, exhaust from each CGT passes through a platinum catalyst (following the SCR units) where oxygen in the gas stream reacts with CO to produce CO_2. The CO oxidation catalyst technology is capable of reducing CO concentration by 90+%.

Per the PSD permit, CO emission concentrations and rates from the CGTs are required to be continuously monitored. The CO CEMS must 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. CO CEMS requirements are incorporated by reference in the permit.

From the CO CEMS data, GHE can verify compliance with both short-term and long-term average limits. In addition, the CEMS triggers an alarm when CO concentrations approach any of the short-term average CO limits. This is done automatically by the CO data acquisition system (DAS).

CGT SO_2, H_2SO_4 and PM_{10} Control and Monitoring

Combusting only natural gas is the principle means for minimizing emissions of particulate matter, sulfur dioxide and sulfuric acid from each CGT. Per the PSD permit, continuous monitoring of the rate of natural gas combustion by each turbine and DB is required. In addition, natural gas is required to be sampled monthly and analyzed to determine sulfur and heat content.

For SO_2 and H_2SO_4, the PSD permit imposes only PMR limits. Monitoring compliance is accomplished by calculating emissions rated using sulfur balance calculations based on the actual amount and composition of natural gas combusted and emissions factors from stack testing relating the percent of H_2SO_4 to SO_2. The amount of natural gas combusted is continuously monitored by a gas flow meters on each turbine and DB. Meters measure the gas flow rate and automatically correct to standard temperature and pressure units based on the monitored pipeline gas temperature and pressure. This data is periodically crossed checked by GHE against fuel certifications provided by the Williams Pipeline Company.

Per the PSD permit, gas flow meters are required to be installed, operated and maintained according to 40 CFR Part 75, Appendix D. Also, natural gas heat and sulfur content are required to be determined monthly through direct sampling and analyzing the natural gas per 40 CFR Part 75, Appendix D. 40 CFR Part 75, Appendix D is incorporated by reference in the permit.

PM_{10} emissions from the CGTs are each limited to no more than 22.6 lb/hr of filterable plus condensable PM_{10}. The required monitoring means is to calculate PM_{10} emissions based on the actual amount of natural gas combusted during each 24-hr period time an emissions factor based on the most recent particulate stack testing.

Reference method testing is the required means for monitoring compliance with the particulate grain loading limit. For the first three years of operation testing was required annually. Provided testing verifies compliance, the required testing frequency is relaxed to once every 5-years. Stack testing results must be reported as total particulate, filterable particulate and condensable particulate.

CGT Ammonia Emissions Monitoring

Per the PSD permit, NH_3 emissions (NH_3 slip) from each CGT is required to be continuously monitored. NH_3 CEMSs must meet the requirements contained in 40 CFR, Part 63, Appendix A, Reference Method 301, Validation Protocol (Validation Protocol), and 40 CFR, Part 60, Appendix F, Quality Assurance Procedures (Appendix F), or other EFSEC-approved performance specifications and quality assurance procedures. Because neither the Validation Protocol nor Appendix F contain actual performance specifications for operating NH_3 CEMSs, performance specifications needed to be adopted into the AOP to fill this void. Washington's Title V regulations under WAC 173-401-615(1)(b) allow adopting monitoring requirements into a Title V AOP when requirements are not adequately specified. This approach to adding monitoring to a Title V AOP is referred to as “gap-filling monitoring”.

Until NH_3 CEMS performance specifications are adopted as final by EPA, EPA’s Preliminary Performance Specification for Ammonia Continuous Emission Monitors (PPS-001, EPA, 2005) can serve as a surrogate performance specification. PPS-001 has not yet been published in the Federal Register but is proposed by EPA as their preferred performance specifications for NH_3 CEMS. PPS-001 establishes specifications for the allowable range, calibration drift and accuracy for NH_3 CEMS. The PPS-001 performance specifications are then inserted into the Validation Protocol for initial testing of NH_3 CEMS and Appendix F for ongoing quality assurance and control of NH_3 monitors.

CGT Opacity Monitoring

Per PSD permit EFSEC/2001-01 Amendment 4 (PSD), opacity of the exhaust from each CGT must be monitored. Two options are provided for opacity monitoring:

- A certified opacity reader can read and record the opacity of each operating unit during daylight hours daily and then weekly of compliance is maintained for the previous calendar month; or,
- Opacity can be monitored using a Continuous Opacity Monitoring System (COMS) on each CGT as an alternative.

Per the PSD permit, COMS must 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. Both are incorporated by reference in the permit.

3.4 Steam Turbine

Description

The GE D11 steam turbine generates electricity using steam produced by the Heat Recovery Steam Generators (HRSGs). Each HRSG produces superheated steam using leftover heat energy from its associated gas turbine plus supplemented heat energy from its associated DB. The steam turbine itself is not an emissions unit but is an integral part of the combined cycle power plant. The steam turbine power cycle requires operation of the CGTs (turbines + DBs), Cooling Tower and Auxiliary Boiler. The steam turbine generator can produce up to an additional 300 MW of electric power. The steam power cycle is a closed loop process where exhaust steam from the steam turbine is condensed by passing through the cooling towers and then pumped as liquid water back to the HRSGs in a continuous closed-loop arrangement. Since the steam turbine has no direct air pollutant emissions, it is not designated as an emissions unit.

3.5 Auxiliary Boiler

Description

Start-up of the combined cycle power plant requires an auxiliary heat source to provide heat while the CGTs are warming up. This is accomplished by a separate, 29.3 MMBtu/hr natural gas-fired Auxiliary Boiler. The Auxiliary Boiler provides initial steam for the steam turbine during startup.

Auxiliary Boiler Emissions Control and Monitoring

The Auxiliary Boiler employs low NO_x burners, good combustion practices and the use of natural gas for controlling air pollutant emissions.

The PSD permit establishes hourly and annual emissions limits for the Auxiliary Boiler for NO_x, CO, SO_2, VOC, PM_{10}, and opacity. The PSD permit does not require CEMS for the Auxiliary Boiler but does require periodic stack testing to demonstrate compliance with permit limits. The PSD permit also requires monthly calculation of emissions over the previous 12-consecutive month period to monitor compliance with annual emissions limits to verify compliance with annual emissions limits. The prescribed calculation method for all pollutants except SO_2 requires using actual natural gas consumption data and emissions factors based on the most recent stack testing results. For SO_2, emissions must be based on fuel sulfur monitoring data and sulfur balance calculations. For opacity, certified opacity readings are required once per month.

3.6 Cooling Tower

Description

As mentioned previously, the steam power cycle is a closed-loop process whereby steam remaining after expanding through the steam turbine is condensed so the entire flowrate of the "working fluid" can be pumped back to the HRSGs in order to complete the steam power cycle. Pumping produces the high pressures in the working fluid loop, which is needed by the steam turbine to generate power. The Cooling Tower enables the closed loop steam power cycle by expelling waste heat through one, nine-cell, forced draft cooling unit. The Cooling Tower transfers heat to the ambient air through evaporation of water. Water used by the Cooling Tower is pumped from a well located nearby on the Chehalis River.

GHE maintains Cooling Tower water quality to prevent high concentrations of chemicals and dissolved solids that would lead to particulate emissions and odors. Cooling Tower water is continuously monitored for pH, free chlorine, oxidation reduction potential (ORP) and conductivity to assure water quality. Sodium Hypochlorite (bleach) is added to prevent biological growth in the Cooling Tower. The sodium hypochlorite is added automatically to maintain 0.2 – 0.6 ppm free chlorine. Sulfuric acid (H_2SO_4) to prevent scaling is added automatically to maintain pH between 8.1 and 8.5. The bleach and H_2SO_4 are added to the water via constant volume pumps that are automatically controlled based on continuous monitoring of the water quality.

Design operating specifications for GHEC's Cooling Tower are as follows:

- 1,535,200 cubic feet per minute (ft3/min) air flow at design conditions (9 fans total)
- 175,000 gallons per minute (gpm) recirculating water flow
- 1165 milligrams per liter (mg/L) total dissolved solids

- Addition of 93% H_2SO_4 (sulfuric acid) to water at a variable rate, but approximately 70 gallons per day (gpd) average when the plant is running.
- Addition of 12.5% NaClO (sodium hypochlorite) to water at a variable rate, but approximately 104 gal/day average when the plant is running.
- 2H Drift Eliminators manufactured by ENEXIO with a drift rate less than 0.0005 percent.

Cooling Tower Monitoring

The Cooling Tower emits PM_{10} in the form of particulate suspended or dissolved in tiny airborne water droplets, which are referred to as "drift." VOCs and chlorine compounds may also be emitted in drift if Cooling Tower water quality is not maintained. The GHEC Cooling Tower is equipped with "drift eliminators" to reduce drift and air emissions associated with the drift. GHEC's Cooling Tower employs drift eliminators rated at a drift loss rate of less than 0.0005% of the recirculating cooling water flow rate.

The permit requires monthly calculation of the daily (annual average) and annual cooling tower PM_{10} emissions rates based on design flow rates for the circulating water pumps, circulating water pump operating records, conductivity, conductivity to total dissolved solids (TDS) correlation factor and a drift loss rate of 0.000005 gallons per gallon of recirculating water. The level of TDS in the cooling tower water determines the potential for PM_{10} emissions as dissolved solids precipitate to particulate as the cooling tower water evaporates using the following formula:

$$\frac{Q \times C \times 0.000005 \times 60 \times 8.34}{1000000} = D$$

Where:

Q = Either the actual or design recirculating water flow rate in gallons per minute
C = total dissolved solids concentration in parts per million by weight (ppmw)
D = particulate emission rate in lb/hr.
0.000005 = the drift loss rate in gallon lost/gallon of recirculating cooling water

TDS is monitored indirectly by monitoring conductivity of the cooling tower water (TDS is directly related to conductivity). The level of TDS is controlled by adjusting the rate of make-up water to the cooling tower to maintain conductivity below 1200 microohms conductivity. Conductivity is monitored continuously and an alarm is triggered in the control room when conductivity reaches 1200 micro ohms to alert operators to manually adjust the make-up water-up water rate.

3.7 Emergency Generator

Description

GHEC relies on one 400 kilowatt (536 horsepower) Caterpillar, model 3456, diesel-fired emergency generator (Emergency Generator) to provide electricity during power outages. This is critical for GHEC to power down equipment and maintain operation of lubricating oil pumps during power outages. The manufacture date of the Emergency Engine was 2002.

Engine Make & Model	Caterpillar, model 3456
Engine Serial #	CER00348
Date engine was ordered	7/22/2002
Model year of engine	2002
Engine BHP	536 BHP
Engine KW	400 KW

40 CFR Part 60, Subpart IIII (Subpart IIII) does not apply to the Emergency Generator at GHEC because the order date of the Emergency Generator precedes the effective date of Subpart IIII. 40 CFR Part 63, Subpart ZZZZ (Subpart ZZZZ) does apply. In addition to Subpart ZZZZ, the Emergency Generator is subject to requirements from PSD Amendment 4.

Emergency Generator Monitoring

The permit requires monitoring sufficient to verify the Emergency Generator engine is operated, maintained and repaired in a manner consistent with the manufacturer's emissions-related specifications. In addition, total hours of operation and hours of maintenance testing must be tracked and recorded.

3.8 Diesel-fired Water Pump Engine (Fire Water Pump Engine)

Description

The facility includes a 205 kilowatt (275 horsepower) Fire Water Pump Engine for fire suppression during electrical power outages.

Engine Make & Model	John Deere, model No. 6081AF001
Engine Serial #	RG6081A146553
Date engine was ordered	Pre 2002
Model year of engine	2001
Engine BHP	275 BHP
Engine KW	205 KW

40 CFR Part 60, Subpart IIII (Subpart IIII) does not apply to the Fire Water Pump Engine at GHEC because the order date of the Fire Water Pump Engine precedes the effective date of Subpart IIII. 40 CFR Part 63, Subpart ZZZZ (Subpart ZZZZ) does apply. In addition to Subpart ZZZZ, the Fire Water Pump Engine is subject to requirements from PSD Amendment 4.

Fire Water Pump Engine Emissions Control and Monitoring

The permit requires monitoring sufficient to verify the Fire Water Pump Engine is operated, maintained and repaired in a manner consistent with the manufacturer's emissions-related specifications. In addition, total hours of operation and hours of maintenance testing must be tracked and recorded.

3.9 Table 3: Summary of Emissions Units

ID	Description	Control Devices	Permit #s
EU-1	**Combined Cycle Gas Turbine 1 (CGT1)**: • Combustion Turbine 1 (CT1) – General Electric 7FA natural gas turbine with a maximum design heat rate of 1,671 mmBtu/hr and an output of 234 KVA. • Duct Burner 1 (DB1) – 505 mmBtu/hr natural gas duct burner	• CT1 equipped with Dry-Low NO_x Combustors • DB1 equipped with Low NO_x Burners. • Exhaust from both CT1 and DB1 pass through Selective Catalytic Reduction (SCR) and CO catalyst systems	EFSEC/2001-01 Amendment 4
EU-2	**Combined Cycle Gas Turbine 2 (CGT2):** • Combustion turbine – General Electric 7FA natural gas turbine with a maximum design heat rate of 1,671 mmBtu/hr and an output of 234 KVA. • Duct Burner – 505 mmBtu/hr natural gas duct burner	• CT2 equipped with Dry-Low NO_x Combustors • DB2 equipped with Low NO_x Burners. • Exhaust from both CT2 and DB2 pass through Selective Catalytic Reduction (SCR) and CO catalyst systems	
EU-3	**Auxiliary Boiler:** 29.3 mmBtu/hr natural gas fired boiler used to assist with start-up.	• Low NO_x burners	
EU-4	**Cooling Tower:** Nine cell, 175,000 gal/min forced draft cooling tower	• Equipped with drift eliminators	
EU-5	**Emergency Generator:** 400 kW (536 hp) emergency generator used to help power down equipment and maintain operation of lubricating oil pumps in the event of power outages.	None	
EU-6	**Emergency Fire Water Pump:** 205 kW (275 bhp) diesel-fired water pump to provide for fire suppression during electrical power outages.	None	

3.10 Insignificant Emissions Units (IEUs)

The equipment listed in Table 4 were identified by the GHE as insignificant emissions units (IEUs) as defined under WAC 173-401-200(17). IEUs are exempt from Title V permit program requirements as provided under WAC 173-401-530. None of the IEUs listed in Table 4 are a significant source of emissions or subject to equipment-specific air quality requirements. Because all of the IEUs listed in Table 4 are "categorically exempt" IEUs, they are not required to be listed in in the GHEC AOP.

3.11 Table 4: Insignificant Emissions Units (IEUs)

ID	Description	Size/Capacity	IEU Basis
IEU	Mobile Fugitive Emissions	Na	WAC 173-401-530(1)(d)
IEU	Lubricating Oil Tank	Na	WAC 173-401-532(3)
IEU	Hydraulic Oil Tank	Na	WAC 173-401-532(4)
IEU	Storage of Pressurized Gases	Na	WAC 173-401-532(5)
IEU	Maintenance Shops	Na	WAC 173-401-532(7)
IEU	Continuous Emissions Monitoring Systems (CEMs)	Na	WAC 173-401-532(7)
IEU	Vents	Na	WAC 173-401-532(9)
IEU	Vehicle Internal Combustion Engines	Na	WAC 173-401-532(10)
IEU	Welding Operations	Na	WAC 173-401-532(12)
IEU	Plant Upkeep Activities	Na	WAC 173-401-532(33)
IEU	Pavement Cleaning and Sweeping	Na	WAC 173-401-532(35)
IEU	Food Preparation	Na	WAC 173-401-532(41)
IEU	Portable Drums and Totes	Na	WAC 173-401-532(42)
IEU	Lawn and Landscaping Activities	Na	WAC 173-401-532(43)
IEU	General Vehicle Maintenance	Na	WAC 173-401-532(45)
IEU	Comfort Air Conditioning	Na	WAC 173-401-532(46)
IEU	Office Activities	Na	WAC 173-401-532(49)
IEU	Sampling Connections	Na	WAC 173-401-532(51)
IEU	Parking Lot Exhaust	Na	WAC 173-401-532(54)
IEU	Indoor Activities	Na	WAC 173-401-532(55)
IEU	Repair and Maintenance	Na	WAC 173-401-532(74)
IEU	Air Compressors	Na	WAC 173-401-532(88)
IEU	Steam Leaks	Na	WAC 173-401-532(89)
IEU	Vacuum System Exhaust	Na	WAC 173-401-532(108)

4. Emissions

GHEC's emissions of criteria air pollutants and ammonia are characterized in the following tables. Table 5 shows cumulative, facility-wide emissions in terms of maximum potential to emit (PTE). PTE values represent maximum permitted emissions from all emissions units at GHEC based on enforceable emissions limits and maximum operating rates for all regulated emissions units. Table 6 shows actual emissions for calendar year 2017. Actual emissions are based on monitored fuel consumption rates, measured natural gas heat and sulfur content, and monitored emissions concentrations over calendar 2017. Table 7 shows cumulative, facility-wide HAP emissions in terms of maximum potential to emit (PTE).

4.1 Table 5: Criteria Pollutant Potential to Emit (PTE)

Pollutant	Potential to Emit (tons per year)	Source of Data

CO (Carbon Monoxide)	144	AOP Permit Application
PM 2.5 (Fine Particulate (<= 2.5 microns))	203	AOP Permit Application
PM-10 (Fine Particulate (<=10 microns))	203	AOP Permit Application
NO_x (Nitrogen Oxides)	245	AOP Permit Application
VOC as Volatile Organic Compounds	76	AOP Permit Application
SO_2 (Sulfur Dioxide)	29	AOP Permit Application
H_2SO_4 (sulfuric acid)	19	AOP Permit Application
NH_3 (ammonia)	141	AOP Permit Application

4.2 Table 6: 2017 Actual Emissions

Pollutant	2017Emissions (tons)	Source of Data
CO (Carbon Monoxide)	11.9	ORCAA 2017 Inventory
PM 2.5 (Fine Particulate: <= 2.5 microns)	24.1	ORCAA 2017 Inventory
PM-10 (Fine Particulate:<=10 microns)	24.1	ORCAA 2017 Inventory
NO_x (Nitrogen Oxides)	84.9	ORCAA 2017 Inventory
VOC as Volatile Organic Compounds	2.8	ORCAA 2017 Inventory
SO_2 (Sulfur Dioxide)	2.9	ORCAA 2017 Inventory
H_2SO_4 (sulfuric acid)	0.2	ORCAA 2017 Inventory
NH_3 (ammonia)	10.3	ORCAA 2017 Inventory

4.3 Table 7: HAP Potential to Emit (PTE)

Pollutant	Potential to Emit (tons per year)	Source of Data
Acedaldehyde	0.59	AOP Permit Application
Acrolein	0.094	AOP Permit Application
Arsenic	0.00087	AOP Permit Application
Benzene	0.19	AOP Permit Application
Beryllium	5.23E-5	AOP Permit Application
1,3-Butadiene	0.0063	AOP Permit Application
Cadmium	0.0048	AOP Permit Application
Chromium, trivalent	0.0030	AOP Permit Application
Chromium, hexavalent	0.0030	AOP Permit Application
Cobalt	0.00037	AOP Permit Application
Ethylbenzene	0.47	AOP Permit Application
Formaldehyde	1.6	AOP Permit Application
Hexane	7.8	AOP Permit Application
Manganese	0.0017	AOP Permit Application
Mercury	0.0011	AOP Permit Application
Naphthalene	0.022	AOP Permit Application

Nickel	0.0091	AOP Permit Application
Poly Aromatic Hydrocarbons	0.032	AOP Permit Application
Propylene Oxide	0.42	AOP Permit Application
Selenium	0.00010	AOP Permit Application
Toluene	1.9	AOP Permit Application
Xylenes	0.94	AOP Permit Application
Total HAP	**14.2**	**AOP Permit Application**

5. Regulatory Determinations

Table 8 summarizes regulatory determinations made for GHEC's AOP.

Table 8 Applicability Determinations

Citation	Description	Applicable?	Basis
40 CFR Part 60 Subpart GG	Stationary Gas Turbine NSPS	Yes	Applies to both combustion turbines since they are greater than 10 MMBtu/hr and were constructed after 1977. Establishes emissions standards for NO_x and SO_2 emissions. Also establishes a fuel sulfur content limit.
40 CFR Part 60 Subpart Da	Electric Utility Steam-Generation Units	Yes	Applies to the duct burners since they are greater than 250 MMBtu/hr and were constructed after 1971. Establishes emissions standards for NO_x and SO_2 emissions.
40 CFR Part 60 Subpart Dc	Small Institutional-Commercial-Industrial Steam Generation Units	Yes	Applies to the Auxiliary Boiler since it is greater than 10 MMBtu/hr and constructed after 1987. However, Subpart Dc only requires fuel monitoring for the GHEC Auxiliary Boiler.
WAC 463-78-100	Registration	No	The latest version of EFSECs registration regulations in WAC 463-78-100 (effective 3/26/06) exempts air operating permit sources from EFSECs registration program.
WAC 173-400-112	Requirements for Sources in Nonattainment Areas	No	GHEC is not located in a nonattainment area for any criteria pollutant. Therefore, this regulation is not applicable facility-wide.
WAC 173-400-120	Bubble Rules	No	GHEC has not requested an emission bubble for any regulated pollutant. Therefore, this regulation is not applicable.
WAC 173-400-131	Issuance of Emission Reduction Credits	No	GHEC has not sought emission reduction credits (ERCs). Therefore, this regulation is not applicable.
WAC 173-400-136	Use of Emission Reduction Credits	No	GHEC has not sought to use emission reduction credits (ERCs). Therefore, this regulation is not applicable.
40 CFR Part 63.6080 et seq. Subpart YYYY	National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines	No	Subpart YYYY applies to combustion turbines built after January 14, 2003 and located at major sources of HAP emissions. GHEC is facility is not a major source of HAP emissions. Therefore, Subpart YYYY does not apply.
40 CFR Part 64	Compliance Assurance Monitoring	No	For NOx, CO, Ammonia and opacity emissions, 40 CFR 64.2(b)(iv) provides an exemption from the requirements of Part 64 when a CEMS is otherwise required.

Citation	Description	Applicable?	Basis
			Compliance Assurance Monitoring rule requirements do not apply to particulate, SO2, and H2SO emissions per 40 CFR 64.2(a)(2), which includes an applicability criteria that the unit uses a control device to achieve compliance. A "control device" as defined in 40 CFR Part 64 does not include passive control measures that act to prevent pollutants from forming, such as the use low-polluting fuel or feedstocks. Because no control device is used to control particulate, SO2 or H2SO, this rule does not apply to those pollutants.
40 CFR Part 98	Federal Greenhouse Gas Reporting Requirements	No	The EPA greenhouse gas reporting rule was finalized September 22, 2009. In the preamble EPA responds to a question regarding whether it is an applicable requirement for the purposes of Title V: *As currently written, the definition of "applicable requirement" in 40 CFR 70.2 and 71.2 does not include a monitoring rule such as today's action, which is promulgated under CAA sections 114(a)(1) and 208.* Therefore, these requirements will be enforced directly by the USEPA outside of the Title V AOP program.
40 CFR 63.11193 et seq. Subpart JJJJJJ	National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers - Area Sources	No	GHEC operates the following three steam generating units (boilers): CGT1 Heat Recovery Steam Generator (HRSG), CGT2 HRSG, and the Auxiliary Boiler. Both HRSGs are preceded by duct burners. All three units combust only natural gas and, therefore, are not subject to this regulation.
40 CFR Part 60 Subpart KKKK	Ecology Carbon Dioxide Mitigation Program	No	Establishes requirements for Stationary Combustion Turbines that commenced construction, modification or reconstruction after February 18, 2005. Subpart KKKK does not apply since construction of the GHE facility commenced before 2005.
40 CFR Part 60 Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	No	The "order date" for both the Emergency Generator and Fire Water Pump precede the effective date of Subpart IIII.
40 CFR Part 63 Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.	Yes	Applies to both Emergency Generator and Fire Water Pump.

6. Basis for AOP Terms and Conditions

Energy facilities under the jurisdiction of EFSEC are subject to EFSEC's rules under Chapter 463-78 WAC (EFSEC's Rules). Therefore, the underlying regulatory basis for all conditions in GHEC's AOP comes from EFSEC's Rules. However, because EFSEC's Rules adopt by reference (ABR) relevant state and federal rules which apply to energy facilities, the pertinent details of applicable requirements reside within the adopted rules and regulations themselves. Table 9 provides a mapping of relevant state and federal regulations that have been ABR by EFSEC.

6.1 Table 9: EFSEC Rules Adopted by Reference

Title of Rule Adopted by Reference	Citation	Citation of EFSEC Adopting Rule
Washington Air Operating Permit Regulation	Chapter 173-401 WAC	WAC 463-78-005(2)
Washington's General Regulations for Air Pollution Sources except for Ecology specific sections and adoption of federal New Source Performance Standards	Chapter 173-400 WAC	WAC 463-78-005(1)
Washington's Acid Rain Program	Chapter 173-406	WAC 463-78-005(3)
Washington's Controls for New Sources of Toxic Air Pollutants	Chapter 173-460 WAC	WAC 463-78-005(4);
Federal New Source Performance Standards	40 CFR Part 60	WAC 463-78-115;
National Emission Standards for Hazardous Air Pollutants	40 CFR Part 61	WAC 463-78-005(1)
National Emission Standards for Hazardous Air Pollutants for Source Categories	40 CFR Part 63	WAC 463-78-005(1)

In order to avoid compounding already long strings of regulatory citations in GHEC's AOP, and because pertinent details of applicable requirements reside within the ABR regulations themselves, the ABR regulations are cited in GHEC's AOP without citing the corresponding Chapter 463-78 WAC section that adopts them. Therefore, the following sections discuss the regulatory basis for AOP conditions from the standpoint of state and federal regulations that have been ABR by EFSEC.

Per the Washington Air Operating Permit Program under WAC 173-401-600, the regulatory origin and authority for each condition must be stated in an AOP. For GHEC's AOP, origin and authority are stated at the end of each permit condition. The "origin" cites the state or federal regulation or PSD/NSR permit where the applicable requirement came from. The "authority" cites the specific section in WAC 173-401 providing authority to include the requirement.

The following authorities from the Washington AOP program were used in GHEC's AOP:

6.1 Table 10: Required Permit Content, Washington AOP Program

WAC 173-401 Section:	Provides authority to include in AOP:
WAC 173-401-600(1)(a)	Federal emissions limits and standards.
WAC 173-401-600(1)(b)	State emissions limits and standards.
WAC 173-401-600(1)(c)	Requirements from permits issued by a local air pollution control authority (NOC and PSD permits).
WAC 173-401-615(1)(a)	Monitoring required by an applicable requirement.
WAC 173-401-615(1)(b)	Periodic monitoring where the applicable requirement does not require specific monitoring (commonly referred to as "gap-filling monitoring).
WAC 173-401-615(1)(c)	As necessary, requirements concerning the use, maintenance, and, where appropriate, installation of monitoring equipment or methods.
WAC 173-401-615(2)	All applicable recordkeeping requirements and require, where applicable: - Records of required monitoring; - Records of changes made at the facility that result in emissions of a regulated air pollutant, but not otherwise regulated under the permit; - Retention of records of all required monitoring data and support information for a period of five years from the date the record originated; and, - Monitoring support information including all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation; and, - Copies of all reports required by the permit.
WAC 173-401-615(3)	All applicable reporting requirements and require: - Submittal of reports of any required monitoring at least once every six months; and, - Prompt reporting of deviations from permit requirements, including those attributable to upset conditions.
WAC 173-401-620(2)	Standard Title V provisions from WAC 173-401-620(2).
WAC 173-401-605(1)	Emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance.
WAC 173-401-640(1)	Upon request, the permitting authority shall include in the permit or in a separate written finding issued with the permit a determination identifying specific requirements that do not apply to the source.

6.2 Permit Administration (P1 – P21)

Permit administrative conditions (conditions P1 – P21) include conditions specifying how the AOP is managed according to the State AOP program under Chapter 173-401 WAC and conditions having implications on assuring compliance with all other conditions in the AOP. Many of the permit administrative conditions are "standard terms and conditions" and required to be in the AOP per either Chapter 173-401 WAC or per federal requirements for AOPs.

The origin of each permit administrative condition is stated at the end of each condition. Authority to include permit administrative conditions comes from primarily from WAC 173-401-600(1)(b), which specifies AOPs contain requirements from the Washington Clean Air Act (Chapter 70.94 RCW) and rules implementing that chapter (Washington's AOP program is pursuant to RCW 70.94.162, which under the Washington Clean Air Act.).

Permit administrative conditions specify terms of the AOP such as the permit duration, expiration, renewal and revision requirements. They also explain the “Permit Shield,” extent of AOP enforceability and how the AOP can be revoked or re-opened for cause. They are essential to the proper functioning of the AOP under the State of Washington Program. Because permit administrative conditions do not include any applicable emissions limitations or operational standards, monitoring is not applicable. However, general recordkeeping and reporting requirements apply. Also, compliance with permit administrative conditions must be certified annually. Several key conditions are discussed in detail below.

Standard Conditions (condition P4)

Both the origin and authority to include this condition in the permit come from WAC 173-401-620(2). The condition identifies general duty and administrative requirements that are standard for all AOPs including the duty to comply and duty to provide information.

Confidential Information (condition P16)

The origins of this condition are WAC 173-401-500(5) and WAC 173-401-620(2)(e). The condition identifies the essential standards for considering and handling confidential information. Justification for its inclusion in the AOP is that it establishes the standard for handling confidential information under Title V. Authority to include the condition in the permit comes from WAC 173-401-600(1)(b).

Credible Evidence (condition P17)

Condition P17 contains important provisions from the Credible Evidence Rule under 40 CFR Part 51, and from provisions under 40 CFR Part 60 and 61 concerning credible evidence. In general, these rules provide that the permittee may use any credible evidence outside of the monitoring and testing required by the AOP to support a compliance determination. The authority to include this condition is WAC 173-401-600(1)(a), which requires AOPs contain terms and conditions that assure compliance with all applicable federal requirements. There may be times when the permittee must augment the monitoring and testing required by the AOP with other information in order to demonstrate or assure continuous compliance. This condition allows for the use of credible evidence.

Emergency Provisions (condition P18)

Condition P18 contains the requirements governing how to treat emergencies under the Washington AOP program including what constitutes an emergency, criteria for demonstrating an emergency and effect of an emergency relative to AOP enforcement actions. This applicable requirement is required to be included in all AOPs.

Unavoidable Excess Emissions (conditions P19 & P20)

Condition P19 contains requirements from WAC 173-400-107 governing treatment of unavoidable excess emissions, which are included in the current Washington State Implementation Plan (SIP). The SIP is comprised of rules, which the State of Washington has adopted and EPA has approved, for maintaining the National Ambient Air Quality Standards. The current SIP was adopted by EPA September 20, 1993.

Recently, Washington Department of Ecology (Ecology) adopted updated rules governing unavoidable excess emissions events. These updated rules were adopted under WAC 173-400-108. They were adopted with a provision making them effective on the date EPA removes the currently effective rules under WAC 173-400-107. The future effective date provision was adopted knowing that the length of time for EPA to approve and update the SIP was uncertain. Therefore, the current rule governing unavoidable excess emissions, WAC 173-400-107, remains effective up to the date the EPA removes it from the SIP and inserts WAC 173-400-108.

Condition P19 was written with this "sunset" provision anticipating this change will likely happen sometime during the five-year AOP permit term. Likewise, condition P20, which contains the updated unavoidable excess emissions requirements under WAC 173-400-108, is written into the AOP with an effective date commencing the date EPA adopts it into the SIP.

Following recommendation from Ecology's Air Quality Program, both conditions were included in GHEC's AOP in order to avoid re-opening and modifying GHEC's AOP mid permit term.

Certification (condition P21)

In accordance with WAC 173-401-520, all application forms, reports, and compliance certifications must be certified for truth and accuracy by a responsible official. Therefore, this requirement has implications all other requirements in the AOP requiring compliance reports to EFSEC. The requirement to certify reports for truth and accuracy is considered an applicable requirement. It is included in the AOP under the general authority provided by WAC 173-401-600(1)(b), which requires permits contain terms and conditions sufficient to assure compliance with all applicable requirements under the Washington Clean Air Act.

6.3 General Terms and Conditions (G1 – G17)

General terms and conditions (G1 – G17) cover general compliance and permitting requirements including:

- Access for inspection of GHEC;
- Treatment of insignificant emissions units;
- Pre-construction permitting requirements;
- Temporary source requirements;
- Asbestos and demolition permitting;
- Chemical Accident Prevention Program;
- Stratospheric Ozone Protection Program;
- Outdoor burning requirements;
- General emissions testing requirements; and,
- Acid Rain Program.

These conditions are categorized as General Terms and Conditions in GHEC's AOP because they either have broad implications on multiple conditions in the AOP, or are entire programs that are applicable if triggered, such as the Stratospheric Ozone Protection program. Authority for each condition varies depending on whether the applicable requirement originated from a state or federal regulation. Several general terms or conditions are discussed in detail below.

Inspection and Entry (condition G1)

Condition G1 contains requirements for inspection and entry to the facility. The specific provisions and requirements governing inspection and entry originate from WAC 173-401-630(2) and WAC 173-400-105(3)&(4). Authority to include these requirements in the AOP comes from WAC 173-401-600(1)(b).

New Source Review Requirements (conditions G4 & G5)

Conditions G4 & G5 reference the procedural requirements for securing EFSEC's approval prior to commencing any project triggering an air permit from EFSEC. These requirements include requirements for NOC, PSD and modifications and are generally referred to as "New Source Review." They become applicable when triggered and must be complied with prior to commencing any project triggering an air permit through EFSEC. Authority to include the requirements in GHECs AOP comes from the general authority provided by WAC 173-401-600(1)(b).

Chemical Accident Prevention (condition G8)

Chemical accident prevention under the federal Risk Management Plan (RMP) program (40 CFR Part 68) applies to any industrial facility that uses or stores any extremely hazardous substance. The RMP program requires subject facilities to develop an RMP for all substances used above a threshold quantity.

GHE does use and store aqueous ammonia, which is a chemical regulated under the RMP program. The RMP program applies to facilities that use or store 20,000 pounds of aqueous ammonia (conc 20% or greater) during any year. GHECs use of aqueous ammonia has been below this threshold concentration since the facility began operation. However, because there is a potential for aqueous ammonia to be used above the RMP rule threshold quantity, condition G8 was added to GHECs AOP. The specific requirements of the RMP rule remain dormant unless a regulated substance is used above its threshold quantity.

The RMP program is considered an applicable federal regulatory program. Therefore, authority to include condition G8 comes from WAC 173-401-600(1)(a), which requires permits contain terms and conditions sufficient to assure compliance with all applicable federal emissions limits and standards. Although it is unlikely GHEC will trigger the RMP program, the program must be acknowledged in the AOP as applicable if triggered.

Outdoor Burning (condition G10)

Outdoor burning is generally prohibited but may be permitted as allowed by WAC 173-425. However unlikely for GHEC, the requirement was included in the AOP to allow for permitted outdoor burning. Authority to include it in the AOP comes from the general authority provided by WAC 173-401-600(1)(b). Any permit allowing outdoor burning would be issued by EFSEC's contractor, ORCAA.

Reporting to Verify Emissions from Potential PSD Sources (condition G16)

This requirement from 40 CFR Part 52 is triggered by a project that has a reasonable possibility (50% of significant Emission Rate) of triggering a need to have a PSD permit or PSD permit modification. The requirement is to keep record of and report actual emissions resulting after a project after is has started operations (5-10 years).

Prevention of Significant Deterioration (PSD) (Condition G17)

This condition includes EFSECs PSD and major New Source Review requirements and applies for projects triggering PSD.

6.4 Applicable Requirements

Applicable requirements (AR1 – AR5) cover applicable emissions limits and operating standards from applicable state and federal regulations and NOC and PSD permits issued by EFSEC to GHEC. Origin and authority are stated at the end of each condition. All applicable requirements are in their original form except for minor reorganization for ease of implementation. Primarily, reorganization consisted of separating out monitoring specifics from the applicable limits. All monitoring details are included in the Monitoring section of GHECs AOP.

The following applicable regulations are included:

- General facility-wide standards and prohibitions primarily from Chapter 173-400 WAC (AR1);
- Gas turbine NSPS from 40 CFR 60 Subpart GG (AR2);
- Duct burner NSPS from 40 CFR 60, Subpart Da (AR3);
- PSD Amendment 4 permit requirements for the CGTs (AR4);
- PSD Amendment 4 permit requirements for the Auxiliary Boiler (AR5);
- PSD Amendment 4 permit requirements for the emergency diesel engines (AR6); and,
- PSD and NOC permit requirements for the Cooling Tower (AR7).

NSPS General Duty Requirements (condition AR1.1)

This condition contains the general "blanket" requirement that emissions units subject to NSPS be operated in a manner consistent with good air pollution control practice for minimizing emissions. It is a requirement from the general NSPS requirements under 40 CFR60.11(d) and applies to all emissions units subject to a federal NSPS. For GHEC, the CGTs, Duct Burners, Auxiliary Boiler and Emergency Engines are all subject to federal NSPS and, therefore must abide by this general requirement.

Washington General Standards (condition AR1.2 – 1.10)

Conditions AR1.2 – AR1.10 contain applicable requirements from the States General Regulations for Air Pollution Sources under Chapter 173-400 WAC. These requirements apply plant-wide to all emissions units including insignificant emissions units (IEUs). However, IEUs are not subject to the monitoring, recordkeeping and reporting requirements of the AOP.

Acid Rain Program (condition AR1.11)

Condition AR1.11 contains the plant-wide SO_2 allowance requirement from the GHEC's Acid Rain Program permit. This is the primary requirement from the Acid Rain Program permit.

Required Plans (condition AR1.12)

Condition AR1.12 requires the permittee develop, maintain, and follow:

- An Operating and Maintenance manual (O&M Manual); and,
- An equipment Start-up, Shutdown, and Malfunction Procedures manual (SSM Manual).

Both manuals are required to describe accepted operating procedures for minimizing emissions from all emissions units at the facility. The origin of this requirement is PSD Amendment 4.

NSPS for Stationary Gas Turbines (conditions AR2.1 – AR2.3)

Conditions AR2.1 – AR2.3 contain applicable requirements from the federal Standards of Performance for Stationary Gas Turbines under CFR 60 Subpart GG (Subpart GG). Subpart GG applies to stationary gas turbines with a heat input at peak load equal to or greater than 10 million Btu per hour (MMBtu/hr), based on the lower heating value of the fuel fired. The Turbines at GHEC each have heat input rates well above this threshold at 1,671 MMBtu/hr. Subpart GG imposes both NO_x and SO_2 standards for stationary gas turbines that apply at all times including operations during startup, shutdown and malfunction events.

The Subpart GG standard for NO_x is based on the following calculation found in 40 CFR Part 60.332(a)(1):

NO_x Standard Calculation Method
NO_x STD = 0.0075(14.4)/[(1671mmBtu/hr)(10^6)(1.05556 kj/Btu)/(175MW)(10^6)] + 0 =
0.010715 percent by volume @ 15% oxygen and dry = 107.15 ppmvd @ 15% O_2

The Subpart GG NO_x standard is included in condition AR 2.1. Subpart GG requirements for the NO_x continuous emissions monitoring system (CEMS) incorporate by reference the monitoring requirements from 40 CFR Part 75.

For combined cycle turbine systems where the turbine is followed by a duct burner, Subpart GG allows NO_x to be measured after the duct burner. This allowance is found under 40 CFR Part 60.335(b)(3):

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_x emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_x emission limit in §60.332 for the combustion turbine must still be met.

The Subpart GG standard for SO_2 is 0.015 percent at 15% oxygen on a dry basis (150 ppm@ 15% O_2), which originates from 40 CFR Part 60.333(a). This standard is included as a limit in condition AR2.2 in the GHEC AOP. Required monitoring is based on sulfur mass balance calculations as specified in condition M11, which rely on fuel combustion monitoring and periodically measuring the heat and sulfur content of the natural gas.

NSPS for Electric Utility Steam Generating Units (conditions AR2.4 – AR2.5)

Conditions AR2.4 – AR2.5 contain applicable requirements from the federal Standards of Performance for Electric Utility Steam Generating Units under CFR 60 Subpart Da (Subpart Da). Subpart Da applies to electric utility steam generating units that are capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (including natural gas) for which construction, modification, or reconstruction commenced after September 18, 1978. The Duct Burners at GHEC each have a design heat rate of 505 MMBtu/hr and were constructed after 1978. Therefore, Subpart Da applies.

Subpart Da imposes both NO_x and SO_2 standards that apply at all times the Duct Burners are operating. Subpart Da allows the NO_x CEMS on combined emissions from each Turbine and associated Duct Burner. This monitoring strategy is allowed by 40 CFR 60.48Da(k)(3), which provides that, when a duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burners, compliance with the applicable NO_x emissions limits may be determined by measuring the emissions combined with the emissions from other unit(s) utilizing the common steam turbine. This provision allows a single NO_x analyzer on the stack to determine NO_x concentrations, which are then converted to unit specific NO_x concentrations and pollutant mass rates based on unit specific natural gas monitoring. Therefore, the same NO_x and O_2 monitoring system required for Subpart GG can be used for the Duct Burners as well. The data acquisition system (DAS) for the NO_x is capable of determining both concentrations and pollutant mass rates specific to each combustion unit based on the natural gas combustion rates, which are monitored individually for each unit.

PSD Requirements for CGTs (conditions AR2.6 – AR2.19)

Conditions AR2.6 – AR2.19 include applicable requirements from PSD Amendment 4 (PSD permit) applying to the CGTs. All requirements are in identical form as written in the PSD permit except for some reorganization and adding clarification of requirements for continuous emissions monitoring systems (CEMS) and continuous monitoring systems (CMS).

Clarification of requirements for CEMS and CMS was necessary for two reasons:

1. The CGTs are subject to multiple standards for the same pollutant from different regulations, each which have their own unique CEMS and CMS requirements. As a result, there are redundancies in CEMS and CEM requirements and some apparent conflicting requirements that needed to be resolved and harmonized in the AOP.
2. The PSD permit incorporates by reference federal performance standards and quality assurance procedures for CEMS and CMS, which are general and cover all possible scenarios and fuel types for affected facilities. As a result, requirements applying specifically to GHEC are difficult to identify due to the sheer volume of inapplicable provisions within the referenced federal standards. For example, the adopted requirements for NO_x monitoring under 40 CFR Part 75 spans well over 300 pages of CFR and itself references several other equally extensive sections of the CFR.

Because of this, requirements for CEMS and CMS at GHEC are adopted by reference in the permit.

6.5 Monitoring Terms and Conditions

Applicable monitoring terms and conditions (M1 – M16) include all required monitoring from applicable federal subparts and the PSD permit. Origin and authority are stated at the end of each condition. Although applicable monitoring requirements are included in their original form, additions were required to clarify requirements. This is allowed in Title V AOPs under "gap filling monitoring" provisions in WAC 173-401-615(1)(b) and (1)(c).

Regulatory origins are stated at the end of each condition. Monitoring conditions added to applicable requirements state "N/A - gap filling monitoring" for the regulatory origin. Authority for all monitoring conditions come from WAC 173-401-615(1). Each condition includes WAC 173-401-615(b)&(c) because gap filing monitoring requirements needed to be added to all monitoring conditions. Certain monitoring conditions are exclusively "gap filling monitoring" conditions.

Ammonia Continuous Emission Monitoring Systems (condition M9)

PSD permit condition 18.2 requires continuous monitoring of ammonia from the CGTs:

CGT ammonia Continuous Emissions Monitoring Systems (NH_3 CEMS) 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. The NH_3 CEMS shall be capable of determining emissions during start-up, shutdown, and periods of malfunction.

However, neither the Validation Protocol nor Appendix F of 40 CFR Part 60 which are cited in the condition actually contain performance specifications for ammonia monitors. As explained earlier in this document, preliminary NH_3 CEMS performance specifications adopted by EPA in Preliminary Performance Specification for Ammonia Continuous Emission Monitors (PPS-001, EPA, 2005) can be used as a surrogate until EPA adopts final performance specifications for NH_3. PPS-001 has not yet been published in the Federal Register but is proposed by EPA as the performance specifications required for NH_3 CEMS. PPS-001 establishes specifications for the allowable range, calibration drift and accuracy for NH_3 CEMS. The PPS-001 performance specifications can be used in the Validation Protocol for initial testing of NH_3 CEMS and in

Appendix F requirements for ongoing quality assurance and control.

6.6 General Recordkeeping Requirements

Applicable recordkeeping terms and conditions (RK1 – RK9) include all required recordkeeping requirements for Title V AOPs as required under WAC 173-401-615(2). Origin and authority are stated at the end of each condition.

6.7 Reporting

Applicable reporting terms and conditions (R1 – R13) include all required reporting requirements for Title V AOPs as required under WAC 173-401-615(32). Origin and authority are stated at the end of each condition.