SITE CERTIFICATION AGREEMENT

BETWEEN

THE STATE OF WASHINGTON,

GRAYS HARBOR ENERGY LLC

AND

GRAYS HARBOR ENERGY II LLC

GRAYS HARBOR ENERGY CENTER

LOCATED IN:
GRAYS HARBOR COUNTY, WASHINGTON

Incorporating all provisions up to and including
AMENDMENT NO. 5

EXECUTED OCTOBER 27, 1976
AMENDMENT NO. 1 MARCH 18, 1982
AMENDMENT NO. 2 MAY 21, 1996
AMENDMENT NO. 3 AUGUST 12, 1999
TECHNICAL AMENDMENT, RESOLUTION NO. 297, FEBRUARY 12, 2001
TECHNICAL AMENDMENT, RESOLUTION NO. 298, APRIL 13, 2001
TECHNICAL AMENDMENT, RESOLUTION NO. 309, APRIL 19, 2004
TECHNICAL AMENDMENT, RESOLUTION NO. 312, MARCH 24, 2005
AMENDMENT NO. 5, ORDER NO. 860, DECEMBER 21, 2010

TABLE OF CONTENTS

Site Certification Agreement
Between
The State Of Washington,
Grays Harbor Energy LLC
and
Grays Harbor Energy II LLC

for the
Grays Harbor Energy Center

Located In Grays Harbor County, Washington

PREAMBLE

This Site Certification Agreement is made and entered into pursuant to Chapter 80.50 of the Revised Code of Washington by and between the State of Washington (which is also referred to as the "State" in this document), acting by and through the Governor of the State of Washington, Grays Harbor Energy LLC, a Delaware limited liability company, and Grays Harbor Energy II LLC, a Delaware limited liability company, (referred to collectively as "Certificate Holders").

The initial Site Certification Agreement was executed on October 27, 1976, by Governor Daniel J. Evans and provided for construction and operation of Nuclear Projects No. 3 and No. 5. On March 18, 1982, Governor John Spellman approved Amendment No. 1, which included changes to the terms for the operation of emergency diesel generators for Projects No. 3 and No. 5. On May 21, 1996, Governor Mike Lowry approved an Amended Site Certification Agreement incorporating Amendment No. 2, which provided authorization and the terms and conditions for construction and operation of the combustion turbine project. On August 12, 1999, Governor Gary Locke approved Amendment No. 3 which removed the terms and conditions for Nuclear Projects No. 3 and No. 5 (WNP-3 and WNP-5), but retained the terms and conditions for the combustion turbine project.

On February 12, 2001, the Energy Facility Site Evaluation Council (referred to as the "Council" in this document) approved by resolution the addition of Duke Energy as a co-agreement holder with Energy Northwest. On April 13, 2001, the Council approved, by resolution, technical changes to the project description.

On November 19, 2001, Energy Northwest and Duke Energy submitted an application to amend this Site Certification Agreement, which would have been Amendment No. 4, but they later withdrew the amendment request.

On April 19, 2004, the Council approved, by resolution, technical changes to clarify provisions related to water use. On March 24, 2005, the Council approved a resolution removing Energy Northwest from the Site Certification Agreement and naming Grays Harbor Energy LLC, as the successor to Duke Energy Grays Harbor Energy, LLC, as the Certificate Holder.

On ____________, Governor Christine Gregoire approved Amendment No. 5, which authorized the construction and operation of two additional gas-fired turbines, an additional steam turbine generator and associated facilities at the Grays Harbor Energy Center (GHEC) and added Grays Harbor Energy II LLC as a co-Certificate Holder.

The Grays Harbor Energy Center consists of up to four gas-fired combustion turbine units and two steam turbine-generators, and associated facilities. The project is located on a 22-acre site within a prior construction laydown area on the former Satsop Nuclear Power Plant Site. The balance of the former nuclear site has been transferred to the Grays Harbor Public Development Authority ("PDA"), a political subdivision of Grays Harbor County, to pursue economic development activity pursuant to county ordinances and RCW 80.50.300. Grays Harbor Energy LLC owns the 22-acre Project site and has agreements with the PDA to ensure that all facilities and/or systems necessary to support the construction and operation of the project are available.

This Site Certification Agreement is administered on behalf of the State by the Energy Facility Site Evaluation Council, also referred to as “EFSEC” or the “Council” in this document.

The parties hereto now desire to set forth all terms, conditions, and covenants relating to such site certification in this Site Certification Agreement pursuant to the provisions of RCW 80.50.100(1).

ARTICLE I: DEFINITIONS

"Approval" (by EFSEC) means an affirmative action by EFSEC or its properly-authorized agents, regarding documents, plans, designs, programs, or other similar requirements submitted pursuant to this Agreement.

"Associated facilities" means storage, transmission, handling, or other related and supporting facilities connecting the facility with existing energy and fuel supply, processing, or distribution systems, including, but not limited to, the natural gas fuel line from the Grays Harbor Energy Center metering point to the turbines, utility connections, and the electrical power lines connecting the Grays Harbor Energy Center to existing Bonneville Power Administration electrical transmission lines. The project does not include a natural gas delivery system, other than those elements under the Certificate Holders' control and located on the generating facility site.

"Commencement of construction" means the initiation or beginning of any actual construction activities such as form work, rebar, or pouring concrete for a unit's major components (e.g., the combustion turbine), but excludes site preparation.

"EFSEC" or "Council" means the State of Washington Energy Facility Site Evaluation Council created by Chapter 80.50 RCW, or such other agency or agencies of the State of Washington as may hereafter succeed to the powers of EFSEC for the purpose of this Agreement.

"Certificate Holder" means Grays Harbor Energy LLC after March 24, 2005. After December 21, 2010, "Certificate Holder" means both Grays Harbor Energy LLC and Grays Harbor Energy II LLC, jointly and severally.

"Site Certificate Agreement" or "SCA" refers to this agreement.

"Site preparation" means grading, excavation, and preparation of lay down areas prior to commencement of construction.

"Units 1 and 2" means the energy generation facility, consisting of two combustion turbine generators, one steam generator, and associated facilities, the construction of which was completed in 2008.

"Units 3 and 4" means two additional combustion turbine generators, one steam generator and associated facilities authorized to be constructed and operated pursuant to Amendment No. 5 of this Agreement.

"Will" in this agreement when referencing an action to be taken by the Certificate Holder, means that the certificate holder is obligated to perform the action as set out in the relevant text.

ARTICLE II SITE CERTIFICATION

A. Site Description

The site for the Grays Harbor Energy Center is located in Grays Harbor County, Washington, south of the Chehalis River near the town of Satsop, and is more particularly described in Attachment I, which is incorporated herein by this reference.

B. Site Certification

1. The State authorizes the combined cycle combustion turbine generating project, known as the Grays Harbor Energy Center, and as described below, to be located, constructed, and operated in the locations described in Section I.A.1 and I.A.2.

   a. The project consists of up to four natural gas-fired turbine units, up to two steam turbine-generators, and associated facilities. Two gas turbines, one steam turbine and associated facilities (Units 1 and 2) were constructed and commenced commercial operation pursuant to the applicable Site Certification Agreement in 2008. The Certificate Holders are authorized to construct and operate two more gas turbines, another steam turbine and associated facilities (Units 3 and 4).

   b. The combustion turbine generators (CTGs) will be General Electric Frame 7FA turbines, arranged in two 2x1 combined cycle configurations with General Electric D11 steam turbines. Each combustion turbine unit will have a nominal capacity of 175 megawatts and shall have a heat recovery steam generator (HRSG). Each steam turbine generator (STG) will have a capacity of approximately 300 megawatts. Dry Low NOx Combustors in combination with Selective Catalytic Reduction (SCR) shall be used to minimize the formation of nitrogen oxides (NOx). An oxidation catalyst shall be used to control carbon monoxide (CO) and volatile organic compounds (VOC) emissions. Cooling will be provided by two cooling towers, one consisting of nine cells (Units 1 and 2) and a second consisting of ten cells (Units 3 and 4).

   c. Natural gas will be used as the fuel. Natural gas will be delivered through a 48-mile pipeline, owned and operated by Northwest Pipeline Corporation.

   d. The electrical output of each unit will be delivered through the Bonneville Power Administration's high-voltage system to the existing Bonneville Power Administration Satsop substation.

2. This Site Certification Agreement authorizes the Certificate Holders to begin construction of Units 3 and 4 within ten (10) years of the execution of Amendment No. 5. If construction of Units 3 and 4's major components has not been commenced within ten (10) years of the execution of Amendment No. 5, all rights under this Site Certification Agreement to construction and operation of Units 3 and 4 will cease.

   If the Certificate Holders do not begin construction of Units 3 and 4 within five (5) years of the execution of Amendment No. 5, the Certificate Holders will report to the

Council their intention to continue and will certify that the representations in the application, environmental conditions, pertinent technology and regulatory conditions remain current and applicable, or identify any changes and propose appropriate revisions in the Site Certification Agreement to address changes. Construction may begin only upon prior Council authorization, upon the Council's finding that no changes to the Site Certification Agreement are necessary or appropriate, or upon the effective date of any necessary or appropriate changes to the Site Certification Agreement.

Further, if the Certificate Holders do not begin construction of Units 3 and 4 within five (5) years of the execution of Amendment No. 5 and the Council has adopted by rule changes to the standards governing "construction and operation for energy facilities" specified in WAC chapter 463-62, the construction and operation of Units 3 and 4 will be governed by the regulations in effect at the time the Council authorizes construction to proceed.

ARTICLE III. GENERAL CONDITIONS

A. Legal Relationship

1. This Site Certification Agreement is made in lieu of any permit, certificate or similar document required by any department, agency, division, bureau, commission, board, or political subdivision of this state.

2. This Agreement shall bind the Certificate Holder, and its successors in interest, and the State and any of its departments, agencies, divisions, bureaus, commissions, boards, and its political subdivisions, subject to all the terms and conditions set forth herein, as to the approval of, and all activities undertaken with respect to, the Project or the Site. For regulatory purposes, the co-owners of the Project, Grays Harbor Energy LLC and Grays Harbor Energy II LLC, agree that they are jointly and severally responsible for the operation of the facility as a single entity under this Agreement, and for compliance with all provisions of this Site Certification Agreement. All references in this document to "certificate holder," "applicant," or similar term, unless the context requires otherwise, refers to either or both entities as their interests may appear, so as to provide seamless authority and responsibility for regulatory purposes. The Certificate Holder shall ensure that any activities undertaken with respect to the Project or the Site by its agents (including affiliates), contractors, and subcontractors comply with this Agreement. The term "affiliates" includes any other person or entity controlling, controlled by, or under common control of or with the Certificate Holder.

3. Liquid discharges from the project to navigable waters shall be made in accordance with the National Pollution Discharge Elimination System (NPDES) permit issued by the Council (Attachment II to this Agreement, or as reissued by the Council).

4. Emissions from Units 1 and 2 into the atmosphere of gases or substances will be made in accordance with the Prevention of Significant Deterioration (PSD) permit issued by the Council (Attachment V to this Agreement or as reissued by the Council). Emissions from Units 3 and 4 into the atmosphere of gases or substances will be made in accordance with the PSD permit issued by the Council (Attachment VI to this Agreement or as reissued by the Council).

5. This Site Certification Agreement is subject to federal laws and regulations applicable to the project and to the terms and conditions of any permits and licenses which may be issued to the Certificate Holders by appropriate federal agencies.

6. This document, which results from the cumulative actions of Project sponsors and the State of Washington as recited above, is intended to remove all superseded or irrelevant provisions and to incorporate all relevant existing provisions or conditions resulting from the original application, all applications for amendment, and all resolutions of the Council. To the extent any relevant provision is inadvertently omitted, it is nonetheless the intention of the parties to this document that such provision be interpreted to remain in full force and effect. In the event the Council identifies an inadvertent omission, it will promptly correct the omission by resolution.

7. This Site Certification Agreement constitutes the whole and complete agreement between the parties and supersedes any other negotiations, representations or agreements, whether written or oral, or not set forth herein.

B. <u>Enforcement</u>

1. This Site Certification Agreement may be enforced by means of all remedies available at law or in equity.

2. This Site Certification Agreement may be revoked, suspended, or modified by the State for failure by the Certificate Holders to comply with any of the terms and conditions attached, or for violations of Chapter 80.50 RCW, regulations issued there under, any applicable state or federal laws or regulations, or for violation of any order of the Council, pursuant to the provisions of Chapters 80.50 and 34.05 RCW and Title 463 WAC.

3. When any action of the Council is required by or authorized in this Site Certification Agreement, the Council may, but will not be required to, conduct a hearing pursuant to Chapter 34.05 RCW. If the Council grants a hearing to consider withholding or refusing approval of a required or requested action, the hearing will be conducted pursuant to Chapter 34.05 RCW.

C. <u>Notices and Filings</u>

Filing of any document or notice required by this Site Certification Agreement with the Council will be deemed to have been duly made when delivered to the Council's offices in Olympia, Washington. Notice to be served upon the Certificate Holders will be deemed to have been duly made when deposited in first class mail, postage prepaid, addressed to each Certificate Holder at the address on file with the Council.

D. <u>Right of Inspection</u>

The Certificate Holders agree to provide access to the Grays Harbor Energy Center and all associated facilities to designated representatives of the Council in the performance of their official duties.

E. <u>Site Certification Agreement Compliance Monitoring and Costs</u>

The Certificate Holders will pay to the Council such reasonable costs as are actually and necessarily incurred for the monitoring and compliance activities during the construction and operation of the project as authorized in this Site Certification Agreement and as required in Chapter 80.50 RCW. EFSEC will prescribe the amount and manner of such payment subject to applicable rules and procedures.

F. EFSEC Liaison

The Certificate Holders will designate one or more persons to act as a liaison between the Council and the Certificate Holders for matters relating to the Grays Harbor Energy Center. If the Certificate Holders designates more than one person, notice to or communication by the Council with one shall constitute notice to or communication with all.

G. Site Restoration

1. The Certificate Holders are responsible for site restoration pursuant to Council rules.

2. At least three months prior to beginning construction of Units 3 and 4, the Certificate Holders will present to the Council a modified site restoration plan reflecting the construction of Units 3 and 4, and showing any changes necessary to the previously approved site restoration plan in light of the construction and operation of those units. Construction of Units 3 and 4 may not begin until the Council has approved a plan adequately providing for site restoration and the funding of site restoration of the entire Grays Harbor Energy Center or any part thereof in the event the project is terminated before it has completed its planned useful operating life.

H. Modification of Site Certification Agreement

1. This Site Certification Agreement may be amended pursuant to Council rules and procedures then in effect, and in like manner as the development of the original Site Certification Agreement, including, but not limited to, obtaining approval of the Governor. Any amendments to this Site Certification Agreement will be made in writing. Alteration that does not substantially alter the substance of the Agreement may be accomplished by resolution of the Council pursuant to WAC 463-66-070. Alteration shall occur as a matter of law after five years if the Council adopts by rule changes to its standards governing "construction and operation for energy facilities" as specified in WAC 463-62 and the Certificate Holder has not then commenced construction of Units 3 and 4.

2. Any change of the terms or conditions of a PSD or NPDES Permit or this Site Certification Agreement required by federal law or regulations will be governed by applicable law and regulation and will not require modification of this Site Certification Agreement in the manner prescribed in H.1, above. Any changes in the terms or conditions of Attachment I – Site Legal Description; and Attachment III – Water Withdrawal Authorization; shall not require modification of this Site Certification Agreement in the manner prescribed in H.1 above, unless otherwise required by Council rules or regulations.

3. In circumstances where the Council believes that a significant degree of unforeseen adverse impact on the environment exists or is imminent as a result of the operation or condition of the Grays Harbor Energy Center, the Council may impose specific conditions or requirements upon the Certificate Holders in addition to the terms and conditions of this Site Certification Agreement as a consequence of those circumstances. Such additional conditions or requirements will be effective only while needed to protect the public health, safety or welfare from the adverse

circumstances, for not more than 90 days, and may be extended for additional 90-day periods if deemed necessary by the Council.

ARTICLE IV. PROJECT CONSTRUCTION

A. Construction Commencement and Reporting

1. Construction Schedule and Environmental Monitoring

a. Sixty days prior to beginning site preparation of Units 3 and 4, the Certificate Holders will submit an overall construction and site preparation schedule. The construction schedule will provide a good faith basis to believe that construction of Units 3 and 4 will be completed within twenty-two (22) months of beginning construction. After beginning construction, the Certificate Holders will submit a quarterly Construction Progress Report to the Council, within 30 days after the end of each calendar quarter until construction is completed.

b. The Certificate Holders agree to notify the Council immediately in the event of any significant change in the construction schedules on file with the Council.

c. EFSEC will retain, prior to commencement of site preparation and construction, a qualified firm or individual as environmental monitor. The environmental monitor will be available to assist in resolution of environmental concerns during construction; will verify that development complies with all conditions and requirements of this Agreement; and will personally inspect the site and the activities under this Agreement at appropriate intervals and stages to reasonably ensure compliance.

2. Plans and Specifications

a. The Certificate Holders will submit to EFSEC or its designated representative for approval, at the appropriate time, prior to the commencement of construction, those design documents that demonstrate compliance with all conditions and requirements of this Site Certification Agreement. The design documents will include, but are not limited to, conceptual design studies, flow diagrams, system descriptions, detailed design drawings and specifications as appropriate, and vendor guarantees for equipment and processes.

b. The Certificate Holders will design the proposed facility to comply with requirements for construction in Seismic Zone 3.

c. Project buildings and structures will comply with requirements of the approved design and construction plans, and the building code in effect at the time of construction.

B. Aesthetics and Landscaping

1. The Certificate Holders agree to construct Units 3 and 4 in a manner aesthetically compatible with the existing facility and the adjacent area.

2. One screening berm has been built and landscaped between the Grays Harbor Energy Center and Keys Road. The Certificate Holder will maintain the berm landscaping in an appropriate manner.

C. Surface Run-off and Erosion Control

1. The Certificate Holders will apply for coverage under a National Pollutant Discharge Elimination System (NPDES) Construction Stormwater Permit. The Certificate Holders will comply with all applicable permit requirements.

D. Transmission Lines

1. Associated transmission lines will connect the project to the Northwest Power grid at the Bonneville Power Administration Satsop Substation. The transmission lines will be placed in the existing Bonneville Power Administration rights of way.

2. All associated electrical transmission and service lines will comply in design and construction with all applicable state, federal, and industry standards. In the event of inconsistency among applicable standards, the most stringent standard will apply.

E. Construction Clean-Up

The Certificate Holders agree upon completion of construction to dispose of all temporary structures not required for future use. The Certificate Holders also agree to dispose of used timber or brush, refuse or flammable material resulting from the clearing of lands or from the construction of the project in a manner approved by the Council.

F. As-Built Drawings

The Certificate Holders agree to provide or to allow access by the Council or its designated representatives, on request, to complete sets of as-built drawings for the project.

G. Archaeological Site Protection

1. The Certificate Holders agree to coordinate with the Council and Tribes to develop an acceptable cultural resources monitoring plan, and will implement the plan during construction of the project.

2. The Certificate Holders agree to halt relevant construction activity immediately and report to the Council, Tribes and the Department of Archaeological and Historic Preservation all archaeological or historical findings made during the course of excavation and construction.

3. The Certificate Holders agree to consult with the Council to arrange for preservation of artifacts and for interpretation of any archaeological or historical site discovered in the course of any construction.

H. Construction Phase Spill Prevention and Countermeasures Plan

Three months prior to beginning construction of Units 3 and 4, the Certificate Holders will submit for Council review and approval any necessary modifications of the spill prevention and countermeasure plan that complies with applicable state and federal regulations and provisions of the project's NPDES permit. This program will address oil/chemical storage, containment, site security and personnel training. The program shall also address measures that will be taken to control and contain discharge, cleanup actions, notification of appropriate agencies and a list of available cleanup materials.

I. Septic System for the Project

The Certificate Holders shall be permitted to construct, maintain, and operate a septic system. The Certificate Holder will provide verification to the Council prior to commencement of construction of Units 3 and 4 that the septic system for the proposed expanded facility will comply with applicable county codes.

J. Noise during Construction

1. No construction activities are permitted on Sundays, legal holidays, or between 10:00 p.m. and 6:00 a.m. within 1000 feet of an occupied residential dwelling.

2. All construction equipment will have noise control devices no less effective than those provided originally by the equipment's manufacturer.

3. Pile driving or blasting operations shall not be permitted within 3,000 feet of an occupied residential dwelling on Sundays or legal holidays or between 8:00 p.m. and 8:00 a.m. on other days.

4. Notice of the proposed construction schedule and locations will be well publicized in the area, and nearby residents shall be notified in advance of the anticipated schedule for especially noisy activities, such as blasting or steam blows

K. Construction Traffic

The Certificate Holders shall develop a Traffic Management Plan in consultation with the Grays Harbor County Department of Public Works, and submit it to the Council for approval. The plan shall include measures to encourage construction traffic to use the Wakefield-Lakefield corridor to minimize traffic at the Highway 12-Keys Road intersection, address pedestrian traffic leaving the construction site, and provide for reasonable access to side roads during periods when project-related traffic or construction equipment may impede such access.

L. Fugitive Dust

Fugitive dust will be controlled by spraying water on dry earth in the active construction areas.

ARTICLE V. OPERATION OF THE PROJECT

A. Water Withdrawal

1. The Certificate Holders are hereby authorized to withdraw water to be used for the operation of the project as follows:

   For Units 1 and 2, the Grays Harbor Energy Center is authorized to withdraw a total of 9.2 cubic feet per second of water from the Ranney wells pursuant to the water authorization in Attachment III, incorporated by this reference. If needed, the Certificate Holders may obtain additional water from another valid water right holder, such as the Grays Harbor Public Development Authority ("PDA").

   Following construction of Units 3 and 4 of the Grays Harbor Energy Center, the Certificate Holders may withdraw up to a total of 16 cubic feet per second of water. This water may be supplied through a combination of withdrawals authorized by Attachment III and water obtained from another valid water right holder. The Certificate Holders will notify EFSEC of the source of water to be used for operation of the facility prior to commencing construction of Units 3 and 4, and prior to any change in the source of water.

2. The Certificate Holders are authorized to withdraw up to 300 gallons per minute from ground water in an area near the confluence of the Chehalis and Satsop rivers from a well known as the raw water well. Withdrawal of water from this well for any uses other than domestic supply and fire suppression will be limited to 300 gallons per minute and will be limited by restrictions set forth in Attachment III on withdrawals during periods of low flows.

3. Should the withdrawal for operation of the project impair senior water rights, the Certificate Holders agree to compensate the holder of such rights for the impairment, and to take necessary measures to prevent recurrence or continuation of such impairment.

4. Withdrawal of water pursuant to Attachment III will be adjusted as necessary to ensure that the project does not affect the minimum base flows immediately downstream of the point of diversion. The required minimum base flows are established in Chapter 173-522-020, Washington Administrative Code, and set forth in Attachment III. This authorization is also subject to the provisions of Chapter 173-522 and Chapter 173-500, Washington Administrative Code.

5. During periods in which the withdrawal restrictions set forth in Attachment III are in effect, the Certificate Holders may continue to operate the Grays Harbor Energy Center using water purchased from the PDA or from other water rights holders, so long as the water purchased is derived from water rights that are not subject to base flow restrictions. The Certificate Holders will submit annual reports to EFSEC, Ecology and WDFW indicating when base-flow restrictions were in effect, and describing the measures taken to comply with the base flow restrictions during those periods.

6. The Certificate Holders may use stored water in order to provide the necessary water for the project during the low flow periods set forth in Attachment III, or may obtain water from other holders of valid water rights that are not subject to minimum base flow requirements.

B. Water Discharge

All discharges by the Certificate Holders to state waters shall be in accordance with Chapter 90.48 RCW, this Site Certification Agreement, and the NPDES Permit, as issued by the Council and attached hereto as Attachment II, and as may be later amended by the Council.

C. Emissions Into Air

1. The Certificate Holders will operate Units 1 and 2 of the project so that all emissions to the atmosphere will comply with the Approval of Notice of Construction and Prevention of Significant Deterioration Application as set forth in Attachment V, attached and incorporated by this reference. The Certificate Holders will operate Units 3 and 4 so that all emissions to the atmosphere will comply with the Approval and Notice of Construction and Prevention of Significant Deterioration Application as set forth in Attachment VI, attached and incorporated by this reference.

2. The Certificate Holders will properly operate and maintain in good working order all air pollution control equipment and monitoring equipment required in Attachments V and VI.

3. The Certificate Holders will be subject to the time limitations for construction and renewal conditions as set forth in Attachments V and VI.

D. Lighting

In specific locations where glare or light spillover would impact Keys Road or be visible to nearby residences, lighting angles will be adjusted to minimize glare impacts, or supplemental light shields/vegetation will be used for extra screening.

The Certificate Holders will minimize nighttime lighting that is not essential for operations, safety and security, and will direct lighting downward or install shielding where practical.

E. Noise during Operation

1. Units 1 and 2 have been designed and constructed so that the combustion turbines and several other major sources of sound are enclosed within structures containing acoustical damping and/or surrounded by acoustical enclosures or walls. Acoustically absorptive insulation has been installed on the duct walls of the combustion turbine air intake system; silencers have been installed in the air flow path of the enclosure ventilating systems, and acoustically absorptive silencers have been installed on several emergency relief valves. By June 15, 2011, the Certificate Holders will install the following additional acoustical mitigation devices on Units 1 and 2:

- Acoustical walls around the combustion turbine exhaust transition pieces;
- Silencers in four combustion turbine enclosure ventilation systems; and
- Silencers on one auxiliary steam relief valve and four cold reheat steam valves.

Within six months after installation of additional acoustic devices specified above, the Certificate Holder must conduct a least-cost verification noise study of Units 1 & 2. Prior to conducting the study, the Certificate Holder must submit the least-cost verification study plan to the Council for approval.

2. The project will comply with the maximum noise limits set forth in WAC 173-60-040, as adopted by the Council in WAC 463-62-030. If the Certificate Holder begins construction of Units 3 and 4 more than five (5) years after the execution of Amendment No.5, and in the interim, the Council has amended the noise standard set forth in WAC 463-62-030, the amended standard will apply to the expanded project.

3. Before commencement of construction of Units 3 and 4, and in adequate time to incorporate sound suppression measures into the development of design of Units 3 and 4, the Certificate Holders will retain a qualified acoustical specialist to conduct a field study of Units 1 and 2 to identify additional, reasonable, cost-effective mitigation measures that could be implemented with the construction of Units 3 and 4 to further reduce project noise below the maximum noise limits. The field study will focus on reducing or avoiding sounds annoying nearby residents, rather than merely on reducing A-weighted decibel levels. The Certificate Holder will submit the draft study report to the Council for its review.

4. The Certificate Holders will retain an acoustical specialist to take noise measurements during performance testing of Units 3 and 4 prior to commercial operation. The results of these measurements will be used to determine whether additional acoustical barriers are necessary along the property boundaries, or if in-lieu mitigation waivers are needed from adjacent property owners.

5. After commencement of commercial operation of Units 3 and 4, the Certificate Holders will retain a qualified acoustical specialist to conduct a noise monitoring study to determine whether the expanded facility complies with the maximum noise limits set forth in WAC 173-60-040, as adopted by the Council in WAC 463-62-030.

6. The Certificate Holders have implemented a procedure for recording and responding to communications from nearby residents concerning project noise. The Certificate Holder will report to the Council on a monthly basis regarding noise complaints, responses and follow-up actions.

7. Irrespective of whether the volume of resulting noise is above or below the applicable regulatory noise limits, the Certificate Holders shall maintain all noise suppression equipment and features in good working order and shall use them during all relevant operations of the Project.

ARTICLE VI. PUBLIC AND ENVIRONMENTAL PROTECTION

A. Emergency Plans

The Certificate Holders will develop an Emergency Response Plan describing the methods, means, and resources available to provide for employee safety in the event of emergencies including fire or explosions, in association with the project. No later than three months prior to first operation of the combustion turbines, the plan will be submitted for Council review and approval. In preparing the plan, the Certificate Holders must agree to:

1. Coordinate such plan with local, state and federal agencies directly involved in implementing such a plan.

2. Follow the requirements of WAC 296-24-567 and 296-62-3112 and 29 CFR 1910.38, Emergency Action Plan.

3. Include detailed provisions for public health and safety, emergency medical treatment, special emergency training programs and prevention of property damage.

4. Provide the Council with lists of emergency personnel, communication channels and procedures, and update the information when any changes occur.

5. All employees, contractors, and visitors will be covered by the plan.

6. The Certificate Holder will update the plan and submit it to the Council every two years from the date of the approved amendment.

B. Security Plan

The Certificate Holders will submit a comprehensive physical Security Plan for the protection of the site and project facilities.

C. Spill Prevention Control and Countermeasure Plan

The Certificate Holders will maintain and implement a Spill Prevention, Control and Countermeasure (SPCC) Plan, approved by the Council, consistent with the requirements of the NPDES Permit and with requirements of applicable state and federal laws and rules. The SPCC plan is to be approved by a Professional Engineer and include the amount and type of oils and hazardous materials to be stored at the project site, patterns of usage, transfer procedures and other factors which will indicate the magnitude of spill notification requirements. This SPCC plan shall also describe procedures for securing valves, type of gauges, dike size and design, site security, lighting, alarms, spill response materials and equipment, inspection procedures, personnel training, emergency procedures and spill notification requirements. This SPCC plan shall be submitted to the Council and its designated representatives within one year of beginning construction of the project, and shall be updated at intervals no longer than every two years.

D. <u>Explosions</u>

The Project will be equipped with detectors to provide warning of the release of flammable or explosive gases. The detection system must be described in the final design plans.

ARTICLE VII. MISCELLANEOUS PROVISIONS

A. Discharge of Pollutants

All discharges into waters of the State of Washington must comply with the requirements of an NPDES Permit issued by the Council, pursuant to Chapter 90.48 RCW.

B. Greenhouse Gases and Carbon Dioxide Mitigation

1. The Council has approved a mitigation plan for carbon dioxide emissions associated with the operation of Units 1 and 2.

2. If a comprehensive federal or state mitigation program is implemented, the Council reserves the right to exercise its authority under that program considering and appropriately crediting any measures that the Certificate Holders have accomplished.

3. The Certificate Holders are required to mitigate carbon dioxide emissions from Units 3 and 4 in accordance with RCW chapter 80.70 and Chapter 463-80 WAC. Within 120 days of commencing commercial operation of Units 3 and 4, the Certificate Holders will make a mitigation payment to an independent qualified organization approved by EFSEC in an amount that satisfies the mitigation obligation. Certificate Holders will require the independent qualified organization to consult with Grays Harbor County and provide preference and priority for mitigation projects located within Grays Harbor County.

4. Attachment VII to this Agreement contains preliminary calculations determining the amount of carbon dioxide mitigation payments to be made by Certificate Holders.

C. Attachments

Attachments hereto by this reference are included in the Site Certification Agreement:

I. Site Legal Description

II. National Pollution Discharge Elimination System Permit

III. Water Withdrawal Authorization

IV. GHE Noise Mitigation Commitment Letters of July 9, 2010 and August 30, 2010.

V. Final Approval Notice of Construction and Prevention of Significant Deterioration Application for Units 1 and 2

VI. Final Approval Notice of Construction and Prevention of Significant Deterioration Application for Units 3 and 4

VII. Carbon Dioxide Mitigation Calculations

VIII. Errata Sheet – February 2011

SIGNATURES

Dated and effective this 18th day of February, 2011.

FOR THE STATE OF WASHINGTON

Christine Gregoire

Governor Christine Gregoire

FOR GRAYS HARBOR ENERGY LLC

____

FOR GRAYS HARBOR ENERGY II LLC

____

ATTACHMENT I
SITE LEGAL DESCRIPTION

The Satsop Combustion Turbine Project is located as follows:

All that portion of the southwest quarter of the southeast quarter of Section 7, Township 17 North, Range 6 West, W.M. described as follows:

Commencing at the south quarter corner of said Section 7;
Thence S88°58'07"E along the south line of said Section 7, a distance of 1026.55 feet;
Thence N03°30'07"E, 291.86 feet to a point on the north line of the Bonneville Power Administration (B.P.A.) right of way and the POINT OF BEGINNING;
Thence continuing N03o30'07"E, 545.21 feet;
Thence N86°29'56"W, 989.04 feet to a point on the east line of Keys Road right of way;
Thence S03°46'56"W along said east line of Keys Road, 595.78 feet to an intersection with said north line of the B.P.A. right of way.
Thence S88°48'12"E along said north line of the B.P.A. right of way, 904.96 feet;
Thence N84°19'49"E along said north line of the B.P.A. right of way, 88.86 feet to the POINT OF BEGINNING.

Situate in Grays Harbor County, Washington

And

All that portion of the southwest quarter of the southeast quarter of Section 7, Township 17 North, Range 6 West, W.M. described as follows:

Commencing at the south quarter corner of said Section 7;
Thence S88°58'07"E along the south line of said Section 7 a distance of 1026.55 feet;
Thence N03°30'07"E, 837.07 feet to the POINT OF THE BEGINNING;
Thence continuing N03°30'07"E, 319.39 feet;
Thence N86°29'53"W, 220.60 feet;
Thence N03°30'07"E, 107.60 feet;
Thence N86°29'53"W, 766.35 feet to a point on the east line of Keys Road right of way;
Thence S03°46'56"W along said east line of Keys Road, 427.00 feet;
Thence S86°29'53"E, 989.04 feet to the POINT OF BEGINNING.

Situate in Grays Harbor County, Washington

National Pollutant Discharge Elimination System
Waste Discharge Permit WA-002496-1

State of Washington
ENERGY FACILITY SITE EVALUATION EFSEC
Olympia, Washington 98504-3172

In compliance with the provisions of the:
State of Washington Water Pollution Control Law
Chapter 90.48 Revised Code of Washington; and

State of Washington Energy Siting Law
Chapter 80.50 Revised Code of Washington; and

Federal Water Pollution Control Act
(Clean Water Act)
Title 33 United States Code, Section 1251 et seq.

GRAY HARBOR ENERGY CENTER

Grays Harbor Energy Center
P.O. Box 26
Satsop, Washington 98583

Facility Location:
401 Keys Road
Elma, Washington 98541

Industry Type:
Electric Generating Plant (SIC 4911)

Water Body ID No.: Outfall 001
WA-22-4040

Receiving Water:
Outfall 001:
Chehalis River at RM 19.7

Discharge Location:
Outfall 001: Latitude: 46.971944° N
Latitude: 123.486333° W
Outfall 002B:
Grays Harbor Public Development Authority pond immediately west of Keys Road

Grays Harbor Energy Center is authorized to discharge in accordance with the special and general conditions that follow.

Date: 10/28/10

Chairman, Energy Facility Site Evaluation Council

TABLE OF CONTENTS

List of Tables

Appendices

SUMMARY OF PERMIT REPORT SUBMITTALS

Refer to the Special and General Conditions of this permit for additional submittal requirements.

Permit Condition	Submittal	Frequency	First Submittal Date
S3.A	Discharge Monitoring Report (Process wastewater and stormwater)	Monthly	June 30, 2008
S3.E	Reporting Permit Violations	As necessary	As necessary
S3.F	Other Noncompliance Reporting	As necessary	As necessary
S4.A	Updated Operations and Maintenance Manual	One time	With the application for permit renewal
S5.B.1	Engineering Report Scope of Work	One time	February 1, 2011
S5.B.2	Draft Engineering Report	One time	February 1, 2012
S5.B.3	Final Engineering Report	One time	August 1, 2012
S5.B.4	Letter of Compliance with AKART	One time	February 1, 2013
S5.C	Request for Extension of Schedule of Compliance	One time	As necessary
S6	Application For Permit Renewal	One time	November 13, 2012
S7	Solid Waste Control Plan Update	Twice/permit cycle	January 1, 2009
S8	Spill Prevention Control and Countermeasure Plan Update	As necessary	As necessary
S9	Outfall Inspection	Annual	30 days after completion
S10	Acute Toxicity Testing	Every other month for one year	First report as required in S5, then 60 days after each test completed; summary report with app for permit renewal
S11	Chronic Toxicity Testing	Quarterly for one year	First report as required in S5, then 60 days after each test completed; summary report with app for permit renewal
G4	Notice of Planned Changes	As necessary	As necessary
G5	Plan Review Required	As necessary	At least 180 days prior to any proposed changes.
G20	Reporting Anticipated Non-compliance	As necessary	180 days prior to noncompliance event
G21	Reporting Other Information	As necessary	As necessary

SPECIAL CONDITIONS

S1. DISCHARGE LIMITS

A. General

All discharges and activities authorized by this permit must be consistent with the terms and conditions of this permit.

The discharge of any pollutants more frequently than, or at a level in excess of, that identified and authorized by this permit violates the terms and conditions of this permit.

The discharge of any pollutant not specifically authorized by this permit in concentrations that cause or contribute to a violation of water quality standards established under section 307(a) of the Clean Water Act or Chapter 173-201A WAC constitutes a violation of this permit and the Clean Water Act.

B. Interim Limits

Beginning on the effective date of this permit modification and lasting through February 13, 2013, the Permittee is authorized to discharge process wastewater to the Chehalis River at the permitted location subject to the following limitations:

Table 1: Effluent Limits

Parameter	Daily Maximum[1]	Monthly Average[2]
Temperature	16°C	Not applicable
Ammonia (as N)	321 mg/L	160 mg/L
Free Available Chlorine	0.5 mg/L	0.2 mg/L
pH[3]	6.0 - 9.0	Not applicable
Total Suspended Solids (TSS)	100.0 mg/L	30.0 mg/L
Oil and Grease	20 mg/L	15 mg/L
Chromium, Total	200 µg/L	200 µg/L
Iron, Total	1 mg/L	1 mg/L
Priority Pollutants and PCBs	See Footnote 4	

1 Maximum daily effluent limit means the highest allowable daily discharge. The daily discharge means the discharge of a pollutant measured during a calendar day. For pollutants with limits expressed in units of mass, the daily discharge is calculated as the total mass of the pollutant discharged over the day. For other units of measurement, the daily discharge is the average measurement of the pollutant over the day. This does not apply to pH.

2 Average monthly effluent limit means the highest allowable average of daily discharges over a calendar month. To calculate the discharge value to compare to the limit, you add the value of each daily discharge measured during a calendar month and divide this sum by the total number of daily discharges measured.

3 Permittee must include alarm systems for pH control to provide indication of any variance from established limits.

4 The Permittee must not discharge polychlorinated biphenyl compounds (PCBs). The Permittee must not discharge detectable amounts of priority pollutants (listed in 40 CFR Part 423, Appendix A), except chromium and zinc, or PCBs in the effluent from chemicals added for cooling system maintenance.

C. Mixing Zone Authorization for Outfall No. 001

Chronic Mixing Zone

Chronic aquatic life criteria and human health criteria must be met at the edge of the chronic zone. The chronic dilution factor is 182.

Acute Mixing Zone

Acute aquatic life criteria must be met at the edge of the acute zone. The acute dilution factor is 21.

D. Final Limits

Beginning on February 14, 2013 and lasting through the expiration date of this permit, the Permittee is authorized to discharge process wastewaters to the Chehalis River at the permitted location subject to final effluent limits established in the approved engineering report required in Condition S5 of this permit.

S2. MONITORING REQUIREMENTS

A. Interim Monitoring Schedule

Beginning on the effective date of this permit modification and lasting through February 13, 2013, the Permittee must monitor wastewater discharges as specified in Table 2.

The sampling required by this permit must be representative of normal operations during power generation.

Table 2: Monitoring Schedule - Circulating Cooling Water Blowdown Discharge – Outfall 001

Parameter	Units	Sample Point	Minimum Sampling Frequency	Sample Type
Temperature	^{o}C	Blowdown	Continuous [1]	Meter
Flow	MGD	Blowdown	Continuous [1]	Meter
pH	SUs	Blowdown	Continuous [1]	Meter
Free Available Chlorine	mg/L	Circulating Water or Blowdown	Continuous [1,2]	Meter or Grab
TSS	mg/L	Blowdown	Monthly	Grab
Turbidity	NTU	Blowdown	Monthly	Grab

Parameter	Units	Sample Point	Minimum Sampling Frequency	Sample Type
Arsenic, Total	µg/L	Blowdown	Monthly	Grab
Ammonia, Total as N	mg/L	Blowdown	Monthly	Grab
Priority Pollutants and PCBs	µg/L	Blowdown	Annual	Grab
Chromium, Total	µg/L	Blowdown	Monthly	Grab
Oil and grease (HEM)	mg/L	Blowdown	Monthly	Grab
Iron, Total	mg/L	Blowdown	Monthly	Grab

1 Continuous means uninterrupted - except for brief lengths of time for calibration, power failure, or for unanticipated equipment repair or maintenance. If monitoring equipment fails, Permittee must implement manual monitoring.

2 If the monitoring equipment malfunctions, the Permittee must collect grab samples every 4 hours. The Permittee must collect a grab sample at least weekly to verify continuous monitor performance.

B. Final Monitoring Schedule

Beginning on February 14, 2013 and lasting through the expiration date of this permit, the Permittee is required to monitor its discharges as specified in the approved engineering report required in Condition S5 of this permit. The final monitoring schedule will be incorporated into the permit through a permit modification process.

C. Stormwater Benchmarks, Prohibitions, and Monitoring Requirements

1. Authorized Stormwater Discharges

Beginning on the effective date of this permit modification and lasting through its expiration date, the Permittee is authorized to discharge stormwater offsite of the facility to the C1 Pond. All discharges and activities authorized by this permit must be consistent with the terms and conditions of this permit.

Discharges must not cause or contribute to a violation of Surface Water Quality Standards (Chapter 173-201A WAC), Ground Water Quality Standards (Chapter 173-200 WAC), Sediment Management Standards (Chapter 173-204 WAC), and human health-based criteria in the National Toxics Rule (40 CFR 131.36). Discharges that are not in compliance with these standards are prohibited.

2. General Prohibitions

The Permittee must manage all stormwater discharges to prevent the discharge of crude, synthetic or processed oil, or oil-containing products as identified by an oil sheen.

3. Monitoring Requirements

Beginning on the effective date of this permit, the Permittee must monitor stormwater for the parameters listed in Table 3.

Table 3: Stormwater Benchmarks and Monitoring Requirements

Parameter	Benchmark Value	Monitoring Frequency	Sample Type	Analytical Method	Sample Location
Turbidity	25 NTU's	Quarterly[1]	Grab	EPA 180.1	In accordance with SWPPP
Oil and Grease	[2]	Quarterly	Grab	EPA 413.1	
Total Zinc	117 μg/L	Quarterly	Grab	EPA 200.8	
Total Copper	14 μg/L	Quarterly	Grab	EPA 200.8	
pH	5-9 SU	Quarterly	Grab	EPA 150.1	

1 Stormwater discharges must be sampled at least once each calendar quarter.
2 The benchmark value is "no visible sheen".

a. The Permittee shall sample the discharge from each designated location at least once per quarter:

1st Quarter = January, February, and March
2nd Quarter = April, May, and June
3rd Quarter = July, August, and September
4th Quarter = October, November, and December

b. The Permittee shall sample the stormwater discharge from the first fall storm event each year. "First fall storm event" means the first time after October 1st of each year that precipitation occurs and results in a stormwater discharge from a facility.

c. The Permittee shall collect samples within the first 12 hours of stormwater discharge events. If it is not possible to collect a sample within the first 12 hours of a stormwater discharge event, the Permittee must collect the sample as soon as practicable after the first 12 hours, and keep documentation with the sampling records explaining why they could not collect samples within the first 12 hours.

d. Collect samples that are representative of the flow and characteristics of the discharge.

e. Visually monitor the discharge at the time of sample collection. Visual monitoring must include observations of the presence of floating materials, visible sheen, discoloration, turbidity, odor, etc. in the stormwater discharge.

f. Conduct at least one dry weather inspection annually. Dry weather inspection must note the presence of non-stormwater discharges to the stormwater system that are not authorized by this permit. Any non-stormwater discharges not otherwise authorized must be reported to EFSEC per Condition S3.E.

g. Submit evaluations and visual monitoring observations with the Discharge Monitoring Report.

h. Maintain an up-to-date copy of the SWPPP and original monitoring records, monthly inspection reports, and all relevent stormwater records in the site log at the facility at all times.

The Permittee is not required to sample outside of regular business hours (Monday-Friday, 8:00 am to 5:00 pm) or during unsafe conditions.

4. <u>Response to Monitoring Results Above Benchmark Values</u>

Each time that sampling results are above a benchmark value or outside the benchmark range for pH, the Permittee must take the following actions:

a. Conduct an inspection of the drainage area for the affected outfall as promptly as possible.

b. Identify the possible sources of stormwater contamination from industrial activity that are causing or contributing to the elevated levels of the benchmark parameter.

c. Investigate and select all applicable and appropriate options for capital BMPs and operational source control BMPs to reduce stormwater contamination below benchmark values. Applicable and appropriate BMP's are contained in the 2005 version of Ecology's Stormwater Management Manual for Western Washington.

d. Within 60 days of receipt of sample results complete/implement the additional operational source control BMPs identified in subsection c above.

e. Within 6 months of receipt of sampling results complete installation/construction of the additional capital BMPs identified in subsection c above. If additional time is needed for construction the Permittee must submit to EFSEC a schedule for review and approval.

f. Include a brief summary of inspection results and remedial actions taken with the monitoring report for the time period in which sample results were above benchmark values.

D. Sampling and Analytical Procedures

Samples and measurements taken to meet the requirements of this permit must be representative of the volume and nature of the monitored parameters, including representative sampling of any unusual discharge or discharge condition, including bypasses, upsets, and maintenance-related conditions affecting effluent quality.

Sampling and analytical methods used to meet the monitoring requirements specified in this permit must conform to the latest revision of the *Guidelines Establishing Test Procedures for the Analysis of Pollutants* contained in 40 CFR Part 136.

E. Flow Measurement

The Permittee must select and use appropriate flow measurement devices and methods consistent with accepted scientific practices. The Permittee must install, calibrate, and maintain the flow devices. This work is necessary to ensure that the accuracy of the measurements are consistent with the accepted industry standard and the manufacturers recommendation for that type of device. The Permittee must perform calibration at the frequency recommended by the manufacturer. The Permittee must maintain calibration records for at least three years.

F. Laboratory Accreditation

All monitoring data required by EFSEC must be prepared by a laboratory registered or accredited under the provisions of, *Accreditation of Environmental Laboratories*, Chapter 173-50 WAC. Flow, temperature, settleable solids, conductivity, pH, turbidity, free available chlorine, total residual chlorine, and internal process control parameters are exempt from this requirement. Conductivity and pH must be accredited if the laboratory must otherwise be registered or accredited.

S3. REPORTING AND RECORDKEEPING REQUIREMENTS

The Permittee must monitor and report in accordance with the following conditions. The falsification of information submitted to the Department constitutes a violation of the terms and conditions of this permit.

A. Reporting

The first monitoring period begins on the effective date of the permit. Monitoring results must be submitted monthly. Monitoring data obtained during each monitoring period must be summarized, reported, and submitted on a Discharge Monitoring Report (DMR) form provided, or otherwise approved, by the Department. DMR forms must be postmarked or received no later than the 30th day of the month following the completed monitoring period, unless otherwise specified in this permit. Priority pollutant analysis data must be submitted no later than forty-five (45) days following the monitoring period. Unless otherwise specified, all toxicity test data must be submitted within sixty (60) days after the sample date. The report(s) must be sent to:

EFSEC
PO Box 43172
Olympia, WA 98504-3172

All laboratory reports providing data for organic and metal parameters must include the following information: sampling date, sample location, date of analysis, parameter name, CAS number, analytical method/ number, method detection limit (MDL), laboratory practical quantitation limit (PQL), reporting units, and concentration detected. Analytical results from samples sent to a contract laboratory must have information on the chain of custody, the analytical method, QA/QC results, and documentation of accreditation for the parameter.

DMR forms must be submitted monthly whether or not the facility was discharging. If there was no discharge during a given monitoring period, submit the form as required with the words "no discharge" entered in place of the monitoring results.

B. Records Retention

The Permittee must retain records of all monitoring information for a minimum of three (3) years. Such information must include all calibration and maintenance records and all original recordings for continuous monitoring instrumentation, copies of all reports and plans required by this permit, site logs, inspection reports/checklists and records of all data used to complete the application for this permit. This period of retention must be extended during the course of any unresolved litigation regarding the discharge of pollutants by the Permittee or when requested by the Director.

C. Recording of Results

For each measurement or sample taken, the Permittee must record the following information: (1) the date, exact place, method, and time of sampling or measurement; (2) the individual who performed the sampling or measurement; (3) the dates the analyses were performed; (4) the individual who performed the analyses; (5) the analytical techniques or methods used; and (6) the results of all analyses.

D. Additional Monitoring by the Permittee

If the Permittee monitors any pollutant more frequently than required by this permit using test procedures specified by Condition S2, then the results of this monitoring must be included in the calculation and reporting of the data submitted in the Permittee's DMR.

E. Reporting Permit Violations

The Permittee must take the following action upon violation of any permit condition:

1. Immediate Noncompliance Notification

   Any discharge of untreated wastewater must be reported immediately to the Department of Ecology's Regional Office 24-hr. number 360-407-6300 and EFSEC at 360-956-2047.

   Immediately take action to stop, contain, and cleanup unauthorized discharges or otherwise stop the noncompliance and correct the problem and, if applicable, immediately repeat sampling and analysis.

2. Twenty four hour Noncompliance Notification

   The Permittee must report the following occurrences of noncompliance by telephone, to EFSEC, within 24 hours from the time the Permittee becomes aware of any of the following circumstances:

   a. Any noncompliance that may endanger health or the environment, unless previously reported under subpart 1. above.
   b. Any unanticipated **bypass** that exceeds any effluent limitation in the permit (See Condition S4.B., "Bypass Procedures").
   c. Any **upset** that exceeds any effluent limitation in the permit (See General Condition G.15, "Upset").
   d. Any violation of a maximum daily or instantaneous maximum discharge limitation for any of the pollutants in Condition S1.A.
   e. Any overflow prior to the treatment works, whether or not such overflow endangers health or the environment or exceeds any effluent limitation in the permit.

3. Report Within Five Days

   The Permittee must also provide a written submission within five days of the time that the Permittee becomes aware of any event required to be reported under Condition S3.E subsection 1 or 2, above. The written submission must contain:

   a. A description of the noncompliance and its cause.
   b. The period of noncompliance, including exact dates and times.
   c. The estimated time noncompliance is expected to continue if it has not been corrected.
   d. Steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.
   e. If the noncompliance involves an overflow prior to the treatment works, an estimate of the quantity (in gallons) of untreated overflow.

4. Waiver of Written Reports

EFSEC may waive the written report required in subsection 3 above on a case-by-case basis upon request if a timely oral report has been received.

5. Report Submittal

Reports must be submitted to the address in Condition S3. "Reporting and Recordkeeping Requirements".

F. Other Noncompliance Reporting

The Permittee must report all instances of noncompliance, not required to be reported immediately or within 24 hours, at the time that monitoring reports for Condition S3.A "Reporting" are submitted. The reports must contain the information listed in Condition S3.E.3 above. Compliance with these requirements does not relieve the Permittee from responsibility to maintain continuous compliance with the terms and conditions of this permit or the resulting liability for failure to comply.

The spill of oil or hazardous materials **must** be reported in accordance with the instructions obtained at the following website:
http://www.ecy.wa.gov/programs/spills/other/reportaspill.htm

G. Maintaining a Copy of This Permit

The Permittee must keep a copy of the following documents at the permitted facility and be made available upon request to Department or EFSEC inspectors.

a. Permit

b. Permit coverage notifications

c. Stormwater Pollution Prevention Plan (SWPPP)

d. Site log books, inspection reports/checklists, and monitoring data.

S4. OPERATION AND MAINTENANCE

The Permittee must, at all times, properly operate and maintain all facilities or systems of treatment and control (and related appurtenances) which are installed to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance also includes adequate laboratory controls and appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems, which are installed by a Permittee only when the operation is necessary to achieve compliance with the conditions of this permit.

A. Operations and Maintenance Manual

1. An updated Operations and Maintenance (O&M) Manual must be submitted to EFSEC with the application for permit renewal. The updated O&M

Manual must incorporate any applicable pollution reduction measures detailed in the approved Engineering Report. The O&M Manual must be kept available at the permitted facility and all operators must follow the instructions and procedures of this manual.

In addition to the requirements of WAC 173-240-150(1) and (2), the O&M Manual must include:

a. Emergency procedures for plant shutdown and cleanup in event of wastewater system upset or failure.

b. Wastewater system maintenance procedures that contribute to the generation of process wastewater

c. Any directions to maintenance staff when cleaning, or maintaining other equipment or performing other tasks which are necessary to protect the operation of the wastewater system (e.g. defining maximum allowable discharge rate for draining a tank, blocking all floor drains before beginning the overhaul of a stationary engine.)

d. Operation and maintenance of sampling and monitoring equipment.

B. Bypass Procedures

Bypass, which is the intentional diversion of waste streams from any portion of a treatment facility, is prohibited, and EFSEC may take enforcement action against a Permittee for bypass unless one of the following circumstances (1, 2, or 3) is applicable.

1. Bypass for Essential Maintenance without the Potential to Cause Violation of Permit Limits or Conditions.

   Bypass is authorized if it is for essential maintenance and does not have the potential to cause violations of limitations or other conditions of this permit, or adversely impact public health as determined by EFSEC prior to the bypass. The Permittee must submit prior notice, if possible, at least ten (10) days before the date of the bypass.

2. Bypass Which is Unavoidable, Unanticipated, and Results in Noncompliance of this Permit.

   This bypass is permitted only if:

   a. Bypass is unavoidable to prevent loss of life, personal injury, or severe property damage. "Severe property damage" means substantial physical damage to property, damage to the treatment facilities which would cause them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass.

b. There are no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, stopping production, maintenance during normal periods of equipment downtime (but not if adequate backup equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventative maintenance), or transport of untreated wastes to another treatment facility.

c. EFSEC is properly notified of the bypass as required in Condition S3.E of this permit.

3. Bypass which is Anticipated and has the Potential to Result in Noncompliance of this Permit.

The Permittee must notify EFSEC at least thirty (30) days before the planned date of bypass. The notice must contain (1) a description of the bypass and its cause; (2) an analysis of all known alternatives which would eliminate, reduce, or mitigate the need for bypassing; (3) a cost-effectiveness analysis of alternatives including comparative resource damage assessment; (4) the minimum and maximum duration of bypass under each alternative; (5) a recommendation as to the preferred alternative for conducting the bypass; (6) the projected date of bypass initiation; (7) a statement of compliance with SEPA; (8) a request for modification of water quality standards as provided for in WAC 173-201A-110, if an exceedance of any water quality standard is anticipated; and (9) steps taken or planned to reduce, eliminate, and prevent reoccurrence of the bypass.

For probable construction bypasses, the need to bypass is to be identified as early in the planning process as possible. The analysis required above must be considered during preparation of the engineering report or facilities plan and plans and specifications and must be included to the extent practical. In cases where the probable need to bypass is determined early, continued analysis is necessary up to and including the construction period in an effort to minimize or eliminate the bypass.

EFSEC will consider the following prior to issuing an administrative order for this type bypass:

a. If the bypass is necessary to perform construction or maintenance-related activities essential to meet the requirements of this permit.

b. If there are feasible alternatives to bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, stopping production, maintenance during normal periods of equipment down time, or transport of untreated wastes to another treatment facility.

c. If the bypass is planned and scheduled to minimize adverse effects on the public and the environment.

After consideration of the above and the adverse effects of the proposed bypass and any other relevant factors, EFSEC will approve or deny the request. The public must be notified and given an opportunity to comment on bypass incidents of significant duration, to the extent feasible. Approval of a request to bypass will be by administrative order issued by EFSEC under RCW 90.48.120.

C. Duty to Mitigate

The Permittee is required to take all reasonable steps to minimize or prevent any discharge or sludge use or disposal in violation of this permit that has a reasonable likelihood of adversely affecting human health or the environment.

S5. SCHEDULE OF COMPLIANCE

The Schedule of Compliance consists of development and submittal of a revised Engineering Report to EFSEC for review and approval as specified in this permit condition, as well as implementation of the approved Engineering Report. The Engineering Report was previously submitted to EFSEC.

The Permittee's process wastewater and stormwater discharges must be in compliance with AKART (all known, available, and reasonable methods of prevention, control, and treatment) and applicable water quality standards **by February 1, 2013.** To determine AKART, the Permittee must submit to EFSEC an Engineering Report developed in accordance with WAC 173-240-130 and -160.

The Engineering Report must also verify that the Permittee's stormwater discharges comply with the requirements of this permit and applicable requirements contained in the Industrial Stormwater General Permit.

A. Engineering Report Contents

The Permittee must develop and submit an Engineering Report in compliance with the applicable requirements in WAC 173-240-130. This includes technology-based and water quality-based requirements as specified in federal and state law. EFSEC expects the engineering report will conform to standard engineering practice. Guidance for meeting technology and water quality requirements are given Ecology's *Permit Writer's Manual.*

At a minimum the Engineering Report must contain the following elements:

1. <u>Characterization of the Discharge</u> – A comprehensive characterization of the discharge. The characterization must determine all species of pollutants present in the discharge to allow determination of compliance with the applicable parameters listed in the state surface water quality quality standards and the National Toxics Rule. For example, Chromium must be characterized for both Chromium III and Chromium VI. The Permittee must use the monitoring

methods and meet the detection and quantitation levels listed in Appendix A. The Permittee may use alternative 40 CFR Part 136 EPA-approved methods provided the method produces measureable results. If the Permittee uses an alternative method, not specified in the permit and as allowed above, it must report the test method, detection limit, and quantitation level on the discharge monitoring report or in the required report.

2. AKART - An AKART analysis of process wastewater pollutants. The Permittee must use all applicable portions of the following Ecology guidance document to develope the Engineering Report: STATE REQUIREMENTS FOR SUBMISSION OF ENGINEERING REPORTS AND PLANS FOR INDUSTRIAL WASTEWATER TREATMENT FACILITIES. This document can be downloaded from Ecology's website at: http://www.ecy.wa.gov/biblio/0510014.html.

   Demonstrate compliance with 40 CFR 423.15(j)(1) that limits discharge of priority pollutants contained in chemicals added for cooling tower maintenance, except chromium and zinc, in circulating cooling water blowdown effluent to less than detection limits.

   The AKART analysis must also evaluate and propose best management practices and pollution prevention measures utilized by the power industry to reduce pollution.

3 Compliance with Water Quality Standards - Verify compliance of all pollutant parameters in the process wastewater and stormwater discharges with all applicable water quality standards, including numeric and narrative water quality criteria, and antidegradation. Discharges must not cause or contribute to a violation of Surface Water Quality Standards (Chapter 173-201A WAC), Ground Water Quality Standards (Chapter 173-200 WAC), Sediment Management Standards (Chapter 173-204 WAC), or the human health-based criteria in the National Toxics Rule (40 CFR 131.36).

   a. As may be required by EFSEC, update the 2004 receiving water study to characterize the Chehalis River upstream of the outfall. The Permittee must conduct the study between the confluence of the Satsop and Chehalis Rivers and 300 feet upstream of the outfall. In the event additional receiving water data must be collected, the Permittee must submit an updated Quality Assurance Project Plan (QAPP) to EFSEC for review and approval prior to beginning the study. The Permittee must use the following guidance document to develop the QAPP: Guidelines for Preparing Quality Assurance Project Plans for Environmental Studies, Publ. No. 04-03-030, posted at: http://www.ecy.wa.gov/biblio/0403030.html.

   b. Reconcile technology-based effluent limits, such as TSS and free available chlorine, with similar water quality-based parameters of turbidity and total residual chlorine, respectively.

c. Determine which of the technology-based limits or water quality-based limits for each pollutant present in the discharge is the most stringent. State and federal regulations require that the most stringent of the technology-based or water quality-based limits be incorporated into the permit.

d. Determine whether the discharge complies with the state antidegradation policy. The analysis must be conducted in compliance with requirements in Ecology's antidegradation guidance document, which is posted at: http://www.ecy.wa.gov/programs/wq/swqs/antideg.html

e. Demonstrate compliance with the state's whole effluent toxicity (WET) standards in WAC 173-201A-240(1) as early in the engineering study as possible. If preliminary effluent and receiving water characterizations indicate the Permittee's discharge complies with the water quality standards without the need for additional wastewater treatment, the Permittee must conduct the WET testing specified in Conditions S10 and S11 before submitting the final engineering report to EFSEC.

   If preliminary characterizations indicate additional wastewater treatment of the discharge is necessary before compliance of the water quality standards can be assured, the Permittee may delay WET (as per Condition S5.C.) testing until after the proposed engineering improvements have been implemented.

f. Demonstrate compliance with the stormwater requirements of Condition S2.C and demonstrate substantial compliance with Ecology's Industrial Stormwater General Pemit (ISWGP) issued on October 21, 2009. For example, the Permittee must assess the permit requirements of the 2009 ISWGP and propose revisions to the existing SWPPP that will assure compliance with the ISWGP and this permit on an ongoing basis.

   The point of compliance for stormwater benchmarks is at the stormwater sewer manhole near the entry gate to the facility. If discharges to the sewer exceed benchmark values in Condition S2.C.3, the engineering report must propose source control or treatment BMP's that will assure compliance.

2. Monitoring – Propose a final monitoring program that adequately verifies compliance of the discharges with proposed final effluent limits and applicable water quality standards developed in the engineering report and stormwater benchmarks. The engineering report must propose monitoring parameters and appropriate sampling frequencies, locations, and methods (grab, composite, continuous).

B. Compliance Schedule

   1. Engineering Report Revision - Scope of Work

The Permittee must submit a plan and schedule in the form of an approvable Scope of Work to EFSEC **by February 1, 2011.**

2. Draft Engineering Report Revision

   The Permittee must submit an approvable draft Engineering Report to EFSEC **by February 1, 2012.**

3. Final Engineering Report Revision

   The Permittee must submit a final Engineering Report to EFSEC for review and approval **by August 1, 2012.**

4. Compliance with AKART

   The Permittee must verify compliance with the EFSEC-approved Engineering Report required in this permit condition, by letter, **no later than February 1, 2013.**

C. Request for Extension of Schedule of Compliance

In the event more time is necessary to complete the tasks required in this Schedule of Compliance, the Permittee may request that EFSEC grant an extension. The Permittee must request and extension by formal written letter, which must contain: (1) an explanation of why more time is needed, and (2) a revised schedule for completing the remaining tasks. EFSEC will grant the extension at its discretion through an administrative order or permit modification.

S6. APPLICATION FOR PERMIT RENEWAL

The Permittee must submit an application for renewal of this permit **by November 13, 2012.**

S7. SOLID WASTE DISPOSAL

A. Solid Waste Handling

The Permittee must handle and dispose of all solid waste material in such a manner as to prevent its entry into state ground or surface water.

B. Leachate

The Permittee must not allow leachate from its solid waste material to enter state waters without providing all known, available and reasonable methods of prevention, control, or treatment, nor allow such leachate to cause violations of the State Surface Water Quality Standards, Chapter 173-201A WAC, or the State

Ground Water Quality Standards, Chapter 173-200 WAC. The Permittee must apply for a permit or permit modification as may be required for such discharges to state ground or surface waters.

C. Solid Waste Control Plan

The Permittee must submit an updated solid waste control plan to EFSEC with the application for permit renewal. This plan must address all solid wastes generated by the Permittee. The plan must include at a minimum a description, source, generation rate, and disposal methods of these solid wastes. This plan must not be in conflict with local or state solid waste regulations. Any proposed revision or modification of the solid waste control plan must be submitted to EFSEC for review and approval at least 30 days prior to implementation. The Permittee must comply with the plan and any modifications thereof. The Permittee must submit an update of the solid waste control plan with the application for permit renewal prior to the expiration date of the permit.

S8. SPILL PLAN

The Permittee must review and update the Spill Prevention Control and Countermeasures (SPCC) Plan, as needed and submit any changes to the plan to EFSEC. The plan and any supplements must be followed throughout the term of the permit.

The updated spill control plan must include the following:

a. A description of the reporting system, which the Permittee will use to alert responsible managers and legal authorities in the event of a spill.

b. A description of preventive measures and facilities (including an overall facility plot showing drainage patterns), which prevent, contain, or treat spills of these materials.

c. A list of all oil and chemicals used, processed, or stored at the facility, which may spill into state waters.

For the purpose of meeting this requirement, plans and manuals, or portions thereof, required by 33 CFR 154, 40 CFR 109, 40 CFR 110, 40 CFR Part 112, the Federal Oil Pollution Act of 1990, Chapter 173-181, and contingency plans required by Chapter 173-303 WAC may be submitted.

S9. OUTFALL INSPECTION

The Permittee must inspect, annually, the submerged portion of the outfall line and diffuser to document its integrity and its continued function and perform repairs/maintenance as required. If conditions allow for a photographic verification, it must be included in the report. The Permittee must submit the inspection report EFSEC within 30 days of its completion.

S10. ACUTE TOXICITY

A. Effluent Characterization

The acute critical effluent concentration (ACEC) means the maximum concentration of effluent during critical conditions at the boundary of the acute mixing zone, defined in Condition S1. The ACEC will be determined in the approved engineering report.

The Permittee must conduct acute toxicity testing on the final effluent every other month for one year.

Testing must commence as required by Condition S5.A.3.e. The Permittee must submit a written report to EFSEC within sixty (60) days after each sample date.

The Permittee must use a dilution series consisting of a minimum of five concentrations and a control.

The Permittee must conduct the following two, acute toxicity tests on each sample:

1. Fathead minnow, *Pimephales promelas*, 96-hour static-renewal test (Reference: EPA-821-R-02-012).

2. Daphnid, *Ceriodaphnia dubia, Daphnia pulex*, or *Daphnia magna*, 48-hour static test (Reference: EPA-821-R-02-012).

B. Sampling and Reporting Requirements

1. The Permittee must submit all reports for toxicity testing in accordance with the most recent version of Department of Ecology Publication # WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria.* Reports must contain bench sheets and reference toxicant results for test methods. If the lab provides the toxicity test data in electronic format for entry into EFSEC's database, then the Permittee must send the data to EFSEC along with the test report, bench sheets, and reference toxicant results.

2. The Permittee must collect grab samples for toxicity testing. The Permittee must cool the samples to 0 - 6 degrees Celsius during collection and send them to the lab immediately upon completion. The lab must begin the toxicity testing as soon as possible but no later than 36 hours after sampling was completed.

3. The laboratory must conduct water quality measurements on all samples and test solutions for toxicity testing, as specified in the most recent version of Department of Ecology Publication # WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria.*

4. All toxicity tests must meet quality assurance criteria and test conditions specified in the most recent versions of the EPA methods listed in subsection C. and Ecology of Ecology Publication # WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria*. If EFSEC determines any test results to be invalid or anomalous, the Permittee must repeat the testing with freshly collected effluent.

5. The laboratory must use control water and dilution water meeting the requirements of the EPA methods listed in subsection A. or pristine natural water of sufficient quality for good control performance.

6. The Permittee must conduct whole effluent toxicity tests on an unmodified sample of final effluent.

7. All whole effluent toxicity tests, effluent screening tests, and rapid screening tests that involve hypothesis testing must comply with the acute statistical power standard of 29% as defined in WAC 173-205-020. If the test does not meet the power standard, the Permittee must repeat the test on a fresh sample with an increased number of replicates to increase the power.

8. Reports of individual characterization or compliance test results must be submitted to EFSEC within 60 days after each sample date.

9. The Acute Toxicity Summary Report must be submitted to EFSEC with the next application for permit renewal.

S11. CHRONIC TOXICITY

A. Effluent Characterization

The chronic critical effluent concentration (CCEC) means the maximum concentration of effluent during critical conditions at the boundary of the mixing zone, defined in Condition S1. The CCEC will be determined in the approved engineering report.

The Permittee must conduct chronic toxicity testing on the final effluent quarterly for one year.

Testing must commence as required by Condition S5.A.3.e. The Permittee must submit a written report to EFSEC within sixty (60) days after each sample date.

The Permittee must conduct chronic toxicity testing during effluent characterization on a series of at least five concentrations of effluent and a control. This series of dilutions must include the acute critical effluent concentration (ACEC). The ACEC will be established in the approved engineering report.

The Permittee must conduct the following three, chronic toxicity tests on each sample:

1. Fathead minnow survival and growth, *Pimephales promelas* (Reference: EPA-821-R-02-013).

2. Water flea survival and reproduction, *Ceriodaphnia dubia* (Reference: EPA-821-R-02-013).

3. Alga, *Selenastrum capricornutum/ Raphidocelis subcapitata* (Reference: EPA-821-R-02-013).

B. Sampling and Reporting Requirements

1. The Permittee must submit all reports for toxicity testing in accordance with the most recent version of Department of Ecology Publication # WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria.* Reports must contain bench sheets and reference toxicant results for test methods. If the lab provides the toxicity test data in electronic format for entry into EFSEC's database, then the Permittee must send the data to EFSEC along with the test report, bench sheets, and reference toxicant results.

2. The Permittee must collect grab samples for toxicity testing. The Permittee must cool the samples to 0 - 6 degrees Celsius during collection and send them to the lab immediately upon completion. The lab must begin the toxicity testing as soon as possible but no later than 36 hours after sampling was completed.

3. The laboratory must conduct water quality measurements on all samples and test solutions for toxicity testing, as specified in the most recent version of Department of Ecology Publication # WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria.*

4. All toxicity tests must meet quality assurance criteria and test conditions specified in the most recent versions of the EPA methods listed in subsection C. and the Department of Ecology Publication # WQ-R-95-80, *Laboratory Guidance and Whole Effluent Toxicity Test Review Criteria.* If EFSEC determines any test results to be invalid or anomalous, the Permittee must repeat the testing with freshly collected effluent.

5. The laboratory must use control water and dilution water meeting the requirements of the EPA methods listed in subsection C. or pristine natural water of sufficient quality for good control performance.

6. The Permittee must conduct whole effluent toxicity tests on an unmodified sample of final effluent.

7. All whole effluent toxicity tests that involve hypothesis testing must comply with the chronic statistical power standard of 39% as defined in WAC 173-205-020. If the test does not meet the power standard, the Permittee must repeat the test on a fresh sample with an increased number of replicates to increase the power.

8. Reports of individual characterization or compliance test results must be submitted to EFSEC within 60 days after each sample date.

9. The Chronic Toxicity Summary Report must be submitted to EFSEC with the next application for permit renewal.

S12. PERMIT REOPENER

EFSEC may modify this permit on the basis of monitoring results or other causes consistent with state and federal regulations and/or to modify or establish specific monitoring requirements, effluent limits, or other conditions in the permit. EFSEC will modify this permit in accordance with the requirements of WAC 463-76-041, WAC 463-76-042, and WAC 463-76-043.

GENERAL CONDITIONS

G1. SIGNATORY REQUIREMENTS

All applications, reports, or information submitted to the Department must be signed and certified.

A. All permit applications must be signed by either a responsible corporate officer of at least the level of vice president of a corporation, a general partner of a partnership, or the proprietor of a sole proprietorship.

B. All reports required by this permit and other information requested by the Department must be signed by a person described above or by a duly authorized representative of that person. A person is a duly authorized representative only if:

1. The authorization is made in writing by a person described above and submitted to the Department.

2. The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility, such as the position of plant manager, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters. (A duly authorized representative may thus be either a named individual or any individual occupying a named position.)

C. Changes to authorization. If an authorization under General Condition G1.B.2 above is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph B.2 above must be submitted to the Department prior to or together with any reports, information, or applications to be signed by an authorized representative.

D. Certification. Any person signing a document under this section must make the following certification:

> I certify under penalty of law, that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gathered and evaluated the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

G2. RIGHT OF INSPECTION AND ENTRY

The Permittee must allow entry to an authorized representative of EFSEC, upon the presentation of credentials and such other documents as may be required by law:

1. To enter the premises where a discharge is located or where any records must be kept under the terms and conditions of this permit.
2. To have access to and copy—at reasonable times and at reasonable cost—any records required to be kept under the terms and conditions of this permit.
3. To inspect—at reasonable times—any facilities, equipment (including monitoring and control equipment), practices, methods, or operations regulated or required under this permit.
4. To sample or monitor—at reasonable times—any substances or parameters at any location for purposes of assuring permit compliance or as otherwise authorized by the Clean Water Act.

G3. PERMIT ACTIONS

This permit may be modified, revoked and reissued, or terminated either at the request of any interested person (including the Permittee) or upon EFSEC's initiative. However, the permit may only be modified, revoked and reissued, or terminated for the reasons specified in 40 CFR 122.62, 122.64 or WAC 173-220-150 according to the procedures of 40 CFR 124.5.

1. The following are causes for terminating this permit during its term, or for denying a permit renewal application:
   a. Violation of any permit term or condition.
   b. Obtaining a permit by misrepresentation or failure to disclose all relevant facts.
   c. A material change in quantity or type of wastewater disposal.
   d. A determination that the permitted activity endangers human health or the environment or contributes to water quality standards violations and can only be regulated to acceptable levels by permit modification or termination (40 CFR part 122.64[3]).
   e. A change in any condition that requires either a temporary or permanent reduction or elimination of any discharge or sludge use or disposal practice controlled by the permit (40 CFR part 122.64[4]).
   f. Failure or refusal of the Permittee to allow entry as required in RCW 90.48.090.

2. The following are causes for modification but not revocation and reissuance except when the Permittee requests or agrees:
   a. A material change in the condition of the waters of the state.
   b. New information not available at the time of permit issuance that would have justified the application of different permit conditions.
   c. Material and substantial alterations or additions to the permitted facility or activities that occurred after this permit issuance.
   d. Promulgation of new or amended standards or regulations having a direct bearing on permit conditions, or requiring permit revision.
   e. The Permittee has requested a modification based on other rationale meeting the criteria of 40 CFR Part 122.62.

f. EFSEC has determined that good cause exists for modification of a compliance schedule, and the modification will not violate statutory deadlines.
g. Incorporation of an approved local pretreatment program into a municipality's permit.

3. The following are causes for modification or alternatively revocation and reissuance:
   a. Cause exists for termination for reasons listed above in General Condition G3.1, and EFSEC determines that modification or revocation and reissuance is appropriate.
   b. EFSEC has received notification of a proposed transfer of the permit. A permit may also be modified to reflect a transfer after the effective date of an automatic transfer (General Condition G7.) but will not be revoked and reissued after the effective date of the transfer except upon the request of the new Permittee.

G4. REPORTING PLANNED CHANGES

The Permittee must, as soon as possible, give notice to EFSEC of planned physical alterations or additions to the permitted facility, production increases, or process modification that will result in: (1) the permitted facility being determined to be a new source pursuant to 40 CFR 122.29(b); (2) a significant change in the nature or an increase in quantity of pollutants discharged; or (3) a significant change in the Permittee's sludge use or disposal practices. Following such notice, this permit may be modified or revoked and reissued pursuant to 40 CFR 122.62(a) to specify and limit any pollutants not previously limited. Until such modification is effective, any new or increased discharge in excess of permit limits or not specifically authorized by this permit constitutes a violation.

G5. PLAN REVIEW REQUIRED

Before constructing or modifying any wastewater control facilities, an engineering report and detailed plans and specifications must be submitted to EFSEC for approval in accordance with Chapter 173-240 WAC. Engineering reports, plans, and specifications must be submitted at least 180 days before the planned start of construction unless a shorter time is approved by EFSEC. Facilities must be constructed and operated in accordance with the approved plans.

G6. COMPLIANCE WITH OTHER LAWS AND STATUTES

Nothing in this permit must be construed as excusing the Permittee from compliance with any applicable federal, state, or local statutes, ordinances, or regulations.

G7. TRANSFER OF THIS PERMIT

In the event of any change in control or ownership of facilities from which the authorized discharge emanate, the Permittee must notify the succeeding owner or controller of the existence of this permit by letter, a copy of which must be forwarded to EFSEC.

A. <u>Transfers by Modification</u>

Except as provided in General Condition G7.B below, this permit may be transferred by the Permittee to a new owner or operator only if this permit has been modified or revoked and reissued under 40 CFR 122.62(b) (2), or a minor modification made under 40 CFR 122.63(d), to identify the new Permittee and incorporate such other requirements as may be necessary under the Clean Water Act.

B. Automatic Transfers

This permit may be automatically transferred to a new Permittee if:

1. The Permittee notifies EFSEC at least 30 days in advance of the proposed transfer date.
2. The notice includes a written agreement between the existing and new Permittee's containing a specific date transfer of permit responsibility, coverage, and liability between them.
3. EFSEC does not notify the existing Permittee and the proposed new Permittee of its intent to modify or revoke and reissue this permit. A modification under the subparagraph may also be minor modification under 40 CFR 122.63. If this notice is not received, the transfer is effective on the date specified in the written agreement.

G8. REDUCED PRODUCTION FOR COMPLIANCE

The Permittee, in order to maintain compliance with its permit, must control production and/or all discharges upon reduction, loss, failure, or bypass of the treatment facility until the facility is restored or an alternative method of treatment is provided. This requirement applies in the situation where, among other things, the primary source of power of the treatment facility is reduced, lost, or fails.

G9. REMOVED SUBSTANCES

Collected screenings, grit, solids, sludges, filter backwash, or other pollutants removed in the course of treatment or control of wastewaters must not be resuspended or reintroduced to the final effluent stream for discharge to state waters.

G10. DUTY TO PROVIDE INFORMATION

The Permittee must submit to EFSEC, within a reasonable time, all information that EFSEC may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or to determine compliance with this permit. The Permittee must also submit to EFSEC upon request copies of records required to be kept by this permit (40 CFR 122.41[h]).

G11. OTHER REQUIREMENTS OF 40 CFR

All other requirements of 40 CFR 122.41 and 122.42 are incorporated in this permit by reference.

G12. ADDITIONAL MONITORING

EFSEC may establish specific monitoring requirements in addition to those contained in this permit by administrative order or permit modification.

G13. PAYMENT OF FEES

The Permittee must submit payment of fees associated with this permit as assessed by EFSEC.

G14. PENALTIES FOR VIOLATING PERMIT CONDITIONS

Any person who is found guilty of willfully violating the terms and conditions of this permit must be deemed guilty of a crime, and upon conviction thereof must be punished by a fine of up to ten thousand dollars ($10,000) and costs of prosecution, or by imprisonment in the discretion of the court. Each day upon which a willful violation occurs may be deemed a separate and additional violation.

Any person who violates the terms and conditions of a waste discharge permit must incur, in addition to any other penalty as provided by law, a civil penalty in the amount of up to ten thousand dollars ($10,000) for every such violation. Each and every such violation must be a separate and distinct offense, and in case of a continuing violation, every day's continuance must be deemed to be a separate and distinct violation.

G15. UPSET

Definition – "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the Permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

An upset constitutes an affirmative defense to an action brought for noncompliance with such technology-based permit effluent limitations if the requirements of the following paragraph are met.

A Permittee who wishes to establish the affirmative defense of upset must demonstrate, through properly signed, contemporaneous operating logs or other relevant evidence that: (1) an upset occurred and that the Permittee can identify the cause(s) of the upset; (2) the permitted facility was being properly operated at the time of the upset; (3) the Permittee submitted notice of the upset as required in Condition S3.E; and (4) the Permittee complied with any remedial measures required under Condition S4.C of this permit.

In any enforcement proceeding, the Permittee seeking to establish the occurrence of an upset has the burden of proof.

G16. PROPERTY RIGHTS

This permit does not convey any property rights of any sort or any exclusive privilege.

G17. DUTY TO COMPLY

The Permittee must comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Clean Water Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or denial of a permit renewal application.

G18. TOXIC POLLUTANTS
The Permittee must comply with effluent standards or prohibitions established under Section 307(a) of the Clean Water Act for toxic pollutants within the time provided in the regulations that establish those standards or prohibitions, even if this permit has not yet been modified to incorporate the requirement.

G19. PENALTIES FOR TAMPERING
The Clean Water Act provides that any person who falsifies, tampers with, or knowingly renders inaccurate any monitoring device or method required to be maintained under this permit must, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than two years per violation, or by both. If a conviction of a person is for a violation committed after a first conviction of such person under this Condition, punishment must be a fine of not more than $20,000 per day of violation, or by imprisonment of not more than four (4) years, or by both.

G20. REPORTING ANTICIPATED NONCOMPLIANCE
The Permittee must give advance notice to EFSEC by submitting a new application or supplement at least 180 days before commencement of such discharges, of any facility expansions, production increases, or other planned changes, such as process modifications, in the permitted facility or activity that may result in noncompliance with permit limits or conditions. Any maintenance of facilities that might interrupt operation and degrade effluent quality must be scheduled during noncritical water quality periods and carried out in a manner approved by EFSEC.

G21. REPORTING OTHER INFORMATION
Where the Permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to EFSEC, it must promptly submit such facts or information.

G22. REPORTING REQUIREMENTS APPLICABLE TO EXISTING MANUFACTURING, COMMERCIAL, MINING, AND SILVICULTURAL DISCHARGERS
The Permittee belonging to the categories of existing manufacturing, commercial, mining, or silviculture must notify EFSEC as soon as they know or have reason to believe:

1. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant that is not limited in this permit, if that discharge will exceed the highest of the following notification levels:
   - 100 micrograms per liter (µg/L).
   - 200 µg/L for acrolein and acrylonitrile; 500 µg/L for 2, 4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol; and 1 mg/L for antimony.
   - Five times the maximum concentration value reported for that pollutant in the permit application in accordance with 40 CFR 122.21(g) (7).
   - The level established by EFSEC in accordance with 40 CFR 122.44(f).

2. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant that is not limited in this permit, if that discharge will exceed the highest of the following notification levels:
   - 500μg/L.
   - 1 mg/L for antimony.
   - Ten times the maximum concentration value reported for that pollutant in the permit application in accordance with 40 CFR 122.21(g) (7).
   - The level established by EFSEC in accordance with 40 CFR 122.44(f).

G23. COMPLIANCE SCHEDULES

Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit must be submitted no later than fourteen (14) days following each schedule date.

APPENDIX A
EFFLUENT CHARACTERIZATION FOR WASHINGTON STATE PRIORITY TOXIC CHEMICALS

EPA 307(A) REF. #	Pollutant & CAS No. *(if available)*	Recommended Analytical Protocol	Detection (DL)[1,2] *µg/L unless specified*	Quantitation Level (QL)[1,2] *µg/L unless specified*	Lowest Criteria Values *µg/L unless specified*
	Conventionals				
	Biochemical Oxygen Demand	405.1		2 mg/L	
	Chemical Oxygen Demand	410.1			
	Total Organic Carbon	5310 BCD		1 mg/L	
	Total Suspended Solids	2540 D		10 mg/L	
	Total Ammonia (as N)	4500-NH3- H			
	Flow	Calibrated device			
	Dissolved oxygen	4500-OC			
	Temperature (max. 7-day avg.)	Analog recorder or Use micro-recording devices known as thermistors			
	pH	150.1			
	Nonconventionals				
	Bromide (24959-67-9)	4110 B	100	400	
	Chlorine, Total Residual	4500 Cl G	10.0	40.0	7.5
	Color				
	Fecal Coliform				
	Fluoride (16984-48-8)	4500-F E	25	100	
	Nitrate-Nitrite (as N)	4500-NO2- I	2.5	10	10,000
	Nitrogen, Total Organic (as N)	4500-NO3- B	6.3	25	
	Ortho-Phosphorus (PO_4 as P)	4500-P G	0.8	3.0	
	Phosphorus, Total (as P)	200.8	0.25	1.0	

	Oil and Grease	1664A	1250	5,000	
	Radioactivity				
	Sulfate (as mg/l SO_4)	375.2	750	3,000	
	Sulfide (as mg/l S)	376.1	250	1000	2.0
	Sulfite (as mg/l SO_3)	4500-SO3B	500	2,000	
	Surfactants	5540 C	2.5	10	
	Total dissolved solids	2540 D			500 mg/L[16]
	Aluminum, Total (7429-90-5)	200.8	0.15	0.6	750
	Barium Total (7440-39-3)	200.8	0.5	2.0	
	Boron Total (7440-42-8)	200.8(mod)	1.0	4.0	
	Cobalt, Total (7440-48-4)	200.8	0.03	0.12	
	Iron, Total (7439-89-4)	200.8	12.5	50	300
	Magnesium, Total (7439-95-4)	200.8(mod)	1.0	4.0	
	Molybdenum, Total (7439-98-7)	200.8(mod)	0.1	0.4	
	Manganese, Total (7439-96-5)	200.8(mod)	0.06	0.24	50
	Tin, Total (7440-31-5)	200.8(mod)	0.04	0.16	
	Titanium, Total (7440-32-6)	200.8(mod)	0.04	0.16	
	Metals, Cyanide & Total Phenols				
114	Antimony, Total (Inorganic) (7440-36-0)	200.8	0.08	0.3	14[5]
115	Arsenic, Total (dissolved) (7440-38-2)	200.8	0.9	3.6	36[7]
117	Beryllium, Total (7440-43-9)	200.8	0.1	0.4	4[8]
118	Cadmium, Total (7440-43-9)	200.8	0.1	0.4	0.37[3]
	Chromium (hex) dissolved (185-402-99)	200.8	0.4	1.6	10[7]
119	Chromium, Total (Tri) (7440-47-3)	200.8	0.07	0.28	57.2[3]
120	Copper, Total (7440-50-8)	200.8	0.03	0.12	3.1[3]
122	Lead, Total (7439-92-1)	200.8	0.08	0.32	0.54[3]
123	Mercury, Total (7439-97-6)	1631E	0.0001	0.0005	0.012[7]
124	Nickel, Total (7440-02-0)	200.8	0.2	0.8	8.2[3]
125	Selenium, Total (7782-49-2)	200.8	1.3	5.2	5[7]
126	Silver, Total (7440-22-4)	200.8	0.05	0.2	0.32[3]
127	Thallium, Total (7440-28-0)	200.8	0.09	0.36	1.7[5]
PSP	Tributyltin (688-73-3)	GC/MS[12]	0.001	0.004	0.0074[4]

128	Zinc, Total (7440-66-6)	200.8	0.3	1.0	32.3[3]
121	Cyanide, Total (7440-66-6)	335.4	1.3	5	1.0[7]
PSP	Phenols, Total	420.1	12.5	50	300[9]
	Dioxin				
129	2,3,7,8-Tetra-Chlorodibenzo-P-Dioxin (176-40-16)	1613B	1.3 pg/L	5 pg/L	0.000000013[5]
	Volatile Compounds				
002	Acrolein (107-02-8)	624	12.5QL	50	320/780[5]
003	Acrylonitrile (107-13-1)	603	0.5	2.0	0.059/0.66[5]
004	Benzene (71-43-2)	624	0.07	0.28	5.0[8]
018	Bis(2-Chloroethyl)ether (111-44-4)	611/625	0.25	1.0	0.031[5]
042	Bis(2-Chloroisopropyl) ether (108-60-1)	611/625	0.03	0.10	1400[5]
047	Bromoform (75-25-2)	624	4.7	19.0	4.3[5]
006	Carbon tetrachloride (108-90-7)	624/601 or SM6230B	0.12	0.5	0.25[5]
007	Chlorobenzene (108-90-7)	624	6.0	24.0	680[5]
016	Chloroethane (75-00-3)	624/601	0.52	2.0	
019	2-Chloroethylvinyl Ether (110-75-8)	624	50 QL		3540[10]
023	Chloroform (67-66-3)	624 or SM6210B	1.6	6.4	5.7[5]
051	Dibromochloromethane (124-48-1)	624	0.09	0.36	0.41[5]
048	Dichlorobromomethane (75-27-4)	SM6200B	0.112	0.45	0.27[5]
013	1,1-Dichloroethane (75-34-3)	624	4.7	18.8	
010	1,2-Dichloroethane (107-06-2)	601	0.03	0.12	0.38[5]
029	1,1-Dichloroethylene (75-35-4)	SM6200C	0.035	0.14	0.057[5]
032	1,2-Dichloropropane (78-87-5)	624	6	24	3[13]
033	1,3-dichloropropylene (mixed isomers) (542-75-6)	624	5	20	10[5]
038	Ethylbenzene (100-41-4)	624	7.2	29.0	3100[5]
046	Methyl bromide (74-83-9) (Bromomethane)	624/601	1.2	4.8	48[5]
045	Methyl chloride (74-87-3) (Chloromethane)	601	0.08	0.32	270000[13]
044	Methylene chloride (75-09-2)	624	2.8	11.2	4.7[5]
015	1,1,2,2-Tetrachloroethane (79-34-5)	601	0.03	0.12	0.17[5]

085	Tetrachloroethylene (127-18-4)	SM6200B	0.047	0.19	0.80[5]
086	Toulene (108-88-3)	624	6	24	6800[5]
030	1,2-Trans-Dichloroethylene (156-60-5) (Ethylene dichloride)	624	1.6	6.4	700[4]
011	1,1,1-Trichloroethane (71-55-6)	624	3.8	15.2	200[8]
014	1,1,2-Trichloroethane (79-00-5)	601	0.02	0.08	0.6[5]
087	Trichloroethylene (79-01-6)	624	1.9	7.6	2.7[5]
	Trichlorofluoromethane (75-69-4)	624	0.06	0.24	-
088	Vinyl chloride (75-01-4)	624/SM6200B	0.12	0.48	2[5]
	Acid Compounds				
PSP	Bisphenol A (80-05-7)	625	0.3	1.2	0.9[13]
024	2-Chlorophenol (95-57-8)	625	3.3	13.2	81[4]
031	2,4-Dichlorophenol (120-83-2)	625	2.7	10.8	93[5]
034	2,4-Dimethylphenol (105-67-9)	625	2.7	10.8	380[4]
060	4,6-dinitro-o-cresol (534-52-1) (2-methyl-4,6,-dinitrophenol)	625/1625B	5	20	13.4[5]
059	2,4 dinitrophenol (51-28-5)	625	42	168	70[5]
057	2-Nitrophenol (88-75-5)	625	3.6	14.4	450[13]
058	4-nitrophenol (100-02-7)	625	2.4	9.6	600[13]
PSP	Nonylphenol, total (104-40-5)	625	0.9	5.0	7
022	Parachlorometa cresol (59-50-7) (4-chloro-3-methylphenol)	625	3.0	12.0	-
064	Pentachlorophenol (87-86-5)	604 (ECD)	0.005	0.021[11]	0.28[5]
065	Phenol (108-95-2)	625	1.5	6.0	21000[5]
021	2,4,6-Trichlorophenol (88-06-2)	604(ECD)	0.58	2.3	2.1[5]
	Base/Neutral Compounds				
001	Acenaphthene (83-32-9)	625	1.9	7.6	670[6]
077	Acenaphtylene (208-96-8)	625	3.5	14.0	132000[13]
078	Anthracene (120-12-7)	625	1.9	7.6	9600[5]
005	Benzidine (92-87-5)	605	0.08	0.32	0.00012[5]
067	Benzyl butyl phthalate (85-68-7)	625	2.5	10.0	1500
072	Benzo(*a*)anthracene (56-55-3)	610	0.013	0.05	0.0028[5]
PBT	Benzo(j)fluoranthene (205-82-3)	610M/625M	0.02	0.08	-
PBT	Benzo(r,s,t)pentaphene (189-55-9)	610M/625M	0.02	0.08	
073	Benzo(*a*)pyrene (50-32-8)	610/625	0.023	0.09	0.0028/0.031[5]
074	3,4-benzofluoranthene	610/625	0.018	0.07	

	(Benzo(b)fluoranthene) (205-99-2)				
075	11,12-benzofluoranthene (Benzo(k)fluoranthene) (207-08-9)	610/625	0.017	0.07	0.0028/0.031[5]
079	Benzo(*ghi*)Perylene (191-24-2)	610/625	0.076	0.30	0.1[13]
043	Bis(*2-chloroethoxy)*methane (111-91-1)	625	5.3	21.2	92000[13]
018	Bis(*2-chloroethyl*)ether (111-44-4)	611/625	0.3	1.2	0.031[5]
042	Bis(*2-chloroisopropyl*)ether (108-60-1)	625	5.3	21.2	1400[5]
066	Bis(*2-ethylhexyl*)phthalate (117-81-7)	625	2.5	10.0	1.8[5]
070	Butyl benzyl phthalate	625	0.25	1.0	1500
041	4-Bromophenyl phenyl ether (101-55-3)	625	1.9	7.6	180[13]
020	2-Chloronaphthalene (91-58-7)	625	1.9	7.6	1000[6]
040	4-Chlorophenyl phenyl ether (7005-72-3)	625	4.2	16.8	365[13]
076	Chrysene (218-01-9)	610/625	0.15	0.6	0.0028[5]
PSP	7H-Dibenzo(c,g)carazole (194-59-2)	610M/625M	0.25	1.0	-
PBT	Dibenzo (a,j)acridine (224-42-0)	610M/625M	2.5	10.0	-
PBT	Dibenzo (a,h)acridine (226-36-8)	610M/625M	2.5	10.0	-
082	Dibenzo(a-*h*)anthracene (53-70-3) (1,2,5,6-dibenzanthracene)	625	2.5	10.0	2700[5]
PBT	Dibenzo(a,e)pyrene (192-65-4)	610M/625M	2.5	10.0	-
PBT	Dibenzo(a,h)pyrene (189-64-0)	625M	2.5	10.0	
025	1,2-Dichlorobenzene (95-50-1)	625	1.9	7.6	2700[5]
026	1,3-Dichlorobenzene (541-73-1)	625	1.9	7.6	400[5]
027	1,4-Dichlorobenzene (106-46-7)	625	4.4	17.6	400[5]
028	3,3'-Dichlorobenzidine (91-94-1)	605/625	0.13	0.52	0.04[5]
PSP	1,2-Dichloropropane (788-7-5)	624	0.15	0.6	0.50[6]
070	Diethyl phthalate (84-66-2)	625	1.9	7.6	23000[5]
071	Dimethyl phthalate (131-11-3)	625	1.6	6.4	313000[5]
068	Di-n-butyl phthalate (84-74-2)	625	2.5	10.0	2700[5]
035	2,4-dinitrotoluene (121-14-2)	609	0.01	0.04	0.11[5]

036	2,6-dinitrotoluene (606-20-2)	609/625	0.01	0.04	6250[19]
069	Di-n-octyl phthalate (117-84-0)	625	2.5	10.0	3.1[19]
037	1,2-Diphenylhydrazine (*as Azobenzene*) (122-66-7)	625	10	40.0	0.04[5]
039	Fluoranthene (206-44-0)	625	2.2	8.8	300[5]
080	Fluorene (86-73-7)	625	1.9	7.6	1300[5]
009	Hexachlorobenzene (118-74-1)	612/625	0.05	0.2	0.00075[5]
052	Hexachlorobutadiene (87-68-3)	625	0.09	0.36	0.44[5]
053	Hexachlorocyclopentadiene (77-47-4)	1625B/625	2.5	10	240[5]
012	Hexachloroethane (67-72-1)	625	1.6	6.4	1.9[5]
083	Indeno(*1,2,3-cd*)Pyrene (193-39-5)	610/625	0.043	0.17	0.0028[6]
054	Isophorone (78-59-1)	625	2.2	8.8	8.4[5]
PBT	3-Methyl cholanthrene (56-49-5)	625	2.0	8.0	
055	Naphthalene (91-20-3)	625	1.6	6.4	400[13]
056	Nitrobenzene (98-95-3)	625	1.9	7.6	17[5]
PSP	N-Nitrosodibutylamine (924-16-3)	625	10	40	0.005[15]
PSP	N-Nitrosodiethylamine (55-18-5)	625	10	40	0.0008[14]
061	N-Nitrosodimethylamine (62-75-9)	607/625	0.04	0.15	0.00069[5]
063	N-Nitrosodi-n-propylamine (621-64-7)	607/625	0.12	0.46	0.005[5]
062	N-Nitrosodiphenylamine (86-30-6)	625	1.9	7.6	5[5]
PSP	Pentachlorobenzene (608-93-5)	625	1.9	7.6	0.154[6]
PBT	Perylene (198-55-0)	625	1.9	7.6	
081	Phenanthrene (85-01-8)	625	5.4	21.6	4[13]
084	Pyrene (129-00-0)	625	1.9	7.6	960[5]
008	1,2,4-Trichlorobenzene (120-82-1)	625	1.9	7.6	35[6]
	GC/MS Fraction - Pesticides				
089	Aldrin (309-00-2)	608	0.004	0.016	0.00013[5]
102	alpha-BHC (319-84-6)	608	0.003	0.012	0.0039[5]
103	beta-BHC (319-85-7)	608	0.006	0.024	0.014[5]
104	gamma-BHC (58-89-9)	608	0.009	0.036	0.019[5]
105	delta-BHC (319-86-8)	608	0.004	0.016	7.0[13]
091	Chlordane (57-74-9)	608	0.014	0.056	0.00057[5]
092	4,4'-DDT (50-29-3)	608	0.012	0.048	0.00059[5]

093	4,4'-DDE (72-55-9)	608	0.001	0.003[11]	0.00059[5]
094	4,4' DDD (72-54-8)	608	0.011	0.044	0.00083[5]
PSP	Diazinon (333-41-5)	614/1657	0.0013	0.005[11]	0.17[4]
090	Dieldrin (60-57-1)	608	0.002	0.008	0.00014[5]
095	alpha-Endosulfan (959-98-8)	608	0.014	0.056	0.0087[5]
096	beta-Endosulfan (33213-65-9)	608	0.004	0.016	0.0087[5]
097	Endosulfan Sulfate (1031-07-8)	608	0.066	0.26	0.093[5]
098	Endrin (72-20-8)	608	0.006	0.024	0.0023[5]
099	Endrin Aldehyde (7421-93-4)	608	0.023	0.092	0.76[5]
100	Heptachlor (76-44-8)	608	0.003	0.012	0.00021[5]
101	Heptachlor Epoxide (1024-57-3)	608	0.083	0.33	0.00010[5]
PSP	Parathion (56-38-2)	614/1657	0.003	0.01[11]	0.013[7]
106	PCB-1242 (53469-21-9)	608	0.065	0.26	0.000170[5]
107	PCB-1254 (11097-69-1)	625	36	144	0.000170[5]
108	PCB-1221 (11104-28-2)	625	30	120	0.000170[5]
109	PCB-1232 (11141-16-5)	608	0.13	0.5	0.000170[5]
110	PCB-1248 (12672-29-6)	608	0.13	0.5	0.000170[5]
111	PCB-1260 (11096-82-5)	608	0.13	0.5	10.5[13]
112	PCB-1016 (12674-11-2)	608	0.13	0.5	0.42[13]
113	Toxaphene (8001-35-2)	608	0.24	0.96	0.00073[5]

PBT - Denotes a State of Washington toxic compound or additional parameter.

PSP — Puget Sound Pollutant

1. The DL and QL values were obtained from USEPA Region 10 (as compiled from 40 CFR Part 136), from Ecology Laboratory Manual, or from sources noted by other footnote. USEPA Region 10 compiled their list from the Methods Update Rule (MUR) FR vol. 72, no. 47, Monday, March 12, 2007. Parameter #53 in Table 1c of the MUR was published as 2,3-dinitrophenol which is technically incorrect; parameter #53 should have been listed as 2,4-dinitrophenol and appears corrected here.

   Methods have different ways to express detection limits and quantification limits. When a method published sensitivity information it was listed as a detection limit (DL); when a method indicated an instrument detection limit (IDL) that too was identified as a detection limit (DL). When a method was published with method detection limits (MDL) as per 40 CFR 136 Appendix B, then these limits were listed under MDL. When a method published a working or operational concentration range then the lowest value for that range was used to in the column called LLCR or lowest level of the concentration range. When a method published minimum levels, then these were listed under ML. Where only a DL or QL was provided the corresponding QL or DL was estimated by multiplying by 4 (or 0.25).

2. Detection level (DL) or detection limit means the minimum concentration of an analyte (substance) that can be measured and reported with a 99% confidence that the analyte concentration is greater than zero as determined by the procedure given in 40 CFR part 136, Appendix B.

   Quantitation Level (QL) is equivalent to EPA's Minimum Level (ML) which is defined in 40 CFR Part 136 as the minimum level at which the entire GC/MS system must give recognizable mass spectra (background corrected) and acceptable calibration points. These levels were published as proposed in the Federal Register on March 28, 1997.
3. This criterion is dependent upon receiving water characteristics. This value is the aquatic life chronic value at a hardness of 25 mg/l
4. EPA 822-R-03-031
5. Human health criteria as fresh or marine – EPA National Toxic Rule
6. Fresh water aquatic life as Acute or Chronic – EPA recommended values
7. Aquatic life as Acute or Chronic – WAC 173-201A
8. USEPA Drinking Water Criteria
9. Taste and odor criteria
10. No human health based screening levels were available for 2-chloroethylvinyl ether. This value is the surface water screening values derived by U.S. EPA Region 4 Water Management Division. These values were obtained from Water Quality Criteria documents and represent the chronic ambient water quality criteria values for the protection of aquatic life.
11. USGS 2004-5194. Pesticides Detected in Urban Streams in King County, Washington, 1998–2003.
12. Virginia Institute of Marine Science. 1996. A Manual for the Analysis of Butyltins in Environmental Samples.
13. Estimated effect level
14. Report on Carcinogens. 11th Edition. National Institute of Health. 2007.
15. EPA Region 10 criteria approval, Warm Springs Confederated Tribes. 2006.
16. Chapter 173-200 WAC.

ATTACHMENT III
WATER WITHDRAWAL AUTHORIZATION
FOR THE GRAYS HARBOR ENERGY CENTER

I. WATER WITHDRAWAL FROM THE RANNEY WELLS

A. PRIORITY DATE: December 17, 1973, pursuant to EFSEC authorization.

B. SOURCE: Chehalis River

C. MAXIMUM QUANTITY:

Instantaneous: 9.2 cubic feet per second
Annual: 6,865.65 acre feet

D. PURPOSE OF USE:

9.2 cubic feet per second for power generation and to cool the discharge to the temperature set in the NPDES permit.

E. PERIOD OF USE: Year-round.

F. LOCATION OF WITHDRAWAL:

1400 feet east and 300 feet south of the northwest corner of Section 15, Township 17 N. Range 7 W., E.W.M. (also known as Ranney Well No. 1)

3100 feet east and 400 feet south of the northwest corner of Section 15, Township 17 N. Range 7., E.W.M. (also known as Ranney Well No. 3)

G. LEGAL DESCRIPTION OF PROPERTY ON WHICH WATER IS TO BE USED:

Section 7, Township 17 N., Range 6 W., E.W.M. (and as further described in Attachment I of the Site Certification Agreement)

H. DESCRIPTION OF PROPOSED USE:

The Grays Harbor Energy Center consists of two or more natural gas-fired turbine units and one or more steam turbine-generator.

I. DEVELOPMENT SCHEDULE: Water was put to use in 2008.

II. WATER WITHDRAWAL FROM THE RAW WATER WELL

A. PRIORITY DATE: December 17, 1973, pursuant to EFSEC authorization

B. SOURCE: Ground water

C. MAXIMUM QUANTITY: 300 gallons per minute

D. PERIOD OF USE: Year-round

E. LOCATION OF WITHDRAWAL:

Southeast Corner of the Southwest Corner of Section 6, Township 17N, Range 6W, E.W.M.

F. LEGAL DESCRIPTION OF PROPERTY ON WHICH WATER IS TO BE USED:

Sections 7, 8, 17 and 18 in T. 17N. R.6W, E.W.M.

G. DESCRIPTION OF PROPOSED USE:

Construction, restoration, domestic and fire protection services.

H. DEVELOPMENT SCHEDULE: Water was put into use in 1977.

III. PROVISIONS

A. Instream Flow – The rate of diversion for the Grays Harbor Energy Center, pursuant to this water authorization, is limited to a maximum of 9.2 cubic feet per second. However, the diversion shall be decreased (or stopped) as necessary to ensure that the diversion does not affect the minimum base flows immediately downstream of the point of diversion. The required minimum base flows are established in WAC 173-522-020 and set forth in subsection (B) below. All withdrawals pursuant to this water authorization are subject to the withdrawal restrictions set forth herein concerning periods of low flow.

B. Standard Base Flow – This authorization is subject to the provisions of Chapter 173-522 Washington Administrative Code and the general rules of Ecology as specified under Chapter 173-500 Washington Administrative Code, and others. The base flows for the Satsop Combustion Turbine Project were established at monitoring station 12.0350.02, mile 20, Sec. 7, T.17N., R.6W., E.W.M., and are presented in the following table:

MONTH	DAY	BASE FLOW (cfs)	MONTH	DAY	BASE FLOW (cfs)
January	1	3800	July	1	1085
January	15	3800	July	15	860
February	1	3800	August	1	680
February	15	3800	August	15	550
March	1	3800	September	1	550
March	15	3800	September	15	550
April	1	3800	October	1	640
April	15	3800	October	15	750
May	1	2910	November	1	1305
May	15	2300	November	15	2220
June	1	1750	December	1	3800
June	15	1360	December	15	3800

Base flow hydrographs, found on page 81 of "Water Resources Management Program in the Chehalis River Basin," dated November 1975, shall be used for definition of base flows for the Satsop Combustion Turbine Project on those days not specifically identified in the above table. These base flows will also be established at Station 12.0350.02 (Chehalis River below confluence with Satsop River). No diversion of water under this authorization shall take place such that the flow of the river falls below the above flows.

There is no gauge currently located at Station No. 12.0350.02. The flow of the river at that location will be determined using the following formula:

$$\left(\begin{array}{l} \text{Chehalis River} \\ \text{Flow at Station} \\ \text{No. 12027500} \end{array} + \begin{array}{l} \text{Satsop River} \\ \text{Flow at Station} \\ \text{No. 12035000} \end{array} \right) \times 1.5$$

The Certificate Holder will calculate the running 24-hour average flow rate at monitoring Station No. 12.0350.02, based upon the real time data provided by gauges at Stations No. 12.0275.00 and No. 12.0350.00. The restriction on water withdrawal pursuant to this authorization shall begin whenever the running 24-hour average flow rate falls below the base flow rate established by WAC 173-522-020. The restriction shall end when both the instantaneous flow and the 24-hour average flow rate rises above the base flow established by WAC 173-522-020.[1]

[1] See EFSEC Resolution No. 309.

C. Pumps – Process water for the Grays Harbor Energy Center shall be provided through the Ranney wells by the Grays Harbor Public Development Authority (PDA), or its successors. If necessary to limit the withdrawal to the extent of the PDA's and the Grays Harbor Energy Center's withdrawal authorizations, the existing pumps may be replaced or modified.

D. Meter – An approved measuring device shall be installed and maintained in accordance with RCW 90.03.360, WAC 508-64-020 through -040, for water use. Installation, operation, and maintenance requirements may be obtained from the Department of Ecology's Southwest Regional Office, Water Resources Program. Meter readings shall be recorded at least once monthly.

E. Water Resources Act – The Water Resources Act of 1971 specifies certain criteria regarding utilization and management of the waters of the Washington State in the best public interest. Favorable consideration of the application has been based on sufficient waters available. Ecology has not waived its right to request of the Energy Facility Site Evaluation Council that the use of water be subject to further regulation at certain times, based on the necessity to maintain water quantities for preservation of the natural environment.

F. Water Resources – Under RCW 90.44.250 and 90.54.030, Ecology is directed to become informed about all aspects of the water resources of the State. Ecology is authorized to make such investigations as may be necessary to determine the location, extent, depth, volume, and flow of all ground waters within the State. Accordingly, the Certificate Holder shall monitor and provide an annual summary of the previous year's monthly static water level data and monthly totals of water pumped from the Ranney wells. This summary shall be submitted in tabular format to the Council and to Ecology's Southwest Regional Office annually, during the month of February, or more frequently if requested by Ecology.

G. Ground Water Use – Withdrawal of water from ground water by the Certificate Holder in an area near the confluence of the Chehalis and Satsop rivers for any use other than domestic supply or fire suppression will be limited to 300 gallons per minute and will be limited by restricts set forth in Section B during periods of low flow.

H. Indian Rights – This authorization to make use of public water of the state is subject to existing rights, including existing rights held by the United States for the benefit of Tribes under treaty or settlement.

Grays Harbor Energy LLC

Grays Harbor Energy Center

July 9, 2010

Jim Luce, Chair
Energy Facility Site Evaluation Council
905 Plum Street S.E.
P.O. Box 43172
Olympia, WA 98504-3172

Via Electronic Mail

Re: Grays Harbor Energy Center LLC
Noise Mitigation

Dear Chair Luce:

Since the Grays Harbor Energy Center began commercial operations in July 2008, some nearby residents have expressed concerns about the noise produced by the facility. At the Council's request, Grays Harbor Energy LLC retained the consulting firm Michael Theriault Acoustics, Inc. ("MTA") to conduct a noise monitoring study last year. More recently, the Council retained the consulting firm ICF International ("ICF") to review the MTA study and take its own sound level measurements.

Having reviewed the MTA and ICF reports, Grays Harbor Energy remains convinced that the Grays Harbor Energy Center operates in compliance with WAC chapter 173-60 and it's Site Certification Agreement. Nonetheless, Grays Harbor Energy has decided to voluntarily undertake the following actions at the existing facility:

- Install acoustic walls around combustion turbine exhaust transition pieces;
- Install silencers in four (4) combustion turbine enclosure ventilation systems;
- Install silencers on one (1) auxiliary steam relief valve and four (4) cold reheat steam relief valves.

Grays Harbor Energy will begin planning and budgeting these actions immediately, and will complete implementation no later than June 15, 2011.

Grays Harbor Energy will also incorporate these elements into its design and construction of the proposed expansion, Units 3 and 4. Additionally, as set forth in the Mitigated Determination of Non-significance (MDNS), Grays Harbor Energy will undertake a study to identify reasonable, cost-effective additional mitigation that could be implemented with the construction of Units 3 and 4.

PO Box 26 • Satsop, WA 98583• 360.482.4353 • Fax 360.482.4376

Sincerely,

Todd Gatewood
Plant Manager
Grays Harbor Energy Center LLC

Perkins Coie

1201 Third Avenue, Suite 4800
Seattle, WA 98101-3099
PHONE: 206.359.8000
FAX: 206.359.9000
www.perkinscoie.com

Karen M. McGaffey
PHONE (206) 359-6368
FAX (206) 359-7368
EMAIL KMcGaffey@perkinscoie.com

August 2, 2010

James Luce, Chair
Energy Facility Site Evaluation Council
925 Plum Street SE, Building 4
Olympia, Washington 98504-3172

Re: **Grays Harbor Energy Center**
Application to Amend the Site Certification Agreement

Dear Chair Luce:

We are writing on behalf of Grays Harbor Energy LLC ("GHE") to urge the Council to grant GHE's Application to Amend the Site Certification Agreement ("SCA") for the Grays Harbor Energy Center (formerly known as the Satsop Combustion Turbine Project).

GHE asks EFSEC to amend the existing SCA to authorize the construction and operation of two additional combustion turbine generators, one steam turbine generator and associated facilities. The proposed expansion, referred to as Units 3 and 4, will increase the generating capacity of the Grays Harbor Energy Center by approximately 650 megawatts (MW), to a total of approximately 1300 MW.

The proposed expansion will help EFSEC fulfill its mandate of providing abundant energy at a reasonable cost. Additional clean natural gas-fired generating capacity will help to meet increasing peak electrical demand in the region and facilitate the integration of intermittent renewable generation resources. The expansion will provide significant local economic benefits, including short-term construction jobs, long-term operation jobs, and substantial tax revenues. The expansion is also designed to avoid most adverse environmental impacts and to minimize and mitigate those that are unavoidable.

This letter summarizes the information presented to the Council in connection with the Application.

I. Introduction

A. Background

The Site Certification Agreement at issue in these proceedings dates back to 1976, when the Governor authorized the construction and operation of the Satsop Nuclear Project by the Washington Public Power Supply System (now known as Energy Northwest) on a large site southwest of the Town of Elma in Grays Harbor County. EFSEC adopted Amendment No. 1 in 1982, which modified conditions related to the nuclear project.

In 1996, after construction of the nuclear project had ceased, EFSEC recommended, and the Governor approved, Amendment No. 2. It authorized the construction and operation of a natural gas-fired combustion turbine project within the larger area that had been set aside for the nuclear project. Amendment No. 3, approved in 1999, removed the terms and conditions related to the nuclear project from the SCA.

The Council adopted various resolutions making technical amendments to the SCA in 2001, 2004 and 2005. These resolutions transferred the SCA to Duke Energy North America, and then to GHE, authorized changes in the project design, and clarified provisions related to water use.

GHE currently owns and operates the Grays Harbor Energy Center (Satsop Combustion Turbine Project), a 650 MW natural gas combined cycle power plant. The facility is located on a 22-acre site that is surrounded by the 1,600-acre Satsop Development Park on all four sides. Doc. #1 (Application) at 1-1, 2-1 to 2-2.[1] The existing facility, referred to as Units 1 and 2, began commercial operation in July 2008.

B. Requested Amendment

GHE asks EFSEC to amend the existing SCA to authorize the construction and operation of two additional combustion turbine generators, one steam turbine generator and associated facilities. The proposed expansion, referred to as Units 3 and 4, will increase the generating capacity of the Grays Harbor Energy Center by approximately 650 MW.

Units 3 and 4 will be virtually identical to the existing Grays Harbor Energy Center Units 1 and 2. Like the existing units, Units 3 and 4 will have General Electric (GE) Frame 7FA combustion turbines in a 2-x-1 combined cycle configuration with a GE D11 steam turbine. Each GE 7FA combustion turbine generates a nominal power capacity of 175 MW, while the steam turbine

[1] Citations to documents provided to the Council during these proceedings reference the document numbers ("Doc. #__) assigned in the list of documents provided with the Council's hearing binders. An updated document list is provided with this letter.

generates approximately 300 MW with maximum duct firing at annual average temperature. Doc. #1 (Application) at 2-7 to 2-8. The facility will continue to be fueled by natural gas.

Units 3 and 4 will be located entirely within the boundaries of the previously permitted site on land that has already been disturbed and developed for industrial use.[2] Doc. #1 (Application) at 2-1. Units 3 and 4 will use many of the facilities installed for Units 1 and 2, including the operations building, control room, warehouse, workshops, natural gas pipeline, water wells and supply lines, and the water treatment system and discharge line. Doc. #1 (Application) at 2-2, 2-6. Power produced by Units 3 and 4 will be exported on lines to be installed on the existing tower structures running from the facility site to the Bonneville Power Administration's Satsop substation, which is located approximately 4,000 feet east of the site. Doc. #1 (Application) at I-1, 2-1 to 2-2.

The requested amendment would also change the official name of the project in the SCA from the Satsop Combustion Turbine Project to the Grays Harbor Energy Center.

C. Expansion Benefits

The addition of Units 3 and 4 to the existing Grays Harbor Energy Center will provide significant energy, environmental and economic benefits to Washington.

Units 3 and 4 will double the facility's capacity. Doc. #1 (Application) at I-1, 2-1. This additional dispatchable power will help meet long-term growth in regional peak electricity demand and facilitate the integration of intermittent renewable energy sources such as wind and solar projects. Doc. #11 (Oakleaf Presentation) at 18.

Units 3 and 4 will generate electricity using natural gas and a highly efficient combined-cycle design. This means electricity will be produced with fewer emissions of air pollutants and greenhouse gases than other fossil fuel generation. Doc. #1 (Application) at 2-34; Doc. #11 (Oakleaf Presentation) at 10. The expansion also takes advantage of an existing site and infrastructure, avoiding the environmental impacts associated with new development. Doc. #11 (Oakleaf Presentation) at 10.

There will be significant economic benefits associated with the expansion. Doc. #8 (Technical Narrative: Proposed Expansion) at 2; Transcript 7/13 at 21-22 (Dines). It will create up to 500

[2] GHE initially proposed to enlarge the project site to include an additional ten acres for use as construction laydown, material storage and access. Doc. #1 (Application) at 2-1 to 2-5. In response to concerns expressed by the Washington Department of Ecology ("WDOE") and the Washington Department of Fish and Wildlife ("WDFW"), however, GHE withdrew this proposal. Doc. #4 (MDNS) at 1-2; see also Doc. #8 (Technical Narrative: Proposed Expansion) at 2.

jobs and result in millions of dollars in local spending during the 22 month construction period. Once in operation, there will be 8 new full-time jobs at the facility. The expansion will also substantially increase the local tax base. Doc. #1 (Application) at 4-49 to 4-53; Doc. #11 (Oakleaf Presentation) at 11.

II. Environmental Impacts and Mitigation

The proposed expansion avoids most adverse environmental impacts and mitigates those that are unavoidable. The Council has already issued a MDNS under SEPA, concluding that the addition of Units 3 and 4 would not result in significant unmitigated adverse impacts to the environment. See Doc. #4 (MDNS).

The following sections summarize the information presented on key environmental issues.

A. Air Quality

One of the principal environmental advantages of a natural gas power plant is that it produces electricity without the significant air pollutant emissions that are associated with other fossil fuel-fired electrical generation. In fact, during the public meetings, Robert Moody (ORCA) noted that emissions from this kind of facility are so low that they are difficult to measure.[3]

Under the Clean Air Act, the proposed expansion requires a Notice of Construction (NOC) and Prevention of Significant Deterioration (PSD) permit. At the time of the panel presentations, however, the Council had not yet issued a draft NOC/PSD permit for public comment. However, in their presentations, Eric Hansen (Environ) and Bob Burmark (WDOE) explained that the proposed expansion will satisfy all federal and state air emissions control requirements. See Doc. #27 (Technical Narrative: Air Quality).

A critical element of the NOC/PSD permit is the requirement that new sources implement Best Available Control Technology, known as BACT. Units 3 and 4 will use Selective Catalytic Reduction (SCR), to reduce oxides of nitrogen (NO_x), and an oxidation catalyst to reduce emissions of carbon monoxide (CO) and volatile organic compounds (VOCs). Doc. #29 (Hansen Presentation) at 6. Good combustion practices and the use of natural gas represent the BACT for other pollutants. Id. Mr. Hansen and Mr. Burmark explained that these control technologies are well established and that the NOC/PSD permit will include emission limitations that are at least as strict as any similar project in the region.

[3] The transcripts for the meetings held of July 14 and 15, 2010, are not yet available, so page references are not provided.

In order to obtain an NOC/PSD permit, a new source must also demonstrate that it will not cause ambient air quality standards to be exceeded. GHE retained Environ to perform sophisticated computer modeling, using EPA-approved dispersion models, to predict the effect of the proposed expansion on air quality in Class I and II areas and then compare the results to regulatory standards. The modeling methods use conservative assumptions and consider the "worst-case" maximum emission scenarios. The modeling showed that maximum ambient concentrations of criteria pollutants will be below "Significant Impact Levels" and PSD increments in both Class I and II areas, and that concentrations of toxic pollutants will be below "Acceptable Source Impact Levels." Doc. #29 (Hansen Presentation) at 9, 13.

The Certificate Holder has also evaluated the effect of operating the expanded facility on visibility and haze at Class I areas, including Olympic National Park, and the Columbia River Gorge National Scenic Area. In evaluating regional visibility/haze impacts, the Federal Land Managers use a 5% visibility impact as their threshold of concern. Olympic National Park was the only Class I area with impacts above that threshold, and it had a "just perceptible" change on only two days out of three years simulated in the modeling. Doc. #29 (Hansen Presentation) at 16.

A final air-related issue discussed during the public meetings was odor. During the public meeting in December 2009, some nearby residents commented about chemical odors. GHE investigated these concerns and determined that the chlorine used to keep the facility's cooling tower clean might cause odors nearby under certain weather conditions. GHE has changed the chemicals used in the cooling tower and expects the change to resolve odor concerns. Doc. #11 (Oakleaf Presentation) at 16; Doc. #27 (Technical Narrative: Air Quality) at 2; Doc. #29 (Hansen Presentation) at 19.

B. Greenhouse Gases

Burning fossil fuels results in the emission of carbon dioxide (CO_2), a greenhouse gas. Burning natural gas, however, emits much less CO_2 than burning other fossil fuels. The highly efficient combined-cycle design of the proposed expansion means that more electricity will be produced with fewer greenhouse gas emissions. The proposed expansion is expected to emit approximately 782 pounds of CO_2 per megawatt hour of electricity produced. In contrast, a simple cycle gas plant typically emits approximately 1,320 pounds per MW-hour, and a typical coal plant emits approximately 2,100 pounds per MW-hour. Doc. #1 (Application) at 2-35 to 2-36.

Washington law establishes a greenhouse gas emission performance standard for new electrical generating facilities. RCW ch. 80.80. Greenhouse gas emissions may not exceed 1,100 pounds per MW-hour. At 782 pounds per MW-hour, Units 3 and 4 easily comply with this requirement. Doc. #1 (Application) at 2-36; Doc. #29 (Hansen Presentation) at 18.

Washington law also requires new electrical generation facilities to provide mitigation for CO_2 emissions. RCW ch. 80.70. The statute and implementing regulations provide a specific formula for calculating the mitigation obligation. RCW 80.70.010 - .020; WAC 463-80-050. Rather than implementing its own mitigation projects, GHE has elected to provide mitigation according to the "monetary path" authorized by the statute. See Doc. #1 (Application) at 2-36, 3-16; Doc. #29 (Hansen Presentation) at 18. The statute and regulations authorize mitigation to be provided by a payment for $1.60 per ton to a qualified organization. RCW 80.70.020(5); WAC 463-80-060(3). GHE estimates that the total mitigation payment will be approximately $11.75 million. Pursuant to WAC 463-80-090, EFSEC has approved a list of qualified organizations to receive these payments. See http://www.efsec.wa.gov/IQO.shtml. GHE will not control how the mitigation funds are used, but we understand that these organizations often look for opportunities to fund mitigation projects located near the generation facility providing the funding.

C. Water Use

The Grays Harbor Energy Center uses water to produce steam that turns the steam turbine, and then to cool the steam and equipment. The existing SCA authorizes the Certificate Holder to use up to 9.2 cubic feet per second (cfs) of water. The expanded facility will use up to an additional 6.8 cfs of water. Doc. #34 (Technical Narrative: Water) at 2.

Water for both the existing facility and the proposed expansion will come from the Ranney wells located adjacent to the Chehalis River, approximately 4 miles downstream from the Grays Harbor Energy Center. Doc. #34 (Technical Narrative Water) at 1. The SCA contains a water authorization that allows GHE to withdraw up to 9.2 cfs from the Ranney wells, except at times that the flow in the river falls below established regulatory base flows. At such times, GHE must purchase water from another holder of a valid water right that is not subject to a low flow limitation. In practice, GHE buys water on these occasions from the PDA, which holds a 20 cfs water right that is not subject to low flow limitations. Id. at 2. Likewise, GHE proposes to purchase up to an additional 6.8 cfs of water from the PDA to operate the expansion.[4]

A majority (88%) of the water withdrawn from the Ranney wells comes from the Chehalis River. Doc. #1 (Application) at 3-23. GHE's consultants and staff from WDOE and WDFW considered the proposed increase in water withdrawals and concluded that it would not adversely affect the river or the fish that live in it. Doc. #34 (Technical Narrative: Water); Doc. #39 (Water Resources Summary Sheet).

[4] During the public meetings, PDA CEO Tami Garrow explained that, even with the maximum tenant load, the PDA would have enough water available to supply water to the proposed expansion. We are providing a copy of the Entrix report that Ms. Garrow mentioned in her comments, designated Doc. #40.

GHE's consultant Cameron Ochiltree (URS) looked at river flow data from 2005 to 2009, and determined that the flow ranged from a high of more than 30,000 cfs to a low of about 550 cfs. Doc. #38 (Ochiltree Presentation) at 11. WDOE has established regulatory base flow levels that vary throughout the year, ranging from 550 cfs to 3800 cfs. WAC 173-522-020. In the past five years, flows have fallen below the regulatory base flow levels on 13 to 44 days a year. Doc. #34 (Technical Narrative: Water) at 1. However, many of those days occurred during times of the year when the regulatory base flow is relatively high. The flows on these "below base flow" days ranged from a high of 3,770 cfs to a low of 594 cfs, with an average of 2,118 cfs. Id. at 2. GHE's consultant Brad Rawls (URS) reviewed this data and other information about the Chehalis River's fish population and concluded that the proposed additional withdrawal would not have a measurable impact on aquatic habitat, fish, or other aquatic species. Doc. #34 (Technical Narrative: Water) at 3.

During the panel presentation, Brad Caldwell (WDOE) explained that impact of the additional withdrawals would be negligible. It is a small amount of water, a portion of which is returned to the river through the facility discharge. The withdrawn amount is even less significant considering the natural tidal variation in flows and the fact that the Wynoochee River adds to the Chehalis River shortly downstream of the withdrawal point. See Doc. #39 (Water Resources Summary Sheet) at 2.

D. Water Quality

The Grays Harbor Energy Center currently discharges about 1.5 cfs of process water to the Chehalis River. After the proposed expansion, the facility could discharge up to 3 cfs of process water. Doc. #34 (Technical Narrative: Water) at 2.

The existing facility's discharge is governed by a Clean Water Act NPDES permit. During the public meetings, the Council heard about the facility's compliance history. Mistakes were made in the initial permit writing, resulting in a chloride limit that was much lower than appropriate, and an iron limit measured at an inappropriate point in the process. Doc. #38 (Ochiltree Presentation) at 20; Doc. #45 (LaSpina Presentation) at 8. Both errors are being addressed in the NPDES permit amendment, and no further exceedences are anticipated. Doc. #38 (Ochiltree Presentation) at 20. In the initial operation of the facility a small number of pH exceedences occurred and one temperature exceedence also occurred. GHE implemented changes in the facility's control system and there have been no further exceedences. Id.

Discharges from the expansion will also be required to comply with the NPDES permit. The character of the discharge from Units 3 and 4 will be similar to that from Units 1 and 2. The Amendment Application contains extensive information regarding the characteristics of the discharge and the anticipated effect on water quality in the Chehalis River. See Doc. #1 (Application) at § 2.8.2. During the public meetings, Cameron Ochiltree explained why the discharge from Units 3 and 4 would not adversely affect water quality and would comply with established water quality standards. See Doc. #38 (Ochiltree Presentation) at 18.

The NPDES permit contains requirements and limitations designed to protect water quality and aquatic habitat. Additional information will be gathered as the facility continues operating, and final permit limits will be established after an Engineering Report is completed. See Doc. #42 (Draft NPDES Permit) at 16-19.[5]

E. Plants, Animals and Habitat

The Grays Harbor Energy Center was constructed on a 22-acre site that had previously been filled with several feet of compacted gravel and graded for use during construction of the never-completed nuclear project. The proposed explanation will be located entirely within this previously developed site. No impacts to plants, animals or habitat are anticipated.

GHE initially proposed to expand the site to include 10 acres to the east, some of which is forested. In response to concerns about the potential impact to habitat expressed by WDOE and WDFW, GHE abandoned this proposal. See Doc. #4 (MDNS).

F. Noise

The most extensive discussion during the public meetings concerned noise. The panel of experts agreed that the existing facility complies with state regulatory noise limits and that the proposed expansion would as well. Nonetheless, it is clear that some nearby residents are annoyed by facility noise. GHE has gone beyond the regulatory requirements to propose additional mitigation measures to reduce this annoyance.

1. Existing and Predicted Noise Levels

The panel of experts concerning noise included GHE's consultants Michael Theriault and Michael Hankard, and EFSEC's independent consultant Jim Wilder. These experts agreed on two important facts.

First, the experts agreed that the existing facility operates in compliance with state regulatory noise limits the vast majority of the time. Regulations enacted by Ecology and adopted by EFSEC establish maximum noise levels from industrial sources at residential properties of 60 A-weighted decibels (dBA) during the daytime and 50 dBA during the nighttime. WAC 463-62-030; WAC 173-60-040. Mr. Theriault explained the results of a monitoring study conducted in

[5] By separate letter, GHE is submitting comments regarding the Draft NPDES permit.

2009, which indicated that the facility generally resulted in noise levels of 28 to 40 dBA at nearby residences. See Doc. #17 (Monitoring Study); see also Transcript 7/13 at 79 (Wilder explaining that nighttime levels are 28-30 dBA). The only exception was during an emergency steam relief event, and there have been only 5 similar events since the facility began commercial operation in June 2008. See Doc. #17 (Monitoring Study). Mr. Wilder confirmed that "99.9 percent of the time" the facility complies with the regulations and produces sound well below the regulatory limits. Transcript 7/13 at 76, 79.

Second, the experts agreed that the proposed expansion will also comply with state regulatory limits. Mr. Theriault explained that a doubling of the source would be expected to result in a 3 dBA increase in noise levels, which is just barely perceptible. Transcript 7/13 at 52, 63. Mr. Theriault also described the acoustical modeling he performed that predicted the expanded facility would comply with state regulations. Transcript 7/13 at 64. Mr. Wilder agreed. Transcript 7/13 at 79. Indeed, Mr. Wilder concluded that the modeling was very conservative, and that he expected noise levels from the expanded facility to be much lower than predicted. Doc. #23 (ICF Noise Report) at 8-2.

Upon hearing this consensus from the experts, many of the nearby residents who spoke at the meetings conceded that the facility probably did comply with regulatory requirements. See, e.g., Transcript 7/13 at 104 (Holt), 122 (Farr). Nonetheless, they explained that the noise was annoying either because of the very low noise levels to which they had grown accustomed, or because of the particular tone or frequency of sounds from the facility.

2. Proposed Mitigation

In response to concerns expressed by nearby residents, GHE has proposed several mitigation measures. With respect to the current operation of Units 1 and 2, GHE has proposed to:

- Install acoustical walls around the combustion turbine transition pieces;
- Install acoustical silencers in four combustion turbine enclosure ventilation systems; and
- Install acoustical silencers on one steam relief valve and four cold reheat steam relief valves.

GHE has agreed to begin budgeting and implementing these measures immediately, and to ensure that they are in place by June 15, 2011. Doc. #12 (GHE Letter); see also Transcript 7/13 at 66 (Theriault).

GHE has also proposed to implement the following additional measures if and when it begins construction of Units 3 and 4:

- An acoustical specialist will conduct a field study of Units 1 and 2 to identify additional reasonable, cost-effective mitigation measures that could be implemented with the construction of Units 3 and 4 to further reduce project noise.

- Units 3 and 4 will be designed to include mufflers in the air intake ductwork of the combustion turbine and ventilation systems as well as in the exhaust of the waste heat boilers. High performance acoustical enclosures will house each of the combustion turbines and the existing noise wall will be maintained.

- An acoustical specialist will take noise measurements during performance testing of Units 3 and 4, and will use the results to determine whether additional measures are necessary to comply with Washington noise regulations.

- The facility will comply with the maximum noise limits of Washington's noise regulations. After the expansion begins commercial operation, an acoustical specialist will perform a noise monitoring study to confirm compliance.

See Doc. #15 (Technical Narrative: Noise) at 4; Doc. #4 (MDNS) at 5. By proposing these mitigation measures, GHE has volunteered to go above and beyond the legal requirement to comply with the state noise regulations.

3. Additional Recommendations

Mr. Wilder's report and summary sheet included several recommendations to reduce the annoyance of nearby residents. See Doc. # 21 (Community Noise Summary Sheet); Doc. #23 (ICF Noise Report). Mr. Wilder does not offer an opinion about whether there is any legal basis for requiring GHE to undertake these recommended measures, but nonetheless offers them for the Council's consideration. His recommendations are addressed in turn below.

First, Mr. Wilder recommended the development of project-specific noise limits that are more stringent than Washington's regulatory limits. Doc. #21 (Community Noise Summary Sheet) at 2. GHE strongly opposes this recommendation.

Several years ago, EFSEC undertook a lengthy stakeholder process to develop consistent, predictable standards for certifying energy projects. The process culminated in a rulemaking and the promulgation of the regulations found at WAC chapter 463-62. In particular, WAC 463-62-030 adopts Ecology's maximum noise levels (WAC 173-60-040) as the Council's performance standard for energy facilities. The regulations provide that those limits "shall apply" to energy projects within the Council's jurisdiction. WAC 463-62-010. The only exception is when a SEPA determination has found a unmitigated significant adverse impacts, which is not the case here. Developing and applying a different noise limit to this project would be contrary to the Council's regulations.

Doing so would also be unjustified on the record. There is no evidence to indicate that the established regulatory limits are outdated or inappropriate. To the contrary, Mr. Theriault testified that they are fairly typical of noise regulations throughout the country. Transcript 7/13 at 126. These noise limits are applied to all other facilities in Washington State and there is simply no reason to apply different rules to the Grays Harbor Energy Center.

Some nearby residents appear to believe that they are entitled to a different standard because they have long enjoyed very low noise levels in what has been a relatively undeveloped, rural area. State law does not create such an entitlement, however. In this case, the residents who have expressed concerns about noise live very close to property that Grays Harbor County has zoned for heavy industrial development. Permitted uses in the Satsop Development Zone include noisy industrial uses such as shipping terminals, contractor yards, auto and metal recycling facilities, manufacturing and assembly facilities, and helipads. See Grays Harbor Code 17.57.020. The project site is one of the only areas in Grays Harbor County where electric generation facilities are permitted outright. As PDA CEO Tami Garrow explained during the public hearing, the Satsop Development Park has been the subject of a major redevelopment plan, which envisions significant development including energy facility development. The existing infrastructure of the Development Park, including the transmission line, substation and natural gas pipeline, make the site a natural location for energy facility development. Far from being entitled to a special exemption from the state noise regulations, nearby residents should anticipate the normal consequences of living close to property that the County has zoned for industrial development.

Second, Mr. Wilder recommended that GHE conduct a noise control study to determine whether there are reasonable additional measures that could be implemented to reduce noise. Doc. #21 (Community Noise Summary Sheet) at 2. GHE has proposed to perform this sort of study before constructing Units 3 and 4, but Mr. Wilder recommended that a study of Units 1 and 2 be performed immediately. GHE strongly disagrees with this recommendation. The facility is currently in full compliance with the existing regulations and SCA, so there is no legal justification for imposing additional mitigation requirements on the existing facility.

Furthermore, GHE has volunteered to implement some additional acoustic walls and silencers on Units 1 and 2 to try to reduce annoying noises.

Third, Mr. Wilder recommended that installation of a continuous noise monitoring system. Doc. #21 (Community Noise Summary Sheet) at 2. GHE opposes this recommendation, and Mr. Wilder abandoned it during the panel discussion. According to Michael Theriault, continuous monitoring would be an unnecessary expense and would not be useful in addressing the annoyance of nearby residents. Doc. #18 (Theriault Letter) at 6-7. Mr. Wilder agreed that a continuous monitoring system was not necessary to verify compliance with regulatory noise limits. After learning that GHE has also made a change in the control system alarms to alert the control room in the event of any steam or gas relief valve event (Transcript 7/13 at 35-36), Mr. Wilder agreed that continuous noise monitoring would not be necessary to alert the control room of rare, but loud, upset events. See Transcript 7/13 at 94.

Fourth, Mr. Wilder recommended that GHE conduct daily handheld noise surveys at the project site and the closest homes. Doc. #21 (Community Noise Summary Sheet) at 2. GHE opposes this recommendation for the same reasons it opposes continuous monitoring, and Mr. Wilder appeared to abandon this recommendation during the panel presentations.

Fifth, Mr. Wilder recommended that GHE promptly identify the cause of loud noise events and initiate corrective actions. Doc. #21 (Community Noise Summary Sheet) at 2. As Todd Gatewood explained during the hearing, this has been GHE's practice. Whenever an upset or emergency release occurs, the source of the problem is identified and remedied.

Finally, Mr. Wilder recommended that GHE submit periodic noise monitoring reports to EFSEC. Doc. #21 (Community Noise Summary Sheet) at 2. As explained above, GHE opposes the recommendation of continuous monitoring. GHE does, however, report to EFSEC on a monthly basis regarding noise complaints and associated response actions.

For these reasons, EFSEC should not impose any mitigation requirements above and beyond those already proposed by GHE.

G. Light and Glare

The Grays Harbor Energy Center is lighted for the purposes of operator access, safety and security. In response to concerns expressed during the December 2009 public meeting, GHE has made changes to its standard operating procedures to turn off unnecessary lights. Doc. #11 (Oakleaf Presentation) at 17. With the exception of minimal lighting on the top of each boiler and stairway lighting for night-time access, existing lighting on high elevation access platforms has been turned off and is only turned on in the event that night-time access to towers or stacks is required. Lighting that is needed for night-time security or safe access has been directed downward and shielded. Id. Nearby residents were pleased with these changes. See Transcript 7/13 at 37 (Holt). These same lighting procedures will be implemented with Units 3 and 4. Id.

H. Traffic

Before construction of the existing Grays Harbor Energy Center, GHE made improvements to the Keys Road – SR 12 intersection, adding dedicated turn lanes and a flared approach. During the original construction, a traffic mitigation plan was also developed and implemented. Among other things, the plan encouraged workers to take the Wakefield/Lambert route to and from the site to reduce traffic at the Keys Road – SR 12 intersection.

For construction of the expansion, GHE will update and implement the traffic management plan. During the public meetings, the only concern expressed about construction traffic related to pedestrian traffic as construction workers crossed Keys Road traveling between their vehicles and the site. In updating the traffic management plan, GHE will consider measures to address possible delays caused by pedestrian crossings.

III. Conclusion

For the reasons discussed above, the Council should recommend amendment of the Site Certificate Agreement to allow construction and operation of Units 3 and 4.

Very truly yours,

Karen M. McGaffey

Karen M. McGaffey

Cc: Al Wright, EFSEC Manager
Bruce Marvin, Counsel for the Environment

ATTACHMENT V

ENERGY FACILITY SITE EVALUATION COUNCIL
P.O. BOX 43172
OLYMPIA, WASHINGTON 98504-3172

IN THE MATTER OF:	] NO. EFSEC/2001-01 Amendment 3
Satsop Combustion	]
Turbine Project	] FINAL APPROVAL OF THE PREVENTION OF
Electrical Generating Facility	] SIGNIFICANT DETERIORATION AND
Elma, Washington	] NOTICE OF CONSTRUCTION

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, the federal Prevention of Significant Deterioration regulations, Code of Federal Regulations (CFR), Title 40 Subpart 52.21; 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; 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 (also known as 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 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 original 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 will authorize 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 eighteen months.

6. The total project is proposed to consist of the following major components:

   - Two General Electric gas combustion 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 300 MW;
   - One auxiliary boiler;
   - One forced draft cooling tower system;
   - One emergency backup diesel generator ; and
   - One diesel engine-driven fire water pump.

   These components are configured in a "power island" comprised of 2 gas turbine/duct burner/HRSG units, one steam turbine, one cooling tower, one auxiliary boiler, one emergency generator, and one emergency fire water pump. Each gas turbine/duct burner/HRSG unit is known as a combined cycle gas turbine (CGT). Each CGT has its own exhaust stack.

7. The project is subject to permitting requirements under the federal requirements of 40 CFR 52.21 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 Satsop 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 (VOC).

8. The project is subject to permitting under the requirements of WAC 463-78-005(1) and 005(4) (adopting Chapters 173-400 and 173-460 WAC respectively) for ammonia (NH_3). NH_3 emissions are limited in this permit in its role as in controlling emissions of NO_x.

9. The combustion turbines, duct burners and auxiliary boilers will only use natural gas received from the Northwest Pipeline. The fuel for the diesel engines powering the emergency generators and emergency fire water pumps is to be on-road specification diesel fuel.

10. The site of the proposed project is within an area that is in attainment with regard to all pollutants regulated by the 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.

11. The project is subject to new source review requirements under Chapter 463-78 WAC, which adopts by reference Chapter 173-400 WAC, Chapter 173-460 WAC, and 40 CFR 52.21. The

facility is also subject to emission limitation, monitoring and reporting requirements in 40 CFR 60 Subpart Db, 40 CFR 60 Subpart GG, Chapter 173-400 WAC, 40 CFR 60 Appendices A, B, and F, and 40 CFR 75; and to gas fuel monitoring requirements under 40 CFR 60.334(b)(2) and 40 CFR Part 75 Appendix D.

12. BACT as required under 40 CFR 52.21(j) and WAC 173-113(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.

Pollutant	Plant wide Potential to Emit kg/yr (tpy)	Best Available Control Technology			
		Combustion turbines	Auxiliary boiler	Diesel-fired emergency equipment	Cooling tower
Nitrogen oxides (NOx)	224,091 (246.5)	Selective Catalytic Reduction plus low NOx burners	Flue gas recirculation and low NOx burners	Comply with the internal combustion engine standards in 40 CFR 89, Subpart B	Not applicable
Carbon monoxide (CO)	428,182 (477)	Good combustion practice			Not applicable
Sulfur dioxide (SO_2)	26,545 (29.2)[1]	Natural gas fuel		Use only on-road specification diesel oil	Not applicable
Sulfuric acid mist (H_2SO_4)	17,246 (19)	Natural gas fuel			Not applicable
Volatile organic compounds (VOC)	67,818 (74.6)	Natural gas fuel and Good combustion practice		Comply with the internal combustion engine standards in 40 CFR 89, Subpart B	Not applicable
Particulate matter (PM) and Particulate matter ≤10 micrometers (PM_{10})	184,545 (203)	Natural gas fuel and Good combustion practice			Drift eliminator with less than 0.001% loss of the recirculating water
Ammonia (NH_3)	128,214 (141)	5 ppm ammonia slip limitation	Not applicable		

[1] Based on an annual-average natural gas total sulfur content of 0.5 grains/100 scf

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

13.1 Any state or national ambient air quality standard;

13.2 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)
Particulate (PM_{10})*	24-Hour	4.86	17	0.23	8
	Annual	0.91	30	0.01	4
Nitrogen dioxide* Annual		0.898	25	0.008	2.5
Sulfur dioxide	3-Hour	13.54	20	0.26	25
	24-Hour	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 technical support document and application materials for details.

13.3 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.

14. 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 deposition of nitrogen within Olympic National Park for the 4 turbine proposal was modeled to be slightly above the level established by the National Park Service for concern. The National Park Service has informed EFSEC that the predicted deposition from the 4 turbine project was acceptable. The current 2 turbine project will have deposition levels significantly below the National Park Service's level of concern.

15. 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.

16. Ambient Impact Analysis indicates that degradation of regional visibility or vistas from Olympic National Park due to the Satsop project is acceptable to the National Park Service based on an emission limitation of 2.0 ppm NOx, 24 hr average on the facility.

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

18. EFSEC concludes that

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

18.2 BACT:

18.2.1 Based on comparable permit actions since 2002, EFSEC concludes that BACT for VOC emissions from the auxiliary using good combustion practice is 0.0055 lb/MMBtu (one-hour average).

18.2.2 For all other anticipated pollutants from the gas combustion turbines, heat recovery steam generators, auxiliary boiler, and cooling tower system BACT is the same as determined in Amendment 2.

18.2.3 For the emergency backup diesel generator and diesel engine-driven fire water pump BACT constitutes the use of on-road diesel as defined in the Federal Code of Regulations at the time of purchase of the fuel oil.

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

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

APPROVAL CONDITIONS

1. This Amendment supersedes air quality PSD approval EFSEC 2001-01, Amendment 2 dated October 19, 2004.

2. The CGTs, HRSGs, and auxiliary boilers shall use only natural gas.

3. The diesel emergency generators shall:

3.1 Use only on-road specification diesel oil with a sulfur content as defined at the time of purchase in the Code of Federal Regulations (at the time of issuance of this permit, that definition is in 40 CFR § 80.29(a)(i)).

3.2 Not exceed 500 hours per engine per year of operating time.

4. The emergency fire water pump engine shall use only on-road specification diesel oil with a sulfur content as defined at the time of purchase in the Code of Federal Regulations (at the time of issuance of this permit, that definition is in 40 CFR § 80.29(a)(i)).

5. Each CGT exhaust stack shall not exceed the following:

5.1 Nitrogen oxide (NO_X)emissions limitations:

5.1.1 9.86 kilograms/hour (kg/hr) (21.7 pounds/hour (lb/hr)), 1-hour (1-hr.) average when duct firing,

5.1.2 7.89 kg/hr (17.4 lb/hr), 24-hour moving average, 5.1.3 2.5 parts per million by volume, dry (ppm), 1-hr average, corrected to 15.0% oxygen (O_2),

5.1.4 2.0 ppm, 24-hour moving average, corrected to 15% O_2,

5.1.5 Initial compliance 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, and

5.1.6 Routine compliance will be indicated by continuous emission monitors for NO_X and O_2. The continuous emission monitoring system (CEMS) must meet the requirements of Approval Condition 18.1.

5.2 Carbon monoxide (CO) emissions:

5.2.1 3 ppm corrected to 15.0 percent oxygen, 3-hr. average,

5.2.2 7.23 kg/hr (15.9 lb/hr) at 100% load, 3-hr. average,

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

5.2.4 Routine compliance determinations will be determined through use of a continuous emission monitor meeting the requirements of Approval Condition 18.3.

5.3 Sulfur dioxide emissions:

5.3.1 1.5 kg/hr (3.3 lb /hr), rolling annual-average calculated monthly,

5.3.2 9.0 kg/hr (19.8 lb/hr), 1-hr. average,

5.3.3 Initial compliance for each CGT shall be determined by EPA Reference Method 8, or an equivalent method approved in advance by EFSEC. Grays Harbor Energy LLC shall conduct source testing for sulfur dioxide once per calendar quarter for the first year of operation at each CGT exhaust stack,

5.3.4 Routine compliance shall be determined through:

5.3.4.1 Annual stack test on each CGT stack using the above Reference Method.

5.3.4.2 The timing of the annual stack test will coincide with the annual RATA testing for the installed CEM systems,

5.3.5 Routine compliance shall be indicated through:

5.3.5.1 Monthly calculation of the SO_2 emissions based on

5.3.5.1.1 The quantity of natural gas used by each turbine

5.3.5.1.2 The total sulfur content of the natural gas consumed

5.3.5.1.3 Subtracting the quantity of potential SO_2 converted to

H_2SO_4. The conversion rate of potential SO_2 to H_2SO_4 is determined through the information provided by the Method 8 stack tests required in Approval Conditions 5.3.4.1 and 5.4.3.1.

5.3.5.1.4 Grays Harbor Energy LLC shall report to EFSEC on a monthly basis the quantity and average sulfur content of the natural gas burned by the CGT units at the facility. Total sulfur content of the natural gas shall be substantiated by purchase records and vendor's reports or total sulfur content monitoring performed by Grays Harbor Energy LLC on the gas used at this facility.

5.3.6 Fuel sulfur determination shall follow the more stringent of the procedures in 40 CFR 60.335(d) and (e) and 40 CFR Part 75, Appendix D.

5.4 Sulfuric acid mist emissions

5.4.1 0.984 kg/hr (2.17 lb H_2SO_4/hr), rolling annual average calculated monthly,

5.4.2 Initial compliance with the sulfuric acid emissions limits shall be determined by EPA Reference Method 8, or an equivalent method approved by EFSEC. Grays Harbor Energy LLC shall conduct source testing for sulfuric acid mist once per calendar quarter for the first year of operation at each exhaust stack.

5.4.3 Routine compliance shall be indicated through:

5.4.3.1 An annual emissions test on each CGT exhaust stack using the methods indicated above. After the initial 3 years of tests on each CGT stack have been completed, each CGT stack shall be tested once every 5 years unless the initial 3 years of testing indicates noncompliance with the limitations, then the testing frequency remains annual until 3 consecutive years of testing indicating compliance is achieved. If a once every 5 year test indicates noncompliance, the testing frequency reverts to yearly until 3 consecutive years of testing indicating compliance is achieved. The timing of these annual emissions tests shall coincide with the annual RATA testing, and

5.4.3.2 Monthly calculation of the sulfuric acid mist emissions based on:

5.4.3.2.1 The quantity of natural gas used by each turbine,

5.4.3.2.2 The total sulfur content of the natural gas consumed,

5.4.3.2.3 Subtracting the quantity of potential SO_2 converted to H_2SO_4. The conversion rate of potential SO_2 to H_2SO_4 determined through the Method 8 stack tests required in Approval Conditions 5.3.4.1 and 5.4.3.1 and updated annually.

5.4.4 Fuel sulfur determination shall follow procedures outlined in Approval Condition 5.3.4.1.

5.5 Volatile organic compound (VOC) emissions:

5.5.1 2.86 kg/hr (6.3 lb/hr), 1-hr average, reported as carbon equivalent,

5.5.2 2.8 ppm, 1-hr average, reported as carbon equivalent,

5.5.3 Initial compliance for each CGT shall be determined by EPA Reference Method 25A or 25B, South Coast Air Quality Management District Method 25.3, or an equivalent method agreed to in advance by EFSEC, and

5.5.4 Routine compliance will be indicated through boiler operating records indicating:

5.5.4.1 Hours of operation,

5.5.4.2 Fuel flow,

5.5.4.3 Application of an emission factor derived from stack testing of the installed boiler, and

5.5.4.4 An annual stack test using one of the above referenced methods. After 3 consecutive years of stack testing indicating compliance, Grays Harbor Energy LLC may request and EFSEC may approve an alternative testing frequency. At no time shall stack testing be less frequent than once every 5 years.

5.6 Particulate Matter and Particulate Matter less than or equal to 10 micrometer (PM_{10}) emissions:

5.6.1 246.0 kg/24 hours (542.4 lb/24 hours), filterable plus condensable PM,

5.6.2 0.003 grains/dry standard cubic foot (gr/dscf), filterable plus condensable PM at 15% O_2,

5.6.3 Initial compliance for each CGT exhaust stack shall be determined by use of EPA Reference Methods 5, 201, or 201A, plus Reference Method 202, or an equivalent method agreed to in advance by EFSEC. 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.

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

5.6.5 Routine compliance shall be the following:

5.6.5.1 An annual emissions test on each CGT exhaust stack using the methods indicated above.

5.6.5.2 After the initial 3 years of tests on each CGT stack have been completed, each CGT stack shall be tested once every 5 years unless the initial 3 years of testing indicates noncompliance with the limitations, then the testing frequency remains annual until 3 consecutive years of testing indicating compliance is achieved. If a once every 5 year test indicates noncompliance, the testing frequency reverts to yearly until 3 consecutive years of testing indicating compliance is achieved.

5.6.5.3 The timing of these annual emissions tests shall coincide with the annual RATA testing.

5.6.6 When PM_{10} stack test data is not available, routine compliance shall be indicated by the use of natural gas for fuel and through operating records and the application of a source test derived emission factor.

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

5.7.1 5.0 ppm, 24-hour average corrected to 15.0 percent O_2,

5.7.2 7.3 kg/hr (16.1 lb/hr), 24-hour average,

5.7.3 The emission limits in Conditions 5.7.1 and 5.7.2 are relieved during startup, shutdown and scheduled maintenance,

5.7.4 Initial compliance for each CGT shall be determined 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,

5.7.5 Routine compliance determinations will 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

5.7.6 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 ammonia slip can not be maintained at or below 4.5 ppm, 1 hour average corrected to 15.0 percent 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) will be used for this evaluation. The outage to repair or 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.

5.8 Opacity at the CGT exhaust stack:

5.8.1 Shall not exceed a six minute average opacity of 5 percent,

5.8.2 Determined by use of EPA Reference Method 9 or an equivalent method approved in advanced by EFSEC,

5.8.3 A certified opacity reader shall read and record the opacity of each operating unit once per day, and

5.8.4 Installation of a Continuous Opacity Monitoring system on each CGT can be substituted for use of EPA Reference Method 9 readings for the CGTs. If installed, the continuous opacity monitor must meet the requirements of Approval Condition 18.4.

6. The auxiliary boiler exhaust stack shall not exceed the following:

6.1 NO_X emissions limitations:

6.1.1 0.468 kg/hr (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 Subpart GG and EPA Reference Method 20, except that the instrument span shall be set between zero and 75 ppm, and

6.1.4 Routine compliance will be indicated through

6.1.4.1 Boiler operating records indicating hours of operation and fuel flow and the application of an emission factor derived from stack testing of the installed boiler, and

6.1.4.2 Periodic stack tests taken at 5 year intervals after the initial compliance test.

6.2 CO emissions:

6.2.1 50.0 ppm, 1- hour average corrected to 3.0% O_2, 3-hr. average,

6.2.2 0.485 kg/hr (1.07 lb/hr) at 100% load, 3-hr. average,

6.2.3 Initial compliance for the auxiliary boiler shall be determined by EPA Reference Method 10 or an equivalent method agreed to in advance by the EFSEC.. The span and linearity calibration gas concentrations in Method 10 shall be appropriate to the CO concentration limits specified in this condition, and

6.2.4 Routine compliance will be indicated through:

6.2.4.1 Boiler operating records indicating

6.2.4.1.1 Hours of operation and,

6.2.4.1.2 Fuel flow,

6.2.4.2 The application of an emission factor derived from stack testing of the installed boilers, and

6.2.4.3 Periodic stack tests taken at 5 year intervals after the initial compliance test.

6.3 SO_2 emissions:

6.3.1 0.032 kg/yr (0.07 lb/hr) annual average, calculated monthly,

6.3.2 1 ppm at 3% O_2, 3- hr. average, 6.3.3 Initial compliance for the auxiliary boiler shall be determined by EPA Reference Method 8, or an equivalent method approved in advance by EFSEC,

6.3.4 Routine compliance shall be determined by

6.3.4.1 Fuel consumption records for the auxiliary boiler and

6.3.4.2 Total sulfur content of the natural gas consumed in the boilers, and

6.3.5 Natural gas sulfur content shall be measured and reported through the methods defined in Approval Condition 5.3.4.1.

6.4 VOC emissions:

6.4.1 0.073 kg/hour (0.16 lb/hr), 1-hour average, reported as carbon equivalent,

6.4.2 Initial compliance for the auxiliary boiler shall be determined by EPA Reference Method 25A or 25B, or an equivalent method agreed to in advance by EFSEC, and,

6.4.3 Routine compliance will be indicated through boiler operating records indicating

6.4.3.1 Hours of operation

6.4.3.2 Fuel flow, and

6.4.3.3 Application of an emission factor derived from stack testing of the installed boilers

6.4.3.4 Periodic stack tests, using one of the above referenced methods, taken at 5 year intervals after the initial compliance test.

6.5 PM_{10} emissions:

6.5.1 3.175 kg/day (7.0 lb/day), annual average, filterable plus condensable PM_{10},

6.5.2 0.005 gr/dscf, filterable plus condensable PM at 15% O_2,

6.5.3 Initial compliance for the auxiliary boiler exhaust stack shall be determined by either EPA Reference Methods 5, 201, or 201A, or an equivalent method agreed to in advance by EFSEC. Use of EPA Reference Method 5 assumes all particulate is in the form of 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},

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

6.5.5 Routine compliance will be indicated through:

6.5.5.1 Boiler operating records indicating

6.5.5.1.1 Hours of operation,

6.5.5.1.2 Fuel flow, and

6.5.5.1.3 Application of an emission factor derived from stack testing of the installed boilers.

6.5.5.2 Periodic stack tests, using the above specified methods, taken at 5 year intervals after the initial compliance test.

6.6 Opacity at the auxiliary boiler exhaust stack:

6.6.1 Shall not exceed a six minute average opacity of 5 percent,

6.6.2 Determined by use of EPA Reference Method 9 or an equivalent method approved in advanced by EFSEC,

6.6.3 A certified opacity reader shall read and record the opacity of the operating unit once per day, and

6.6.4 Installation of a Continuous Opacity Monitoring system on the auxiliary boiler exhaust stack can be substituted for use of EPA Reference Method 9 readings. If installed, the continuous opacity monitor must meet the requirements of Approval Condition 18.4.

7. The diesel generator exhaust stack shall not exceed:

7.1 Nitrogen oxides plus non-methane hydrocarbons emissions:

7.1.1 3.2 kg/hr (7.04 lb/hr) or 6.4 grams per kilowatt-hour,

7.1.2 Initial compliance shall be determined and certified by the engine manufacturer in accordance with the methods in 40 CFR Part 89 applicable to a new engine of its engine size for 2002, and

7.1.3 Routine compliance will be indicated through diesel generator operating hour, maintenance, and fuel records and certification of the engine meeting the applicable new engine standards for engines sold in 2002.

7.2 CO emissions:

7.2.1 1.75 kg/hr (3.86 lb/hr) or 3.5 grams per kilowatt-hour,

7.2.2 Initial compliance shall be determined and certified by the engine manufacturer in accordance with the methods in 40 CFR Part 89 applicable to a new engine of its engine size for 2002, and

7.2.3 Routine compliance will be indicated through diesel generator operating hour records and certification of the engine meeting the applicable new engine standards for engines sold in 2002.

7.3 SO_2 emissions:

7.3.1 2.93 kg/day (6.56 lb/day), 1-day average,

7.3.2 Initial compliance shall be determined and certified by the engine manufacturer in accordance with the methods in 40 CFR Part 89 applicable to a new engine of its engine size for 2002, and

7.3.3 Routine compliance will be indicated by calculating the sulfur dioxide emissions based on

7.3.3.1 Generator fuel usage, and

7.3.3.2 Fuel sulfur content records.

7.4 PM_{10} emissions:

7.4.1 2.4 kg/day (5.28 lb/day) or 0.20 grams particulate per kilowatt-hour,

7.4.2 Initial compliance shall be determined and certified by the engine manufacturer in accordance with the methods in 40 CFR Part 89 applicable to a new engine of its engine size for 2002, and

7.4.3 Routine compliance will be indicated through diesel generator operating hour records and certification of the engine meeting the applicable new engine standards for engines sold in 2002.

7.5 Opacity at the diesel generator exhaust stack:

7.5.1 Shall not exceed a six minute average opacity of 10 percent,

7.5.2 Determined by use of EPA Reference Method 9 or an equivalent method approved in advance by EFSEC.

8. The emergency fire water pump engine:

8.1 Shall meet the emission standard requirements in 40 CFR 89 applicable to a new engine of its engine size for 2002.

8.2 Initial and routine compliance shall be demonstrated by demonstration/certification by the engine manufacturer that the engine meets the applicable emission standard in 40 CFR 89.

9. The cooling tower's emissions shall not exceed:

9.1.1 11.11 kg PM_{10}/day (24.5 lb/day), annual average,

9.1.2 4062 kg PM_{10}/yr (4.5 tpy), rolling total, calculated monthly,

9.1.3 Initial compliance shall be determined by:

9.1.3.1 A total solids mass balance across the cooling tower. The analysis shall incorporate factors involving the :

9.1.3.1.1 Cooling tower recirculation rate,

9.1.3.1.2 Cooling tower total dissolved solids (TDS),

9.1.3.1.3 Fan operation effects, and

9.1.3.1.4 Manufacturer's information on drift losses

9.1.3.1.5 The methodology shall be submitted to and accepted by EFSEC prior to the first operation of any cooling tower.

9.1.3.2 An affirmative report by the cooling tower drift eliminator manufacturer, based on an onsite 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,

9.1.4 Routine compliance using the same calculation methodology used for the initial compliance test, once each quarter estimate the PM emissions from the cooling tower.

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

10. Annual emissions shall not exceed the limits in the following table. The annual limits are 12 month rolling totals.

Pollutant	Each CGT kg/year (tons/yr)	Auxiliary boiler kg/year(tons/yr)	Cooling tower kg/year (tons/yr)	Diesel emergency generator kg/year(tons/yr)
NO_x	110,625.5 (121.7)**	1,170 (1.3)	--	1,600 (1.76)*
CO	215,296 (237.0)**	1,216 (1.3)	--	877.3 (1.0)
SO_2	13,140 (14.5)	79.5 (0.088)	--	61.1 (0.1)
H_2SO_4	8623 (9.5)	--	--	--
PM/PM_{10}	89,989.1 (99.0)**	331 (0.4)	4061 (4.5)	50 (0.1)
VOC	41,916.4 (37.5)**	182.5 (0.6)	--	Included in generator NO_x
NH_3	64,107 (70.5)	--	--	--

* Limit for diesel generators is non-methane hydrocarbons plus NO_x. In this presentation the assumption is that all of the emissions are as NO_x.

** Includes the emissions from startup and shutdown events of the CGTs and diesel generators. CGT start up emissions are equally apportioned among the 2 turbines.

*** PM and PM_{10}, conservatively assumed to be equal.

11. Routine equipment startup and shut down

11.1 Each CGT is limited to 130 cold startup and shutdown events per calendar year. A cold startup event is when more than 48 hours has elapsed since the turbines were last fired or heat applied to the HRSG system.

11.2 Each CGT is limited to 2 warm startup and shutdown events 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.

11.3 A warm or cold startup period begins when fuel is first fired in the combustion turbine, 11.4 The warm startup period ends when the earlier of these two operating events occurs:

11.4.1 The proper operating temperature of the oxidation and SCR catalysts serving an operating CGT has been achieved and the combustion turbine achieves operational Mode 6, or

11.4.2 A maximum of 3 hours has elapsed since fuel was first combusted in that CGT.

11.5 The cold startup period ends when the earlier of these two operating events occurs:

11.5.1 The proper operating temperature of the oxidation and SCR catalysts serving one CGT has been achieved and the combustion turbine achieves operational Mode 6, or

11.5.2 4 hours maximum for each turbine in a single power island has elapsed since fuel was first combusted in the first turbine.

11.6 The Shutdown period begins when the combustion turbine leaves operational Mode 6 and ends when fuel is no longer being introduced to any burner.

11.7 Operational Mode 6 is defined by the turbine manufacturer as the low emission mode during which all 6 of the burner nozzles are in use, burning a lean premixed gas for steady-state operation.

11.8 The proper operating temperature of the oxidation and SCR catalysts and the point at which all dry-low-NO_x burners for each combustion turbine are operational shall be determined from the manufacturer's design specifications and must be reported in writing to EFSEC before commercial operation of the combustion turbines,

11.9 Compliance with short-term emission limits (during startup and shutdown periods) shall be determined using manufacturer's emission factors or source test data using the EPA Reference Methods noted above. Where source test data and manufacturer's emission factors conflict, source test data shall be used to determine compliance,

11.10 Emissions resulting from these startup and shutdown events shall be included in the quarterly emissions reporting of Approval Condition 19.

11.11 The following emission factors may be used for calculating the emissions generated during cold startup of the CGTs in a single power island until emissions test data is developed by Grays Harbor Energy LLC, submitted to and approved by EFSEC that demonstrates a different value is appropriate:

Pollutant	Cold Startup Emission Factor (per pair turbines in one power island)
Nitrogen oxides	1536 lb/startup
Carbon monoxide	5288 lb/startup
Volatile organic compounds	354 lb/startup

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 NOx, ammonia, SO_2, opacity, VOC, CO, PM_{10} and H_2SO_4 noted above.

The initial performance testing shall be performed by an independent testing firm. A test plan shall be submitted to EFSEC for approval at least 30 days prior to the testing. The initial compliance tests and all subsequent compliance tests shall be made at maximum load.

13. Initial start-up for determining when the initial compliance testing, CEM system performance testing, and other, non acid rain program purposes is 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

    13.2 180 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 thirty 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 will 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. Sampling ports and platforms for the auxiliary boiler and diesel engine 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 Emitting Equipment:

    17.1 Unless otherwise specified above, operating records shall be 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 quality

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

            17.2.1.3 Unit operating parameters such as

                17.2.1.3.1 Exhaust temperature,

                17.2.1.3.2 Percent excess air,

                17.2.1.3.3 Output rate (pounds of steam/hour, kW output, etc), 17.2.1.3.4 Operating hours during the reporting period and cumulative for the year.

18. Continuous Emission Monitoring Systems (CEMS):

18.1 CEMS for NOx 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.

19. CEMS and process data shall be submitted quarterly, in written form (or electronic if permitted by the EFSEC) monthly within thirty days of the end of each calendar quarter to EFSEC, its authorized representative (if any), and to the EPA Region X Office of Air Quality.

20. The format of the reporting described in Approval Condition 19 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:

20.1 Process or control equipment operating parameters,

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

20.3 The duration and nature of any monitor down-time,

20.4 Results of any monitor audits or accuracy checks,

20.5 Results of any required stack tests, and

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

20.7 The above data shall be retained at the Satsop CT Project site for a period of at least five years

21. For each occurrence of monitored emissions in excess of the standard, the quarterly emissions report (per Approval Conditions 19 and 20) shall include the following:

21.1 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.

21.2 For all other pollutants:

21.2.1 The time of the occurrence,

21.2.2 Magnitude of the emission or process parameters excess,

21.2.3 The duration of the excess,

21.2.4 The probable cause,

21.2.5 Corrective actions taken or planned, and

21.2.6 Any other agency contacted

22. Grays Harbor Energy LLC shall have on site, and shall follow, an Operating and Maintenance manual, and an equipment Start-up, Shut-down, 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 the authorized representative of EFSEC 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 shall be notified whenever the manual is updated.

22.1 The Operating and Maintenance manual should contain equipment specific operating parameter and maintenance information. Examples of the operational information to include are:

22.1.1 Control equipment normal operating ranges such as:

22.1.1.1 Normal operating temperature range.

22.1.1.2 Normal pressure drop and acceptable range of pressure drops.

22.1.1.3 Fan speed range.

22.1.1.4 Reagent feed rate.

22.1.1.5 Scrubber liquor pH range.

22.1.1.6 Scrubber liquor feed rate and pressure.

22.1.2 Boiler operating parameters such as:

22.1.2.1 Fuel feed rate.

22.1.2.2 Steam pressure.

22.1.2.3 Combustion air flow rate.

22.1.3 Combustion turbine operating parameters such as:

22.1.3.1 Temperature ranges at inlet, combustors, turbine exhaust.

22.1.3.2 Allowable vibration range.

22.1.3.3 Inlet humidity.

22.1.3.4 Operating speed (rpm) range.

22.1.3.5 Turbine fuel feed rate.

22.1.4 Similar type operational measures for other emitting equipment, such as diesel generators and cooling towers.

22.2 The Start-up, Shut-down, 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 and efficiently start and stop the various equipment at the station under all reasonably ascertainable normal and abnormal start-up and shut-down situations.

23. Construction time:

23.1 Amendment 3 allows for a suspension of construction on the approved facility.

23.2 This permit becomes void if construction is not restarted by July 20, 2007 or if the sum of all delays in continuous construction after January 20, 2006 exceeds eighteen months.

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 EFSEC enforcement under applicable regulations. 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.

(continued next page)

25. Access to the source by EFSEC, the authorized representative of EFSEC, or the U.S. Environmental Protection Agency (EPA), shall be permitted upon request for the purpose of compliance assurance inspections. Failure to allow access is grounds for action under the Federal Clean Air Act or the Washington Clean Air Act.

Prepared by:

Bernard Brady, P.E.
Engineering and Technical Services
Air Quality Program
Washington Department of Ecology

BERNARD J. BRADY
STATE OF WASHINGTON
26670
REGISTERED
PROFESSIONAL ENGINEER
3-20-07

3/17/06
Date

Approved by:

James O. Luce
Energy Facility Site Evaluation Council

3/14/06
Date

Approved by:

Richard Albright
Director
Office of Air Quality
U.S. Environmental Protection Agency
Region 10

3/29/06
Date

ENERGY FACILITY SITE EVALUATION COUNCIL
P.O. BOX 43172
OLYMPIA, WASHINGTON 98504-3172

IN THE MATTER OF:	**NO. EFSEC/2009-02**
Grays Harbor Energy Center Units 3 and 4	**FINAL APPROVAL**
Grays Harbor Energy, LLC	**NOTICE OF CONSTRUCTION**
Grays Harbor County, Washington	**AND PREVENTION OF**
	SIGNIFICANT DETERIORATION

Pursuant to the Energy Facility Site Evaluation Council (EFSEC) Permit Regulations for Air emissions permits and authorizations (Washington Administrative Code (WAC) 463-60-536(1)) and Chapter 463-78 WAC, the Washington State Department of Ecology (Ecology) regulations for new source review Chapter 173-400 WAC and Chapter 173-460 WAC, the federal Prevention of Significant Deterioration (PSD) regulations Code of Federal Regulations (CFR) Title 40 Subpart 52.21, and based upon the Notice of Construction Application (NOC) submitted by Invenergy, LLC for Grays Harbor Energy, LLC dated October 30, 2009, and the technical analysis performed by Ecology for EFSEC, EFSEC now finds the following:

FINDINGS

1. Grays Harbor Energy, LLC is proposing to add two combustion turbine generators (Units 3 and 4) and a single steam generator to the existing Grays Harbor Energy Center. This will increase the maximum electrical generation capacity by approximately 650 MW, with a total site nominal average capacity of approximately 1,300 MW.

2. Units 3 and 4 would be constructed entirely within the boundaries of the approximately 22-acre Satsop Combustion Turbine (Grays Harbor Energy Center) project site. The site is within the Satsop Development Park in unincorporated Grays Harbor County, near the town of Elma, on the site of the un-built Satsop nuclear facility.

3. The project is proposed to consist of a "power island" in a 2x1 combined cycle configuration consisting of the following major components:

   - Two General Electric (GE) Frame 7FA combustion turbines each with a generator producing up to 175 MW.

   - Two heat recovery steam generators (HRSG) containing supplementary duct burners.

   - One steam turbine with a generator producing up to 300 MW.

   - One auxiliary boiler rated at 29.3 MMBtu/hr.

- One approximately 400 KW emergency generator with an approximately 600 hp diesel engine.
- One firewater pump with an approximately 275 hp diesel engine.
- One forced draft evaporative cooling tower configured in two parallel sets of five cells.

4. The fuel for the combustion turbines, duct burners, and auxiliary boiler will be natural gas only, and will be supplied by an existing pipeline that was constructed as part of the initial site development.

5. The fuel for the emergency generator and firewater pump will be diesel fuel with a maximum of 15 ppm sulfur content.

6. The project will use a water-cooled steam condensation system.

7. The site of the proposed project is within an area that is in attainment with regard to all pollutants regulated by the 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.

8. The project application was declared complete on December 24, 2009.

9. The project is subject to the EFSEC Permit Regulations for Air emissions permits and authorizations (Washington Administrative Code (WAC) 463-60-536(1)) and Chapter 463-78 WAC. These regulations adopt and reference applicable state and federal NSR regulations including 173-400 WAC, 173-460 WAC, and 40 CFR 52.21.

10. The project is subject to permitting requirements under the federal requirements of 40 CFR 52.21 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 project has the potential to emit Prevention of Significant Deterioration (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}), particulate matter less than 2.5 micrometers ($PM_{2.5}$), and volatile organic compounds (VOC).

11. The project is subject to applicable emission limitations, monitoring, and reporting requirements of New Source Performance Standards (NSPS) 40 CFR 60 Subparts A, Dc, KKKK, IIII, and Appendices A, B, and F.

12. Ammonia (NH_3) and other toxic pollutant emissions from the project are subject to permitting under the requirements of WAC 463-78-005(1) and 005(4), which adopt Chapters 173-400 and 173-460 WAC, respectively. Non-PSD applicable criteria and toxic pollutant

emissions are considered, and permitted if necessary, in the NOC part of this permit. There are no applicable federal NESHAPs for the combustion turbines.

13. The project is subject to the Title 4 Acid Rain provisions, including monitoring and reporting provisions of 40 CFR 72 and 40 CFR 75 Appendix D.

14. The project is subject to 40 CFR Part 70 and is required to file for a modification of the site's then current Title V air operating permit application within 12 months after Units 3 and 4 commence operation.

15. Best available control technology (BACT) as required under 40 CFR 52.21(j) and WAC 173-400-113(2), and toxic best available control technology (T-BACT) as required under WAC 173-460-040(4) (the version adopted by current EFSEC rules) will be used for the control of all air pollutants which will be emitted by the project. The following table lists the project's potential emissions and the turbine and auxiliary boiler BACT control technologies and limits.

Table 1. Project Emissions and BACT Control Technology for Turbines with and without Duct Burning and Auxiliary Boiler

Pollutant	Project Potential to Emit (tpy)*	Combustion Turbines with and without duct burning		Auxiliary Boiler	
		BACT Control Technology	BACT Limit	BACT Control Technology	BACT Limit
Nitrogen Oxides (NO_X)	176.0	Lean premix dry low NO_X turbine burners and low NO_X duct burners with Selective Catalytic Reduction (SCR)	2 ppmvd, with and without duct burning	Ultra-low NO_X burners	9 ppmvd
Carbon Monoxide (CO)	451	Lean premix dry low NO_X turbine burners and low NO_X duct burners with Oxidation Catalyst	2 ppmvd, with and without duct burning	Burner design	50 ppmvd

Pollutant	Project Potential to Emit (tpy)*	Combustion Turbines with and without duct burning		Auxiliary Boiler	
		BACT Control Technology	BACT Limit	BACT Control Technology	BACT Limit
Sulfur Dioxide (SO_2)	63.0	Natural gas fuel	0.0029 lb/MMBtu with duct burning (12-month rolling average), 0.0058 lb/MMBtu with duct burning (1-hour average)	Natural gas fuel	0.0058 lb/MMBtu
Sulfuric Acid Mist (H_2SO_4)	32.1	Natural gas fuel	3.66 lb/hr (12-month rolling average), with or without duct burning	Natural gas fuel	No limit proposed
Volatile Organic Compounds (VOC)	53.1	BACT same as CO	1 ppmvd, with or without duct burning	Burner design	0.004 lb/MMBtu
Particulate Matter (PM) and Particulate Matter less than 10 microns (PM_{10})	170.0	Natural gas fuel with good combustion practices	0.0078 lb/MMBtu with duct bruners and 0.0072 lb/MMBtu without duct burning (filterable plus condensable)	Natural gas fuel	0.005 lbs/MMBtu
Particulate Matter less than 2.5 microns ($PM_{2.5}$) (filterable only)	45.1	Natural gas fuel with good combustion practices	0.0020 lb/MMBtu with or without duct burning (filterable only)	Natural gas fuel	0.005 lbs/MMBtu
Ammonia	162.0	Proper SCR operation	5.0 ppmvd ammonia slip, with or without duct burning	N/A	N/A

* About 107 tons per year of the potential annual CO emissions would be created during normal 8,760 operation of the two turbines. The balance is an estimate of CO that would be created if the maximum start-up and shutdown schedule actually occurs. The other pollutant rates in this column represent normal operation at 8,760 hours annually because that is more than would be emitted under the maximum start-up/shutdown scenario.

16. BACT for the emergency generator and firewater pump engines is that the engine be new and meet the 40 CFR 89 federal engine standards for the year of engine purchase, use of diesel fuel that has a sulfur content of no more than 15 ppm, and nonemergency operation (routine testing and training, etc.) of no more than 100 hours per year for each unit.

17. BACT for the cooling tower is installation of a demister guaranteed to have a drift loss of 0.0005 percent or less of the recirculating water flow rate.

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

    18.1. Any state or national ambient air quality standard.

    18.2. Any applicable PSD increment. Table 2 indicates the maximum Class I and Class II impacts by this project and compares the impact to Significant Impact Levels (SILs). If a SIL is not exceeded, no further increment or cumulative impact analysis is required for the applicable pollutant and area. An AQRV analysis is always required for Class I areas.

Table 2: Class I and Class II Maximum Impact Summary of the Project

Pollutant	Maximum Ambient Class I Area Impact: Class I Areas With Maximum Impact	Maximum Ambient Class I Area Impact: $\mu g/m^3$	Class I Area FLM Recommended SIL ($\mu g/m^3$)	Maximum Ambient Class II Area Impact ($\mu g/m^3$)	Class II Area SIL ($\mu g/m^3$)
NO_2 annual	Olympic NP Mt. Rainier NP	0.0018 0.0006	0.03	0.0889	1
CO 1-hr CO 8-hr	N/A[a]	N/A[a]	N/A[a]	365 18.1	2,000 500
SO_2 1-hr[b] SO_2 3-hr SO_2 24-hr SO_2 Annual	Olympic NP	N/A 0.1596 0.0313 0.0007	N/A 0.48 0.07 0.03	29.9 9.99 1.38 0.0311	30 25 5 1
PM_{10} 24-hr PM_{10} annual	Olympic NP	0.1074 0.0044	0.27 0.08	2.71 0.127	5 1
$PM_{2.5}$ 24-hr $PM_{2.5}$ annual (filterable only)[c]	N/A[d]	N/A[d]	N/A[d]	0.836 0.0485	N/A[d] N/A[d]

a. CO impacts analysis not required in Class I areas.
b. No special Class I area standard exists.
c. $PM_{2.5}$ filterable only is used for impacts analysis and PSD applicability per interim EPA guidance. Total $PM_{2.5}$ is equal to total PM10 when condensable particulate is considered.
d. SILs for $PM_{2.5}$ have been proposed but have not been promulgated.

19. The combined impacts on Class I areas of emissions from the existing site's two turbines and the project's additional two turbines were modeled. As expected, the impact concentrations were about double that of the project alone. For instance, the annual NO_2 impact was 0.0042 $\mu g/m^3$. All impacts were below the FLM recommended SILs.

20. Ambient Impact Analysis indicates the project will have no adverse impact from pollutant deposition on soils and vegetation in any Class I area. The highest impact was on Olympic National Park, with an annual deposition rate of 0.0018 kg/ha/yr for both nitrogen (N) and sulfur (S). Deposition from the project and the two existing turbines modeled at 0.0042 kg/ha/yr nitrogen and 0.0035 kg/ha/yr sulfur. The FLM concern level begins at 0.005 kg/ha/yr for both N and S.

21. For regional haze impact, the Federal Land Managers (FLMs) use a five percent visibility impact as their threshold for possible concern. Olympic National Park was the only Class I area with impacts above that threshold. Using the CALPOST 2 method, six days in the 3-year evaluation period exceed this threshold. Using the newer CALPOST 8 method, two days in the 3-year evaluation period exceeded the threshold. Startup of all 4 turbines (two existing and two new) within a 24 hour period was also modeled. The National Park Service considered both normal operation and startup impacts acceptable. The United States Forest Service determined that it had no concerns with this project based on expected emission increases and the substantial distances to the Forest Service Class I areas.

22. Since the turbine annual NO_X emissions are greater than 100 tpy, an ozone impacts analysis was done. Ozone modeling indicated that impacts were fairly localized, with a maximum increase of 2.25 ppbV in the modeling cell adjacent to the facility. Impacts fell to less than 0.33 ppbV within about 20 km of the facility. Emissions did not impact the traditionally higher ozone sites in Washington. The increase near the Enumclaw (Mud Mountain) observation sites was less than 0.0004 ppbV. This was determined to be acceptable by both Ecology and EPA.

23. The emissions of toxic air pollutants from the project will not exceed any acceptable source impact level (ASIL) established under WAC 173-460-150 or 160.

24. No significant effect on industrial, commercial, or residential growth in the Grays Harbor County area is anticipated due to the project.

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

APPROVAL CONDITIONS

1. For the Units 3 and 4 combustion gas turbines (CGT) , duct burners , and auxiliary boiler to be constructed and operated:

1.1. Natural gas shall be the only fuel for the CGTs, duct burners, and auxiliary boiler.

1.2. Compliance shall be monitored by written affirmation of the type of fuel burned with each Title V compliance statement.

1.3. Each of the two uprated General Electric (GE) Frame 7FA combustion turbines shall be limited to a maximum design heat input rate of 1895 million British Thermal Units per hour (MMBTU), based on the higher heating value (HHV) of the fuel.

1.4. While the CGT is firing natural gas, the Heat Recovery Steam Generator (HRSG) may combust natural gas in the duct burners up to a maximum heat capacity of 556 MMBTU, HHV. The Permittee shall ensure that the duct burners are not operated unless the associated turbine units are in operation.

1.5. Exhaust gases from the combustion turbine and duct burners shall be directed to a single stack that rises to 54.9 meters above grade with a flue diameter of 5.49 meters.

1.6. The auxiliary boiler shall be limited to a maximum design heat input rate of 29.3 MMBtu/hr.

1.7. With the exception of turbine startups, the auxiliary boiler shall not operate simultaneously with the combustion turbine.

1.8. Exhaust gases from the auxiliary boiler shall be directed to a stack that rises to 14.9 meters above grade with a flue diameter of 0.54 meters.

1.9. Oxides of nitrogen (NO_x) emissions from each CGT and/or duct burner shall be controlled by use of a lean pre-mix dry low-NO_x turbine burners, low NOx burners, a selective catalytic reduction (SCR) control system using ammonia injection, and good combustion practices as BACT. At all times, the exhaust gas from each CGT and duct burner(s) shall be directed to the SCR system.

1.10. Carbon Monoxide (CO) and Volatile Organic (VOC) emissions from each CGT and/or duct burner shall be controlled by lean pre-mix dry low NOx turbine burners, dry low NOx duct burners, oxidation catalyst and good combustion practices as BACT. At all times, the exhaust gas from each CGT and duct burners shall be directed to an oxidation catalyst.

1.11. The natural gas heating value of 23,275 Btu/lb (HHV) shall be used in determining the maximum heat input capacity.

2. For the emergency generator and fire pump:

2.1. Diesel fuel with a sulfur content of 15 ppm maximum shall be the only fuel.

2.2. Compliance shall be monitored by fuel purchase records.

2.3. The emergency diesel generator shall be limited to an electrical capacity of 400 MW and and engine power capacity of 600 horsepower.

2.4. Exhaust gases from the emergency diesel generator shall be directed to a stack that rises to 12.2 meters above grade with a flue diameter of 0.15 meters.

2.5. The Emergency Diesel Fire Pump shall be limited to an engine power capacity of 275 horsepower.

2.6. Exhaust gases from the Emergency Diesel Fire Pump shall be directed to a stack that rises to 10.7 meters above grade with a flue diameter of 0.13 meters.

3. At all times, Permittee shall not discharge or cause the discharge of emissions from each CGT unit, Unit 3 and Unit 4, including when the associated duct burners are or are not firing into the atmosphere in excess of the following:

3.1. Except as provided for during start-up and shutdown, NO_X emission limits:

3.1.1. 2.0 parts per million by volume, dry (ppmdv), 3-hour rolling average, corrected to 15% oxygen (O_2) when the duct burners are or are not firing,

3.1.2. 9.07 kilograms per hour (kg/hr) (20.0 pounds/hour (lb/hr)), 3-hour average, when the duct burners are firing,

3.1.3. 7.22 kilograms per hour (kg/hr) (15.9 pounds/hour (lb/hr), 3 hour average, when the duct burners are not firing,

3.1.4. 1,550 lbs/day, 24-hour rolling average, corrected to 15% O_2, when the duct burners are or are not operating. For purposes of this requirement, emissions during periods of startup, shutdown, and malfunction are used to calculate the 30-day rolling average,

3.1.5. 15 ppmdv @15% O_2 or 0.43 lb/MW-hr, 30-day rolling average, when the duct burners are or are not operating, in accordance with 40 CFR 60 Subpart KKKK. For purposes of this requirement, emissions during periods of startup, shutdown, and malfunction are used to calculate the 30-day rolling average,

3.1.6. Initial compliance with the limits in Condition 3.1 shall be determined in accordance with 40 CFR 60 Subpart KKKK and EPA Reference Method 20, except that the instrument span shall be reduced appropriately for accuracy, and

3.1.7. Continuous compliance with the limits in Condition 3.1 shall be determined by continuous emission monitors for NO_X and O_2. The continuous emission monitoring system (CEMS) must meet the requirements of Approval Condition 15.1.

3.2. Except as provided for during start-up and shutdown, CO emission limits:

3.2.1. 2.0 ppmdv, 3-hour average, corrected to 15% oxygen (O_2), when the duct burners are or are not firing,

3.2.2. 5.53 kg/hr (12.2 lb/hr), 3-hour average, when the duct burners are firing,

3.2.3. 4.39 kg/hr (9.66 lb/hr), 3-hour average, when the duct burners are not firing,

3.2.4. Initial compliance with the limits in Condition 3.2 shall be determined by use of EPA Reference Method 10, except that the instrument span shall be reduced appropriately for accuracy, and

3.2.5. Continuous compliance with the limits in Condition 3.2 shall be determined by continuous emission monitors for CO and O_2. The CEMS must meet the requirements of Approval Condition 15.2.

3.3. Sulfur dioxide emissions limits:

3.3.1. 0.0058 lb/MMBtu, 1-hour average, when the duct burners are firing,

3.3.2. 6.41 kg/hr (14.15 lb/hr), 1-hour average, when the duct burners are firing,

3.3.3. 3.26 kg/hr (7.17 lb/hr), rolling annual-average calculated monthly, when the duct burners are firing,

3.3.4. 0.0029 lb/MMBtu, rolling annual-average calculated monthly, when the duct burners are firing,

3.3.5. Initial compliance with the limits in Condition 3.3 shall be determined using the test methods specified by 40 CFR Part 60 Subpart KKKK including all referenced sections and appendices, or an equivalent method approved by EFSEC and EPA,

3.3.6. Grays Harbor Energy, LLC shall conduct source testing for sulfur dioxide once each operating quarter for the first four operating quarters of each CGT exhaust stack starting with the initial compliance test,

3.3.7. Continuous compliance with the limits in Condition 3.3 3 shall be determined using the methods of 40 CFR Part 60 Subpart KKKK including all referenced sections and appendices. A CEMS or alternative method as allowed by 40 CFR PART 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR Part 75 (acid rain program monitoring),

3.3.8. Continuous compliance with the limits in Condition 3.3 shall be determined through a stack test once every four operating quarters on each CGT stack using the test method prescribed in Condition 3.3.55. The timing of the stack test will coincide with the RATA test for the installed NO_X CEM systems required for that period,

3.3.9. Continuous compliance with all the limits in Condition 3.3 shall be determined through monthly calculation of the SO_2 emissions based on the quantity of natural gas used by each turbine and associated duct burners and the total sulfur content of the natural gas consumed determined according to: Subtracting the quantity of potential SO_2 converted to H_2SO_4 based on the unit specific conversion rate of potential SO_2 to H_2SO_4 determined in Approval Condition 3.4. Total sulfur content of the natural gas shall be determined using the methods specified by 40 CFR Part 60 Subpart KKKK. A CEMS or alternative method as allowed by 40 CFR PART 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR Part 75 (acid rain program monitoring). Not less than once per calendar month Grays Harbor Energy LLC will sample the natural gas burned in CGTs 3 and 4 and associated duct burners., and

3.3.10. Grays Harbor Energy, LLC shall report to EFSEC on a monthly basis the monthly quantity and monthly average sulfur content of the natural gas burned by the CGT and duct burner units at the facility.

3.4. Sulfuric acid mist emissions limits:

3.4.1. 1.66 kg/hr (3.66 lb H_2SO_4/hr), 12-month rolling average calculated monthly, including when the duct burners are or are not firing,

3.4.2. Initial compliance with the sulfuric acid emissions limits shall be determined by EPA Reference Method 8 results, or an equivalent method approved by EFSEC and EPA,

3.4.3. Grays Harbor Energy, LLC shall conduct source testing for the sulfuric acid mist emissions limit once each operating quarter for the first four operating quarters starting with the initial compliance test to determine unit specific conversion factors. The unit specific conversion factors are to be used to apportion the calculated potential SO2 emissions into sulfuric acid mist emissions and SO2 emissions. This testing will be at the same time as the testing required in Condition 3.3.6. ,

3.4.4. After the first four operating quarters of testing, continuous compliance shall be determined through an emissions test on each CGT exhaust stack once every four operating quarters using the methods in Condition 3.4 , and

3.4.5. After four continuous operating years (12 operating quarters) of compliance has been demonstrated, testing may be reduced to once every five calendar years. If any test indicates noncompliance, then the testing schedule reverts to the normal once every four operating quarters until a new 4-year operating period of compliance is demonstrated.

3.4.6. Compliance with the rolling 12-month emission limit shall be determined monthly based on:

3.4.6.1. The quantity of natural gas used by each CGT and duct burners,

3.4.6.2. The total sulfur content of the natural gas consumed according to the procedures outlined in Approval Condition 3.3.9,

3.4.6.3. The conversion rate of potential SO_2 to H_2SO_4 is determined through the Method 8 stack tests required in Approval Conditions 3.4. Until a stack test-based conversion rate is approved by EFSEC, a conversion rate approved by EFSEC may be used, such as the 30% rate estimated in the application.

3.5. Except as provided for during startup and shutdown, Volatile Organic Compound (VOC) emissions limits:

3.5.1. 1.25 kg/hr (2.76 lb/hr), 1-hour average, when the duct burners are not firing,

3.5.2. 1.58 kg/hr (3.48 lb/hr), 1-hour average, when the duct burners are firing,

3.5.3. 1.0 ppmvd, 1-hour average, corrected to 15% O_2, when the duct burners are or are not firing,

3.5.4. Initial compliance with the limits in Condition 3.5 shall be determined by EPA Reference Method 25A or 25B, South Coast Air Quality Management District Method 25.3, or an equivalent EPA method agreed to in advance by EFSEC,

3.5.5. Continuous compliance with the limits in Conditions 3.5.1shall be determined through a stack test once every four operating quarters on each CGT including when the duct burners are or are not firing using the test method prescribed in Condition 3.5.4. The timing of the stack test will coincide with the RATA test for the installed NO_X CEM systems required for that period,

3.5.6. After four continuous operating years (12 operating quarters) of compliance has been demonstrated, testing may be reduced to once every five calendar years. If any test indicates noncompliance, then the testing schedule reverts to the normal once every four operating quarters until a new 4-year operating period of compliance is demonstrated, and

3.5.7. Continuous compliance with all the limits in Condition 3.5 shall be determined through calculation based on hours of operation of each CGT and duct burners, fuel flow, and application of an emission factor derived from stack testing using one of the above referenced methods in Condition 3.5.4.

3.6. Particulate Matter (PM) and Particulate Matter less than or equal to 10 micrometer including condensable PM (PM_{10}) shall be considered equal for this permit, and referenced and reported as PM_{10}. PM_{10} Emissions limitations are:

3.6.1. 207.3 kg/24 hours (456.0 lb/24 hours) of filterable plus condensable PM, when the duct burners are firing,

3.6.2. 147.3 kg/24hours (324.0 lb/24 hours) of filterable plus condensable PM, when the duct burners are not firing,

3.6.3. 0.0078 lbs/MMBtu , filterable plus condensable PM, 1-hour average, at 15% O_2, when the duct burners are firing,

3.6.4. 0.0072 lbs/MMBtu, filterable plus condensable PM, 1-hour average, at 15% O_2, when the duct burners are not firing,

3.6.5. Initial compliance with the limits in Condition 3.6 shall be determined by use of EPA Reference Methods 5, 201, or 201A, plus Reference Method 202, or an equivalent EPA PM_{10} test method approved by EFSEC. 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,

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

3.6.7. Continuous compliance with the limits in Condition 3.6 shall be determined by an annual emissions test using the methods indicated above,

3.6.8. After the initial four years of tests have been completed, compliance with the limits in Condition 3.6 shall be tested once every five years unless the initial four years of testing indicates noncompliance with the limitations, then the testing frequency remains annual until four consecutive years of testing indicating compliance is achieved. If a once every 5-year test indicates noncompliance, the testing frequency reverts to yearly until four consecutive years of testing indicating compliance is achieved,

3.6.9. The timing of these annual emissions tests shall coincide with the annual RATA testing, and

3.6.10. Initial and continuous compliance with the limit in Condition 3.6 shall be determined by calculating the emissions rates based on the amount of natural gas consumed and using emission factors determined from source test data.

3.7. Particulate Matter less than or equal to 2.5 micrometer ($PM_{2.5}$) :

3.7.1. 51.8 kg/24 hours (114 lb/24 hours), filterable only, when the duct burners are firing,

3.7.2. 0.0020 lbs/MMBtu , filterable, 1-hour average, at 15% O_2, when the duct burners are or are not firing,

3.7.3. 36.8 kg/24 hours (81 lb/24 hours), filterable only, when the duct burners are not firing,

3.7.4. Initial compliance with the limits in Condition 3.7 shall be determined by use of EPA Reference Methods 5, 201, or 201A, or an equivalent EPA $PM_{2.5}$ test method approved by EFSEC. Use of EPA Reference Method 5 assumes all filterable particulate is $PM_{2.5}$. Use of EPA Reference Method 201 or 201A, assumes that the mass of filterable PM is equal to the mass of filterable $PM_{2.5}$. If Method 201 or 201A is used, the mass of particulate retained in the cyclone shall be determined and reported,

3.7.5. Continuous compliance shall be determined by an annual emissions test on each CGT exhaust stack using the methods indicated above,

3.7.6. After the initial four years of tests have been completed, compliance with the limits Condition 3.7 shall be tested once every five years unless the initial four years of testing indicates noncompliance with the limitations, then the testing frequency remains annual until four consecutive years of testing indicating compliance is achieved. If a once every 5-year test indicates noncompliance, the testing frequency reverts to yearly until four consecutive years of testing indicating compliance is achieved,

3.7.7. The timing of these annual emissions tests shall coincide with the annual RATA testing, and

3.7.8. Initial and continuous compliance with the limits in Condition 3.7 shall be determined by calculating emissions rates based on the amount of natural gas consumed and using emission factors determined from source test data.

4. At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from the auxiliary boiler in to the atmosphere, in excess of the following:

4.1. Shall not exceed 2,500 hours of operation per year.

4.2. NO_X emissions limitations:

4.2.1. 0.146 kg/hr (0.32 lb/hr), 1-hour average,

4.2.2. 9 ppm at 3% O_2, 1-hour average,

4.2.3. Initial compliance shall be determined within 180 days of installation in accordance with 40 CFR 60, Appendix A, Reference Method 7E, or an equivalent EPA method agreed to in advance by EFSEC. The span and linearity calibration gas concentrations shall be appropriate to the NO_X concentration limits specified in this condition,

4.2.4. Continuous compliance will be determined through periodic stack tests performed at least once every 60 calendar months after the initial compliance test, and

4.2.5. Emissions shall be determined by monthly calculation using fuel consumption and emission factors based on testing conducted in Approval Condition 4.2.3 and 4.2.4.

4.3. CO emissions limitations:

4.3.1. 50.0 ppm, 1-hour average, corrected to 3.0% O_2,

4.3.2. 0.49 kg/hr (1.08 lb/hr) , 1-hour average,

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

4.3.4. Continuous compliance shall be determined through periodic stack tests performed at least once every 60 calendar months after the initial compliance test, and

4.3.5. Continuous compliance shall be determined by monthly calculation using fuel consumption and emission factors based on testing conducted in 4.3.

4.4. SO_2 emissions limitations :

4.4.1. .0.0058 lb/MMBtu/hr, 1-hr average, corrected to 3% O2,

4.4.2. 0.0029 lb/MMBtu , annual average, calculated monthly,

4.4.3. Initial compliance shall be determined by EPA Reference Method 8, or an equivalent EPA method approved in advance by EFSEC, 4.4.4. Continuous compliance shall be determined by monthly calculation using fuel consumption and total sulfur content of the natural gas consumed in the boilers, and

4.4.5. Natural gas sulfur content shall be measured and reported through methods defined in Approval Condition 3.3.

4.5. VOC emission limitations:

4.5.1. 0.004 lb/MMBtu, 1-hour average, corrected to 3% O_2,

4.5.2. 0.055 kg/hour (0.12 lb/hr), 1-hour average, corrected to 3% O_2,

4.5.3. Initial compliance shall be determined by EPA Reference Method 25A or 25B, or an equivalent EPA method agreed to in advance by EFSEC,

4.5.4. Continuous compliance shall be determined by monthly calculation using fuel consumption and an emission factor derived from stack testing conducted in Approval Condition 4.5.3. and 4.5.5., and

4.5.5. Continuous compliance shall be determined through periodic stack tests using one of the above referenced EPA methods, taken at 5 year intervals after the initial compliance test.

4.6. PM/PM_{10}/$PM_{2.5}$ emissions limitations:

4.6.1. 0.005 lbs/MMBTU, 1-hour average, filterable plus condensable PM10 at 3.0% O_2,

4.6.2. 0.067 kg/hr (0.147 lb/hr), filterable plus condensable PM10 at 3.0% O_2,

4.6.3. Initial compliance with the limits in Condition 6.5 shall be determined by either EPA Reference Methods 5, 201, or 201A, or an equivalent EPA method agreed to in advance by EFSEC. Use of EPA Reference Method 201 or 201A assumes that the mass of filterable PM is equal to the mass of filterable PM10,

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

4.6.5. Continuous compliance shall be determined by monthly calculation using fuel consumption and an application of an emission factor derived from stack testing conducted under this Condition 4.6, and

4.6.6. Periodic stack test, using the above specified methods, taken at 5-year intervals after the initial compliance stack test.

5. At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from the emergency generator into the atmosphere, in excess of the following:

   5.1. Be operated only as needed for its maintenance, for training, and for emergency power,

   5.2. Not exceed 100 hours operation in any consecutive 12-month rolling average period for maintenance, testing, and training,

   5.3. Meet applicable federal new engine standards (40 CFR 60 Subpart IIII, which references 40 CFR 89) for engines sold in 2010 or for the year of purchase, whichever is later,

   5.4. Compliance with Conditions 5.1 and 5.2 shall be monitored by installing and operating a nonresetable hour meter with monthly recording of the operating hour meter reading to determine the operating hours, or by automated data collection. The reason for operation shall be logged,

   5.5. Compliance with Condition 5.3 shall be by initial certification of the engine manufacturer,

   5.6. NO_X and SO_2 emissions shall be calculated and reported using operating data such as hours of operation, emission factors, and fuel data. Reporting shall be per Condition 16, and

   5.7. The emergency generator shall not be operated for testing and/or maintenance during startup of any of the CGTs,

6. At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from the fire pump into the atmosphere, in excess of the following:

   6.1. Be operated only as needed for its maintenance, for training, and for emergency fire suppression,

   6.2. Not exceed 100 hours operation in any consecutive 12-month period for its maintenance, for training, and for emergency fire suppression,

   6.3. Meet applicable federal new engine standards (40 CFR 60 Subpart IIII) for engines sold in 2010 or in the year of purchase, whichever is later,

   6.4. Compliance with Conditions 6.1 and 6.2 shall be by installing and operating a nonresetable hour meter with monthly recording of the operating hour meter reading to determine the operating hours, or by automated data collection. The reason for operation shall be logged,

   6.5. Compliance with Condition 6.3 shall be by initial certification of the engine manufacturer,

   6.6. NO_X and SO_2 emissions shall be calculated and reported using operating data such as hours of operation, emission factors, and fuel data. Reporting shall be per Condition 16, and

6.7. The emergency water fire pump shall not be operated during startup of any of the CGTs.

7. At all times, including equipment startup and shutdown, Permittee shall not discharge, or cause the discharge of emissions from the Cooling tower into the atmosphere, in excess of the following:

7.1. 8.60 kg PM_{10}/day (19.0 lb/day), 24-hour average,. This emission limit is achieved when the following two work practice standards in Approval Conditions 7.2 and 7.3 are accomplished,

7.2. The drift eliminators have been installed in accordance with manufacturer's specifications to achieve a drift loss of 0.0005 percent of the recirculating water flow rate,

7.3. The cooling water 7-day average TDS content is less than 1,800 ppmw,

7.4. Initial compliance shall be determined by no later than 180 days after the corresponding CGTs and duct burners commences commercial operation GHE shall obtain an affirmative report certified 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, and has a drift loss of 0.0005% or less of the recirculating water flow rate,

7.5. Continuous compliance with Approval Condition 7.2 shall be determined by maintaining the assembled cooling tower drift eliminators consistent with manufacturer's recommendations as described in the operating manual for the cooling tower,

7.6. Initial compliance with Approval Condition 7.3 shall be demonstrated no later than 180 days after the corresponding CGTs and duct burners commences commercial operation pursuant to the following conditions: Measure the water's TDS content in accordance with the following procedures: Collect a grab sample of the cooling water at least once per day for seven consecutive operating days, analyze each sample in accordance with Standard Methods, 18th Ed., Method 2540 C or EPA Method 160.1, at 40 CFR Section 136.3, and

7.7. 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, maintaining, and testing the drift eliminators.

8. Annual total emissions on a 12-month rolling average basis from the units specified in this permit and notice of construction shall not exceed the emission limits for each of the pollutants specified in the following table:

Pollutant	Total Facility[a] (tons/year)[a]
NO_X	176
CO	451
SO_2	63
H_2SO_4	32.2
PM/PM_{10}	170[b]
$PM_{2.5}$	45.1[c]
VOC	53.1
NH_3	162

a. Includes the emissions from start-up and shutdown events .
b. PM and PM_{10} includes condensable PM.
c. $PM_{2.5}$ is filterable only. Actually, all PM is about $PM_{0.1}$, so difference is due to condensables.

8.1 Annual emission limits are derived from the estimated overall emission contribution from emission and operating limits, including periods of startup and shutdown. By the last day of each month the permittee shall, using monitoring data collected pursuant to the requirements of this permit, calculate and record the monthly emissions of each pollutant in the table for the preceding month. By the last day of each month, the permittee shall calculate and record the rolling 12-month emissions of each pollutant in the table by using the monthly emissions calculated for the previous 12 months.

9. Start-up and shutdown for Units 3 and 4:

9.1. Each CGT is limited to 130 cold startups per calendar year and two warm and hot start-up events per calendar day. This limitation does not apply during the period between initial firing of a combustion turbine for testing purposes and 180 days following the start-up condition specified in Approval Condition 11.

9.2. A start-up period begins when fuel is first fired in the combustion turbine, and ends when the earlier of approval condition 9.2.1 or 9.2.2 occurs:

9.2.1. The proper operating temperature of the oxidation and SCR catalysts serving an operating CGT has been achieved as specified in Approval Condition 9.4 and the combustion turbine achieves operational Mode 6, or

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

9.2.2.1. Five hours 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 been shut down for 48 hours or more.

9.2.2.2. Three hours 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 been shut down for more than eight but less than 48 hours.

9.2.2.3. Two hours 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 been shutdown for 8 hours or less

9.3. The shutdown period begins when the combustion turbine leaves operational Mode 6 and ends when fuel is no longer being introduced to any burner and not to exceed 0.5 hours per shutdown event.

9.4. The proper operating temperature of the oxidation and SCR catalysts and the point at which all dry-low-NOx burners for each combustion turbine are operational shall be determined from the manufacturers design specifications and must be reported in writing to EFSEC before commercial operation of the combustion turbines. Ammonia feed must begin to the SCR as soon as this temperature is achieved during the startup procedure.

9.5. During start-up and shutdown periods, the normal operation limits for NO_X, CO, and VOC in Conditions 3.1.1, 3.1.2, 3.1.3, 3.2.1, 3.2.2, 3.2.3, 3.5.1, 3,5,2, and 3.5.3, respectively, are relieved. Instead, the following limitations apply:

9.5.1. NO_X emissions are limited to 80 Kg/hr, (175 lb/hr) per turbine per startup period based on the total emissions averaged over the time associated with each startup.

9.5.2. CO emissions are limited to 46 Kg/hr, (100 lb/hr) per turbine per startup period based on the total emissions averaged over the time associated with each startup.

9.5.3. VOC emissions are limited to 14 Kg/hr, (30 lb/hr) per turbine per startup period based on the total emissions averaged over the time associated with each startup.

9.5.4. NOx, CO, and VOC emissions are limited to 46 kg (100 lbs), 296 kg (650 lbs), and 19 kg (40 lbs) per turbine per shutdown event, respectively.

9.6. During any start-up and shutdown periods, NO_X and CO CEMs shall record their respective emissions. VOC emissions shall be determined using an emission factor based on stack tests conducted under Approval Condition 3.5..

9.7. Emissions resulting from these start-up and shutdown events shall be included in annual emissions limited in Approval Condition 8, and reported in the quarterly emissions reporting of Approval Condition 16.

9.8. The permittee shall record the time, date, and duration of each startup and shutdown period including when all dry low NOx burners for each combustion turbine are operational and Mode 6 is achieved.

9.9. Operational Mode 6 is defined by the turbine manufacturer as the low emission mode during which all 6 of the burner nozzles are in use, burning a lean pre-mixed gas for steady-state operation.

10. Within 180 days after initial start-up of the auxiliary boiler, the permittee shall conduct the initial performance tests for pollutants as described in Condition 4. For the purpose of this permit, initial start-up occurs when fuel is first introduced to the boiler. The initial performance testing shall be performed by an independent testing firm. A test plan shall be submitted to EFSEC for approval at least 30 days prior to the testing. The initial compliance tests and all subsequent compliance tests shall be conducted at least 90% of rated capacity.

11. Within 180 days after initial start-up of each combustion turbine and/or duct burner, the permittee shall conduct the initial performance tests for pollutants as described in Condition 3. For the purpose of this permit, initial start-up occurs when fuel is first introduced to the subject combustion turbine and/or its associated duct burner. The initial performance testing shall be performed by an independent testing firm. A test plan shall be submitted to EFSEC for approval at least 30 days prior to the testing. The initial compliance tests and all subsequent compliance tests shall be conducted as follows::

11.1. For each series of four (either quarterly or annual) tests, at least two of the tests for each turbine shall be conducted at least 90% of rated capacity and with the duct burners off, and at least two of the test for each turbine shall be conducted at least 90% of rated capacity and with the duct burners at least 90% of rated capacity.

11.2. For each series of once-every-five year tests, at least one of the tests for each turbine shall be conducted at least 90% of rated capacity and with the duct burners off, and at least one of the tests for each turbine shall be conducted at least 90% of rated capacity. The required tests may be conducted in different years.

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

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

12.2. Initial start-up as defined in Approval Condition 10 and 11.

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

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

13. 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. Sampling ports and platforms shall be available on the auxiliary boiler and emergency generator and fire pump diesel engine stacks. Sampling ports and platforms shall meet the requirements of 40 CFR Part 60, Appendix A, Method 1. Other arrangements may be acceptable if approved by EFSEC.

14. Operating records for emitting equipment:

    14.1. Unless otherwise specified above, operating records shall be information necessary to determine the operational and compliance status of the equipment. The permittee shall retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

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

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

    14.2.1.1. Fuel quality.

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

    14.2.1.3. Unit operating parameters such as:

    14.2.1.3.1. Exhaust temperature.

    14.2.1.3.2. Percent excess air.

    14.2.1.3.3. Output rate (pounds of steam/hour, kW output, etc.).

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

15. Continuous Emission Monitoring Systems (CEMS):

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

    15.2. 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 except that the RATA, linearity check, and leak test schedule shall respect the testing frequency concepts of QA operating quarter and grace period in 40 CFR 75 Appendix B.

16. 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, its authorized representative (if any).

17. The submittals described in Approval Condition 16 shall be in a format approved by EFSEC that shall include at least the following:

    17.1. Process or control equipment operating parameters,

    17.2. The hourly (or the applicable averaging period) maximum and average concentration, in the units of the standards, for each pollutant monitored,

    17.3. The duration and nature of any monitor down-time,

    17.4. Results of any monitor audits or accuracy checks,

    17.5. Results of any required stack tests, and

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

    17.7. The above data shall be retained at the project site for a period of at least five years.

18. For each occurrence of monitored emissions in excess of the emission limits of this permit and notice of construction, the quarterly emissions report (per Approval Conditions 16 and 17) shall include the following:

    18.1. 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.

    18.2. For all other pollutants:

        18.2.1. The time of the occurrence,

        18.2.2. Magnitude of the emission or process parameters excess,

        18.2.3. The duration of the excess,

        18.2.4. The probable cause,

        18.2.5. Corrective actions taken or planned, and

18.2.6. Any other agency contacted.

19. 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, EPA, or the authorized representative of EFSEC 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 shall be notified whenever the manual is updated.

20. At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate each emission unit, including any associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EFSEC, EPA, or the authorized representative of EFSEC. This information may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

21. The permittee shall construct and operate all equipment, facilities, and systems in accordance with the application and supporting materials submitted by the permittee and in accordance with this permit and notice of construction. Any activity that is undertaken by the company or others in a manner that is not in accordance with the application materials and this permit and notice of construction shall be subject to enforcement under the applicable regulations. Nothing in this permit shall relieve GHE of its obligations under any state, local, or federal laws or regulations.

22. Access to the source, by EFSEC, the authorized representative of EFSEC, or the EPA, shall be permitted upon request for the purposes of compliance assurance inspections. Failure to allow such access is grounds for enforcement action under the federal Clean Air Act or the Washington Clean Air Act.

23. This PSD permit and notice of construction shall become invalid if construction is not commenced, as defined in 40 CFR Part 52.21(b)(9), within eighteen (18) months after receipt of final approval, or if construction of the facility is discontinued for a period of eighteen (18) months, or construction is not completed within a reasonable time. EPA and EFSEC may extend the 18-month period upon a satisfactory showing that an extension is justified, pursuant to 40 CFR 52.21(r)(2).

24. The effective date of this permit shall not be earlier than the date upon which the USEPA notifies EFSEC that the USEPA has satisfied its obligations, if any, under Section 7 of the Endangered Species Act 16 U.S.C. § 1531 et seq., 50 C.F.R. part 402, subpart B (Consultation Procedures) and Section 305(b)(2) of the Magnuson-Stevens Fishery and Conservation Act 16 U.S.C. § 1801 et seq., 50 C.F.R. part 600, subpart K (EFH Coordination, Consultation, and Recommendations).

25. For federal regulatory purposes and in accordance with 40 CFR 124.15 and 124.19: During the public review period for the preliminary determination, any public reviewer may submit a request for a change in any permit condition. If this occurs, the effective date of this permit shall not be earlier than 30 days after service of notice to the commenters and applicant of the final determination accompanied by the associated summary of responses to comments.

    25.1. If a review of the final determination is requested under 40 CFR 124.19 within the 30-day period following the date of the final determination, the effective date of the permit be suspended until such time as the review and any subsequent appeal against the permit are resolved.

    25.2. If there was no public comment requesting a change in the preliminary determination or a proposed permit condition during the public review and comment period, this permit is effective upon the date of finalization subject to consideration of Condition 24 (EPA's ESA requirement) above.

This Prevention of Significant Deterioration permit has been prepared by:

Robert C. Burmark — 12/21/2010

Robert C. Burmark, P.E.
Science and Engineering Section
Air Quality Program
Washington State Department of Ecology
Date

ROBERT C. BURMARK
STATE OF WASHINGTON
29848
REGISTERED
PROFESSIONAL ENGINEER

This Prevention of Significant Deterioration permit has been approved by:

12/21/10

James O. Luce, Chair
Energy Facility Site Evaluation Council
State of Washington
Date

This Prevention of Significant Deterioration permit has been approved by:

12/17/10

Richard Albright, Director
Office of Air, Waste and Toxics
U.S. Environmental Protection Agency, Region 10
Date

25. For federal regulatory purposes and in accordance with 40 CFR 124.15 and 124.19: During the public review period for the preliminary determination, any public reviewer may submit a request for a change in any permit condition. If this occurs, the effective date of this permit shall not be earlier than 30 days after service of notice to the commenters and applicant of the final determination accompanied by the associated summary of responses to comments.

    25.1. If a review of the final determination is requested under 40 CFR 124.19 within the 30-day period following the date of the final determination, the effective date of the permit be suspended until such time as the review and any subsequent appeal against the permit are resolved.

    25.2. If there was no public comment requesting a change in the preliminary determination or a proposed permit condition during the public review and comment period, this permit is effective upon the date of finalization subject to consideration of Condition 24 (EPA's ESA requirement) above.

This Prevention of Significant Deterioration permit has been prepared by:

Robert C. Burmark, P.E. — Date
Science and Engineering Section
Air Quality Program
Washington State Department of Ecology

This Prevention of Significant Deterioration permit has been approved by:

James O. Luce, Chair — Date
Energy Facility Site Evaluation Council
State of Washington

This Prevention of Significant Deterioration permit has been approved by:

Richard Albright, Director — Date: 12/20/10
Office of Air, Waste and Toxics
U.S. Environmental Protection Agency, Region 10

NOTICE OF CONSTRUCTION APPROVAL CONDITIONS

1. Ammonia (free NH_3 and combined measured as NH_3) emissions from each CGT exhaust stack:

    1.1. 5.0 ppm, 24-hour average, corrected to 15.0 percent O_2.

    1.2. 8.39 kg/hr (18.5 lb/hr), 24-hour average.

    1.3. The emission limits in Conditions 1.1 and 1.2 are relieved during start-up, shutdown, and scheduled maintenance.

    1.4. Initial compliance for each CGT shall be determined by Bay Area Air Quality Management District Source Test Procedure ST-1B, "Ammonia, Integrated Sampling," EPA Conditional Test Method 027, or an equivalent EPA method approved in advance by EFSEC.

    1.5. Continuous compliance will be determined through use of a CEMS, which meets the requirements of Approval Condition 1.7, 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 1.7.

    1.6. 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 ammonia slip cannot be maintained at or below 4.5 ppm, 1-hour average, corrected to 15.0 percent 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) will 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.

    1.7. 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.

2. Opacity at each CGT exhaust stack:

    2.1. Shall not exceed a 6-minute average opacity of 5%, monitored weekly.

    2.2. Determined by use of EPA Reference Method 9 or an equivalent EPA method approved in advanced by EFSEC.

2.3. Compliance may be monitored weekly by EPA Method 22, or an equivalent EPA method approved in advance by EFSEC. If the observation indicates opacity greater than zero, then:

2.3.1. The owner shall determine the cause of the opacity detected and initiate a program to correct the cause, and

2.3.2. A Method 9 or other EFSEC approved test shall be performed within two non-holiday weekdays.

2.4. If a holiday falls during the 2-day time period, the testing shall be performed on the first non-holiday weekday after the holiday.

2.5. If the turbine is shut down before retesting using Method 9 or other EFSEC approved test, retesting shall be done on the first non-holiday weekday after restarting.

2.6. Installation of a Continuous Opacity Monitoring system on each CGT and duct burner can be substituted for use of EPA Reference Method 9 and Method 22 readings for the CGTs and duct burners. If installed, the continuous opacity monitor must meet the requirements of Approval Condition 2.7.

2.7. 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.

3. Opacity at the auxiliary boiler exhaust stack:

3.1. Shall not exceed a 6-minute average opacity of 5 percent.

3.2. Determined by use of EPA Reference Method 9 or an equivalent EPA method approved in advanced by EFSEC.

3.3. Compliance may be monitored each operating month by EPA Method 22 or an equivalent EPA method approved in advance by EFSEC. If the observation indicates opacity greater than zero, then:

3.3.1. The owner shall determine the cause of the opacity detected and initiate a program to correct the cause, and

3.3.2. A Method 9 or other EFSEC approved test shall be performed within two weeks.

3.3.3. Installation of a Continuous Opacity Monitoring system on the boiler can be substituted for use of EPA Reference Method 9 and Method 22 readings. If installed, the continuous opacity monitor must meet the requirements of Approval Condition 2.7.

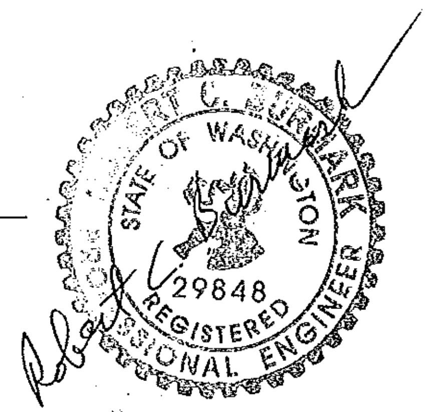
4. Performance monitoring of the auxiliary boiler shall be conducted as described in Appendix A of this permit during each calendar year after the initial performance test was done as described in the PSD portion of this permit.

This Notice of Construction approval has been prepared by:

Robert C. Burmark

Robert C. Burmark, P.E.
Science and Engineering Section
Air Quality Program
Washington State Department of Ecology

12/21/2010
Date



This Notice of Construction has been approved by:

James O. Luce
Chair
Energy Facility Site Evaluation Council
State of Washington

12/21/10
Date

APPENDIX A

PERFORMANCE MONITORING REQUIREMENTS
AUXILIARY BOILER

1. Introduction:

   a. The purpose of periodically monitoring the exhaust of the auxiliary boiler is to minimize emissions and provide a reasonable assurance that the unit is operating properly.

   b. Periodic monitoring may be conducted with an electrochemical cell combustion analyzer, analyzers used for reference method testing, or other analyzers pre-approved by EFSEC.

2. Monitoring Requirements:

   a. Monitoring to determine emission concentrations of the following constituents shall be conducted for the boiler during each calendar year. The use of an alternative test schedule must be pre-approved by EFSEC in writing.

      <u>Constituents to be Measured</u>
      Carbon Monoxide (CO)
      Nitrogen Oxides (NO_X)
      Oxygen (O_2)

   b. Source operation during monitoring must be representative of maximum intended operating conditions during that year.

   c. Alternative monitoring methodologies must be pre-approved by EFSEC.

3. Minimum Quality Assurance/Quality Control Measures:

a. The analyzer(s) response to span gas of a known concentration shall be determined before and after testing. No more than 12 hours may elapse between span gas response checks. The results of the analyzer response check shall not be valid if the difference between the pre-test and post-test response checks exceeds 10 percent of the pre-test response value.

b. The CO and NO_X span gas concentrations shall be no less than 50 percent and no more than 200 percent of the emission concentration corresponding to the permitted emission limit. A lower concentration span gas may be used if it is more representative of measured concentrations. Ambient air may be used to zero the CO and NO_X cells/analyzer(s) and span the oxygen cell/analyzer.

c. Sampling of the exhaust stack shall consist of at least one test consisting of at least five minutes of data collection following a "ramp-up phase." The ramp-up phase ends when analyzer readings have stabilized (less than five percent per minute change in emission concentration). Emission concentrations shall be recorded at least once every 30 seconds during testing. All test data collected following the ramp-up phase(s) shall be reported to EFSEC or their representative. Alternative testing methods may be utilized provided pre-approval is obtained from EFSEC.

d. If the test results from any monitoring event indicate that emission concentrations may exceed 12 ppmvd NO_X @ 3% O_2 or 50 ppmvd CO @ 3% O_2, the permittee shall either perform 60 minutes of additional monitoring to more accurately quantify CO and NO_X emissions, or initiate corrective action. Additional testing or corrective action shall be initiated as soon as practical, but no later than three days after the potential exceedance is identified. Corrective action includes tuning, maintenance by service personnel, limitation of boiler load, or other action taken to maintain compliance with permitted limits. Monitoring of unit emissions must be conducted within three days following completion of any corrective action to confirm that the corrective action has been effective. Corrective action shall be pursued until observed emission concentrations no longer exceed 12 ppmvd NO_X or 50 ppmvd CO, corrected to 3% O_2. Initiation of corrective action does not shield the permittee from enforcement actions by EFSEC.

4. Reporting:

a. All monitoring results shall be recorded at the facility and reported to EFSEC. The following information shall be included in the report:

(1) Time and date of the emissions evaluation;

(2) Identification of the personnel involved;

(3) A summary of results, reported in units consistent with the applicable emission standard(s) or limit(s);

(4) A summary of equipment operating conditions;

(5) A description of the evaluation methods or procedures used including all field data, quality assurance/quality control procedures and documentation; and

(6) Analyzer response check documentation.

b. Performance monitoring test results shall be corrected to 3% O_2.

(1) Monitoring results shall be reported to EFSEC within 15 calendar days of test completion.

ENVIRON

ATTACHMENT VII

November 8, 2010

MEMORANDUM

To: . Al Wright, EFSEC Manager

From: Eric Hansen

Subject: Grays Harbor Energy Units 3 and 4 Carbon Dioxide Emission Calculations

---

ENVIRON International Corporation assisted Grays Harbor Energy LLC with air quality technical support for the addition of Units 3 and 4 at the existing Grays Harbor Energy facility in Satsop, Washington. The purpose of this memorandum is to document the calculation of carbon dioxide emissions from the new electrical generation units to be mitigated under RCW chapter 80.70 and WAC chapter 463-80. This memorandum calculates the mitigation obligation using the steps set forth in WAC 463-80-50. Language from the regulation is displayed in bold below, followed by the calculation for Units 3 and 4.

Step 1 is to calculate the total quantity of CO2. The total quantity of CO2 is referred to as the maximum potential emissions of CO2. The maximum potential emissions of CO2 is defined as the annual CO2 emission rate. The annual CO2 emission rate is derived by the following formula unless a differing analysis is necessary or appropriate for the electric generating process and type of equipment:

$$CO_{2\,rate} = \frac{Fs \times Ks \times Ts}{2204.6} + \frac{F1 \times K1 \times T1}{2204.6} + \frac{F2 \times K2 \times T2}{2204.6} + \frac{F3 \times K3 \times T3}{2204.6} \ldots \frac{Fn \times Kn \times Tn}{2204.6}$$

where:

CO_{2rate} = Maximum potential emissions in metric tons per year

F1 - n = Maximum design fuel firing rate in MMBtu/hour calculated as manufacturer or designer's guaranteed total net station generating capability in MWe times the new equipment heat rate in Btu/MWe. Determined based on higher heating values of fuel

K1 - n = Conversion factor for the fuel(s) being evaluated in lb CO2/MMBtu for fuel Fn

T1 - n = Hours per year fuel Fn is allowed to be used. The default is 8760 hours unless there is a limitation on hours in a site certification agreement

Fs = Maximum design supplemental fuel firing rate in MMBtu/hour, at higher heating value of the fuel

Ks = Conversion factor for the supplemental fuel being evaluated in lb CO2/MMBtu for fuel Fn given fuel

Ts = Hours per year supplemental fuel Fn is allowed. The default is 8760 hours unless there is a limitation on hours in a site certification agreement

Based on information from Grays Harbor Energy:

F (the maximum design fuel rate) is 2,333MMBtu/hr for each combustion turbine/HRSG.

K (the conversion factor for the fuel) is 110 lb CO2/MMBtu.
This emission factor is derived from Table 3.1-2a of AP42 Section 3.1 (Stationary Gas Turbines. Given that WAC 173-407-050(1) provides the option of using a differing analysis if appropriate, we elected to use the combustion turbine emission factor rather than the generic emission factors from AP 42 Section 1.4 (Natural Gas Combustion), which is cited in the regulation. The generic emission factor is more commonly applied to boilers combusting natural gas.

T (the hours per year supplemental fuel firing) is 8,760 hours.

The calculation for Units 3 and 4 is simplified because Grays Harbor Energy proposes to install two identical combustion turbines, supplemental firing is allowed at all times, and only natural gas will be combusted.

$CO_{2\ rate}$ = (2,333MMBtu/hr*110 lb/MMBtu*8,760 hours/year)*2 =2,039,444 tonnes/year

Step 2 - Insert the annual CO2 rate to determine the total carbon dioxide emissions to be mitigated. The formula below includes specifications that are part of the total carbon dioxide definition:

Total CO2 Emissions = CO2rate x 30 x 0.6 =

Total CO_2 Emissions = 2,039,444 tonnes/year*30*0.6= 36,709,987 tonnes

Step 3 - Determine and apply the cogeneration credit (if any).

No cogeneration credit is appropriate for this proposal.

Step 4 - Apply the mitigation factor.

(a) RCW 80.70.020(4) states that "Fossil-fueled thermal electric generation facilities that receive site certification approval or an order of approval shall provide mitigation for twenty percent of the total carbon dioxide emissions produced by the facility."

(b) The CO2 emissions mitigation quantity is determined by the following formula:

Mitigation Quantity = Total CO2 Emissions x 0.2 - Cogeneration Credit where:

Mitigation quantity = The total CO2 emissions to be mitigated in metric tons.

CO_2rate = The annual maximum CO_2 emissions from the generating facility in tons/year.[1]

0.2 = The mitigation factor in RCW 80.70.020(4).

For the addition of Units 3 and 4 to the Grays Harbor Energy Center,

Mitigation quantity = 36,709,987 tonnes * 0.2 = 7,341,997 tonnes

At $1.60 per tonne of CO_2, the required mitigation payment is $11,747,196.

[1] This is an error in the regulation. Rather than citing "CO_2rate", an annual value, this text should refer to the "Total CO_2 emissions", the 30-year emissions at a 60 percent capacity factor. The equation is clear, but the reference to CO_2 rate in this section is inappropriate and misleading.

ERRATA SHEET
SITE CERTIFICATION AGREEMENT
GRAYS HARBOR ENERGY CENTER
FEBRUARY, 2011

This Site Certification Agreement (SCA) was submitted by EFSEC to the Washington State Governor's Office on Dec. 23, 2010. During staff review of the SCA within the Governor's Office a number of questions and/or concerns were raised. This errata sheet addresses or resolves those questions and/or concerns.

1. **Pg. 4; Article II, B, 2. First paragraph, last sentence, the word "of" was missing between the words "operation" and "Units"**
   Response: The word "of" was inserted.

2. **Pg. 6; Article III, A,2. First paragraph, third line from bottom, a comma after the word Agreement should be a period.**
   Response: The comma was removed and replaced by a period.

3. **Pg. 6; Article III, 6. Last two sentences, there was concern expressed how would one know if the provision was "inadvertently" omitted?**
   Response: The "inadvertent" applies only to the term "intent of the parties". The second sentence provides the remedy of Council action.

4. **Pg. 7; Article III, 7. Last half of first paragraph, beginning with the word "Provided", there was concern expressed regarding the extensive and broad based nature of this statement.**
   Response: This provision is a carryover from previous EFSEC SCA's, attempting to capture all commitments made during the Adjudicative Proceedings into the SCA. This process had no adjudicative proceedings and the statement beginning with the word "Provided" has been removed.

5. **Pg. 10; Article IV, A., 1., a. Second sentence, there was concern expressed that the SCA calls out "site preparation" and "construction" as separate actions but this provision calls for only construction schedules sixty days prior, with no mention of site preparation.**
   Response: The intent has always been that construction schedules included site preparation activities. The sentence has been changed to read, "the Certificate Holders will submit an overall construction and site preparation schedule."

6. **Pg. 12, Article IV., J., Coastal Zone Management – There was concerned expressed about the Certificate Holder being able to "ensure" consistency with the CZM.**
   Response: Again, this provision was a holdover from an older SCA and now there is no part of this project within the CZM or within a Shoreline master program. Provision J. is removed.

7. **Pg. 16, Article 5,E., 4. Noise during Construction – Last sentence, there was concerned expressed regarding the direct issues the term "waivers" were intended to address.**
   Response: The term "waivers" from adjacent property owners was intended to relate to "in-lieu mitigation" waivers from property owners in place of the additional barriers being constructed if deemed necessary. To better clarify the statement, the words "in-lieu mitigation" have been added to "waivers".

8. **Pg. 19, Article VII, A. Discharge of Pollutants – The words "and other applicant regulations." At the end seemed unnecessary since Chapter 90.48 RCW is not a regulation.**
   Response: The words "and other applicable regulations." have been removed.

9. **Attachment III – There was a question asked regarding the EFSEC water use permit as a State Water Right?**
   Response: The EFSEC water use permit is not anything like a State Water Right issued by the Department of Ecology.

10. **Attachment VI. – There was some confusion regarding the signature block of the PSD Air Quality Permit.**
    Response: The confusion was resolved.