Draft Statement of Basis for
Atlantic Power dba Frederickson Power LP Electric Generating Station AOP Renewal
<TBD>

1 Purpose of this Statement of Basis

1.1 General

This document summarizes the legal and factual bases for the draft permit conditions in the Frederickson Power LP air operating permit to be issued under the authority of the Washington Clean Air Act, Chapter 70.94 Revised Code of Washington, Chapter 173-401 of the Washington Administrative Code and Puget Sound Clean Air Agency (PSCAA) Regulation I, Article 7. Unlike the permit, this document is not legally enforceable. It includes references to the applicable statutory or regulatory provisions that relate to Frederickson Power emissions to the atmosphere. In addition, this Statement of Basis provides a description of the facility's activities and a compliance history.

2 Why Frederickson Power LP is an Air Operating Permit Source

Frederickson Power LP has federally enforceable limits that restrict the facility's emissions to below major source levels for all criteria pollutants expected to be emitted from the plant (see Section 7.1). The facility's potential emissions of hazardous air pollutants are also under the major source thresholds. It is not a "major source" as defined in the federal or state clean air act or the rules implementing these acts. However, it is subject to the requirement to obtain an air operating permit because it is an "affected source" regulated under Title IV (Acid Deposition Control) of the FCAA. These facilities are required to obtain an operating permit under Title V of the federal Clean Air Act (CAA) Amendments of 1990 and its implementing regulations, 40 CFR Part 70, and WAC Chapter 173-401-300(1)(a)(v).

3 Source Location and Description

The Frederickson Power LP Generating Station is a pipeline natural gas-fired electrical power generating plant located at 18610 50th Avenue East in Tacoma, Pierce County, Washington. The facility is owned jointly by Atlantic Power Services, LLC (also referred to as Atlantic Power Corporation) and Puget Sound Energy, and is operated solely by Atlantic Power Services, dba Frederickson Power LP.

The electrical power generating equipment includes the following:

- One GE-PG7241-FA Frame No. 7 (FA) primary combustion gas turbine generator (CTG, 167MW);
- One Heat Recovery Steam Generator (HRSG) which runs a secondary steam turbine and is fired by duct burners rated at 350 MMBTU/hr; and
- Ancillary units, including a diesel-fired internal combustion engine to power an emergency firewater pump and insignificant emission units including cooling towers.

Both combustion sources (the gas turbines and the duct burner) produce a single exhaust stream, which is directed to an Oxidation Catalyst unit to control carbon monoxide (CO) and volatile organic compound (VOC) emissions, and a Selective Catalytic Reduction (SCR) unit to control oxides of nitrogen (NOX) emissions.

The plant is rated at 269 megawatts (MW) combined cycle with 6.66 MW auxiliary losses. The CTG is rated at 167 MW while burning 1,599 MMBtu/hr of natural gas and the steam turbine is rated at 102 MW. The duct burner is rated at a heat input capacity 350 MMBtu/hr of natural gas higher heating value. Given the nature of power generation equipment, these numerical descriptions are approximate. The facility had previously operated only on an "as needed" basis, however in 2022 the facility began operation full time. There are no limitations on the facility's hours of operation and this does not affect the conditions in the permit.

4 Permitting History

4.1 New Source Review Permitting for the Facility

<u>Puget Sound Clean Air Agency New Source Review</u>

Order of Approval No. 8695 (cancelled) was issued on June 19, 2003, for the installation of an additional gas turbine (referred to as "Fred 2"). The second turbine was never installed and the Order of Approval for its construction is no longer valid.

Order of Approval No. 7968 was initially issued on April 25, 2000, for the installation of the facility and included a 249.33 MW combined cycle electric power generating plant using natural gas and No. 2 fuel oil. That OA was cancelled and superseded by the version issued November 9, 2001. This updated OA included all the applicable requirements from the earlier version. Its purpose was to, "change the brand name of the selective catalytic reduction unit in the project description, amend Conditions No. 5, 8(b) and 13 to use parametric monitoring for flow rate measurements per 40 CFR 75 and redefine start up and shutdown descriptions" per Condition 19 of the OA. This OA is still in effect and is the only OA in effect at the facility.

<u>Prevention of Significant Deterioration (PSD) permit PSD-</u>

Order of Approval No. 7968 includes limits on all pollutants subject to PSD to avoid PSD applicability. A PSD permit was not required.

4.2 Regulatory Orders Issued to the Facility

No regulatory orders have been issued to the facility.

4.3 Operating Permit Issuance and Renewal

An initial air operating permit application was received by the Agency from the applicant on April 16, 2003, pursuant to WAC 173-401-500(3). The application was later determined to be complete. The permit was issued on September 23, 2010.

This is the first renewal of the original AOP. The application was received July 23, 2014. The application was received on time and with more than one year remaining on the active permit, which expired on September 23, 2015. On September 23, 2014, the Agency determined the renewal application was complete. In accordance with WAC 173-401-640, Frederickson Power operated under the authority of their permit shield from the expiration date of the original operating permit (September 23, 2015) until the Agency issued this renewal of the permit.

On January 4, 2022, the Agency received a request from Frederickson Power to change the Responsible Official listed on the AOP to Paul Skopnik. Administrative Amendment 1 to make this change was issued on March 31, 2022.

5 Compliance History

Onsite inspections of the facility since the issuance of the original AOP were performed at least once per calendar year from 2011 through 2022. Inspections performed in 2020 and 2021 were conducted via telephone due to the COVID-19 measures to protect agency and Frederickson Power's employees.

The previously issued permit required the facility to perform a stack test for Ammonia, NOx and CO every year. Tests for these pollutants have been performed every year from 2002 through 2021. All tests showed compliance with the three limits (NOx, CO and ammonia).

The facility has received three notices of violation in the last five years:

- NOV 3-A000446 (violation date of 2/29/2016) for failing to meet the maintenance requirements for the fire pump engine
- NOV 3-000468 and NOV 3-000531 (violation dates of 10/9/20212 and 12/1/202) both for failing to meet the 21-day notice requirement for a performance test

6 Potential to Emit and Actual Emission Inventories

The facility's potential to emit (PTE) of criteria pollutants is defined by their synthetic minor limits as follows:

Pollutant	PTE, TPY
CO	91.2
SO_2 (oil/natural gas)	54.4/4.82*
VOC	37.7
PM_{10}	83.3
NO_x	98.9

*The facility was initially permitted to burn fuel oil with a PTE of 54.4 TPY SO_2 via their synthetic minor limit. They never installed the facilities to use fuel oil and are now restricted to burning only natural gas. The PTE of SO_2 for natural gas combustion is 4.82 TPY.

The facility is a natural minor for HAP based on the calculated potential to emit. Total HAP PTE emissions are 3.68 tons per year. The PTE for the highest HAP is 1.77 tons per year of formaldehyde.

The table below summarizes Frederickson Power's primary air emissions for the most recent available 5 years. Emission inventories are estimates of actual emissions from the facility developed by the permittee and submitted to the Agency annually. Emissions at this facility come from the operation of the gas turbine and duct burner. Emissions will vary from year to year depending on the usage of the equipment.

Table 1. Emission Inventory Summary (tons per year)

Pollutant	2020	2019	2018	2017	2016
CO	0.3	0.1	0.1	0	0.2
TAC	2.1	2.9	1.5	2	1.8
SO2	2.1	2.9	1.5	2	1.8

Pollutant	2020	2019	2018	2017	2016
VOC	15.4	21.5	11.3	15	13.8
PM10	33.2	46.2	24.3	32	29.7
NO2	38.6	50.6	27.1	38	34.6

7 Compliance Assurance Monitoring, NESHAP and NSPS Applicability Review

7.1 Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) rule requires owners and operators to monitor the operation and maintenance of their control equipment, so they can evaluate the performance of their control devices and ensure they are working properly. The CAM rule applies at major sources with emission units that have control devices and emissions could exceed 100 tons per year if the control device was not operated. The CAM rule defines a major source using the definition in the Part 70 regulations at 40 CFR 70.2. The three types of major sources in Part 70 are:

- Major HAP sources – sources that emit 10 tpy or more of a single HAP or 25 tpy or more of all HAPs combined.
- Major air pollutant source – sources that have the potential to emit 100 tpy or more of any air pollutant subject to regulation
- Major source in nonattainment areas – sources with specified potential to emit of certain pollutants in nonattainment areas.

The facility's Order of Approval and the AOP include limits on the emissions of criteria pollutants that keep the potential to emit below 100 tpy for each pollutant. The facility does not emit or have the potential to emit HAPs or any other air pollutants at or above the major source thresholds. The source is not located in a nonattainment area. As it does not meet the definition of major source, the facility is not subject to the CAM rule.

7.2 NESHAP: Stationary Reciprocating Internal Combustion Engines (40 CFR 63 Subpart ZZZZ)

The facility has one diesel-fueled internal combustion engine used to pump water in case of a fire. It was installed May of 2002 and is rated at 265 BHP.

The engine is exempt from the NESHAP based on 40 CFR 63.6585(f)(2) which states that existing commercial emergency stationary RICE at area sources are not subject to this subpart if they meet certain criteria. These criteria are:

1) The engine must meet the definition of "emergency stationary RICE" found at 40 CFR 63.6675 which includes fire pump engines that operate less than 100 hours per year for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine.
2) The engine must be "existing" per 40 CFR 63.6590(a)(1)(iii) "For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced

construction or reconstruction of the stationary RICE before June 12, 2006." The engine was installed May of 2002 and is therefore an existing RICE

3) The engine can run for unlimited hours when needed for an emergency.

Because this NESHAP includes criteria to qualify for the exemption, the permit contains requirements to record the hours of operation of the engine and the purpose of the operation and report to the Agency if the hours of operation exceed 100.

7.3 NSPS Applicability

As part of the renewal process, the Agency reviewed new federal New Source Performance Standards (NSPS) finalized since the last renewal that might apply to this facility to determine applicability. No new NSPS apply, but a summary of previous NSPS reviews are included below:

7.3.1 Standards of Performance for Stationary Gas Turbines (40 CFR Part 60, Subpart GG)

This NSPS applies to stationary gas turbines constructed after October 3, 1977, with a heat input rate equal to or greater than 10 MMBtu/hr. The turbine in Emission Unit 1 was constructed in 2002 and has a heat input rate of 1,799 MMBtu/hr. As previously determined, NSPS Subpart GG applies to the stationary gas turbine. The permit contains requirements related to NO_{x}, SO_{2}, and other NSPS requirements in Section 2.

7.3.2 Standards Of Performance for Electric Utility Steam Generating Units, Subpart Da

This NSPS applies to electric utility steam generating units which commenced construction after September 18, 1978. The rule applies specifically to heat recovery steam generators used with duct burners capable of combusting more than 250 MMBTU/hr of fossil fuel and associated with a stationary combustion turbine. Only emissions resulting from the combustion of fuels in the duct burners are subject to Subpart Da. The opacity/particulate matter standard in this rule does not apply because the duct burner only combusts natural gas. The permit contains requirements related to NO_{x}, SO_{2}, and other NSPS requirements in Section 2.

7.3.3 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII)

The provisions of NSPS Subpart IIII apply to owners or operators of stationary compression ignition internal combustion fire pump engines manufactured after July 1, 2006. The fire pump engine was manufactured before April 1, 2006, and NSPS Subpart IIII does not apply.

8 Applicable Requirements and Other Changes in the Renewal

8.1 Emission Unit Summary Table

A new table was added to the permit located before Section 1 that gives a general description of the emission units at the facility. The table is reproduced below and lists the emission units regulated under this permit located at the facility. The information in the table is for informational purposes only.

Source	Description	Emission Control Equipment on Common Stack	Install Date	Maximum Capacity (based on acid rain Certificate of Representation)
EU 1	One GE-PG7241-FA Frame No. 7 (FA) natural gas-fired combustion turbine One Heat Recovery Steam Generator (HRSG) consisting of natural gas-fired duct burner and secondary steam turbine Both exhaust through a common stack with flowrate of approximately 1,024,700 cfm at 189ºF Common stack is monitored with NO_X CEMS, a CO CEMS, and an O2 diluent monitor	Grace Emission Control Product Oxidation Catalyst (for CO and VOC) and Haldor Topsoe Selective Catalytic Reduction (for NOx) with a parametric monitoring requirement for ammonia	August 19, 2002	Natural Gas Fired CTG: 167 MW and 1,799 MMBTU/hr Natural Gas Fired Duct Burner: 350 MMBTU/hr Steam Turbine: 102 MW
EU 2	Compression ignition engine emergency fire water pump Detroit Diesel Model DDFP-L6FA 8393	No add-on controls	May 7, 2002	265 BHP
EU 3 Other Emissions Units	Diesel tank for fire water pump, 267 gallons installed August 2002 Propane heaters Combustion source less than five million Btu/hr. exclusively using natural gas, butane, propane and/or LPG); Miscellaneous welding associated with maintenance activities (Welding using not more than one ton per day of welding rod); One Four-Cell Cooling Tower (Water cooling	None		

	towers and ponds, not using chromium-based corrosion inhibitors, not used with barometric jets or condensers, not greater than ten thousand gpm, not in direct contact with gaseous or liquid process streams containing regulated air pollutants) Miscellaneous painting associated with maintenance activities, touch-up painting post-welding and painting of small beams and angle irons (Surface coating, using less than two gallons per day).			

The table includes the emission unit covered in the previous permit and also includes two additional emission units that were existing units, but not explicitly identified in the previous AOP. Emission Unit 2 is the emergency fire water pump engine which is exempt from the RICE NESHAP and NSPS. Emission Unit 3 covers all other equipment on site that emits NO_x, CO, SO_2, VOC and/or PM_{10}. Because all the emissions of NO_x, CO, SO_2, VOC and/or PM_{10} at the facility have to be included in the synthetic minor limits, the emissions from these emission units must be included as they are subject to this federally enforceable requirement. The equipment in EU 3 would normally meet the definition of insignificant emission units. However WAC 173-401-530(2)(a) states that emission units that have federally enforceable requirements, that are not generally applicable requirements, are not insignificant emission units.

Sections 1 and 2 are reformatted in the AOP renewal so that all facility-wide requirements and the corresponding compliance methods are in Section 1, and the emission unit specific requirements and corresponding compliance methods are in Section 2. The intent was to make it easier to connect the applicable requirement and the compliance method. Applicable requirements for Emission Unit 1 are in both Sections 1 and 2. Applicable requirements for Emission Unit 2 are only in Section 1, facility-wide requirements. There are no emission unit specific requirements for Emission Unit 2.

8.2 Updates, Changes, and Additions to Applicable Requirements

Many updates, changes and additions were made to the AOP during the renewal process. These are summarized in this section.

PSCAA State Implementation Plan (SIP) Changes

The PSCAA State Implementation Plan (SIP) required by US EPA was updated since the last Frederickson Power permit was issued. This update resulted in replacing multiple state WAC rules with PSCAA rules. Below are the WAC rules that were changed or eliminated from the permit and the PSCAA replacements:

WAC 173-400-040(1)(c) is replaced by PSCAA Reg I, 3.04

WAC 173-400-040(2) is replaced by PSCAA Reg I, 9.03

WAC 173-400-040(6) Is replaced by PSCAA Reg I, 9.11(a)

WAC 173-400-040(7) Is replaced by PSCAA Reg I, 9.07

WAC 173-400-040(8) is replaced by PSCAA Reg I, 9.13

WAC 173-400-040(9)(a) is replaced by PSCAA Reg I, 9.15

WAC 173-400-050(1) and (3) and -060 is replaced by PSCAA Reg I, 9.09

Additional and Modified Conditions

There are applicable requirements that were not included, were incomplete or were insufficient in the previous AOP. Title V of the federal Clean Air Act requires that all air pollution regulations applicable to the source be include in the permit. It also requires that each applicable requirement have a federally enforceable means of "reasonably assuring continuous compliance." Title V, 40 CFR Part 70, and WAC 173-401-615 all contain a "gap filling" provision that enables PSCAA to add monitoring where no monitoring is present. In addition, 40 CFR 70.6(c)(1) and WAC 173-401-630(1) also contain authority to address situations where monitoring exists but is deemed insufficient. PSCAA relied on these authorities to add monitoring where needed.

The Agency has added or changed conditions to address these issues. These additions and changes include:

1) PSCAA Reg I, 3.25 Federal Regulation Reference Date – this rule is cited where federal rules are the underlying requirement for a condition. It specifies that the effective date of the federal rule is the one cited in this Agency regulation.
2) Condition 1.19 was updated to separate the main turbine/duct burner common stack from the other units on site for opacity monitoring. This was done because the permittee's response to address to visible emissions from the common stack is different than the response required for visible emissions from other emission units onsite.
3) Condition 1.22 and 1.24 were changed to cover all emission units onsite.
4) Condition 1.26 was added which makes it clear that all emissions from all emission units be included in the total emission calculations for the synthetic minor limits. Conditions 1.14, 1.15, 1.16, 1.17, 1.18, and 1.26 were edited to also make it clear that all emission units on site be included in the synthetic minor calculation.
5) Conditions 1.27, 1.29, 1.31 and 1.33 clarify the calculation methods for determining compliance with Order of Approval 7968 which included multiple emission limits in different units of measure for SO_2, VOC, PM_{10}, NOx and CO. These included concentrations, pounds per million BTU, lb/hour, daily emissions, monthly emissions, and annual tons per year. Condition 1.27 also added that the F factor used in the equations is zero as stated in the U.S. EPA Applicability Determination Index 02000068, dated 7/25/2002 for the facility.
6) Conditions 1.28, 1.30, 1.32 and 1.34 require the calculation of emissions all other emission units onsite other than the turbine/duct burner common stack. These emissions must be counted towards the facility-wide totals.

7) Applicable requirements for the duct burner from 40 CFR 60 Subpart Da were added. These are found in conditions 2.12, 2.13, 2.16, 2.24, 2.25, 2.26, 2.27, 2.47, 2.48, 2.49. Emission limits are determined at the common stack, all other conditions are specific to the duct burner.

8) Applicable requirements for the turbine from 40 CFR 60 Subpart GG were modified or added to ensure all applicable requirements are in the permit and are as clear as possible. These are found in conditions 2.14, 2.15, 2.16, 2.17, 2.18-2.24, 2.31, 2.32. Most of these conditions are self-explanatory and it is inherently clear why they are included in the permit. However some conditions warrant additional explanation, which is provided below.

9) For condition 2.14, the NSPS Subpart GG NOx limit compliance method was updated to confirm that the NOx and diluent CEMs are used to show compliance with the hourly NOx limit in this condition.

10) For condition 2.15, generally it is anticipated the permittee will use fuel sulfur monitoring to show compliance. However a second option is available, which is to show compliance with the sulfur concentration at the stack using stack testing. The permit also allows the Agency to require the permittee to demonstrate compliance via condition 5.12 “Investigations and Testing.”

11) For condition 2.16, the Agency added a requirement to record the dates and times of startups and shutdown using sufficiency monitoring authority found in WAC 173-401-630(1).

12) For condition 2.17 the Agency added the requirement to submit and follow a test plan for the NOx, CO, NH3 testing. This annual test as well as the CEMs are used to show compliance with the limits. This condition also cites the U.S. EPA Applicability Determination Index to allow the use of zero for fuel bound nitrogen.

13) For condition 2.18 the Agency added language and proper citations to incorporate feedback from the Region 10 US EPA audit of the previous AOP for this facility. The permit previously referred to 40 CFR Part 75 for CO and NOx. This CFR does not include or regulate CO or O_2 monitors. Performance specifications for the CO and O_2 monitors from 40 CFR 60 were added to this condition.

14) For condition 2.20 the Agency added explicit language that identifies the CEMS as the means of compliance with the NO_x and CO 1-hour and 8-hour concentration limits in addition to the annual testing. The Agency also specified that if a quality assurance test or audit is failed, data is not included in the average until a passing quality assurance test or audit is complete.

15) For condition 2.24 the fuel sampling requirement was added to require sulfur content of the fuel to be determined each calendar quarter.

16) For condition 2.25 the Agency added this requirement from 40 CFR 60 Da for SO_2. The limit is based on 30 successive “boiler operating days” of the duct burner meaning a 24-hour period where the duct burner was combusting natural gas for the entire 24 hours. The facility does not run full time, so it could take longer than 30 days to reach “successive boiler operating days”. However, the permit allows the use of an assumed emission factor to show compliance unless fuel sampling indicates an issue. The facility currently performs monthly sulfur sampling of the natural gas, and this was included in this condition.

17) For condition 2.26 NSPS Da allows either the use of a continuous flow monitoring system or fuel flowmeters to facilitate determining NOx emissions. Frederickson Power has fuel flowmeters, one for the duct burner and one for the turbine and uses that option to determine compliance with the NSPS Subpart Da NO_x emission rate limit.

18) For condition 2.28 the Agency has added a requirement to perform stack tests to show compliance with the VOC emission limit. The previous AOP allowed compliance with the CO limit to show compliance with the VOC limit. There is no data for this facility showing that this is an accurate method to determine compliance with a VOC limit. The Agency received feedback from Region 10 US EPA based on an audit they performed of the previous AOP for this facility. They stated there was no assurance that the VOC limit is being met via the CO emissions and directed the Agency to include a direct measurement of the VOC. This condition was added to address this audit finding.

19) For condition 2.29 the Agency has added a requirement to perform stack tests to show compliance with the PM_{10} limit. Similar to the VOC limit, there is no evidence that opacity or other surrogates are adequate to show compliance with the PM_{10} limit.

20) For condition 2.30 the Agency has added a requirement to perform an Ecology Method 9A opacity test on the combined turbine/duct burner stack if during the monthly facility wide visible emissions other than uncombined water are seen from the stack. The previous AOP did not require any specific determination of compliance with the opacity limit on the combined stack.

21) In conditions 2.33-41, the NSPS testing general provisions were added to the permit. These would need to be followed if Frederickson Power was required by U.S. EPA or the Agency to perform a test to show compliance with a New Source Performance Standard.

22) For condition 2.45, 60.7(c) does not apply directly as it only applies if the facility is required to have the CEMS under the NSPS, which is not the case. However, 60.334(j) requires voluntarily installed CEMS to follow 60.7(c) for report submission.

23) For condition 2.45.b., the Agency added that if a stack test shows emissions over the limit in Condition 2.15, those are considered excess emissions.

24) For condition 2.51 the Agency added a requirement that all planned maintenance activities for the oxidation catalyst included in the planned maintenance system be performed and records of this maintenance be kept. The catalyst controls both CO and VOC. Performing this maintenance acts as a continuous method to assure the catalyst is controlling VOC. This is not needed for CO as the CEMS will identify concerns with CO emissions.

25) In multiple places the permit was updated to clarify that certain emission limits apply at the common stack. This applicable requirement is in condition 2.50 and based on WAC 173-400-040(1)(b). The emissions from the turbine and the duct burner both vent out a common stack. Frederickson Power confirmed that the two units cannot be tested separately and are therefore subject to this rule.

26) Conditions 2.52 and 2.53 incorporate the Acid Rain applicable requirements.

27) Conditions 2.54 through 2.56 for the emergency fire pump engine were added to identify it as an explicit emission unit and to include the applicable requirements to keep records of the information needed to show the engine is not subject to the RICE NESHAP.

28) A third emission unit was added to cover all other emission units onsite whose emissions are included in the synthetic minor limit. There are no emission unit specific requirements for these, solely the requirements in Sections 1 and 3-9.

29) In multiple places a condition was added (5.12 Investigations and Testing) which allows the Agency to require testing of emission units as allowed by PSCAA Regulation I, Section 3.05(b).

30) For condition 6.3 the requirement to retain records for 10 years for Greenhouse Gas related requirements was added.

31) For Condition 6.20, the Agency added an applicable requirement from PSCAA Regulation III, Section 1.11, requiring the facility to report toxic air contaminant emissions annually, regardless of the emission thresholds in Regulation I, Section 7.09(a).

Format Changes

The format and organization of the AOP has been updated from the previous version to match the Agency's current format and organization. Sections 3 through 9 were updated as follows:

Section 3: Standard Terms and Conditions

Section 4: General Permitting Requirements

Section 5: General Compliance Requirements

Section 6: General Applicable Requirements

Section 7: Test Methods and Averaging Periods

Section 8: Inapplicable Requirements

Section 9: Insignificant Emission Units and Activities

Acid Rain Permit Changes

The last significant change to the AOP was the change in how the Acid Rain Permit was included in the AOP. It was updated to better align with current practices used by Washington agencies at both the state and local level.

The Acid Rain Permit application and Certificate of Representation, which represent the Acid Rain Permit for the facility, are included in AOP Section 10. Section 9 of this Statement of Basis is the Statement of Basis for the Acid Rain Permit.

9 Acid Rain Permit Statement of Basis

Title IV of the Clean Air Act authorizes the EPA to establish the Acid Rain Program. The Program is codified in 40 CFR Parts 72, 73, 74, 75, 77, and 78 and includes: Permits, Allowance System, Sulfur Dioxide Opt-Ins, Continuous Emission Monitoring, Excess Emissions, and Appeal Procedures. The purpose of the Acid Rain Program is to significantly reduce emissions of sulfur dioxide and nitrogen oxides from utility electric generating plants in order to reduce the resultant adverse health and ecological impacts of acidic deposition (or acid rain). The EPA promulgated these rules in 1993. The Frederickson Power facility is subject to the Acid Rain Program. Applicable requirements of the Program are included in Section 10 of the AOP.

In accordance with and pursuant to the Washington Administrative Code (WAC) 173-406 "Acid Rain Regulation" and WAC 173-401, "Operating Permit Program", the Puget Sound Clean Air

Agency issue this permit. WAC 173-406 is based on the provisions of Title 40 CFR Parts 72-76, established under Title IV of the Federal Clean Air Act, 42 U.S.C 7401, et seq.

10 Public Comments and Responses during renewal process

<include discussion after public comment period>

11 EPA Comment Period

<include discussion after EPA review>