Public Utility District Number 1 of Snohomish County

Facility Connection Requirements

September 29, 2011

Revision History:

Number	Date	Description
Original	Sept. 29, 2011	Document Origination – Compilation of: 1) SNPD Electric Service Requirements 2) SNPD Customer Service Regulations 3) SNPD General Planning Guidelines, 2/4/10 4) SNPD Electric Transmission Protection Engineering Guidelines, 12/19/08 5) SNPD Electric Distribution Protection Engineering Guidelines, 12/19/08
Revision 1	Dec. 18, 2013	Renumbered sections according to the NERC standard requirements numbering change. Minor edits throughout documents.

Facility Connection Requirements

Table of Contents

1.0 Introduction and Summary Requirements (R1)

The Facility Connection Requirements ("FCR") described herein provide a summary of technical requirements for applicants connecting generation resources, transmission lines, and loads onto the Public Utility District No. 1 of Snohomish County ("District") electric system. The purpose of these requirements is to assure the safe operating integrity and reliability of the District owned electric system. Contractual matters, such as costs, ownership, scheduling, and billing are not the focus of these requirements. All requests for transmission services, distribution services, and ancillary agreements must be made independent of the interconnection requests pursuant to the terms of the District Customer Service Regulations and Transmission Services Policies. The term "applicant" describes the utility, developer or other entity that requests a new or modified connection for a line, load or generation resource and includes both current District customers served under one of its retail electric rate schedules and entities that are not currently District electric customers but who intend to connect in the District's electric system. Requests to interconnect generating resources or loads are typically submitted by the applicant. The District evaluates and studies each interconnection request individually with a "**Feasibility Review**" as it was described in the request and determines impacts to the District electric system. Specific interconnection requirements are then provided back to the applicant. Interconnection requirements are intended to comply with NERC Reliability Compliance Standards FAC-001-1 and FAC-002-1.

Physical laws that govern the behavior of electric systems do not recognize boundaries of electric facility ownership. Therefore the electric power system must be studied, without regard to ownership, to develop a properly designed interconnection that is compatible with the future electric system as well as present conditions. The complete review may include studies of short-circuit fault duties, system protection requirements transient recovery voltages, reactive power requirements, stability requirements, harmonics, safety, operations, maintenance and prudent electric utility practices. It may also be required for the District to perform a "**System Impact Study**","**Interconnection Facility Study**" and/or "**Joint Study**" with other utilities to address any potential impact to the reliability of the bulk electrical system.

The FCRs identified in this document are not intended as a design specification or an instruction manual and the information presented is expected to change periodically based on industry events, evolving standards, and internal and external changes to the District's electric system. Technical requirements stated herein are consistent with the District's current internal electric facility planning guidelines and practices for system additions and modifications. These requirements are intended to be in full compliance with the **North American Electric Reliability Corporation** (NERC), and **Western Electricity Coordinating Council** (WECC) requirements and also to be consistent with the general principles and practices of the **Institute of Electrical and Electronics Engineers** (IEEE) and **American National Standards Institute** (ANSI) if applicable. To the extent that the codes, standards, criteria and regulations are applicable, the new or modified facilities shall be in compliance with those standards and practices.

The District will make the final determination as to whether the District's facilities are properly protected before an interconnection is energized. The customer is responsible for proper protection of their own equipment and installation of the protection equipment before facilities are energized or interconnected operation begins. The District may determine equivalent measures to maintain the safe operation and reliability of the District electric systems. For most generators and some loads, this will include District capability for direct tripping through special protection schemes. The interconnected facility's periodic maintenance, testing, and validation are required and must be consistent with NERC/WECC standard guidelines.

Integrating generation, transmission lines, distribution lines, and load facilities and associated equipment shall include the following goals:

- Insure the safety of the general public and District personnel.
- Minimize the possible damage to the property of the general public, the District and District Customers.
- Minimize adverse service impacts to present and future District customers.
- Minimize adverse impacts to the present and future District electric system.
- Adhere to District standards and requirements.
- Minimize adverse operating conditions on the present and future District's system.
- Provide required information to the District before District analysis is started.
- Obtain a review and approval by the District prior to interconnection.
- Avoid adverse rate and capital cost impacts.
- Permit the customer to operate their generating equipment in parallel with the District's system in a safe and efficient manner.

In order to achieve these interconnection goals, certain protective devices (relays, control schemes, circuit breakers, etc.) must be installed to properly disconnect the customer's generation from the District electric system whenever a fault or abnormality occurs. The determination of what type of protective devices is required depends primarily on three major factors:

- The type and size of the customer's load and/or generation equipment (i.e. synchronous, induction, inverter-based, etc.), or transmission lines.
- The location of the customer on the District system.
- The manner in which the installation will operate (one-way vs. two-way power flow).

In addition to protective devices, certain modification and/or additions may be required on the District's system due to the addition of the customer's generation. Each request for interconnection will be handled individually, and the District will make the final determination of the protective devices, maintenance and operation requirements, communications and control requirements, modifications and/or additions required. The District will work with the customer to achieve an installation that meets the requirements of both the customer and the District.

The District cannot assume any responsibility for protection of the applicant's generating equipment, or of any other portion of the customer's electrical equipment. The applicant is solely responsible for protecting its equipment in such a manner that faults, imbalances, or other disturbances on the District system do not cause damage to the applicant's equipment.

2.0 Facility Connection Requirements (R3)

Interconnection of New or Modified Facilities (R3.1)

For any service requests, the District should be contacted as early as possible in the planning process for any potential generation, load, or transmission or distribution line project within or adjacent to the District system where the project will interconnect with the District electric system. Requests for transmission services are not addressed in this document. Contact the Power Rates & Transmission Management Services Division. Consistent with applicable law, transmission service requires compensation from the customer to mitigate stranded costs if a new transmission system interconnection will bypass or otherwise strand investment in an existing District facility.

The **Electrical Service Requirements** manual contains policies, standards and general requirements for providing overhead and underground service to District customers. For all interconnection requests, the applicant shall have the responsibility of reading and understanding the **Electrical Service Requirements** document, available from Customer Engineering.

The following is the initial process for any potential generation, load, or transmission/distribution line interconnections to the District's electric system:

1. Generation Interconnection

Customers having interconnected generation capable of being operated in parallel with the District system are required to complete the District "**Preliminary Application for Operation of Customer-Owned Generation Form 6-1**". Requests for connection may also require additional related information as listed in "**Information Requirements for Generators, Transmission Lines, Distribution Lines, and Load Facilities**" in Appendix A of this document. There are three classes of customer generation interconnections as follows:

For Distribution System Interconnection 12.5 kV

- 0 – 3 MVA, connection to existing 12.5 kV distribution feeder with existing customers.
- 3 – 10 MVA, connection to dedicated 12.5 kV distribution feeder for generation only.

For Transmission System Interconnection 115 kV

- > 10 MVA, connection to 115kV transmission system.

For interconnection of customer-owned generation facilities greater than 100 kVA, the detailed interconnection requirements are described in: "**Electrical Service Requirements (Section 6)**" available from Customer Engineering, and "**Interconnection Requirements for Customer-Owned Generating Facility Connected to District High Voltage System**" (Appendix B of this document) and "**Interconnection Requirements for Customer-Owned Generating Facility Connected to District Distribution System**" (Appendix C of this document).

The completed application and supporting information and documents will be used by the District to perform a "**System Impact Study**" to determine the required additions and modifications to District's transmission or distribution lines, controls, and communication circuits to accommodate the proposed interconnection.

2. *Transmission and Distribution Lines, and Load Facility Interconnection*

The District "New Service Questionnaire" form must be completed and submitted to the District for any proposed transmission or distribution lines interconnected to the District electric system. The District should be contacted as early as possible in the planning process for any potential transmission or distribution line when the project will interconnect with the District electric system. The completed application and supporting information and documents will be used by the District to perform a **"System Impact Study"** or **"Engineering Study"** to determine the required additions and modifications to District electric system necessary to accommodate the proposed interconnection.

3. *Feasibility Review and System Impact Studies*

The completed new generation, transmission and distribution lines, or load facility application and supporting information and documents by the applicant will be used by the District to perform a "**Feasibility Review**" to determine the required additions and modification to District substations, transmission lines, distribution lines, controls and communication circuits to accommodate the proposed interconnection.

In addition, based on the findings of the "**Feasibility Review,"** a more thorough "**System Impact Study**" may be required. During this interconnection study, additional details of the proposed facility may be required and will be requested from the applicant as needed. Meetings will be held as required between the District representative and the applicant, their consulting engineer, contractor, or equipment manufacturer to establish the details of the proposed installations.

The studies required will vary depending upon the type of interconnection requested. These studies can require considerable time and effort, depending on the size of the project and its potential system impacts. In general the "**Feasibility Review"** will take four to six weeks to complete. The studies will investigate the impact on system performance of the interconnecting projects. This may include analysis of potential thermal overloads, operating voltage limits, voltage stability, power factor, harmonics, transient stability, and short circuit interrupting requirements. Technical issues directly associated with the project, such as voltage regulation, machine dynamics, metering requirements, protective relaying, and substation grounding, will also be addressed as required in development of the preferred plan of service.

Upon the completion of the "**Feasibility Review,**" the District will provide the following to the customer:

- A determination of whether the applicant's generation is classified as parallel or non-parallel operation with the District's electric system.
- Preliminary details of any modifications required to the District's system and/or the applicant's proposed configuration.

After reviewing an applicant's request for interconnection service and preparing a "**Feasibility Review,**" the District shall determine on a nondiscriminatory basis whether a "**System Impact Study**", "Interconnection Facility Study" and/or "**Joint Study**" is needed. If the District determines that a "**System Impact Study**" , "Interconnection Facility Study" and/or "**Joint Study**" is necessary to accommodate the requested service, it shall so inform the applicant, as soon as practicable. In such cases, the District shall, tender a "**System Impact Study Agreement**" pursuant to which the applicant may be required to reimburse the District for performing the required "**System Impact Study**". If the applicant elects not to execute the System Impact Study agreement, his application for service shall be deemed withdrawn.

Following the initiation of a System Impact Study Agreement, the customer shall prepare and submit the "**Final Application for Operation of Customer-Owned Generation -Form 6-2"** provided in the **Electrical Service Requirements** (Section 6). The customer shall provide the data required by the Preliminary Interconnection Study, Study Requirements (Section 6.D) of the **Electrical Service Requirements**. The customer may also be required to provide additional data as described in Appendix A, "Information Requirements for Generators, Transmission Lines, Distribution Lines, and Load Facilities".

The "**System Impact Study"** will be consistent with the Electric Facilities General Planning Guidelines. The study will use good utility practice, engineering and operating principals, and standards, guidelines, and criteria of the District, BPA, WECC, and NERC, or any similar organization that exists in the future of which the District is then a member. The study will identify District facilities that limit available transfer capability (ATC) and determine possible upgrades, expansions, other modifications, or re-dispatch to relieve the constraint. If a limit occurs in neighboring electric systems, the District will cooperate with other entities to develop solutions jointly acceptable to all parties. This may require that a "**Joint Study"** be performed with other regional utilities.

Studies performed by the District include both near-term (operating and operational planning) studies and also long range (planning) studies. Operating and operational planning studies are normally performed for conditions with a one-year period. These studies identify contingency-related transmission and distribution deficiencies that may be encountered, and formulate corrective measures to mitigate the deficiency. Planning studies generally involve studies beyond one year. Planning studies have a longer degree of uncertainty than operating studies. These studies identify deficiency areas in the transmission and distribution and generation system and solutions are proposed which may include facility additions, upgrades, other modifications or re-dispatch that the applicant may be responsible for, including the cost to the applicant.

The District will protect proprietary and confidential information as much as possible as required or permitted by applicable law concerning requests for customer transmission and distribution system information. The Customer shall provide the District with sufficient information for adequate system impact study.

General Requirements

2.1 Procedures for coordinating joint studies of new facilities and their impacts on the interconnected transmission systems (R3.1.1)

The District, as a Transmission Owner, Transmission Operator, Generator Owner, Generation Operator, Distribution Entity, Purchasing and Selling Entity, shall comply with the latest applicable NERC/WECC reliability standards, including:

- Facility Design and Connections (FAC)
- Modeling, Data and Analysis (MOD)
- Protection and Control (PRC)
- Transmission Operation (TOP)
- Transmission planning (TPL)
- Interconnection Reliability Operation and Coordination
- Voltage and Reactive (VAR)

Impacts to the transmission and distribution system will be identified using load-flow analysis, fault analysis, transient stability analysis, and transfer analysis, as applicable, depending on the proximity of the source or sink listed in the customer service agreements. The District reserves the right to obtain all base cases from WECC as starting seed cases, before inserting the applicant's proposed facilities for the time frame requested in the applicant's load and/or generation study request.

A **"System Impact Study"** will be performed using suitable acceptable utility industry load-flow software modeling tools. The cases used in the System Impact Study shall come from the approved WECC cases with the latest system configuration, generating resources and projected loads. Planned maintenance outages of generation, transmission, and distribution facilities matching the time frame of the applicant's service request shall also be modeled in the base case(s).

If insufficient Available Transfer Capability ("ATC") is calculated based on limits on a neighboring transmission provider system, then the District will contact the neighboring transmission provider to verify that limit. If the neighboring transmission provider verifies the limit, the District will honor the external limit and will notify the eligible customer. If insufficient ATC is calculated based on the District transmission facility limits, the District will issue a "**System Impact Study"** report to the applicant detailing the limitations and providing a rough estimate of system upgrade costs. The District shall conduct the stability studies and reserve the right to select a non-District competent third party professional engineering services to assist in transient stability impact studies using either GE PSLF or other WECC approved software.

After a signed agreement between SNPD and the applicant ("**System Impact Study Agreement") and reception of all required information and fees from the applicant**, the study shall proceed with one of the following options:

1. SNPD performs the study to identify any system constraints, re-dispatch options, and the need for any modifications to the District transmission system including direct assignment of facilities and network upgrades. The District shall notify the applicant immediately upon completion of the System Impact Study if the transmission system will be adequate to accommodate all or part of a request for service or that costs are likely to be incurred for new transmission facilities or upgrades.

2. SNPD hires an outside consultant to perform the impact studies. The applicant shall be responsible for the cost of the study. The District shall notify the applicant upon study completion as specified above.

There are three levels of planning, each of which requires differing coordination efforts.

- District (local) Planning – This includes transmission planning for the District transmission system in Snohomish County and Camano Island areas, or between the District and neighboring systems(s) that are embedded within the District's system that have no potential impacts to the electrical system outside of the District's service area.

- Sub-Regional Planning – This includes transmission planning within a larger geographical area that spans several local areas that have electric impacts on neighboring utility system(s) such as Bonneville Power Administration (BPA), Puget Sound Energy (PSE), Seattle City Light (SCL), or Tacoma Power (TPWR).

- Regional Planning – This includes transmission planning that involves the Northwest Power Pool, Columbia Grid foot prints and limited to the WECC's Northwest area.

The District will use Columbia Grid (CG) as its sub-regional planning entity. The District is a major entity in the Northwest and is committed to participating actively in the CG planning processes. In addition, the District participates in sub-regional planning as an active member of the Northwest Power Pool (NWPP). On the regional level, the District will also participate in the Western Electricity Coordinating Council (WECC) planning process.

If needed, a "**Joint Study"** will include evaluating requirements inside the DISTRICT as well as impacts on neighboring electric systems of BPA, PSE, SCL, and TPWR.

2.2 Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible (R3.1.2)

The District shall, as required and necessary, advise other regional entities of any proposed and/or implemented new or modified facilities interconnected to the District's Electric System. The District will notify Columbia Grid ("CG"), its area coordinator, and Puget Sound area utilities, BPA, SCL, PSE and TPWR, at the earliest stage of the project as feasible.

The District complies with the NERC Facility Standard FAC-002 for notification of new or modified facilities to others. Furthermore, the District reviewed, revised, and submitted WECC base cases with projects under construction, budgeted, and planned for in the current capital construction plan. Below is the routine, annual data transmission and information exchange procedures with others to ensure correct data model exchange for use in system impact studies:

Transmission Data and Information Exchange

1. The District shall submit annual system data to the Northwest Area Coordinator for a final submittal to WECC. The system data shall include but not be limited to the projected loads, system topology, and generation resources used in its planning studies.
2. The District will submit as needed any generation dynamic characteristic modifications to WECC via Columbia Grid, the Northwest Area Coordinator. The District will coordinate all dynamic data submittal to WECC.
3. Technical steady state and dynamic data used for District planning studies will be made available to other regional entities subject to appropriate non-disclosure, including the District planning base cases.

4. The District transmission system planning base-case model is to be updated annually and includes the latest updates of generation, and customer and transmission connections.
5. The applicable District General Planning Guidelines, Electric Service Requirements, and Customer Service Regulations are also to be made available.
6. Transmission system steady state and dynamic data will be stored in a System Planning & Protection share drive. Data will not be located on a public share drive.
7. Information is exchanged in regional and sub-regional planning forums including WECC, BPA, NWPP, and CG. These listed entities have procedures to make planning information available subject to appropriate non-disclosure.

2.3 Voltage level, MW and MVAR capacity or demand at point of connection (R3.1.3)

Assessments and studies shall comply with the latest applicable NERC Reliability Standards and WECC System Performance Criteria. Data requested from the applicant includes, but shall not be limited to, fuel type, maximum MW output, generator terminal voltage, transformer high-side and low-side voltages, generator MVA, generator nominal power factor and dynamic data in the GE PSLF format.

2.4 Breaker duty and surge protection (R3.1.4)

Switchgear

1. *General Requirements*

Circuit breakers, disconnect switches, and all other current-carrying equipment connected to the District transmission and distribution facilities shall be capable of carrying normal and emergency load currents, and must also withstand available fault currents without damage. This equipment shall not become a limiting factor in the ability to transfer power on the District electric system. During prolonged steady-state operation, all such equipment shall be capable of carrying the maximum continuous current that the interconnected facility can deliver. All circuit breakers and other fault-interrupting devices shall be capable of safely interrupting fault currents for any fault that they may be required to interrupt. Application shall be in accordance with ANSI/IEEE C37 Standards.

2. *Circuit Breaker Operating Times*

The rated interrupting times in cycles typically required of circuit breakers on the District electric system are as follows: 5 cycles or less for the 12.5 kV system, and 3 cycles or less for the 115 kV system.

3. *Other Fault-Interrupting Device*

Depending on the application, the use of other fault-interrupting devices such as circuit switchers may be allowed. Fuses may be adequate for protecting the high-voltage delta side of a delta-wye-grounded transformer. Use of transformer fuses may result in single phasing of low-side connected loads.

4. Surge Protection

Voltage stresses, such as lightning or switching surges, and temporary over voltages may affect equipment duty. Remedies depend on the equipment capability and the type and magnitude of the stress. In general, stations with equipment operated at 12.5 kV and above, as well as all power transformers shall be protected against lightning and switching surges by the use of the surge arrester devices and/or shielding. Typically this includes station shielding against direct lightning strokes, surge arresters on all power transformers, and surge protection with rod gaps or arresters on the incoming lines.

Temporary over voltages can last from seconds to minutes, and are not characterized as surges. These over voltages are present during islanding, faults, loss of load, or long-line situations. All new and existing equipment must be capable of withstanding these duties. The District follows NESC operating procedures such that normal voltage control practices do not cause temporary over voltage.

2.5 System protection and coordination (R3.1.5)

The District will work with the applicant to achieve an installation that meets the customer's and District requirements. The District cannot assume any responsibility for protection of the applicant's equipment. Applicants are solely responsible for protecting their equipment in such a manner that faults, imbalances, or other disturbances do not cause damage to their facilities or result in problems for other customers.

The protection system must be designed to reliably detect faults or abnormal system conditions and provide an appropriate means and location to isolate the equipment or system automatically. The protection system must be able to detect power system faults within the protection zone. The protection system should also detect abnormal operating conditions such as equipment failures or open-phase conditions. Special relaying practices may also be required for system disturbance, such as under voltage or under frequency detection for load shedding or reactive device switching. For most generation and some load, the customer will also be required to participate in special protection schemes or remedial action schemes (RAS) including automatic tripping or damping.

The protection schemes and equipment necessary to integrate the new connection must be consistent with these practices, standards, and guidelines. The District's protection requirements address the following objectives:

- Ensure the safety of the general public, District and other utility personnel.
- Prevent property damage to the general public, District and customers.

- Minimize adverse operating conditions affecting the District and customers.
- Comply with NERC, WECC and NWPP protection criteria in existence.

In order to achieve these objectives, certain protection equipment (relays, circuit breakers, etc,) must be installed. These devices ensure that during faults or other abnormal conditions, the appropriate equipment is promptly disconnected from the District electric system. Protective equipment requirements depend on the specific equipment design and operation requirements of customer service connection. Significant issues that could affect these requirements include:

- The location and configuration of the proposed connection
- The level of existing service and protection to adjacent facilities
- The connection of a line or load that coincidentally connects a generation resource, which was not previously connected to the District electric system.

2.6 Metering and telecommunications (R3.1.6)

System Metering Requirements

1. *Revenue and Interchange Metering System*

All interconnections of facilities capable of exchanging at least 1 kVA of active power require District qualified metering for revenue or interchange. Energy data recording is required for District's billing and scheduling functions. Revenue metering includes energy (kWh) and reactive energy (kVArh) recorded by revenue meters on a demand interval basis. Interchange metering includes bi-directional energy and reactive data as well as special telemetering requirements for scheduling purposes. The metering shall be located to measure the net power at the point of interface to or from the District power grid. The District typically owns and maintains the revenue metering at the load-metering and generation metering sites.

Revenue and interchange metering, telemetering, and data communication facilities require calibration and testing on a programmed periodic basis to ensure correct data readings.

2. *Generation Metering System*

Generation metering usually consists of bi-directional meters and related communications systems providing active power (in kW) and energy (in kWh) from the point of interface with the District. Active power is telemetered on a continuous basis for AGC and hourly energy and is sent each hour to the District control center for District accounting. Effective telemetering requires real-time knowledge of the quality of measurement. Associated with the telemetering signal, various indications of telecommunications quality or failure should be included.

Generation metering, telemetering, and data communication facilities require calibration and testing on a programmed periodic basis to ensure correct data readings.

System Telecommunications Requirements

Telecommunications facilities shall be installed to fulfill the control, protection, operation, dispatching, scheduling, and revenue metering requirements. They may be owned by the District, another utility, a service customer, or a third party. At a minimum, telecommunications facilities must be compatible with, and have similar reliability and performance characteristics to, telecommunications facilities currently used for operation of the District power system to which the new generation or loads will be connected. Telecommunication facilities will be identified in the project requirements. Depending upon the performance and reliability requirements of the control and metering systems to be supported, the facilities may consist of the following:

1. *Radio System*
2. *Fiber Optic Systems*
3. *Wireline Facilities*
4. *Power Line Carrier*
5. *Voice Communications*
6. *Data Communications*
7. *Telecommunications for Control and Protection*
8. *Telecommunications During Emergency Conditions*

2.7 Grounding and safety issues (R3.1.7)

The applicant's facilities must be designed in accordance with good utility practice, IEEE Std. 80, and the National Electric Safety Code. Studies must be performed to guarantee step and touch, as well as transfered, voltages are limited to safe levels. Furthermore, testing must be performed to verify the integrity of the installed system.

Any applicant's substation must have a ground grid that is solidly connected to all metallic structures and other non-energized metallic equipment. This grid shall limit the ground potential gradients to such voltage and current levels that will not endanger the safety of people or damage equipment which are in, or immediately adjacent to, the station under normal and fault conditions. The ground grid size and type are in part based on local soil conditions and available electrical fault current magnitudes. In areas where ground grid voltage rises beyond acceptable and safe limits, grounding rods or grounding wells are to be used to reduce the ground grid resistance to acceptable levels. Refer to IEEE Standard 80 for design formulations. If the new ground grid is close to another substation, the two ground grids may be isolated or connected. If the ground grids are to be isolated, there must be no metallic ground connections between the two substation ground grids. Cable shields, cable sheaths, station service ground sheaths and overhead transmission shield wires or distribution ground conductors can all inadvertently connect ground grids.

For an interconnection to the District electric system, an isolating device, typically a disconnect switch, shall be provided to allow physical and visible isolation between the District electric system and the connected facilities. The isolation device may be placed in a location other than the point of interconnection. The following requirements apply for all isolating devices:

- Must simultaneously open all three phases to the connected facilities
- Must be accessible by the District
- Must be lockable in the open position by the District
- Will not be operated without advance notice to affected parties, unless an emergency condition requires that the device be opened to isolate the connected facilities
- Must be suitable for safe operation under all foreseeable operating conditions

Connected facilities shall not prevent the District from taking a transmission line or line section or other equipment out of service for operation or maintenance purposes.

2.8 Insulation and insulation coordination (R3.1.8)

Power system equipment is designed to withstand voltage stresses associated with expected operation. Adding or connecting new facilities can change equipment duty and may require that equipment be replaced or switchgear, telecommunications, shielding, grounding and/or surge protection be added to control voltage stress to acceptable levels. **Preliminary Interconnection Studies** and **System Impact Studies** include the evaluation of the impact on equipment insulation coordination. The District may identify additional requirements to maintain an acceptable level of District electric system availability, reliability, equipment insulation margins, and safety.

2.9 Voltage, Reactive Power, and power factor control (R3.1.9)

Voltage schedules are necessary, in order to maintain optimal voltage profiles across the regional transmission system. Optimal profiles minimize transmission of reactive power, and preserve flexibility in use of reactive power control facilities. To this end, a voltage schedule will be mutually developed between the District and the customer, which will be coordinated via time changes developed by the WECC for such coordination purposes. The District maintains voltages according to the ANSI Standard C84.1. This allows for variances for plus or minus 5% from nominal for all voltage levels.

Each entity shall provide for its own reactive power requirements, at both leading and lagging power factors unless otherwise specified by the District. The District generally requires customers to minimize exchange of reactive power with the District electric system within limits specified in the “Electrical Service Requirements.” Reactive flows at interchange points between control areas should be kept at a minimum as per the “WECC Minimum Operating Reliability Criteria.”

Unless otherwise specifically agreed, the District shall not be obligated to deliver Electric energy to the Customer at any time at a power factor below 95% (refers to Average overall power factor for each individually metered service).

2.10 Power quality impacts (R3.1.10)

In general, the customer has the responsibility not to degrade the voltage of the District system servicing other users by requiring nonlinear currents from District electric system. The customer also has certain responsibilities to account for transmission system events like switching transients and fault induced voltage sags. If it is determined that the new connection facility is causing a power quality problem, then the customer will be held responsible for installation of the necessary equipment or operational measures to mitigate the problem. All loads or system connections to the District shall comply with the requirements established by IEEE Std. 519 and IEEE Std. 1547.

2.11 Equipment Ratings (R3.1.11)

The District’s electric system has been developed with careful consideration for equipment ratings. Some new connections to the District’s electric system require that one or more District’s lines be looped through the end-user’s facilities, or sectionalized with the addition of switches. The design and ratings of the applicant’s facilities shall not restrict the capability of the line(s) or contractual transmission and distribution path rights. Generation facility ratings shall be based on limits provided by the generator manufacturer including the generator capability curve. Generators shall be rated at nameplate rating unless testing provides evidence to support an increase or decrease in capabilities.

2.12 Synchronizing of facilities (R3.1.12)

The applicant’s facility shall be automatically or manually synchronized with DISTRICT’s system at all times and the applicant shall be responsible for the automatic/manual synchronization. Automatic or manual synchronization shall be supervised by a synchronizing check relay. If a synchronizing check relay is used to supervise synchronization, then its output contacts shall be rated to interrupt the circuit breaker closing circuit current and the interrupting device shall be capable of trip-free operation. As mentioned above, synchronization shall be done at the utility tie breaker and also at the generator breaker(s). Interrupting devices with longer than 5-cycle closing time (such as reclosers) shall not be used for synchronization.

2.13 Maintenance coordination (R3.1.13)

Transmission and distribution elements (e.g. lines, line rights of way, power transformers, circuit breakers, control and protection equipment, metering, and telecommunications) that are part of the proposed connection and could affect the reliability of the District electric system must be inspected and maintained in conformance with NERC and WECC standards, whichever is the most stringent. The customer has full responsibility for the inspection, testing, calibration, and maintenance of their equipment, up to the location of change of ownership or point of service. Transmission Maintenance and Inspection Plan (TMIP) requirements are a portion of the WECC Reliability Management System for Transmission Lines. The following is a summary for the applicant to follow:

- Include the interval schedule for any time-based maintenance activities and a description of conditions that will initiate any performance-based activities.
- Describe the maintenance and inspection methods including specific details for each activity or component.
- Provide any checklists, forms, or reports used for maintenance activities.
- Where appropriate, provide criteria to be used to assess the condition of a transmission facility or component.
- Where appropriate, specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the transmission facilities.
- The TMIP shall describe the maintenance practices for all applicable transmission line activities including patrols and inspections, vegetation management, and contamination control.
- The TMIP shall describe the station maintenance practices for all applicable station facilities including circuit breakers, power transformers, regulators, protective relay systems, and remedial action schemes.
- Maintenance records of all maintenance and inspection activities shall be retained for at least five years. The records of maintenance and inspection activities shall be made available to the WECC, the District, or other regulatory bodies, as requested.
- Revenue and interchange metering will be calibrated at least every two years. Other calibration intervals may be allowed if prudent. All interested parties or their representatives may witness the calibration test. Calibration of standard meters and instruments must meet accuracy requirements of the National Institute of Standards and Technology.

2.14 Operational issues (abnormal frequency and voltages) (R3.1.14)

Power System Disturbances and Emergency Conditions

1. *Considerations to minimize Disturbances*

The new facilities shall be designed, constructed, operated, and maintained in conformance with other related District requirements, applicable laws and regulations, and standards to minimize the impact of the following:

- Abnormal power flows

- Power system faults or equipment failures
- Over voltages during ground faults
- Audible noise, radio, television, and telephone interference
- Power system harmonics
- Other disturbances that might degrade the reliability of the interconnected District electric system

2. *System Frequency during Disturbances*

Power system disturbances initiated by system events, such as faults and forced equipment outages, expose the system to oscillations in voltage and frequency. It is important that lines remain in service for dynamic oscillations that are stable and damped. Large-scale blackouts can result from the excessive loss of generation, outage of a major transmission facility, or load rejection during a disturbance. In order to prevent such events, underfrequency load shedding has been implemented throughout WECC, including the Pacific Northwest. Depending on the type and location of any new customer load, the customer may be required to participate in this scheme. It is important that lines and generators remain connected to the system during frequency excursions both to limit the amount of load shedding required and to help the system avoid a complete collapse.

3. *Voltages during Disturbances*

In order to prevent voltage collapse in certain areas of the Pacific Northwest, undervoltage load shedding has also been implemented. Most of the load interruptions will occur automatically near 0.9 per unit voltage after delays ranging from 3.5 to 8.0 seconds. Depending on the type and location of any new customer load, the customer may be required to participate in this scheme.

4. *Local Islands*

For those generators interconnected to the District electric system through a tapped transmission line, a local island is created when the breakers at the ends of the transmission line open. This leaves the generator and any other loads that also are tapped off this line isolated from the power system. Delayed fault clearing, over voltage, Ferro-resonance, and extended undervoltage can result from this local island condition and shall not be allowed to persist.

Ancillary Services

All loads and transmission and distribution facilities are part of the BPA's Balancing Authority (BA) serving the District. The host BA provides critical ancillary services, including load regulation, frequency response, operating reserves, voltage control from generating resources, scheduling, system controls and dispatching service, as defined by FERC, or their successors. All new connections to the District electric system also require a transmission contract with the BA.

All generators shall be operated in voltage control mode, regulating the voltage to a District and/or BPA provided schedule. SNPD reserves the right to review, accept or reject other control modes. Typically the generator should supply reactive power for its station service loads and reactive power losses up to the point of interconnection. Generator projects may be requested to supply reactive power as an ancillary service.

Normally, the generator will operate its governor to respond independently for frequency deviations. If the governor is controlled through the plant central controller, the governor shall be in 'droop control' mode. Droop setting shall be set at 5% and performance shall comply with NERC and WECC reliability standards.

2.15 Inspection requirements for existing or new facilities (R3.1.15)

Transmission and distribution elements (e.g. lines, line rights of way, power transformers, circuit breakers, control and protection equipment, metering, and telecommunications) that are part of the proposed connection and could affect the reliability of the District electric system need to be inspected and maintained in conformance with NERC and WECC standards whichever is the most stringent. The applicant has full responsibility for the inspection, testing, calibration, and maintenance of their equipment, up to the location of change of ownership or point of service. Transmission Maintenance and Inspection Plan (TMIP) requirements are a portion of the WECC Reliability Management System for Transmission Lines for the applicant to follow as listed in section 2.1.13 of the document.

The applicant is responsible for pre-energization and testing of their generation, line, and load facility equipment. For equipment that can impact the District electric system, the customer shall develop an "Inspection and Test Plan" for pre-energization and energization testing. The customer is responsible for the generator performance testing, monitoring and validation. The District may require additional tests as necessary to ensure compliance with WECC standards.

2.16 Communications and procedures during normal and emergency operating conditions (R 3.1.16)

Applicant must provide a point of contact with reliable communication so that the District's and applicant's personnel can monitor, coordinate, and cooperate to ensure the reliable operation of the electric system during normal and emergency conditions.

The applicant shall not energize any de-energized District equipment unless the District Dispatcher specifically approves the energization. Where the applicant is connected to a radial line, the circuit may be interrupted and re-energized by the District by means of an automatic reclosing device. In cases where the interconnection breaks an existing District line, an auto-isolation scheme may be required to maintain continuity to the District line. If the interconnected facilities are networked or looped back to the District electric system or where generation resources are present, a switching device must open to eliminate fault contributions or neutral shifts. Once open, the device must not reclose until approved by the District Dispatcher.

If the generation or load facility requires any type of telemetering, then voice communications to the District operator are also required. If the facility is not staffed with operators, alternative arrangements may be made subject to District approval. A dedicated, direct automatic ring down trunk (or equivalent) voice circuit between the District control center and the operator of the generators or loads may be required for generators or loads of 10 MVA or greater.

Emergency telecommunications conditions may develop that affect telecommunications equipment with or without directly affecting power transmission system facilities. Equipment redundancy and telecommunication route redundancy can protect against certain kinds of failure and telecommunications path interruption. A repair team dedicated to the telecommunications of the interconnecting facility should be retained along with an adequate supply of spare components

3.0 Documentation requirements (R4)

The District shall maintain and update the Facility Connection Requirements reflected in this document as necessary to maintain compliance with current NERC, WECC and District standards and guidelines.

Copies of this document will be provided within 5 business days upon request by contacting the District at the contact shown in section 4 of this document.

4.0 Public Utility District No. 1 of Snohomish County Contact Information (R4)

To obtain a copy of the Facility Connection Requirements, please send your written request to:

Manager, System Planning and Protection
Public Utility District No. 1 of Snohomish County
P.O. Box 1107
Everett, WA 98206-1107

5.0 Glossary and Acronyms

For industry standard definitions of electric industry terminology, please refer to The New IEEE Standard Dictionary of Electrical and Electronic Terms, IEEE Std. 100-1992, or latest edition.

For the purposes of this document the following definitions apply:
Applicant – A customer that owns and/or develops a new load delivery, transmission interconnection, or generation facility and plans to connect to DISTRICT's electric system.
Applicant's Operator – The Company that operates a load delivery, transmission interconnection, or generation facility, which plans to connect to DISTRICT's electric system.
SNPD- Public Utility District No. 1 of Snohomish County
Connection Point - The physical location on the power system where there is a change of ownership between the District and the facility that wants to connect.

Facility – The load delivery (end-user), transmission connection, or generation facility and all equipment associated with the Facility up to the Connection Point with the District. The District owns none of the facilities that make up the Facility.
FCR – Facility Connection Requirements
FCR Study – Technical study to determine how a new facility (generation, transmission, end-user) can connect to SNPD's electric system and ensure reliable and safe operation of Bulk Electric System
WECC – Western Electricity Coordinating Council
Interconnection – Transmission system tie point between two control areas.
NERC - North American Electric Reliability Corporation
SCADA (Supervisory Control and Data Acquisition) - A system of remote control and telemetry used to monitor and control the transmission system.
Voltage Regulation - The difference between expected maximum and minimum voltage at any particular delivery point. The voltage regulation limits are expressed as a percent of the nominal voltage and are defined for both normal and contingency conditions. Voltage regulation for delivery point voltages should not exceed the guideline

Appendix A

Information Requirements for Generators, Transmission Lines, Distribution Lines, and Load Facilities

A. Introduction

When a request is submitted for a connection to the District electric system certain information must be included so the District can properly consider the interconnection request. The actual information required by the District will vary depending upon the type of request. Customers should contact the District Account Executive and request applications forms and procedures. This appendix describes typical information and data that the District will require.

B. Connection Location

The District needs location information for the proposed interconnection in order to adequately study the impacts. Location information required will vary depending upon the proposal. Locations of new substations, generators or new taps on existing lines must include the township, range, elevation, latitude and longitude. The District also requires driving directions to the location for a site evaluation.

C. Electrical Data

The electrical data required will depend upon the type of connection requested.

C.1 Electrical One-Line Diagram

The electrical one-line diagram should include equipment ratings, equipment connections, transformer configuration, generator configuration and grounding, bus, circuit breaker and disconnect switch arrangements.

C.2 Generator Data

If one or more generators are included as part of the connection request, the following data is needed. If different types of generators are included, data for each different type of generator and generator step up transformer is needed.

a. Generator General Specifications
   - Energy source
   - Number of rotating generators
   - Number of turbines (combustion, steam, hydro, wind, etc.)

- Total project output, MW at 0.95 power factor for synchronous
- Station service load for plant auxiliaries, kW, kVAr
- Station service connection plan

b. Generator Data, Synchronous Machines

Data for each different rotating-machine generator assembly (generator, turbine, and shaft) is required. Also, provide the graphs and parameters for each type and size of specified generator as supporting technical documentation:

- Machine capability, PQ curves
- Vee curves
- Open circuit saturation curve
- Identifier (e.g. GTG#12)
- Number of similar generators
- Complex power, kVA
- Active power, kW
- Terminal voltage, kV
- Machine parameters
  Sb – Complex power base, (MVA)
  H – Inertia constant, normalized rotational kinetic energy of the generator, kW- sec/kVA
  WR2 – Moment of inertia, Lb-Ft^2
  Ra – Armature resistance, pu
  Xd – Direct axis unsaturated synchronous reactance, pu
  X'd – Direct axis saturated and unsaturated transient reactances, pu
  X'q – Quadrature axis saturated and unsaturated transient reactances, pu
  X''d – Direct axis saturated and unsaturated subtransient reactances, pu
  X"q – Quadrature axis saturated and unsaturated Subtransient reactances, pu
  Xl – Stator leakage reactance, pu
  X2 – Negative–sequence reactance, pu
  Zg – Grounding impedance, ohm
  T'do – Direct axis transient open circuit time constant, seconds
  T'qo – Quadrature axis transient open circuit time constant, seconds
  T''do – Direct axis sub transient open circuit time constant, seconds
  T''qo – Quadrature axis sub transient open circuit time constant, seconds
  S(1.0) – Saturation factor at rated terminal voltage, A/A
  S(1.2) – Saturation factor at 1.2 per unit of rated terminal voltage, A/A

- Excitation system modeling information

- Type (static, brushless, rotating, etc.)
- Maximum/Minimum/Rated field current
- Maximum/Minimum/Rated field voltage
- Nameplate information
- Excitation system model for GE PSLF
- Power System Stabilizer (PSS) type, characteristics, and model for GE PSLF
- Speed governor information with detailed modeling information for each type of turbine

  Turbine type
  Total capability, MW
  Number of stages
  Manufacturer and model
  Frequency vs. time operational limits, seconds at Hz
  Maximum turbine ramping rates, MW/minute
  Governor model for GE PSLF

c. Generator Data, Asynchronous Machines

- Shunt reactive devices for power factor correction with induction generators or converters.
  PF without compensation
  PF with full compensation
  Reactive power of total internal shunt compensations voltage, kVAr

- AC/DC Converter devices employed with certain types of induction motor installations or with dc sources
  Number of converters
  Nominal ac voltage, kV
  Capability to supply or absorb reactive power, kVAr
  Converter manufacturer, model name, number, version
  Rated/Limitation on Fault current contribution, kA
- Machine parameters
  Sb - Complex power base, (MVA)
  H – Inertia constant, normalized rotational kinetic energy of the generator, kW- sec/kVA
  WR2 – Moment of inertia, Lb-Ft^2
  Ra – Armature resistance, pu
  Xd – Direct axis unsaturated synchronous reactance, pu
  X’d – Direct axis saturated and unsaturated transient reactances, pu
  X’q – Quadrature axis saturated and unsaturated transient reactances, pu

X''d – Direct axis saturated and unsaturated subtransient reactances, pu
X"q – Quadrature axis saturated and unsaturated Subtransient reactances, pu
Xl – Stator leakage reactance, pu
X2 – Negative–sequence reactance, pu
Zg – Grounding impedance, ohm T'do – Direct axis transient open circuit time constant, seconds
T''do – Direct axis sub transient open circuit time constant, seconds
S(1.0) – Saturation factor at rated terminal voltage, A/A
S(1.2) – Saturation factor at 1.2 per unit of rated terminal voltage, A/A
Vt – Voltage threshold for tripping, pu
Vr – Voltage at which reconnection is permitted, pu
Tv – Pickup time for voltage-based tripping, seconds
Tvr – Time delay for reconnection, seconds
Ft – Frequency threshold for tripping, Hz
Tf – Pickup time for frequency-based tripping, seconds
Reactive power required at no load, kVAr
Reactive power required at full load, kVAr

- External Shunt compensation
  Bus Voltage
  Number and rating of each shunt capacitor section
  Voltage/PF controller scheme description and time delays

d. DC Sources
If the generator project includes dc sources such as fuel cells or photovoltaic devices, the number of dc sources and maximum dc power production per source, kW, is required.

C.3 Load Facility Information Requirements

If a new load facility or point of delivery is requested, the following information will generally be required.

a. Type of load, such as industrial, commercial, residential or combination

b. Load data

- Delivery voltage, kV
- Projected peak load, kW

- Summer peak load, kW
- Winter peak load, kW
- Anticipated power factor patterns (summer, winter, peak, etc.)

C.4 Transformer Data

If one or more power transformers are included as part of the proposed connection, the following data is required for each unique transformer. The District may require specific primary and secondary winding connections.

a. Transformer number or identifier
b. Number of similar transformers
c. Transformer type and number of windings
d. Transformer winding data. For a two winding transformer, only winding H and X data is required.
    - Transformer MVA ratings
        Winding H to X, MVA
        Winding H to Y, MVA
        Winding X to Y, MVA
    - Transformer impedances, positive and zero sequence
        Winding H to X %X and R at MVA
        Winding H to Y %X and R at MVA
        Winding X to Y %X and R at MVA
    - Transformer tap changer information
        No load and/or load
        Tap changer winding location, H, X, or Y
        Available taps
    - Transformer cooling requirements if required from the District
        Load, amps
        Voltage, single or three phase, Volts

C.5 Transmission or Distribution Line Data

If a new transmission or distribution line is to be included as part of the proposed connection, the following transmission and distribution line data is required.

a. Nominal operating voltage, kV
b. Line length , miles
c. Line capacity, amps at $27^{o}C$
d. Overhead/underground construction

e. Positive and zero sequence line characteristics in primary values
f. Shunt susceptance, B μ S (or $\mu\Omega^{-1}$)

Appendix B

Interconnection Requirements for
Customer-Owned Generating Facility
Connected to District High Voltage System

This document is intended to state the minimum requirements for the safe and reliable operation of the Customer-owned generating facility that will be connected and operated in parallel with the Snohomish County PUD (District hereafter) high voltage system. The document is also intended to be used in conjunction with District Generating Facility Planning Requirements for general interconnection requirements. Customer-owned generating facilities qualified for Net-Metering (100 kVA or less), please refer to Interconnection Requirements for Small Power Producers and Cogeneration. Any questions regarding technical requirements stated in this document should be directed to System Planning and Protection Group.

All interconnection costs shall be borne by the Customer. These costs include all the costs of study, engineering, inspection, connection, switching, metering, transmission, distribution, safety provisions, equipment to be owned by the District, and administrative costs incurred by the District directly related to the installation and maintenance of the physical facilities necessary to permit the Customer-owned generating facility operation.

The Customer shall purchase all equipment required to connect the Customer-owned generating facility to the existing District high-voltage system and all required equipment shall meet the District equipment specifications.

1. **Compliance** - Installation shall be in compliance with the National Electrical Code (NEC), National Electrical Safety Code (NESC), North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), Washington State Safety Standards as applicable, District Electrical Service Requirements as applicable, District Generating Facility Planning Requirements as applicable, and District Construction Standards as applicable.

   The District reserves the right to require the Customer to provide corrections or additions to existing protective devices in the event of modification of government or industry regulations and standards at the Customer's expense.

2. **Scope** - The technical requirements contained herein generally apply to all new or expanded generating facilities, regardless of type or size. The location of the generating facility, interconnection, and impacts on the District system or another utility's system determine the specific requirements. The Customer-owned generating facility and its interconnecting facilities must not degrade the safe operation, integrity, and reliability of the District system. The requirements in this document are intended to protect the District facilities and customers, but cannot be relied upon to protect the Customer-owned generating facilities.

3. **Placement of Customer-owned Generating Facility –** To maintain the existing District high-voltage/distribution system's reliability, all Customer-owned generating facilities shall meet the following conditions:

- A Customer-owned generating facility shall not be allowed within 150 feet (horizontal clearance) from any existing overhead electrical distribution (12.47kV and 55kV) facilities and 250 feet (horizontal clearance) from any existing high-voltage (115kV and higher) electrical facilities.
- Exhaust fumes shall not be directed to any existing overhead electrical facilities.
- Only one Customer-owned generating facility per distribution substation shall be allowed.

4. **System Study** - Customers shall contact the District as early in the planning process as possible for any potential generation project within or adjacent to the District system and/or where the output will enter the District Control Area. The Customer shall not make its own assumptions about the final location, voltage, or interconnection requirements. Certain areas within the District system can accept only limited amount of generation without costly system upgrades. The District may have to add or modify its high voltage system substantially before connecting a Customer-owned generating facility. An interconnection study must be made to determine the required interconnection facilities and also modifications to accommodate the Customer-owned generating facility. This study may also address the high voltage system capability, transient stability, voltage stability, losses, voltage regulation, harmonics, voltage flicker, electromagnetic transients, machine dynamics, Ferro-resonance, metering requirements, protective relaying, substation grounding, and fault duties. The Customer shall provide the District with sufficient information for adequate system study. The sufficient information may include, but not limited to, the following:

a) Electrical one-line diagrams, type of generation (natural gas, hydro, wind, geothermal, etc.), proposed nameplate ratings, site location maps, site plan, high-voltage system routing, and a description of the proposed connection to the District system.

b) All available generator and transformer data. Note that the machine portion of these data generally means synchronous machine data. Other types of generators (such as induction generators or DC generators with inverters) are handled on a case-by-case basis.

c) Validated models and data for power flow and dynamic (stability) simulation. This validated data can be specified as a requirement of commissioning tests. Generator electrical data shall be at the sub-transient level. The data requirements include:

- **1)** Generator reactive power limits (generator PQ capability curve) addressing effects of all control, protection, and operating/equipment limits that can restrict reactive power output,
- **2)** Exciter, including power system stabilizer and other limiters, and high side voltage controls,
- **3)** Prime mover, governor, over frequency protection, and under frequency protection,
- **4)** Generator sub transient, transient, and steady-state reactance and time constant data, and
- **5)** Generator step-up transformer impedance data.

d) A description of anticipated operating profile of the Customer-owned generating facility, including the peak monthly megawatt (MW) output of the Customer-owned generating facility, expected period of operation, and maintenance periods. Tariff and Reference Number of their official request for wheeling services from the District.

5. **Special Generator Disturbance Study –** The District uses high-speed reclosing and also time-delayed reclosing at switching stations. These devices and operating modes, as well as other disturbances and imbalances, may cause stress on the Customer-owned generating facilities. This includes the possibility of electro-mechanical resonance (e.g., sub-synchronous resonance) between the generator and the power system. The Customer is responsible for any studies necessary to evaluate possible stresses to his/her generating facilities and for all corrective actions.

6. **Fault Duty Increase and Equipment Ratings –** The high voltage circuit 3-phase fault duty may increase considerably due to the Customer-owned generating facility and the single-line-to-ground fault duty may also increase. All existing high-voltage/distribution system apparatus (such as breakers, reclosers, fuses, current transformers, etc.) near the proposed generating facility shall be upgraded to handle these fault duty increases as required at the Customer's expense.

7. **Loading Increase and Equipment Ratings –** The high voltage equipment loading may increase considerably due to the Customer-owned generating facility. All existing high voltage system apparatus (such as breakers, disconnect switches, current transformers, conductors, switching station busses, autotransformers, etc.) shall be upgraded to handle these loading increases as required at the Customer's expense.

8. **Power System Stabilizer Requirements (PSS) –** WECC Policy Statement on Power System Stabilizers, dated April 18, 2002, states, "PSS should be installed on all new generators, regardless of ownership or unit size, having suitable excitation systems as defined above."

9. **Governor Setting Requirements –** WECC requires all generation over 10 MVA to have working governors set at 5% droop.

10. **Switching Station Requirements –** All Customer-owned generating facility connections to the District's high voltage system requires a new switching station in accordance with the District's specifications. The acceptable bus configurations of the new switching station shall be a ring, main-and-transfer, and breaker-and-a-half. The District does not allow a three-terminal line configuration due to complexity of 3-terminal line protection and switching operation and also due to undesirable impact to system stability.

11. **Control and Protection -** The District coordinates its protective relays and control schemes to provide for personnel safety and equipment protection and to minimize disruption of services during disturbances. Generating facility interconnection usually requires the addition or modification of protective relays and/or control schemes. New generating facilities shall be compatible with the existing protective relay schemes. Sometimes the addition of voltage transformers (VTs), current transformers (CTs), or pilot relaying scheme(s) are also necessary, depending on the interconnection point.

12. **Generator Step-up Transformer Connection –** The District requires a delta/wye-grounded transformer with wye-grounded on the high side and delta on the low side. This type of connection will allow the District to continue using the conventional high voltage line protective devices and surge arresters without any major modifications to protective schemes and also to minimize hazardous Ferro-resonance/neutral-shift conditions.

13. **Islanding –** Islanding describes a condition where the power system splits into isolated load and generation groups, usually when breakers operate for fault clearing or system stability remedial action. Generally, the 'islanded groups' do not have a stable load to generation resource balance. However, it is possible that, under unique situations, generator controls can establish a new equilibrium in an islanded group.

Some utilities isolate their distribution system and use local generation to feed loads during power system outages. The District does not allow islanding conditions to exist that include its facilities. When District customer loads are being served over another utility's high-voltage/distribution system, where generation is also interconnected, the implications of islanding must be addressed to minimize adverse impacts on these loads.

When certain high voltage system relays are applied to detect faults and remove the generator infeed, they also prevent extended islanding. Two additional relays are applied to detect an island condition after it occurs; these are necessary to protect District customer loads from damage: over/under voltage (type 59/27), and over/under frequency (type 81). These relays are intended to trip the generator for the large voltage and frequency deviations that would tend to occur during a 'local' islanding condition. However, they are also set so the generator does not trip for the less severe deviations that could occur during most major disturbances on the interconnected power system.

14. **Neutral Shifts –** When the Customer-owned generating facility is connected to the low-voltage side of a delta-grounded wye transformer, the remote end breaker operations initiated by the detection of ground faults on the high-voltage side can cause overvoltages that can affect personnel safety and damage equipment. This type of overvoltage is commonly described as a neutral shift and can increase the voltage on the unfaulted phase to as high as 1.73 per unit. At this high voltage, the equipment insulation withstand duration can be very short. Therefore, one of the following remedies shall be implemented:

- Provide an effective ground ($X_0/X_1 < 3$ & $R_0/X_1 < 1$) on the high-side of the transformer that is independent of other high voltage system connections.
- Size the high-voltage side equipment to withstand the amplitude and duration of the neutral shift.
- Rapidly separate the generator from the step-up transformer by tripping a breaker using either the remote relay detection with pilot scheme (transfer trip) or local relay detection of overvoltage condition.

15. **Direct Transfer Trip Relaying –** This pilot relaying scheme is required to minimize problems such as poor power quality, slow protective device response due to low fault currents, accidental out-of-synchronization, damages to the Customer-owned generator(s), District-owned line apparatus, etc. At the District switching station the District will install two multi-functions transmission relay (SEL-421, SEL-321, SEL-311, equivalent or the appropriate upgraded relay) with mirrored bit feature. Since these relays are three phase, multi-function relays, one of the two will be the primary and the other is a back up (for redundancy). The customer-owned generation facility shall also have the same arrangements at the utility tie breaker. A protection logic processor

(SEL-2100, equivalent or the appropriate upgraded device) will needed to be installed either at the District Substation and/or at the utility tie breaker, depending on possible configuration changes or contingencies.

In addition, the District requires either Line Differential or Permissive Over-reaching Transfer Trip relaying scheme along with the Direct Transfer Trip relaying. No additional device is normally required to add one of these proposed schemes.

16. **Under/Over Frequency and Voltage Relays –** To prevent any hazardous operating conditions, the Customer-owned generating facility shall be isolated from the District high voltage system for over/under-voltage conditions in accordance with the setting recommendation. In addition, the Customer-owned generating facility shall be isolated from the District high voltage system for any unacceptable over-frequency and under-frequency conditions within a reasonable period of time also shown later. The Customer's frequency relay settings shall be reviewed and approved by the District prior to start-up of the Customer-owned generating facility. In addition, the District shall verify the Customer's relay settings by adequate functional testing.

The over/under voltage relay setting/delays listed below are intended to insure that generators trip when the connections to the power system have been interrupted, preventing extended 'local islanding.' The 0.8-second minimum undervoltage delay is intended to coordinate with local fault-clearing times to avoid unnecessary generator tripping.

These requirements also insure that generators do not disconnect for dynamic (transient) oscillations on the power system that are stable and damped. The oscillatory frequency of the system during a disturbance ranges between 0.25 and 1.5 Hertz. Also, each occurrence of over/under voltage on the system lasts for a short time period (less than one second) and is nearly damped within 20 seconds following the disturbance. During severe system voltage disturbances it is critical that generators do not trip prior to the completion of all automatic under voltage load shedding. The settings below coordinate with Pacific Northwest under voltage load shedding, where loads are interrupted at voltages ranging from 0.90 to 0.92 per unit with time delays of 3.5, 5.0 or 8.0 seconds.

Overvoltage (type 59)

Voltage	Action
1.10 PU	5.0-second minimum delay before unit tripping

1.20 PU	2.0-second minimum delay before unit tripping
1.25 PU	0.8-second minimum delay before unit tripping
1.30 PU and above	no intentional delay before unit tripping

<u>Undervoltage</u> (type 27)

Voltage	Action
0.90 PU	10-second minimum delay before unit tripping
0.80 PU	2.0-second minimum delay before unit tripping
0.75 PU and below	0.8 -second minimum delay before unit tripping

The following frequency ranges and minimum setting/delay requirements for over/under frequency relays (type 81) have been established by the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Program. The objective of these settings is to use the machine capability to support the power system and prevent unnecessary loss of system load during disturbances, and ultimately, to help prevent system collapse. Generating resources must not trip off before load is shed by underfrequency relays. Underfrequency tripping will be set by the Northwest Power Pool Enhanced Underfrequency Load Shedding Program and/or WECC.

Voltage and frequency relays must have a dropout time no greater than 2 cycles. Frequency relays shall be solid state or microprocessor technology; electro-mechanical relays used for this function are considered unacceptable.

17. **Telecommunication Requirements –** Telecommunications facilities shall be tailored to fulfill the control, protection, operation, dispatching, scheduling, and revenue metering requirements. At a minimum, telecommunications facilities shall be compatible with, and have similar reliability and performance characteristics to, that currently used for operation of the District power system to which the generation is being interconnected. Depending on the performance and reliability requirements of the control and metering systems to be supported, telecommunications facilities may consist of the following:

- Fiber Optic Systems – The District's preferred telecommunications facilities wherever feasible.
- Microwave Systems
- Wireline facilities

18. **Dedicated Communications Link for Pilot Relaying –** The District prefers a fiber optic communications link, but other types of communications links may be acceptable pending approval by the District. Whichever communications link is used, the signal transmission delay caused by a communications link and all associated communications equipment shall not exceed 15 milliseconds. A leased telephone line may be acceptable as long as the required high-speed (less than 15-millisecond signal transmission delay) is ensured. In general, an analog communications link is too slow to meet our transfer trip relaying requirements. However, an analog communications link may be acceptable if a high-speed analog modem is used (this would need prior approval).

19. **Dedicated Communications Link for SCADA –** To ensure safety of working personnel and prompt response to system abnormalities, the District shall be allowed to know the status of certain breakers (e.g., utility tie breaker, interconnection breaker, and generator breaker(s)) and the real & reactive power flow at the generator breakers and at the District primary meter. A RTU shall be installed at the generating facility and it shall be able to open and close the interconnection breaker remotely.

A dedicated communications link for SCADA shall be required. In general, a District-owned local Remote Terminal Unit (RTU) shall be installed at the Customer-owned generating facility to perform certain control and monitoring functions as specified elsewhere in this document.

20. **General Telemetering Requirements** – The District System Operations Center requires telemetry data for the integration of new generation resources. This typically consists of the continuous telemetering of kW quantities and hourly transmission of the previous hour's kWh from the Customer-owned generating facility to the District System Operations Center. The net Customer-owned generating facility output, which is the Customer-owned generating facility generation less the station service load and step-up losses, is normally telemetered.

A dedicated communications link is required for General Telemetry, but this link may be shared with the Revenue Metering System and Voice Communications. Table 1 summarizes telemetry requirements and the following includes specific requirements based on Customer-owned generating facility size:

a) Telemetry is required when the output of the Customer-owned generating facility entering the District Load Control Area is 3.0 MVA or greater: For this case, the telemetry of real power and energy (kW and kWh), and reactive power (kVAr and kVArh) is normally required.

b) For Customer-owned generating facilities below 3.0 MVA, the District determines telemetry needs on a case-by-case basis. Note that should an existing plant expand to over 3.0 MVA, telemetry is required for the entire plant output.

21. **Dedicated Communications Link for Automatic Generation Control (AGC) if Required** - The district is not a Load Control Area provider and does not provide any AGC services. The customer is required to obtain AGC services from Load Control Area provider (BPA). The customer is required to install the equipment required for the Load Control Area provider to provide the service.

22.

Table 1. General Metering and Telemetering Requirements

District Data Requirements[1]			
System or Quantity	**System Operations Center**	**High Voltage Scheduling**	**Revenue Billing**
KW	Yes	No	No[2]
KWh	Yes	Yes	Yes
KVAr	Yes	No	No
KVArh	Yes	No	Yes
KV	Yes	No	No
Number of Units	Number on Line Number Available	Number on Line Number Available	No
Resource Size	≥ 3.0 MVA[1]	≥ 1 MVA	≥ 1 kW
Data Sample Rate	1 Second or other approved rate compatible with	Last Hour kWh sent each hour	Hourly kWh Data Retrieved

	NERC Policy		daily
Generation Reserves	Contingency non-spinning MW Contingency Spinning MW Regulating MW	Contingency non-spinning MW Contingency Spinning MW Regulating MW	No

Notes:

1. Requirements for Customer-owned generating facilities below 3.0 MVA are determined on an individual basis.
2. A kW reading for revenue billing may be required where special transmission arrangements are necessary.

23. **Dedicated Voice Communications Link –** For coordination of system protection, control, and communications maintenance activities between the District and the Customer-owned generating facility, a dedicated voice communications link shall be required, in addition to communications links specified elsewhere in this document. A dedicated communications link is required for telemetry, but this link may be shared with the Revenue Metering System and General Telemetry.

24. **Primary Metering (Revenue Metering System) –** The District shall own, furnish, and install the standard bi-directional primary metering in a padmount (or overhead) enclosure to measure the energy delivered by the District to the Customer and the energy received by the District from the Customer. A dedicated communications link is required for this Revenue Metering System, but this link may be shared with the Voice Communications and General Telemetry.

25. **Visible Disconnect Switch Requirements** - At the interconnection point to the District system, an isolating device(s) shall be placed in an appropriate location, by agreement of the District and affected parties. The motor-operated, visible disconnect switch(es) at the interconnection point(s) shall be equipped with a lockable mechanism for clearance tagging to provide the visible air gap and also to isolate the Customer-owned generating facility from the District high voltage system. This requirement may be waived on a case-by-case basis (with a mutually agreed-upon alternative developed). In any case the device:

- Must simultaneously open all phases (gang-operated) to the Customer-owned generating facility.
- Must be accessible by the District and ultimately under the District System Operations Center jurisdiction.
- Must be lockable in the open position by the District.
- Would not be operated without advanced notice to either party, unless an emergency condition requires that the device be opened to isolate the Customer-owned generating facility.
- Must be suitable for safe operation under the conditions of use.

The District personnel may lock the device in the open position and install safety grounds:

- If it is necessary for the protection of maintenance personnel when working on de-energized circuits.
- If the Customer-owned generating facility or the District equipment presents a hazardous condition.
- If the Customer-owned generating facility or the District equipment interferes with the operation of the District system.
- If the District system interferes with the operation of the Customer-owned generating facility.

Since the device is primarily provided for safety and cannot normally interrupt load current, consideration shall be given as to the capacity, procedures to open, and the location of the device.

26. **Utility Tie Breaker(s) Owned by the Customer –** The Customer-owned utility tie breaker shall reliably detect all faults on the District high voltage system and trip without any intentional delay. The nominal breaker tripping time of 3 cycles shall be required to be used as a utility tie breaker. The automatic isolation shall be done prior to the District switching station breaker reclosing and within a reasonable period of time, typically less than 2 seconds in the absence of direct transfer trip relaying. In addition to all required relays as mentioned elsewhere in this document, the utility tie breaker should have an automatic/manual synchronizing capability and also be able to handle a recovery voltage of 2 times rated voltage.

27. **Mechanical (or Electrical) Interlocking System –** To ensure safety of working personnel, the District requires a mechanical (or electrical) interlocking system between the utility tie breaker and the visible disconnect switch.

28. **Disturbance Monitoring -** Unique and unanticipated protection problems can result from the changed system configuration due to interconnection with the Customer-owned generating facility. District may, at its discretion, install or require monitoring equipment to identify possible protection scheme problems and to provide power quality measurements of the new configuration. If the monitoring or relay performance indicates inadequate protection of the District system, the owner of the Customer-owned generating facility will be notified of additional protection requirements. The disturbance monitor provides information similar to that of an oscillograph or fault recorder. The availability of current and voltage measurements determines the number of channels for the device. Monitoring equipment is also installed to aid in the understanding of the electrical phenomena such as overvoltages and Ferro-resonance that can be associated with these Customer-owned generating facilities. Remote access to monitored quantities is often accomplished using the Revenue Metering System (RMS) communication equipment.

29. **Starting as Induction Motor (if applicable) –** In general, induction generators start as motors and also synchronous generators may be designed to start as motors. The Customer-owned generator(s) starting as a motor(s) shall meet the motor starting requirements in the District Electrical Service Requirements. The District may require the Customer to provide, at his/her expense, special or additional starting equipment.

30. **Voltage Fluctuation –** Turning the generator on and off may cause undesirable voltage fluctuation. A maximum of 3.5% voltage fluctuation is allowed, but the voltage dip caused by the Customer-owned generating facility shall not exceed the Borderline of Visibility as shown in IEEE Standard 241 and also IEEE Standard 141.

31. **Phase Unbalance –** Unbalanced phase voltages and currents can affect protective relay coordination and cause high neutral currents and thermal overloading of transformers. To protect the District's and Customer-owned equipment, the Customer-owned generating facility's contribution at the interconnection point shall not cause a voltage imbalance greater than 1% nor a current imbalance greater than 5%. Phase unbalance is the percent deviation of one phase from the average of all three phases.

32. **Power Quality and Reliability –** The interconnection of the Customer-owned generating facility with the District high voltage system shall not cause any reduction in the quality and reliability of service provided to other District customers. This includes, but not limited to, the following: There shall be no objectionable generation of abnormal voltages or voltage fluctuations and the harmonic content of the Customer-owned

generating facility output must be below that level which would cause undue interference with other customer loads, other utilities, or District equipment.

To minimize all interference, the District requires that the Customer-owned generating facility shall meet the power quality requirements specified in the IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems, IEEE Std 519-1992. In addition, the Customer-owned generating facility shall meet all requirements elsewhere in this document and the District Electrical Service Requirements.

33. **Synchronization –** The Customer-owned generating facility shall be automatically or manually synchronized with the District high voltage system at all times and the Customer shall be responsible for the automatic/manual synchronization. All automatic or manual synchronization shall be supervised by a synchronizing check relay. If a synchronizing check relay is used to supervise synchronization, then its output contacts shall be rated to interrupt the circuit breaker closing circuit current and the interrupting device shall be capable of trip-free operation. As mentioned above, synchronization shall be done at the utility tie breaker(s) and also at the generator breaker(s). Interrupting devices with long closing time shall not be used for synchronization unless otherwise determined adequate.

34. **Operating Limits –** In general, the Customer-owned generating facility shall not take reactive power from the District distribution system. Prior to start-up of the Customer-owned generating facility, the generator operating limits shall be reviewed and approved by the District. The Customer-owned generating facility will be expected to supply up to maximum available reactive capability and/or to adjust generation levels including reducing to zero if requested by the District System Operations Center. This will always be for reliability purposes.

35. **No Automatic Reclosing –** The District 115-kV power circuit breaker control schemes are normally designed to have at least one automatic reclosing in order to minimize unnecessarily prolonged outages. To minimize potentially hazardous operating conditions or equipment damages due to non-synchronized operation caused by automatic reclosing, no automatic reclosing shall be allowed to the utility tie breaker(s) and generator breaker(s).

36. **Automatic Disconnection and Time-Delayed Automatic Reconnection –** The Customer-owned generating facility shall be designed to automatically disconnect and lockout when the District high voltage system service is interrupted for any reason.

Automatic reconnection to the District high voltage system shall be done on Hot-Bus/Hot-Line/Sync-Check at least 5 minutes after the automatic disconnection.

37. **Generating Facility Grounding –** There are additional safety concerns that should be addressed when considering circuit grounding of the Customer-owned generating facility interconnected to the utility electric system. To ensure proper grounding of the Customer-owned generating facility, the Customer shall follow all applicable, established grounding rules of the National Electrical Code, National Electrical Safety Code, Washington State Safety Standards, IEEE Guide for Safety in AC Substation Grounding, etc.

Each generation site and/or interconnecting switching station shall have a ground grid that solidly grounds all metallic structures and other non-energized metallic equipment. This grid shall limit the ground potential gradients to such voltage and current levels that will not endanger the safety of people or damage equipment which are in, or immediately adjacent to, the station under normal and fault conditions. The size, type, and ground grid requirements are in part based on local soil conditions and available electrical fault current magnitudes. In areas where ground grid voltage rises are not within acceptable and safe limits (due for example to high soil resistivity or limited substation space), grounding rods and wells can be used to reduce the ground grid resistance to acceptable levels.

If the generation site is close to another switching station or distribution substation, the two ground grids may be isolated or connected. If the ground grids are to be isolated, there may be no metallic ground connections between the two substation ground grids. Cable shields, cable sheaths, station service ground sheaths, and overhead high-voltage system shield wires can all inadvertently connect ground grids. Fiber-optic cables are excellent choices for telecommunications and control between two substations to maintain isolated ground grids. If the ground grids are to be interconnected, the interconnecting cables must have sufficient capacity to handle fault currents and control ground grid voltage rises. The District shall approve any connection to a District switching station (or distribution substation) ground grid.

The integration of generation may substantially increase fault current levels at nearby substations. Modifications to the ground grids of existing stations may be necessary to keep grid voltage rises within safe levels. The system study will determine if modifications are required and the estimated cost.

38. **Generating Facility Protection –** The Customer shall be fully responsible for the protection of his/her generators and all of their associated equipment. Protection shall be provided for the Customer-owned equipment failures, faults, and other disturbances on the District system. If a three-phase, multi-functional, microprocessor-based generator protection relay is used; the Customer is required to install one additional relay (backup relay) of the same kind to ensure adequate protection. The Customer shall provide equipment specifications, protection arrangement, and design drawings to the District for review and written approval prior to installation.

39. **Blackstart Capability** - Blackstart is the condition when one unit of a generation project starts up under local power, in isolation from the power system. Blackstart capability is needed in some rare circumstances, depending on the size and location of the Customer-owned generating facility. It is generally not needed for small generators at the Customer-owned generating facilities that are near other major generation. This capability is addressed in the planning and review process, and indicated on the specific Interconnection Requirements.

Things to consider for blackstart capability include the following:

- Proximity to major generation facilities (i.e., Can startup power be provided more efficiently from an existing plant?);
- Location on the high voltage system (i.e., is the Customer-owned generating facility near major load centers and far from generation?);
- Cost of on-site start-up, and
- Periodic testing to ensure personnel training and capability.

40. **Start-Up –** Prior to initial energization of the Customer-owned generating facility, inspection and/or tests shall be jointly performed by both the Customer and designated District personnel to verify the proper operation of the generator(s) and associated equipment to the District’s satisfaction.

41. **District Inspection and Customer Maintenance Records –** The Customer shall maintain his/her generating facility in good working order. The Customer-owned generating facility (generator and associated equipment) may be subject to District inspection upon reasonable notice by the District. The Customer shall assume full responsibility for the routine maintenance of the generating facility and associated protective devices and the keeping of records for such maintenance. These records shall be available to the District for inspection at all times.

42. **Surge Protection –** The Customer shall be fully responsible for the protection of his/her generating facility from transient surges initiated by lightning, switching, or other system disturbances.

Power system equipment is designed to withstand voltage stresses associated with expected operation. Interconnecting new generation resources can change equipment duty, and may require that equipment be replaced or switchgear, communications, shielding, grounding and/or surge protection added to control voltage stress to acceptable levels. The system study includes the evaluation of the impact of the Customer-owned generating facility on equipment insulation coordination. The District may identify additions required to maintain an acceptable level of the District system availability, reliability, equipment insulation margins, and safety.

Voltage stresses, such as lightning or switching surges, and temporary overvoltages may affect equipment duty. Remedies depend on the equipment capability and the type and magnitude of the stress. Below are summarized possible additions that may be required to meet the intent of District's reliability criteria and Standards. In general, stations with equipment operated at 15-kV and above, as well as all transformers and reactors, shall be protected against lightning and switching surges. Typically this includes station shielding against direct lightning strokes, surge arresters on all wound devices, and shielding with rod gaps (or arresters) on the incoming lines.

43. **Lightning Surges**

Those high voltage lines at voltages of 115-kV and higher that terminate at District switching stations must meet additional shielding and/or surge protection requirements. Incoming lines must be shielded for **½ mile at 115-kV** and **1 mile at 230kV**. Rod gaps must also be installed at the station entrance. For certain switching stations at 115-kV and below, the District may require only an arrester at the station entrance in lieu of line shielding, or a reduced shielded zone adjacent to the station. These variations depend on the line length, the presence of a power circuit breaker on the high voltage side of the transformer, and the size of the transformer.

44. **Switching Surges**

At voltages below 230-kV, modifications to protect the District system against Customer-owned generating facility-generated switching surges are not anticipated. However, the system study identifies the actual needs.

45. **Temporary Overvoltages**

Temporary overvoltages can last from seconds to minutes, and are not characterized as surges. These overvoltages are present during islanding or faults.

46. **Future Modification or Expansion –** Any future modification or expansion of the Customer-owned generating facility shall require an engineering review and approval by the District.

47. **System Emergency –** The District reserves the right to discontinue or interrupt the Customer-owned generation to correct any system emergency condition, outage, required system maintenance, or equipment failure.

48. **Design Standards –** In addition to all requirements as shown above, the Customer-owned generating facility shall meet the requirements specified in the latest IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems, ANSI/IEEE Std 1001, and also the latest Standard for Interconnecting Distributed Resources with Electric Power Systems, IEEE P1547.

Appendix C

Interconnection Requirements for
Customer-Owned Generating Facility
Connected to District Distribution System

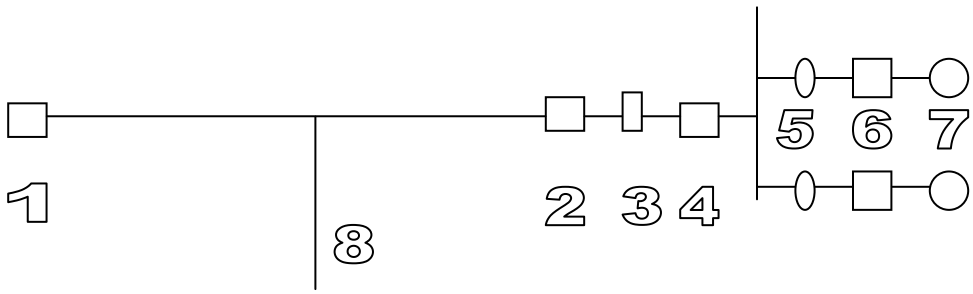
This document is intended to state the minimum requirements for the safe and reliable operation of the Customer-owned generating facility that will be connected and operated in parallel with the Snohomish County PUD (District) distribution system. This document is also intended to be used in conjunction with <u>District Generating Facility Planning Requirements</u> for general interconnection requirements. Customer-owned generating facilities qualified for Net Metering (100 kVA or less), please refer to Interconnection Requirements for Small Power Producers and Cogeneration. Any questions regarding technical requirements stated in this document should be directed to System Planning and Protection Group.

All interconnection costs shall be borne by the Customer. These costs include all the costs of study, engineering, inspection, connection, switching, metering, transmission, distribution, safety provisions, equipment to be owned by the District, and administrative costs incurred by the District directly related to the installation and maintenance of the physical facilities necessary to permit the Customer-owned generating facility operation.

Customer-owned generation facilities can be connected using the following schemes. It must be emphasized that these are typical installations only and final installation may vary significantly. The exact protective devices, system improvements, and system connections will be established during the interconnection studies.

The Customer shall purchase all equipment required to connect the Customer-owned generating facility to the existing District distribution substation or feeder and all required equipment shall meet the District equipment specifications.

0 – 3.0MVA Connection



1: feeder breaker

2: interconnection breaker owned by District

3: primary meter

4: utility tie breaker owned by the Customer

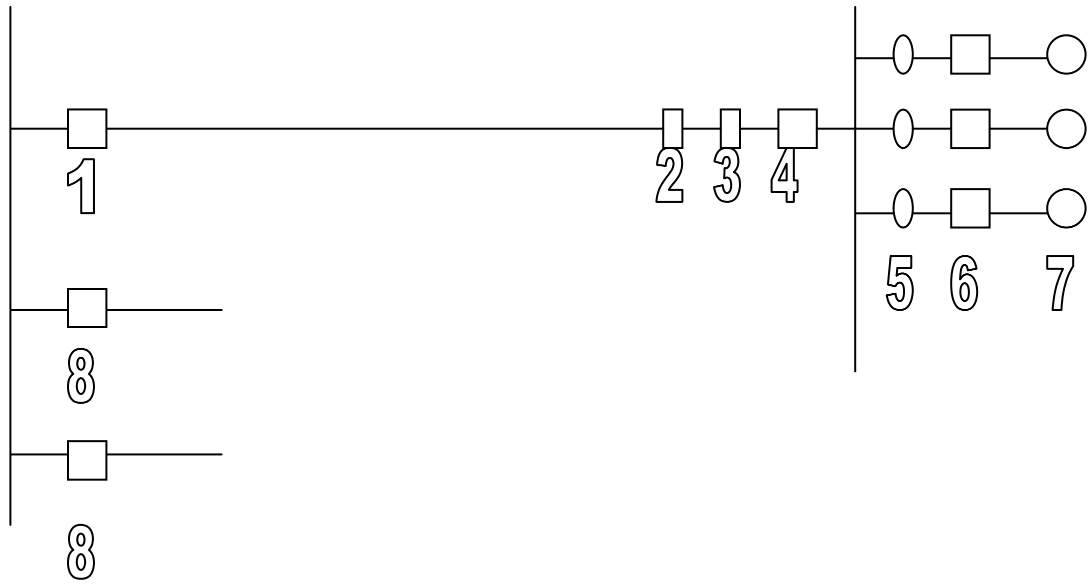
5: step-up transformers

6: generator breakers

7: generators

8: District customer load

3.0 – 10MVA Connection



1: breaker dedicated to the Customer's generating facility (no distribution load connected)

2: primary meter

3: visible disconnect switch owned by District

4: utility tie breaker owned by the Customer

5: step-up transformers

6: generator breakers

7: generators

8: District feeder breakers

1) **Compliance –** Installation shall be in compliance with the National Electrical Code, National Electrical Safety Code, North American Electric Reliability Council, Western Electricity

Coordinating Council, Washington State Safety Standards as applicable, District Electrical Service Requirements as applicable, District Generating Facility Planning Requirements as applicable, and District Construction Standards as applicable.

The District reserves the right to require the Customer to provide at the Customer's expense corrections or additions to existing protective devices in the event of modification of government or industry regulations and standards

2) **Scope** - The technical requirements contained herein generally apply to all new or expanded generating facilities, regardless of type or size. The location of the generating facility, interconnection, and impacts on the District system or another utility's system determine the specific requirements. The Customer-owned generating facility and its interconnecting facilities must not degrade the safe operation, integrity, and reliability of the District system. The requirements in this document are intended to protect the District facilities and customers, but cannot be relied upon to protect the Customer-owned generating facilities.
3) **Placement of Customer-owned Generating Facility –** To maintain the existing District high-voltage/distribution system's reliability, all Customer-owned generating facilities shall meet the following conditions:

   - A Customer-owned generating facility shall not be allowed within 150 feet (horizontal clearance) from any existing overhead electrical distribution (12.47kV and 55kV) facilities and 250 feet (horizontal clearance) from any existing high-voltage (115kV and higher) electrical facilities.
   - Exhaust fumes shall not be directed to any existing overhead electrical facilities.
   - Only one Customer-owned generating facility per distribution substation shall be allowed.

4) **System Impact Study** - Customers shall contact the District as early in the planning process as possible for any potential generation project within or adjacent to the District system and/or where the output will enter the District Electric System. The Customer shall not make its own assumptions about the final location, voltage, or interconnection requirements. Certain areas within the District system can accept only limited amount of generation without costly system upgrades. The District may have to add or modify its distribution system substantially before connecting a Customer-owned generating facility. An interconnection study must be made to determine the required interconnection facilities and also modifications to accommodate the Customer-owned generating facility.

   Part of the interconnection study will address distribution issues, it may be necessary to remove capacitor banks, relocate capacitor banks, reconductor a circuit(s), install current limiting fuses (normally a current limiting fuse in series with each overhead transformer fuse), and/or to change certain fuse sizes.

5) **Transient Stability Study –** Required as needed.

6) **Fault Duty Increase and Equipment Ratings –** The distribution circuit 3-phase fault duty may increase due to the Customer-owned generating facility and the single-line-to-ground fault duty may also increase. All existing distribution line apparatus (such as breakers, reclosers, sectionalizes, fuses, switches, etc.) shall be upgraded to handle these fault duty increases as required at the customer's expense.

7) **Loading Increase and Equipment Ratings –** The distribution system equipment loading may increase considerably due to the Customer-owned generating facility. All existing distribution system apparatus (such as breakers, power fuses, current transformers, conductors, power transformers, switches, regulators, etc.) shall be upgraded to handle these loading increases as required at the Customer's expense.

8) **Power System Stabilizer Requirements (PSS) –** <u>WECC Policy Statement on Power System Stabilizers</u>, dated April 18, 2002, states, "PSS should be installed on all new generators, regardless of ownership or unit size, having suitable excitation systems as defined above."

9) **Governor Setting Requirements –** WECC requires all generation over 10 MVA to have working governors set at 5% droop.

10) **Impact to Protective Device Coordination –** The District uses a fuse saving scheme for distribution feeder protection. The fault duty increase as mentioned above will make the fuse saving scheme less reliable because a fuse may see more fault current than before (without the Customer-owned generating facility) and/or than the substation feeder breaker. This is a real concern, but there is no simple fix for this problem. System protection & control engineers shall review the existing distribution feeder coordination carefully and make necessary changes as required at the Customer's expense.

11) **Generator Step-up Transformer Connection –** The District requires a delta/wye-grounded transformer with wye-grounded on the high side and delta on the low side. This type of connection will allow the District to continue using the existing overcurrent-sensing protective devices and surge arresters without any major modifications to protective schemes and also minimize hazardous Ferro-resonance/neutral-shift conditions. Because of the wye-grounded connection on the high side, all step-up transformers are grounding transformers. Other types of transformer connections may be allowed on a case-by-case basis.

12) **Generator Self-Excitation and Ferro-resonance (Islanding) –** In general, generators proposed by Customers are capable of continuously operating in an isochronous mode. If an isolated generator is connected to a distribution system having capacitance equal to or greater than its magnetizing reactance requirements, then the generator terminal voltage can be as high as 1.5 to 2.0 per unit. In general, all induction generators are susceptible to this type of

Ferro-resonance, but new research results revealed that synchronous generators are also susceptible. The Customer shall be fully responsible for protecting his/her own facility and District's facilities under this type of islanding condition. To minimize this type of ferro-resonance problem, the District requires an under/over voltage relay and also an under/over frequency relay at the utility tie breaker, in addition to a high-speed utility tie breaker and a direct transfer trip relaying scheme as specified elsewhere in this document.

Under islanding conditions, the District existing overcurrent-sensing protective devices may not reliably detect faults because the Customer-owned generator(s) cannot generate sufficient amount of fault currents to faults on the District distribution system. This is another reason why the District requires a high-speed, direct transfer trip relaying scheme.

13) **Neutral Shifts –** When the Customer-owned generating facility is connected to the low-voltage side of a delta-grounded wye transformer, the remote end breaker operations initiated by the detection of ground faults on the high-voltage side can cause overvoltages that can affect personnel safety and damage equipment. This type of overvoltage is commonly described as a neutral shift and can increase the voltage on the unfaulted phase to as high as 1.73 per unit. This is one main reason why the District requires the generator step-up transformers with wye-grounded connection on the high-voltage side.

14) **Direct Transfer Trip Relaying –** This pilot relaying scheme is required to minimize problems such as poor power quality, slow protective device response due to low fault currents, accidental out-of-synchronization, ferro-resonance due to generator self-excitation, damages to Customer-owned generator(s), District-owned line apparatus, etc. At the District substation the District will install two multi-function distribution relays (SEL-351, equivalent or the appropriate upgraded relay) with the mirrored bit feature. Since SEL-351 is a three-phase, multi-function relay, one of the two will be the primary and the other is a back up (for redundancy). The Customer-owned generating facility shall also have the same arrangements at the utility tie breaker. A protection logic processor (SEL-2100, equivalent or appropriate upgraded device) will need to be installed either at the District substation or at the utility tie breaker, depending on possible configuration changes or contingencies.

In addition, the District requires either Line Differential or Permissive Over-reaching Transfer Trip relaying scheme along with the Direct Transfer Trip relaying. No additional device is normally required to add one of these proposed schemes.

15) **Feeders Capable of Load Transfer to Another Feeder or Feeders** (applicable to 0 - 3.0MVA connection only) **–** In general, the District's individual feeder is capable of transferring its loads to more than one feeder. If a section of Feeder A with the Customer-owned generating facility is transferred to Feeder B temporarily, then the circuit breaker of Feeder B must also have all required interconnection relaying to accommodate the transferred Customer-owned generating facility. Therefore, all feeders capable of taking the

Customer-owned generating facility temporarily shall have all required interconnection relaying.

16) **Under/Over Frequency and Voltage Relays –** To prevent any hazardous operating conditions, the Customer-owned generating facility shall be isolated from the District distribution system for any under-voltage (lower than 80% of nominal voltage) and over-voltage conditions (higher than 110% of nominal voltage) within 2 seconds in the absence of direct transfer trip relaying and other pilot relaying. For extremely high voltages, the over-voltage relay shall operate fast enough (without any intentional delay) to prevent equipment damages. In addition, the Customer-owned generating facility shall be isolated from the District distribution system for any unacceptable over-frequency and under-frequency conditions within a reasonable period of time. The Customer's frequency relay settings shall be reviewed and approved by the District prior to start-up of the Customer-owned generating facility. In addition, the District shall verify the Customer's relay settings by adequate functional testing.

17) **Telecommunication Requirements –** Telecommunications facilities shall be tailored to fulfill the control, protection, operation, dispatching, scheduling, and revenue metering requirements. At a minimum, telecommunications facilities shall be compatible with, and have similar reliability and performance characteristics to that currently used for operation of the District power system to which the generation is being interconnected. Depending on the performance and reliability requirements of the control and metering systems to be supported, telecommunications facilities may consist of the following:

- Fiber Optic Systems – The District's preferred telecommunications facilities wherever feasible.
- Microwave Systems
- Wireline facilities

18) **Dedicated Communications Link for Pilot Relaying –** The District prefers a fiber optic communications link, but other types of communications links may be acceptable pending approval by the District. Whichever communications link is used, the signal transmission delay caused by a communications link and all associated communications equipment shall not exceed 15 milliseconds. A leased telephone line may be acceptable as long as the required high-speed (less than 15-millisecond signal transmission delay) is ensured. In general, an analog communications link is too slow to meet our transfer trip relaying requirements. However, an analog communications link may be acceptable if a high-speed analog modem is used.

19) **Dedicated Communications Link for SCADA –** To ensure safety of working personnel and prompt response to system abnormalities, the District shall be allowed to know the status of certain breakers (e.g., utility tie breaker, interconnection breaker, and generator breaker(s))

and the real & reactive power flow at the generator breakers and at the District primary meter. A RTU shall be installed at the generating facility and it shall be able to open and close the interconnection breaker remotely.

A dedicated communications link for SCADA shall be required. In general, a District-owned local Remote Terminal Unit (RTU) shall be installed at the Customer-owned generating facility to perform certain control and monitoring functions as specified.

20) **General Telemetering Requirements** – The District System Operations Center requires telemetry data for the integration of new generation resources. This typically consists of the continuous telemetering of kW and kVAr quantities and hourly transmission of the previous hour's kWh and kVArh from the Customer-owned generating facility to the District System Operations Center. The net Customer-owned generating facility output, which is the Customer-owned generating facility generation less the station service load and step-up losses, is normally telemetered.

A dedicated communications link is required for General Telemetry, but this link may be shared with the Revenue Metering System and Voice Communications. Table 1 summarizes telemetry requirements and the following includes specific requirements based on Customer-owned generating facility size:

b) Telemetry is required when the output of the Customer-owned generating facility entering the District Electric System is 3.0 MVA or greater: For this case, the telemetry of real power and energy (kW and kWh), and reactive power (kVAr and kVArh) is normally required.

c) For Customer-owned generating facilities below 3.0 MVA, the District determines telemetry needs on a case-by-case basis. Note that should an existing plant expand to over 3.0 MVA, telemetry is required for the entire plant output.

Table 1. General Metering and Telemetering Requirements

District Data Requirements[1]			
System or Quantity	**System Operations Center**	**High Voltage Scheduling**	**Revenue Billing**
kW	Yes	No	No[2]
kWh	Yes	Yes	Yes
kVAr	Yes	No	No
kVArh	Yes	No	Yes
kV	Yes	No	No
Number of Units	Number on Line Number Available	Number on Line Number Available	No
Resource Size	≥ 3.0 MVA[1]	≥ 1 MVA	≥ 1 kW
Data Sample Rate	1 Second or other approved rate compatible with NERC Policy	Last Hour kWh sent each hour	Hourly kWh Data Retrieved daily
Generation Reserves	Contingency non-spinning MW Contingency Spinning MW Regulating MW	Contingency non-spinning MW Contingency Spinning MW Regulating MW	No

Notes:

1. Requirements for Customer-owned generating facilities below 3.0 MVA are determined on an individual basis.

2. A kW reading for revenue billing may be required where special transmission arrangements are necessary.

21) **Automatic Generation Control (AGC).** The District is not a Load Control Area provider and does not provide any AGC services. The customer is required to obtain AGC services from Load Control Area provider (BPA). The customer is required to install the equipment required for the Load Control Area provider to provide the service.

22) **Dedicated Voice Communications Link –** For coordination of system protection, control, and communications maintenance activities between the District and the Customer-owned generating facility, a dedicated voice communications link shall be required. A dedicated communications link is required for telemetry, but this link may be shared with the Revenue Metering System and General Telemetry.

23) **Primary Metering (Revenue Metering System) –** The District shall own, furnish, and install the standard bi-directional primary metering in a padmount (or overhead) enclosure to measure the energy delivered by the District to the Customer and the energy received by the District from the Customer. A dedicated communications link is required for this Revenue Metering System, but this link may be shared with the Voice Communications and General.

24) **Interconnection Breaker Owned by the District (applicable to 0 – 3.0MVA connection only) –** The District requires an interconnection breaker to separate the generating facility from the District distribution system under certain operating conditions. The District will install (or require) a circuit breaker or electronically-controlled pole-mounted (or padmounted) recloser with SCADA control, a set of disconnect switches (or an appropriate switching device such as a padmounted switchgear) on the line side of the recloser, and another set of disconnect switches on the generator side. The disconnect switches shall be equipped with a lockable mechanism for clearance tagging to provide the visible air gap and also to isolate the Customer-owned generating facility from the District distribution system. The electronically-controlled recloser requires two 120-Vac sources (one from the line side and one from the generator side) requiring installation of two small single-phase transformers (installed on the outside of disconnect switch – recloser – disconnect switch section). The recloser shall not have any synchronizing capability because it is too slow for the synchronizing function.

25) **Visible Disconnect Switch (applicable to 3.0 – 10MVA connection only) –** The visible disconnect shall be equipped with a lockable mechanism for clearance tagging to provide the visible air gap and also to isolate the Customer-owned generating facility from the District distribution system.

26) **Utility Tie Breaker(s) Owned by the Customer –** The District interconnection breaker (or recloser) can detect faults reliably on the generator side, but cannot reliably detect faults on the District distribution system because of the insufficient fault contribution from the Customer-owned generating facility. Therefore, the Customer-owned utility tie breaker shall reliably detect all faults on the District distribution system and trip without any intentional delay. The automatic isolation shall be done prior to the District feeder breaker (or line recloser) reclosing and within a reasonable period of time, typically less than 2 seconds in the absence of direct transfer trip relaying and other pilot relaying. In addition to all required relays as specified elsewhere in this document, the utility tie breaker should have an automatic/manual synchronizing capability and also be able to handle a recovery voltage of 2 times rated voltage.

27) **Mechanical (or Electrical) Interlocking System –** To ensure safety of working personnel, the District requires a mechanical (or electrical) interlocking system between the utility tie breaker and the interconnection breaker (or the dedicated feeder breaker for 3.0 – 10MVA connection).

28) **Starting as Induction Motor (if applicable) –** In general, induction generators start as motors and also synchronous generators may be designed to start as motors. The Customer-owned generator(s) starting as a motor(s) shall meet the motor starting requirements in the District Electrical Service Requirements and System Protection. The District may require the Customer to provide, at his/her expense, special or additional starting equipment.

29) **Voltage Fluctuation –** Turning the generator on and off may cause undesirable voltage fluctuation. A maximum of 3.5% voltage fluctuation is allowed, but the voltage dip caused by the Customer-owned generating facility shall not exceed the Borderline of Visibility as shown in IEEE Standard 241 and also IEEE Standard 141.

30) **Line Voltage Regulator Bank (applicable to 0 – 3.0MVA connection only) –** To minimize any undesirable voltage fluctuation, a future voltage regulator bank (if planned by the District) should be placed carefully so that it may not lock itself up under certain operating conditions.

31) **Power Quality and Reliability –** The interconnection of the Customer-owned generating facility with the District distribution system shall not cause any reduction in the quality and reliability of service provided to other District customers. This includes, but is not limited to,

the following: There shall be no objectionable generation of abnormal voltages or voltage fluctuations and the harmonic content of the Customer-owned generating facility output must be below that level which would cause undue interference with other customer loads, other utilities, or District equipment.

To minimize all interference, the District requires that the Customer-owned generating facility shall meet the power quality requirements specified in the IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems, IEEE Std 519. In addition, the Customer-owned generating facility shall meet all requirements elsewhere in this document and the District Electrical Service Requirements.

32) **Synchronization –** The Customer-owned generating facility shall be automatically or manually synchronized with the District distribution system at all times and the Customer shall be responsible for the automatic/manual synchronization. Automatic or manual synchronization shall be supervised by a synchronizing check relay. If a synchronizing check relay is used to supervise synchronization, then its output contacts shall be rated to interrupt the circuit breaker closing circuit current and the interrupting device shall be capable of trip-free operation. As mentioned above, synchronization shall be done at the utility tie breaker and also at the generator breaker(s). Interrupting devices with longer than 5-cycle closing time (such as reclosers) shall not be used for synchronization.

33) **Operating Limits –** In general, the Customer-owned generating facility shall not take reactive power from the District distribution system. Prior to start-up of the Customer-owned generating facility, the generator operating limits shall be reviewed and approved by the District

34) **No Automatic Reclosing –** The District feeder breaker control and also 115-kV power circuit breaker control schemes are normally designed to have at least one automatic reclosing in order to minimize unnecessarily prolonged outages. To minimize potentially hazardous operating conditions or equipment damages due to non-synchronized operation caused by automatic reclosing, no automatic reclosing shall be allowed to the utility tie breaker, the interconnection breaker, and customer-owned generator breaker(s).

35) **Automatic Disconnection and Time-Delayed Automatic Reconnection –** The Customer-owned generating facility shall be designed to automatically disconnect and lockout when the District service is interrupted for any reason. Automatic reconnection to the District distribution system shall be done on Hot-Bus/Hot-Line/Sync-Check at least 5 minutes after the automatic disconnection.

36) **Generating Facility Grounding –** There are additional safety concerns that should be addressed when considering circuit grounding of the Customer-owned generating facility interconnected to the utility electric system. To ensure proper grounding of the Customer-owned generating facility, the Customer shall follow all applicable, established grounding rules of the National Electrical Code, National Electrical Safety Code, Washington State Safety Standards, etc.

37) **Generating Facility Protection –** The Customer shall be fully responsible for the protection of his/her generators and all of their associated equipment. Protection shall be provided for the Customer-owned equipment failures, faults, and other disturbances on the District system. If a three-phase, multi-functional, microprocessor-based generator protection relay is used; the Customer is required to install one additional relay (backup relay) of the same kind to ensure adequate protection. The Customer shall provide equipment specifications, protection arrangement, and design drawings to the District for review and written approval prior to installation.

38) **Start-Up –** Prior to initial energization of the Customer-owned generating facility, inspection and/or tests shall be jointly performed by both the Customer and the designated District personnel to verify the proper operation of the generator(s) and associated equipment to the District's satisfaction.

39) **District Inspection and Customer Maintenance Records –** The Customer shall maintain his/her generating facility in good working order. The Customer-owned generating facility (generator and associated equipment) may be subject to District inspection upon reasonable notice by the District. The Customer shall assume full responsibility for the routine maintenance of the generating facility and associated protective devices and the keeping of records for such maintenance. These records shall be available to the District for inspection at all times.

40) **Surge Protection –** The Customer shall be fully responsible for the protection of his/her generating facility from transient surges initiated by lightning, switching, or other system disturbances.

41) **Future Modification or Expansion –** Any future modification or expansion of the Customer-owned generating facility shall require an engineering review and approval by the District.

42) **System Emergency –** The District reserves the right to discontinue or interrupt the Customer-owned generation to correct any system emergency condition, outage, required system maintenance, or equipment failure.

43) **Design Standards –** In addition to all requirements as shown above, the Customer-owned generating facility shall meet the requirements specified in the latest IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems, ANSI/IEEE Std 1001, and also the latest Standard for Interconnecting Distributed Resources with Electric Power Systems, IEEE P1547.