



FACILITY CONNECTION REQUIREMENTS
FOR
GENERATION RESOURCES

PORTLAND GENERAL ELECTRIC
PORTLAND, OREGON
FEBRUARY 2000
[UPDATED MAY 2008]

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

CONTENTS

<u>SECTION</u>	<u>PAGE</u>
1. Introduction	1
2. Scope	2
3. Interconnection Studies and Sponsor-Supplied Information	3
A. Initial Request to PGE for Interconnection	3
B. Coordination with Affected Utilities	3
C. System Impact and Detailed Facilities Study	3
D. Study Results	4
E. Notification of Additions/Modification to other parties	4
4. General Requirements	5
A. Safety	5
B. Point of Interconnection Considerations	5
C. Substation Grounding	7
D. Insulation Coordination	8
E. Inspection, Test, Calibration, and Maintenance	9
F. Station Service and Start-Up Power	10
G. Blackstarting	11
5. Performance Requirements	12
A. Electrical Disturbances	12
B. Switchgear	12
C. Generators, Step-Up and Auxiliary Transformers	13
D. Excitation Equipment including Power System Stabilizers, and Voltage Controls	13
E. Governor Speed and Frequency Control	15
F. Abnormal Voltage and Frequency Operation	15
G. Generation Reserves	15
H. Power Quality	15
6. Protection Requirements	17
A. Introduction	17
B. Protection Criteria	17
C. Relay Coordination	24
D. Protective Relays	25
7. System Operation and Generation Scheduling Data Requirements	27
A. Introduction	27
B. System Operation Requirements	27
C. Generation Scheduling Requirements	29
D. Revenue or Interchange Metering	29
E. Calibration of Revenue and Interchange Metering Facilities	30
8. Telecommunication Requirements	31
A. Introduction	31
B. Voice Communications	31
C. Data Communications	32
D. Telecommunications for Control and Protection	32
9. Definitions	33
10. References	37

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

1. Introduction

Portland General Electric has prepared this document to identify technical requirements for integrating generation resources into the PGE transmission system (PGE System). These technical requirements apply to new (including expanded, restarted and significantly modified) generating resources located within or adjacent to the PGE System. The purpose of this document is to specify the minimum requirements necessary to assure the safe operation, integrity and reliability of the PGE System.

Proposals for integrating generating resource projects (Projects) are generally submitted by the Project Sponsor or interconnecting utility. PGE then evaluates these proposals on a case-by-case basis, pursuant to its prevailing tariff. Specific interconnection requirements are provided to the Project Sponsor or interconnecting utility accordingly.

Contractual matters, such as costs, ownership, scheduling, and billing are not the focus of this document. However, in general, the Project Sponsor or interconnecting utility assumes the cost of all facilities needed to satisfy the technical requirements identified for integration of the Project.

To design an interconnection properly, the electric systems must be studied and analyzed critically, without regard to ownership. If an interconnection could affect the PGE System, PGE studies the situation, using data from the appropriate sources. The Project Sponsor or interconnecting utility usually assumes the cost of detailed interconnection studies. The studies will consider issues such as short-circuit duties, transient voltages, reactive power requirements, stability requirements, harmonics, safety, operations, maintenance and Prudent Electric Utility Practices. Before finalizing these studies, PGE will coordinate and review its study results with any affected systems. Upon completion of the studies, and after execution of an interconnection agreement, PGE will provide appropriate notification of new or modified facilities to WECC and others.

This document is not intended as a design specification or an instruction manual. Technical requirements stated herein are generally consistent with the Western Electric Coordinating Council (WECC), North American Electric Reliability Council (NERC) and Northwest Power Pool (NWPP) principles and practices. This document is also intended to be consistent with the Federal Energy Regulatory Commission (FERC) regulations governing separation of transmission and generation functions. The information presented is subject to change.

PGE wishes to thank the many organizations which provided input and to acknowledge The Bonneville Power Administration for certain selected material used in this document.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

2. Scope

The technical requirements contained herein generally apply to all new or expanded generating resources, regardless of type or size. The location of the resource, interconnection, and impacts on the PGE System or another utility's system determine the specific requirements. The Project and its interconnecting facilities must not degrade the safe operation, integrity and reliability of the PGE System or the systems of others. The requirements in this document are intended to protect PGE facilities, but cannot be relied upon to protect the Project's facilities.

- **Applicable Codes, Standards, Criteria and Regulations**

To the extent that the Codes, Standards, Criteria and Regulations are applicable, the Project shall be in compliance with those listed in Section 10 of this document.

- **Safety, Protection, and Reliability**

PGE, in cooperation with affected parties, makes the final determination as to whether the PGE System is properly protected from Project related problems before an interconnection is closed. The Project Sponsor and/or interconnecting utility is responsible for correcting such problems before interconnected operation begins. However, PGE may determine equivalent measures to maintain the safe operation and reliability of the PGE System. In situations where there is direct interconnection with another utility's system, the requirements of that utility also apply.

- **Non-PGE Responsibilities**

The Project Sponsor is responsible for the planning, design, construction, reliability, protection, and safe operation of non-PGE-owned facilities (e.g. generator, interconnected equipment, etc.). The design is subject to applicable local, state and federal statutes.

- **Special Generator Disturbance Studies**

PGE uses series capacitors, high-speed reclosing and single-pole switching at various locations. These devices and operating modes, as well as other disturbances and imbalances, may cause stress on the Project. This includes the possibility of electro-mechanical resonance (e.g., sub-synchronous resonance) between the generator and the power system. The Project Sponsor is responsible for any studies necessary to evaluate possible stresses to the Project and for all corrective actions.

- **Estimates for Interconnection Studies**

PGE develops cost estimates on a case-by-case basis when asked to perform interconnection studies. PGE may provide estimates for the required interconnection facilities that are identified by the interconnection studies and shown on the approved Project Requirements Diagram.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

3. Interconnection Studies and Sponsor-Supplied Information

Project sponsors should contact PGE as early in the planning process as possible for any potential generation project within or adjacent to the PGE System and/or where the output will enter the PGE Control Area. The Project Sponsor should not make its own assumptions about the final location, voltage, or interconnection requirements. Certain areas within the PGE System can accept only limited amounts of generation without costly reinforcements. PGE may have to add or modify its system substantially before connecting a Project. An interconnection study must be made to determine the interconnection facilities required, as well as any system modifications necessary to accommodate the Project. This study may also address the transient stability, voltage stability, losses, voltage regulation, harmonics, voltage flicker, electromagnetic transients, machine dynamics, ferroresonance, metering requirements, protective relaying, substation grounding, and fault duties.

3-A. Initial Request to PGE for Interconnection

The Project Sponsor should provide PGE with sufficient information for adequate review of its Project proposal. The Sponsor should submit an Interconnection Request form (See PGE's OATT—the SGIP or LGIP, for applicable forms and instructions) as early as possible with all available information. PGE then performs a series of interconnection studies, basing its analysis on the information provided and previous experience with similar facilities.

3-B. Coordination with affected utilities

As part of its study process, PGE will determine if any surrounding systems are affected (affected systems). Pursuant to its prevailing tariff, PGE will coordinate the conduct of the System Impact Study with any affected system that is affected by the Interconnection request, and, if possible, include those results (if available) in its applicable interconnection study and/or report. PGE will make a reasonable effort to include such affected system operators in all meetings held with the Requestor. The Requestor is expected to cooperate with PGE in all matters related to the conduct of studies and the determination of modifications to affected systems.

3-C. System Impact and Detailed Facilities Study

If a System Impact and Detailed Facilities Study is required, PGE will notify the Requester and forward a study agreement to cover the cost of the study. The Requester will then be expected to complete the form. This form provides PGE with specific information required for system impact studies.

The System Impact and Detailed Facilities Study can require considerable time and effort, depending on the type of connection and its potential system impacts. Because of this, PGE and the Requester must enter into an agreement prior to performing the study. At the conclusion of the studies, PGE will issue a report which outlines the study results and may also include study assumptions, alternatives considered and jointly coordinated recommendations, if any.

A detailed interconnection study request should include the following:

1. A Technical Description of the Project, Including:

- a) Electrical one-line diagrams, type of generation (natural gas, hydro, wind, geothermal, etc.), proposed nameplate ratings, site location maps, site plan, transmission routing, and a description of the proposed connection to the PGE System or the interconnecting utility.
- b) All available generator and transformer data. Note that the machine portion of this Form requests synchronous machine data. Other types of generators (such as induction generators or DC generators with inverters) are handled on a case-by-case basis.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

- c) Validated models and data for power flow and dynamic (stability) simulation in PTI or GE format. 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, voltage regulator including stabilizer and limiters, and high side voltage controls,
 - 3) Prime mover, governor, overfrequency protection, and underfrequency protection,
 - 4) Generator subtransient, transient, and steady-state reactance and time constant data, and
 - 5) Generator step-up transformer impedance data.
2. **A Description of Anticipated Operating Profile of the Project**, including the peak monthly megawatt (MW) output of the Project, expected period of operation, and maintenance periods.
3. **Tariff and Reference Number** of their official request for wheeling services from PGE.

3-D. Study Results

The System Impact and Detailed Facilities Study results may include the following:

- The alternate locations where the Project facility(s) may be interconnected to the PGE System,
- Any modifications and/or additions needed to the PGE System to accommodate the Project,
- The major interconnection equipment that the Project Sponsor is required to furnish,
- The requirements for voltage regulation, harmonics, and power factor control,
- Revenue metering and telemetry/Automatic Generating Control (AGC) requirements,
- Protective relaying and control requirements,
- Telecommunication requirements,
- Operational control of facilities,
- Approximate schedule and lead times for PGE to perform its design, material procurement, construction and energization,
- An estimate of costs for additions and modifications to the PGE System, and
- A preliminary Project Requirements Diagram.

3-E. Notification of Additions/Modification to other parties

After execution of the interconnection agreement, PGE will report the addition and/or modification of facilities to the Western Electric Coordinating Council (WECC) as part of its Annual Progress Report and Significant Additions filing for non-WECC members. Requestors who are WECC members will submit additions not considered part of the PGE system. Furthermore, those additions and/or modifications will be reported to the regional security coordinator once they are placed in service.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

4. General Requirements

4-A. Safety

At the Point of Interconnection to the PGE System, an isolating device, which is typically a disconnect switch, shall be provided that physically and visibly isolates the PGE System from the Project. Safety and operating procedures for the isolating device shall be in compliance with the PGE and Project Sponsor's safety manuals. The Project Operator shall visibly mark all switchgear that could leave equipment energized, so that all maintenance crews are aware of the potential hazards. The isolating device may be placed in a location other than the Point of Interconnection, by agreement of PGE and affected parties. In any case the device:

- Must simultaneously open all phases (gang-operated) to the Project.
- Must be accessible by PGE and under ultimate PGE Dispatcher jurisdiction.
- Must be lockable in the open position by PGE.
- Would not be operated without advanced notice to either party, unless an emergency condition requires that the device be opened to isolate the Project.
- Must be suitable for safe operation under the conditions of use.

PGE 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 deenergized circuits.
- If the Project or PGE equipment presents a hazardous condition.
- If the Project interferes with the operation of the PGE System.

If the isolating device is located in a PGE substation or switchyard, any persons accessing the device for inspection, operation or maintenance must be fully trained and qualified as defined in the applicable OSHA regulations. These persons must also receive training by PGE on PGE's operating and safety practices. This training will be at the Requester's expense. All clearances will be under the jurisdiction of the PGE dispatcher. All operations and clearances will follow the procedures in the PGE Electrical System Switching and Tagging Handbook.

If the isolating switch is located at a substation or switchyard owned by the Requester, an operating one-line must be provided to PGE. Revisions to this one line shall be issued to PGE when changes are made to the station.

4-B. Point of Interconnection Considerations

1. General Configurations and Constraints

Integration of generation projects into power systems usually falls into one of three categories:

- a) Interconnection into a 57-kV to 230-kV bulk power substation, with (depending on the bus configuration) the transmission and generator feeder lines each terminated into bays containing one or more breakers.
- b) Interconnection on the low-voltage side (typically 13-kV) of an existing customer service transformer that was originally designed to serve loads and that taps an existing transmission line.
- c) Interconnection at 57-kV to 230-kV by directly tapping a transmission line.

The categories above include the situation where another utility owns the transmission line or equipment that directly connects to the PGE System.

Interconnections b) and c) above create the condition of a multi-terminal line, where the generator becomes an additional current source beyond the existing sources at the line terminals. A line with three or more terminals

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

affects PGE's ability to protect, operate, dispatch, and maintain the transmission line. The increased complexity of the control and protection schemes affect system stability and reliability. PGE determines the feasibility of multi-terminal line interconnections on a case-by-case basis as discussed below.

2. Special Configurations and Constraints

The constraints and considerations described below may substantially affect the costs of a particular integration plan, sometimes making an alternate Point of Interconnection more desirable.

a) Interconnection to Main Grid Transmission Lines

Main Grid transmission lines include all 500-kV, and some 230-kV lines, as defined by PGE's Reliability Criteria. These circuits form the backbone of the Pacific NW transmission system and provide the primary means of serving large geographical areas. As noted above, the use of three-terminal lines on the Main Grid often adversely affects system stability and reliability, as well as critical operation and maintenance of these lines. The use of three terminal lines will be evaluated individually based on the above considerations provided the following criteria is met:

- The line protection meets PGE Protection Requirements (Section 6),
- Except by specific waiver, generation requirements shall not restrain PGE from taking a transmission line out of service for prudent purposes and generator outages shall not force the line out of service, and
- The line and all components are maintainable within current guidelines, including the contractual right to maintain.

Otherwise, a substation, with additional breakers at the Point of Interconnection, may have to be developed. The cost of this step may make interconnection to non-Main Grid lines more appropriate for smaller projects. A Main Grid line configuration with more than three terminals is not allowed.

3. Other Considerations

a) Equipment

Existing electrical equipment, such as transformers, power circuit breakers, disconnect switches, arresters, and line conductors were purchased based on the duties expected in response to system additions identified in long-range plans. However, with the interconnection of a new generating resource, some equipment may become underrated and need to be replaced.

b) System Stability and Reliability

The PGE System has been developed with careful consideration for system stability and reliability during disturbances. The size of the Project, breaker configurations, generator characteristics, and the ability to set protective relays will affect where and how the Point of Interconnection is made. The Project may also be required to participate in special protection schemes (remedial action) such as generator dropping.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

c) Control and Protection

PGE coordinates its protective relays and control schemes to provide for personnel safety and equipment protection and to minimize disruption of services during disturbances. Project interconnection usually requires the addition or modification of protective relays and/or control schemes. New Projects must be compatible with existing protective relay schemes. Sometimes the addition of voltage transformers (VTs), current transformers (CTs), or pilot scheme (transfer trip) also are necessary, based on the Point of Interconnection. PGE uses single-pole protective relaying on most 500 kV lines and pilot tripping on most 230 kV lines. Conventional directional zone protection is usually used on 57 to 230 kV lines. Distribution type protection is generally used for circuits below 57 kV. At the time of the connection request, PGE will supply the Requester with an approved list of protective relay systems suitable for the interconnection. Should the Requester select a relay system not on our approved list, PGE reserves the right to perform a full set of acceptance tests, at the Requester's expense, prior to granting permission to use the selected protection scheme.

d) Dispatching and Maintenance

PGE operates and maintains its system to provide reliable customer service while meeting the seasonal and daily peak loads even during equipment outages and disturbances. Project integration requires that the equipment at the Point of Interconnection not restrict timely outage coordination, automatic switching or equipment maintenance scheduling. Preserving reliable service to all PGE customers is essential and may require additional switchgear, equipment redundancy, or bypass capabilities at the Point of Interconnection for acceptable operation of the system.

The generator power factor requirements at the point of interconnection to the PGE system shall be between 90% over-excited (lagging) and 95% under-excited (leading). Induction machines or inverters shall be equipped with adequate reactive power capability to support the above acceptable power factor range.

The generator will be expected to supply up to maximum available reactive capability and/or to adjust real power generation levels including reducing to zero if requested by the PGE dispatcher. This will always be for reliability purposes.

e) Atmospheric and Seismic

The effects resulting from wind storms, floods, lightning, elevation, temperature extremes, and earthquakes must be considered in the design and operation of the Project. The Project Sponsor is responsible for determining that the appropriate standards, codes, criteria, recommended practices, guides and prudent utility practices are met.

4-C. Substation Grounding

Each Generation Site and/or Interconnecting Substation must 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 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 transmission shield wires can all inadvertently connect ground grids. Fiber-optic cables are an excellent choice for telecommunications and control between two substations to maintain isolated ground grids. If the ground grids are to be interconnected, the interconnecting cables

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

must have sufficient capacity to handle fault currents and control ground grid voltage rises. PGE must approve any connection to a PGE substation ground grid.

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

The project ground grid should be designed to ANSI/IEEE Std. 80-1986, *IEEE Guide for Safety in AC Substation Grounding*, and should be measured in accordance with IEEE - 81 Part 1: *Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Potentials* and Part 2: *Measurement of Impedance and Safety Characteristics of Large, Extended or Interconnected Grounding Systems*. Project grounding requirements shall also comply with the *National Electrical Safety Code*, ANSI/IEEE - 665 *Guide for Generating Station Grounding*, IEEE - 837 *Standard for Qualifying Permanent Connections Used in Substation Grounding*, IEEE - 487 *Protection of Wire-Line Communication Serving Electric Power Stations*, ANSI/IEEE 367-1987 *IEEE Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault*, and any applicable state and local codes.

4-D. Insulation Coordination

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. Interconnection studies include the evaluation of the impact of the Project on equipment insulation coordination. PGE may identify additions required to maintain an acceptable level of PGE 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 PGE'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.

1. Lightning Surges

If the Project proposes to tap a shielded transmission line, the tap line to the substation must also be shielded. For an unshielded transmission line, the tap line does not typically require shielding beyond that needed for substation entrance. However, special circumstances such as the length of the tap line may affect shielding requirements.

Those transmission lines at voltages of 57-kV and higher that terminate at PGE substations must meet additional shielding and/or surge protection requirements. Incoming lines must be shielded for ½ mile at 57-115-kV and 1 mile at 230-500-kV. Rod gaps must also be installed at the station entrance, except at 500-kV, when arresters are required. For certain customer service substations at 230-kV and below, PGE 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 tap line length, the presence of a power circuit breaker on the transmission side of the transformer, and the size of the transformer.

2. Switching Surges

At voltages below 500-kV, modifications to protect the PGE System against Project-generated switching surges are not anticipated. However, the interconnection study identifies the actual needs. At 500-kV, PGE requires that arresters be added at the line terminations of the Project and PGE substations.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

3. Temporary Overvoltages

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

a) Islanding

A *local* island condition can expose equipment to higher-than-normal voltages. As described in Section 6-B3d, PGE does not normally allow its facilities to become part of a *local* island for an extended duration. Special relays to detect this condition and isolate the generator from PGE facilities are described in Section 6-B.

b) Neutral Shifts

When generation is connected to the low-voltage side of a delta-grounded wye (D-YG) customer service transformer, remote end breaker operations initiated by the detection of 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 phases to as high as 1.73 per unit. At this voltage, the equipment insulation withstand-duration can be very short. Several alternative remedies are possible:

- Provide an effective ground (as described below) on the high-voltage side of the transformer that is independent of other transmission 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 remote relay detection with pilot scheme (transfer trip) or local relay detection of overvoltage condition (see Section 6-B3).

Effectively grounded is defined as an $X_0/X_1 \leq 3$ & $R_0/X_1 \leq 1$. Methods available to obtain an effective ground on the high-voltage side of the transformer include the following:

- A step-up transformer with the high voltage (PGE's) side connected in a grounded-wye configuration and low voltage (Project) side in closed delta.
- A three-winding transformer with a closed-delta tertiary winding and the high voltage side connected in grounded wye.
- Installation of a properly sized grounding transformer on the high voltage (PGE) side.

Any of these result in an effectively grounded system with little risk of damage to lightning arresters and other connected equipment.

4-E. Inspection, Test, Calibration and Maintenance

The Project Sponsor has full responsibility for the inspection, testing, calibration and maintenance of its equipment, up to the Point of Interconnection, consistent with the interconnection agreement.

1. Pre-energization Inspection and Testing

Before initial energization, the Project Sponsor shall develop an Inspection and Test Plan for pre-energization and energization testing. PGE may require additional tests; the costs of these tests are subject to negotiation. The Sponsor shall make available to PGE all drawings, specifications, and test records of the Project equipment pertinent to interconnected operation.

2. Calibration and Maintenance

a) Revenue Metering

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

Revenue metering shall be calibrated at least every two years. More frequent calibration intervals may be negotiated. All interested parties or their representatives may witness the calibration tests. Calibration records shall be made available to all interested parties.

b) All other electrical equipment

The Project Sponsor shall provide a plan for and carry out a preventive maintenance program for the electrical equipment. The program may be based on time or on other factors, including performance levels or reliability. Prudent electric utility preventive maintenance practices shall be followed. Maintenance records of the Project equipment pertinent to interconnected operation shall be made available to PGE. The Project Sponsor shall prepare a written description of, and update as necessary, its maintenance and inspection plan.

The maintenance and inspection plan shall:

- Include the schedule interval (i.e., every two years) for any time-based maintenance activities and a description of conditions that will initiate any performance-based activities;
- Describe the maintenance methods for each substantial type of component and shall provide any checklists or forms that may be required for the activity;
- Provide criteria to be used to assess the condition of a transmission facility or component;
- Specify, for each type of equipment, the condition or performance assessment criteria and the appropriate response to each condition.

3. Periodic Testing

Following energization, the Project Sponsor shall perform periodic testing and model validation of generating units' dynamic control and protection systems as required by WECC (or its successor). The tests shall be sufficient to validate dynamic model parameters for the generator, turbine, exciter, power system stabilizer, governor, and over/under excitation limiters/trip settings. Reactive limits should also be periodically reviewed and field tested, as required by NERC Planning Standards (or its successor), to ensure that reported VAR limits are attainable. All test/model data shall be submitted to PGE upon request.

4-F. Station Service and Startup Power

Power provided for local use at a generating plant or substation to operate lighting, heat and auxiliary equipment is termed *station service*. In addition, power generated by a generator and then consumed by equipment that contributes to the generation process is considered station service. (This is usually the difference between gross generator output and net generator output, possibly adjusted for interconnection losses.) Alternate station service is a backup source of power, used only in emergency situations or during maintenance when primary station service is not available.

Station service power is the responsibility of the Project Sponsor. The station service requirements of the Project, including voltage and reactive requirements, shall not impose operating restrictions on the PGE transmission system beyond those specified in applicable NERC, WECC, and Northwest Power Pool reliability criteria.

Appropriate providers of station service and alternate station service are determined during the project planning process, including Project Requirements Diagram development and review. Generally, the local utility will be the preference provider of primary station service unless 1) it is unable to serve the load, or 2) costs to connect the local utility are prohibitive.

The Project Sponsor must provide metering for station service and alternate station service, as specified by the metering section of this document.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

4-G. Blackstarting

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 Project. It is generally not needed for small generators or for projects that are near other major generation. This capability is addressed in the planning and review process, and indicated on the Project Requirements Diagram.

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 transmission system (i.e., Is the Project near major load centers and far from generation?);
- Cost of on-site start-up, and
- Periodic testing to ensure personnel training and capability.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

5. Performance Requirements

The following performance requirements can be satisfied by various methods. It is the responsibility of the Project Sponsor to propose a preferred method for PGE concurrence.

5-A. Electrical Disturbances

The Project shall be designed, constructed, operated and maintained in conformance with this document, applicable laws/regulations, and standards to minimize the impact of the following:

- Electric disturbances that produce abnormal power flows,
- Overvoltages during ground faults,
- Audible noise, radio, television and telephone interference, and
- Other disturbances that might degrade the reliability of the interconnected PGE System.

5-B. Switchgear

1. All Voltage Levels

Circuit breakers, disconnect switches, and all other current carrying equipment connected to PGE's transmission facilities shall be capable of carrying normal and emergency load currents without damage. This equipment shall not become a limiting factor (bottleneck) in the ability to transfer power on the PGE System.

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. The circuit breaker shall have this capability without the use of intentional time delay in clearing, fault reduction schemes, etc. Application shall be in accordance with ANSI/IEEE C37 Standards. These requirements apply to the Generation Site, the Interconnecting Substation, the Point of Interconnection as well as other locations on the PGE System. Minimum fault-interrupting requirements are supplied by PGE, and are based on the greater of the fault duties at the time of the interconnection request or those projected in long-range plans.

The circuit breaker shall be capable of performing all other required switching duties such as but not limited to: capacitive current switching, load current switching, and out-of-step switching. The circuit breaker shall perform all required duties without creating transient overvoltages that could damage PGE equipment. Switchgear on the high side of a D-YG transformer that can interrupt faults or load must be capable of the increased recovery voltage duty involving interruptions while ungrounded. When generation is connected to the low-voltage side of a D-YG transformer, the high-voltage side may become ungrounded when remote end breakers open, resulting in high phase-to-ground voltages. This phenomena is described in Section 4-D3b under 'neutral shifts.'

2. Circuit Breaker Operating Times

Table 5-1 specifies the operating times typically required of circuit breakers on the PGE System. These times apply to equipment at the Generation Site and the Point of Interconnection. System stability considerations may require faster opening times than those listed. Breaker close times are typically four to eight cycles. The automatic recloser times listed above are the summation of the breaker close time plus intentionally added delay to allow for extinction of the fault arc (de-ionization), and the protective relay requirements.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

Table 5-1 Circuit Breaker Operating Times

Voltage Class	Rated Interrupting Time (Cycles)	Automatic Reclose Time (Cycles)
500-kV	2	20 – 90
230-kV	3	35 – 60
57-kV - 115-kV	3	5 Sec – 15 Sec
Below 57-kV	5	*

* - Varies significantly by line.

3. Other Fault-Interrupting Device Operating Times

Depending on the application, the use of other fault-interrupting devices such as circuit switchers may be allowed. Trip times of these devices are generally slower, and current interrupting capabilities are often lower than those of circuit breakers.

5-C. Generators, Step-Up and Auxiliary Transformers

For Sections 5-C, 5-D, and 5-E of this document, NERC Planning Standards Sections IIB and IIIC apply. The NERC Planning Standards are available at www.nerc.com.

Synchronous generators shall have an overexcited power factor rating of 0.9 or lower. Under-excited power factor rating shall be 0.95 or lower. Alternatively, a power factor capability rating at the point of interconnection (network side of step-up transformer) may be negotiated with PGE. The active power output should be limited to rated power (MVA rating times rated overexcited power factor) so that rated continuous reactive power output is available for power system emergencies. Planned operation above rated power must be negotiated with PGE and the Northwest Security Coordinator. NERC Planning Standards guide IIIC G2 states:

G2 - Generators and turbines should be designed and operated so that there is additional reactive power capability that can be automatically supplied to the system during a disturbance.

Transformer reactances and tap settings should be coordinated with PGE to optimize the reactive power capability (lagging and leading) that can be provided to the network. Refer to IEEE Std. C57.116, Guide for Transformers Directly Connected to Generators. The generator continuous reactive power capability shall not be restricted by main or auxiliary equipment, control and protection, or operating procedures. Induction generators with solid-state inverters shall have reactive power capability similar to synchronous generators. Induction generators without solid-state inverters shall provide at a minimum, sufficient reactive power capability or the 'equivalent' to deliver the Project output at unity power factor at the Point of Interconnection.

5-D. Excitation Equipment including Power System Stabilizers, and Voltage Controls

Synchronous generator excitation equipment shall follow industry best practice and applicable industry standards. Excitation equipment includes the exciter, automatic voltage regulator, power system stabilizer and over-excitation limiter. Supplementary controls are required to meet PGE transmission voltage schedules.

The following NERC Planning Standards shall be followed. See Section IIIC of the standards.

S1 - All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

system operator. (The intent is that continuous automatic voltage control *not* be overridden by supplementary power factor or reactive power controls.)

S2 - Generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with the electric system voltage requirements.

S4 - Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays.

Normally the exciter is of the brushless rotating type or the static thyristor type. The excitation system nominal response shall be 2.0 or higher (for definitions see IEEE 421.2). The excitation system nominal response defines combined response time and ceiling voltage. In some cases, the high initial response static type may be required to economically improve power system dynamic performance and transfer capability.

Automatic voltage regulators (AVRs) should be continuously acting solid state analog or digital. Tuning should be in accord with NERC Planning Standard guide IIC G8 reproduced below. Tuning results should be included in commissioning test reports provided to PGE.

G8 - Generator voltage regulators to extent practical should be tuned for fast response to step changes in terminal voltage or voltage reference. It is preferable to run the step change in voltage tests with the generator not connected to the system so as to eliminate the system effects on the generator voltage. Terminal voltage overshoot should generally not exceed 10% for an open circuit step change in voltage test.

The voltage regulator shall include a power system stabilizer. This is a long-standing WECC requirement. The PSS should be tuned in accord with WECC guidelines and other industry practice. The dual-input accelerating power type of stabilizer (Delta P-omega or variant) is preferred.

The voltage regulator shall include an overexcitation limiter. The overexcitation limiter shall be of the inverse-time type adjusted to coordinate with the generator field circuit time-overcurrent capability. Operation of the limiter shall cause a reduction of field current to the continuous capability. Automatic voltage regulation shall automatically be restored when system conditions allow field current below the continuous rating. PGE may request connection of the voltage regulator line drop compensation circuit to regulate a virtual location 50–80% through the step-up transformer reactance.

A supplementary automatic control is required to adjust the AVR setpoint to meet the PGE network side voltage schedule. This supplementary control should operate in a 10–30 second time frame, and may also balance reactive power output of the power plant generators.

PGE operates the transmission network through a range of 95% to 105% of nominal voltage except for the 500-kV network (operated by BPA) where the range is 100% to 110% of 500-kV. Voltage schedules are normally in the upper half of this range. Limitations at generation facilities must not restrict this range of operation. Voltage schedules may be changed at any time to meet transmission requirements, e.g., a line out of service. Timing for schedule changes are coordinated by the NWPP with all utilities in the region.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

5-E. Governor Speed and Frequency Control

NERC Planning Standards standard IIC S5 and guide IIC G6 apply:

S5 - Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

G6 - Prime mover control (governors) should operate freely to regulate frequency. In the absence of Regional requirements for the speed/load control characteristics, governor droop should generally be set at 5% and total governor deadband (intentional plus unintentional) should generally not exceed $\pm 0.06\%$. These characteristics should in most cases ensure a coordinated and balanced response to grid frequency disturbances. Prime movers operated with valves or gates wide open should control for overspeed/overfrequency.

PGE realizes that some generating facilities will operate at maximum turbine output unless providing frequency control and spinning reserve ancillary services.

5-F. Abnormal Voltage and Frequency Operation

Power system disturbances initiated by system events such as faults and forced equipment outages, expose connected generators to oscillations in voltage and frequency. It is important that generators remain in service for dynamic (transient) oscillations that are stable and damped. Therefore each generator must be capable of continuous operation at 0.95 to 1.05 pu voltage and 59.5 to 60.5 Hz and limited time operation for larger deviations. Over/under voltage and over/under frequency relays are normally installed to protect the generators from extended off-nominal operation.

To avoid large-scale blackouts that can result from the excessive generation loss during a disturbance, underfrequency load shedding has been implemented in the Pacific Northwest. When system frequency declines, loads are automatically interrupted in discrete steps, with most of the interruptions between 59.3 and 58.6 Hz. Load shedding attempts to stabilize the system by balancing the generation and load. It is imperative that generators remain connected to the system during frequency declines, both to limit the amount of load shedding required and to help the system avoid a complete collapse. In certain areas of the Pacific Northwest, undervoltage load shedding has also been implemented to avoid voltage collapse. Most of the load interruptions will occur automatically near 0.9 per unit voltage after delays ranging from 3.5 to 8.0 seconds.

5-G. Generation Reserves

PGE's control area is required to carry and amount of generation reserves that satisfies requirements specified by the NERC, the WECC and the Northwest Power Pool. These include regulating reserves, contingency spinning reserves and contingency non-spinning reserves. Reserves are the obligation of the Project Operator or the obligation may be assumed by the purchasing entity. Reserves may be provided by the Project, some other generator via contract, or by purchasing the reserves from a separate entity. A portion of those reserves must be maintained as spinning reserves. In any case, PGE must approve reserve arrangements for a generation resource in the PGE Control Area.

5-H. Power Quality

1. Voltage Fluctuations and Flicker

Voltage fluctuations may be noticeable as visual lighting variations (flicker) and can damage or disrupt the operation of electronic equipment. *IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems* (IEEE Standard 519) provides definitions and limits on acceptable levels of voltage fluctuation. Projects connecting to the PGE System shall comply with the limits set by IEEE 519.

2. Voltage and Current Harmonics

Harmonics can cause thermal heating in transformers, can disable solid state equipment and can create resonant overvoltages. In order to protect equipment from damage, harmonics must be managed and mitigated. The

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

Project shall not cause voltage and current harmonics on the PGE System that exceed the limits specified in IEEE Standard 519. Harmonic distortion is defined as the ratio of the root mean square (rms) value of the harmonic to the rms value of the fundamental voltage or current. Single frequency and total harmonic distortion measurements may be conducted at the Point of Interconnection, Generation Site, or other locations on PGE's System to determine whether the Project is the source of excessive harmonics.

3. Phase Unbalance

Unbalanced phase voltages and currents can affect protective relay coordination and cause high neutral currents and thermal overloading of transformers. To protect PGE and customer equipment, the Project's contribution at the Point of Interconnection shall not cause a voltage unbalance greater than 1% nor a current unbalance greater than 5%. Phase unbalance is the percent deviation of one phase from the average of all three phases.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

6. Protection Requirements

6-A. Introduction

The protection requirements identified in this document are intended to achieve the following objectives:

- Minimize damage to the property of the general public, PGE, and PGE's customers.
- Minimize adverse operating conditions on the PGE System and PGE's customers.
- Permit the Sponsor to operate the Project in parallel with the PGE System in a safe and efficient manner.

To achieve these objectives, certain protective equipment (relays, circuit breakers, etc.) must be installed. These devices ensure that faults or other abnormalities initiate prompt and appropriate disconnection of the Project from the PGE System. Protective equipment requirements depend on the plan of service. Significant issues that could affect these requirements include:

- The configuration of the Project.
- The Point of Interconnection to the power system.
- The level of existing service and protection to adjacent facilities (including those of other PGE customers and potentially those of other utilities).

In addition, certain modifications and/or additions to the PGE System may be required for Project interconnection. Each individual request for interconnection must result in a protection system consistent with these technical requirements. PGE makes the final determination as to the protective devices and identifies modifications and/or additions required by the Project. PGE works with Sponsors to achieve an installation that meets the Sponsor's and PGE's requirements.

PGE cannot assume any responsibility for protection of the Sponsor's Project. Sponsors are solely responsible for protecting their equipment in such a manner that faults, imbalances, or other disturbances on the PGE System do not cause damage to the Project facilities.

6-B. Protection Criteria

The protection system must be designed such that the Project generating equipment is automatically isolated for the following situations:

- Internal faults within the Project.
- External faults within the power system (as necessary).
- Conditions that indicate abnormal operation, including islanding of the Project.

1. General Protection Practices as Applied to the PGE System

The information below is provided to identify general protection practices as applied to PGE System transmission lines and interconnections thereto. The protection schemes necessary to integrate the Project must be consistent with these practices and the equipment used to implement them.

a) All voltages above 100 kV:

1. Breaker failure relays are required as needed.
2. Dual trip coils are required (>230-kV).
3. Redundant relay and communications are required if stability and cascading is an issue for time delay cleared faults.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

4. Dual batteries are NOT required but each set of relays must have its own separately protected DC source (>230-kV).
5. Redundant relays should not be connected to a common current transformer winding (>230-kV).

b) All voltages

1. As described in Section 4-B, a generator may tap an existing transmission line only if the line protection can be coordinated without compromising reliability, system stability, or quality of service to PGE's existing customers.
2. Relays, breakers, etc. are required at the Point of Interconnection or the Interconnecting Substation to isolate PGE equipment from the Project (or the distribution system containing the Project) during faults.
3. A dedicated generator breaker is required at the Sponsor's Generation Site.
4. The Project is to be synchronized to the power system.
5. An automatic synchronizing function must supervise each breaker closure connecting the generator to the power system.
6. Any breaker dedicated for the sole purpose of isolating the generator from the interconnecting power system shall open all three phases and shall not automatically reclose.
7. The Project is not allowed to energize a de-energized line in the PGE System without approval of the PGE Dispatcher.
8. Breaker reclose supervision (automatic and manual including SCADA) may be required at the Interconnecting Substation and/or electrically 'adjacent' stations; e.g., hot bus/dead line check, synchronization check, etc.

c) 500-kV

1. Two independent sets of directional line protection with separate pilot communication for each relay set shall be installed at each line terminal to trip the line terminal breakers.
2. Total fault clearing time with a pilot scheme must not be more than four cycles, including relay and breaker time.
3. Relays shall provide backup protection for loss of communication channel.
4. Line protection may be required to be compatible with existing or future series compensation.
5. Protection must be able to interface with PGE's single-pole protection schemes.
6. Breaker failure relay (BFR) protection at the Sponsor's facilities is required. It must not have more than eight cycle pickup delay for backup tripping. Total time for BFR scheme fault-clearing must not exceed 14 cycles.
7. Automatic reclosing shall be no faster than 35 cycles and usually no slower than 60 cycles for standard three-pole or single-pole switching.
8. Automatic reclosing is not allowed for multiphase faults.

d) 230-kV

1. Two independent sets of directional line protection shall be installed at each line terminal to trip the line terminal breakers.
2. A pilot communication scheme may be required. A scheme common to both relay sets is acceptable.
3. Total fault clearing time with a pilot scheme must not be more than four cycles, including relay and breaker time.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

4. Pilot scheme must be compatible with existing PGE equipment.
5. Relays shall provide backup protection for loss of communication channel.
6. BFR protection at the Sponsor's facilities is required. It must not have more than eight cycle pickup delay for backup tripping. Total time for BFR scheme fault clearing must not exceed 14 cycles.
7. Automatic reclosing for single line-to-ground faults shall be no faster than 35 cycles and no slower than 60 cycles.
8. Automatic reclosing is not allowed for multiphase faults.

e) 115-kV and below

1. Two independent sets of directional line protection shall be installed at each line terminal to trip the line terminal breakers.
2. A pilot communication scheme may be required. A scheme common to both relay sets is acceptable.
3. Total fault-clearing times, with or without a pilot scheme, must be provided for PGE review and concurrence. Breaker operating times, relay models, and relay settings must be identified specifically.
4. If a pilot scheme is necessary, it must be compatible with existing PGE equipment.
5. If a pilot scheme is necessary, relays shall provide backup protection for loss of channel.
6. BFR protection at the Sponsor's facilities may be required above 115-kV. Backup protection measures for breaker failure must be identified and associated total fault clearing times for these measures must be provided for PGE review and concurrence.
7. Automatic reclosing for single line-to-ground faults shall be no faster than 35 cycles.
8. Automatic reclosing is allowed for multiphase faults.

2. Implications for Project Interconnection to an Existing Distribution Substation

Many generation projects are proposed for integration into utility power systems through a step-down transformer that is designed only to serve loads; e.g., connection at the 12.5-kV side of a 115-kV/12.5-kV transformer.

Existing facilities may have fuse protection only on the high-voltage side of the transformer; other installations may use a circuit switcher or breaker with relay control. The device and associated relays (if any) at these sites are provided to isolate the PGE System from faults within the transformer and act as backup to the distribution feeder protective devices. The existing protection at these installations was applied under the assumption that there was not a source from the low-voltage side to infeed to faults in the power system.

Other protective relaying strategies are necessary when generation is connected into these sites. 'Neutral shift' can be attributed to interconnection into stations with a D-YG transformer. Ferroresonance is also cause of concern, regardless of transformer connection. Equipment damage, relay performance, and saturation of measuring devices are only a few of the issues.

Primary and/or backup relays used for detection of faults in the power system may be required at the Project as well as the Interconnecting Substation. Usually, changes to existing protection and reclosing schemes are not limited to those at the Interconnecting Substation.

3. Protection Measures

Protection systems must be capable of performing their intended function during fault condition. This includes the generator contribution to the fault and neutral shift of the unfaulted phases. The duration of this contribution

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

and neutral shift varies with generator size, type, and excitation. The magnitude of depends on the fault type, system configuration, and fault location. The discussion below identifies the conditions under which relay schemes must operate. Notably, the issues are:

- Infeed detection to phase and ground faults.
- Islanding
- Synchronizing and reclosing
- Unique problems related to system configuration.

a) Isolation

The Project shall not energize a *de-energized* PGE line unless the energization is specifically approved by the PGE Dispatcher. If, for any reason, the PGE System is disconnected from the Project (fault conditions, line switching, etc.), the switching device connecting the Project to the system must open and not reclose until approved by the PGE dispatcher or as specified in the interconnection agreement.

b) Synchronization

The Project shall synchronize its equipment to the PGE System. Automatic synchronization shall be supervised by a synchronizing check relay, IEEE device 25. This assures the unit is not connected to the energized power system out of synchronization.

c) Phase fault detection

Phase overcurrent (type 50/51) and neutral overcurrent (type 50/51-N) relays are provided to detect abnormally high currents. These non-directional relays are used to detect faults on the feeder line and serve to back up generator overcurrent relays. Line differential relays may be a necessary consideration for some projects when coordination with other relays is not possible.

Infeed detection to faults within the power system usually requires directional current-sensing relays to remove the Project's contribution to the fault. Zone-distance relays (type 21) usually serve this need. However, some generation projects (generally 'small-capacity') may not contribute sufficient infeed to power system phase faults to make distance-relay detection feasible. In these cases, relays at the Project need to provide the necessary detection.

d) Ground fault detection

Ground fault detection has varying requirements. The most significant consideration in ability to detect ground faults on the utility power system is the winding configuration of the transformer connecting the Project to the transmission system. The scenarios below assume that the Project is connected to the low-voltage side of this transformer.

1. Transformer grounded wye connection on the transmission side

If the transformer is connected in grounded-wye on the primary (high-voltage) side and delta on the secondary (low-voltage) side (YG-D), then a ground overcurrent relay (type 50/51-G) connected in the neutral of the wye is used to provide detection. This relay also protects the integrating transformer. This arrangement also applies to a transformer connected YG-Y(G) with delta tertiary. Either of these connections provide what is often referred to as a 'ground source' for the wye grounded terminal(s). The measured quantity in the transformer grounded-wye neutral is caused by zero-sequence circulating currents in the delta winding during ground faults.

A directional ground overcurrent relay (type 67-N) is generally provided for detection of ground faults in the transmission system when transformer connections are of the types identified above. Since this relay

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

function complements zone-distance protection used for phase fault detection, it is included in many presently manufactured relays.

2. Transformer Delta Connection on the Transmission Side

Under the second common, the interconnecting transformer is connected delta on the high-voltage winding and connected wye-grounded on the low-voltage winding (D-YG). For ground faults on the high voltage system, protective relaying cannot detect zero sequence current at this location unless a ground source (grounding bank) is connected to the high-voltage side of the transformer. Protective relay operation at the remote transmission line terminal(s) will isolate the line. However, the generator infeed (voltage effect) will continue to energize the transmission line and, with one phase grounded, can result in significant overvoltages (neutral shift). Thus protection must be applied to this situation to detect the fault and trip the generator as rapidly as possible.

A detection method for this situation uses three VTs or bushing potential devices on the primary side of the transformer connected phase-to-ground. The VTs or bushing potential devices must be capable of measuring voltages up to 1.9 PU without the output collapsing by the operation of a protective device, such as a protective gap. The VT's secondary windings are connected 'broken-delta' with an overvoltage relay (type 59-Z) connected across the 'open' corner of the delta. The relay measures the sum of the phase-to-neutral voltages. Under normal conditions, the measurement is near zero, while a ground fault either close to the transformer or with the remote line end(s) open yields a substantial voltage. The relay initiates a trip to eliminate the generator infeed on the faulted line. Fault detection using a single VT and an over/under voltage relay is not usually acceptable. Fault impedance, connected loads, and/or additional ground sources on the line can significantly compromise the ability of this scheme to detect the over-or-under voltage condition.

If 1) the minimum load (MW) in the 'local island' is four or more times the generator rating (MVA) and 2) the available system reactive power (capacitive VARs) is less than 25% of the generator rating, the system voltage should rapidly collapse after the remote end breakers trip. Under these circumstances, a single VT scheme is acceptable.

Pilot trip from the end(s) of the transmission line is an acceptable alternative. A grounding bank connected to the high side (delta side) of the interconnecting power transformer is another acceptable alternative.

e) High-Side Overvoltage Protection

For scenario 2, described above, with the high side connected in Delta, the transmission line becomes ungrounded after the line-end breakers open. With a generator energizing the circuit and a fault on the transmission line, the voltages on the unfaulted phases can reach 1.7 PU and higher (full neutral shift). This can stress equipment insulation and cause rapid failure of surge arresters. Additional protective relays are required, to detect this overvoltage situation quickly and disconnect the generator from the circuit.

Three single-phase instantaneous overvoltage relays (type 59) are to be installed to detect phase-ground voltage using the three high-side VTs or bushing potential devices. These relays should be set to trip at 1.5 pu phase-ground voltage and have approximately a one-cycle detection time. Like the ground-fault detection scheme above, pilot trip from the transmission line end(s) is an acceptable alternative to this high-side overvoltage protection.

The 'open delta' protection scheme described above is intended to detect ground faults and assure a local trip of the generator. However, proper coordination of this scheme often requires relaying delays. Such delays may not provide adequate protection for equipment such as high-side arresters. The open delta scheme also cannot protect for the case of overvoltages created when a small generator is isolated in a 'local island' with a relatively large amount of capacitance, such as a long line or a capacitor bank. The simple and inexpensive

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

set of three overvoltage relays described above are intended to protect the arresters and other equipment on the high-voltage side with no intentional delays, regardless of the cause of the overvoltages.

f) Islanding

Some utilities isolate their distribution system and use local generation to feed loads during power system outages. PGE does not allow islanding conditions to exist that include its facilities, except for a controlled (temporary, area-wide) grid separation.

Two additional relays are applied to detect an island condition after it occurs; these are necessary to protect PGE 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' island condition. However, they should also be set so the generator does not trip for the less severe deviations that could occur during most major disturbances on the interconnected power system.

g) Relay Performance / Transfer Trip Requirements

Relay systems discussed above are designed to isolate the Project from the PGE System at the Point of Interconnection. However, the performance (clearing time speed) of these local relay systems and the associated isolating devices (breakers, etc.) will vary. Integration of generating projects into the power system requires equal or better performance of protection systems. See 6-B.1 for general requirements associated for integration of the Project. In many cases, transfer trip (pilot) communications are necessary. Transfer trip is required when any of the conditions listed below implies the need for it.

1. Transient or steady state studies identify system instability under conditions that require immediate isolation of the Project from the power system. Or as determined by operational control needs.
2. The total clearing times listed in the table below identify the maximum permissible fault duration times allowed to provide prudent response to fault conditions. Extended fault duration represents an additional safety hazard to personnel and can cause significant damage to power system equipment (lines, transformers). Relay operate times are adjusted to coordinate for faults based on the local configuration (e.g. three terminal lines), fault currents available, etc. If protective relay schemes cannot be altered to accommodate the Project to meet the clearing times listed below, high speed tripping will become necessary.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

Integration Voltage, kV	Total Clearing Time, Cycles	Maximum Relay Operate Time, Cycles	PCB Trip Time, Cycles	Time Delayed Tripping Acceptable?
500	4	1	2	No*
230	28*	≤ 25*	3	Yes
57 to 115	47	≤ 42	5	Yes
≤ 57	68	≤ 60	8	Yes

*backup relays

3. If time delayed fault clearing on lines in the vicinity of a customer can cause problems (voltage sag) to a customers' manufacturing process, high speed tripping may become necessary. This scenario is a distinct possibility should a PGE circuit which connects other customer loads become part of a local island which includes the Project.

4. When remote breaker tripping is required to clear faults in a transformer not terminated by a high side breaker, high speed tripping will be necessary. Other unique configurations may impose the same requirement.

h) Synchronizing and Reclosing

The Project generator(s) shall be synchronized to the power system. The point of synchronism depends on the configuration of the Project's interconnection. All breaker closing operations must automatically synchronize the Project generator to the power system. The breaker used to synchronize the generator to the power system is usually the dedicated generator breaker.

If the Project connects to an existing line, automatic reclosing schemes at the remote line breakers will need to be modified to accommodate the generator. A hot bus/dead line check before attempting an automatic reclose is usually needed at one end. Hot bus/hot line with synchronism check supervision is necessary for automatic reclosing at the other end. When acceptable, automatic reclosing can be cutout at one or both remote ends. If the Project uses only induction generators, automatic reclosing of the breakers at the ends of the integrating line may be performed without supervision, but will usually be time delayed to assure isolation of the Project.

i) Disturbance Monitoring

Unique and unanticipated protection problems can result from the changed system configuration due to interconnection with the Project. PGE may, at its discretion, install monitoring equipment to identify possible protection scheme problems and to provide power quality measurements of the new configuration. If monitoring or relay performance indicates inadequate protection of the PGE System, the owner of the Project will be notified of additional protection requirements. The 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 ferroresonance that can be associated with these projects. Remote access to monitored quantities is often accomplished using the communication equipment.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

6-C. Relay Coordination

Voltage and frequency relays used for protecting a generator and preventing a 'local island' condition from persisting must meet the following requirements to allow proper coordination with the adjacent power system(s). These relays are usually installed at the Generation Site or at the Interconnecting Substation.

The ranges, settings, and delays below for both voltage and frequency relays are understood by PGE to be well within the capabilities of small and large modern steam turbines as well as other generators. PGE will evaluate a Sponsor's proposed alternative voltage/frequency settings based upon the impact on system performance and reliability. The settings must comply with existing NWPP requirements.

1. Voltage Relays

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 undervoltage load shedding. The settings below coordinate with Pacific Northwest undervoltage load shedding, where loads are interrupted at voltages ranging from 0.85 to 0.92 per unit with time delays of 3.5, 5.0 or 8.0 seconds.

Overvoltage (type 59)

<u>Voltage</u>	<u>Action</u>
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

Undervoltage (type 27)

<u>Voltage</u>	<u>Action</u>
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

2. Frequency Relays

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. The relay settings below insure that the underfrequency generator tripping coordinates with the Northwest Power Pool Enhanced Underfrequency Load Shedding Program, where most of load is shed as the system frequency declines from 59.3 down to 58.6 Hz.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

Underfrequency Range	Overfrequency Range	Minimum Time Delay Setting
60.0-59.5 Hz	60.0-60.5 Hz	No Generator Tripping (Continuous)
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
Less than 56.4 Hz	Greater than 61.7 Hz	Instantaneous Trip

For generators that are not susceptible to damage for the frequency ranges listed above (e.g. typical hydro units), tripping at 61.7 and 56.4 Hz, with no intermediate steps is suggested. For steam generators and similar units, relay(s) with multiple frequency setpoints and discrete time delays could be used to realize the settings above.

Often, large generation resources are directly connected to a substation at the transmission level voltage and would not be part of the 'local island' condition described in Section 5-F. For these generators, the 61.7 Hz trip level may be raised and the 56.4 Hz trip level may be lowered. However, the minimum delays listed above for all frequency deviations from 60 Hz must be maintained. For those generators that can be part of a 'local island', a maximum delay of 0.1 sec at 56.4 and 61.7 Hz should be used. This will help insure that the generator trips for the 'local islanding' condition.

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.

6-D. Protective Relays

1. Relays to be Installed for Integration of the Project

This set of relays has been developed in recognition of varied detection requirements. Relay performance under certain fault scenarios is also a consideration in the selection of these relays. The specific relays used must be functionally consistent with, and complementary to, PGE's general protection practices identified in Section 6-B1.

The relays generally necessary to serve this purpose are:

- | | |
|--|----------------|
| a. Phase overcurrent (non-directional) | (type 50/51) |
| b. Neutral overcurrent (non-directional) | (type 50/51-N) |
| c. Zone distance | (type 21/21-N) |
| d. Directional ground overcurrent | (type 67-N) |
| e. Ground overcurrent | (type 51-G) |
| or ground fault detection scheme | (type 59-Z) |
| f. Over/under voltage | (type 59/27) |
| g. Over/under frequency | (type 81) |
| h. Instantaneous overvoltage (ungrounded high-side) | (type 59) |
| i. Remote automatic breaker reclose supervision
(HB/DL, HB/HL with synchronism check) | (type 79-X) |

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

Except for Item i above, these relays are usually located in the Interconnecting Substation that contains the step-up transformer. Some or all may be located elsewhere if the interconnection to the Project suggests an equally acceptable or more logical location. All relays shall be of 'utility grade' quality, subject to review by PGE.

Slow clearing or other undesirable operations (e.g., extended overvoltages, ferroresonance, etc.), which can not be resolved by local conventional protection measures, will require the addition of pilot trip using remote relay detection at other substation sites.

Refer to Section 8-D for telecommunication issues as they pertain to control and protection requirements. See Figures 6-1 through 6-4 for examples of some typical integration plans.

2. Additional Relays

Although not required by PGE, the Sponsor may note value in additional relays to isolate and protect the generator. Some of the most often used include:

- | | |
|---------------------------------------|--|
| a. Percentage differential | (type 87) |
| b. Phase balance current | (type 46) |
| c. Phase sequence voltage | (type 47) |
| d. Reverse power | (type 32) (assumes one-way power flow) |
| e. Thermal | (type 49) |
| f. Loss of field | (type 40) |
| g. Over-speed device | (type 12) |
| h. Transformer sudden pressure | (type 63) |
| i. Voltage controlled/restrained o.c. | (type 51-V) |
| j. Volts per Hertz (overexcitation) | (type 24) |
| k. Neutral overvoltage | (type 59-N) |

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

7. System Operation and Generation Scheduling Data Requirements

7-A. Introduction

All transmission arrangements for power schedules within, across, into or out of the PGE Control Area require metering and telemetering. Transmission arrangements with generating resources may include wheeling, reserves and Automatic Generation Control (AGC). The technical plan of service for interconnecting a generating resource, as shown on the Project Requirements Diagram, will include the metering and telemetering equipment consistent with the transmission contract provisions. Such metering and telemetering equipment may be owned, operated, and maintained by PGE or by other parties approved by PGE.

Revenue metering, system dispatching, operation, control, transmission scheduling and power scheduling each have slightly different needs and requirements concerning metering, telemetering, data acquisition, and control. Specific requirements also vary depending upon whether the Project is directly connected to the PGE System and within or outside the PGE Control Area. Under some arrangements, only a portion of the Project output may be incorporated into the PGE Control Area.

Beyond the basic production and delivery of electrical energy, successful operation of generators, loads, and the transmission system requires Ancillary Services. Some of these services include scheduling, control and dispatch, reactive support from generators, load regulation, and operating reserves. Ancillary Services are purchased by or for load customers and generation resource operators. PE purchases Ancillary Services from certain generation resources and may provide these services to others. PGE metering and telemetering requirements may depend upon whether or not the Project is a dispatchable resource for Ancillary Services.

7-B. System Operation Requirements

1. Telemetry Requirements

PGE's System Control Center (SCC) 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 Project to the PGE SCC. The net Project output, which is the Project generation less the station service load and step-up losses, is normally telemetered.

Section 8-C2 discusses telecommunications requirements for telemetry and AGC. Table 7-1 summarizes telemetry requirements and Table 7-2 identifies requirements based on Project location. The following includes specific requirements based on Project size:

- a) Telemetry is required when the output of the Project entering the PGE Control Area is three MVA or greater: For this case, telemetry of real power and energy (kW, kWh), and reactive power (kVAr, kVArh) is normally required.
- b) For Projects below three MVA, PGE determines telemetry needs on a case-by-case basis. Note that should an existing plant expand to over three MVA, telemetry is required for the entire plant output.
- c) Station service load may require separate telemetry if it comes from a different Control Area.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

2. Data Requirements for Control Area Services

Data requirements for PGE Control Area services, such as AGC, apply only to generation resources inside the PGE Control Area. For resources that are not part of PGE's Control Area, the operator of the Host Control Area determines the data requirements for Control Area services.

For generation resources inside PGE's Control Area, Ancillary Services, (e.g. reserves) must be acquired. Provision for all Ancillary Services are specified in the transmission contract. PGE must specifically approve all arrangements for Projects intending to provide Ancillary Services to PGE. If the Project is capable of providing Ancillary Services in excess of its obligation, then PGE may choose to contract with the Project operator to provide additional Ancillary Services. Certification procedures conform to NERC Standards and should be portable to all control areas. This removes the need to re-certify Project capability.

The technical information below is included for general conceptual purposes only. Technical discussions are necessary before the specific implementation requirements can be determined. The AGC data to be passed over the data link may include some or all of the data quantities listed in Table 7-3. The list in Table 7-3 provides an example of the quantities necessary for a generation resource that is operating on full AGC regulation.

- a) If PGE is purchasing AGC services from the Project, AGC control of the generator capability is required on a long-term basis. Prior to purchasing AGC services, an investigation of the AGC control capabilities of the Project is required to determine the specific AGC requirements
- b) Ancillary Services requirements are also driven by how the Project operator or the purchaser chooses to meet the reserve obligations of the Project, as described below. Either the Project operator or the entity making the transmission arrangements is liable for the reserve obligations associated with the operation of the Project. The responsible party may fulfill these obligations in any of the following ways:
 - Make these reserves available to PGE from the Project.
 - Make these reserves available to PGE from another one of their generation resources.
 - Contract with another Project operator to make these reserves available to PGE on their behalf.
 - Contract with PGE to cover this reserve obligation.

3. Supervisory Control and Data Acquisition (SCADA) Requirements

Interconnection may require PGE SCADA control and status indication of the power circuit breakers and associated isolating switches used to connect PGE to the Project. SCADA indication of real and reactive power flows and voltage levels are also required. If the Project is interconnected directly to another utility's transmission system, SCADA control and status indication requirements shall be jointly determined among that utility, the Project Sponsor, and PGE. SCADA control of breakers and isolating switches that are located at the Generation Site is not normally required; however, status indication may be necessary. Section 8-C1 discusses telecommunications requirements for SCADA systems.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

7-C. Generation Scheduling Requirements

Scheduling and accounting of generation normally requires telemetered data, from the Project to the transmission control center of the Control Area operator. This data is termed Generation Metering/Telemetering by PGE and includes kW and kWh quantities. PGE requires that all generation be pre-scheduled for each hour using the normal scheduling procedures. The end-of-hour actual generation must be conveyed each hour to the PGE Control Area Operator in the SCC. This can be accomplished through the use of telemetry or data link.

1. Generation Metering Requirements

Generation Metering generally consists of bi-directional meters and related communications systems providing kW and kWh at or near the Point of Interconnection. The kW measurement is telemetered on a continuous basis for AGC and hourly kWh is sent each hour to the Numbers accounting function. Telemetry is required when the generation is 3 MVA or greater and in the PGE Control Area. Telemetry is also required when PGE is responsible for wheeling the output of a Project that is outside of the PGE Control Area.

All generation Projects in the PGE Control Area of 1 MVA or greater requires hourly pre-scheduling. PGE may require indication of the number of units both available and on line. PGE requires indication of the MW of spinning reserve available and the MW of reserve under control. (See Section 5-G for more information on reserves.)

2. Data Acquisition System

Projects such as wind, tidal, geothermal, etc. require additional data to make generation scheduling more predictable. Such additional data may include, but not be limited to, ambient temperature, wind speed, solar index, pressure gradients etc. SCADA control may also be required. Specific requirements and needs are determined for each Project. Section 8-C3 discusses telecommunications requirements for telemetering and data acquisition.

7-D. Revenue or Interchange Metering

All Projects one kW or greater require PGE-qualified Revenue and Interchange Metering and data recording for the PGE billing processes. Interchange Metering includes instantaneous power measurement (kW) and energy data (kWh) produced by revenue meters. The metering shall be located to measure the net power output from the Project to the PGE System, which is the Project generation, less the station service load and step-up or other losses.

Hourly kWh data is downloaded from the metering recorder on a daily basis over voice-grade telephone lines. All recorders must be fully compatible with the PGE data acquisition system. Demand data will be available to the Customer or their Agent.

1. Revenue and Interchange Metering Requirements for Billing Data

Metering shall be bi-directional to record reactive flow to or from the Project as well as Generation out of the Project and Station Service (if any) from the transmission system into the Project.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

Project meters will be considered, subject to PGE approval, if the metering and telemetering functions are performed by an authorized non-PGE party. Three-element, three-phase, four-wire meters shall be used on grounded power systems. Two-element, three-phase, three-wire meters can be used on ungrounded power systems.

Section 8-C4 discusses telecommunications requirements for Revenue Metering.

2. Meter Accuracy

Watt-hour meters shall be calibrated to $\pm 0.1\%$ accuracy at unity power factor for both full load and light load. Watt-hour meters shall also be calibrated to $\pm 0.3\%$ accuracy for 0.5 power factor at full load. VAr-hour meters shall have $\pm 0.2\%$ accuracy at unity power factor and $\pm 0.6\%$ accuracy at 0.5 power factor. Full load is defined as nominal voltage, 100% meter current rating. Light load is nominal voltage, 10% meter current rating.

3. Instrument Transformers

Voltage and current instrument transformers shall be 0.3% accuracy class for both magnitude and phase angle over the burden range of the installed metering circuit. The instrument transformers shall be of a shielded design. This is a safety requirement to prevent unintentional energization of the transformer secondary during a transformer failure.

4. Loss Compensation

Transmission system losses (such as transformer losses in the revenue metering process) often must be accounted for. PGE prefers that this accounting be done as a calculated part of the PGE billing process. If the Project strongly desires that the loss compensation be performed in the meter rather than calculated, PGE will consider modifying the revenue metering to accommodate the request. However, compensation in JEM-1 meters will not be performed. (Compensation affects only the pulse integrator circuits, which disturbs the relationship between the direct analog outputs and the integrated pulse outputs).

5. Station Service Power

Depending upon its electrical source and electrical location within the Project, station service power may also require Revenue Metering. It may not be necessary to meter station service VAR hours although most modern electronic meters include this feature as part of the meter. The other requirements of this section do apply to station service metering.

7-E. Calibration of Revenue and Interchange Metering Facilities

Revenue and Interchange Metering shall be calibrated every two years. More frequent calibration intervals may be negotiated. All interested parties or their representatives may witness the calibration tests. Calibration records shall be made available to all interested parties. The calibration standards used for calibration shall have their accuracy traceable to the National Institute of Standards and Technology, (NIST). The calibration standard shall have been calibrated and certified within twelve months prior to the actual meter calibration.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

8. Telecommunication Requirements

8-A. Introduction

Telecommunications facilities shall be tailored to fulfill the control, protection, operation, dispatching, scheduling, and revenue metering requirements. At a minimum, telecommunications facilities must be compatible with, and have similar reliability and performance characteristics to that currently used for operation of the power system to which the generation is being interconnected. Telecommunications facilities will be identified on the Project Requirements Diagram and, depending on the performance and reliability requirements of the control and metering systems to be supported they may consist of any or all of the following:

1. Microwave systems

A microwave requires transmitters/receivers, communication fault alarm equipment, antennas, batteries, and multiplex equipment. It may also include buildings, towers, emergency power systems, mountaintop repeater stations and their associated land access rights, as needed to provide an unobstructed and reliable communications path. Microwave path diversity, equipment redundancy, and/or route redundancy may be required to meet power system reliability requirements by protecting against communications outage caused by equipment failure or atmospheric conditions.

2. Fiber-optic systems

A fiber-optic system requires light wave transmitters/receivers, communication fault alarm equipment, multiplex equipment, batteries, emergency power systems, fiber-optic cable (underground or overhead) and rights-of-way. Cable route redundancy may be required to protect against cable breaks and resulting communications outage.

3. Wireline facilities

A wireline facility requires communications cable (underground or overhead), high-voltage isolation equipment and rights-of-way; it may also include multiplex equipment, emergency power systems, and batteries, depending on the wireline technology employed. Cable route redundancy may be required to protect against cable breaks and resulting communications outage.

Dedicated telecommunication facilities are required for the operation of main grid power system control and protection functions. Main grid facilities are defined by the PGE Reliability Criteria for System Planning to be 500-kV and certain 230-kV facilities. Common carrier telecommunications are not considered acceptable for supporting main grid control and protection functions. However, for secondary transmission systems (other 230-kV and below), common carrier telecommunications alternatives may be considered, subject to reliability and availability requirements and capabilities.

8-B. Voice Communications

If the resource is within the PGE Control Area:

1. **Voice communications** to the Project Operator are required whenever any type of telemetry is required.
2. **A dedicated, direct, automatic ringdown trunk** (or equivalent) voice circuit between the appropriate PGE dispatchers and the Project Operator is required for: Projects with 50 MW or greater output, or Projects that provide automatic generation dropping for PGE power system remedial action.
3. **Independent voice communications** for coordination of system protection, control, and communications maintenance activities between PGE and the Project should be provided, in addition to the voice communications specified above.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

8-C. Data Communications

Communications for SCADA and Telemetry must function at the full performance level before, during and after any power system fault condition. Communications for revenue metering must function at the full performance level before and after any power system fault condition.

- 1. SCADA requirements** typically include one or more dedicated circuits between the Project and the PGE transmission dispatching center.
- 2. AGC Interchange and Control telemetering** for operations and scheduling applications typically require one or more dedicated circuits between the Project and the PGE transmission dispatching center.
- 3. General Telemetry** for kWh typically require one or more circuits between the Project and the appropriate kWh data acquisition system.
- 4. Revenue Metering** remote equipment requires commercial 'dial-up' telephone exchange line facilities. The circuit used for this purpose may also be shared with voice communications and other dial-up data communications.

8-D. Telecommunications for Control & Protection

Communications for Control and Protection must function at the full performance level before, during, and after any power system fault condition.

- 1. Main Grid Transmission Systems.** Projects interconnecting to the PGE Main Grid, and projects for which generation dropping is required for remedial actions on the PGE System, shall have redundant (i.e. hot-standby or frequency-diversity) telecommunications systems. Alternately routed communications circuits shall be used where deemed necessary.
- 2. Secondary Transmission Systems.** Projects interconnecting to PGE secondary grid transmission may require redundant telecommunications systems.
- 3. Speed of Operation.** Throughput operating times of the telecommunications system must not add unnecessary delay to the clearing or operating times of protection or remedial action schemes. Maximum permissible throughput operating times of control schemes are determined by system studies.
- 4. Equipment Compatibility.** In order to provide maintainability and operability between the Project and the PGE System, teleprotection terminal equipment such as transfer trip units shall be functionally compatible. 'Tone' equipment must be of the same functional type. The need or implementation of peripheral capabilities such as signal counters, test switches, etc. are not required to be identical to those used at PGE facilities. PGE prefers the use of terminal equipment that is the current PGE standard for the control application. PGE will acknowledge the use of alternative equipment and/or technologies as proposed by the Project Sponsor as long as the equipment is suitable for the purposes of the control application required.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

9. Definitions

For the purposes of this document the following definitions apply:

Active Power - The component of total voltamperes in an electric circuit where the voltage and current are in phase. It is also called real power and is measured in watts (W), kW or MW. This is the electrical power associated with useful energy, including mechanical work and heat. Active power used or transmitted over time is measured in kilowatt-hours (kWh) or MWh.

Ancillary Services - The term used by FERC to describe the special services that must be exchanged among generation resources, load customers and transmission providers to operate the system in a reliable fashion and allow separation of generation, transmission and distribution functions. These include: 1) scheduling, system control and dispatch, 2) reactive supply and voltage control from generators, 3) regulation and frequency response, 4) energy imbalance, 5) spinning reserves, and 6) supplemental reserves. Most of these services are included in a similar set by NERC and termed Interconnected Operations Services, which also include load following and black start capability.

Automatic Generation Control (AGC) System - A system that measures instantaneous loads at interchange points (boundaries with adjacent Control Area) and adjusts generation to follow load. It consists of continuous, real time load signal (kW) from the site, telemetered to AGC computers at a transmission control center.

NERC Definition: Equipment which automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus frequency bias.

Bi-directional Metering - Measures kWh and kVArh flowing in both directions ('in' and 'out' kWh and leading and lagging reactive).

Blackstart Capability- The ability of a generating plant to start its unit(s) with no external source of electric power. (WECC)

Demand - The rate at which energy is being used by a customer. (NERC)

Disturbance - An unplanned event that produces an abnormal system condition. (WECC)

Effectively Grounded - A system that provides an $X_0/X_1 < 3$ & $R_0/X_1 < 1$ where X_0 and R_0 are zero sequence reactance and resistance, and X_1 is positive sequence reactance.

Fault - A short-circuit on an electrical transmission or distribution system between phases or between phases(s) and ground, characterized by high currents and low voltages.

Ferroresonance - A phenomenon usually characterized by overvoltages and very irregular wave shapes and associated with the excitation of one or more saturable inductors through capacitance in series with the inductor (IEEE). A condition of sustained waveform distortion and overvoltages created when a relatively weak source of voltage energizes the combination of capacitance and saturable transformers. A sufficient amount of damping, or resistance, in the circuit usually controls or eliminates the phenomenon.

Generation Site - The geographical location of the Project generator(s) and local generator equipment. This may be near or far from either the Point of Interconnection or the Interconnecting Substation.

Hybrid Switching - A variation of single-pole switching that is used on long lines to extinguish the secondary arc of single line-to-ground faults. The faulted phase is detected and opened first via single-pole relaying. After approximately fifty cycles the two unfaulted phases are opened to extinguish the secondary arc. Three-phase automatic reclosing follows.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

Interchange Metering - Metering at interchange points between two controlling utilities. Consists of AGC (continuous kW) telemetering and hourly kWh (on-the-hour hourly load kWh). These quantities must go to both controlling utilities so they can manage their respective Control Areas.

Interchange Point - Locations where power flows from one Control Area to another (i.e. connection between two controlling utilities).

Interconnecting Substation - Normally the substation closest to the Point of Interconnection which contains the step-up transformer and feeder breakers. This substation may be owned by PGE, the Project, or an Interconnecting Utility.

Interconnecting Utility - The utility that owns the transmission or distribution system that connects the Project to the PGE System at the Point of Interconnection.

Intertie Point - Connects electrical regions together such as Northwest to California or Canada, or east-side generation to west-side load. These connections can be entirely inside the PGE System and not metered at all, or can be interchanges with other Control Areas (with interchange metering). Not all interchanges are interties.

Island - A portion of the interconnected WECC system which has become isolated due to the tripping of transmission system elements. 'Local' Island - A portion of the transmission system, often a single line, that is isolated from the main system and energized by a local generator. Generally, system islands do not have a stable generation-resource balance.

kWh System (Kilowatt Hour System) - Provides interchange point hourly data *each hour* (as compared to a revenue metering system that reports hourly load data each day). Requires connection into PGE microwave system. Old system provides bi-directional kWh; new system (presently being installed to replace old one) will also provide bi-directional reactive. kWh data is used to verify hourly schedules.

Control Area - 1. The electrical (not necessarily geographical) area within which a controlling utility has the responsibility to adjust its generation to match internal load and power flow across interchange boundaries to other Control Areas. 2. A resource or portion of a resource that is scheduled by a specific utility. If the utility schedules the resource, the resource becomes part of its Control Area. Physical location of the Project does not determine its Control Area.

***WECC Definition:** A system which regulates its generation in order to maintain its interchange schedule with other Control Areas and contributes its frequency bias obligation to the interconnection.*

Main Grid - As presently defined by the PGE Reliability Criteria and Standards, PGE's Main Grid transmission facilities include all 500-kV lines, 500-kV substations, 500/230-kV transformers, and selected 230-kV lines and substations.

Non-spinning Reserve - That portion of the operating reserve capable of being connected to the bus and loaded within ten minutes. Also included is any load which is designated for use as reserve and can be reduced by dispatcher action within ten minutes. (WECC)

Non-Synchronous Generators - Power-generating equipment that uses induction machines or dc-to-ac conversions.

Operating Reserve - That reserve above firm system load capable of providing for regulation within the hour to cover load variations and power supply reductions. It consists of spinning reserve and non-spinning reserve. (WECC)

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

Portland General Electric Transmission System (PGE System) - The transmission facilities owned or controlled by PGE.

Phase Unbalance - The percent deviation of voltage or current in one phase as compared to the average of all three phases.

Pilot Protection - A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line. (IEEE) The communication channel may be power line carrier, microwave or other radio, fiber optics, leased telephone line or a dedicated hardwire circuit.

Point of Interconnection (POI) - The physical location on the power system of the change of ownership between PGE and the Project or PGE and an Interconnecting Utility. This may be at a different location than the Generation Site.

Power Factor - The ratio of real power in watts to the product of volts times amperes in an alternating current circuit. The power factor is unity when the voltage and current are in phase. A 'lagging' power factor is associated with a partially or wholly inductive load that 'absorbs' positive reactive power. A 'lagging' power factor is also associated with a generator that 'delivers' positive reactive power. A 'leading' power factor is associated with a capacitive load that 'delivers' or a generator that 'absorbs' positive reactive power. See reactive power.

Power System - The integrated electrical generation and transmission facilities owned or controlled by one electric utility organization. (WECC)

Power System Stabilizer (PSS)- A device that provides an additional input to the exciter of a machine to provide damping of power system oscillations and improve system stability.

Project - The generator and all equipment associated with the integration of a generation resource, up to the Point of Interconnection with PGE.

Project Requirements Diagram (PRD) - A PGE simplified drawing showing the electrical interconnection and integration of a new project to the PGE System.

Project Operator - The company that operates a generating resource.

Project Sponsor - A company that owns and/or develops a new generating resource.

Prudent Electric Utility Practices or 'Prudent Utility Practice' - The generally accepted design, practices, methods, and operation of a power system, to achieve safety, dependability, efficiency, and economy, and to meet utility and industry codes, standards, and regulations.

Rating Criteria – The assumptions used for rating PGE transmission line facilities are: 2.93 ft/sec wind speed, 40°C summer ambient temperature, 0°C winter ambient temperature, 75°C conductor temperature for copper, AAC and ACSR conductors under normal operation, 93°C conductor temperature for AAC conductors under emergency operation and 100°C conductor temperature for copper and ACSR under emergency operation.

Reactive Power - The component of total volt-amperes in an alternating current circuit where the voltage and current are out of phase by ninety electrical degrees. It is measured in units of volt-amperes reactive (VAr), kVAr or MVar. It represents the power involved in the alternating exchange of stored energy in inductive and capacitive electromagnetic fields. Although this type of power supplies no useful energy, it is an inherent requirement for all alternating current power systems. By convention, positive reactive power is 'absorbed' by an inductance and

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

'generated' by a capacitance. Reactive power transferred over time is measured in VAR-hours (VARh). See power factor.

Real Power - The component of total volt-amperes in an electric circuit where the voltage and current are in phase. It is also called active power and is measured in watts (W), kW or MW. This is the electrical power associated with useful energy, including mechanical work and heat. Real power used or transmitted over time is measured in kilowatt-hours (kWh) or MWh.

Real Time - Data reported as it happens, with reporting (update) intervals no longer than a few seconds. Applies to AGC type data, but not to kWh or revenue metering data, which are accumulated and reported only when queried by a master station.

Remedial Action - Special pre-planned corrective measures which are initiated following a disturbance to provide for acceptable system performance. (WECC)

Remedial Action Scheme (RAS) - - A protection system that automatically initiates one or more remedial actions. Also called 'Special Protection System.' (WECC)

Revenue Metering - General term for metering which is calibrated to ANSI Standards for Billing Accuracy.

Single Pole Switching (SPS) - The practice of tripping and reclosing one pole (phase) of a multipole circuit breaker without changing the state of the remaining poles. Tripping is initiated by single-pole relays that respond selectively to the faulted phase. Notes: 1) Circuit breakers used for single pole switching must inherently be capable of independent pole opening. 2) In most single pole switching schemes it is the practice to trip all poles for any fault involving more than one phase. (IEEE)

Spinning Reserve - That portion of the operating reserve which is synchronized to the system, responds automatically to fluctuations in system frequency, and is capable of assuming load up to the cited spinning reserve magnitude within ten minutes. (WECC)

Station Service - The electric supply for the ancillary equipment used to operate a generating station or substation. (NERC)

Supervisory Control and Data Acquisition (SCADA) - A system of remote control and telemetry used to monitor and control the transmission system. (NERC)

Telemetry - Continuous, real time data reporting, as for AGC and Generation kW (but not for kWh or Revenue Metering Systems, which are not continuously reported).

Three-Pole Switching - A relay system and corresponding switchgear that trips or opens all three poles (phases) regardless of fault type.

Wheeling - Transmitting power from one point to another within a Control Area or between Control Areas.

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.

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**

10. References

- **Applicable State and Local Codes**
- **ANSI/IEEE Std 80** - *Guide for Safety in AC Substation Grounding*
- **ANSI/IEEE Std 665** - *Guide for Generating Station Grounding*
- **IEEE Std 100** - *IEEE Standard Dictionary of Electrical and Electronic Terms,*
- **IEEE Std 421.4** - *IEEE Guide for the Preparation of Excitation System Specifications*
- **IEEE Std 519** - *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*
- **IEEE Std 81 Part 1** - *Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System & Part 2: Guide for Measurement of Impedance and Safety Characteristics of Large, Extended or Interconnected Grounding Systems.*
- **IEEE - 487** - *Recommend Practice for the Protection of Wire-Line Communication Facilities Serving Electric Power Stations*
- **IEEE - 837** - *Standard for Qualifying Permanent Connections Used in Substation Grounding*
- **NESC C2** - *National Electrical Safety Code*
- **NERC Operating Standards**
- **NERC Planning Standards**
- **NWPP Operating Manual**
- **Uniform Building Code**
- **WECC Reliability Criteria** including:
 - Reliability Criteria for System Design*
 - Power Supply Design Criteria*
 - Minimum Operating Reliability Criteria.*

**Please note that this document is subject to revision.
It will be periodically reviewed and updated as necessary.**