EFFECTIVE DATE:

This document is effective as of the date of the last approval signature.

APPROVAL:

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Date: 4/30/18

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PERIODIC REVIEW OF THIS STANDARD:

To ensure this standard remains current and applicable, an asset number has been assigned in Maximo and a periodic interval as stated below has been established.

WP Asset #	PM	Review
79290	14623	Annual

Table of Contents

1. Introduction

Chelan PUD (District) has prepared this facilities connection document to identify technical requirements for connecting generation, transmission, and end-user facilities to the District's electric system. As a vertically integrated utility, this includes but is not limited to connection to Transmission, Generation, and Distribution facilities. The purpose of these requirements are to assure the safe operation, integrity and reliability of the District's Electric system. Contractual matters, such as costs, ownership, scheduling, and billing are not the focus of this document. Transmission services involving power transfers over the District's electrical system are also not addressed within this document. All requests for transmission services must be made independent of the interconnection requests.

In this document, the term 'Requester' describes the utility, developer or other entity that requests a new or modified connection for a line, load or generation resource.

Requests to interconnect generation, transmission, and end-user facilities (Project(s)) are typically submitted by the Requester but may also be in conjunction with an interconnecting utility. The District evaluates and studies each Project individually, as it was described in the request and determines impacts to the District's Electric system facilities. Specific interconnection requirements are then provided back to the Requester.

An interconnecting generator may request the District to perform an enhanced study examining both interconnection and transfer capabilities, or the District may conduct such studies at its own volition. Additionally, the District shall have the option to perform one interconnect study or an enhanced interconnection/transfer capability study that encompasses multiple proposed generation facilities when said facilities are located in the same geographical area and the interconnection requests are received in a narrow timeframe. Said enhanced studies shall not confer any rights to transmission services nor is either a guarantee of the upgrades that may be required if any generator subsequently requests transmission service.

Physical laws that govern the behavior of electric systems do not recognize boundaries of electric facility ownership. Therefore the electric power systems must be studied, without regard to ownership, to develop a properly designed interconnection. The completed review may include studies of short-circuit fault duties, transient voltages, reactive power requirements, stability requirements, harmonics, safety, operations, maintenance and prudent electric utility practices.

This document also addresses interconnection through another utility that may not result in a direct interconnection to the District's Electric system. Through telemetering and communications interconnections, the District can incorporate Projects into the District's Balancing Authority Area. This type of interconnection, which uses dynamic signals and telemetering, may transfer ancillary services from one party to another.

This document is not intended as a design specification or an instruction manual and the information presented is expected to change periodically based on industry events and evolving standards. Technical requirements stated herein are consistent with the District's current internal practices for system additions and modifications. These requirements are generally consistent with principles and standards of the North American Electric Reliability Council (NERC), Western Electric Coordinating Council (WECC), Northwest Power Pool (NWPP), Institute of Electrical and Electronics Engineers (IEEE) and American National Standards Institute (ANSI). Standards of the above listed organizations are also subject to change. The most recent version of such standards shall apply to each interconnection request. Important terms used in this document are defined in Section 10-Definitions.

The Requestor is expected to comply with all appropriate policies, principles and standards of the North American Electric Reliability Council (NERC), Western Electric Coordinating Council (WECC), Northwest Power Pool (NWPP), Institute of Electrical and Electronics Engineers (IEEE) and American National Standards Institute (ANSI) as appropriate. The District assumes no compliance or reporting responsibilities for the Requestor unless expressly agreed to in writing. The Requestor must provide the District documentation of compliance in a timely manner when requested.

2. Scope

These technical requirements generally apply to all new or modified interconnections to the District's Electric system and telemetered balancing authority area interconnections. The location and type of the facility, and impacts on the District's Electric system or another utility's system determine the specific requirements. The interconnection must not degrade the safe operation, integrity and reliability of the District's Electric system. The interconnection requirements are intended to protect the District's facilities, but cannot be relied upon to protect the Requester's facilities.

2-A. Applicable Codes, Standards, Criteria and Regulations

To the extent that the codes, standards, criteria and regulations are applicable, the new or modified facilities shall be in compliance with those listed in Section 12.

2-B. Safety, Protection, and Reliability

The District will make the final determination as to whether District facilities are properly protected before an interconnection is energized. The Requester and/or interconnecting utility is responsible for proper protection of their own equipment and for correcting such problems before facilities are energized or interconnected operation begins. The District may determine equivalent measures to maintain the safe operation and reliability of the District's Electric system. For most generation facilities and some end-user facilities, this may include The District's capability for direct tripping through special protection schemes. In situations where there is direct interconnection with another utility's system, the requirements of that utility also apply.

2-C. Responsibilities

The District, the Requester and interconnecting utility are each responsible for the planning, design, construction, compliance with applicable statutes, reliability, protection, and safe operation and maintenance of their own facilities unless otherwise identified in the construction, operation and/or maintenance agreements. The District reserves the right to require the Requester to provide corrections or additions to existing Requester owned equipment in the event of modification of government or industry regulations and standards at the Customer's expense.

2-D. Special Disturbance Studies

The District may use shunt 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 interconnected facilities. This may include the possibility of electromechanical resonance between a generator and the electric system, or large angle changes when considering high-speed reclosing. The District will conduct studies of interconnection impacts to the District's facilities at the Requester's expense. The Requester is solely responsible for any studies necessary to evaluate possible stresses on their equipment and for any corrective actions.

2-E. Cost Estimates

The District develops cost estimates on a case-by-case basis when asked to perform interconnection studies since each interconnection is different and impacts District facilities differently.

In general, all costs for integrating the project are the responsibility of the Requester, unless expressly agreed to in writing by the District. These costs include, but are not limited to, all the costs of study, engineering, inspection, connection, switching, metering, transmission, distribution, safety provisions, equipment to be owned by the District, and administrative costs incurred by the District directly related to the installation and maintenance of the physical facilities necessary to permit the customer-owned generating facility operation.

3. Requesting Interconnection of New Facilities

The Requestor may request interconnection of a generation, transmission, or end-user facilities to the District's Electric system. Inclusion of such facilities within the District's Balancing Authority Area may also be requested. For any of these requests, the District should be contacted as early as possible in the planning process. An interconnection study must be performed to determine the required additions and modifications to the District's substations, transmission lines, control and communications circuits to accommodate the proposed interconnection.

Requests for transmission services are not included in this document.

3-A. Requesting an Interconnection

Requests for new interconnections should be made through the appropriate District Representative by contacting service@chelanpud.org. All requests should be accompanied by connection related information as listed in Section 9, Information Requirements . More information about the facility interconnection process and necessary forms are available on the District's web site, http://www.chelanpud.org.

3-B. Interconnection Studies

The District performs technical studies to determine the feasibility of the interconnection request. The studies required will vary depending upon the type of interconnection requested. These studies can require considerable time and effort, depending on the size of the Project and its potential system impacts. The studies will investigate the impact on system performance of the interconnecting project. This may include analysis of equipment thermal overloads, voltage stability, transient stability, and short circuit interrupting requirements. Technical issues directly associated with the project, such as voltage regulation, machine dynamics, metering requirements, protective relaying, and substation grounding will also be addressed as required in development of the preferred plan of service. The requester shall not make any assumptions about final location or other technical aspect of the interconnection.

The detailed interconnection study results may include, but is not limited to, the following:

- The preferred and alternate locations where the facility(s) may be interconnected to the District's Electric system,
- Any modifications and/or additions needed to the District's system to accommodate the customer-owned generating facility(s),
- The major interconnection equipment that the Requestor 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 the District to perform its design, material procurement, construction and energization,
- An estimate of costs for additions and modifications to the District system, and
- A preliminary, customer-specific Interconnection Requirements that illustrate items above.

The District requires specific analysis to consider impacts to the transmission system for end-user facilities that request to interconnect to the District's Electric system at the transmission level with either a looped or radial service. The District also requires end-user facilities greater than 5 MW that request to interconnect to the District's Electric system at the distribution level will also be assessed for potential impacts to the District's transmission system. See Figure 3-1 for examples of such end-user interconnection requests.

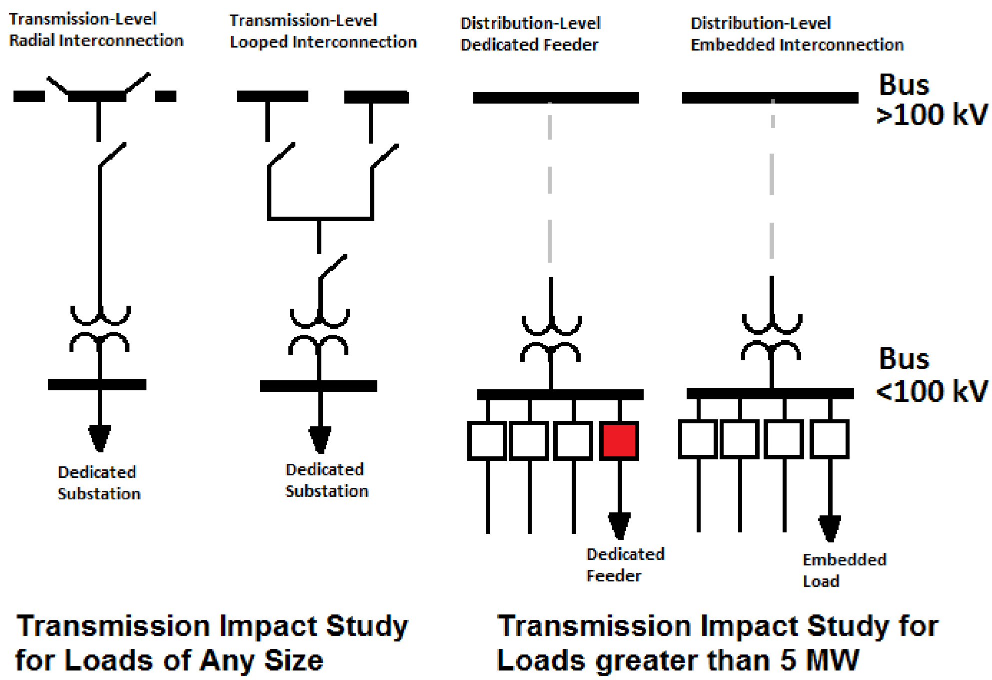

FIGURE 3-1

Typical end-user interconnection requests that require analysis for impacts to the District's transmission facilities.

3-C. Coordination of impacts to the interconnected transmission system

New or materially modified interconnections will be jointly studied with the District and its neighbors to evaluate the impacts on the interconnected transmission system. These joint studies are conducted through the District's contractual relationship with ColumbiaGrid as a party to the Planning and Expansion Functional Agreement (PEFA). All of the District's neighboring utilities participate in the PEFA process as well. Those responsible for the reliability of the affected system(s) of new or materially modified facilities are to participate in these joint study teams with the District at ColumbiaGrid to evaluate such new or materially modified interconnections. The ColumbiaGrid Biennial Plan documents new or materially modified transmission system interconnections affecting the Regional Interconnected Systems. New or materially modified interconnections that will impact only a single party's transmission system are included in Biennial Plans for informational purposes.

After adoption, ColumbiaGrid's Biennial Plan and plan updates are distributed to members of the study team and posted on the ColumbiaGrid Web site at www.columbiagrid.org. Those responsible for the reliability of the affected system(s) of new or materially modified facilities will receive notification of those impacts through the ColumbiaGrid biennial plans.

Notification of new or modified facilities are also provided through the WECC base case development process.

4. General Requirements

4-A. Safety and Isolating Devices

For an interconnection to the District's Electric system, an isolating device, typically a motor operated disconnect switch with a visible air gap for clearance tagging, shall be provided to physically and visibly isolate the District's Electric system from the connected facilities. The isolation device may be placed in a location other than the Point of Interconnection (POI), by agreement of the District and affected parties. Safety and operating procedures for the isolating device shall be in compliance with the District's Switching and Clearances Handbook and the Requester's and/or interconnecting utility's operating safety manuals. The following requirements apply for all isolating devices:

- Must simultaneously open all three phases (gang operated) to the connected facilities.
- Must be accessible by District personnel.
- Must be lockable in the open position by District personnel.
- Will not be operated without advance notice to affected parties, unless an emergency condition requires that the device be opened to isolate the connected facilities.
- Must be suitable for safe operation under all foreseeable operating conditions.
- All switchgear that could energize equipment shall be visibly identified, so that all maintenance crews can be made aware of potential hazards.

All work practices involving District owned, maintained, and/or operated equipment, must be done in accordance with the principles contained in the District's Switching and Clearances Handbooks and done at the direction of the District's system operations personnel. District personnel may lock the isolating device in the open position and install safety grounds:

- For the protection of maintenance personnel when working on de-energized circuits.
- If the connected facilities or equipment presents a hazardous condition.
- If the connected facilities interferes or jeopardize the operation of the District's System.
- If the District's system interferes or jeopardizes the operation of the connected facilities.

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

4-B. Considerations at Point of Interconnection

4-B.1 General Constraints

Connected facilities shall not restrict the District's right to schedule and perform maintenance on the interconnection line and all of its components.

4-B.2 General Configurations

Connection of new facilities into the transmission system usually falls into one of three categories:

a. Connection into an existing 115 kV or 230 kV bulk power substation, with (depending on the bus configuration) the existing transmission and new connecting lines each terminated into bays containing one or more breakers.

b. Connection into an existing 115 kV or 230 kV transmission line via a tap

c. Connection by looping an existing 115 kV or 230kV transmission line into a new customer or District owned substation. These three categories may include the situation where another utility owns the transmission line or equipment that directly connects to the District's Electric system.

The District must maintain full operational control of the transmission path. This may include, but not be limited to, SCADA control and monitoring of circuit breakers, disconnects and other equipment in the new substation. Additionally, the District will retain contractual path rights. Any new equipment shall not degrade the operational capability of the line.

A multi-terminal line is created when the new connection, such as (b) or (c) above, becomes an additional source of real power and fault current beyond the existing sources at the line terminals. A line with three terminals affects the District's ability to protect, operate, dispatch and maintain the transmission line. the District determines the feasibility of multi-terminal line connections on a case-by-case basis. Examples of possible configurations based on magnitude of customer owned generation and necessary system protection are outlined in Section.6-D, Generator Configuration and Protection.

4-B.3 Special Configurations

The District's Bulk Electric System transmission lines include all networked 230 kV and 115 kV, as defined by the District's Reliability Criteria and Standards. These circuits form the backbone Of the District's transmission system and provide the primary means of serving large geographical areas. In general, The District requires a substation with additional breakers at the POI to maintain reliability and security of the main grid system. Depending on generator (or load) size, contractual arrangements and the Interconnection study results, multiple connection points including additional transmission lines and breakers may also be required.

Small generators less than 10 MVA may be connected directly to the District's distribution system at Distribution level voltages. Refer to Section 6-D, Generator Configuration and Protection for typical configurations.

In instances where there is an interconnection request from a third party Facility to interconnect to one of the District's Generation facilities that connects to one of the District's Transmission systems (under FAC-002-2), the connection requirements within this document are applicable.

4-B.4 Mechanical (or Electrical) Interlocking System

To ensure safety of working personnel, the District may require a mechanical (or electrical) interlocking system between the utility tie breaker and the visible disconnect switch at the POI.

4-C. Transformer Considerations

4-C.1 New Installations

Transformers connecting to the transmission system where a source of real power flows through the transformer to the District's high voltage transmission system shall provide a ground source of current on the high voltage side. The District typically requires a **delta/wye-grounded transformer with wye-grounded on the high side and delta on the low side**. This type of connection will allow the District to continue using conventional high voltage line protective devices and surge arresters without any major modifications to protective schemes and also to minimize hazardous ferroresonance/neutral-shift conditions. A YG- Δ -YG transformer with the Y-ground connection on the high voltage side can also accomplish this. A YG-YG connection is only appropriate if there is a sufficient ground source on the low voltage side and will need to be evaluated by the District before being permitted. New Δ -YG transformers with the delta connection on the high side are typically only permitted to serve loads.

4-C.2 Existing Installations

Generation or transmission facility connections to existing Δ -YG transformers used to serve load may require additional system equipment, such as a grounding bank, to provide adequate protection against ungrounded system operation. Relay protection schemes may also be required to ensure immediate disconnection of the power source following disconnection of the transmission system components. The District will consider these on a case-by-case basis only.

4-D. Other Interconnection Considerations

4-D.1 Existing Equipment

The proposed new connection may cause existing equipment such as transformers, power circuit breakers, disconnect switches, arresters, and transmission lines to exceed their ratings. New connections may require equipment replacement or an alternate plan of service.

4-D.2 System Stability and Reliability

The District's Electric system has been developed with careful consideration for system stability and reliability during disturbances. The type of connection, size of the source or load, breaker configurations, source or load characteristics, and the ability to set protective relays will affect where and how the connection is made. For most generators and some end-user facilities, the Requester will also be required to participate in special protection or remedial action schemes (RAS) including automatic tripping or damping of generation or load. Section 6 provides additional information and requirements for these schemes.

4-D.3 Control and Protection

The District coordinates its protective relays and control schemes to provide for personnel safety, equipment protection and to minimize system instability and disruption of services during disturbances. New connections usually require the addition or modification of protective relays and/or control schemes, including replacement or modification of equipment at the remote terminal(s). The new protection must be compatible with existing protective relay schemes and present standards. The addition of voltage transformers, current transformers, or pilot scheme (transfer trip) may also be necessary. The District will supply the Requester with recommended protective relay systems. Should the Requester select a relay system different from standard District applications, the District reserves the right to perform a full set of acceptance tests prior to granting permission to use the selected protection scheme. Requester selected equipment must have interfaces compatible with District equipment.

4-D.4 Dispatching for System Operations and Maintenance

The District operates and maintains its system to provide reliable customer service while meeting the seasonal and daily peak loads even during equipment outages and disturbances. New line and load connections must not restrict timely outage coordination, automatic switching or equipment maintenance scheduling. Preserving reliable service to all District customers is essential and may require additional switchgear, equipment redundancy, or bypass capabilities at the POI for acceptable operation of the system.

4-D.5 Atmospheric and Seismic

The effects of fires, windstorms, floods, lightning, elevation, temperature extremes, icing, contamination and earthquakes must be considered in the design and operation of the connected facilities. The Requester is responsible for determining that the appropriate standards, codes, criteria, recommended practices, guides and prudent utility practices are met for equipment that they are installing.

4-D.6 Physical and Cyber Security

The potential vulnerability of the facility to sabotage or terrorist threat should be factored into the design and operating procedures. Both physical security and cyber security shall be evaluated. The Requester is responsible for determining that the appropriate standards, codes, criteria, recommended practices, guides and prudent utility practices are met for equipment that they are installing.

4-D.7 Ownership

The District shall own any and all improvements or equipment attached to the District's distribution or transmission system on the District's side of the Primary Metering installation. All required equipment shall meet the District's equipment specifications. The District shall be deemed the owner of such equipment and/or improvements upon completion of construction.

4-E. Transmission and Substation Facilities

Some new connections to the District's Electric system require that one or more District lines (a transmission path) be looped through the Requester's facilities, or sectionalized with the addition of switches. The design and ratings of these facilities shall not restrict the capability of the line(s) and the District's contractual transmission path rights.

4-E.1 Transmission Line Designs

The District's owned or maintained transmission lines shall be designed such that the requirements of the District's Standards and Switching Protocols are met. Among these requirements are the following:

- **a.** The requirements of the NESC C2,WISHA and OSHA shall be met.
- **b.** The minimum approach distances shall be designed in accordance with chapter 296-45 WAC of the Washington State safety standard for electrical workers.
- **c.** The line shall be designed and sagged to meet or exceed the NESC C2 clearance to ground while operating at rated maximum operating temperature.
- **d.** All new transmission lines connecting to a District substation shall have one or more overhead ground wires (OHGW) to provide substation shielding. For transmission lines 115 kV, the OHGW shall be ½ mile in length. For transmission lines 230 kV, the OHGW shall be 1 mile in length. The OHGW design and connection points shall be approved by the District.
- **e.** All lines connecting to a District substation shall include surge arresters for substation entrance protection. District staff will recommend the appropriate level of entrance protection.
- **f.** Access to all structures shall be provided.
- **g.** Underbuilds to existing District transmission line facilities will generally not be allowed. If an underbuild is requested and approved, a special 'pole contract agreement' will have to be negotiated.
- **h.** Planned facility ratings, including bottleneck data, shall be supplied to the district as part of the interconnection request. There ratings shall be in accordance with applicable NERC, WECC, and District Standards and Work

Practices. Any applicable methodologies used by the Requestor shall also be supplied.

4-E.2 Customer Built Substations and Facilities

Customer built substations that interrupt an existing District transmission path and customer-built facilities in a District substation must meet the requirements of the District's Standards and Switching Protocols. A summary of these requirements follows:

- **a.** The facility must be designed to applicable requirements of the NESC C2, NEC, ANSI and IEEE Standards.
- **b.** The site selection must consider environmental aspects, oil containment and fire suppression.
- **c.** Grounding must be in accordance with IEEE Standard 80.
- **d.** Where District transmission is considered critical, two sources of station service is required. Exceptions will be considered on a case by case basis.
- **e.** Electrical equipment in the substation must be sized to carry the full current rating of the interrupted transmission path. This includes circuit breakers, disconnect switches, current transformers and all the ancillary equipment that will serve as the continuation of the path during any switching configuration.
- **f.** Planned facility ratings, including bottleneck data, shall be supplied to the district as part of the interconnection request. There ratings shall be in accordance with applicable NERC, WECC, and District Standards and Work Practices. Any applicable methodologies used by the Requestor shall also be supplied.
- **g.** The acceptable bus configurations of any new switching stations shall be either ring or breaker-and-a-half. In some cases the District may not allow three-terminal line configurations due to complexity of 3-terminal line protection and switching operation and due to undesirable impact to system stability.

4-F. Insulation Coordination

Power system equipment is designed to withstand voltage stresses associated with expected operation. Adding or connecting new facilities can change equipment duty, and may require that equipment be replaced or switchgear, telecommunications, shielding, grounding and/or surge protection be added to control voltage stress to acceptable levels. Interconnection studies include the evaluation of the impact on equipment insulation coordination. The District may identify additional requirements to maintain an acceptable level of The District's Electric system availability, reliability, equipment insulation margins and safety. The Customer shall be fully responsible for the protection of his/her generating facility from transient surges initiated by lightning, switching, or other system disturbances.

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. 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 transformers, and surge protection with arresters on the incoming lines. The following requirements may be necessary to meet the intent of the District's Standards.

4-F.1 Lightning Surges

If the Requester 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.

Lines at voltages of 115 kV and higher that terminate at District substations must meet additional shielding and/or surge protection requirements identified in Section 4-E. For certain customer service substations at 115 kV and below, the District may require only an arrester at the station entrance in lieu of line shielding, or a reduced shielded zone adjacent to the station. These variations depend on the tap line length, the presence of a power circuit breaker on the transmission side of the transformer, and the size of the transformer.

4-F.2 Temporary Overvoltages

Temporary overvoltages can last from seconds to minutes, and are not characterized as surges. These overvoltages are present during islanding, faults, loss of load, or long-line situations. All new and existing equipment must be capable of withstanding these duties.

4-F.3 Local Islanding

When the connection involves tapping a transmission line, a local island may be created when the breakers at the ends of the transmission line open. This can leave generating resources and any other end-user facilities that also are tapped off this line isolated from the power system. Delayed fault clearing, overvoltages, ferroresonance, extended undervoltages and degraded service to other District customers can result from this local island condition. Therefore local islands involving District transmission facilities are not allowed to persist, except for a temporary, area-wide grid separation under control of the District's System Operator. Special relays to detect this condition and isolate the local generation from District facilities are described in Section 6-B2.

4-F.4 Neutral Shifts

When generation is connected to the low-voltage, grounded wye side of a delta-grounded wye (Δ – YG) transformer, opening the high voltage connection due to fault clearing may cause overvoltages on the high voltage terminal. These high voltages 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. Alternative remedies to avoid neutral shift and its potential problems are as follows:

a. Effectively Grounded System

Utilize appropriate transformer connections on the high-voltage side to make the system 'effectively grounded' and independent from other high voltage system connections. Effectively grounded is defined as a system X0/X1 less than or equal to 3.0 and R0/X0 less than or equal to 1.0. Any of these methods can result in an effectively grounded system that will minimize the risk of damage to surge arresters and other connected equipment. Methods available to obtain an effective ground on the high voltage side of a transformer include the following:

- A transformer with the transmission voltage (District) side connected in a YG configuration and low voltage side in a closed Δ.
- A three winding transformer with a closed Δ tertiary winding and both the primary and secondary sides connected YG.
- Installation of a grounding transformer on the high voltage side.

b. Increase Insulation Levels

Size the insulation of equipment connected to the transmission line high-voltage side to be able to withstand the expected amplitude and duration of the neutral shift. This may include equipment at other locations.

c. High Speed Separation

Rapidly separate the back-feed source from the step-up transformer by tripping a breaker, using either remote relay detection with pilot scheme (transfer trip) or local relay detection of the overvoltage condition (See Section 6-B2).

4-G. Substation Grounding

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

If a new ground grid is close to another substation, the two ground grids may be isolated or connected. If the ground grids are to be isolated, there must be no metallic ground connections between the two substation ground grids. Cable shields, cable sheaths, station service ground sheaths and overhead transmission shield wires can all inadvertently connect ground grids. Fiber-optic cables are preferred for providing telecommunications and control between two substations while maintaining isolated ground grids. If the ground grids are to be interconnected, the interconnecting cables must have sufficient capacity to handle fault currents and control ground grid voltage rises. The District must approve any connection to a District substation ground grid.

New interconnections of Projects 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 ground grid should be designed to all applicable NESC, ANSI, IEEE and WISHA Standards relating to safety in substation grounding [Ref.1.9,2.1, 2.2, 2.4, 2.7, 2.9,2.14].

4-H. Inspection, Test, Calibration and Maintenance

Transmission elements (e.g. lines, line rights of way, transformers, circuit breakers, control and protection equipment, metering, and telecommunications) that are part of the proposed connection and could affect the reliability of the District's Electric system need to be inspected and maintained in conformance with regional standards. The Requester has full responsibility for the inspection, testing, calibration, and maintenance of their equipment, up to the location of change of ownership or POI. Transmission Maintenance and Inspection Plan (TMIP) requirements are a portion of the WECC Reliability Management System for Transmission and the NERC reliability standards. The Requester or utility may be required by WECC/NERC to annually certify that it has developed, documented, and implemented an adequate TMIP.

4-H.1 Pre-energization Inspection and Testing

The Requester is responsible for the pre-energization and testing of their equipment. Section 6-F describes specific installation testing requirements for protections systems.

For equipment that can impact the District's Electric system, the Requester shall develop an Inspection and Test Plan for pre-energization and energization testing. The District may request to review the test plan prior to the test(s). The District may require additional tests. The Requester shall make available to the District, upon request, all drawings, specifications, and test records of the POI equipment. Also upon request the District will make available to the Requester similar documents describing the District's POI equipment.

4-H.2 WECC Transmission Maintenance and Inspection Plan (TMIP)

The Requester is responsible for implementing a Transmission Maintenance and Inspection Plan as applicable per WECC Regulatory Standards.

4-H.3 Calibration and Maintenance of Revenue and Interchange Metering

Revenue and interchange metering will be calibrated as scheduled by the District. Other calibration intervals may be negotiated. All interested parties or their representatives may witness the calibration test. Calibration records shall be made available to all interested parties.

Each meter shall be calibrated against a standard or reference instrument or meter that has been calibrated and certified during the preceding twelve months. Calibration of standard meters and instruments must meet accuracy requirements of the National Institute of Standards and Technology.

4-H.4 District Inspection and Maintenance Records

The Requestor shall maintain their facilities in good working order. All customer owned facilities may be subject to District inspection upon reasonable notice by the District. The Requestor shall assume full responsibility for the routine maintenance of the facility equipment and associated protective devices and the keeping of records for such maintenance. These records shall be available to the District for inspection at all times.

4-I. Station Service

Power that is provided for local use at a substation to operate lighting, heat and auxiliary equipment is termed station service. 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 Requester. The station service requirements of the new facilities, including voltage and reactive requirements, shall not impose operating restrictions on the District's Electric system beyond those specified in applicable NERC, WECC and NWPP Reliability Criteria.

Appropriate providers of station service and alternate station service are determined during the interconnection study and planning process, including project diagram (PD) development and review. Generally, the local utility will be the preferred provider of primary station service unless it is unable to serve the load .

The Requester must provide metering for station service and alternate station service, as specified by the metering section of this document or negotiate other acceptable arrangements.

4-J. Ancillary Services

All generators, end-user facilities and transmission facilities must be part of a balancing authority area. The balancing authority area provides critical ancillary services, including load regulation, frequency response, operating reserves, voltage control from generating resources, scheduling, system controls and dispatching service, as defined by FERC, NERC or their successors. All new connections to the District's Electric system also require a transmission contract. The Requester must choose the balancing authority area in which the new facilities will be located and the source and/or provider of ancillary services. This election and associated data requirements should be identified in the ancillary service exhibit of the transmission contract.

Of particular importance is the Requester's selection of the source for regulating and contingency reserves, if needed. The District will then determine the telemetering, controls, and metering that will be required to integrate the load or facility into the chosen balancing authority area and to provide the necessary ancillary services. If the Requester chooses a self-provision or a third party provision of reserves, then special certification and deployment procedures must be incorporated into the District's automatic generation control, (AGC) system. The provision of the required ancillary services must meet all relevant NERC, WECC and NWPP reliability standards and criteria.

The generator must operate in voltage control mode, regulating the voltage to a District provided schedule. Typically the generator should supply reactive power for its station service loads and reactive power losses up to the POI. Generator projects may be requested to supply reactive power as an ancillary service.

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

5. Performance Requirements

5-A. System Operation and Power Quality

5-A.1 Isolating

The Requester shall not energize any de-energized District equipment unless the District's System Operator specifically approves the energization. Where the connection is to a radial load the circuit may be interrupted and reclosed by the District. In cases where the interconnection breaks an existing District line, an automatic isolation scheme may be required to maintain continuity to the District's line. If the interconnected facilities are networked or looped back to the District's Electric system or where generation resources are present, a switching device must open to eliminate fault contributions or neutral shifts. Once open, the device must not reclose until approved by the District's System Operator or as specified in the interconnection agreement.

5-A.2 Synchronizing

The Requester's system or portion of system with energized generators must synchronize its equipment to the District's Electric system. The exception to this is under large-scale islanding conditions, where the District's Electric system will re-synchronize to neighboring systems over major interties. This re-synchronizing is directed by the Peak Reliability Coordinator. Automatic or manual synchronization shall be supervised by a synchronizing check relay, IEEE Device 25. Please refer to Section 6-D.2, for specific requirements regarding synchronizing and reclosing.

5-A.3 Voltage Schedules

Voltage schedules are necessary, in order to maintain optimal voltage profiles across the transmission system. Optimal profiles minimize transmission of reactive power, and preserve flexibility in use of reactive-power control facilities. To this end, a voltage schedule will be mutually developed between he District and the Requester in coordination with regional voltage requirements. The District maintains voltages according to the ANSI Standard C84.1. This allows for variances of ±5% from nominal for all voltage levels on the District's system. Limitations of equipment connected to the District's Electric system must not restrict this range of operation. Deviations from the voltage schedule may be ordered by the District's System Operator in order to meet unexpected system conditions.

5-A.4 Reactive Power

Each entity shall provide for its own reactive power requirements, at both leading and lagging power factors unless otherwise specified by the District. The District generally requires customers to minimize exchange of reactive power with the District's system, especially under peak load conditions. This can be accomplished by installing equipment to allow matching of internal supply and demand of reactive power.

In general, customer owned generating facilities shall not take reactive power from the District's system. Generator operating limits shall be reviewed and approved by the District prior to start up. For reliability reasons the District's system operator may request customer owned generations to supply maximum available reactive capability and/or to adjust generation levels all the way to zero if necessary.

Closely coupled generators may also receive telemetered voltage schedules to minimize var conflict. (See Section 7) Minimizing flow of reactive power on a given line can increase its transfer capability and reduce its losses. Reactive flows at interchange points between Balancing Authorities should be kept at a minimum as per NERC reliability requirements.

5-A.5 Power Quality

Power quality is the responsibility of both the facility connected to a utility system and the utility(s) providing distribution and transmission. Since this document focuses on the interconnection of generation, transmission and end-user facilities to the District's Electric system, this section will deal primarily with power quality problems typically introduced by the Requester as termed in this document. The Requester is expected to address, in the design of their facilities, potential sources and mitigation of power quality degradation prior to interconnection. Design considerations should include applicable standards including, but not limited to IEEE Standards 142, 519, 1100 1159, 1547, ANSI C84.1 and the District's Electrical Service Requirements.

In general, the Requester has the responsibility not to degrade the quality and reliability of service provided to the District's facilities or customers. The Requester also has certain responsibilities to account for transmission system events like switching transients and fault induced voltage sags. Standards exist for manufacturers and system designers to take into account short duration system events in order to design equipment or systems with sensitivities capable of riding through events that are within utility system operating standards. If it is determined that the new connection facility is causing a power quality problem, then the Requester will be held responsible for installation of the necessary equipment or operational measures to mitigate the problem. Typical forms of power quality degradation include, but are not limited to voltage regulation/unbalance, harmonic distortion, flicker, voltage sags/interruptions, and transients. Some of the more common forms of degradation are discussed below.

a. 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 Standard 519, 241 and 141 provide definitions and limits on acceptable levels of voltage fluctuation. End-user facilities or system connections to the District's Electric system shall comply with the limits set by these standards.

b. Harmonic Distortion

Nonlinear devices such as adjustable or variable speed drives (ASD/VSD), power converters, arc furnaces, and saturated transformers can generate harmonic voltages and currents on the transmission system. These harmonics can cause telecommunication interference, increase thermal heating in transformers and reactors, disable or cause misoperations of solid-state equipment and create resonant overvoltages. In order to protect power system equipment from damage or misoperations, harmonics must be managed and mitigated. The new connection shall not introduce harmonics into the District's Electric system in excess of the limits specified in IEEE Standard 519.

In addition to end-user facilities with nonlinear devices new generation resources or distributed resources should be evaluated not only for possible injected harmonics, but also for potential resonant conditions. For example, some generation resources, whether due to power factor correction capacitors or cable capacitances, may be capacitive during certain operating configurations. These types of configurations may result in resonant conditions within the project or in combination with the utility system. The short circuit ratio (SCR) tests as listed in IEEE 1547 and IEEE 519 can be good indicators of this potential problem. If the evaluation of the new connection indicates potential harmonic resonance the requester may be required to filter, detune, or mitigate in some way the potential resonant conditions associated with connection of the new resource.

For individual end users, the IEEE 519 Standard limits the level of harmonic currents injected at the POI (listed in IEEE as the PCC) between the end user and the utility. Recommended limits are provided for individual harmonic components and for the total demand distortion. These limits are expressed as a percentage of the customer's demand current level, rather than as a percentage of the fundamental, in order to provide a basis for evaluation over time. There are also limits for voltage distortion for both individual frequency and total harmonic distortion.

c. Phase Unbalance

Unbalanced phase voltages and currents can affect coordination of protective relaying, induce higher flows of current on neutral connections, and cause thermal overloading of transformers. A phase unbalance is measured as a percent deviation of one phase from the average of all three phases. To protect equipment owned by the District and by the Requester, the contribution from the new facilities at the POI shall not be allowed to cause a voltage unbalance greater than 1% or a current unbalance greater than 5%.

System problems such as a blown transformer fuse or open conductor on a transmission system can result in extended periods of phase unbalance. It is the Requester's responsibility to protect all of its connected equipment from damage that could result from such an unbalanced condition.

5-B. Reliability and Availability

5-B.1 Maintaining Service

All users, operators and owners of the Bulk Power System share in the responsibility for maintaining system reliability in accordance with The Energy Policy Act of 2005. An adequate level of reliability occurs when the system is planned, constructed and operated such that:

1. The System remains within acceptable limits.
2. The System performs acceptably after credible contingencies
3. The System prevents instability and cascading outages
4. The System's facilities are protected from severe damage; and
5. The System's integrity can be restored if it is lost.

5-B.2 Transmission Lines

The Requestor's facilities may be part of or connected to key transmission lines that must be kept in service as much as possible. They may be removed from service only after power flow studies, in accordance with WECC requirements, indicate that system reliability will not be degraded below acceptable levels. The entity responsible for operating such transmission line(s) shall promptly notify other affected control areas, per the "Peak RC Data Request and Specification for Data Provision" and the "Peak RC Outage Coordination Process" documents when removing such facilities from and returning them back to service.

5-B.3 Switchable Devices

Devices frequently switched to regulate transmission voltage and reactive power shall be switchable without de-energizing other facilities. Switches designed for sectionalizing, loop switching, or line dropping shall be capable of performing their duty under heavy load and maximum operating voltage conditions.

5-B.4 Frequency and Duration of Outages

Planned outages of significant system equipment shall be coordinated with all affected parties to minimize their impact on the remaining system. The operator of the Requester's facilities should respond promptly to automatic and forced outages in order to mitigate any impacts on the remaining system, and in a manner that treats all interruptions with the same priority.

5-B.5 Key Reliability and Availability Considerations

a. New or modified interconnected facilities shall meet all NWPP, NERC, WECC, and District Planning Standards as well as respective NERC/WECC Operating

Policies, Reliability Standards, and any other WECC guides or policies that apply.

b. Tools and spare equipment must be readily available to accomplish necessary operations and maintenance tasks.
c. Bypass equipment must be fully rated to allow continued operation without creating a bottleneck. Alternate feeds, when provided, shall have sufficient rating to not restrict operation of the District's Electric system.
d. Shielding and electromagnetic interference (EMI) protection shall be provided to ensure personnel safety and proper equipment functioning during disturbances such as faults and transients.
e. Standardized design, planning, operating practices and procedures should be used so the new connection may be readily incorporated into the existing transmission network.
f. For reliable operation, the telecommunications, control and protection equipment must be redundant to the extent described in Sections 6 and 8.
g. The equipment for the new connection shall have sufficient capabilities for both the initial operation and for long-range plans.
h. Operations and maintenance personnel must be properly trained for both normal and emergency conditions

5-C. Power System Disturbances and Emergency Conditions

5-C.1 Minimizing Disturbances

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

- Electric disturbances that produce abnormal power flows
- Power system faults or equipment failures
- Overvoltages during ground faults
- Audible noise, radio, television, and telephone interference
- Power system harmonics
- Other disturbances that might degrade the reliability of the interconnected Electric system

5-C.2 System Frequency During Disturbances

Power system disturbances initiated by system events such as faults and forced equipment outages, expose the system to oscillations in voltage and frequency. It is important that lines remain in service for dynamic oscillations that are stable and damped.

Large-scale blackouts can result from the excessive loss of generation, outage of a major transmission facility, or rejection of load during a disturbance. In order to prevent such events, under frequency load shedding (UFLS) has been implemented throughout the western interconnection. When system frequency declines, discrete blocks of load are automatically interrupted by frequency relays, with most of the interruptions initiated between 59.3 Hz and 58.6 Hz. Load shedding attempts to stabilize the system by balancing the generation and load. It is important that lines and generators remain connected to the system during frequency excursions, both to limit the amount of load shedding required and to help the system avoid a complete collapse. The limited ability of some generators to withstand off-nominal frequency operation has been taken into account in the development of frequency relay setting delays provided in Section 6-D.3.

5-C.3 Voltages During Disturbances

In order to prevent voltage collapse in certain areas of the Pacific Northwest, undervoltage load shedding (UVLS) has also been implemented. Most of the load interruptions will occur automatically near 0.9 per unit voltage after delays ranging from 3.5 to 8.0 seconds. Depending on the type and location of any new load, the Requester may be required to participate in this scheme. The undervoltage relay settings in Section 6-D.3 shall coordinate with the undervoltage load shedding program.

5-C.4 Responsibilities During Emergency Conditions

Balancing Authorities are ultimately responsible for maintaining system frequency within their prescribed boundaries. All emergency operations involving the District's balancing authority area and transmission system must be coordinated with the District's system operations. Each party, as appropriate, must participate in any pre-defined local or regional remedial action schemes. All end-user facilities or generators tripped by underfrequency or undervoltage action must **not** be restored without the District's system operator's permission. Schedule cuts also need to be promptly coordinated according to NERC/WECC reliability standards. All parties have the responsibility for clear communications and to report promptly any suspected problems affecting others.

5-D. Switchgear

5-D.1 General Requirements

Circuit breakers, disconnect switches, and all other current-carrying equipment connected to the District's transmission system shall be capable of carrying normal and emergency load currents, and must also withstand available fault currents without damage. This equipment shall not become a limiting factor, or bottleneck, in the ability to transfer power on the District's Electric system. During prolonged steady-state operation, all such equipment shall be capable of carrying the maximum continuous current that the interconnected facility can reasonably deliver.

All circuit breakers and other fault-interrupting devices shall be capable of safely interrupting fault currents for any fault that they may be required to interrupt. Application shall be in accordance with ANSI/IEEE C37 Standards. These requirements apply to the equipment at the POI as well as other locations on the District's Electric system. The District supplies the fault-interrupting requirements.

The connection of a transmission line or load can coincidentally include other generating resources. When this system configuration is connected to the low-voltage side of a Δ-YG transformer, the high-voltage side may become ungrounded when remote end breakers open, resulting in high phase-to-ground voltages. This neutral shift phenomenon is described in Section 4-F.5. Switchgear on the high side of a Δ-YG transformer that interrupt faults or load must be capable of withstanding increased recovery voltages. Circuit breakers shall be capable of performing other duties as required for specific applications. These duties may include capacitive current, and out-of-step switching. Circuit breakers shall perform all required duties without creating transient overvoltages that could damage District equipment.

Generally, circuit breakers for transmission lines are required to provide automatic high-speed reclosing, with reclose times ranging from 1/3 of a second to two seconds (20 to 120 cycles).

5-D.2 Circuit Breaker Operating Times

Table 5-1 specifies the interrupting times typically required of circuit breakers on the District's Electric system. These times will generally apply to equipment at or near the POI. System stability considerations may require faster opening times than those listed. Modern breaker close times are typically four to eight cycles. Circuit breaker interrupting time may vary from those in Table 5-1 but must coordinate with other circuit breakers and protective devices.

Table 5-1 Typical Circuit Breaker Interrupting Times

age Class (kV L-L rms)	Rated Interrupting Time (Cycles)
Below 100 kV	≤ 5
115 kV	≤ 3
230 kV	≤ 2

5-D.3 Other Fault-Interrupting Devices

Depending on the application, the use of other fault-interrupting devices such as circuit switchers may be allowed. Fuses may be adequate for protecting the high-voltage delta side of a Δ-YG transformer. Trip times of these devices are generally slower, and current-interrupting capabilities are often lower, than those of circuit breakers. These devices must have been tested for the duty in which they are to be applied and they must coordinate with other protective devices operating times. Use of transformer fuses may result in 'single phasing' of low-side connected end-user facilities.

5-D.4 Automatic Isolation and synchronization

Depending on the application, the District may require automatic isolation and lockout when the District's high voltage system service is interrupted for any reason. In these cases the isolation shall be done prior to the District's switching station breaker reclosing and typically less than two seconds in the absence of direct transfer trip relaying. In addition to all required relays mentioned in section six of this document, the utility tie breaker should have an automatic/manual synchronizing capability and also be able to handle recovery voltage of two times rated voltage.

5-E. Transformers, Shunt Reactance and Phase Shifters

Transformer tap settings (including those available for under load and no load tap changers), reactive control set points of shunt reactive equipment, and phase shift angles for phase shifters must be coordinated with the District to optimize both reactive flows and voltage profiles. Automatic controls may be necessary to maintain these profiles on the interconnected system.

Transformer reactance and tap settings for generator transformers should also be coordinated with the District to optimize the reactive power capability (lagging and leading) that can be provided to the network. Refer to IEEE Standard, C57.116, Guide for Transformers Directly Connected to Generators and Standard S2 of the NERC/WECC Planning Standards in Section III.C. The continuous reactive-power capability of the generator shall not be restricted by main or auxiliary equipment, control and protection, or operating procedures.

5-F. Generators (General Requirements)

The latest applicable NERC/WECC Reliability Standards must be followed for all generator interconnections.

5-F.1 Generator Operation During Emergency System Conditions

The generator, when requested by the District's System Operator during emergency conditions, will be expected to supply reactive power up to its maximum available capability, even if reductions in real power output is necessary to make this happen. Dispatch for non-synchronous sources will be examined on a case-by-case basis, depending upon the performance characteristics of the source and its location within the District's electric system.

5-F.2 Generator Performance During System Disturbances (Swings)

Response to frequency and voltage variances during a system disturbance are defined in Section 6-D.3. Unless otherwise allowed, the generators are to stay connected and operational during such disturbances, up to the limits provided in Section 6-D.3. Deviation from these requirements will be reviewed on a case-by-case basis and may result in additional reserve requirements or other system compensation.

5-F.3 Generator Ride-Through Capability

Depending on generator size and other system factors, the generator(s) may be required to stay on-line for nearby faults, not including the line connected to or the adjacent buses, for faults cleared assuming the relay and breaker clearing times given in Table 6-1. Deviation from these requirements will be reviewed on a case-by-case basis and may result in additional reserve requirements or other system compensation.

5-F.4 Reactive Power Requirements

Generators shall be designed to maintain a composite power delivery at continuous rated power output at the POI at a power factor within the range of 0.95 leading to 0.95 lagging. The design shall consider the effects of step-up transformer reactance and voltage taps/turns ratios, and bus-fed auxiliary load.

5-F.5 Placement of Customer-owned Generating Facility

Customer owned generating facilities shall not be allowed within 150 feet (horizontal distance) from any existing overhead electrical distribution (less than 100kV) facilities and 250 feet (horizontal distance) from any high voltage (100kV and higher) electrical facilities. Exhaust fumes shall not be directed toward any existing overhead electrical facilities. The District also does not allow more than one customer owned generating facility per District owned distribution substation.

5-F.6 Starting as Induction Motor (if applicable)

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

5-G. Asynchronous Generators

5-G.1 Asynchronous Generators With Solid-State Inverters or Double-fed Wound Rotor Induction Generators

These machines shall be operated to provide reactive power similar to that of synchronous generators within the capabilities of the machines. This may include operation on voltage schedules provided by the District's System Operators.

5-G.2 Voltage Control

Voltages at the POI shall not vary more than 0.5% per capacitor switching operation; and shall not deviate more than 3% due to changes in generation output caused by rapid fluctuations in the prime mover speed. The automatic voltage control system shall be fast enough to react to the maximum change in generation anticipated without invoking the operation of system voltage control devices such as shunt capacitors and tap changers. Further, the control system shall be coordinated to minimize operation of customer load regulation equipment including voltage regulators and tap changers. This may typically require the control system to adjust reactive compensation in less than 30 seconds. The alternative may be to require controllable compensation such as static var compensators (SVC).

5-H. Synchronous Generators

5-H.1 Excitation Equipment

Synchronous generator excitation equipment shall follow industry best practice and the latest applicable industry standards. Operation of excitation systems shall be as specified by current NERC and WECC reliability standards or criteria. Excitation equipment includes the exciter, automatic voltage regulator, power system stabilizer and over-excitation limiter. Supplementary controls may also be required to meet District transmission voltage schedules.

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. Automatic voltage regulation shall be restored automatically when system conditions allow field current below the continuous rating. The District may request connection of the voltage regulator line drop compensation circuit to regulate a virtual location 50–80% through the step-up transformer reactance.

The supplementary automatic control is required to adjust the AVR set point to meet the District's 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.

5-H.2 Governors

Design and operation of generator governors shall be as specified by current NERC and WECC reliability standards and criteria.

The District realizes that some generating facilities will operate at maximum turbine output unless providing frequency control and spinning reserve ancillary services. The District requires governor controls to be set for 'droop control mode'.

5-I. Generator Performance Testing, Monitoring and Validation

A generator owner is responsible for providing a WECC-approved dynamic model of its generating plant to the District. The model will characterize plant responses to system disturbances (voltage and frequency deviations at point of interconnection, oscillations) and control signals (power and voltage schedule). The dynamic model will be a part of the power system model used in system studies to determine operating transfer limits and network reinforcements. An incorrect model may result in incorrect transfer limits, which can either put the system at risk of failure or unnecessarily restrict transmission use.

5-I.1 Parametric Testing

Parametric testing is a detailed test performed on a generator to determine parameters of a synchronous machine and its controls, as defined in the WECC test guidelines. Parametric testing shall be done for the following equipment:

- Synchronous machines
- Exciter and voltage regulators
- Turbine – governor
- Power System Stabilizer (PSS)
- Over-Excitation Limiter (OEL)

Typical data can not be substituted for actual parametric test data which is required for every generator greater than 10 MW:

- On a new generator during commissioning.
- When the generator or turbine is retrofitted.
- When the generator controls are replaced or retuned.
- When a severe discrepancy is observed in performance validation.

5-I.2 Performance Validation

Performance validation of the generator model is done using measurements recorded during actual disturbances and tests. Recorded generator voltage and frequency are input into the model to verify that simulated real and reactive power responses are in good agreement with the recorded responses. Owners of generation facilities shall provide an Evidence of Performance Validation in accordance with NERC/WECC reliability requirements. Performance validation shall include:

- Responses to at least three frequency excursions greater than 0.1 Hz (alternatively 1% speed or 20% power reference steps);
- Responses to at least three voltage changes greater than 2% (alternatively 2% voltage reference steps).

5-I.3 Performance Monitoring

The transmission operator at the POI will monitor performance of the generating plant by taking measurements of bus voltage and frequency, generator current and power, and control signals sent to the generating plant.

Performance monitoring is recommended for use with performance validation. The transmission operator will collect disturbance data and will perform performance validation. If a severe discrepancy is observed, the owner of the generation facility shall be required to perform parametric testing of the generation equipment in question. See section 6-G for additional requirements for performance and disturbance monitoring.

5-J. Generator Blackstart Capability

Blackstart is the term describing the startup of a generating plant under local power, isolated from the power system. Blackstart capability is needed in some rare circumstances, depending on the size and location of the generation facility. 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 Diagram. Loads that are scheduled and available for blackstarts are selected to avoid the trip-out of generation units by exceeding frequency and voltage set points. During the restoration, the tapped connection must be able to be opened to avoid interference with District restoration procedures on the District's transmission path.

Considerations related to blackstart capability include the following:

1. Proximity to other major generation facilities (i.e. Can startup power be provided more efficiently from an existing plant?)
2. Location on the transmission system (i.e. Is the generation facility near major load centers and far from generation?)
3. Cost of on-site start-up
4. Periodic testing to ensure personnel training and capability.

5-K. Generator Facility Planning Requirements

Small customer-owned generation facilities (0–10 MVA) can usually be connected to District substations via a power circuit breaker and a radial line or may be able to be connected to the District's existing distribution system. All small customer-owned generating facilities connected to a 115 kV or higher voltage line, between two District busses, typically can be connected via a three terminal ring bus unless the District agrees upon another scheme**.** All cases must to be modeled and evaluated separately due to the technical nature of each generation application.

Customer-owned generating facilities that qualify for Net Metering (25 kW or less and energy sources such as hydroelectric power, fuel cell, photovoltaic generation, and wind energy conversion system), should refer to the District's Interconnection Requirements for Small Power Producers and Cogenerators. Generating facilities not qualified for Net Metering, should refer to the Distribution System Interconnection Standard, which is available upon request.

Generation up to 10 MVA will typically require a dedicated feeder from a 115 to 12.5 kV, three-phase distribution substation while generation smaller than 3.5 MVA may be able to be connected on an existing feeder along with other customers. **In all cases the District shall allow only one Customer-owned generating facility per substation with circuit breakers typically required at both the substation and generator locations.**

Generation greater than 10 MVA will typically require a 115 kV or 230 kV, three-phase connection. The generator(s) shall be connected to a 115 kV (or 230 kV) high-voltage line. Generation facilities greater than 50 MVA may also require additional breakers and/or transmission line connections depending on contractual requirements and interconnection study results. Typical configurations and protection schemes are shown in section 6-D, Generator Configuration and Protection.

6. Protection Requirements

6-A. Introduction

The protection requirements identified in this document address the following objectives:

- Ensure the safety of the general public, The District and other utility personnel.
- Minimize property damage to the general public, The District, and its customers.
- Minimize adverse operating conditions affecting The District and its customers.
- Comply with all current NERC, WECC and NWPP protection criteria.

In order to achieve these objectives, certain protective equipment (relays, circuit breakers, etc) must be installed. These devices ensure that faults or other abnormal conditions the appropriate equipment is promptly disconnected from the District's Electric system. Protective equipment requirements depend on the plan of service. Significant issues that could affect these requirements include:

- The location and configuration of the proposed connection.
- The level of existing service and protection to adjacent facilities (including those of other District customers and potentially those of other utilities).
- The connection of a line or load that coincidentally connects a generation resource, which was not previously connected to the District's Electric system. In this case, the Requester will also have to follow the additional requirements for interconnection of generation resources.

The District will work with the Requester to achieve an installation that meets the Requester's and The District's requirements.

The District will not assume any responsibility for protection of Requester's equipment. Requester is solely responsible for protecting their equipment in such a manner that faults, imbalances, or other disturbances do not cause damage to their facilities or result in problems with other customers.

6-B. Protection Criteria

The protection system must be designed to reliably detect faults or abnormal system conditions and provide an appropriate means and location to isolate the equipment or system automatically. The protection system must be able to detect power system faults within the protection zone. The protection system should also detect abnormal operating conditions such as equipment failures or open phase conditions. Special relaying practices may be required for system disturbances, such as undervoltage or underfrequency detection for load shedding or reactive device switching. For some generation and end-user facilities, the Requester may be required to participate in special protection schemes or RAS including automatic tripping or damping.

6-B.1 General Protection Practices

The following summarizes the general protection practices as required by NERC and WECC, as well as specific practices and applications as applied to

The District's transmission lines and interconnections. The protection schemes and equipment necessary to integrate the new connection must be consistent with these practices. Table 6-1 specifies maximum allowable operating times for protection systems and breakers by voltage category.

a. Protection Requirements For All Voltages

1. Relays and circuit breakers, etc. are required at the POI, or a connecting substation to isolate District equipment from the Requester's system during faults.
2. At the POI, the Requester is not allowed to energize a de-energized line connected to the District's Electric system without approval of the District's System Operator.
3. Breaker reclose supervision (automatic and manual including SCADA) may be required at the connecting substation and/or electrically 'adjacent' stations; e.g., hot bus and dead line check, synchronization check, etc.
4. Redundant protection elements including but not limited to relays, batteries, DC source, voltage (potential) transformers, current transformers, and breaker trip coils may be required for protection system reliability.
5. Relay settings shall not infringe upon the District's ability to operate at maximum transfer levels, even with system voltages as low as 0.8 per unit (pu).
6. Protection schemes shall be designed with sufficient number of test switches and isolating devices to provide ease of testing and maintenance without the necessity for lifting wires. Isolating switches shall be alarmed or operating and maintenance tagging procedures developed and followed to assure switches are not inadvertently left in an open position.
7. The POI protection system security and dependability and their relative effects on the power system must be carefully weighed when selecting the protection system.
8. The District reserves the right to review and recommend changes to the protection system and settings for POI protection equipment.
9. If required, automatic underfrequency load tripping total trip time, including relay operating time and breaker operating time, shall not exceed 14 cycles. Any underfrequency load tripping must comply with the NERC, WECC and NWPP requirements.
10. Use of capacitive voltage transformers (CVTs) and magnetically coupled voltage transformers (MVTs) are generally acceptable for protection purposes.
11. Use of bushing potential devices for protective relaying may not be appropriate. If the device needs to respond to overvoltages and frequency deviations, bushing potential devices may not be acceptable.
12. Current transformers used for protective relaying should be sized to prevent saturation.
13. Total fault-clearing times, with or without a pilot scheme, must be provided for District review and concurrence. Breaker operating times, relay makes, types and models, and relay settings must be identified specifically.

14. Generator protection shall meet WECC under/overvoltage and under/over frequency requirements as specified in Section 6-D3.

b. Additional Protection Requirements for Voltages Below 115 kV

1. Redundant or overlapping relay systems are required such that no single protection system component failure would disable the entire relay system and result in the failure to trip for a fault condition.
2. Multi-shot automatic reclosing is allowed for single and multi-phase faults. The total number of automatic recloses should not exceed three.

c. Additional Protection Requirements for Voltages 115 kV and Above

1. Breaker failure relays, (BFR) are required. Total time for BFR scheme fault clearing must not exceed eight cycles for three cycle breakers. Clearing time may be longer for slower breakers. System requirements may dictate faster BFR operating times. Breaker failure relays need not be redundant.
2. Dual circuit breaker trip coils are required.
3. Redundant relay systems are required if a single point of failure could disable the entire relay system. Both relay systems shall contain an instantaneous trip element with the ability to issue a trip in 1.5 cycles or less, for faults within 80% of the line. If ground distance elements are used, the relay must include ground overcurrent elements to provide tripping for high-resistance ground faults.
4. A pilot telecommunication scheme must be installed for either of the following conditions: 1) high-speed clearing is necessary for any fault location for stability purposes or 2) remote tripping for equipment protection. If a pilot telecommunications scheme is required for stability purposes, it must be redundant or designed to allow high-speed tripping by the protective relays upon failure of the pilot scheme.
5. The relay systems shall provide backup protection for loss of the telecommunication channel(s).
6. The selected pilot schemes and telecommunication system must be compatible with existing District protection and telecommunications equipment.
7. The telecommunications and pilot scheme channels required for protection systems should be continuously monitored.
8. Redundant relays shall not be connected to a common current transformer secondary winding.
9. Directional relay systems are required on all non-radial connections.
10. Automatic reclosing for single line-to-ground faults shall be no faster than 35 cycles.
11. Automatic reclosing is allowed for multiphase faults, excluding three phase faults. Automatic reclosing is not allowed for three phase faults.

12. Multi-shot automatic reclosing may be required for automatic line sectionalizing schemes. The total number of automatic recloses should not exceed three.

e. Additional Protection Requirements for Voltages at 230 kV

1. For most lines, total fault clearing time with a pilot scheme must not be more than four cycles, including relay and breaker operating times. Slower times may be acceptable for some lines. Refer to Table 6.1.
2. Automatic reclosing for single line-to-ground faults shall be no faster than 20 cycles and usually no slower than 60 cycles.
3. Automatic reclosing is not allowed for three phase faults. It is acceptable to block reclosing for time-delayed trips or loss of all pilot channels on the protected line.

6-B.2 Protection Measures

Protection systems must be capable of performing their intended function during fault conditions. The magnitude of the fault depends on the fault type, system configuration, and fault location. It may be necessary to perform extensive model line tests of the protective relay system to verify that the selected relay works properly for various system configurations. Power system swings, major system disturbances and islanding may require the application of special protective devices or schemes. The following discussion identifies the conditions under which relay schemes must operate.

a. Phase Fault Detection

The relay system must be able to detect multi-phase faults and trip at high speed for high fault currents. Non-directional overcurrent, directional overcurrent, distance, and line differential relays may be applicable depending on system requirements.

Infeed detection to faults within the power system usually requires directional current-sensing relays to remove the contribution to the fault from the POI. The distance relay (21) is a good choice for this application since it is generally immune to changes in the source impedance.

b. Ground Fault Detection

Ground fault detection has varying requirements. The availability of sufficient zero-sequence current sources and the ground fault resistance both significantly affect the relay’s ability to properly detect ground faults. The same types of relays used for phase fault detection are suitable for ground fault detection. If ground fault distance relays are used, backup ground time overcurrent relays should also be applied to provide protection for the inevitable high-resistance ground fault.

c. Islanding
Islanding describes a condition where the power system splits into isolated load and generation groups, usually when breakers operate for fault clearing or system stability remedial action. Some utilities isolate their distribution system and use local generation to feed end-user facilities during power system outages. The District does not allow islanding conditions to exist that include its facilities, except for a controlled, temporary, area-wide grid separation. Where generation is connected, implications of islanding must be addressed to minimize adverse impacts on connected end-user facilities.

During an islanded condition or system disturbance, power swings may result which can affect the operation of protective relays, especially distance relays. Out-of-step blocking is commonly available for distance relays to prevent them from operating during a power swing. However, the application of such schemes must be coordinated with the District to assure that the blocking of the distance elements will not result in inappropriate or undesirable formation of islands.

d. Relay Performance and Transfer Trip Requirements
Relay systems are designed to isolate the transmission line and/or other facilities from the District's Electric system. However, the performance (clearing time speed) of these local relay systems and the associated isolating devices (circuit breakers, circuit switchers, etc) will vary. The protection equipment of the new connection must at least maintain the performance level of the existing protection equipment at that location. This may require transfer trip (pilot telecommunications) to ensure high-speed and secure fault clearing. Other types of pilot tripping such as current differential may also be acceptable if the scheme chosen can achieve the total clearing times required. Transfer trip is required when any of the following conditions apply to the new connections:

1. Transient or steady-state studies identify conditions where maintaining system stability requires immediate high-speed separation of the POI facility from the power system.
2. Special operational control considerations require immediate separation of the POI from the District's Electric system.
3. Extended fault duration represents an additional safety hazard to personnel and can cause significant damage to power system equipment.
4. Slow clearing or other undesirable conditions such as extended overvoltages or ferroresonance which, cannot be resolved by local conventional protection measures, will require the addition of pilot tripping using remote relay detection at other substation sites. This scenario is a distinct possibility should a District circuit that connects other customer loads become part of a 'local island' that includes a generator.
5. When remote circuit breaker tripping is required, in order to clear faults in a transformer not terminated by a high side breaker, high-speed transfer

tripping will be required. The transfer trip may also be required to block automatic reclosing. Other unique configurations may impose the same requirement.

6. Relay operate times are adjusted to coordinate for faults on the local configuration such as a three terminal lines, fault currents available, etc. Total clearing times must be less than those listed in Table 6-1. Refer to Section 8-D for telecommunication issues as they pertain to control and protection requirements.

Table 6-1 Relay and Breaker Operating Times by System Voltage

Connection Voltage (Line-Line rms)	Total Clearing Time (Cycles)	Maximum Relay Operate Time (Cycles)	PCB Trip Time (Cycles)	Time Delayed Tripping Acceptable?
< 115 kV	≤9-11*	≤ 4-6*	≤ 5	Yes
115 kV	≤ 5-7*	≤ 2-4*	≤ 3	Yes
230 kV	≤ 4-6*	≤ 2-4*	≤ 2	Yes/No**

* Relay operating and total clearing times are for instantaneous element trips at the terminal closest to the fault. Inverse time and time delayed elements are considerably longer. Sequential instantaneous or time delay tripping may occur at the remote terminal.

** Transfer trip or other communications aided-tripping may be required.

e. Synchronizing and Reclosing

If the connection is made to an existing line, automatic reclosing schemes at the remote line breakers may need to be modified. On transmission lines below 230 kV, automatic-sectionalizing schemes may be installed to isolate a portion of the system that has a permanent fault. This includes multi-shot automatic reclosing at remote terminals. A new interconnection should be compatible with such existing schemes. If the new connection results in the possibility of connecting a generation source, special considerations may be required. Section 6-D identifies protection requirements specifically related to generator additions.

6-C. Protection System Selection and Coordination

6-C.1 Protection Requirements for the Interconnecting System

Upon request, the District will supply the Requester with a list of protective relay systems considered to be suitable for use at the POI. Should the Requester select a relay system not on our approved list, the District reserves the right to perform a full set of acceptance tests prior to granting permission to use the selected protection scheme. Alternatively, the relay vendor or a third party may be asked to perform thorough model line tests of the proposed relay system. If there are special performance requirements for the protective relays at the POI, the District will notify the Requester.

6-C.2 Protection System Coordination and Programming

The following are basic considerations that must be used in determining the settings of the protection systems. Depending upon the complexity and criticality of the system at the POI, complete model line testing of the protection system, including the settings and programming, may have to be performed prior to installation to verify the protection system performance.

a. Fault study models used for determining protection settings should take into account significant zero-sequence impedances. Up-to-date fault study system models shall be used.
b. Protection system applications and settings should not normally limit transmission use. NERC/WECC relay loadability criteria shall be followed.
c. Application of zone three relays or other relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible and shall be in accordance with applicable NERC and WECC Reliability Standards.
d. Protection systems should prevent tripping for stable swings on the interconnected transmission system.
e. Protection system applications and settings should be reviewed and coordinated with the District whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.
f. All protection system trip misoperations shall be analyzed for cause, and corrective action taken in accordance with NERC and WECC Reliability Standards.

6-C.3 Relays for the Point of Interconnection

The following list of relays has been developed in recognition of varied interconnection 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 The District's general protection practices identified in Section 6-B1.

The relay functions generally necessary to serve this purpose as used by The District include:

a. Phase overcurrent (non-directional)	(50/51)
b. Neutral overcurrent (non-directional)	(50/51-N)
c. Zone distance (phase or phase and ground distance)	(21/21-N)
d. Directional ground overcurrent	(67-N)
e. Ground overcurrent	(51-G) or ground
fault detection scheme	(59-Z)
f. Over/under voltage	(59/27)
g. Over/under frequency	(81)
h. Instantaneous overvoltage (ungrounded high side)	(59)
i. Remote automatic breaker reclose supervision	(79-X) (HB/DL,
HB/HL with synchronism check)	
j. Current differential	(87)

Except as otherwise agreed by The District, The District will furnish, install, operate and maintain all relaying at the POI for the purposes of protecting the District's Electric system. Other relaying for protection of the Requester's equipment will be the responsibility of the Requester. All relays, which can adversely affect the District's Electric system, shall be of 'utility grade' quality, subject to review by The District.

Refer to Section 8-D for telecommunication issues as they pertain to control and protection requirements.

6-D. Generator Configuration and Protection

Integration of new generation has special requirements in addition to the previously described protection requirements. This section primarily deals with the protection requirements for the integration of synchronous and induction rotating machines. The actual protection requirements and choice of relay type will vary depending upon several factors:

- MVA capacity of the generation
- Type of generation: synchronous or non-synchronous
- Location of the generation interconnection on the transmission grid
- Voltage level of the generation interconnection
- Transformer winding configuration for the generator step-up transformer and/or interconnecting transformer
- Change in the fault current capacity as a result of the added generation
- Availability of telecommunications facilities

Examples of typical generator integration plans are shown on pages 41-47.

6-D.1 Fault Protection

Protective relays will be required to detect phase and ground faults on the generator interconnection. The relay systems shown in Figures 6-1 through 6-5 are designed to isolate the generator from the District's electric system at or near the POI. However, the performance (clearing time speed) of these local relay systems and the associated isolating devices (circuit breakers, circuit switches etc.) will vary. In most cases, protective devices described in Section 6-B will also be appropriate for this interconnection.

Ground fault detection has varying requirements. The most significant consideration in the ability to detect ground faults on the District's Electric system is the winding configuration of the transformer connecting the generator to the electric system. The scenarios below assume that the generator is connected to the low-voltage side of this transformer.

a. Transformer Grounded Wye (YG) Connection on the District's Electric system Side

This is the District's required transformer connection when adding a new generation resource to the transmission grid. The transformers will either be YG-Δ or YG-Δ-YG. Either of these connections provides a solid ground source for the transmission grid.

For a transformer connected with a grounded-wye on the primary (high voltage) side, a ground overcurrent relay (50/51-G) connected in the neutral of the wye winding provides transmission fault detection. This relay also protects the transformer.

A directional ground overcurrent relay (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 function complements zone-distance protection used for phase fault detections, it is included in many presently manufactured relays. See Figures 6-1, 6-2 and 65 for typical examples of this configuration.

b. Transformer Delta (Δ) Connection on the District's Grid Side and Potential Overvoltages

Some smaller generation projects are proposed for integration into existing utility power systems through a delta transformer connection to the transmission grid. This Δ-YG transformer was originally designed only to serve loads; e.g., connection at the 12.5 kV side of the 115 kV/12.5 kV transformer. This common transformer configuration requires special relay considerations when generation is proposed for connection to the low voltage terminal. 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. The District will review all such requests on a case-by-case basis to determine acceptability. New relays, transfer trip, ground detection equipment, or a grounding transformer may be required to assure timely removal of the generation source for safe clearing of faults on the transmission system.

Generation Integration Configuration diagrams

The following figures 6-1 through 6-5 show recommended protection schemes as well as the type of overall interconnection configuration needed based on generation facility type and size.

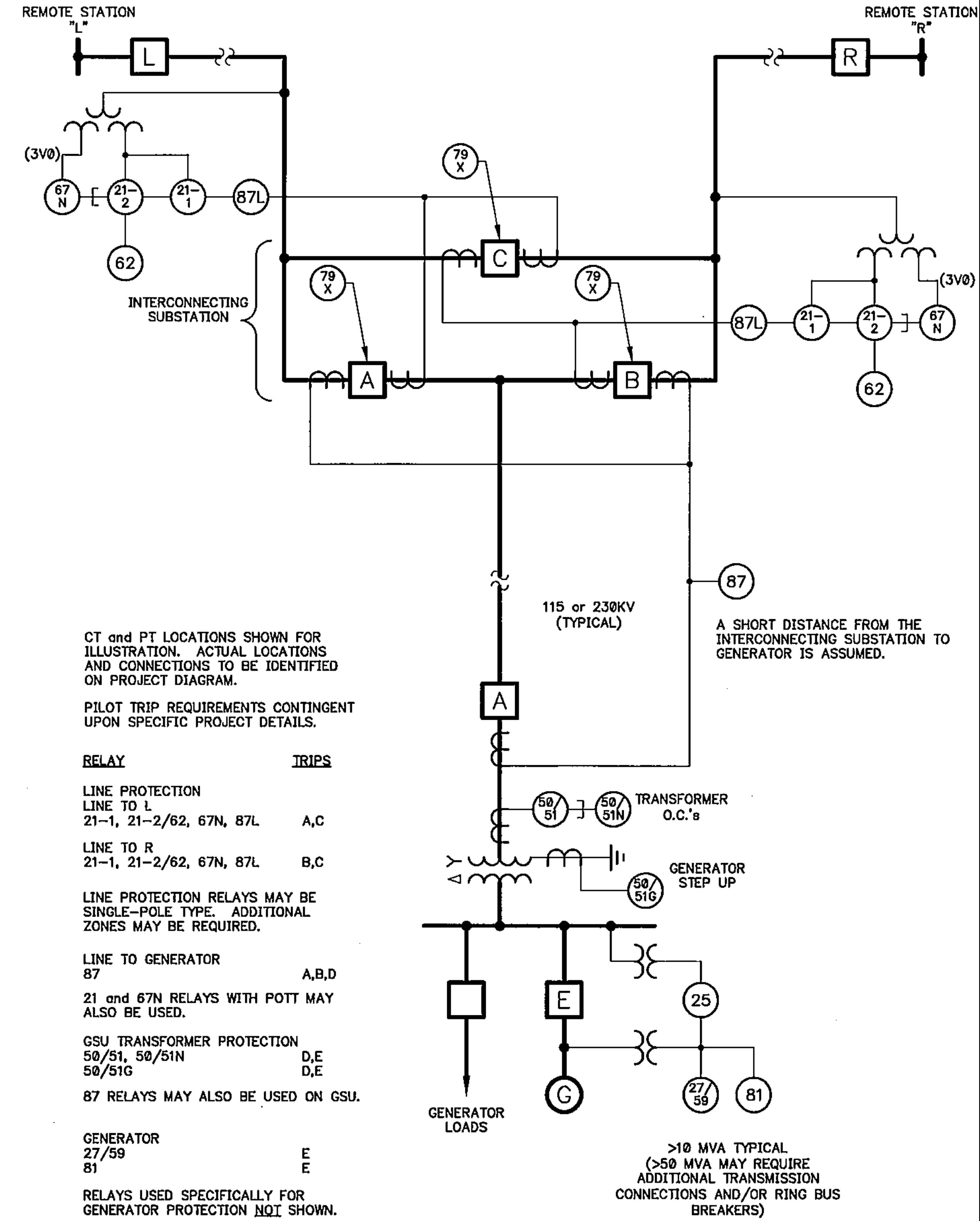

FIGURE 6–1

2000–25SK–0001

INTEGRATION OF GENERATION INTO A TRANSMISSION LEVEL SUBSTATION

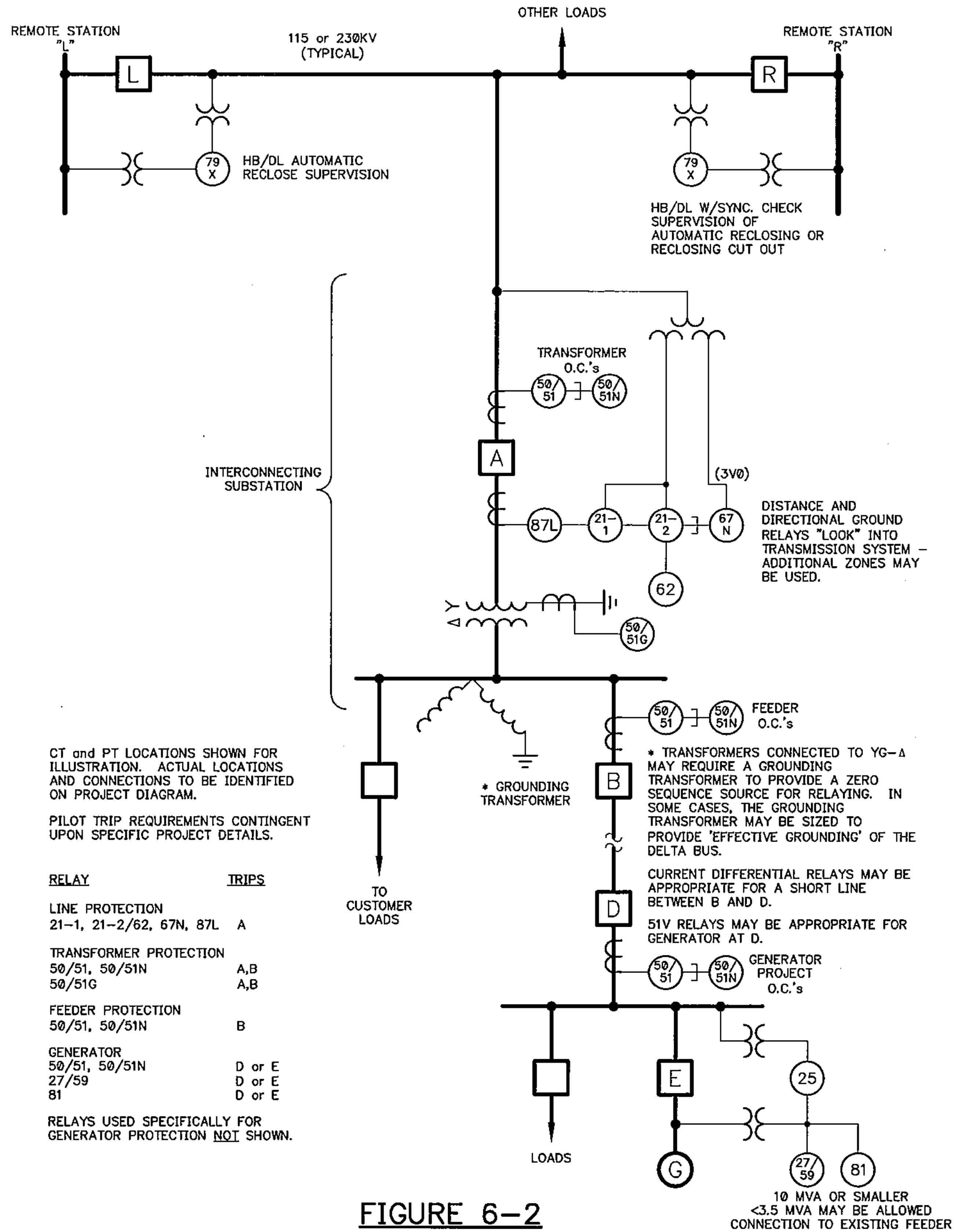

FIGURE 6-2

2000-25SK-0001

INTEGRATION OF GENERATION INTO A LOW VOLTAGE SUBSTATION PROTECTED BY A HIGH SIDE CIRCUIT BREAKER AND CONNECTED TO A TRANSMISSION LINE THROUGH A YG-Δ (AS SHOWN) OR YG-Δ-YG TRANSFORMER. (THIS CONNECTION IS NOT TYPICAL)

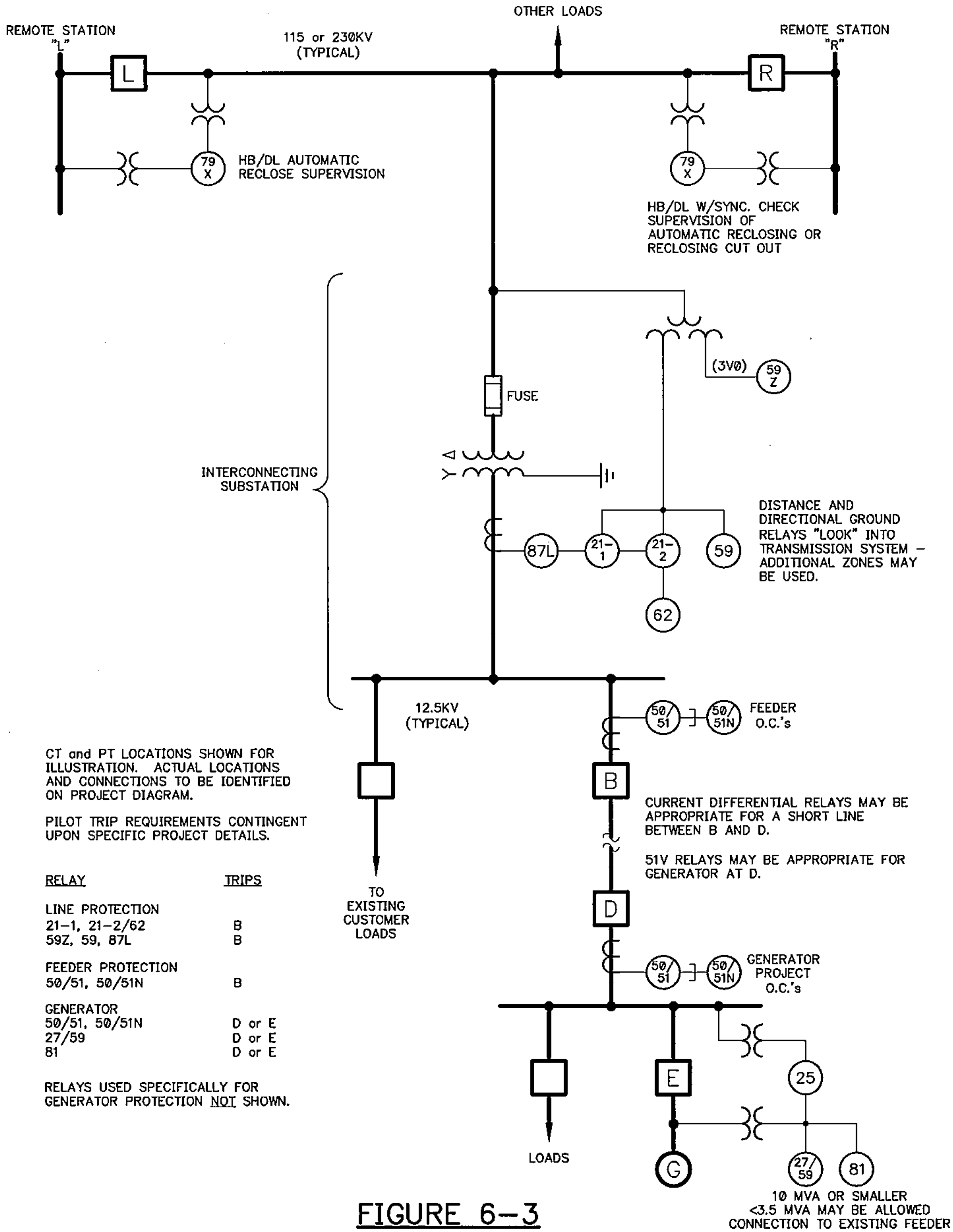

FIGURE 6-3

2000-25SK-0001

INTEGRATION OF GENERATION TO AN EXISTING LOW VOLTAGE SUBSTATION CONNECTED TO THE TRANSMISSION LINE THROUGH A FUSED Δ-YG TRANSFORMER (ONLY ALLOWED FOR EXISTING FUSED TRANSFORMERS)

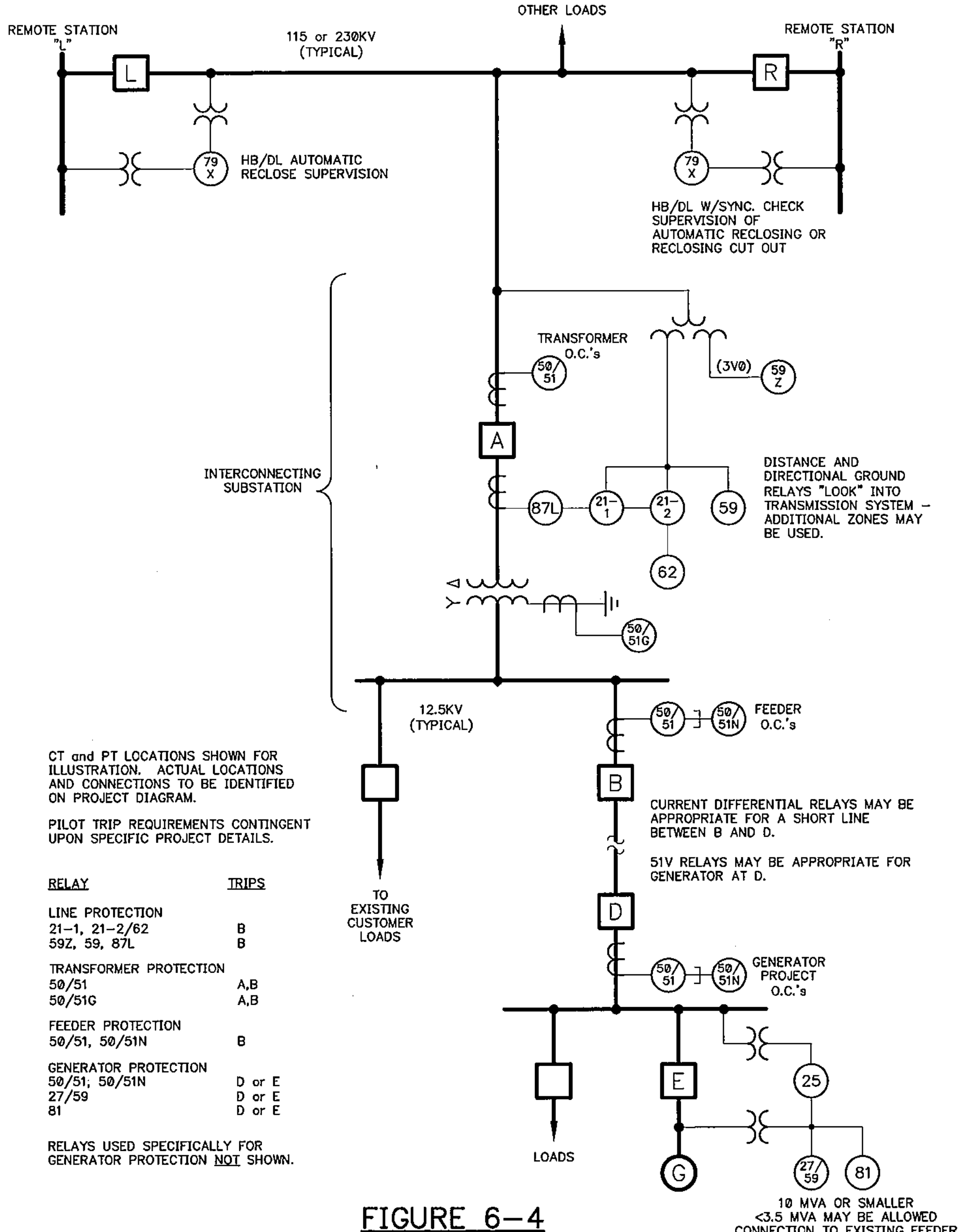

FIGURE 6-4

2000-25SK-0001

INTEGRATION OF GENERATION TO AN EXISTING LOW VOLTAGE SUBSTATION CONNECTED TO A TRANSMISSION LINE A Δ -YG TRANSFORMER AND PROTECTED BY A HIGH SIDE CIRCUIT BREAKER (SWITCHER). (REQUIRED FOR NEW INSTALLATIONS).

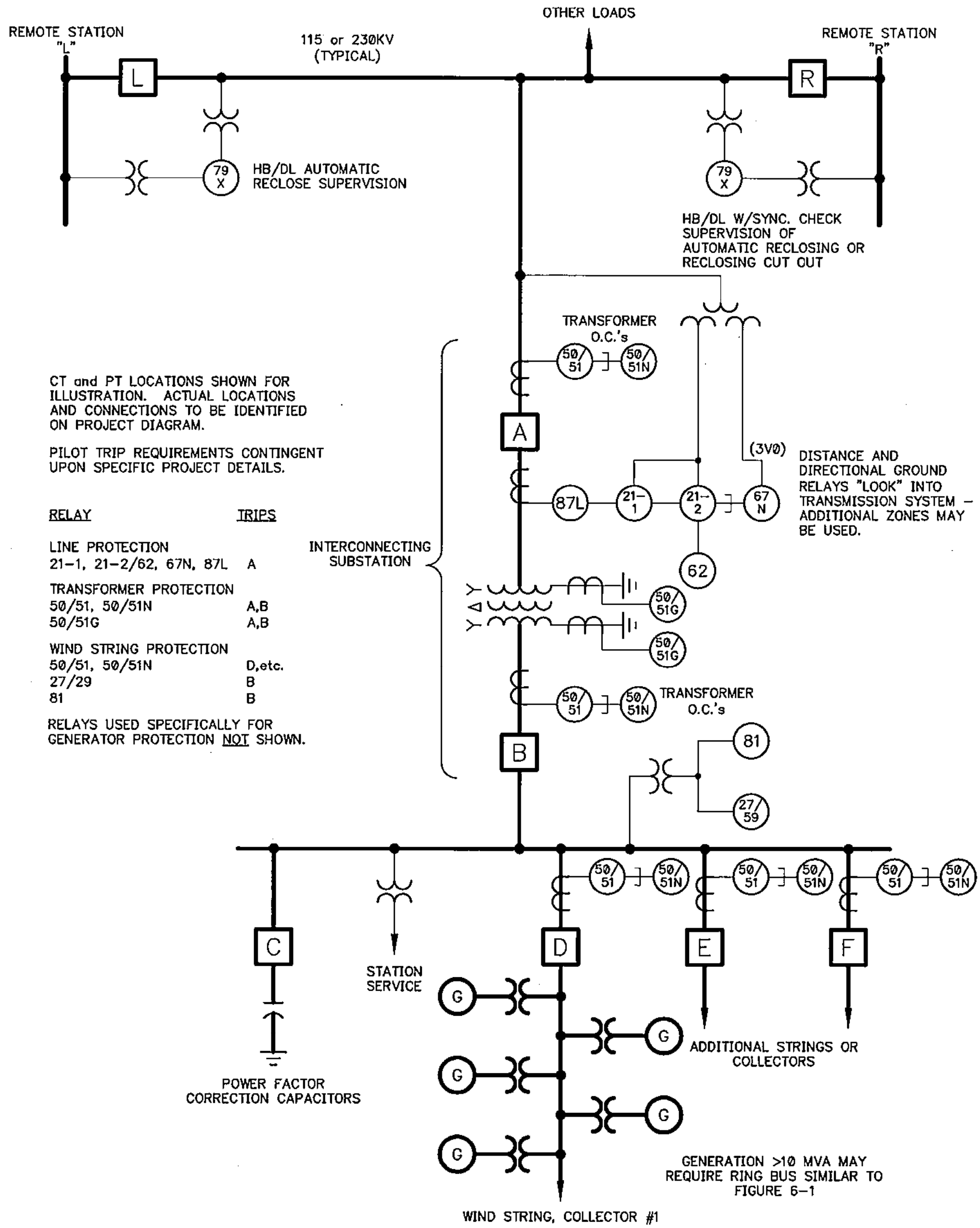

FIGURE 6-5

2000-25SK-0001

INTEGRATION OF A TYPICAL WIND FARM INDUCTION GENERATOR TO A 115KV OR 230KV TRANSMISSION LINE THROUGH A YG-Δ-YG TRANSFORMER

Table 6.2 identifies only the protection equipment which may affect the operation of the District's Electric system. The type of resource proposed and location of the POI will determine any special protection requirements for other types of resources, such as photovoltaic, tidal, etc.

Table 6-2 Relay Functions for Figures 6-1 to 6-5

Interconnecting Substation, High Voltage Transmission Line Protection		
The following relays are intended for the interconnecting substation to detect faults on the District's Electric system and isolate the interconnecting substation from the District's Electric system.		
Figure	**Relay**	**Intent**
6.1, 6.2, 6.4, 6.5	21-1, 21-2 / 62	Distance relays trip line breakers for multi-phase faults on the transmission lines to the Interconnecting Substation. Ground distance relays may be used for ground faults. These relays may have single pole switching capability. They also may be connected to a transfer trip or other pilot channel. More than two zones may be required.
6.1, 6.2, 6.4, 6.5	67 N	Directional ground overcurrent relay trips line breakers for ground faults on the transmission lines to the Interconnecting Substation. These relays may have single pole switching capability. They also may be connected to a transfer trip or other pilot channel. Potential polarization: shown in the figures. Current polarizing or negative sequence polarizing may also be used.
6.1, 6.2, 6.4, 6.5	87 L	Line differential relays are often necessary to avoid coordination problems with other relays to limit nuisance trips of the generator. Distance relays (21), directional overcurrent ground relays (67N), and a permissive overreach transfer trip may also be used.
6.1 - 6.5	79 X	Automatic reclose supervision is necessary at the interconnecting substation and/or the remote high voltage substations when a generator is added. This includes a hot bus/dead line (HB/DL) check and a synchronism check. The automatic reclose supervision will prevent the transmission line from reclosing if the generator remains in service and is not in synchronism with the District's Electric system.
6.3, 6.4	59	This relay detects overvoltages, and ground faults as indicated above. With an instantaneous trip at 1.5pu overvoltage. It is provided to avoid arrester failure for ground faults. This scheme is most often required when the interconnecting substation includes a Δ-YG transformer.
6.3, 6.4	59 Z	A ground fault detection scheme is used to detect ground faults on the tapped transmission line. (Normally the open delta 3V0 scheme with inverse time characteristic). Trips of this relay may need to be time coordinated with other relays so that faults beyond the tapped transmission line do not cause unnecessary trips of the generator feeder. This scheme is most often required when the interconnecting substation includes a Δ -YG transformer.

Table 6-2 (cont.) Interconnecting Substation, Transformer Protection		
The following devices are typically used at the interconnecting substation to provide protection of the power transformer that interfaces between the generator and the District's Electric system.		
Figure	**Relay**	**Intent**
6.3	Fuse	Some existing Δ-YG transformers may have high side fuse protection. This is generally not acceptable for new installations.
6.1 - 6.5	50/51, 50/51N	These relays protect transformers from overcurrent conditions caused by low side faults extreme overloads or unbalances. Phase overcurrent relays are usually set to pickup at approximately twice the transformer thermal rating. These relays are time-coordinated with low side feeder relaying. Voltage restrained time overcurrent relays may be used instead of the standard 50 element. 50/51 relays may also provide backup for transformer 87 relays.
6.1, 6.2, 6.4, 6.5	50/51G	This relay protects transformers from overcurrent conditions caused by low side ground faults or extreme unbalances. These relays are time-coordinated with low side feeder relaying.
6.1 - 6.5	63	Sudden pressure or Buchholz relays may also be provided for the transformer.
6.1 - 6.5	87 T	Transformer differentials relays may be used for transformer protection.

Table 6-2 (cont.) Generator Interconnection		
The following relays are required at or near the generation. These relays do not provide fault protection for the generator itself, which is the responsibility of the generator owner.		
Figure	**Relay**	**Intent**
6.1 - 6.4	25	This relay provides synchronism check supervising function for all closes of generator breakers.
6.1 - 6.5	27/59	These relays detect abnormal voltage conditions often caused by islanded operation scenarios. The undervoltage relay can serve as a means of fault detection for instances of weak fault current infeed from generator to faults on the feeder or interconnected system. It protects generator against extended operation at abnormal voltages. Undervoltage relay settings are coordinated with Pacific Northwest undervoltage load shedding plan (Section 6-D.3).
6.1 - 6.5	81	This relay detects abnormal frequency conditions, often caused by islanded operation scenarios. It protects generator against extended operation at abnormal frequencies. Underfrequency relay settings are coordinated with the WECC and NWPP underfrequency load-shedding plan (Section 6-D.3).

c. Potential Overvoltages with Delta Connection on the Transmission Side
For ground faults on the high voltage system, protective relaying at the transformer cannot detect zero sequence current at this location unless a ground source (grounding bank) is connected to the high-voltage side of the transformer. Circuit breaker operation(s) at the remote terminal(s) of the transmission line will isolate the line. However, the generator will continue to energize the transmission line creating a 'local island' condition described previously. With one phase grounded, energizing from the transformer low side can result in significant overvoltages (neutral shift) on the unfaulted phases of the transmission line.

It is normally assumed that these overvoltages would equal 1.7 pu. However, studies indicate that the voltages on the unfaulted phases of the transmission line can be even higher than the 1.7 pu, particularly if the generation is large compared to the local load that is islanded with the generator when the line-end breakers trip.

When induction machines are at or near full load, there is usually a considerable amount of capacitance also in service to keep the delivered power factor near 1.0. When the transmission line breakers open, the generator(s) are suddenly unloaded, and there is generally enough capacitance to make the induction machines self-excite. This, in combination with the line capacitance, will cause the voltage to increase above one (pu) at the generator terminals and consequently on the transmission line.

When a synchronous generator is at full load, the excitation system creates a high equivalent internal voltage, supplying the necessary vars to keep the overall delivered power factor near 1.0 and assist with local voltage control. When the system breakers open, unloading the generator, the high internal excitation will increase the voltage on the generator terminals and on the transmission line.

If the generator rating is about the same as the local load on the islanded transmission line, additional overvoltages above 1.7 pu would not be expected. Studies show that if the generator rating is considerably smaller (1/3 or less) than the minimum local load, then the voltage on the islanded system should quickly collapse.

d. Acceptable Solutions to Transmission Line Overvoltages
Overvoltages can potentially damage lightning arresters and other equipment connected to an isolated transmission line. There are three acceptable solutions to resolve the potential overvoltage problems resulting from the ΔYG transformer neutral shift following a line to ground fault on the transmission line.

1. **High Side Grounding**
   The best and preferred solution to eliminate the 1.7 pu overvoltages is to replace the Δ-YG transformer with a YG-Δ or YG-Δ-YG transformer or install a separate ground source on the transmission line. Wind turbine sites usually require a grounded distribution or collection system, so the YG-Δ-YG transformer configuration is necessary. See Figure 6-5. If the

transformer configuration is changed or a separate grounding transformer added, overcurrent protection similar to that described in Section 6-D.1 (a) above can be used.

2. **Transfer Trip**
   Transfer trip is installed from the circuit breaker(s) that clear the transmission line to breakers that can isolate the generator. The breaker that is used for this separation should be as fast as available. One of the line end breakers may even need to be slowed down to ensure that it clears last and the islanded generator condition does not occur. Transfer trip is usually necessary when the high side grounding solution is not feasible or for an existing station with a delta connected high side transformer winding. Transfer trip may still be required, even with high side grounding, to meet special protection and/or remedial action requirements.

3. **Broken Delta 3V0 Voltage Detection Scheme**
   It may be possible to use a zero sequence overvoltage (3V0-59) relay connected to the high side of the .-YG transformer to detect this ungrounded operation. The 3V0 protection scheme uses three voltage transformers on the primary side of the transformer connected phase-to-ground. The voltage transformers must have a full line-to-line voltage rating and must be capable of measuring voltages up to 1.9 pu voltage continuously. The relay initiates a trip to eliminate the generator infeed on the faulted line. The District will review each application to determine the acceptability of this scheme. If the 3V0 voltage detection scheme is selected, it may also require the replacement of lightning arresters on the transmission line. The new arresters require a higher rated voltage and higher temporary overvoltage capability properly sized to withstand the expected overvoltage conditions. Other high voltage line to ground equipment that may be damaged by the overvoltage also needs to be replaced.

   The 3V0 open delta scheme 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. Under and overvoltage relays (27, 59) measuring each phase voltage may be used in conjunction with the 3V0 overvoltage relay to provide additional protection for these conditions.

   If a transfer trip scheme or 3V0 scheme is selected to detect a ground on the transmission side of the step-up transformer, it is also critical that the device trip a circuit breaker on the low voltage or grounded side of the step-up transformer. Neutral shift on the high side can limit the interrupting capability of high side devices, possibly causing failure. The number of low side devices allowed to trip for a high side fault may be a consideration. The District reserves the right to require additional equipment, such as a low side circuit breaker on the transformer, to minimize the number of devices tripped.

6-D.2. Synchronizing and Reclosing

The generator(s) shall be synchronized to the District's Electric system. Circuit breakers under the control of the District, required to maintain system integrity, shall not be used for synchronization. All circuit breaker closing operations must automatically synchronize the generator to the transmission system. The District's system operations must give the operator of the customer-owned generation permission before a generator is synchronized to the District's Electric system.

If a synchronizing check relay is used to supervise synchronization, then its output contacts shall be rated to interrupt the circuit breaker closing circuit current and the interrupting device shall be capable of trip-free operation.

If the generator connects to an existing line, automatic reclosing schemes at the remote terminals will need to be modified to accommodate the generator. A hot bus/dead line check is usually needed at one terminal before attempting an automatic reclose. Hot bus/hot line with synchronism check supervision is necessary for automatic reclosing at the other terminal. For an induction unit(s), automatic reclosing of the breakers at the terminal(s) of the integrating line may be performed without supervision, but will usually be time delayed to assure isolation of the generator(s).

6-D.3. Required Generator Relay Settings

Voltage and frequency relays used for protecting a generator and preventing a 'local island' condition from persisting must meet the requirements listed below to allow proper coordination with the power system. 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 the District to be well within the capabilities of small and large modern steam turbines as well as other generators. The District will evaluate proposed alternative voltage/frequency settings based upon the impact on system performance and reliability. The settings must comply with existing WECC and NWPP requirements.

a. Voltage Relays (27, 59)

The over/under voltage relay setting/delays listed below are intended to ensure 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.

Western Washington and Western Oregon load requirements also ensure 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 Hz. Also, each occurrence of over/undervoltage 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 NERC PRC-024-2 Attachment 2 requirements.

Overvoltage (59)

Voltage	**Action**
≥1.100 pu	1 second minimum delay before unit tripping
≥1.150 pu	0.5 second minimum delay before unit tripping
≥1.175 pu	0.2 second minimum delay before unit tripping
≥1.200 pu and above	no intentional delay before unit tripping

Undervoltage (27)

Voltage	**Action**
<0.900 pu	3.0 second minimum delay before unit tripping
<0.750 pu	2.0 second minimum delay before unit tripping
<0.650 pu	0.30 second minimum delay before unit tripping
<0.450 pu	0.15 second minimum delay before unit tripping

b. Frequency Relays (81)

If a generator facility includes a frequency relay (81) for under and/or overfrequency protection, the frequency settings and time delays must coordinate with the underfrequency load shedding plan. The frequency ranges and minimum setting/delay requirements for over/under frequency relays (81), shown in Table 6-3, have been established by the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Program and the NWPP Enhanced Underfrequency Load Shedding 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. A generator should not be tripped by frequency relays for frequencies between 59.5 Hz and 60.5 Hz. For frequencies below 57.1 Hz or above 61.7 Hz there are no special requirements for tripping times. However, in the frequency ranges of 57.1 Hz to 59.5 Hz and 60.5 Hz to 61.7 Hz the generator frequency tripping either must not occur, or operate slowly enough to coordinate with load shedding schemes.

Table 6-3 Under and Overfrequency Relay Settings and Operate Times (NERC PRC-024-2 Attachment 1)

Underfrequency Range	Overfrequency Range	Minimum Time Delay Setting
60.0 Hz - 59.5 Hz	60.0 Hz - 60.5 Hz	No generator tripping allowed
59.4 Hz - 58.5 Hz	60.6 Hz - 61.5 Hz	180 seconds
58.4 Hz - 57.9 Hz	61.6 Hz - 61.7 Hz	30 seconds
57.8 Hz - 57.4 Hz		7.5 seconds
57.3 Hz - 57.1 Hz		0.75 seconds
Less than 57.1 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 Hz and 57.1 Hz, with no intermediate steps is suggested. For steam generators and similar units, relay(s) with multiple frequency set points 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 previously 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..

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

6-D.4 Generator Relays

Except as specifically identified in these technical requirements, the District does not have requirements for the type of protection used for a generator. Generator protection is the responsibility of the Requester. However, the protection should meet the general requirements of the NERC/WECC Planning and Reliability Standards. The level of redundancy and overlap of protection schemes are determined by the Requester. The District's primary concern with generator protection is that the protection is available to isolate a generator fault from the District's Electric system. Types of protection used to isolate a generator from the District's Electric system include:

a. Percentage differential (87)
b. Phase balance current (46)
c. Phase sequence voltage (47)
d. Reverse power (32)
e. Thermal (49)
f. Loss of field (40)
g. Over-speed device (12)
h. Transformer sudden pressure (63)

i. Voltage controlled/restrained o.c. (51-V)
j. Volts per Hertz (overexcitation) (24)
k. Neutral overvoltage (59-N)
l. Under-, overvoltage relays (27, 59)*
m. Under-, overfrequency relays (81)*
* The settings of 27, 59 and 81 relays must be reviewed and approved by the District.

6-E. Special Protection or Remedial Action Schemes

Connections to the District's Electric system may require special protection or remedial action schemes, (RAS). The need for RAS will be determined during the interconnection studies. The type of RAS depends upon several factors such as type of connection, location of connection, etc. Some RAS must be fully compliant with WECC requirements. WECC RAS criteria specifies no single point of failure which, in most cases, includes geographically diverse communication paths. WECC compliant RAS schemes must also be tested on a maintenance schedule in accordance with WECC reliability standards. The test includes an operational or functional test of the scheme. The most common special protection schemes include load shedding, line loss detection, and generator tripping.

District staff will design most RAS schemes, but if any part of the scheme is designed by the Requester or their designate, that design must be reviewed and approved by the District. The District will ensure the design meets District and WECC requirements. If the Requester designs a portion of the scheme, they must be prepared to present the design to the WECC Remedial Action Scheme Reliability Subcommittee for acceptance. If the WECC Remedial Action Scheme Reliability Subcommittee determines changes must be made, the changes will be the responsibility of the Requester.

The Requester is expected to provide sufficient rack space in their facilities to accommodate additional equipment for relaying, telecommunications, special protection or RAS Schemes needed to facilitate the interconnection.

6-E.1 Load Shedding

The proposed connection may require special load shedding schemes based upon The District's Balancing Authority Area requirements. These may include underfrequency load shedding, undervoltage load shedding, or direct load tripping. The intent of load shedding is to balance the load to the available generation resources, reduce the possibility of voltage collapse, and to minimize the impact of a system disturbance. Underfrequency load shedding generally includes a coordinated restoration plan, which is intended to minimize frequency overshoot following a load shedding condition. Tripping levels, restoration, and other details of load shedding schemes will be determined by the District, following NERC, WECC and NWPP criteria. Section 6-D3 includes specific requirements for generation tripping by voltage and frequency relays.

a. Direct Load Tripping

Direct load tripping may be required for certain large loads. Direct load tripping is achieved with the use of redundant, dedicated transfer trip schemes from the remedial action scheme controllers to the load. Communications channels may be either digital or analog. Communication channels should be alternately routed. The District's System Operators will enable or disable direct load tripping schemes depending upon system conditions.

b. Underfrequency Load Tripping

Underfrequency load tripping may be required to balance generation resources and loads. Underfrequency load shedding must meet the following requirements:

1. Electromechanical frequency relays (81) are not allowed.
2. Frequency relays should be of the definite time variety.
3. Total operate time for underfrequency load tripping, including circuit breaker tripping, shall not exceed 14 cycles.
4. The frequency relay should be voltage supervised to prevent operation when the bus voltage drops below 0.7 pu voltage.
5. The frequency element (81) may be included as a part of a multifunction protective relay.
6. Frequency setting levels will be supplied by the District.
7. Load restoration settings will be supplied by the District.

c. Undervoltage Load Tripping

Undervoltage load tripping may be required to prevent possible voltage collapse on loss of major transmission paths or generation resources. Undervoltage load shedding must meet the following requirements:

1. Electromechanical voltage relays (27) are not allowed.
2. Voltage relays should be of the definite time variety.
3. The voltage transformer source for the voltage relay (27) must be on the source side of any automatic load tap changers or voltage regulators.
4. A three-phase voltage element must be used to detect the undervoltage condition. Averaging of the three phase voltages is not acceptable.
5. The undervoltage element (27) may be included as a part of a multifunction protective relay.
6. The undervoltage relay should not operate for a single-phase low voltage nor for a three phase low voltage below 0.5 pu.
7. Total operate time for undervoltage load tripping shall be greater than expected fault clearing times, typically 30 cycles or 0.5 seconds.
8. Voltage setting levels and operate time delays will be supplied by The District. Typical settings may be 0.9 to 0.92 pu voltage with a delay of 3.5 to 8 seconds.
9. Restoration settings will be determined by The District.

6-E.2. Transmission Line Loss

New transmission lines may require line loss detection logic, (LLL). Line loss is typically sensed by the position of the circuit breaker (52/b) auxiliary switch, isolating disconnect switch status, and also from the circuit breaker trip bus. Substation bus configuration and the type of protective line relaying will determine the exact requirements for implementing line loss detection logic. Line loss sensing must be implemented at all terminals of the transmission line. Line loss detection is sent to the appropriate District RAS controllers via redundant transfer trip channels.

6-E.3. Generation Reduction

New generation may require the addition of a generator dropping and perhaps a generator run back scheme. These schemes are intended to maintain the balance between system loads and available generation during and following a system disturbance. They may also be used to prevent transmission system overloads during abnormal operating conditions. The District's System Operators will arm or disarm generator tripping and run back depending upon system conditions. These schemes must be fully redundant. District RAS controllers will send generator reduction signals to the generators via redundant transfer trip channels. If the new connection includes generation not previously part of the District's Balancing Authority Area, the generation may also require additional special trip schemes and RAS arming procedures. These schemes will typically require a sequential events recorder as described in Section 6-G.

It is the plant operator's responsibility to develop and maintain procedures for the arming of the generator units for the RAS and also procedures for plant restoration following a RAS action.

a. Generator Dropping

Generator dropping or tripping is the most commonly applied RAS. Generator dropping is achieved with the use of redundant, dedicated transfer trips from the District's RAS controllers to the power plant unit breaker trip circuits.

b. Generator Run Back or Ramp Down

Generator run back may be used in addition to generator tripping. Runback will allow the generation output levels to be decreased to a pre-agreed upon level within a pre-agreed upon time. A stand alone run back or ramp down scheme is rarely allowed. If the runback scheme must be WECC compliant, it will be backed up by a WECC compliant generation dropping scheme.

6-E.4 Other Special Protection and Control Schemes

The location of the POI, amount of load or generation expected and various other system conditions may require special protection schemes. The need for and type of schemes required will be determined as part of the system studies done following the request for a new connection. For example, RAS may be required for stability purposes or out-of-step tripping may be needed for controlled system grid separations. Generator or load tripping may be required to prevent line or equipment overloading. Special breaker tripping or closing schemes such as staggered closing or point-on-wave closing may be necessary to reduce switching transients. These special protection and control schemes may require stand-alone relay systems or additional capabilities of particular substation equipment.

6-E.5 Telecommunications Requirements for Special Protection or Remedial Action Schemes

Many of the special protection schemes described in this section will require telecommunications channels for transfer trip between the RAS controllers and the remote device. If the RAS is part of a scheme that must comply with WECC criteria, it will require redundant transfer trips, redundant channels, and in most cases, geographically diverse communication paths. Specific details for telecommunications channels are in Section 8, Telecommunications Requirements.

6-E.6 RAS Design and Operational Requirements

Minimum requirements for a RAS scheme include the following:

- The RAS should be independent of all other control actions.
- The RAS will have a common architecture as much as possible with existing schemes.
- The RAS will utilize standard alarms to identify operation actions and trouble.
- The RAS scheme must be designed with the ability to safely test the scheme.
- The RAS will be provided with the ability to arm/disarm via SCADA if a SCADA RTU is available.

6-E.7 Future Modifications or Revisions to Special Protection or Remedial Action Schemes

Any modification, change, or revision of an installed RAS scheme at a requestor's site must be reviewed by the District before it is implemented. Proposed changes may also have to be reviewed by the WECC Remedial Action Scheme Reliability Subcommittee.

6-F. Installation and Commissioning Test Requirements for Protection Systems

Thorough commissioning or installation testing of the protection system(s) is an important step for the installation of a new terminal or when changes to the protection system are made. The protection system includes the protective relays, protective relay settings, the circuit breakers, instrument transformer inputs, and all other inputs and outputs, auxiliary relays (typically 86 lockout relays), DC trip paths, pilot schemes, and supervisory alarms associated with the protection scheme. The actual protection equipment used will determine the type and extent of commissioning tests required. Following are the minimum tests that must be performed on protection schemes at the POI that could affect the District's Electric system.

6-F.1 Verify All Protective System Inputs

a. Check for proper ratio, polarity, connections, accuracy, and appropriate grounding on current and voltage transformer circuits.
b. Verify that shorting of unused current transformer windings is proper and that windings used for protection systems are not shorted.
c. Verify that all other inputs to the protection system including battery supplies, circuit breaker auxiliary switches, pilot channel inputs, etc. are correct.

6-F.2 Verify Protection System Settings

a. Check protection system settings and programming.
b. Perform acceptance or calibration tests of the protection system if it was not performed previously.
c. Verify that any changes in relay settings required for relay acceptance testing are restored to the desired settings.

6-F.3 Protection System Drawings and Wiring

a. Verify switchboard panel wiring is intact and matches drawings.
b. Verify interconnections between protection system and other devices are intact and match drawings.
c. Verify that the drawings are correct.

6-F.4 Verify All Protective System Outputs

a. Verify that all trip outputs will trip intended trip coil(s), including auxiliary relays.
b. Verify that all close outputs will properly close the breaker(s); ensure lock-out relays (86) block close.
c. Verify proper relays signal all appropriate transfer trip inputs.
d. Verify other outputs such as breaker failure initiate, special protection scheme signals, reclose initiate and reclose block, relay alarms, event recorder points, and any other relay outputs to other equipment.

6-F.5 Perform Trip or Other Operational Tests

a. Assure correct operation of the overall protection systems.
b. Test automatic reclosing.

6-F.6 Pilot Schemes

a. Measure channel delays.
b. Check for noise immunity.
c. Check for proper settings, programming, etc.
d. Check transmit and receive levels.
e. If automatic channel switching or routing is utilized, check for proper relay operation for alternate routing.
f. Perform end-to-end trip checks.

6-F.7 In Service, Load and Directional Tests

a. Measure AC current and/or voltage magnitudes applied to the relay system.
b. Measure AC current and/or voltage phase angles applied to the relay system.
c. Test the relay system for proper directional operation when applicable.

6-F.8 Special Protection Scheme/Remedial Action Scheme Testing

a. The RAS must be thoroughly tested prior to energization. This includes an end-to-end test, functional test, or operational tests.
b. Ensure compliance with applicable NERC and WECC Reliability Standards.

Use coordinated end-to-end tests to verify the overall operation of the protection system and the pilot channel as part of their commissioning tests.

Modifications to a protection system or RAS scheme also requires testing similar to that listed above. The extent of testing and types of tests required depend upon the changes made. Modifications include changes or additions to protection circuits, changes or upgrades of protective relay firmware, and changes in protective relay logic and/or programming. Many utilities also consider it good practice to perform various levels of tests and calibrations following changes in protective relay settings. When making protection system modifications, attention must be paid to any circuits that may be inadvertently affected (e.g.) an auxiliary relay having multiple circuits tied to its outputs.

6-G. Disturbance Monitoring

Depending upon the type of connection, location, and operating voltage, disturbance monitoring equipment may be required. The monitoring equipment is intended to record system disturbances, identify possible protection scheme problems, and to provide power quality measurements. Sequential event recorders, digital fault recorders, (DFR) and dynamic disturbance recorders may be required. The District may require remote access to these recorders and relay systems at the POI. Upon request, and if available, the District will reciprocate by supplying the Requester with limited access to the corresponding equipment at the remote District terminals.

6-G.1. Sequential Event Recorders (SER)

These devices time tag digital events occurring in a substation. They must have a one millisecond time resolution when recording events. The SER uses a Global Positioning Satellite (GPS) clock receiver for a timing reference. The SER should have sufficient channels to monitor relay and RAS performance, circuit breaker positions, generator status, and other events within the interconnecting substation or generator plant. SERs are required in all 115 kV and above substations. Generators that are part of a WECC compliant RAS must also have SERs.

6-G.2 Digital Fault Recorders (DFR)

The DFR must have sufficient analog channels to monitor critical currents and voltages. The DFR may also include digital channels to monitor selected equipment status in the substation. The DFR must be time synchronized via a GPS satellite clock. For 115 kV and higher substations, a stand-alone DFR is required. Such a relay must be synchronized to a GPS clock. Both the DFR and digital relays that provide protection for the District's Electric system must have remote communications capability such that District personnel can retrieve information, subject to the District's policies and procedures governing the NERC CIP standards.

6-G.3 Dynamic Disturbance Recorders

A dynamic disturbance recorder may be required at key 230 kV and higher voltage substations, major load centers, and generating stations with a combined 1500 MW or greater output at the same POI. Precise details and locations are addressed in NERC Reliability Standard PRC-002-2.. The disturbance recorder should record bus voltage and frequency, line currents, MW and Mvar. Measurement of additional status and control information may be required. The recorder must be able to either record data locally with a ten day minimum continuous archive or be connected to the master station at the District's control center for real-time data transmission and recording. Phasor measurements are preferred, but other measurement types may be acceptable. Data must be time stamped to at least one millisecond accuracy, though phasor measurements should be at a five-microsecond accuracy in accordance with the IEEE standard (PC37.118). Additional status and control system measurements may be required for WECC compliance.

7. Data Requirements for System Operation and Scheduling

7-A. Introduction

All transmission arrangements for power schedules within, across, into or out of the District's Balancing Authority Area require metering and telemetering. Some generation or end-user facilities physically located in another Balancing Authority, referred to as the 'host' Balancing Authority, may also require metering and telemetering to the District's Balancing Authority Area. Transmission arrangements with end-user facilities, genera oration facilities, or transmission facilities may include voltage control, and automatic generation control (AGC). The Peak Reliability Coordinator for the region also needs data to ensure the reliable operation of the entire grid. The technical plan of service for interconnecting a load, generator, or new transmission facility is shown on the PD and includes the metering and telemetering equipment consistent with the transmission contract, or transmission services agreement. Such metering and telemetering equipment may be owned, operated, and maintained by the District or by other parties approved by the District. Telecommunications requirements for data collection are included in Section 8.

Revenue billing, 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 new connection is physically connected to the District's Electric system or electronically connected via telemetering placing the Project within the District's Balancing Authority Area. In all cases, the requester will be required to follow the latest approved NERC Cyber Security (CIP) Standards, which can be found on the NERC website, and the District's implementation of those standards.

7-B. Telemetering Control Center Requirements

The District requires telemetering data for the integration of new interconnections at adjacent Balancing Authority boundaries, as well as new generation within the District's Balancing Authority. This typically consists of the continuous telemetering of active power quantities (in kW) and hourly transmission of the previous hour's energy (in kWh) from the POI to the District's operations control center. Table 7-1 summarizes the general metering and telemetering requirements and Table 7-2 identifies requirements based on connection location. The following are general requirements for telemetering:

7-B.1 Facilities Tied to the District's Balancing Authority Area Boundary

Telemetering is required for all interconnections at a District Balancing Authority boundary. For this case, telemetering of active power and energy (kW, kWh) is required. There may also be a need for reactive power (kvar, kvarh) information for purposes of billing based on power factor. High capacity interconnections may require redundant metering and telemetering.

For connections that are to be normally open, or closed only for emergencies, the District determines telemetering needs on a case-by-case basis.

Table 7-1 General Metering and Telemetering Data Requirements

District Data Requirements[1]			
System or Quantity	**System Operations Center**	**High Voltage Scheduling**	**Revenue Billing**
KW	Yes	No	No[2]
KWh	Yes	Yes	Yes
KVAr	Yes	No	No
KVArh	Yes	No	Yes
KV	Yes	No	No
Number of Units	Number on Line Number Available	Number on Line Number Available	No
Resource Size	≥ 3.5 MVA[1]	≥ 1 MVA	≥ 1 kW
AGC	≥ 20 MVA[3]	No	No
Data Sample Rate	1 Second or other approved rate compatible with NERC Policy	Last Hour kWh sent each hour	Hourly kWh Data Retrieved daily
Generation Reserves	Contingency non-spinning MW Contingency Spinning MW Regulating MW	Contingency non-spinning MW Contingency Spinning MW Regulating MW	No

Notes:

1. Requirements for customer-owned generating facilities below 3.5 MVA are determined on an individual basis.
2. A kW reading for revenue billing may be required where special transmission arrangements are necessary.
3. The actual AGC requirements shall be determined on an individual basis.

Table 7-2 Metering, Telemetering and SCADA Data Requirements vs. Connection Location

Connection to District's Electric system	Connection Located Inside District's Balancing Authority Area	Connection Located Outside District's Balancing Authority Area
Direct Electrical Connection[1]	kW, kWh, RMS[2], kvar, kvarh, kV circuit breaker status & control	kW, kWh, RMS[2], kvar, kvarh, kV circuit breaker status & control
No Direct Electrical Connection	kW, kWh, RMS[2]	kW[3]

Notes:

1. Dedicated circuit is required for kW, kWh, kvar, kvarh, and kV.
2. Dial-up phone line required for RMS.
3. kW is required if capacity of WECC path the District manages is impacted.

Table 7-3 Metering, Telemetering and SCADA Data Requirements for Loads, (L), Incl. Station Service, At the Meter Point and inside District's Balancing Authority Area

Quantity	$5 \leq L < 25$ MVA	$L \geq 25$ MVA
Billing Information [RMS[3]]; Hourly kWh & kvarh[2]	Yes	Yes
Hourly Estimate of Load (by web, FAX, or phone)	Yes[4]	Yes[4]
Continuous Data	Yes	Yes
Loss of Meter Potential Alarm	Yes	Yes
Telemetering Equipment Failure Alarm	Yes	Yes
Uni-Directional kW & Bi-Directional kvar Meter	No	No
kV	Yes If $L \geq 10$ MVA	Yes
Kvar	Yes If $L \geq 10$ MVA	Yes
Redundant Meters	No	Yes

Notes:

1. Hourly estimate of load must equal the sum of transmission schedules for delivered power.
2. Hourly integration of kvar may be used for reactive billing if kvarh not available from meters.
3. RMS requires dial-up phone line.
4. Required from the scheduling agent to the District.

Table 7-4 Metering, Telemetering and SCADA Data Requirements for Generation

System or Quantity	G < 3.5 MVA	3.5 ≤ G < 50 MVA Local[2] Load Only	3.5 ≤ G < 50 MVA Exporting Output	G ≥50 MVA
Billing information (RMS)	Yes, if X≥1 kW No, if X<1 kW	Yes	Yes	Yes
Hourly Estimate of Generation[1] (by web, FAX, or phone)	Conditional2	Yes	Yes	Yes
Hourly kWh (telemetered)	No	Yes	Yes	Yes
kW Continuous Data	Yes If G ≥1 MVA	Yes	Yes	Yes
Loss Of Meter Potential	No	Yes	Yes	Yes
MW & Mvar on Each Unit[3]	No	No	Yes	Yes
Uni-directional kW & Bidirectional kvar meter	Yes	Yes	No	No
Bi-directional kW & kvar Meter	No	No	Yes	Yes
Redundant Meters	No	Yes If G ≥20 MVA	Yes If G ≥20 MVA	Yes
Gen-ICCP (Redundant Links)	No	No	No	Yes[4]

Notes:

1. Hourly estimate of generation must equal the sum of transmission schedules for marketed power. It is required from the scheduling agent to the District
2. Hourly estimate is not required if generation is serving local load only. It is required if generation is being used as a marketing resource. Local load is defined as load that is on the generator side of the meter.
3. Separate meters for each unit are required when generators per line are not identical.
4. Possible exception for intermittent projects such as wind generators.
5. Required if the District is the designated scheduling agent.

7-B.2 Loads Within the District's Balancing Authority Area

For end-user facilities with direct electrical connections to the District's Balancing Authority Area, AGC telemetering is not normally required. For interruptible loads, the District determines telemetering needs on a case-by-case basis. Connecting eccentric (non-conforming) end-user facilities may require an interface to the District's AGC system. Existing practices throughout North America usually require a warning signal of pre-loading in order to assure that adequate generation reserves are spinning before any sudden load change occurs. Table 7-3 summarizes metering, telemetering, and SCADA requirements for end-user facilities based upon size.

7-B.3 Generation Within the District's Balancing Authority Area

For generation connected internally to the District's Balancing Authority Area, telemetering is required for generation facilities of aggregate output equaling or exceeding 3.5 MVA. For this case, telemetering of real power and energy (kW, kWh), and reactive power (kvar, kvarh) is normally required. The District will determine telemetering needs on a case-by-case basis for generation sites that remain below 3.5 MVA. Station service load may require separate telemetering if it comes from a different Balancing Authority. Station service taken directly from the generator POI may require separate metering and separate current transformers to accurately measure the station service load. Table 7-4 summarizes metering, telemetering and SCADA requirements for generation within the District's Balancing Authority Area.

Metering and telemetering for temporary generation installations (planned for less than one year of service) will be determined on a case-by-case basis.

Generation sites with an aggregate output equaling or exceeding 20 MVA may require a direct link with the District via a generation ICCP communication server in order to send and receive data directly from the District's AGC System. ICCP is the Inter-Control Center Communications Protocol, defined by IEC 870-6 TASE.2 standard. See Section 7-C.2 for additional details on the ICCP requirements. Wind projects and other intermittent generation may be exempted from these criteria, subject to a case-by-case review.

The Peak Reliability Coordinator (RC) requires certain data per the current RC data request. The Requestor must provide the required data to the Peak RC in conformance with the data request unless expressly agreed to otherwise in writing.

7-B.4 Jointly-owned Load or Generation

Telemetering for interconnection of shared or jointly owned end-user facilities or generation commonly use dynamic signals. These signals are usually a calculated portion of an actual metered value. The calculation may include adjustments for losses, changing ratios of customer obligations or shares, or thresholds and limits. Two-way dynamic signals are used when a customer request for MW change that can only be met by an actual change in generation. In this case, a return signal is the official response to the request and its integrated value is designated the official meter reading. Previous integration intervals were typically one hour. Some types of dynamic signals may require shorter integration intervals. The integration interval is determined by the type of service provided consistent with the District's procedures to properly account for transmission usage. The District uses the NERC recommended 'accumulator method' for accounting, not the 'rounding method' for integrated values.

7-B.5 Generation in the District's Balancing Authority Area Not Controlled by the District

Telemetering is required for generation located internal to the District's Balancing Authority to account for the scheduling that is required to deliver that energy to the appropriate host Balancing Authority. The requirements are similar to interchange telemetering requirements. In this case, Gen ICCP is typically not required by The District.

7-C. Data Requirements for Balancing Authority Services

This section contains the data requirements for Balancing Authority services if the Requestor wishes to locate a generation or end-user facility in the District's Balancing Authority Area. **Provision for all ancillary services are normally specified in the contract. The technical information below is included for general conceptual purposes only.** Technical discussions between the Requestor and the District are necessary before specific implementation requirements can be determined.

7-C.1 Requirements for Interconnected End-user facilities

Non-traditional sources are sometimes used for supplying ancillary services. If a load provides regulating or contingency reserve services, data requirements for deployment of the reserves will be similar to those applied to generating resources. To the extent that a third party may externally supply regulating or contingency reserve services at the District's Balancing Authority Area interconnecting boundary, data requirements for their deployment may be similar to those applied to generating resources.

Technical discussions are necessary before the specific data requirements can be determined. The following provides a brief overview of these requirements:

a. Supplemental AGC Services

If The District is purchasing supplemental AGC services, AGC interface is required on a long-term basis. Prior to The District purchasing supplemental services, an investigation into the capabilities, cost, and benefits of AGC control is required to determine the specific AGC requirements. Most supplemental services are scheduled and delivered using real-time dynamic signals, thus requiring telemetering.

b. Ancillary Services

Ancillary Services requirements are also driven by how the interconnected customer chooses to meet these obligations. Either the Requester or the entity making the transmission arrangements is responsible for meeting obligations for necessary ancillary services associated with the interconnection. Most self-provided ancillary services are scheduled and delivered using real-time dynamic signals, which require telemetering. The responsible party may fulfill these obligations in any of the following ways:

- Directly provide ancillary services by making resources available to the District to deploy

- Contract with a third party to make resources available to the District to deploy
- Contract with the District to cover this ancillary services obligation

The Requester must demonstrate that the selected options are technically sound and are in compliance with all relevant reliability standards and criteria of NERC, WECC and NWPP or their successors as well as the District's approved business practices.

Where a third party is providing ancillary services, the following data is required with a sampling rate established in the District's business practices – typically four seconds between samples for regulation and ten seconds for operating reserves:

- Net instantaneous active power transferred (in MW)
- Instantaneous reactive power (in Mvar) and total reactive power (Mvarh) transferred
- Operating reserve capability during the upcoming ten minutes
- kWh for most-recent hour
- Area Control Error (Station Control Error for Generating unit)
- Actual Scheduled Interchange

c. Supervisory Control and Data Acquisition System (SCADA)
Additional data may be required from end-user facilities such as steel rolling mills and wind tunnels, in order to make generation control performance more predictable. Such additional data may include, but not be limited to, precursor signals of expected load changes. SCADA control may also be required. Specific requirements and needs are determined for each load. This may require a separate SCADA remote terminal unit or it may require data be added into an existing SCADA as determined by the District.

7-C.2 Requirements for Interconnected Generation

Data requirements for Balancing Authority services, such as regulation or operating reserves, apply only to generation resources inside the District's Balancing Authority Area. For resources that are not part of The District's Balancing Authority, the operator of the host Balancing Authority determines the data requirements.

Inter-Control Center Communication Protocol (ICCP) is a standard communications protocol for data exchange used by the District and many other entities. ICCP is an international standard for communications of real time data. The IEC 870-6 TASE.2 Standard defines the ICCP. The ICCP protocol is being revised to include certificate authentication and encryption for security purposes. When this package is available, all ICCP servers must be retrofitted. The District has two systems that communicate via ICCP. The first is GEN ICCP used for exchanging generation data between the District's Control Center and the Generation facility. It is an internal, point-to-point service. The second system, called simply ICCP, was previously known as inter-utility data exchange. It is used to exchange SCADA data between the District and other utilities and balancing authority area operators. This form of data exchange uses public switched telecommunications services.

For generation resources inside the District's Balancing Authority Area, ancillary services, (e.g. reserves) must be acquired. Provision for all ancillary services are specified in the transmission or Balancing Authority services contract. The District must specifically approve all arrangements for generators intending to provide Ancillary Services to the District. If the generator is capable of providing Ancillary Services in excess of its obligation, then the District may choose to contract with the generator operator to provide additional Ancillary Services. Technical discussions between the District and generator developers are necessary before the specific implementation requirements can be determined. For generation facilities with a total capacity of 20 MVA or above, Gen ICCP will generally be required to bring in unit information as well as MW, Mvar and kV from the project. The AGC data to be passed over the data link may include some or all of the data quantities listed in Table 7-5. For each project a detailed data requirements list with definitions will be provided during the design phase of the interconnection of the project. Actual generator specific data requirements are developed after an Interconnection Agreement or Balancing Authority Services Agreement is signed.

Wind projects may be exempt from the ICCP requirement, but will be required to provide kW, kvar, kV and interconnection circuit breakers(s) status, at a minimum. All wind projects with external capacitor compensation will be required to have automatic control on a voltage schedule provided by The District's System Operators. Status and availability of each external capacitor may also be required. Projects with internal automatic var compensation (i.e. double fed wound rotor) may be required to receive a voltage set point signal. This will be determined on a case-by case basis.

a. Automatic Generator Control Services

If the District is purchasing ancillary services from the generation facility, AGC control of the generator capability is required on a long-term basis. Prior to purchasing AGC services, a capabilities, cost, and benefit investigation as to the AGC control capabilities of the generation facility is required to determine the specific AGC requirements.

b. Ancillary Services

Requirements for Ancillary Services are also driven by how the generator operator or the purchaser chooses to meet the reserve obligations of the generation facility, as described below. Either the generation operator or the entity making the transmission arrangements is liable for the reserve obligations associated with the operation of the generation facility. Generation marketed as interruptible power is treated separately under special provisions and guidelines by the WECC and the District. The responsible party may fulfill these obligations in any of the following ways:

- Make these reserves available to the District from the generating facility
- Make these reserves available to the District from another one of their generation resources
- Contract with another generator operator to make these reserves available to the District on their behalf
- Contract with the District to cover this reserve obligation

c. Supervisory Control and Data Acquisition (SCADA) Requirements

New substations may require the District's SCADA control and status indication of the power circuit breakers and associated isolating switches used to connect with the District. SCADA indication of real and reactive power flows and voltage levels are also required. If the connection is made directly to another utility's transmission system, SCADA control and status indication requirements shall be jointly determined with the Requester, and the District. SCADA control of breakers and isolating switches that are located at other than the generating facility are not normally required, although status and indication may be necessary for system security purposes. Section 8-D discusses telecommunications requirements for SCADA systems.

d. GEN ICCP Installation

A GEN ICCP installation is required for generation facilities greater than 20 MVA. If the District is not providing any ancillary services, a GEN ICCP configuration with single server and single router are acceptable. If The District is providing ancillary services, a primary server and back up server must be installed. If The District is performing automatic generation control, redundant servers and redundant routers are required. The GEN ICCP installation at the generating facility provides capability to bring additional data from the generator(s) to the District's control centers. Table 7-5 shows the typical GEN ICCP data required.

Table 7-5a Automatic Generation Control (AGC) Quantities

Generation Plant to District's Control Center(s):	
1.	Plant in District AGC mode / local mode[1]
2.	Net instantaneous power output (MW), unit MW output for plants >20 MW
3.	Plant output attributed to natural governor response (MW)
4.	Plant ramp rate capability – maximum raise and lower
5.	Plant jerk rate capability (rate of change of ramp rate) – maximum raise and lower
6.	Regulating reserve capability - during next 10-minutes
7.	Spinning reserve capability - during next 10-minutes
8.	Operating reserve capability - during next 10-minutes
9.	Maximum capability - normal conditions
10.	Maximum capability - power system emergency conditions

11.	Minimum generation capability
12.	Unit power system stabilizer and automatic voltage regulation status
13.	Unit status - defined below for each generator unit in numerical order.
	- Out of Service - unit not available for use on 10 minutes notice.
	- Standby Mode - unit available for use on 10 minutes notice.
	- Standby Mode - unit available for use within 60 minutes
	- On-line / Not on AGC
	- On-line / On AGC
	- On-line / Condensing
14.	Total Mvar output, unit Mvar output for plants >200 MW
15.	Total instantaneous maximum Mvar capacity boost or each POI voltage level
16.	Total maximum Mvar capacity boost or each POI voltage level
17.	Total instantaneous maximum Mvar capacity buck or each POI voltage level
18.	Total maximum Mvar capacity buck
19.	Plant in District kV mode / local kV mode[2]

Notes:

1. When plant is in District AGC mode, the District's AGC system is enabled at the plant. The plant is controlling power output to meet the generation request and generation rate of response (MW/minute) originating from the District. When the plant is in local mode the District's AGC system is disabled. The plant is not controlling its power output to meet generation request and generation rate of response originating from the District.
2. When plant is in District kV mode, the coordinated var control system is enabled at the plant. The plant is controlling reactive power output to meet the voltage schedule originating from the District. When the plant is in local kV mode, the District coordinated var control system is disabled at the plant but automatic voltage regulators are still in service. The plant is controlling its reactive power output to meet the nominal voltage schedule originating from the District.

Table 7-5b Automatic Generation Control (AGC) Quantities

District Control Center(s) to Generation Plant:	
1.	Generation request at rated frequency set point - AGC-requested power output level in MW for the following look-ahead time horizons: 0, 5, 10, 15, 20, and 30 minutes.
2.	Generation requested rate of response.
3.	Amount of regulating reserve to carry.
4.	Generation base point - The generation level in MW at which the District expects to be operating the plant at the end of the ramp.
5.	Plant MW control mode - regulating, base load, standby, or off control
6.	District operating mode indication to the plant – normal, assist, emergency
7.	Bus voltage schedule(s) in kV and actual measurement(s)
8.	District AGC control center identifier – Primary or Backup Control Center
9.	District Mvar Control Mode – coordinated voltage schedule, nominal voltage schedule

7-D. Generation and Transmission Interchange Scheduling Requirements

Any new transmission, end-user or generation facility being integrated into the District's Electric system must adhere to the scheduling requirements of the District under which it is taking transmission or balancing authority area service from the District. Customers may be required to provide the District's scheduling department with an estimate of the their hourly load, hourly generation schedules, and/or net hourly interchange transactions. These estimates will be used for both pre-scheduling and planning purposes. The District will require customers to provide these estimates as necessary in order for the District to manage the load or resource balance within the District's Balancing Authority Area and to determine usage of the District's Electric system.

In the case of new transmission facilities, scheduling and accounting procedures are needed if the facility is part of an interface between the District's Balancing Authority Area and another Balancing Authority. This scheduling and accounting of interchange between two balancing authority areas normally requires telemetered data from the POI to the control centers of the Balancing Authority operators. This data is termed interchange metering and telemetering by the District and includes kW and kWh quantities. The District requires that all balancing authority area transactions be pre-scheduled for each hour using the normal scheduling procedures. The end-of-hour actual interchange must be conveyed each hour to the District's system control center. This can be accomplished through the use of telemetering or data link.

When the new interconnection represents a shared or jointly owned interface to The District, or a split resource between The District's Balancing Authority and any other, then a calculated allocation is usually required to divide up the total metered interchange. This non-physical interface is accomplished by dynamic signal. A two-way dynamic signal is required when a combined request and response interface is used. An example is supplemental AGC services. A one-way dynamic signal is required when a response (or following) interface is used. Moving a balancing authority area boundary is an example of this requirement.

7-D.1 Generation Metering Requirements

Generation metering usually consists of bi-directional meters and related communications systems providing active power (in kW) and energy (in kWh) from the POI. Active power is telemetered on a continuous basis for AGC and hourly energy is sent each hour to the Interchange accounting for the District. All generation projects of aggregate size equaling or exceeding one MVA require hourly pre-scheduling. The District may also require indication of available spinning reserve and controlled reserves, both in MW. (See section 7-F for more on reserves

a. Interchange Metering Requirements

Interchange telemetering generally consists of bi-directional meters and related telecommunications systems providing kW and kWh at or near the POI. The kW measurement is telemetered on a continuous basis for AGC and hourly kWh is sent each hour to the control center. (Tables 7-1, 2 and 4 summarize the requirements). Interchange telemetering accuracy and calibration requirements are identical with those stated in Sections 7-F and 4-H.

Effective telemetering requires real-time knowledge of the quality of measurement. Associated with the telemetering signal are various indications of this quality. Analog telemetering is commonly accompanied with squelch and telemetering carrier fail alarms. A loss of meter potential or meter potential phase unbalance should trigger a telemetering carrier failure alarm. Digital telemetering has equivalent signal failure alarms. The metering equipment must also be monitored and alarmed in the telemetering signal. Typical alarms include but are not limited to:

- Meter potential phase unbalance
- Loss of telemetering signal
- Loss of meter potential signal

b. Generation Station Service and Start-Up Metering

If the District supplies a generation site station service, then that station service must be properly and accurately metered. This may require separate dedicated meters for station service. It is preferred to meter generation by locating metering accuracy current transformers such that accurate station service can also be metered. Then net generation, start-up and station service can be accomplished from one-meter location. However, if this is not possible, then metering with demand interval data recording (MV90™ compatible) and communications would be required at the station service transformer(s). Meter data is recorded when the District is supplying either transmission, energy or both.

7-E. Revenue and Interchange Metering System

All interconnections of facilities capable of exchanging at least 1 kW of active power require District qualified metering for revenue or interchange. Energy data recording is required for the District's billing and scheduling functions. Revenue metering includes energy (kWh) and reactive power (kvarh) produced by revenue meters and recorded on a demand interval basis. Interchange metering includes bi-directional energy and reactive data as well as special telemetering requirements for scheduling purposes. The metering shall be located to measure the net power at the POI to or from the District's Electric system.

The revenue metering system (RMS) includes a remote metering system to record the hourly kWh data. The 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 MV-90™ protocol. Demand data will be available to the customer or their agent.

The District typically owns and maintains the revenue metering at load-metering sites. The District will supply the Requester with a list of pre-qualified metering systems should the Requester desire to furnish, own or maintain the metering system. If the selected system is not on the District's pre-qualified list, the District reserves the right to perform a full set of acceptance tests, possibly at the Requester's expense, prior to granting permission to use the selected system

7-E.1 Requirements for Revenue and Interchange Metering

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 balanced, ungrounded power systems. Both revenue metering and interchange metering shall be bi-directional to record both active and reactive power flows to or from the POI. Metering packages include a kWh recording device compatible with the District's RMS or scheduling system, as applicable.

Should the new POI result in the addition of generation to the District's Electric system not previously accounted for, there will be additional metering requirements. Tables 7-1 through 7-4 identify revenue metering requirements. Section 8 discusses telecommunications requirements for the RMS system.

7-E.2 Required Accuracy of Meters

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

7-E.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 in order to prevent unintentional energization of the transformer secondary during a transformer failure. Instrument transformers for metering must be located such that the input to the metering and telemetering is not interrupted during possible switching configurations at the POI.

7-E.4 Loss Compensation

Transmission system losses, such as those in transformers, often must be accounted for in the revenue metering process. The District prefers that this accounting be done as a calculated part of the District's billing and settlement process.

7-E.5 Station Service Power

Depending upon its electrical source and electrical location, the station service power for the connecting substation facilities 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.

7-F. Calibration of Metering, Telemetering, and Data Facilities

7-F.1 Revenue and Interchange Metering

The meter owner is responsible to calibrate and document revenue and interchange metering at least every two years. More frequent calibration intervals may be negotiated. All parties to the transmission interconnection agreement may witness the calibration. Calibration information will be maintained for 7 years and will be made available to the District upon request.

7-F.2 SCADA and ICCP Data

SCADA and ICCP data shall be calibrated every two years as a minimum or more often if significant errors occur affecting the state estimator results. All parties to the transmission interconnection agreement may witness the calibration.

8. Telecommunication Requirements

8-A. Introduction

Telecommunications facilities shall be installed to fulfill the control, protection, operation, dispatching, scheduling, and revenue metering requirements. They may be owned by the District, another utility or a third party. 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 new facility will be connected. Telecommunications facilities will be identified on the PD. Depending on the performance and reliability requirements of the control and metering systems to be supported, the facilities may consist of any or all of the following:

8-A.1 Radio Systems

A radio system requires transmitters, receivers, telecommunication fault alarm equipment, antennas, batteries, chargers, 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 telecommunications path. In order to meet power system reliability requirements, radio path diversity, equipment redundancy or route redundancy may be required. These measures protect against telecommunications outages caused by equipment failure or atmospheric conditions.

8-A.2 Fiber Optic Systems (District's preferred option wherever feasible)

A fiber optic system requires light wave transmitters, receivers, telecommunication fault alarm equipment, multiplex equipment, batteries, chargers, emergency power systems, fiber optic cable (underground or overhead) and rights-of-way. Cable route redundancy may be required in order to prevent telecommunications outages caused by cable breaks.

8-A.3 Wireline Facilities

A wireline facility (e.g., leased line) requires telecommunications 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 in order to prevent telecommunications outage.

8-A.4 Power Line Carrier (District's least preferred option)

A power line carrier current system uses the actual power line conductor(s) as the transmission media. Coupling capacitors, line tuning units and wave traps are used to connect the carrier transmitter and receiver to the power line. Power line carrier availability and performance is greatly affected by line outages.

8-B. Voice Communications

8-B.1 Basic Requirements

If the generation or load facility is within the District's Balancing Authority Area and any type of telemetering is required, then voice communications to the operator are also required. If the facility is not staffed with operators, alternative arrangements may be made subject to the District's approval.

8-B.2 Automatic Ringdown Trunks

Dedicated, direct automatic ringdown trunk (or equivalent) voice circuits between each appropriate District control center and the operator of the generation or end-user facilities may be required for:

- Generation or end-user facilities of 20 MW or greater,
- Eccentric (non-conforming) generators or end-user facilities
- Connected networks that include automatic generation dropping for District Transmission system remedial action.
- A non-radial interconnection to another electric utility with a transfer capability in either direction of 20 MW or greater.

8-B.3 Independent Communications

Independent voice communications for coordination of system protection, control and telecommunication maintenance activities between The District and the generation facility or POI should also be provided.

8-C. Data Communications

General telemetering of power and energy data (in kW, kvar, kWh) and data acquisition systems typically require one or more dedicated communication circuits. These circuits link the new facility to the master computer receiving the data

Telecommunications for SCADA, RMS and telemetering must function at the full performance level before and after any power system fault condition. Repair personnel must restore service continuity immediately after the fault without the need for intervention. The following requirements for telemetering of data are specified:

8-C.1 SCADA

For communication of SCADA information, one or more dedicated circuits are typically required between a new facility and the appropriate District control center(s).

To ensure safety of working personnel and prompt response to system abnormalities, the District shall be allowed to know the status of certain breakers (e.g., utility tie breaker, interconnection breaker, and generator breaker(s)) and the real & reactive power flow at the generator breakers and at the District primary meter. A dedicated communications link for SCADA shall be required. In general, a District-owned local Remote Terminal Unit (RTU) shall be installed at the customer-owned facility to perform certain control and monitoring functions as specified elsewhere in this document.

8-C.2 Automatic Generator Control (AGC) Interchange and Control Telemetering

One or more dedicated circuits are typically required between the new generation facility and the appropriate District control center(s) for telemetering of AGC Interchange and control information for operations and scheduling applications. If AGC services are required, data will be sent to and from the appropriate District control center(s) using the ICCP over private control synchronous communication channels operating at a minimum rate of 9600 baud.

8-C.3 Revenue Metering System (RMS)

Commercial dial-up telephone exchange line facilities are required for support of the MV-90™ compatible remote RMS equipment. The exchange line facilities communicate with the MV-90™ compatible master computer at the District's designated location. The circuit used for this purpose may also be shared with voice communications and other dial-up data communications.

8-D. Telecommunications for Control and Protection

Telecommunications for control and protection must function at the full performance level before, during and after any power system fault condition. The delivery of a false trip or control signal, or the failure to deliver a valid trip signal is unacceptable. Active telecommunication circuits for control and protection must not be tested, switched, shorted, grounded or changed in any manner by any worker, unless prior arrangements have been made through the District's system operations control center.

8-D.1 Application on Bulk Electric System Transmission

The highest telecommunications performance level as specified by the WECC (ref 3.6) is 99.95% availability. This level of performance is required on all protection circuits for lines connected to the District's Bulk Electric System. This performance level is also required for RAS circuits that must meet WECC compliance criteria. These circuits require totally redundant schemes.

Availability is determined for the total path of the protective relaying circuit, from one end of the transmission line to the other. Options for achieving these availability requirements by utilizing two or more separate telecommunication methods, routes or systems may be considered. When alternately routed telecommunications for protective relaying schemes are required, a combination of two of these telecommunications methods may be used to meet availability requirements.

8-D.2 Non-Bulk Electric System Transmission Applications

A telecommunications performance level of 99.5% (ref 3.6) is required for less critical protection circuits. This level of performance is also required for RAS circuits not required to meet the WECC criteria. Redundant telecommunications systems are only required in certain circumstances to ensure the reliability and speed of the transmission of signals for protection and RAS.

8-D.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 RAS. System studies and WECC trip time requirements (ref 3.6) determine maximum permissible throughput operating times of control schemes.

8-D.4 Equipment Compatibility

Protection systems and supporting telecommunications equipment installed at the interconnecting facility must be functionally compatible or identical to the corresponding equipment employed at the District's facility. This functionality need not extend to peripherals, such as signal counters and test switches that might be present on the District's equipment. Teleprotection equipment employed by the Requester must be approved by the District prior to installation. At the time of the request for interconnection the District will supply the Requester with a list of acceptable, pre-qualified equipment. Should the Requester choose to employ equipment not on this list, the District reserves the right to test the equipment for acceptable performance in the required control application. Equipment that passes this testing can be approved by the District for subsequent installations.

Teleprotection systems, including transfer trip, must be properly designed and tested to demonstrate that they perform their intended functions. When applying digital telecommunications systems to protection schemes, care must be taken ensure equipment compatibility

8-E. Telecommunications During Emergency Conditions

8-E.1 Emergency Conditions

Emergency telecommunications conditions may develop that affect telecommunications equipment with or without directly affecting power transmission system facilities.
Examples of telecommunications emergencies include the following:

- Interruption of power to telecommunications repeater and relay stations
- Telecommunications equipment failure, whether minor or catastrophic
- Interruption or failure of commercial, public switched telephone network facilities or services
- Damage to telecommunications facilities resulting from accident, acts of vandalism, or natural causes

Equipment redundancy and telecommunications route redundancy can protect against certain kinds of failure and telecommunications path interruption. A repair team dedicated to the telecommunications of the interconnecting facility should be retained along with an adequate supply of spare components.

8-E.2 Backup Equipment

Where commercial, public telephone network facilities or services support important power system telecommunications, a backup strategy should always be developed by the Requester to protect against interruption of such services. Backup methods could include redundant services, self-healing services, multiple independent routes, carriers and combinations of independent facilities such as wireline and cellular, fiber and radio, etc. Backup telecommunications system equipment such as emergency standby power generators with ample on-site fuel storage and reserve storage battery capacity must be incorporated in critical telecommunications facilities. Backup equipment should also be considered for certain non-critical telecommunications to provide continued operation of telecommunications during interruption of transmission services.

8-E.3 Disaster Recovery

The Requester shall have a disaster recovery plan in place for telecommunications restoration that shall also be exercised periodically in accordance with NERC/WECC reliability requirements. The disaster recovery plan shall include the ability to provide equipment capable of bypassing or replacing entire telecommunication stations or major apparatus until permanent repairs can be made.

8-E.4 Telecommunications Security

The operation of power system telecommunications facilities should be continuously monitored at a central alarm point so that problems can be immediately reported, diagnosed and repaired. Telecommunication sites and facilities should be secured against unauthorized access.

9. Information Requirements

9-A. Introduction

When a request is submitted for a connection to the District's Electric system certain information must be included so the District can properly consider the interconnection request. The actual information required by the District will vary depending upon the type of request. Requestors should contact a Customer Services Representative and refer to the District's web site, http://www.chelanpud.org/my-pud-services, for application forms and procedures. This section describes typical information and data that The District will require.

9-B. Connection Location

The District needs location information for the proposed interconnection in order to adequately study the impacts. Location information required will vary depending upon the proposal.

Locations of new substations, generators or new taps on existing lines must include the state, county, township, range, elevation, latitude and longitude. The District also requires driving directions to the location for a site evaluation.

1. Identify the substation if connecting to an existing District substation.
2. If the connection is between two existing substations, then both substations need to be identified.
3. For connection to an existing District transmission line, identify the line by name as well as the location of the proposed interconnection.
4. If the request includes a new substation or generator site, the proposed location is required.

9-C. Electrical Data

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

9-C.1 Electrical One-Line Diagram

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

9-C.2 Generator Data

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

a. Generator General Specifications

1. Energy source (e.g., natural gas, coal, wind, hydro, co-generation, geothermal, etc.)
2. Number of rotating generators
3. Number of turbines, combustion, steam, wind, hydro, etc.

4. Total project output, MW, (@ 0.95 PF for synchronous generators)
5. Station service load for plant auxiliaries, kW, kvar
6. Station service connection plan
7. Description of operating profile, including peak monthly outputs and expected maintenance periods.

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

1. Reactive capability, 'P-Q' curves
2. Excitation 'Vee' curves
3. Saturation and synchronous impedance curves
4. Identifier (e.g., GTG #12)
5. Number of similar generators
6. Complex power, kVA
7. Active power, kW
8. Terminal voltage, kV
9. Machine parameters
   a. S_b – Complex power base (MVA) upon which machine data is specified
   b. H – Normalized rotational kinetic energy of the generator/turbine/shaft assembly, kW-sec/kVA
   c. WR2 – Moment of inertia, lb. Ft^2
   d. Ra – Armature resistance, pu
   e. Xd – Direct axis unsaturated synchronous reactance, pu
   f. X'd – Direct axis unsaturated transient reactance, pu
   g. X'q – Quadrature axis saturated and unsaturated transient reactance, pu
   h. X"d – Direct axis saturated and unsaturated subtransient reactance, pu
   i. XI – Stator leakage reactance, pu
   j. X2 – Negative-sequence reactance, pu
   k. X0 – Zero-sequence reactance, pu
   l. Xn – Zero-sequence unit grounding reactance, pu
   m. Rn – Zero-sequence unit grounding resistance, pu
   n. T'do – Direct axis transient open circuit time constant, seconds
   o. T'qo – Quadrature axis transient open circuit time constant, seconds
   p. T"do – Direct axis subtransient open circuit time constant, seconds
   q. T"qo – Quadrature axis subtransient open circuit time constant, seconds
   r. S(1.0) – Saturation factor at rated terminal voltage, A/A
   s. S(1.2) – Saturation factor at 1.2 per unit of rated terminal voltage, A/A
10. Excitation system modeling information
    a. Type (static, ac rotating, etc.)
    b. Maximum/Minimum dc current
    c. Maximum/Minimum de voltage
    d. Nameplate information
    e. Block diagram
    f. Power System Stabilizer (PSS) type and characteristics

11. Speed governor information with detailed modeling information for each type of turbine.
    a. Turbine type (Combustion, Steam, Wind, Hydro)
    b. Total capability, MW (available peak operation rating)
    c. Number of stages
    d. Manufacturer and model, if known
    e. Frequency vs. time operational limits, seconds at Hz
    f. Maximum turbine ramping rates, MW/minute, ramp up and ramp down

c. Generator Data, Asynchronous Machines

1. Shunt reactive devices (capacitor banks) for power factor correction with induction generators or converters.
    a. PF without compensation
    b. PF with full compensation
    c. Reactive power of total internal shunt compensation voltage, kvar
2. AC/DC Converter devices employed with certain types of induction-motor installations or with dc sources.
    a. Number of converters
    b. Nominal ac voltage, kV
    c. Capability to supply or absorb reactive power, kvar
    d. Converter manufacturer, model name, number, version
    e. Rated/Limitation on Fault current contribution, kA
3. Machine parameters
    a. S_b – Complex power base (MVA) upon which machine data is specified
    b. H – Normalized rotational kinetic energy of the generator/turbine/shaft assembly, seconds
    c. Ra – Armature resistance, pu
    d. Xd – Direct axis saturated and unsaturated synchronous reactance, pu
    e. X'd – Direct axis saturated and unsaturated transient reactance, pu
    f. X"d – Direct axis saturated and unsaturated subtransient reactance, pu
    g. XI – Stator leakage reactance, pu
    h. X2 – Negative-sequence reactance, pu
    i. X0 – Zero-sequence reactance, pu
    j. Xn – Zero-sequence unit grounding reactance, pu
    k. Rn – Zero-sequence unit grounding resistance, pu
    l. T'do – Direct axis transient open circuit time constant, seconds
    m. T"do – Direct axis subtransient open circuit time constant, seconds
    n. S(1.0) – Saturation factor at rated terminal voltage, A/A
    o. S(1.2) – Saturation factor at 1.2 per unit of rated terminal voltage, A/A
    p. Vt – Voltage threshold for tripping, pu
    q. Vr – Voltage at which reconnection is permitted, pu
    r. Tv – Pickup time for voltage-based tripping, seconds
    s. Tvr – Time delay for reconnection, seconds
    t. Ft – Frequency threshold for tripping, Hz
    u. Tf – Pickup time for frequency-based tripping, seconds
    v. Reactive power required at no load, kvar

w. Reactive power required at full load, kvar

4. External Shunt Compensation
    a. Bus Voltage
    b. Number and rating of each shunt capacitor section
    c. Voltage/PF controller scheme description and time delays

d. Direct Current (DC) Sources

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

9-C.3 Load Information Requirements

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

1. Type of load, such as industrial, commercial, residential or combination
2. Load data
    a. Delivery voltage, kV
    b. Projected peak load, kW
    c. Summer peak load, kW
    d. Winter peak load, kW
    e. Anticipated power factor

9-C.4 Transformer Data

If one or more power transformers are included as part of the proposed connection, the following data is required for each unique transformer.

1. Transformer number or identifier
2. Number of similar transformers
3. Transformer type and number of windings, (e.g. Autotransformer, two winding)
4. Transformer winding data. For a two winding transformer, only winding H and X data is required.
    a. For each winding, H, X, y:
        1) Nominal voltage, kV
        2) Configuration (Δ or Y) and Y winding connection (ungrounded, solid ground or impedance ground)
    b. Transformer MVA ratings:
        1) Winding H to X, MVA
        2) Winding H to Y, MVA
        3) Winding X to Y, MVA
    c. Transformer impedances, positive and zero sequence:
        1) Winding H to X, % X and R at MVA
        2) Winding H to Y, % X and R at MVA
        3) Winding X to Y, % X and R at MVA
    d. Transformer tap changer information
        1) No load or load
        2) Tap changer winding location, H, X, Y

3) Available taps

e. Transformer cooling requirements if required from The District

1) Load, amps
2) Voltage, single or three phase, volts

9-C.5 Transmission Line Data

If a new transmission line is to be included as part of the proposed connection, the following transmission line data is required:

1. Nominal operating voltage, kV
2. Line length, miles
3. Line capacity, amps at ºC
4. Overhead/underground construction
5. Positive and zero sequence transmission line characteristics in primary values
    a. Series resistance, R Ω
    b. Series reactance, X Ω
    c. Shunt susceptance, B μ S (or $\mu\ \Omega^{-1}$)

10. Definitions

For industry standard definitions of electric industry terminology, please refer to:
The Authoritative Dictionary of IEEE Standards Terms, IEEE 100.

For the District's definitions of electric utility terminology, please refer to:
Learning Center, Glossary of Electricity on the District web site: http://www.chelanpud.org/glossary-of-electricity.html

For the purposes of this document the following definitions apply:

Active Power - The 'real' component of complex power carried by an alternating-current circuit, produced by mutually-in-phase components of voltage and current waveforms. Active power can be calculated as the product of apparent power and the power factor. Measured in units of watts (W), kW or MW, active power is associated with useful work, including mechanical work and heat. Active power used or transmitted over time is energy, measured in kilowatt-hours (kWh) or megawatt-hours (MWh.). Also known as 'real power'. See also 'power factor'.

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 dispatching, 2) reactive power 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.

> **NERC Definition:** *Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (From FERC order 888-A.)*

Area Control Error (ACE) - Area Control Error (ACE) is the instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including a correction for meter error.

Automatic Generation Control (AGC) System - (NERC Definition) Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.

> **NERC Definition:** *Equipment which automatically adjusts a Balancing Authority's generation from a central location to maintain its interchange Schedule Plus frequency bias.*

Balancing Authority 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 balancing authority 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 balancing authority area. Physical location of the connection point does not determine its balancing authority area.

> **NERC Definition**: *The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.*

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

Blackstart Capability Plan – A documented procedure for a generating unit or station to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan. (NERC definition)

Blackstart Resource - A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan he ability of a generating plant to start its unit(s) with no external source of electric power. (NERC definition)

Bulk Electric System –
NERC Definition: *Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.*
Inclusions:
• I1 - Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher unless excluded by application of Exclusion E1 or E3.
• I2 – Generating resource(s) including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above with:
a) Gross individual nameplate rating greater than 20 MVA. Or,
b) Gross plant/facility aggregate nameplate rating greater than 75 MVA.
• I3 - Blackstart Resources identified in the Transmission Operator's restoration plan.
• I4 - Dispersed power producing resources that aggregate to a total capacity greater than 75 MVA (gross nameplate rating), and that are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage of 100 kV or above. Thus, the facilities designated as BES are:
a) The individual resources, and b) The system designed primarily for delivering capacity from the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.
• I5 –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side

voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I1 unless excluded by application of Exclusion E4.

Exclusions:

• E1 - Radial systems: A group of contiguous transmission Elements that emanates from a single point of connection of 100 kV or higher and:

a) Only serves Load. Or,

b) Only includes generation resources, not identified in Inclusions I2, I3, or I4, with an aggregate capacity less than or equal to 75 MVA (gross nameplate rating). Or,

c) Where the radial system serves Load and includes generation resources, not identified in Inclusions I2, I3 or I4, with an aggregate capacity of non-retail generation less than or equal to 75 MVA (gross nameplate rating).

Note 1 – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion. Note 2 – The presence of a contiguous loop, operated at a voltage level of 50 kV or less, between configurations being considered as radial systems, does not affect this exclusion.

• E2 - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.

• E3 - Local networks (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);

b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and

c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

• E4 – Reactive Power devices installed for the sole benefit of a retail customer(s). Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Coordinated Voltage Control (CVC) - Using AGC data links to the power plant, the District will request a power plant to deviate from the published time-of-day high side bus voltage schedule to coordinate closely coupled power plants to operate at the same power factor. By minimizing circulating var flow between power plants, all power plants will minimize their var production requirements. The CVC program runs once every two-minutes. It is a slow adjustment of voltage schedules and is not intended to replace the function of the automatic voltage regulator. Closely coupled power plants are determined by incrementing and decrementing the bus voltages 0.01 pu in a power flow study. Plants that show significant response by a change in var production are considered closely coupled.

District System Operator - The District System Operator or system operator is the ultimate authority on all operations, switching, etc. that can affect the District's Electric system. The District's System Operators work 24/7 in a control center located at Wenatchee, Washington.

District's Grid -The transmission facilities owned or controlled by the District (CHPD)

District's Electric System – All Electric facilities owned or controlled by the District (CHPD)

Directional Relay - A relay that responds to the relative phase position of a current with respect to another current or voltage reference, with the intent of distinguishing the direction of the fault location.

Distribution - That part of the electric system associated with delivery of energy to customers. Distribution-level nominal voltages are generally considered to be 34.5 kV or lower.

Disturbance – (NERC Definition)
1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.
3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Dynamic Signal - A telemetered reading or value that is updated in real time, and which is used either as a tie line flow or as a schedule in the AGC/ACE equation (depending on the particular circumstances). Common applications of dynamic signals include 'scheduling' jointly owned generation to or from another Balancing Authority and to move Balancing Authority boundaries. Another application provides for an entity to request (schedule) a change in power flow. The resulting response is telemetered to the entity signifying the actual movement of a resource. This form of dynamic signal is applied to supplemental Balancing Authority services. The integrated value of this signal is used for interchange accounting purposes, as appropriate.

Eccentric (Non-Conforming) End-user facilities -Any cyclic load with the ability to change periodically by more than 15MW at a rate of greater than 15MW per minute, regardless of the duration of this change.

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 respectively, 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.

Feeder - 1. A radial electrical transmission circuit, generally operating at or below 115 kV serving one or more customers. 2. A radial electric distribution circuit, generally operating at or below 34.5 kV serving one or more customer.

FERC - Federal Energy Regulatory Commission On-line at www.ferc.gov.

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 definition). 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.

Harmonic - A sinusoidal component of a periodic wave or quantity having a frequency that is an integer multiple of the fundamental frequency. (*IEEE definition*) Harmonics can damage equipment, cause misoperation of relays, and can interfere with communications. Thus, they are an important aspect of power quality, and must be controlled by filtering or other methods.

Host Balancing Authority –(NERC Definition)

1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries.

2. The Balancing Authority within whose telemetered boundaries a jointly owned unit is physically located.

Hybrid Single Pole 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.

IEEE - Institute of Electrical and Electronic Engineers

Interchange Metering - Metering at interchange points between two controlling utilities, consisting 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 balancing authority areas.

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

Inter-Control Center Communications Protocol (ICCP) -Inter-Control Center Communication Protocol (ICCP) is an international standard communications protocol for real time data exchange. The ICCP is defined in the international standard IEC 870-6 TASE.2.

Island - A portion of an interconnected system that has become isolated due to the tripping of transmission system elements. A *local island* is a portion of the transmission system, often a single line, that is isolated from the main system and energized by a local generator.

MV-90™ - The Multi-Vendor Translation System interprets a variety of metering communication protocols used for data collection and analysis. Data is retrieved over dial-up (voice grade) telephone lines by the MV-90™ master located at the District's Offices. The master automatically polls the remotes daily can be used to poll a remote at any time. In addition to polling raw impulses from the recorders, MV-90™ can perform data validation, editing, reporting and historical database functions.

NERC - North American Electric Reliability Corporation is a not-for-profit corporation formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of eight Regional Reliability Councils, one of which is the Western Electricity Coordinating Council. On-line at www.nerc.com.

OASIS - Open Access Same-Time Information System is an electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously.

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

Pilot Protection (Pilot Telecommunications) - A communications signal between two protective relay terminals used to provide a trip signal between terminals. The communication channel may be power line carrier, microwave (or other radio-based) path, fiber optic circuit, leased telephone line, or a dedicated hardwire circuit.

Point of Interconnection (POI) - The physical location on the power system at which Requester-owned facilities connect to those owned by the District, defining the 'change of ownership.

Power Factor - The dimensionless ratio of active power to apparent power in an alternating-current (ac) circuit. The power factor can range only between unity (with voltage and current mutually in phase), and zero (with voltage and current 90 electrical degrees mutually out of phase). A condition of 'lagging' power factor occurs when active power and reactive power propagate in the same direction – e.g., with inductive loads, which always consume reactive power; or with generators, when delivering reactive power. A condition of 'leading' power factor occurs when active power and reactive power propagate in opposite directions – e.g., with capacitive loads, which always delivers reactive power; or with generators, when consuming reactive power. For generators, operation with a lagging power factor is called an 'overexcited' condition; a leading power factor implies 'under excited' operation. Power factor is the cosine of the electrical angle between the voltage and current.

Power System - Integrated electrical power generation, transmission and distribution facilities.

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

Project - Non-District owned facilities included in the interconnection request.

Project Diagram (PD) -A District simplified drawing showing the electrical requirements for the connection of a generator, a transmission line or a load to the District's Electric system. The PD consists of one or more pages that may include a connection diagram of the 60 Hz high voltage equipment, telecommunications and data requirements, and remedial action scheme (RAS) requirements.

Reactive Power - The 'imaginary' component of complex power carried by an alternating-current circuit, produced by components of voltage and current waveforms that are mutually out of phase by 90 electrical degrees. Reactive power can be calculated as the product of apparent power and the sine of the power factor angle. Measured in units of volt-amperes reactive (var), kvar or Mvar, reactive power is associated with the alternating exchange of stored energy between electric and magnetic fields. Although reactive power does no useful work, it is inherently required for operating any alternating-current power system or HVDC converter. By convention, reactive power is absorbed or consumed by an inductance and generated or produced by a capacitance. Reactive power transmitted over time is measured in var-hours (varh). See also 'power factor'.

Real Power - See 'Active Power'.

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

Remedial Action Scheme (RAS) (Also known as Special Protection System (SPS)) - An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). (NERC Definition – becomes inactive 3/31/2017)

New NERC definition effective 4/1/2017:

A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:
• Meet requirements identified in the NERC Reliability Standards;
• Maintain Bulk Electric System (BES) stability;
• Maintain acceptable BES voltages;
• Maintain acceptable BES power flows;
• Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:
a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
c. Out-of-step tripping and power swing blocking
d. Automatic reclosing schemes
e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated
g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device
h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched
i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open
j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)
k. Automatic sequences that proceed when manually initiated solely by a System Operator
l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations
m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)
n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g. automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

Requester - An electrical utility or other customer or their representative that is requesting a facility connection to the District's Electric system.

Reserve - (*NERC definitions*)

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Operating Reserve - Spinning - The portion of Operating Reserve consisting of:

- Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or

- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Regulating Reserve - An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. (NERC Definition)

Operating Reserve - Supplemental - The portion of Operating Reserve consisting of:

- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or

- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

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

Revenue Metering System (RMS) - Provides hourly data daily (as compared to kWh system that reports hourly load each hour). A meter and recording device are installed at points where billing quality data is required. The device meters kW and kVAr (bi-directional for Points of Interconnection) and records kWh and kVArh data on an hourly basis. Data is retrieved over dial-up (voice grade) telephone lines by the MV-90™ system located at the District's Offices. The MV-90™ system automatically polls the device every morning beginning at 0001 am. The MV-90™ system can also poll at other times if necessary.

Single Pole Switching - The practice of tripping and reclosing one phase of a three phase transmission line without tripping the remaining phases. Tripping is initiated by protective relays that respond selectively to the faulted phase. Circuit breakers used for single pole switching must be capable of independent phase opening. For faults involving more than one phase, all three phases are tripped. The purpose of single pole switching is to improve system stability by keeping two of the three transmission line phases energized and carrying power while the fault and secondary arc are removed from the faulted phase. See also 'hybrid single pole switching'

Station Service - The electric supply for the ancillary equipment used to operate a generating station or substation. Generally, main grid substations require two sources of station service for reliability.

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

System Operator — An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System (BES) in Real-time. (*NERC definition*)

Tap Line - A line that connects to an existing transmission or distribution line without breakers at the tap point, resulting in an additional terminal on the existing line. The connection point may or may not include disconnect switches for isolation of one or all terminals.

Telemetering - Continuous, real time data reporting, as for AGC and generation kW (but not for kWh or RMS systems, which are not continuously reported).

> **NERC Definition:** *The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.*

Transmission - That part of the electric system associated with bulk transfer of energy, at high nominal voltages (generally defined as 100 kV or above). The District owns and operates transmission facilities at voltages of 230 and 115 kV.

Transformers and Transformer Connections - Large three-phase power transformers can be constructed using separate windings, as autotransformers or a combination of these. Transformers can use one tank for each phase or have all three phases in a single tank. The external winding connections can be delta (Δ) or grounded wye (YG), creating winding combinations such as Δ - YG, YG - YG, YG - Δ - YG.

> **Autotransformer**: Transformer construction using a single coil where the lower voltage or 'winding' is created by simply tapping that coil at the desired voltage level, creating a metallic connection between the two windings. This is the typical construction used to transform voltages at transmission levels and uses a YG, three-phase connection (e.g. 230:115kV).
> Separate windings: Transformer construction where the higher and lower voltage windings are individual coils, only coupled by a magnetic field. This is the typical construction used to transform voltages from transmission to distribution levels and for generator step-up transformers (e.g. 115:13.8 kV).
>
> **Wye (Y) connection**: Transformer connections where one end of each winding of the three phases is connected to a common point and then typically grounded (YG), possibly through an impedance.
>
> **Delta (Δ) connection**: Transformer connections where one end of each winding of the three phases is connected to the next phase, creating a closed loop of windings with no connections to a common point.

WECC -Western Electricity Coordinating Council, is the reliability region to which the District belongs. WECC was formed on April 22, 2002 by the merger of the former Western Systems Coordinating Council (WSCC), Western Regional Transmission Association (WRTA), and Southwestern Regional Transmission Association (SRTA). WECC enforces reliability standards for operating and planning the bulk electric system in the region. On-line at www.wecc.biz . It is the largest and most diverse of the eight regional reliability councils, operating under delegated authority from the North American Electric Reliability Corporation (NERC).

11. Document Retention

Documentation showing compliance shall be retained for the entire audit period, regardless of whether the standard provides for a shorter data retention time frame. The audit period begins the day after the end date of the prior compliance audit by the Compliance Enforcement Authority (WECC), and continues through the end date of the next compliance audit. If the standard allows for a shorter retention period and the volume of data or information required creates an undue burden, the Standard Owner may request an exception to this data retention requirement from the District's General Counsel/Chief Compliance Officer, utilizing the Data Retention Requirement Exception Request/Approval form and process. In order to be approved, the Standard Owner must be able to demonstrate that alternative evidence exists to prove compliance for the entire audit period. Approvals of such data retention requirement exception requests must be in writing and presented to the Reliability Compliance Department subsequent to approval.

12. References

1. **District Codes, Standards and Requirements**
   - 1.1 District Definitions (Learning Center, Glossary of Electricity)
   - 1.2 Switching And Clearances Handbook
   - 1.3 Transmission and Distribution Standards – (Construction, Design & Reliability)
   - 1.4 Electrical Services (http://www.chelanpud.org/my-pud-services/residential-services/electric-service/establish-a-new-electric-service)
   - 1.5 District documents regarding PURPA (http://www.chelanpud.org/my-pud-services/rates-and-policies/public-utility-regulatory-policies-act-(purpa))

2. **ANSI – IEEE - NFPA**
   - 2.1 IEEE Std 80 -Guide for Safety in AC Substation Grounding
   - 2.2 ANSI/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
   - 2.3 IEEE 100 – The Authoritative Dictionary of IEEE Standards Terms
   - 2.4 IEEE Std 367 -Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault
   - 2.5 ANSI/IEEE Std 421.1 – IEEE Standard Definitions for Excitation Systems for Synchronous Machines

2.6 IEEE Std 421.2 – IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
2.7 IEEE Std 487 -Recommended Practice for the Protection of Wire-Line Communication Facilities Serving Electric Power Stations
2.8 IEEE Std 519 -IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems
2.9 IEEE Std - 837 -Standard for Qualifying Permanent Connections Used in Substation Grounding
2.10 IEEE Std – 1159 – Recommended Practice for Monitoring Electric Power Quality
2.11 IEEE Std – 1547 – Interconnecting Distributed Resources with Electric Power Systems
2.12 IEEE Std – C37.118 – Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery
2.13 IEEE Std, C57.116, Guide for Transformers Directly Connected to Generators
2.14 NESC C2 -National Electrical Safety Code
2.15 ANSI C84.1 – Electric Power System and Equipment – Voltage Ratings (60 Hz)
2.16 NFPA 70 -National Electrical Code
2.17 IEC 870-6 TASE.2 -Inter-Control Center Communication Protocol (ICCP) Standard.
2.18 IEEE Std. 141 Recommended Practice for Electric Power Distribution for Industrial Plants.
2.19 IEEE Std. 241 Recommended Practice for Electrical Systems in Commercial Buildings.

3. NERC-NWPP -WECC

3.1 NERC Operating Standards
3.2 NERC Reliability Standards
3.3 NERC/WECC Planning Standards
3.4 NWPP Operating Manual
3.5 NERC/WECC Reliability Criteria including:
    3.5.1 Reliability Criteria for System Design
    3.5.2 Power Supply Design Criteria
    3.5.3 Minimum Operating Reliability Criteria.
    3.5.4 Reliability Management System
3.7 WECC Communications Systems Performance Guide for Protective Relaying Applications

4. Other Applicable References

4.1 National Environmental Policy Act - 42 U.S.C. & 4321 et seq.
4.2 Uniform Building Code
4.3 Occupational Safety and Health Administration
4.4 Open Access Transmission Tariff
4.5 Washington Industrial Safety and Health Act (WISHA)

13. Revision History

Owner	Rev Date	Ver	Section/Item Number(s) Changed	Approved By
Ken Johnson	11/29/2007	0	New – (integrates multiple facility connection documents into a single work practice)	Reliability Compliance Team
Z. Zornes	1/18/2013	1	See Appendix A for changes	S. Wickel
Z. Zornes	10/13/2014	1.1	Modified for 950.001 to enumerate applicability to third party interconnections to GOs	S. Wickel
Z. Zornes	5/15/2015	1.2	Modified 950.001 to clarify types of end-user interconnection requests that require assessment of transmission system impacts (Section 3-2, Table 7-3); updated to CHPD standard template format and section titles, including addition of standard document retention language.	S. Wickel
Z. Zornes	9/10/2015	1.3	Added language to document coordination at ColumbiaGrid for interconnections that impact neighboring entities (new Section 3-C)	S. Wickel
Z. Zornes	1/13/2017	1.4	Updated references to new District website, applicable NERC, WECC, and Peak criteria and definitions. Applied UFLS and UVLS criteria from NERC PRC-024 to generators section	S. Wickel
Z. Zornes	4/30/2018	1.5	Periodic review Hyperlinks updated for new CHPD website 1. p. 8 service @chelanpud.org 2. p. 90 CHPD Glossary of terms not in new site – removed reference from this document 3. p. 100 updated PURPA link 4. p. 100 updated electrical services link Updated additional references to Peak RC (p. 22, 64, 69) Updated typo on page 81 – “generation” Updated FAC-002-1 reference to FAC-002-2 (p. 13) Updated reference to WECC Disturbance Work Group to NERC PRC-002 standard (p. 63) Distribution System Interconnection Standard noted as available upon request (p. 34).	S. Wickel

Appendix A: Revisions to document 1/18/2013

The following revisions were completed on 1/18/2013.

1. Changed originator from Johnson to Zornes; Changed approval from RC Team to Wickel.
2. Added signature block
3. Added revision history table
4. Changed BES requirement in 4-B.3 to align with present BES definition
5. Changed '100C MOT' to 'rated MOT' in 4-E.1
6. Added reference to 'Cyber Security' in 4-D.6
7. Added 4-E.1.h to address planned ratings and scheduled for ratings; same wording added in 4-E.2.f.
8. Changed 'at least every two years. Other calibration may be negotiated' to 'as scheduled by the District' in 4-H.3.
9. Changed references of 'Customer' to 'Requestor' in 4-H.4
10. Added note of 'This re-synchronizing is directed by the WECC Reliability Coordinator' to 5-A.2
11. Added reference of 'PRC-002-WECC-CRT' to 5-A.4. This WECC criteria replaced the MORC document, but is still considered to be for all intents the WECC MORC document.
12. Changed voltage levels in 5-F.5 to match BES voltage threshold (100 kV)
13. Removed much of 5-H.1 and added NERC and WECC references.
14. Removed much of 5-H.2 and added NERC and WECC references.
15. Added clarifier for 'WECC-approved dynamic model' in 5-I.
16. Removed notes about the district's 34 kV system in 5-K.
17. Added redundant protection elements note in place of redundant batteries in 6-B.1.a.4.
18. Modified reclosing criteria in 6-B.1.c.11 to exclude automatic reclosing for three phase faults.
19. Corrected several uses of 'insure' to 'ensure'
20. Added note that relay settings changes should be 'coordinated with the District' in 6-C.2.
21. Added notes that relay settings, auxiliary relays, DC trip paths, and pilot schemes are elements in a protection system in 6-F.
22. Added notes to ensure auxiliary relays are tested in 6-F.4.a, b.
23. Updated tables 7-1, 7-2, 7-3, 7-4 and 7-5a.
24. Changed 'Loss of meter potential' to 'Meter potential phase unbalance' in 7-D.1.
25. Updated Definitions section to include most recent NERC definitions (in place of WECC definitions)
26. 'Ancillary Services' changed to NERC definition
27. 'Automatic Generation Control (AGC) System' updated to NERC definition
28. 'Balancing Authority Area' updated to NERC definition
29. 'Black Start Capability' replaced by 'Black Start Capability Plan' and 'Black Start Resource' for NERC definitions.
30. 'Bulk Electric System' updated to NERC definition
31. 'Disturbance' updated to NERC definition
32. 'Host Balancing Authority Area' changed to 'Host Balancing Authority'; updated to NERC definition
33. 'Remedial Action Scheme (RAS)' updated to NERC definition
34. 'Reserve' section updated to NERC definitions
35. 'Station Service' is no longer a NERC-defined term – removed reference to NERC definition
36. 'Telemetering' updated with NERC definition