# Facility Connection Requirements for Distribution Systems

(35-kV and Lower Voltages)

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**November 2025**

This document and all attachments are subject to change, and serve as a template for interconnecting new generation, lines, or end-user facilities. In addition, customer generation interconnections are governed by the applicable tariff schedules and regulations approved by the Idaho Public Utilities Commission ("IPUC") including Schedule 68 "Interconnections to Customer Distributed Energy Resources", which also applies in Oregon pursuant to Oregon Public Utility Commission Schedule 84 "Customer Energy Production Net Metering". This document provides technical information on additional details which may be needed for projects requiring advanced studies or technical requirements. Not all interconnections may require all of the items in this document, and engineering judgment will be made on a case-by-case basis. The current version of this document will be posted on the Idaho Power OASIS page. The current version of the IPUC-approved tariff Schedule 68 can be found on: idahopower.com/customergeneration.

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# 1. Definitions

**Abnormal Operating Performance Categories**—The grouping for a set of requirements that specify technical capabilities and settings for a distributed energy resource (DER) under abnormal operating conditions (i.e., outside the continuous operation region).

**Acceptance Test**—A test performed or witnessed for a specific protection package or device to determine whether specified requirements are met.

**Affected System**—An electric system other than the Transmission Provider's transmission system that may be affected by the proposed interconnection.

**Automatic Disconnect Device**—An electronic or mechanical device used to isolate a circuit or piece of equipment from a source of power without human intervention.

**Circuit**—A conducting part through which an electric current is intended to flow.

**Circuit Interrupting Device**—A device designed to open and close a circuit by non-automatic means and to open the circuit automatically as a result of a system excursion without damage to itself when properly applied within its rating.

**Customer Generation**—Facilities with load and generation, not including any load which is required for the generation system (e.g., the tracking system for a photo voltaic system).

**Decommissioned Generation Facilities**—Facilities that were actively connected to Idaho Power's electrical system in the past, but presently are not connected nor actively producing power.

**Direct Transfer Trip**—Remote operation of a circuit interrupting device by means of a communication channel.

**Disconnect (verb)**—To isolate a circuit or equipment from a source of power. If isolation is accomplished with a solid-state device, disconnect shall mean to cease the transfer of power.

**Disconnect Device**—A mechanical device used for isolating a circuit or equipment from a source of power.

**Distributed Energy Resource (DER)**—A source of electric power that is capable of exporting active power to Idaho Power's system but is not directly connected to a bulk power system. DER includes both generators and energy storage technologies. An interconnection system or a supplemental DER device that is necessary for compliance is part of a DER. (Controllable loads used for demand response are not included in the definition of DER.)

**Disturbance**—Trouble on the electrical system normally referring to fluctuation of frequency or voltage values.

**Electric Generator**—A machine or device that transforms energy (solar, mechanical, etc.) into electrical power.

**Electric Power System (EPS)**—Facilities that deliver electric power to a load.

**Energize**—To apply voltage to a circuit or piece of equipment.

**Equipment**—A general term including material, fittings, devices, appliances, fixtures, apparatus, and the like used as a part of, or in connection with, an electrical installation.

**Facility**—A set of electric equipment that operates as a single bulk electric system element (e.g., a line, a generator, a shunt compensator, transformer, etc.).

**Facility Owner**—Generator, transmission owner, or end user.

**Fault**—An electrical short circuit between elements of potential difference.

**Feeder**—All circuit conductors between the utility distribution substation or other power supply source and the final point of interconnection with a customer or generator.

**Frequency**—The number of cycles occurring in a given interval of time (usually one second) in an electric current. Frequency is commonly expressed in hertz (Hz).

**Generating Facility**—The interconnection customer's device for the production of electricity identified in the interconnection request; it shall not include the interconnection customer's interconnection facilities.

**Ground**—A conducting connection, whether intentional or accidental, between an electrical circuit or equipment and the earth (zero potential), or to some conducting body that serves in place of the earth.

**Hertz (Hz)**—The term denoting cycles per second or frequency.

**Interconnection**—The physical electrical connection that allows the transfer of electrical energy between a generating facility and the utility.

**Interconnection Customer**—Any entity that proposes to interconnect its generating facility with Idaho Power's electrical system.

**Interconnection Equipment**—The equipment required by prudent electrical utility practice and applicable electrical and safety codes to interconnect, operate, and safely deliver energy from the generator to the utility system.

**Interconnection Request**—An interconnection customer's written application, under Idaho Power's Open-Access Transmission Tariff (OATT) or state-jurisdictional process, as applicable, to interconnect a new generating facility or to increase the capacity of, or make a material modification to, the operating characteristics of an existing generating facility interconnected with Idaho Power's electrical system.

**Islanding**—A condition in which a portion of the Idaho Power system that contains both load and distributed generation is isolated from the remainder of the Idaho Power system.

**Maintenance Test**—A test performed upon initial installation and repeated periodically to determine if there is continued acceptable performance.

**Material Modification**—Modifications that have a material impact on the cost or timing of any interconnection request with a later queue priority date.

**Nameplate Rating**—Output rating information appearing on a generator nameplate in accordance with applicable industry standards.

**Network Upgrades**—Additions, modifications, and upgrades to the Idaho Power system required at or beyond the point at which the interconnection facilities connect to Idaho Power's electrical system to accommodate the interconnection.

**New Generation Facilities**—Facilities that have not been and are not yet connected to the Idaho Power transmission system.

**Normal Operating Performance Categories**—The grouping for a set of requirements that specify technical capabilities and settings for DER under normal operating conditions (i.e., inside the continuous operation region).

**Open Access Transmission Tariff (OATT)**—Idaho Power's Federal Energy Regulatory Commission (FERC)-approved tariff through which open access transmission service and interconnection service are offered.

**Outage**—A condition existing when a circuit is de-energized.

**Overvoltage**—Voltage higher than that desired or for which equipment is designed.

**Parallel**—To electrically connect a generator or energized source, operating at an acceptable frequency and voltage, with an adjacent generator or energized system, after matching frequency, voltage, and phase angle.

**Parallel Operation**—The operation of a non-utility generator while connected to the utility's grid for longer than 100 milliseconds. Parallel operation may be solely for the generator's operating convenience or for the purpose of delivering power to the utilities grid.

**Point of Interconnection**—The point where the generator's facilities physically connect to Idaho Power facilities (i.e., point of ownership change).

**Power**—The time rate at which electrical energy is emitted, transferred, or received; usually expressed in watts (W).

**Power Factor**—The ratio of actual power to apparent power.

**Power System Stabilizer (PSS)**—A control system applied to a generator that monitors generator variables, such as current, voltage, and shaft speed and sends the appropriate control signals to the voltage regulator to dampen system oscillations.

**Primary**—Normally considered as the high-voltage winding of a substation or distribution transformer.

**Protection Equipment**—Circuit-interrupting device, protective relaying, and associated instrument transformers (if applicable).

**Prudent Electrical Practices**—Practices, methods, and equipment commonly used in prudent electrical engineering and operations to design and operate electrical equipment lawfully and with safety, dependability, efficiency, and economy.

**Reference Point of Applicability (RPA)**—The location where the interconnection and interoperability performance requirements specified apply.

**Relay**—A device operated by a variation in the condition of one electric circuit to affect the operation of another device in the same or in another electric circuit.

**Secondary**—The winding of a transformer normally operated at a lower voltage than the primary winding.

**Synchronism**—Expresses the condition across an open circuit wherein the voltage sine wave on one side matches the voltage sine wave on the other side in frequency and without phase-angle differences.

**System**—The entire generating, transmitting, and distributing facilities of an electric company.

**System Operator**—A generic term used to describe the individuals responsible for the integrity or operational control of the transmission owner's system and any successor thereto.

**Transmission Owner's System**—The integrated system of electrical generation, transmission, and distribution facilities—and all equipment and facilities ancillary thereto—owned and/or operated by the transmission owner.

# 2. Introduction

This document addresses the technical requirements for generation facilities and end-user facilities interconnected with Idaho Power's distribution system. This document, along with Idaho Power's Open Access Transmission Tariff (OATT), ensures adverse impacts on reliability of the distribution and transmission systems are avoided.

This document addresses certain aspects of interconnection; its scope is primarily technical and does not include the commercial requirements for connecting generators or end-user facilities.

Technical studies will determine whether Idaho Power will be required to modify its distribution and/or transmission system to interconnect the requested facilities. Technical studies may be performed by Idaho Power, a third-party contracted by Idaho Power, or some combination of the two. Parties requesting interconnection may be responsible for the expense of these technical studies.

# 3. Interconnection Request

This document applies to generation, and end-user facilities physically connected to, or that desire to physically connect to Idaho Power's distribution system. Applicability is further defined by the categories below:

## 3.1. Generation Facilities

### *3.1.1. Interconnected and Separate Systems for Generators*

For facilities with load and generation, the facility owner may elect to run its generator in parallel (interconnected) with Idaho Power or as a separate system with the capability of nonparallel load transfer between the two independent systems. The two methods of operation are outlined as follows.

A parallel system is one in which the facility owner's generation equipment can be connected to Idaho Power's system, resulting in a transfer of power between the two systems.
A consequence of such parallel operation is that the parallel generator becomes an electrical part of Idaho Power's system, which must be considered in the operation and protection of Idaho Power's facilities. The general requirements for parallel generation installations are discussed in this document. The specific requirements for parallel generation in Idaho and Oregon can be found in Idaho Power's Schedule 68.

A separate system is one in which there is either an Open Transition with no possibility of delivering energy to the Idaho Power system from the customer's equipment or a Closed Transition with a sustained parallel operation of less than 100 milliseconds.

#### 3.1.1.1. Open Transition

For this operation to be practical, the facility owner may want to maintain the capability of transferring load between the two systems, but such transfer must be accomplished in an open-transition or nonparallel mode. This can be accomplished by an electrically or mechanically interlocked switching arrangement that precludes operation of both switches in the closed position simultaneously.

If the facility owner has a separate open transition system, Idaho Power will require verification that the transfer scheme meets the nonparallel requirements. This verification will be accomplished by review and approval of drawings and equipment specifications by Idaho Power and, if Idaho Power so elects, by field inspection of the transfer scheme. Idaho Power will not be responsible for approving the facility owner's generation equipment and assumes no responsibility for its design or operation.

#### 3.1.1.2. Closed Transition

If the facility owner has a separate closed transition system, Idaho Power will require verification that the transfer scheme meets the closed transition parallel requirements. The facility owner shall submit for acceptance by Idaho Power copies of the single line, specifications, complete vendor prints, relay settings, and a description of operation of the system. The requirements for closed transition switching include the following:

- Closed transition switching shall occur within 100 milliseconds.
- Closed transition switching shall not be initiated until 5 minutes of healthy utility voltage has been present. Healthy voltage shall be defined as within the range of 95 to 105% of nominal.
- Once the parallel is made, a transfer failure relay shall monitor the utility and generator breaker to ensure the transfer operation has been completed. If the transfer has not been completed within 250 milliseconds, the transfer failure relay shall trip the generator breaker. For automatic transfer switch installations, the transfer failure relay shall monitor the switch contacts.

Idaho Power may elect to perform field inspection of the transfer scheme. Idaho Power will not be responsible for approving the facility owner's generation equipment and assumes no responsibility for its design or operation.

### 3.1.2. Interconnected Generation Facilities

New generation facilities are facilities that have not been and are not yet connected to the Idaho Power system. Additional technical requirements may apply to special business arrangements or electrical configurations of Idaho Power's distribution system or the interconnection point(s). Decommissioned generation facilities requesting to return to service must meet the current requirements outlined in this policy.

Requests for new generation interconnections or existing generation interconnections seeking to make a material change will be consistent with the process for interconnection outlined in the Idaho Power OATT or the applicable State-jurisdictional process[1] (Public Utility Regulatory Policy Act [PURPA] process) for generators interconnecting to the distribution system. Where applicable for generation interconnection requests, the specific timeline, queuing, and submission requirements in the Idaho Public Utilities Commission (IPUC) tariff Schedule 68 or applicable PURPA process will be followed. Requests for generation interconnection require significant information regarding the Project. Specifics of required information as well as more information about the generation interconnection process and necessary forms are available on Idaho Power's Open Access Same Time Information System (OASIS) at: Idaho Power OASIS and Idaho Power's website at: Generator Interconnection - Idaho Power.

### *3.1.3. Material Changes for Generation Facilities*

| Description | Detailed Example(s) |
|---|---|
| Change in generator output | • Change that affects its Seasonal Real Power or Reactive Power capability by more than 10% of the last reported verified capability and is expected to last more than six months.<br>• Change in power factor capability of the generator |
| Change of GSU | • Change of a Generator Step-Up (GSU) transformer that results in any of the following differences:<br>  • Reduction in rating by more than 10%<br>  • Impedance changes by more than 10%<br>    • Change in transformer losses<br>    • Change in transformer saturation differences |

[1] Including, as applicable, IPUC tariff Schedule 72 "Generator Interconnections to PUPRA Qualifying Facility Sellers" for Idaho PURPA projects up to 20 megawatts (MW); the Large Generator Interconnection Procedures for Idaho PURPA projects between 20 and 80 MW; the Oregon Small Generator Interconnection Rules set forth in Chapter 860, Division 82 of the Oregon Administrative Rules for Oregon small generator facilities of 10 MW or less; and the Standard Oregon Qualifying Facility Large Generator Interconnection Procedures for Oregon PURPA projects that exceed 20 MW.

| Description | Detailed Example(s) |
|---|---|
| Change in generator characteristics | • Change in the inertia of the Generator by more than 10%<br>• Change in steady state transient and sub-transient reactance of the Generator or generator Interconnection facilities by more than 10%<br>• Changes that alter the equipment response characteristic<br>  ◦ Includes excitation control system, plant volt/var, active power/frequency control, or turbine/governor & load control functions<br>• Changes to a generator's electromagnetic transient models. |
| Change in Protection System of the generator facilities or generator interconnection facilities | • Changes in relay settings that prevent an applicable generating unit with frequency or voltage protection from meeting the criteria in this document, or the removal of settings that previously limited voltage and/or frequency operation from meeting the applicable criteria of this document.<br>  ◦ includes high and low frequency settings along with delay times, if applicable<br>  ◦ includes high and low voltage settings along with delay times, if applicable |
| Inverter-Based Resource (IBR) Only: Change in Inverter or inverter settings | • Change of 10% or more of the IBR units at a facility that is not replacement in-kind.<br>• Change in any control settings:<br>  ◦ resulting in a difference in frequency or voltage support of the IBR<br>  ◦ resulting in a difference in when the IBR discontinues current injection to the GRID (i.e., blocking commands) |
| Unplanned change in governor or governor settings | Uncharacteristic changes that result in how the generator responds to grid frequency deviations and are expected to last more than six months. |
| Unplanned change in exciter or exciter settings | Uncharacteristic changes that result in how the generator responds to grid voltage deviations and are expected to last more than six months. |
| Change in power system stabilizer | Addition or removal of power system stabilizer<br>Setting changes of power system stabilizer |

## 3.2. End-user Facilities

Any proposed load customer interconnecting with Idaho Power's distribution system or existing end-user interconnection seeking to make a material change shall require a service request.

Information regarding Idaho Power's electric service requirements for new load (end-user) connections, applicable tariffs, project initiation information requirements, and contact numbers may be found on the Idaho Power web site (Idaho Power). Submittal of project information to an Idaho Power customer service representative will start the communication and evaluation process. Forms to do so may be found at Service Request Forms - Idaho Power.

# 4. Interconnection Studies

## 4.1. Generation Facilities

Generation interconnection studies will be consistent with the process for generation interconnection outlined in IPUC tariff Schedule 68 or applicable PURPA process, which includes, as applicable, IPUC tariff Schedule 72 "Generator Interconnections to PUPRA Qualifying Facility Sellers" for Idaho PURPA projects up to 20 MW; the Large Generator Interconnection Procedures for Idaho PURPA projects between 20 and 80 MW; the Oregon Small Generator Interconnection Rules set forth in Chapter 860, Division 82 of the Oregon Administrative Rules for Oregon small generator facilities of 10 MW or less; and the Standard Oregon Qualifying Facility Large Generator Interconnection Procedures for Oregon PURPA projects that exceed 20 MW.

## 4.2. End-user Facilities

An engineering assessment (EA) will evaluate the network impact, provide details of the upgrades required for the requested load, provide a rough estimate for the upgrade costs, and provide a timeline for installation. The timeframe for the EA will vary based on project complexity. Should the interconnection customer decide to move forward, the EA is followed by a Construction Study. Construction Studies require a deposit.

# 5. Generation Interconnection Model Requirements

The model requirements identified in this section apply to all distributed energy resource (DER) projects with a capacity 10 megavolt amperes (MVA) or greater, or for smaller projects identified during the study process as needing to provide some or all of these model requirements.

## 5.1. Steady State Models

Details on the steady state modeling technical data requirements can be found in the Small Generator Technical Data Requirements document located on OASIS.

## 5.2. Dynamic Models

Details on the dynamic modeling technical data requirements can be found in the Small Generator Technical Data Requirements document located on OASIS.

## 5.3. Data Verification

Data sufficiency verifications on the submitted technical data include:

- Model values such as impedances, capacities, ratings, line lengths, reactive capability, battery energy storage systems (BESS) discharge time, etc., should match the data filled out in the project's application and single-line diagram (SLD).
- AC-coupled hybrid plants must use the repc_b model for their Plant-Level Controller.
- Any plants containing BESS (except for direct current [DC]-coupled hybrid plants with DC-side charging only) must use the reec_c or reec_d model for their BESS Electrical Controller.
- DC-coupled hybrid plants, with DC-side charging only, must use the reec_a or reec_d model for their BESS Electrical Controller.
- Voltage Protection (lhvrt) and Frequency Protection (lhfrt) model settings should meet NERC PRC-024 standards and should monitor the POI voltage.
- Control mode should be Voltage Control.
- Primary frequency response should be enabled with a maximum droop of 5% and + 0.036 Hertz (Hz) deadband. More stringent settings are acceptable.
- Transient stability simulation results should include the following:
    - Flat response for a no disturbance run.
    - Stable recovery to pre-disturbance output following the clearing of a solid three-phase fault.
    - Fault ride-through for voltage and frequency excursions should follow North American Electric Reliability Corporation (NERC) PRC-024 Western Electricity Coordinating Council (WECC) curves.
    - Step response that regulates voltage to 90% of setpoint within 30 seconds.

## 5.4. Electromagnetic Transient (EMT) Model Requirements

EMT models are required to support current and future study efforts, which are required to maintain a reliable power system. Some of the most common studies that require the use of EMT models are as follows:

- Interconnection to a weak system
- Risk of Island Analysis
- Risk of Ground Fault Overvoltage Analysis
- Control Interaction Analysis

### *5.4.1. Interconnection to a Weak System*

When a generator interconnecting to a distribution system is large relative to the rest of the distribution system, it has a relatively large dynamic influence on the system, and the system may be termed weak. "Weak" is a relative term, and typically does not have hard quantitative metrics associated with it. It is not always initially clear when a system will become too weak to support generation. Conventional modeling tools may not be sufficiently detailed to represent the issues that will be encountered in actual equipment.

Power electronic equipment provided by different manufacturers may respond differently to similar network conditions. Additionally, influences from nearby devices may or may not have a significant impact on a particular generator interconnection.

### *5.4.2. Risk of Island Analysis*

Isolated distribution systems may be at risk of forming an unintentional island configuration. The ability to model the system correctly will require EMT studies of all connected DER to that isolated system.

### *5.4.3. Risk of Ground Fault Overvoltage Analysis*

Isolated distribution systems may be at risk of forming a ground fault overvoltage on the transmission system under certain transmission operations. The ability to model the system correctly will require EMT studies of all connected DER to that isolated system.

### *5.4.4. Control Interaction Analysis*

Power electronic-based devices such as wind turbines, Static Synchronous Compensators (STATCOM), and Static Var Compensator (SVC) are highly controllable, and the controls may operate to perform specific functions within a wide range of timeframes and operating conditions. If two or more of these devices are in operation in close electrical proximity to each other but have been designed and commissioned in isolation from each other, there is a potential for the controllers to interfere with each other, and the overall system performance could be degraded.

Due to the level of detail required in the models to accurately represent the fast control loops used in these devices, EMT models are required.

### 5.4.5. Model Requirements

The model must:

1. Represent the full detailed inner control loops of the power electronics. The model cannot use the same approximations classically used in transient stability modeling, and must fully represent all fast inner controls, as implemented in the real equipment.

2. Represent all control features pertinent to the type of study being done. Examples include external voltage controllers, customized Phase Locked Loops (PLL), ride-though controllers, Sub-Synchronous Control Interaction (SSCI), damping controllers, and others. As in point 1, actual hardware code is required to be used for most control and protection features. Operating modes that require system specific adjustment must be user accessible.

3. Represent plant level control. Power Plant Control (PPC) representation must be included that represents the specific controllers used in the plant. Plant controllers must be represented in sufficient detail to accurately represent short-term performance, including specific measurement methods, communication time delays, transitions into and out of ride-through modes, settable control parameters or options, and any other specific implementation details which may impact plant behavior. Generic PPC representation are not acceptable unless the final PPC controls are designed to exactly match the generic PPC model. If multiple plants are controlled by a common controller, or if the plant includes multiple types of IBRs (e.g., Hybrid BESS/photovoltaic [PV]) this functionality must be included in the plant control model. If supplementary or multiple voltage control devices (e.g., STATCOM) are included in the plant, these should be coordinated with the PPC.

4. Represent all pertinent electrical and mechanical configurations. This includes any filters and specialized transformers. There may be other mechanical features such as gearboxes, pitch controllers, or others which must be modeled if they impact electrical performance within the timeframe and electrical purview of the study. Any control or dynamic features of the actual equipment that may influence behavior in the simulation period which are not represented, or which are approximated, must be clearly identified.

5. Have all pertinent protections modeled in detail for both balanced and unbalanced fault conditions. Typically, this includes various overvoltage (OV) and undervoltage (UV) protections (individual phase and route mean squared [RMS]), frequency protections, DC bus voltage protections, converter overcurrent protections, and often other

inverter-specific protections. Any protections which can influence dynamic behavior or plant ride-through in the simulation period must be included. Actual hardware code is recommended to be used for these protection features.

6. Be configured to match expected site-specific equipment settings. Any user-tunable parameters or options must be set in the model to match the equipment at the specific site being evaluated, as far as they are known. Default parameters are not appropriate unless these will match the configuration in the installed equipment.

7. Have control or hardware options pertinent to the study accessible to the user. Although the plant must be configured to match site-specific settings as far as they are known, parameters pertinent to the study must be accessible for use by the model user. Examples of this could include protection thresholds, real power recovery ramp rates, frequency or voltage droop settings, voltage control response times, or SSCI damping controllers. Diagnostic flags (e.g., flags to show control mode changes or which protection has been activated) should be visible to aid in analysis.

8. Be accurate when running at a simulation time step of 10 microseconds (µs) or higher.

9. Operate at a range of simulation time steps. The model must not be restricted to operating at a single time step but must be able to operate withing a range (e.g., 10 µs–20 µs).

10. Include documentation and a sample implementation test case. Test case models must be configured according to the site-specific real equipment configuration up to the Point of Interconnection. This would include (for example): aggregated generator model, aggregated generator transformer, equivalent collector branch, main plant transformers, gen-tie line, power plant controller, and any other static or dynamic reactive resources. Test case must use a single machine infinite bus representation of the system, configured with an appropriate representative Short Circuit Ratio (SCR).

11. Have an identification mechanism for configuration. The model documentation must provide a clear way to identify the specific settings and equipment configuration that will be used in any study, such that during commissioning the settings used in the studies can be checked. This documentation may be control revision codes, settings files, or a combination of these and other identification measures.

12. Accept external reference variables. This includes real and reactive power ordered values for Q control modes, or voltage reference values for voltage control modes. Model must accept these reference variables for initialization and be capable of changing these reference variables mid-simulation (i.e., Dynamic signal references).

13. Be capable of initializing itself. Once provided with initial condition variables, the model must initialize and ramp to the ordered output without external input from simulation engineers. Any slower control functions that are included (such as switched shunt controllers or power plant controllers) must also accept initial condition variables if

required. Note that during the first few seconds of simulation (e.g., 0–2 seconds), the system voltage and corresponding terminal conditions may deviate from nominal values due to other system devices initializing, and the model must be able to tolerate these deviations or provide a variable initialization time.

14. Be able to scale plant capacity. The active power capacity of the model must be scalable in some way, either internally or through an external scaling component. This is distinct from a dispatchable power order and is used for modeling different capacities of a plant or breaking a lumped equivalent plant into smaller composite models.
15. Be able to dispatch its output to values less than nameplate. This is distinct from scaling a plant from one unit to more than one and is used for testing plant behavior at various operating points.
16. Initialize quickly. Model must reach its ordered initial conditions as quickly as possible (example.g., < 5 seconds) to user supplied terminal conditions.

#### *5.4.6. Model Test Checklist*

All criteria outlined in Idaho Power's EMT Model Test Checklist document must be met. The EMT Model Test Checklist document will be sent upon request.

# 6. Interconnection Facility Documentation

1. SLD of the generation facility.
2. Manufacturer documentation for equipment to be installed.

# 7. Interconnection Coordination

Once a new request is considered feasible for interconnection, and Idaho Power has determined it affects other interconnected electric system owners, Affected System(s) will be identified, and Idaho Power will facilitate notification.

# 8. Interconnection Customer Requirements

## 8.1. Access to Facilities

With reasonable notice and supervision, the interconnection customer shall allow Idaho Power personnel ingress and egress to equipment for operation, maintenance, repairs, tests (or witness tests), inspection, replacements, or removal of facilities/equipment. Idaho Power personnel shall be provided with an escort if necessary (rather than taking a special training course to enter the facility). If this access is not allowed, and it affects Idaho Power's customers, including emergency incidents or other power-delivery-related activities, Idaho Power reserves the right to exercise the disconnection provision of the facility interconnection agreement.

## 8.2. Responsibilities

Interconnected parties are responsible for designing, installing, operating, and maintaining interconnection equipment they own (i.e., generators, transformers, switches, relays, breakers, etc.). All protective devices necessary to protect the interconnected facilities are the responsibility of the customer.

Idaho Power's requirements specified in this document are designed to protect Idaho Power facilities and maintain grid reliability pursuant to applicable reliability criteria.

Interconnected customers must satisfy the requirements in all of the following:

1. This policy
2. Applicable rules and tariffs of jurisdictional state regulatory agencies and the Federal Energy Regulatory Commission (FERC)
3. Idaho Power's project-specific requirements (interconnection agreement or Electric Service Agreement [ESA] / Generation Interconnection Agreement [GIA])
4. Applicable policies of the WECC, the NERC, or their successor organizations.

Idaho Power's review and written acceptance of the interconnected entity's equipment specifications and plans shall not be construed as confirming or endorsing the interconnected entity's design, as warranting the equipment's safety and durability, or in any way relieving the interconnecting entity from its responsibility to meet the above or any other applicable requirements. Idaho Power shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built to such specifications, nor shall Idaho Power's acceptance be deemed an endorsement of such equipment.

# 9. Ownership Policy and Operation of Interconnection Equipment

All interconnection equipment electrically located on the facility owner's side of the point of interconnection shall be owned and maintained by the facility owner. All interconnection equipment electrically located on the Idaho Power side of the point of interconnection shall be owned, operated, and maintained by Idaho Power. However, exceptions may be allowed, and certain facility, operations, and maintenance agreements will apply.

## 9.1. Point of Interconnection

If Idaho Power owns the dedicated transformer, the point of interconnection shall be the facility owner's side of the utility revenue meter. If the facility owner owns the dedicated transformer, the point of interconnection shall be the facility owner's side of the primary voltage disconnect device. Regardless of dedicated transformer ownership, the point of interconnection shall be the facility owner's side of the disconnect device for large customers (greater than 1 MVA).

## 9.2. Generation Facilities

In general, the generator facility shall be served through a dedicated transformer that serves no other customers.

### *9.2.1. Generation Projects*

For inverter-based generation projects greater than 1 MVA and all rotating machine projects equal to or greater than 500-kilovolt-Ampere (KVA), Idaho Power will own, operate, and maintain the disconnect device and circuit interrupting device. For other projects, the ownership and requirement of the circuit interrupting device will be determined on a case-by-case basis. All rotating machine projects and inverter-based projects greater than 200 KVA up to 1 MVA will be required to provide their system protection plan for review including backup relays and settings. The customer disconnect switch is not permitted to be fused disconnects for any project rated 25 KVA or greater.

### *9.2.2. Customer Generation Projects*

For inverter-based customer generation projects greater than 3 MVA and all rotating machine projects equal to or greater than 500-kilovolt-ampere (kVA), Idaho Power will own, operate, and maintain the disconnect device and circuit interrupting device on the Idaho Power side of the point of interconnection. For other projects, the ownership and requirement of the circuit interrupting device will be determined on a case-by-case basis. All rotating machine projects will be required to provide their system protection plan for review, including backup relays and settings. On a case-by-case basis, inverter-based projects greater than 200 kVA up to 3 MVA will be required to provide their system protection plan for review, including backup relays and settings. The customer disconnect switch is not permitted to be fused disconnects for any project rated 25 kVA or greater.

# 10. Revisions and Updates

Idaho Power may revise the technical requirements periodically to comply with new requirements and/or recommendations from FERC, NERC, state, other governmental authorities. Idaho Power may require that all generator, transmission line, and end-user interconnections comply with new regulations by implementing similar procedures and/or upgrades as would be expected on Idaho Power facilities in a non-discriminatory manner. If the interconnection customer does not comply, Idaho Power may require an upgrade of the interconnection customer’s facilities as necessary to be compliant. Any such upgrades shall be executed at the customer’s expense. Alternately, Idaho Power may disconnect the interconnection customer after notification.

# 11. Transmission Capability

Interconnections to Idaho Power’s electric system may require modifications to Idaho Power’s transmission system. The design and ratings of these facilities shall not restrict the capability of the lines and Idaho Power’s contractual transmission path rights.

# 12. General Provisions

Idaho Power, at its sole discretion, may elect to upgrade or change the voltage level of the Idaho Power electric system serving the interconnection customer.

The interconnection design shall be capable of accommodating Idaho Power electric system reclosing practices.

The interconnection design shall incorporate protection equipment to detect system abnormalities or disturbances in either the interconnection customer’s system or the Idaho Power system. This equipment shall have the capability to isolate the sources of the disturbance.

The interconnection customer’s design and facilities shall provide all necessary equipment to protect against over-tripping, unnecessary loss of generation, or inadvertent rapid and repetitive tripping and reclosing of the interconnection on the Idaho Power system.

The customer shall not cause the Idaho Power electric system to violate WECC System Performance Criterion.

The customer shall control the electrical real (MW) and reactive (MVAr) power output such that it will not exceed the capacity of the interconnection facilities.

The interconnection customer's three-phase generation shall be connected to the Idaho Power system with three-phase automatic disconnecting devices (circuit breakers), which are intended to significantly reduce the possibility of damaging the interconnection customer's generation equipment due to single-phase operation. These disconnecting devices shall be equipped with auxiliary contacts that indicate the actual status of the devices' main contacts.

Idaho Power may disconnect the facility in the event of any planned or unplanned maintenance or repair of the system connected to the facility. In the event of unplanned maintenance or repairs, no prior notice will be provided. In the event of planned repairs, Idaho Power will attempt to notify the facility owner of the time and duration of the planned outage.

A facility owner shall provide a 24-hour telephone contact(s) to Idaho Power. Idaho Power will use this contact to arrange access for repairs, inspection, or emergencies. Idaho Power will make such arrangements (except for emergencies) during normal business hours.

Idaho Power will provide a name and telephone number so the generator facility owner can obtain information about any Idaho Power activity impacting the generation facility (outages, disconnection, etc.).

A disconnect device, typically a switch, must be installed to isolate the interconnection customer and Idaho Power systems physically and visibly. The disconnect shall be operated by Idaho Power to provide a visible air gap with clearances for adequate grounding, maintenance, and repairs of the Idaho Power electric system. Idaho Power may require the capability to apply safety grounds on the Idaho Power side of the disconnect. The customer shall not remove any Idaho Power padlocks or safety tags as per OSHA lockout/tagout requirements. In any case the device:

- must simultaneously open all phases (gang operated) to the interconnected facilities,
- must be accessible by Idaho Power and must be under Idaho Power Dispatcher jurisdiction,
- must be lockable in the open position by Idaho Power,
- shall not be operated without advance notice to affected parties, unless an emergency condition requires the device be opened to isolate the interconnected facilities, and
- must be suitable for safe operation under all foreseeable operating conditions.

Idaho Power personnel may lock the device in the open position and install safety grounds in any of the following situations:

- if it is necessary for the protection of maintenance personnel when working on de-energized circuits
- if the interconnected facilities or Idaho Power equipment presents a hazardous condition
- if the interconnected facilities jeopardize the operation of Idaho Power's system

Industry standard basic insulation level (BIL) ratings shall be used for electric system additions and electric system interface equipment. The electric equipment shall meet the Institute of Electrical and Electronics Engineers (IEEE) C62.41 or C37.90.1, V&I Withstand Requirements.

The harmonic content of the voltage and current wave forms of both the interconnection customer's and Idaho Power's systems shall comply with the latest version of the IEEE Standard 519, Recommended Practices and Requirements for Harmonic Control in Electric Power Systems.

The customer shall be capable of withstanding electromagnetic interference environments in accordance with American National Standards Institute (ANSI)/IEEE Standard C37.90.2. The interconnection system and protection system shall not mis-operate due to electromagnetic interference, including hand-held communication devices.

Idaho Power may install disturbance recording equipment or Phasor Measurement Units (PMU), at the customer's expense.

Telecommunication services required for, but not limited to, supervisory control and data acquisition (SCADA) and Phasor Measurements are the sole responsibility of the customer to establish and maintain. Failure of these circuits may result in Idaho Power disconnecting the interconnection customer after notification.

The interconnection design shall incorporate adequate facilities to enable the on-site generation to be synchronized with Idaho Power's system prior to interconnection. The interconnection customer's generator protection shall incorporate elements to block out-of-sync closing of the customer's facilities. The customer shall be solely responsible for synchronizing the generator to the system.

All points at which the generator can be paralleled with the Idaho Power electrical system must be clearly defined as synchronization points in the submittal documentation. A given installation may be designed with several synchronization points.

# 13. Generation Interconnect Metering Standards

This section provides the metering requirements for the interconnection of a generating facility to Idaho Power's  transmission system.

## 13.1. General Information

Revenue metering equipment shall be installed to accurately measure energy delivered and received at DER connections, load connections, and at the Idaho Power system point of interconnect. Idaho Power will specify, procure, own, operate, and maintain the revenue metering packages at the generating facility, including Idaho Power metering instrument transformers potential transformers and current transformers (PTs and CTs), mounting structures, conduits, meter sockets, meter socket enclosures, and transformer cabinets at the interconnecting customers' expense. Auxiliary meters used for operational metering data or as a check meter may be installed in tandem with the Idaho Power meters as needed but must be designed and installed in a manner to not impede the function and/or accuracy of Idaho Power revenue metering equipment.

Idaho Power meters shall be installed to measure net generation and account for local service and any auxiliary loads created at the generation facility. All new metering not intended for exclusively measuring local service or auxiliary loads shall be installed on the high side of the transformer, on a structure as close to the instrument transformers as practical, and within 0.5 miles from the point of interconnect. Local service and/or auxiliary loads shall be independently metered and may be measured on the low side of the transformer.
The interconnecting customer's protection equipment shall not share electrical equipment and instrument transformers associated with Idaho Power revenue metering.

Metering configuration, design, type, and layout will be determined by the type of generating equipment, the location of the generation facility on Idaho Power's system, and the required system operations (bi-directional vs. unidirectional power flow). For all metering configurations, Idaho Power's grid will be considered the source. Energy flowing to the customer will be represented as channel 1, and energy flowing to the grid as channel 2.

If metering standards cannot be met, an exception may be requested through the Idaho Power Metering team.

## 13.2. Loss Compensation

If metering generation on the high side and/or metering within 0.5 miles of the point of interconnect is proven to be impractical, exceptions may be granted. Meters installed on the low side of the transformer or placed 0.5 miles or more from the point of interconnect must correct for transformer and/or line losses for both energy generation and energy consumption. Idaho Power requires any applicable loss compensation be stored in Idaho Power's MV-90 data (transformer losses) and Web Accounting (line losses) systems. A transformer test record and loss calculation report shall be submitted by the interconnecting customer indicating percentages of calculated additive or subtractive losses.

Any generation metering that requires loss calculations shall be reviewed by the Idaho Power Metering team for approval.

## 13.3. DER with Multiple Generation and Energy Storage

DER sites with multiple generating technologies such as wind collectors, solar arrays, and batteries considered as one unified transaction are defined as a Hybrid resource and require metering at a single point of interconnection only.

Sites with multiple generating technologies considered as separate transactions are defined as a Co-located resource and require metering at each generation facility point.

Co-located resources will require separate metering for each local service or auxiliary load. Local service/auxiliary load metering shall take place on the low side of the transformer and have losses compensated.

When energy storage devices (batteries) are utilized, it will be necessary to meter the storage facility and the generating facility separately if the resources are considered co-located. This means both sources are grid-connected and will require one metering package located on the high side of the generating facility and one metering package on the high side of the energy storage facility.

When energy storage (batteries) is charged from Idaho Power's system and a generation solar/wind site, separate metering will be required. That is, metering will be required at the generation facility/energy storage facility and at the point of interconnection. Facility loads will be metered separately and exclusively for both a storage facility and generation facility.

## 13.4. Revenue Metering Requirement

Metering equipment shall be of revenue grade, meeting all applicable industry standards (e.g., ANSI, IEEE, National Electric Manufacturers Association[NEMA}), be listed as a California Independent System Operator (CAISO) Authorized Revenue Meter, and be compliant with the local regulatory authority (LRA) standards (if applicable). Unless otherwise required by the system configuration and approved by the Idaho Power Metering team, Idaho Power's most current standard high-end form 9S socket meter shall be used for all generation interconnect projects.

## 13.5. Specifications

Metering data shall be collected utilizing 4-quandrant metering, and meters shall be capable of recording, storing, and transmitting bidirectional data recorded in 5-minute intervals.
The metering package shall be capable of storing data for a minimum of 60 days. Idaho Power will require real-time data for individual generators with ratings 3 MW and above or individual generators whose combined output exceed 3 MW at the same point of interconnection.
The following quantities are required for all meters, in accordance with CAISO standard meter requirements:

1. Kilowatt-hours—delivered
2. Kilowatt-hours—received
3. Kilovar-hours—delivered, received for each quadrant

4. Kilovoltamp-hours—delivered, received for each quadrant
5. Ampere-squared-hours
6. Volts-squared-hours
7. Kilowatts—delivered
8. Kilowatts—received
9. Kilovars—delivered, received for any quadrant
10. Kilovoltamps—delivered, received for any quadrant

## 13.6. Instrument Transformers

All instrument transformers shall be of revenue grade in accordance with applicable industry standards and fall within the CAISO instrument transformer requirements. CTs shall have a minimum accuracy of +/-0.3% for Burdens B0.1 through B1.8 and have a continuous current thermal rating factor sized appropriately for the application.

## 13.7. Communications

Metering requires an Ethernet, cellular, or other data quality communication for use with the Idaho Power MV-90 remote meter data collection system and to remotely interrogate the meter. The interconnecting customer shall supply the communications facilities to an Idaho Power provided demarcation point unless the Point of Interconnect is located inside an Idaho Power station where existing Idaho Power communication circuits are in place and available for utilization. Communications used to support metering data transfer shall be provided at the metering and use an Ethernet network connection. Exceptions may be allowed if Ethernet connections are proven not practical, in which case, an RS232 serial connection shall be used as an alternate.

## 13.8. Meter Compliance Testing

If the interconnecting generation site is a part of an Energy Imbalance Market (EIM), Idaho Power shall inspect, test, recalibrate, and certify all metering equipment upon installation and at least biennially thereafter to verify and maintain accuracy according to CAISO and/or Idaho Power requirements.

Non-EIM facilities testing will occur biennially for facilities over 10 MW, every four years for facilities between 10 MW and 1 MW, and as part of Idaho Power’s random sampling process for facilities below 1 MW.

# 14. Telecommunication Requirements for Facility Interconnection

## 14.1. Application

Before a new facility is interconnected to the Idaho Power system, Idaho Power will specify the associated telecommunications-related equipment required. This involves multiple critical systems on the power grid including metering and telemetering, protective relaying and interrupting devices, SCADA, and other data channels to support integration of the new facility. Due to the safety and reliability considerations involved, Idaho Power requires that all such telecommunications-related equipment be owned, installed, and maintained by Idaho Power at the generation facility's expense. For the protective relaying component, this requirement is limited to equipment installed to protect Idaho Power's system, or to the tie line into Idaho Power's system (if pilot line relay systems are required). The relays intended for protection of the interconnected generation facility are owned, installed, and maintained by the interconnection customer. When telecommunication channels are required as part of a protection and/or metering scheme, the general requirements below are to be followed.

SCADA connections are required for all projects 3 MW and larger. Typical SCADA points required include, but are not limited to, the following:

From the point of interconnection:

- Statuses:
    - Point of Interconnection (POI) Breaker Status
    - Cap/Reactor Breaker Status
    - Generator Output Limit Control (GOLC) Control Status
    - Frequency Response Status
- Controls:
    - POI Breaker Control
    - GOLC Control
    - Frequency Response Control
- Setpoints:
    - GOLC Setpoint

    - Volt/Var Setpoints
- Analogs:
    - Net generation MW
    - Net generator MVAR
    - Total generating capacity/nameplate (MW)
    - GOLC Setpoint Feedback
    - Volt/VAr Setpoint Feedback
- Accumulator Pulses:
    - Interchange metering kWh

Additional SCADA points required for solar generation projects:

- Analogs:
    - Total farm generation (MW)
    - Average farm atmospheric pressure (Bar)
    - Average farm temperature (Celsius)
    - Irradiance ($W/m^2$)

Additional SCADA points required for wind generation projects:

- Analogs:
    - Total wind farm generation (MW)
    - Average wind farm wind speed (m/s)
    - Average wind farm atmospheric pressure (Bar)
    - Average wind farm temperature (Celsius)
    - Wind direction

## 14.2. General Requirements

The interconnection customer will be responsible for acquiring the communication lines from the local telephone company or multiple telephone companies as required to meet the telecommunications required of the new generation facility for the alternate metering data circuit. Due to the critical nature of the protection, metering, and SCADA, Idaho Power will own the communication facilities providing these circuits. The only exception to this is if no communication is required for protective relaying, in which case the SCADA may be on a leased communication circuit.

## 14.3. Telecommunication Circuit Requirements

### *14.3.1. New Generation Facilities Less than 3 MW with no Teleprotection Requirement*

Metering requires a cell phone or other data communication connection for use with the Idaho Power MV-90 remote meter data collection system. An Ethernet connection is encouraged, but not required.

### *14.3.2. New Generation Facilities at or over 3 MW or New Generation Facilities Less than 3 MW with Teleprotection Requirement*

An Ethernet connection for use with the Idaho Power MV-90 remote meter data collection system is required. If an Ethernet connection is not possible, a land line or other data communication connection is required to remotely interrogate the meter.

#### 14.3.2.1. Dispatch Business Telephone Line

A business telephone line is required so operating instructions from Idaho Power can be given to the designated operator of the generation facility equipment. Unless other arrangements are made to use Idaho Power’s existing telecommunications network, the interconnection customer must provide a local telephone service.

#### 14.3.2.2. Protective Relay Remote Access Business Telephone Line

A business telephone line is required at the location of the protective relay equipment for remote access to the protective relay equipment. Unless other arrangements are made to use Idaho Power’s existing telecommunications network, the interconnection customer must provide a local telephone line. Relevant critical infrastructure protection (CIP) standards apply.

#### 14.3.2.3. Protective Relays

Idaho Power will determine if non-pilot protective relays will be adequate for emergency tripping of the generation facility and/or protection of the distribution or transmission system or if tele-protected-type protection equipment is required. Idaho Power will design and provide telecommunications channels suitable for the protective relay package required at the expense of the generation facility. Local telephone company leased lines are not acceptable for protective relay channels. Telecommunication channels for protective relay equipment may consist of fiber optic system, power line carrier, microwave radio, or a combination of these systems.

#### 14.3.2.4. SCADA RTU

For projects 3 MW or larger, real-time data and/or control via a SCADA remote terminal unit (RTU) is to be communicated to Idaho Power's control center(s). Unless other arrangements are made to use Idaho Power's existing telecommunications network, the interconnection customer must provide either a local telephone company VG36, Class B, Type-3, 4-wire, full-duplex communication line or an MPLS T1 from the generation facility to Idaho Power's location where the communication line terminates. Idaho Power will specify the location where the communication line will terminate. Telecommunication channels for SCADA RTU equipment, when using Idaho Power's telecommunications network, may consist of fiber optic system, microwave radio, other radio system, or a combination of these systems. The communication medium and protocols are required to support a serial RS232 communication circuit for DNP3 communications.

#### 14.3.2.5. Alternate Telemetry

An alternate-meter telemetering of the total generation facility's kilowatt (kW) output is to be communicated on a separate channel, but in a manner similar to the SCADA channel, to meet requirements for NERC Standard EOP-008-0, Plans for Loss of Control Center(s) Functionality. Unless other arrangements are made to use Idaho Power's existing telecommunications network, the interconnection customer must provide either a local telephone company VG36, Class-B, Type-3, 4-wire, communication line or an MPLS T1 from the generation facility to Idaho Power's control center(s). Idaho Power will specify the location of their closest communications facilities where the communication line will terminate. Telecommunications channel for the alternate-meter telemetering equipment, when using Idaho Power's telecommunications network, may consist of fiber optic cable, microwave radio, or a combination of these systems. The alternate-meter telemetering channel may use the same telecommunications system as the SCADA RTU channel, providing it is not routed through Idaho Power's control center(s).

## 14.4. Communication Operating Conditions

### *14.4.1. Normal Operating Conditions*

The customer shall provide Idaho Power with the information necessary to communicate with the equipment and/or personnel at the generation facility during routine operating conditions. This information shall be updated as soon as a material change becomes available for use by notifying Idaho Power's grid operations department.

### 14.4.2. Emergency Operating Conditions

The interconnection customer shall provide Idaho Power with the information necessary to communicate with the equipment and/or personnel at the generation facility during the loss of the primary communication medium. This would be considered the emergency operating condition. This information is also to be updated as soon as a material change becomes available for use by notifying Idaho Power's grid operations department.

# 15. Protection and Control Policy

## 15.1. Protection Overview

The protection devices specified throughout this document are intended to protect Idaho Power's electrical distribution facilities and Idaho Power customers from damage or disruptions caused by a failure, malfunction, or improper operation of the DER. These devices are also necessary to address the safety of Idaho Power workers and the public. The DER must implement a protection and control system capable of complying with IEEE 1547-2018 section 6. This will enable DER tripping for fault conditions, open phase tripping, over/under voltage tripping, and maintain ride-through requirements.

The requirements specified herein do not address any additional relaying, nor other protective and/or safety devices as may be required by industry or government codes and standards, equipment manufacturer requirements, and prudent engineering design and practice to fully protect the customer's DER. The customer is solely responsible for the protection of its equipment from automatic reclosing by the utility. Safety requirements and contractual agreements between Idaho Power and the customer take precedence over the general provisions of this document.

## 15.2. Transformers

### 15.2.1. Dedicated Transformer

In general, the generator facility shall be served through a dedicated transformer that serves no other customers. The dedicated transformer shall either be provided by Idaho Power at the facility owner's expense or be provided by the facility owner conforming to the latest version of ANSI C57 and to the requirements in this document. If the customer chooses to provide the transformer, the transformer shall be multi-tap, where applicable, and the winding connections shall be discussed with Idaho Power prior to purchasing the transformer.

### *15.2.2. Transformer Configuration*

Generation facilities connecting to Idaho Power's distribution system are required to provide effective grounding at the interconnection point, and the transformer winding configuration shall not result in a return path for ground current. This is achieved through the proper configuration of the facility owner's transformer that connects the generation interconnection system to the Idaho Power distribution system. For example, a wye-grounded/wye-grounded transformer has the proper winding configuration to prevent ground current from returning to Idaho Power's system through the transformer connections while providing effective grounding at the point of interconnection.

The facility's grounding system is required to limit ground fault zero sequence current to be less than 20 amps, as measured on the Idaho Power side at the point on interconnection.

## 15.3. Grounding and Safety Issues

A safe grounding design must accomplish the following two basic functions:

1. Ensure a person in the vicinity of grounded structures and facilities is not exposed to critical levels of step or touch potential.

2. Provide a path for electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting the continuity of service.

Accordingly, each electrical facility must have a grounding system or grid that solidly grounds all metallic structures and equipment in accordance with the standards outlined in ANSI/IEEE 80-2013 (IEEE Guide for Safety in alternating current [AC] Substation Grounding), ANSI/IEEE C2-2023 (National Electrical Safety Code [NESC]), or any subsequent standards as they may be updated.

When various switching devices are opened on an energized circuit, the ground reference may be lost if all sources are not effectively grounded. This situation may cause over-voltages that can affect personnel safety and damage equipment. This is especially true when one phase faults to ground. Therefore, the interconnected power system is to be effectively grounded from all sources.

### *15.3.1. Synchronous Machine System Effective Grounding*

Effectively grounding is defined for synchronous machine systems using symmetrical components with $X_0/X_1 < 3$ and $R_0/X_1 < 1$.

### 15.3.2. Inverter-Based Machine System Effective Grounding

Effectively grounding is defined for inverter-based machines systems using symmetrical components $0.01 < X_0/ R_0 < 0.3$ and $1 < Z_0/Z_1 < 2$.

## 15.4. Communications

Depending on the location of the interconnection, communication upgrades and/or integration may be required. Typical communication infrastructure for protective relaying at Idaho Power uses fiber optics.

Signals between Idaho Power facilities and an interconnection facility may be required. These signals will be carried over a fiber optic medium and, as an example, are used for tripping isolation devices in the interconnection facility and/or Idaho Power facilities.

### 15.4.1. Direct Transfer Trip

Idaho Power may require direct transfer trip (remote operation of a circuit breaker by means of a communications channel) to generation facilities in the following situations:

- The minimum load-to-generation ratio on a circuit is such that a ferroresonance condition could occur.
- It is determined the interconnection protective relaying may not operate for certain conditions or faults.
- It is determined the addition of the project creates the risk of a ground fault overvoltage for the connected transmission system.

## 15.5. Generation Facilities

Idaho Power will install protection based on the MVA rating at the point of interconnection. The interconnection package shall be equipped with a circuit-interrupting device (circuit breaker) with associated relaying that will prevent the generator from being connected to a de-energized or single-phased (if normally three-phase) source. The protective relay will be set in accordance with IEEE 1547-2018 or any subsequent standards as they may be updated.

When the generation customer provides the interrupting device, a power source for tripping and control consisting of a DC power source and storage battery must be provided for the protection system by a DC system. The DC system is to be sized with enough capacity to operate all tripping devices after eight hours without a charger, per IEEE standards. In either case, the facility will be tripped for a loss of the DC system. An under-voltage alarm must be provided for remote monitoring by the facility owner, who shall take immediate action to restore power to the protective equipment.

Live line, dead bus (LLDB) control is used in the interconnection circuit breaker reclosing scheme when generation facilities are connected to Idaho Power. The circuit breaker cannot be closed unless the generation side has zero voltage. The interconnection circuit breaker shall not be used to synchronize a generator to the distribution system. Instead, the generation facilities shall have their own synchronizing facilities.

After a generation facility disconnect (resulting from a voltage or frequency excursion), the generation facility shall remain disconnected until Idaho Power's service voltage and frequency are within the operating voltage range of 106 volts (V) to 132 V (120-V base), and frequency range of 58.8 Hz to 61.2 Hz for a minimum of five minutes.

### *15.5.1. Non-Export Control System*

Non-Exporting Systems must incorporate one of the following three options:

**Option 1 ("Advanced Functionality")**: The use of an internal transfer relay, Energy Management System, or other customer facility hardware or software system(s) may be used to ensure power is never exported across the point of interconnection. To ensure Inadvertent Export of power is limited to acceptable levels, all of the following conditions must be met: (a) inverter-based DERs must utilize IEEE 1547-2018 compliant Smart Inverter(s); (b) the DER must monitor the total Inadvertent Export; (c) the DER must disconnect from the company's distribution system or halt energy production within two seconds after the period of continuous Inadvertent Export exceeds 30 seconds; (d) the DER must enter a safe operating mode where Inadvertent Export will not occur as a result of a failure of the control or Smart Inverter system for more than 30 seconds, which results in loss of control signal, loss of control power or single component failure, or related control sensing of the control circuitry.

**Option 2 ("Reverse Power Protection")**: To ensure power is never exported, a reverse power relay protective function must be implemented at the point of interconnection. The default setting for this protection equipment, when used, shall be 0.1% (export) of the DERs Total Nameplate Capacity, with a maximum 2.0 second time delay.

**Option 3 ("Minimum Power Protection")**: To ensure at least a minimum amount of power is imported at all times (and, therefore, that power is not exported), an under-power protective function may be implemented at the point of interconnection. The default setting for this non-export control system, when used, shall be 5% (import) of the DERs Total Nameplate Capacity, with a maximum 2.0 second time delay.

### *15.5.2. Non-Export Control System Failure*

Where applicable, any failure of the customer's DER control system for 30 seconds or more, which includes, but is not limited to; the internal transfer relay, energy management system, or other customer facility hardware or software system(s) intended to prevent the reverse power flow, shall cause the customer's DER to enter a safe operating mode whereby the production of energy from the Non-Export DER is autonomously limited to an amount that shall not cause Inadvertent export to occur until such time that the customer has re-established real power output control of the non-export control system.

### *15.5.3. Limited Export Control System*

Limited Exporting Systems must incorporate of the following two options:

**Option 1—Directional Power Protection Device (Device 32)**: To limit export of power across the point of interconnection, a directional power protective function must be implemented using a utility grade protective relay. The default setting for this protective function is the export capacity value, with a maximum 2.0 second time delay to limit Inadvertent export. When a project is located on a circuit using high-speed reclosing, the public utility may require a maximum delay of less than 2.0 seconds to safely facilitate the reclosing.

**Option 2—Configured Power Rating**: A reduced output power rating utilizing the power rating configuration setting may be used to ensure the small generator facility does not generate power beyond a certain value lower than the nameplate rating. The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE Std 1547, as described in subclause 10.4. A local small generator facility communication interface is not required to utilize the configuration setting as long as it can be set by other means. The reduced power rating may be indicated by means of a nameplate rating replacement, a supplemental adhesive nameplate rating tag to indicate the reduced nameplate rating, or a signed attestation from the customer confirming the reduced capacity.

# 16. Generation Interconnection Performance Requirements

All generating sources shall comply with all Idaho Power design requirements and applicable FERC, WECC and/or NERC policies, criteria, and standards, including ANSI Standards C50.10 and C50.13, regarding waveform and telephone interference.

Generation facilities shall meet the performance requirements for voltage and frequency outlined in IEEE 1547-2018. These requirements include reaction time, rise time, settling time, overshoot, and settling band. Synchronous machine-based DER shall comply with normal performance Category A and abnormal performance Category I. Inverter-based DER shall comply with normal performance Category B and abnormal performance Category III.

Certain circumstances may exist that necessitate the imposition of performance criteria considered more stringent than the default criteria specified herein. Such circumstances shall be identified during the feasibility, system impact, or facility studies for each generator.

Under no circumstances will a customer's DER be allowed to sustain an island condition with any part of the Idaho Power's distribution system beyond the Point of Common Coupling due to potential damage to Idaho Power or other customers' equipment. The customer's DER must be equipped with protection to sense a possible island and disengage from Idaho Power's distribution system within the 2-second time frame of the formation of an island condition as specified by IEEE Standard 1547-2018 (or any successive standard).

The generating unit(s) must meet all applicable ANSI and IEEE standards. The prime mover, generator, and plant auxiliary equipment should also be able to operate within the full range of voltage and frequency excursions that may exist on the Idaho Power system without damage. To enhance system stability during a system disturbance, the generating unit must be able to operate through the specified frequency ranges for the time durations listed in IEEE 1547-2018.

## 16.1. Reactive and Voltage Control

In general, facilities will be required to operate the system in Volt/VAr control mode to regulate voltage at the Required Point of Applicability (RPA), unless otherwise specified. In general, the RPA will be the point of interconnection which requires the voltage to be sensed electrically at that point. Unless exempted by Idaho Power, each generating interconnection shall maintain the Volt/Var schedule provided by Idaho Power. When instructed to modify voltage, the generation interconnection shall comply or provide an explanation of why the schedule cannot be met. Generation interconnections shall notify Idaho Power of a status change in the automatic voltage regulator (AVR), power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. Generation interconnections shall notify Idaho Power within 30 minutes of becoming aware of a change in reactive capability due to factors other than the previously described status changes.

## 16.2. Synchronous Generators

### *16.2.1. Synchronizing Relays*

Synchronous generators and other generators with standalone capability must use one of the following methods to synchronize with the Idaho Power system:

1. Automatic Synchronization (ANSI Device 25)
   The automatic synchronizing relay must have a slip frequency-matching window of 0 to 0.2 Hz, a voltage-matching window of ± 10% or less, a phase angle-acceptance window of ± 10 degrees or less, and breaker-closure time compensation. The automatic synchronizing relay sends a close signal to the breaker after the above conditions are met. For an automatic synchronizer that does not have breaker-closure time compensation, a tighter frequency window (± 5 degrees) with a one-second time-acceptance window shall be used to achieve synchronization within ± 10 degrees phase angle.

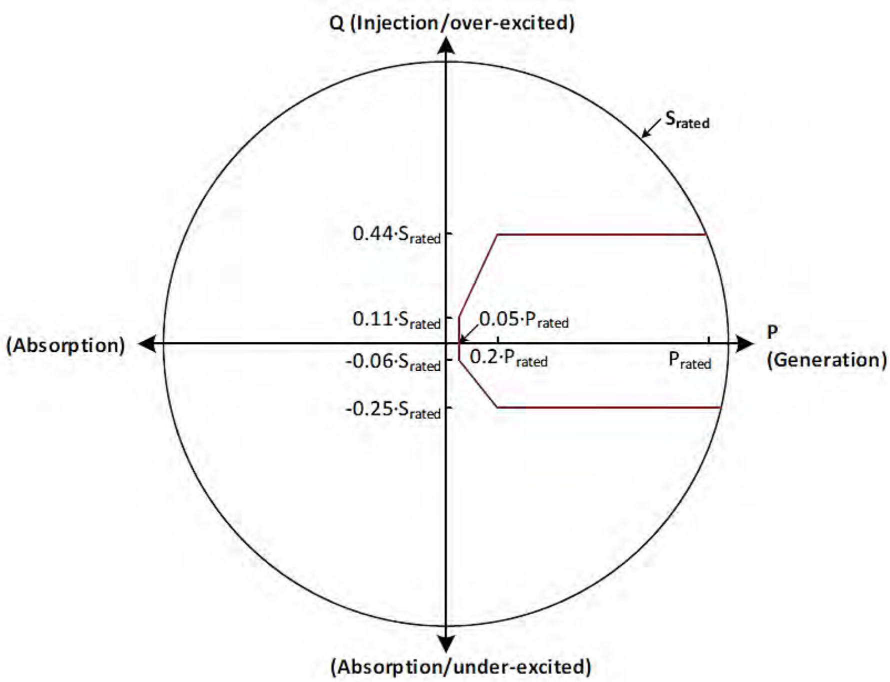
2. <u>Manual Synchronization with Synchroscope and Synch Check (ANSI Device 25) Relay Supervision</u>
   The synch check relay must have a voltage-matching window of ± 10% or less and a phase angle-acceptance window of ± 10 degrees or less.
   Generators with greater than 1,000 kW aggregate nameplate rating must have automatic synchronizing relay or automatic synchronizer.

### 16.2.2. Frequency/Speed Control

Unless otherwise specified by Idaho Power, a governor shall be required on the prime mover to enhance system stability. Governor characteristics shall be set to provide a 5% droop characteristic (a 0.15 Hz change in the generator speed shall cause a 5% change in the generator load). Governors on the prime mover must be operated unrestrained to help regulate Idaho Power's system frequency.

### 16.2.3. Reactive Power Requirements

Synchronous generators must be capable of injecting reactive power (over-excited) and absorbing reactive power (under-excited) corresponding to +44% to -25% of rated system volt-amperes for all active power outputs between 20% and 100% of nameplate active (real) power rating and a lower rating between 5 to 20% of nameplate active (real) power as shown as Category A in Figure 1.




Category A

**Figure 1**
Minimum reactive power capability of Category A distribution connected energy resources (DER)

### *16.2.4. Excitation System Requirements*

An excitation system is required to regulate generator output voltage. Static systems shall have a minimum ceiling voltage of 150% of rated full-load field voltage with 70% of generator terminal voltage and a maximum response time of two cycles (0.033 seconds).

Rotating systems shall have an ANSI voltage response ratio of 2.0 or faster. Excitation systems shall be capable of responding to the full generator reactive capability in both the buck and boost directions. Under certain conditions, Idaho Power may grant an exemption for generation facilities with excitation systems not meeting these requirements. Requests for exemption should be sent to Idaho Power account manager.

## 16.3. Inverter-Based Resources (IBR)

### *16.3.1. IBR Default Settings*

IBRs will be programmed with the default settings listed in Appendix A, unless otherwise instructed by Idaho Power.

### *16.3.2. Plant Controller*

IBR facilities rated for 500kVA or larger and with multiple inverter units will be required to provide a plant controller as part of their IBR system.

### *16.3.3. Reactive Power Requirements*

Regardless of system size, the IBR system must be capable of injecting reactive power (over-excited) and absorbing reactive power (under-excited) corresponding to ±44% of rated system volt-amperes for all active power outputs between 20 and 100% of nameplate active (real) power rating and a lower rating between 5 and 20% of nameplate active (real) power as shown as Category B in Figure 2.

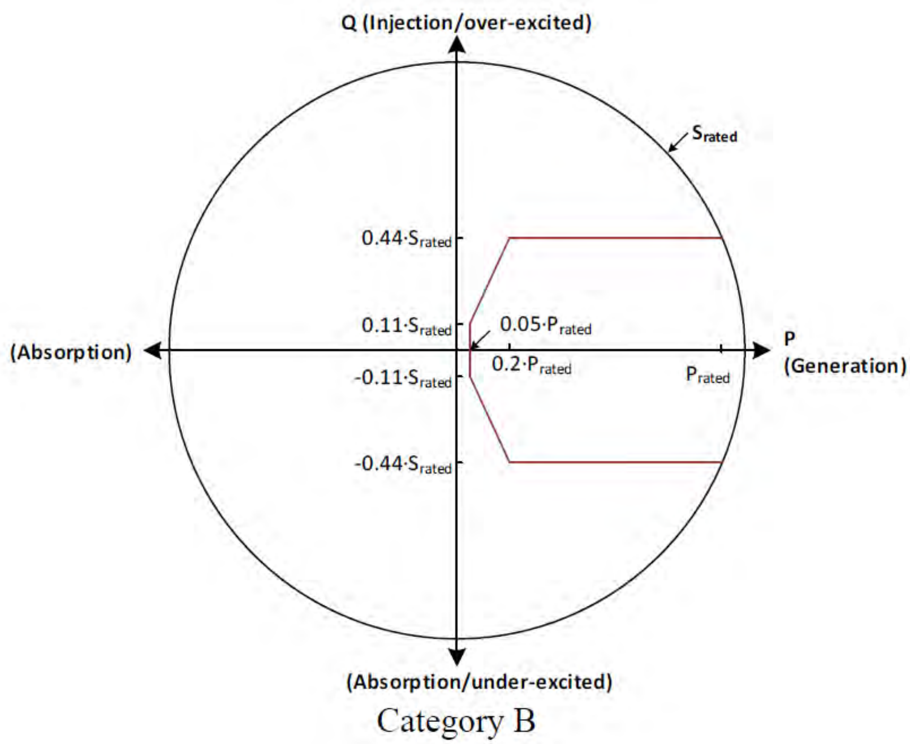



**Figure 2**
Minimum reactive power capability of Category B distribution connected energy resources (DER)

### *16.3.4. Miscellaneous*

The requirements specified in this standard are intended to apply over the lifetime of the IBR plant. When the distribution or transmission system operating and network conditions change significantly enough that changes in the IBR plant become necessary to reliably operate the IBR plant to support, or not degrade, system reliability, equitable remedy measures shall be coordinated between the transmission system owner, transmission system operator, and the IBR owner and operator.

Examples for significant transmission system operating and network condition changes are new plants interconnecting close to an IBR plant, installation of new equipment by the transmission system owner, and changes in the SCR at the RPA.

This standard does not address the effects of single-pole tripping and reclosing employed on the transmission system on performance of IBRs. The transmission system owner may specify additional performance requirements for satisfactory operation of IBR plants during single-phase tripping and reclosing events.

The IBR owner shall inform the transmission system owner/transmission system operator of any such environmental limitations: extreme temperature impacts on mechanical or electrical components (including battery capacity and component ratings); extreme wind impacts on mechanical or structural components; and seismic impacts on mechanical, structural, or electrical components, etc.

The IBR plant shall, in a secure way, provide a local IBR communication interface with bi-directional communication capability, and shall be capable of securely providing real-time operational information of its status, mode of operation, and several steady-state, dynamic, and transient measurements.

The IBR plant shall provide the capabilities of the following mutually exclusive operating modes of reactive power control functions:

1. Voltage control
2. Power factor control
3. Reactive power set point control

The IBR plant shall be capable of activating each of these modes one at a time. The Physical and Operational Margins (POM) control mode shall be voltage control by default mode of the installed IBR plant unless otherwise specified by the transmission system operator.

# 17. Close-Out Requirements

The interconnection customer’s interconnection facilities shall be designed and constructed in accordance with good utility practice.

Within 120 calendar days after the commercial operation date, unless both parties agree on another mutually acceptable deadline, the interconnection customer shall deliver to the transmission provider "as-built" drawings, information, and documents for the interconnection facility, including the following:

- A one-line diagram
- A site plan showing the interconnection
- Elevation drawings showing the layout of the interconnection facility
- A relay functional diagram
- The facilities connecting the large generating facility to the step-up transformers and the interconnection facility, and the impedances (determined by factory tests) for the associated step-up transformers and the large generating facility.

If applicable, the interconnection customer shall also provide the transmission provider with specifications for the following:

- The excitation system
- Automatic voltage regulator
- Large generating facility protection and control settings
- Transformer tap settings
- Communications facilities
- Distribution facilities

Additionally, the interconnection customer shall provide reports documenting generating unit baseline and model validation testing, per applicable WECC and NERC criteria, to Idaho Power's Distribution Planning:

Idaho Power Distribution Planning
1221 W. Idaho St.
Boise, ID 83702

# 18. Revision History

This document has been approved and revised according to the revision history recorded below.

| Review Date | Section(s) | Revisions |
|---|---|---|
| 11/04/2025 | All | Document was implemented. |

**Attachment A**
Inverter settings

The required inverter settings are in a downloadable CSV common file format:

idahopower.com/pdfs/BusinessToBusiness/CustomerGeneration/Idaho_Power_Inverter_Settings.csv

## Reactive Power Capability and Voltage/Power Control Performance

All inverter-based Customer Generator System Smart Inverters will be set for normal operating performance Category B as defined in Institute of Electrical and Electronic Engineers (IEEE) 1547, with the default reactive power control mode set for the Voltage-reactive power mode and the parameters listed in Table 1. All inverter-based Customer Generator System Smart Inverters will be set for abnormal voltage and ride through operating performance Category III as defined in IEEE 1547 using the default settings. The remaining smart inverter settings will be set to the default values specified in IEEE 1547.

**Table 1**
Voltage-reactive power settings for smart inverters

| Voltage-reactive power parameters | Default Settings |
|---|---|
| V1 | 0.92 per unit of nominal voltage |
| Q1 | 44% of nameplate apparent power rating, injecting |
| V2 | 0.98 per unit of nominal voltage |
| Q2 | 0 |
| V3 | 1.03 per unit of nominal voltage |
| Q3 | 0 |
| V4 | 1.06 per unit of nominal voltage |
| Q4 | 44% of nameplate apparent power rating, absorption |
| Open-loop response time | 5 seconds |

The distributed energy resource (DER) shall disable the voltage-active power function.

The DER shall disable the constant power factor function.

## Response to Abnormal Conditions

The DER shall ride-through consecutive temporary disturbances in accordance with IEEE 1547 default settings for Category III DER. Table 2 has the abnormal voltage settings, and Table 3 has the abnormal frequency settings. Table 4 has the frequency droop settings.

**Table 2**
Inverter DER response (shall trip) to abnormal voltages

| Shall Trip – Inverter Based DER | | |
|---|---|---|
| | Default Setting | |
| Shall Trip Function | Clearing Time (s) | Voltage (p.u. of nominal) |
| UV2 | 2 | 0.50 |
| UV1 | 21 | 0.88 |
| OV1 | 13 | 1.10 |
| OV2 | 0.16 | 1.20 |

**Table 3**
DER response (shall trip) to abnormal frequencies

| Shall Trip – Inverter Based DER | | |
|---|---|---|
| | Default Setting | |
| Shall Trip Function | Clearing Time (s) | Voltage (p.u. of nominal) |
| UF2 | 0.16 | 56.5 |
| UF1 | 300 | 58.5 |
| OF1 | 300 | 61.2 |
| OF2 | 0.16 | 62.0 |

**Table 4**
Frequency droop operating parameters

| Parameter | Default Setting |
|---|---|
| dbOF, dbUF (Hz) | 0.036 |
| kOF, kUF | 0.05 |
| Tresponse (small signal) (s) | 5 |

dbOF—A single-sided deadband value for high frequency and low-frequency, respectively, in Hertz (Hz)

dbUF—A single-sided deadband value for high frequency and low-frequency, respectively, in Hz

kOF—The p.u. frequency change corresponding to 1 per-unit output change (frequency droop), unitless

kUF—The p.u. frequency change corresponding to 1 per-unit output change (frequency droop), unitless

## Communication Protocols and Ports Requirements

According to Section 10 of IEEE 1547, the following is applicable to communications interoperability functions. Idaho Power will determine the application of these requirements.

- A DER shall have provisions for a local DER interface capable of communicating (local DER communication interface) to support the information exchange requirements specified in the IEEE 1547 standard for all applicable functions supported in the DER.
- Under mutual agreement between Idaho Power and the DER operator, additional communication capabilities are allowed.
- The decision to use the local DER communication interface or to deploy a communication system shall be determined by Idaho Power.
- Emergency and standby DER are exempt as specified from the interoperability requirements specified in the IEEE 1547 standard.

The DER shall support at least one of the protocols specified in Table 5. The protocol to be utilized may be allowed by mutual agreement between Idaho Power and the DER operator. Idaho Power's preferred protocol is DNP3. Additional physical layers may be supported along with those specified in the table.

**Table 5**
List of eligible communication protocols

| Protocol | Transport | Physical Layer |
|---|---|---|
| IEEE Std 2030.5 (SEP2) | TCP/IP | Ethernet |
| IEEE Std 1815 (DNP3) | TCP/IP | Ethernet |
| SunSpec Modbus | TCP/IP | Ethernet |
| SunSpec Modbus | N/A | RS-485 |