Facilities Study Report

[redacted] #748

20 MW Energy Storage

Jerome, ID

Idaho Power Company—Power Supply

March 27, 2025

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1. Study Overview

1.1 Introduction

Idaho Power Company—Power Supply (Interconnection Customer) contracted with Idaho Power Company (IPC) to perform a Facilities Study (FS) for interconnection of the proposed 20 MW [redacted] #748 (Project) to the 13.8kV [redacted] in the [redacted] yard of IPC's Hunt Station. In accordance with Section 1.1.1 of IPC's Small Generator Interconnection Procedures (SGIP), the Project was studied for Energy Resource Interconnection Service (ERIS).

In accordance with Section 3.5 of IPC's SGIP, this Facilities Study Report (FSR) documents the basis for and results of the FS for the Project. The FSR provides a non-binding estimate of the cost of—and schedule for—equipment, engineering, procurement, and construction work required to implement the conclusions of the most recent study to connect the Project physically and electrically to the Transmission System. This report satisfies the FS requirements of IPC's SGIP.

This FSR is a study and preliminary evaluation only and does not constitute, or form the basis of, a definitive agreement related to the matters described in this FSR. Unless and until a Small Generator Interconnection Agreement (SGIA) is executed by IPC and Interconnection Customer, no party will have any legal rights or obligations, express or implied, related to the subject matter of this FSR. An SGIA under IPC's Open Access Transmission Tariff (OATT) between Interconnection Customer and IPC for the Project will be prepared following finalization of this FSR. The SGIA will be a definitive agreement that contains terms and conditions that supersede this FSR.

1.2 Study Assumptions

- For ERIS, Interconnection Customer's ability to inject its Small Generating Facility output beyond the Point of Interconnection (POI) will depend on the existing capacity of IPC's Transmission System at such time as a transmission service request is made that would accommodate such delivery. Transmission Service may require the construction of additional Network Upgrades.

- Senior-queued Interconnection Requests that were considered in this study are listed in Section 3.1. If any of these Interconnection Requests are withdrawn, IPC reserves the right to restudy this Project, and the results and conclusions could significantly change.

- The following IPC planned system improvements were assumed in service:

    - Boardman to Hemingway 500 kV transmission line (2027)

    - 50% series capacitance compensation on the Kinport to Midpoint 345 kV transmission line (2026)

    - Midpoint Substation T502 500:345 kV transformer (2026)

  - Hemingway to Bowmont 230 kV transmission line (2026)
  - Bowmont to Hubbard 230 kV transmission line (2026)
  - Midpoint to Hemingway #2 500 kV transmission line (2028)

- This report is based on information available at the time of study. Interconnection Customer is responsible to check IPC's OASIS site and website regularly for Generation Interconnection and Transmission System updates:
  - OASIS (https://www.oasis.oati.com/ipco/)
  - Planning and Electrical Projects (https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/)

1.3 No Transmission Service

This FSR is a study of a request for ERIS as defined in Section 1 of IPC's Large Generator Interconnection Procedures (LGIP). This FSR identifies the facilities necessary to interconnect the Generating Facility with IPC's Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. ERIS does not in and of itself convey any right to transmission service or to deliver electricity to any specific customer or Point of Delivery.

The battery energy storage system (BESS) component of this Project was studied for grid-charging. This FSR identifies the facilities necessary to interconnect the Project such that grid-charging can be achieved. The grid-charging results do not convey any right to transmission service for, or constitute an agreement to allow, the BESS to charge from the grid. Additional agreements (e.g., Transmission Service Agreement or Battery Services Agreement) external to the Generation Interconnection study process must be sought prior to the Project commencing any grid-charging activities.

2. Interconnection Facilities and Upgrades

2.1 Interconnection Customer's Interconnection Facilities

General Facility Description

The proposed Project will consist of a [redacted] battery energy storage system (BESS) in Jerome County, Idaho and connect to IPC's transmission system through the 13.8kV [redacted] in the [redacted] yard of IPC's Hunt Station ([redacted]). The total Project output as studied is 20 MW.

Interconnection Customer's Interconnection Facilities are all facilities and equipment located between the Generating Facility and the Point of Change of Ownership (POCO), including any modification, addition, or upgrades to such facilities and equipment. Interconnection Customer is responsible for funding and constructing Interconnection Customer's Interconnection Facilities, including the gen-tie line and facilities to the POCO.

Interconnection Customer's Interconnection Facilities are located in IPC's [redacted] region in Township [redacted], Range [redacted], and Section [redacted] and are [redacted] from Transmission Provider's Interconnection Facilities. Interconnection Customer will install disconnect switches, distribution collector system, transformers, controllers, appropriate grounding measures, and associated auxiliary equipment.

The [redacted] main step-up transformers specified in the Interconnection Request are [redacted] transformers. The proposed transformers do not provide an adequate ground return path for transmission line protection/relaying. See the Ground Fault Equipment portion of Section 5.2 of this FSR for additional details.

Interconnection Customer will build facilities to the POCO, including a transmission line with a minimum 24-count optical ground wire (OPGW) from Interconnection Customer's Interconnection Facilities to IPC's Interconnection Facilities. Interconnection Customer is responsible to mirror IPC's System Protection relays to include dual SEL-411L installation for protection of the interconnection intertie.

Operating Assumptions for Battery Energy Storage System

The BESS component of the Project was studied charging from the grid in an unstressed case and limited local area N-1 contingency analysis. There may be times during the year where system load in the local area will prevent charging of the BESS from the grid at full capacity; for example, a forced outage that would require IPC to curtail charging. Should the Project require non-curtailable grid charging, firm Point-to-Point transmission service from the energy market/source to the BESS would be required.

No additional upgrades are required to support grid charging for the Project.

Point of Change of Ownership

The POCO for the Project will be at the first structure outside Hunt Station on Interconnection Customer's side of disconnect switch 021Y. The structure at the POCO will be part of Interconnection Customer's Interconnection Facilities. The jumper will be part of IPC's Interconnection Facilities. The following drawing provides generic information and standard requirements for the POCO.

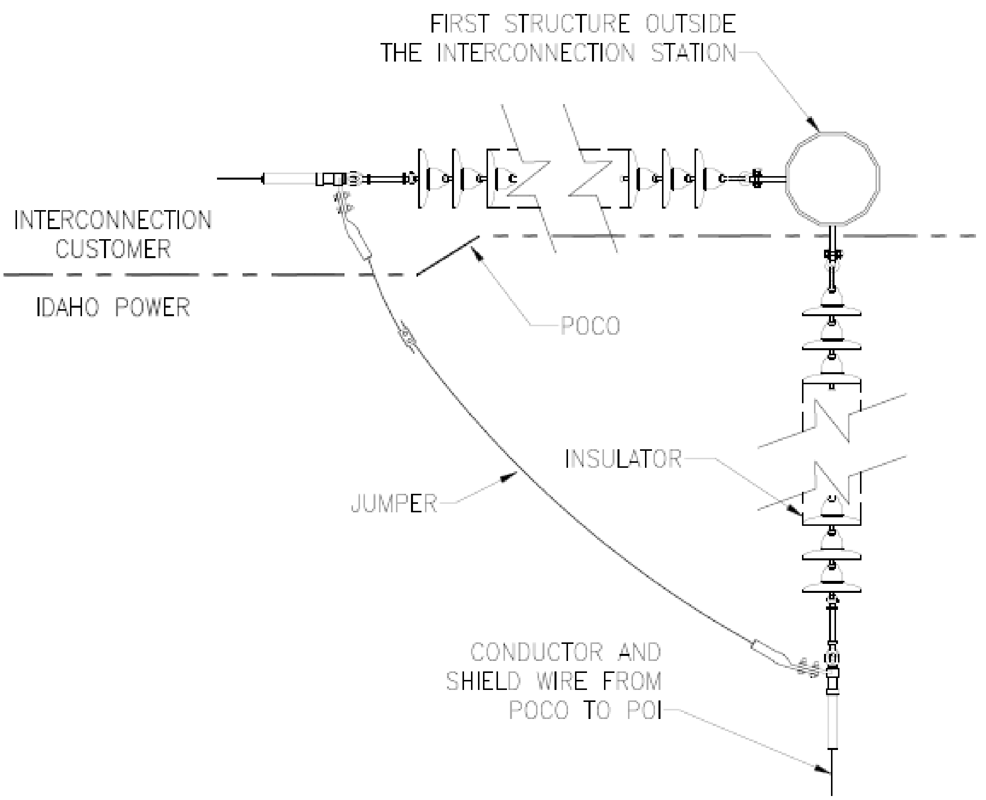

Figure 1
Generic Point of Change of Ownership (POCO) configuration.

Note the following related to the POCO:

- The first structure outside the interconnection station shall be designed as follows:
  - Vertical construction
  - 90-degree max line angle
  - IPC phase spacing
- Interconnection Customer's OPGW shall terminate at an Interconnection Customer-provided splice box on the structure.

- Interconnection Customer shall inform IPC of the conductor size.
- IPC and Interconnection Customer shall coordinate phase configuration (e.g., 321, 213, etc.).
- Insulator parts shown in the diagram are for representation only; actual parts used will be dependent on final design.

2.2 Transmission Provider's Interconnection Facilities

Transmission Provider's Interconnection Facilities (IPC's Interconnection Facilities) are all facilities and equipment owned, controlled, or operated by IPC from the POCO to the POI, including any modifications, additions or upgrades to such facilities or equipment. Costs for IPC's Interconnection Facilities are the sole responsibility of Interconnection Customer and are not reimbursable.

Point of Interconnection

The Project's POI will be at Interconnection Customer's requested POI of the 13.8kV [redacted] in the [redacted] yard of Hunt Station. The preliminary configuration for the POI interconnects the Project on IPC's side of air-break switch [redacted]. A drawing detailing the configuration is attached as Exhibit 1. This configuration will be finalized during construction, and the final configuration will be captured in an SGIA amendment, if necessary.

Metering

All metering for the Project will be installed, configured, and maintained in accordance with IPC's publicly posted Facility Interconnection Requirements for Transmission Systems, as may be updated from time to time.

IPC's Interconnection Facilities

To allow interconnection of the Project, IPC will install the following facilities up to the POCO:

- [redacted] single-bay ALP (Aluminum Low Profile) structure
- [redacted] steel bus tee
- [redacted] air-break switch[1]
- [redacted] disconnect switch
- [redacted] circuit breaker

[1] It is IPC's standard practice to install [redacted] air-break switches in [redacted] applications to increase clearances and reduce outages.

- [redacted] meter
- [redacted] current transformers (CT)
- [redacted] bus potential transformers (PT)
- Required foundations, bus, bus supports, underground conduit and cable runs, and fiber communication equipment
- The last span of the Project's gen-tie line, including insulators, conductor, and associated hardware

IPC will install equipment to collect and transmit Phasor Measurement Unit (PMU) data to IPC. The communication circuits required for this data transmission are described in Section 5.2 of this FSR. The data can be made available to Interconnection Customer on request.

2.3 Substation Network Upgrades

Substation Network Upgrades are Network Upgrades that are required at the substation located at the POI; this includes all switching stations. Actual costs for Substation Network Upgrades are reimbursable. The following Substation Network Upgrades are required for this Project:

- [redacted] transformer[2]
- New transformer protection to include the tertiary and wrapping to tertiary total breaker
- Associated bus supports, foundations, relaying, communications, and control equipment in the station yard and building

2.4 System Network Upgrades

System Network Upgrades are Network Upgrades that are required beyond the substation located at the POI. Actual costs for System Network Upgrades are reimbursable.

No System Network Upgrades were identified for this Project.

2.5 Distribution Upgrades

Distribution Upgrades are additions, modification, and upgrades to IPC's Distribution System at or beyond the POI to facilitate interconnection of the Generating Facility. Actual costs for Distribution Upgrades are not reimbursable.

[2] Risk of failure due to addition of load on the [redacted] transformer as well as the potential for through-faults, which would be detrimental to the transformer, are not acceptable for IPC's system reliability. A new transformer will be required to interconnect this project.

No Distribution Upgrades were identified for this Project.

2.6 Estimated Costs

The following good faith estimates are provided in 2025 dollars and are based on a number of assumptions and conditions. IPC does not warrant or guarantee the estimated costs in the table below, which are estimates only and are subject to change. Interconnection Customer will be responsible for all actual costs incurred in connection with the work to be performed by IPC and its agents, under the terms and subject to the conditions included in any SGIA executed by IPC and Interconnection Customer. Costs for any work being performed by Interconnection Customer and/or Affected Systems are not included.

Full funding of the estimated costs identified below (or as updated in the SGIA) must be received or other arrangements acceptable to IPC must be made with IPC's Credit Department prior to any work commencing on the Interconnection Facilities and/or identified upgrades.

Table 1
Estimated cost of Interconnection Facilities and Network Upgrades.

Description	Ownership	Cost Estimate
IPC Interconnection Facilities:		
Facilities between the POCO and POI as described in Section 2.2	IPC	$192,532
Contingency 20%		$38,506
Overheads 3%		$6,931
Total		**$237,970**
Substation Network Upgrades:		
Upgrades to POI station as described in Section 2.3	IPC	$4,661,194
Contingency 20%		$932,239
Overheads 3%		$167,803
Total		**$5,761,236**
	GRAND TOTAL	**$5,999,205**

3. Contingent Facilities and Affected Systems

3.1 Generation Interconnection Queue

Interconnection Customer has applied to interconnect the Project to IPC's transmission system for an injection of 20 MW at a single POI at the 13.8kV [redacted] in the [redacted] yard of IPC's Hunt Station.

If a senior-queued Interconnection Request that is responsible for constructing Network Upgrades should withdraw from the queue or otherwise be terminated, junior-queued Interconnection Requests in the electrically relevant area may be restudied and assigned additional Network Upgrades identified as necessary to facilitate their interconnection.

As of the date of this report, Interconnection Request #633 is a senior-queued Interconnection Request to the Project. The recommended upgrades for this senior-queued Interconnection Request were assumed to be completed prior to the interconnection of the Project. Costs related to Network Upgrades could be passed on to the Project should changes be made to this senior-queued Interconnection Request.

3.2 Contingent Facilities and Planned System Improvements

Contingent Facilities

Contingent Facilities are those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.

No Contingent Facilities were identified for the Project.

Contingent Transmission Provider Planned System Improvements

No contingent IPC planned system improvements were identified for the Project.

3.3 Affected Systems

An Affected System is an electric system other than IPC's Transmission System that may be affected by the proposed interconnection.

IPC has not identified an Affected System for this Project. If an Affected System is later identified, IPC will notify both Interconnection Customer and Affected System, and an Affected System study may be required.

4. Estimated Milestones

4.1 Milestones Overview

The milestone dates in this section assume, among other things, that materials can be timely procured, labor resources are available, and that outages to the existing transmission system are available to be scheduled. Additionally, there are several matters, such as permitting issues and the performance of subcontractors that are outside the control of IPC that could delay the estimated Commercial Operation Date (COD). For purposes of example only, federal, state, or local permitting, land division approval, identification of Interconnection Facilities location, access to proposed Interconnection Facilities location for survey and geotechnical investigation, coordination of design and construction with Interconnection Customer, failure of IPC's vendors to timely perform services or deliver goods, and delays in payment from Interconnection Customer may result in delays of any estimated milestone and the COD of the Project. To the extent any of the foregoing are outside of the reasonable control of IPC, they shall be deemed Force Majeure events. For these and other reasons, IPC does not warrant or guarantee the estimated milestone dates, which are estimates only.

Interconnection Customer proposed the following schedule dates in the Facilities Study Agreement:

Table 2
Interconnection Customer proposed schedule dates.

Milestone	Proposed Date
Begin Construction	[redacted]
In-Service Date (back feed power available)	[redacted]
Generation Testing	[redacted]
Commercial Operation	6/1/2027

4.2 Estimated Milestones Detail

Interconnection Customer has requested a COD of June 1, 2027. IPC has developed the milestone dates in good faith considering many factors, including the requested COD, known long-lead times, and the schedule of other in-progress projects. The estimated milestone schedule captured in the following table does not align with the requested COD.

These milestones will begin, and the milestone schedule referenced below will only be valid, upon receipt of funding from Interconnection Customer or its authorized third party no later than the date set forth in the ultimate SGIA for such payment. IPC will not commit any resources toward Project construction that have not been funded by Interconnection Customer. Additionally, failure by Interconnection Customer to make the required payments as set forth in the ultimate SGIA by specified date(s) may result in the loss of milestone dates and construction schedules set forth below.

Table 3
Estimated Milestones

Estimated Date	Responsible Party	Milestone
30 Business Days following receipt of executable SGIA	Interconnection Customer	**Project Initiation** (all three must be complete to initiate Project): • Executed SGIA • IPC receives Notice to Proceed for design, procurement, and construction • Construction funding or arrangements acceptable to IPC are made with IPC's Credit Department
18 months following Project Initiation	IPC	Engineering and Design complete
36 months following Project Initiation	IPC	Long Lead Material procured/received
10 months prior to COD	Interconnection Customer	Provide updated EMT models to complete modeling in accordance with IPC's OATT Attachment O
8 months prior to IPC Commissioning	IPC	Network modeling submission Failure to submit by given lead time will result in Project delay
180 Calendar Days prior to Trial Operation	Interconnection Customer	Provide a completed copy of the Small Generating Facility data requirements contained in Appendix 1 of the SGIP
180 Calendar Days prior to Initial Synchronization	Interconnection Customer	Provide initial specifications for Interconnection Customer's Interconnection Facility
90 Calendar Days prior to Initial Synchronization	Interconnection Customer	Provide final specifications for Interconnection Customer's Interconnection Facility
42 months following Project Initiation	IPC	Construction of IPC's Interconnection Facilities and Network Upgrades Complete
44 months following Construction Complete	IPC	Commissioning of IPC's Interconnection Facilities and Network Upgrades Complete Back feed power is available
5 days after switching request made to IPC Dispatch	Interconnection Customer	**In-Service Date** Switch at the POI can be closed to obtain back feed power
TBD	Interconnection Customer	**Initial Synchronization Date** Interconnection Customer Trial Operation begins; test energy can be generated only if the IC has arranged for the delivery of such energy
30 Calendar Days prior to COD	Interconnection Customer	Notify IPC of COD
Prior to COD	Interconnection Customer	Pass Generating Facility Functional Testing
10 BD prior to COD	Interconnection Customer	Provide Certificate of Insurance

Estimated Date	Responsible Party	Milestone
Prior to COD	Interconnection Customer	Provide as-built or as-tested performance data that differs from the initial Small Generating Facility data requirements contained in Appendix 1 of the SGIP
TBD	Interconnection Customer	**COD**
120 Calendar Days following COD	Interconnection Customer	Provide as-built drawings, information, and documents for Interconnection Customer's Interconnection Facilities

5. Interconnection Details

5.1 Generating Facility

The Generating Facility is Interconnection Customer's device(s) for the production and/or storage for later injection of electricity identified in the Interconnection Request but shall not include Interconnection Customer's Interconnection Facilities.

Interconnection Customer's system will be constructed as follows:

1. The BESS inverter system will comprise of [redacted] inverters.
2. A plant controller will be used to control the inverter system and to implement smart inverter functionality for operating the Project within a voltage range specified by IPC at the POI.

The above-referenced inverters, or equivalent inverters that have the same specifications and functionality as stated above, must be utilized. Additional study and/or equipment may be necessary if a different inverter is utilized that has different specifications and functionality than that which was studied.

The BESS component of the Project was studied as charging from the grid.

5.2 Other Facilities Provided by Interconnection Customer

Telecommunications

Interconnection Customer is not responsible for any third-party communication circuits for the IPC's Interconnection Facilities. Any additional telecommunication requirements, including OPGW on the gen-tie line, will be the sole responsibility of Interconnection Customer.

Ground Fault Equipment

Interconnection Customer will install transformer configurations that will provide a ground source to the transmission system.

The tertiary provides no ground reference and, thus, no ground source. This means there is no current-based method for the protective relays to detect ground faults. Ground fault detection is a requirement.

The preferred option for the ground fault detection is for Interconnection Customer to install a grounding transformer to provide a ground return path to allow ground current to flow. This will allow current-based detection of ground faults and limit the tripping to in-zone faults (e.g., between IPC tertiary total breaker and BESS total breaker). This ground transformer shall be owned and maintained by Interconnection Customer; however, Idaho Power must be involved in testing and will provide testing procedures to ensure the ground transformer will meet the needs for the ground source.

Alternatively, Interconnection Customer can request Idaho Power use voltage unbalance detection in the line protection to trip tertiary total breaker and transfer trip the BESS system. This is a non-directional protection method and would require an entire BESS outage for troubleshooting the location and root cause of the ground fault, which is a time-consuming process. Reenergization of the BESS would not be allowed until the cause of the fault is found and may result in an extended outage of the BESS.

Generator Output Limit Control

Interconnection Customer will install equipment to receive/transmit signals from IPC Load Serving Operations for Generation Output Limit Control (GOLC)—see Section 5.5 of this FSR. IPC's recommended method of communication for GOLC is via fiber between the Interconnection Facilities and the Project.

Local Service

Interconnection Customer is required to take local service from the local service provider as a retail customer. Interconnection Customer is responsible to arrange for local service to Interconnection Customer's Interconnection Facilities and/or Generating Facility.

If receiving local service from IPC, Interconnection Customer shall coordinate such requirements with IPC so that local service can be provided in accordance with the provisions contained within the applicable service schedule. The service schedule and functional settlement will be determined during construction of the Project.

Property

Interconnection Customer may be required to obtain easements and/or transmission line crossing agreements from IPC depending on the designed path of Interconnection Customer's [redacted] gen-tie line.

Site Work

No site work was identified beyond that required for Network Upgrades on property already owned by IPC.

Monitoring Information

If Interconnection Customer requires the ability to monitor information related to the IPC breaker/relay (i.e., Mirrored Bits) in the interconnection station, Interconnection Customer is required to supply its own communications circuit to the interconnection yard. The fiber communication circuit used for GOLC is acceptable.

Generator Technical Information and Drawings

During Project design development, Interconnection Customer shall provide draft design prints containing technical information, including but not limited to impedances and equipment brand and models. After construction, Interconnection Customer shall submit to IPC all the as-built information, including prints with the latest approved technical information and commissioning test results in accordance with the timing requirements outlined in the SGIA.

5.3 Operating Requirements

Voltage Fluctuation

The Project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-2014 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

Low Voltage Ride Through

The Project must be capable of riding through faults on adjacent sections of the power system without tripping due to low voltage. Interconnection projects must meet or exceed the low voltage ride-through requirements as set forth in NERC Standard PRC-024.

Frequency Response Requirements

The Project must be capable of providing Primary Frequency Response for both positive and negative frequency deviations from 60Hz (+/- 0.036 Hz) with a droop of up to 5% for Bulk Electric System disturbances. Provided the Project meets the above Primary Frequency Response requirements, IPC shall not curtail the Project when such curtailments are caused by a need to comply with applicable Frequency Response reliability standards.

Momentary Cessation Requirements

Momentary cessation should not be used within the voltage and frequency ride-through curves specified in PRC-024 and PRC-029, when effective. Use of momentary cessation is not considered ride through within the No Trip zone curves of PRC-024 or mandatory and continuous operation regions of PRC-029. The use of momentary cessation should be eliminated to the extent possible consistent with NERC's *Reliability Guideline for BPS-Connected Inverter-Based Resource Performance*.

Interconnection Customer will be able to modify power plant facilities on Interconnection Customer side of the POCO only if 1) there is no impact on the operation of the transmission or distribution system, 2) the generation facilities are electrically isolated from the system via the [redacted] disconnect switch, and 3) a terminal clearance is issued by IPC's Load Serving Operator.

5.4 Reactive Power

The Project will be required to provide reactive power versus real power capability measured at the high side of the main power transformer that complies with IEEE 2800-2022 *IEEE Standard* *for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems*, or any subsequent standards as they may be updated from time to time.

The Project must have equipment capable of receiving an analog setpoint, via DNP 3.0 from IPC for Voltage Control. IPC will issue an operating voltage schedule for the Project prior to the Project's In-Service Date. For more detail, see Section 5.5 of this FSR.

5.5 Generation Interconnection Supervisory Data Requirements

Interconnection Communications

All supervisory data points described in this Section 5.5 of the FSR are to be communicated between Interconnection Customer and IPC via serial DNP3 protocol. The physical transport will be fiber cables.

Interconnection Customer is responsible for this fiber connection from their PLC or other controls equipment to the POCO.

Generator Output Limit Control

The Project will be subject to reductions directed by IPC Load Serving Operations during transmission system contingencies and other reliability events. When these conditions occur, the Project will be subject to Generator Output Limit Control (GOLC) and will have equipment capable of receiving an analog setpoint via DNP 3.0 from IPC for GOLC. GOLC will be accomplished with a setpoint and discrete output control from IPC to the Project indicating maximum output allowed.

IPC requires interconnected Projects to accept GOLC signals from IPC's energy management system (EMS) when they are connected to IPC's transmission system.

The GOLC signals will consist of four points shared between the IPC EMS (via the IPC RTU) and Interconnection Customer Generator Controller (SGC). The IPC RTU will be the master, and the SGC will be the slave.

- **GOLC Setpoint:** An analog output that contains the MW value Interconnection Customer should curtail to, should a GOLC request be made via the GOLC On/Off discrete output Control point.

- **GOLC Setpoint Feedback:** An analog input feedback point must be updated (to reflect the GOLC setpoint value) by the SGC upon the SGC's receipt of the GOLC setpoint change, with no intentional delay.

- **GOLC On/Off:** A discrete output (DO) control point with pulsing Trip/Close controls. Following a "GOLC On" control (DNP Control Code "Close/Pulse On"), the SGC will run power output back to the MW value specified in the GOLC Setpoint. Following a "GOLC Off" control (DNP Control Code "Trip/Pulse On"), Interconnection Customer is free to run to maximum possible output.

- **GOLC On/Off Feedback:** A discrete input (DI) feedback point must be updated (to reflect the last GOLC DO Control Code received) by the SGC upon the SGC's receipt of the GOLC DO control, with no intentional delay. The feedback DI should latch to an OFF state following the receipt of a "GOLC OFF" control and it should latch to an ON state following the receipt of an "GOLC ON" control.

If a GOLC control is issued, it is expected to see MW reductions start within 1 minute and plant output to be below the GOLC Setpoint value within 10 minutes.

Voltage Control

IPC requires interconnected Projects to accept voltage control signals from IPC's EMS when they are connected to IPC's transmission system.

The voltage control will consist of one setpoint and one feedback point shared between the IPC EMS and the SGC.

- **Voltage Control Setpoint:** An analog output that contains the voltage Interconnection Customer should target for plant operation. This setpoint will have a valid control range between 0.95 and 1.05 per unit (p.u.) of nominal system voltage.

- **Voltage Control Setpoint Feedback:** An analog input feedback point must be updated (to reflect the Voltage Control Setpoint) by the SGC upon the SGC's receipt of the voltage setpoint change, with no intentional delay.

The control will always be active; there is no digital supervisory point like the GOLC On/Off control above.

The voltage control system should operate at the voltage indicated by the voltage control setpoint with an accuracy of +/- 0.5%.

Interconnection Customer should supervise this control by setting up "reasonability limits" (i.e., configure a reasonable range of values for this control to be valid). As an example, they will accept anything in the valid control range (between 0.95 and 1.05 p.u.) but reject values outside this range. If they were fed an erroneous value outside the valid range, their control system would default to the last known, good value.

Auxiliary Data Points

Additional status points relating to local weather, equipment, and other supervisory information is required in accordance with the following Generation Interconnection Supervisory Data Table. This table includes a comprehensive list of data points to be sent and received via the fiber connection described in the Interconnection Communications portion of this Generation Interconnection Supervisory Data Requirements section.

Table 4
BESS Generation Interconnection Supervisory Data Table.

Digital Inputs to IPC (DNP Obj. 01, Var. 2)			
Index	Description	State (0/1)	Comments:
0	GOLC Off/On (Control Feedback)	Off/On	Feedback provided by Interconnection Customer
1	52A Interconnection Customer Main Breaker (if present)	Open/Closed	Sourced at substation
2	52A Interconnection Customer Capacitor Breaker (if present)	Open/Closed	Sourced at substation

Digital Outputs to Interconnection Customer (DNP Obj. 12, Var. 1)		
Index	Description	Comments:
0	GOLC Off/On	Control issued by IPC
1	EMS COMM Off/On	Control issued by IPC

Analog Inputs to IPC (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint Value Received (Feedback)	32767	-32768	TBD	TBD	MW	Provided by Interconnection Customer
1	Voltage Control Setpoint Value Rec'd (Feedback)	32767	-32768	TBD	TBD	kV	Provided by Interconnection Customer
2	Maximum Park Generating Capacity	32767	-32768	TBD	TBD	MW	Provided by Interconnection Customer
3	SPARE						
4	SPARE						
5	SPARE						
6	SPARE						
7	SPARE						
8	SPARE						
9	SPARE						
10	SPARE						
11	SPARE						
12	SPARE						

Analog Inputs to IPC (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
13	SPARE						
14	SPARE						
15	SPARE						
16	SPARE						
17	SPARE						

Analog Outputs to Interconnection Customer (DNP Obj. 41, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint	32767	-32768	TBD	TBD	MW	Control issued by IPC
1	Voltage Control Setpoint	32767	-32768	TBD	TBD	kV	Control issued by IPC
2	SPARE						
3	SPARE						
4	SPARE						
5	SPARE						
6	SPARE						
7	SPARE						
8	SPARE						
9	SPARE						

Revision History

Date	Author	Revisions
3/27/2025	Laura Nelson	Interconnection Facilities Study Report version 1.0 issued.