# Interconnection Facilities Restudy Report

[redacted] #659
1,650 MW Solar, Combustion Turbine & Energy Storage
Jerome County, ID
[redacted]

**September 8, 2025**

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# 1. Study Overview

## 1.1 Introduction

[redacted] (Interconnection Customer) has an executed Large Generator Interconnection Agreement (LGIA) with Idaho Power Company (IPC) for interconnection of the proposed 1,650 MW [redacted] #659 (Project) to IPC's 500kV Midpoint Station. The LGIA is for Energy Resource Interconnection Service (ERIS).

Following the Project's execution of the LGIA and subsequent First Amendment to the LGIA, senior-queued Interconnection Request #530's LGIA was terminated. Due to this senior-queued LGIA termination, the Project requires an Interconnection Facilities Restudy (RFS) to be performed. This Interconnection Facilities Restudy Report (RFSR) identifies the work required to interconnect the Project to the requested Point of Interconnection (POI) at IPC's 500kV Midpoint Station.

In accordance with Section 8.2 of IPC's Large Generator Interconnection Procedures (LGIP), this RFSR is specific to the Project and documents the basis for, and results of, the RFS for the Project. The RFSR provides a non-binding estimate of the cost of—and schedule for—equipment, engineering, procurement, and construction work required to connect the Project physically and electrically to the Transmission System. This report satisfies the RFS requirements of IPC's LGIP.

This RFSR 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 RFSR. Unless and until an LGIA amendment 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 RFSR. An LGIA amendment under IPC's Open Access Transmission Tariff (OATT) between Interconnection Customer and IPC for the Project will be prepared following finalization of this RFSR. The LGIA amendment will be a definitive agreement that contains terms and conditions that supersede this RFSR.

## 1.2 Study Assumptions

- For ERIS, Interconnection Customer's ability to inject its Large 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 500kV transmission line (2027)
    - 50% series capacitance compensation on the Kinport to Midpoint 345kV transmission line (2026)
    - Midpoint Substation transformer T502 500:345kV transformer (2026)
    - Hemingway to Bowmont 230kV transmission line (2026)
    - Bowmont to Hubbard 230kV transmission line (2026)
    - Hemingway to Mayfield 500kV transmission line (2028)
    - Mayfield to Midpoint 500kV transmission line (2030)
- 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 RFSR is a study of a request for ERIS as defined in Section 1 IPC's LGIP. This RFSR identifies the facilities necessary to interconnect the Project with IPC's Transmission System and be eligible to deliver the Project'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 RFSR 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 [redacted] solar; [redacted] combustion turbine (CT); and [redacted] battery energy storage (BESS) in Jerome County, Idaho and interconnect at a single Point of Interconnection (POI) at IPC's 500kV Midpoint Station ([redacted]). The net Project output at the POI as studied is 1,650 MW.

Interconnection Customer's Interconnection Facilities are defined in Section 1 of IPC's LGIP as 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] ([redacted]) and are approximately [redacted] away from Transmission Provider's Interconnection Facilities (IPC's Interconnection Facilities). Interconnection Customer will install disconnect switches, collector system, transformers, controllers, appropriate grounding measures, and associated auxiliary equipment.

Interconnection Customer's [redacted] main step-up transformer(s) are [redacted] transformers. The proposed [redacted] transformers specified in the Interconnection Request should provide an adequate ground return path for transmission line protection/relaying.

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

### *Point of Change of Ownership*

The POCO for the Project will be at the first structure outside IPC's northwest section of the 500kV Midpoint Station (POI Station). 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.

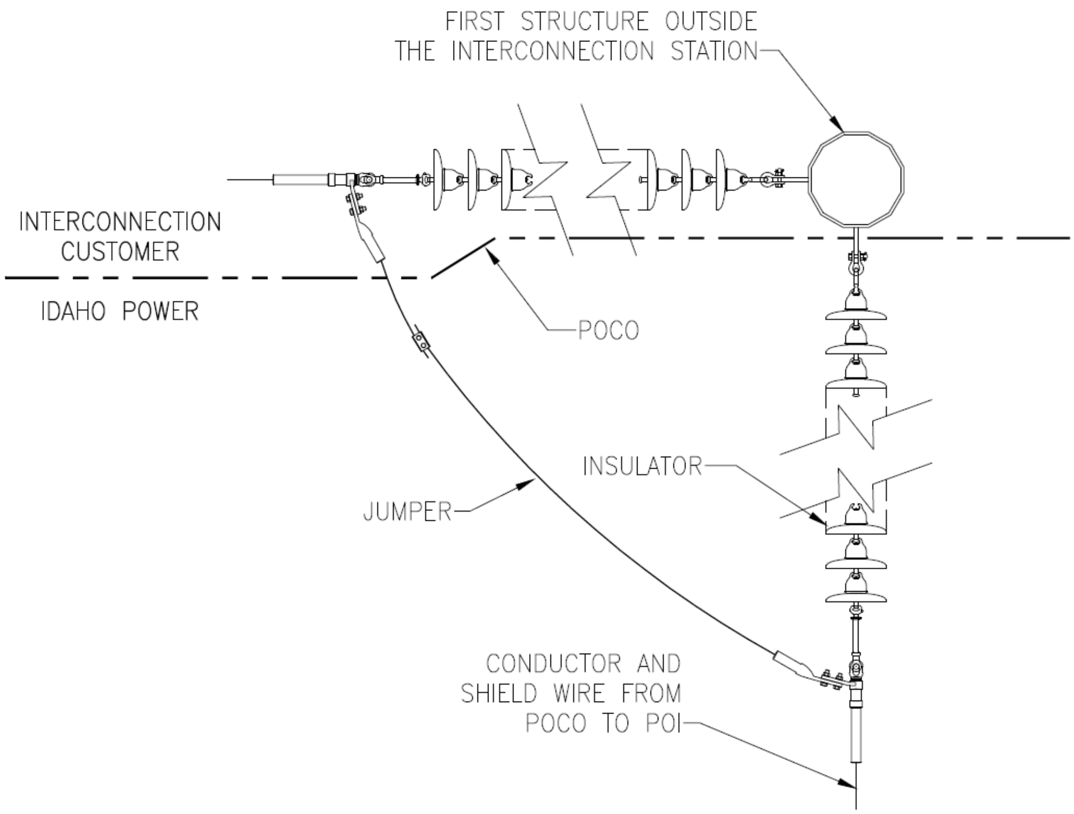


**Figure 1**
Generic Point of Change of Ownership (POCO) configuration.

Note the following related to the POCO:

- The first structure outside the POI Station shall be designed as follows:
  - 90-degree max line angle
  - Steel
  - 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 defined in Section 1 of IPC's LGIP as 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. In accordance with Section 4.2.1 of IPC's LGIP, costs for IPC's Interconnection Facilities are directly assigned to Interconnection Customer and are not reimbursable.

### *Point of Interconnection*

The Project's POI will be at Interconnection Customer's requested POI of IPC's 500kV Midpoint Station. The preliminary configuration for the POI is in the northwest section of the 500kV Midpoint Station at the node connection between air-break switches [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 LGIA 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] meter
- [redacted] steel dead-end structures
- [redacted] air-break switch
- [redacted] current transformers (CT)
- Required foundations, bus, bus supports, 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 RFSR. The data can be made available to Interconnection Customer on request.

**Table 1**
Transmission Provider Interconnection Facilities

| Facility Description | Unloaded Cost Estimate |
|---|---|
| Interconnection Facilities | $1,852,335 |

## 2.3 Substation Network Upgrades

Substation Network Upgrades are defined in Section 1 of IPC's LGIP as Network Upgrades that are required at the substation located at the POI; this includes all switching stations. This section includes both Substation Stand Alone Network Upgrades (SANU) and Substation Network Upgrades, the actual costs of which are reimbursable.

### *Substation Stand Alone Network Upgrades*

SANUs are defined in Section 1 of IPC's LGIP as Network Upgrades that Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction.

No Substation SANUs were identified for this Project.

### *Substation Network Upgrades*

The following Substation Network Upgrades are required for this Project:

- Construct one (1) new line terminal in the northwest section of the 500kV Midpoint Station
    - [redacted] breakers
    - [redacted] air-break switches
    - [redacted] capacitance-coupled voltage transformers (CCVT)
    - Relay protection panel, bus, structures, and equipment and associated precast and drilled pier foundations to accommodate the protection of the new 500kV line terminal

**Table 2**
Substation Network Upgrades

| Facility Description | Unloaded Cost Estimate |
|---|---|
| POI Station | $11,839,745 |

## 2.4 System Network Upgrades

System Network Upgrades are defined in Section 1 of IPC's LGIP as Network Upgrades that are required beyond the substation located at the POI. This section includes both System SANU and System Network Upgrades, the actual costs of which are reimbursable.

### *System Stand Alone Network Upgrades*

SANUs are defined in Section 1 of IPC's LGIP as Network Upgrades that Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction.

No System SANUs were identified for this Project.

### *System Network Upgrades*

No System Network Upgrades were identified for this Project.

### *Additional Studies*

Based on Interconnection Customer's request to connect combustion turbine generators to an IPC substation that contains series compensation transmission lines, a separate Sub-Synchronous Control Interaction (SSCI) Study will be required to determine the mitigation requirements for identified sub-synchronous resonances and sub-synchronous interactions. Interconnection Customer is responsible for implementing solutions to eliminate the possibility of SSCI events up to and including tripping the combustion generation component of the Project offline.

The study will be performed as LGIA milestone and may result in additional System Network Upgrades.

## 2.5 Distribution Upgrades

Distribution Upgrades are defined in Section 1 of IPC's LGIP as additions, modification, and upgrades to IPC's Distribution System at or beyond the POI to facilitate interconnection of the Generating Facility. In accordance with Article 11.3 of IPC's LGIA, costs for Distribution Upgrades are directly assigned to Interconnection Customer and are not reimbursable.

Note that the identified Distribution Upgrades do not include distribution facilities to support local service to Interconnection Customer's Interconnection Facilities, Generating Facility, auxiliary load, etc. See the Local Service portion of Section 5.2 of this RFSR for additional information on local service requirements.

No Distribution Upgrades were identified for this Project.

## 2.6 Estimated Costs

The following good faith estimates are provided in 2025 US 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 performed by IPC and its agents for the scope identified in the ultimate LGIA and subsequent amendments, under the terms and subject to the conditions included in any LGIA and subsequent amendments executed by IPC and Interconnection Customer for this Project. Costs for work being performed by Interconnection Customer and/or Affected Systems are not included.

The estimated cost below is required to be paid in full by Interconnection Customer, or other arrangements acceptable to IPC are made with IPC's Credit Department, in accordance with Article 11.5 of the LGIA prior to IPC commencing construction of a discrete portion of IPC's Interconnection Facilities or Network Upgrades.

There are identified contingent planned system improvements that are required to be completed prior to the interconnection of this Project. Details on the contingent facilities identified are in section 3.2 of this RFSR. For this and other reasons, the cost estimates included in this RFSR are estimates only, are based on currently known or assumed facts that may not be accurate or materialize, and are subject to change.

**Table 3**
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 | $1,852,335 |
| Contingency 20% | | $370,467 |
| Overheads 4% | | $88,912 |
| *Total* | | $2,311,714 |
| ***Substation Network Upgrades:*** | | |
| **Upgrades to POI Station as described in Section 2.3** | IPC | $11,839,745 |
| Contingency 20% | | $2,367,949 |
| Overheads 4% | | $568,308 |
| *Total* | | $14,776,002 |
| | | |
| | ***GRAND TOTAL[1]*** | **$17,087,716** |

[1] Funding responsibility is described in the standard LGIA in Idaho Power's OATT (Attachment M). Interconnection Facilities are funded by the Interconnection Customer without reimbursement. Distribution Upgrades are funded by the Interconnection Customer without reimbursement. Network Upgrades are funded by the Interconnection Customer, and those funds are eligible for reimbursement under LGIA section 11.4.1.

# 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 1,650 MW total at a single POI at IPC's 500kV Midpoint Station. IPC jointly owns this station with PacifiCorp (PAC).

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 Requests #551, #557, #558, #570/587, #590, #604, #605, #614/616, #624, #625, #630, #632, #633, #635, and #656 are senior-queued Interconnection Requests to [redacted] #659. Costs related to Network Upgrades could be passed on to the Project should changes be made to one or more of these senior-queued Interconnection Requests.

## 3.2 Contingent Facilities and Planned System Improvements

### *Contingent Facilities*

Contingent Facilities are defined in Section 1 of IPC's LGIP as 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.

The following table details the identified Contingent Facilities associated with GIs #570 and #635 that are required to be completed prior to the interconnection of this Project.

**Table 4**
Identified Contingent Facility Network Upgrades.

| Assigned To | Contingent Facility | Estimated In-Service |
|---|---|---|
| GI #570 | Midpoint Station [redacted] breaker [redacted] | 2030 |
| GI #635 | Expand the existing Midpoint 500kV Station to the Northwest creating the Midpoint Northwest Yard | TBD[2] |
| GI #635 | Relocate the existing Hemingway [redacted] capacitor bank and reactors from the existing [redacted] to the new Midpoint Northwest yard | TBD |
| GI #635 | Install facilities in the existing Midpoint 500kV Station to facilitate connection to the new Midpoint Northwest yard | TBD |

[2] As of the date of this report, GI #635 is in Suspension.

### *Contingent Transmission Provider Planned System Improvements*

The following table details the identified contingent IPC planned system improvements that are required to be completed prior to the interconnection of this Project.

**Table 5**
Contingent Transmission Provider planned system improvements.

| Planned System Improvement | Estimated In-Service |
|---|---|
| Mayfield to Midpoint 500kV transmission line | 2030 |

## 3.3 Affected Systems

Affected System is defined in Section 1 of IPC's LGIP as an electric system other than IPC's Transmission System that may be affected by the proposed interconnection.

Because the proposed interconnection is to the 500kV Midpoint Station, which is jointly owned by IPC and PAC, PAC is an Affected Party. While PAC previously confirmed that they do not anticipate any impacts to PAC requiring mitigation, a copy of this report will be shared with PAC, and an Affected System Study may be required. If an Affected System Study is required, Interconnection Customer will work directly with PAC to complete the necessary study.

# 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 satisfy the definition of Force Majeure hereunder, 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.

In the event Interconnection Customer is unable to meet the dates as outlined in the ultimate LGIA and any subsequent amendments, Interconnection Customer may request suspension of up to a total of three years pursuant to Article 5.16 of the LGIA. Upon suspension of work pursuant to Article 5.16 of the LGIA, the applicable construction duration, timelines, and schedules set forth in the ultimate LGIA and any subsequent amendments shall be likewise suspended. The estimated milestones in the following table may be updated and revised for inclusion in the LGIA in light of subsequent developments and conditions.

## 4.2 Estimated Milestones Detail

Interconnection Customer has requested a COD of December 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 LGIA and any subsequent amendments 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 LGIA and any subsequent amendments by the specified date(s) may result in the loss of milestone dates and construction schedules set forth below.

**Table 6**
Estimated Milestones

| Estimated Date | Responsible Party | Milestone |
|---|---|---|
| September 12, 2023 | Interconnection Customer | **Complete**<br>LGIA Executed |
| [redacted] | Interconnection Customer | **Complete**<br>Provide required documentation:<br>• Reasonable evidence to show one or more of the development milestones as per LGIP Section 11.3 has been achieved<br>• Continued site control<br>• Certificate of Insurance |
| [redacted] | Interconnection Customer | Project placed in Suspension |
| 15 Business Days following receipt of final LGIA Amendment | Interconnection Customer | LGIA Amendment Execution |
| No later than 3 years following Suspension | Interconnection Customer | **Project Re-Initiation**<br>Provide required documentation:<br>• Unsuspend LGIA<br>• Updated construction funding or arrangements acceptable to IPC made with IPC's Credit Department<br>• Notice to Proceed |
| 24 months following Project Re-Initiation | IPC | Engineering and Design complete |
| 47–66 months following Project Re-Initiation[3] | IPC | Long Lead Material procured/received |
| 18 months prior to COD | Interconnection Customer | Provide updated EMT models to complete modeling in accordance with IPC's OATT Attachment O and to perform the required SSCI study (Additional Studies in Section 2.4) |
| 8 months prior to Commissioning of IPC's Interconnection Facilities | IPC | Network modeling submission<br>Failure to submit by given lead time will result in Project delay |
| 180 Calendar Days prior to Initial Synchronization | Interconnection Customer | Provide a completed copy of the Large Generating Facility data requirements contained in Appendix 1 of the LGIP per LGIA Article 24.3 |
| 180 Calendar Days prior to Initial Synchronization | Interconnection Customer | Provide initial specifications for Interconnection Customer's Interconnection Facilities per LGIA Article 5.10.1 |
| 90 Calendar Days prior to Initial Synchronization | Interconnection Customer | Provide final specifications for Interconnection Customer's Interconnection Facilities per LGIA Article 5.10.1 |

[3] Construction cannot be complete until long-lead items are received.

| Estimated Date | Responsible Party | Milestone |
|---|---|---|
| 3 months prior to Initial Synchronization | Interconnection Customer | Provide notification of local Balancing Authority per LGIA Article 9.2 |
| 55–74 months following Project Re-Initiation | IPC | Construction of IPC's Interconnection Facilities and Network Upgrades Complete |
| 2030 | IPC | All Transmission Provider planned system improvements assumed in-service complete (Section 1.2), including identified Contingent Planned System Improvements (Table 5) |
| TBD | IPC | Identified Contingent Facility Network Upgrades in service (Table 4) |
| 1 month following completion of all previous construction milestones | IPC | Commissioning of IPC's Interconnection Facilities and Network Upgrades Complete<br>Back feed power is available |
| Any time after Commissioning Complete<br>**Note**: Switching request must be made a minimum of 5 days prior to In-Service Date | Interconnection Customer | **In-Service Date**<br>Switch at the POI can be closed to obtain back feed power |
| TBD | Interconnection Customer | **Initial Synchronization Date**<br>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 |
| Prior to COD | Interconnection Customer | Provide as-built or as-tested performance data that differs from the initial Large Generating Facility data requirements contained in Appendix 1 of the LGIP per LGIA Article 24.4 |
| TBD | Interconnection Customer | **COD** |
| Within 30 Calendar Days following COD | Interconnection Customer | Submit completed Appendix E of the LGIA confirming completion of Trial Operation and COD |
| 120 Calendar Days following COD | Interconnection Customer | Provide as-built drawings, information, and documents for Interconnection Customer's Interconnection Facilities per LGIA Article 5.10.3 |

# 5. Interconnection Details

## 5.1 Generating Facility

The Generating Facility is defined in Section 1 of IPC's LGIP as 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 solar generation system will comprise of [redacted] inverters and [redacted] transformers.
2. The combustion turbine generation system will comprise of [redacted] CT synchronous generators and [redacted] transformers.
3. The BESS generation system will comprise of [redacted] inverters and [redacted] transformers.
4. 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.

### *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.

## 5.2 Other Facilities Provided by Interconnection Customer

### *Telecommunications*

Interconnection Customer is not responsible for any third-party communication circuits for 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.

### *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 RFSR. IPC's recommended method of communication for GOLC is via fiber between the POI 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*

IPC does not anticipate the need for additional land to be acquired for this Project. IPC's Interconnection Facilities will be owned and maintained by IPC.

Interconnection Customer may be required to obtain transmission 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 senior-queued projects.

### *Monitoring Information*

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

### *Meteorological Data*

To integrate the solar energy into IPC's system and operate IPC's solar forecasting tool, Interconnection Customer must provide solar irradiation and weather data from the Project's physical location to IPC via real-time telemetry in a form acceptable to IPC. The associated cost for obtaining this data is Interconnection Customer's responsibility.

The data must be provided at ten (10)-second intervals and consist of:

1. Global Horizontal Irradiance
2. Plane of Array Irradiance
3. Ambient Temperature
4. Wind Speed and Wind Direction
5. Relative Humidity

The installed instruments must equal or exceed the specifications of the following instruments:

- ***Temperature and Relative Humidity*****:** R.M Young Relative Humidity and Temperature Probe Sensors Model 41382
- ***Wind*****:** R.M Young Wind Monitor Model 05103
- ***Pyranometer*****:** Apogee Instruments Model SP-230

### *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 LGIA and any subsequent amendments.

## 5.3 Operating Requirements

To maintain compliance with NERC Reliability Standard FAC-001, the Project is required to comply with IPC's publicly posted Facility Interconnection Requirements for Transmission Systems, as may be updated from time to time.

## *Voltage and Current Distortion Limits*

### Combustion Turbine

The Project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-2022 *IEEE Standard for Harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

### Solar and BESS

The Project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 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.

## *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 Reliability Standard PRC-024 and PRC-029, when effective.

## *Frequency Response Requirements*

To the extent the Project has operating capability in the needed direction, 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] air-break switch, and 3) a terminal clearance is issued by IPC's Load Serving Operator.

## 5.4 Reactive Power

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 RFSR.

### *Combustion Turbine*

The synchronous generation portion of the Project must be capable of +/- 0.95 power factor operation, as measured at the POI, for all MW production levels.

### *Solar and BESS*

The non-synchronous generation portions of 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.

## 5.5 Generation Interconnection Supervisory Data Requirements

### *Interconnection Communications*

All supervisory data points described in this Section 5.5 of the RFSR are to be communicated between Interconnection Customer and IPC via serial DNP 3.0 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 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 ten (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 are 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 of the RFSR.

**Table 7**
Solar 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 |

| Analog Inputs to IPC (DNP Obj. 30, Var. 2) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Index | Description | Raw High | Raw Low | EU High | EU Low | EU Units | Comments: |
| 3 | Ambient Temperature | 32767 | -32768 | 327.67 | -327.68 | DEG C | Provided by Interconnection Customer |
| 4 | Wind Direction | 32767 | -32768 | 327.67 | -327.68 | Deg from North | Provided by Interconnection Customer |
| 5 | Wind Speed | 32767 | -32768 | 327.67 | -327.68 | M/S | Provided by Interconnection Customer |
| 6 | Relative Humidity | 32767 | -32768 | TBD | TBD | % | Provided by Interconnection Customer |
| 7 | Global Horizontal Irradiance | 32767 | -32768 | TBD | TBD | W/M^2 | Provided by Interconnection Customer |
| 8 | Plane of Array Irradiance | 32767 | -32768 | TBD | TBD | W/M^2 | Provided by Interconnection Customer |
| 9 | SPARE | | | | | | |
| 10 | SPARE | | | | | | |
| 11 | SPARE | | | | | | |
| 12 | SPARE | | | | | | |
| 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 | | | | | | |

| Analog Outputs to Interconnection Customer (DNP Obj. 41, Var. 2) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Index | Description | Raw High | Raw Low | EU High | EU Low | EU Units | Comments: |
| 6 | SPARE | | | | | | |
| 7 | SPARE | | | | | | |
| 8 | SPARE | | | | | | |
| 9 | SPARE | | | | | | |

**Table 8**
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 | | | | | | |

| Analog Inputs to IPC (DNP Obj. 30, Var. 2) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Index | Description | Raw High | Raw Low | EU High | EU Low | EU Units | Comments: |
| 5 | SPARE | | | | | | |
| 6 | SPARE | | | | | | |
| 7 | SPARE | | | | | | |
| 8 | SPARE | | | | | | |
| 9 | SPARE | | | | | | |
| 10 | SPARE | | | | | | |
| 11 | SPARE | | | | | | |
| 12 | SPARE | | | | | | |
| 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 |
|---|---|---|
| 9/8/2025 | Laura Nelson | Interconnection Facilities Restudy Report version 1.0 issued. |