Final Transitional Cluster Restudy Report

[redacted] #724

100 MW Energy Storage

Canyon County, ID

[redacted]

December 8, 2025

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1. Study Overview

1.1 Introduction

[redacted] (Interconnection Customer) contracted with Idaho Power Company (IPC) to perform a Transitional Cluster Study (TCS) for interconnection of the proposed 100 MW [redacted] #724 (Project) to IPC's Bowmont Station at 230kV. The Project was requested to be studied for Network Resource Interconnection Service (NRIS) and was included in the transitional Cluster Area 4 (CA4).

Following issuance of the updated draft final Transitional Cluster Study Report on June 27, 2025, which captured updates caused by GI #731's withdrawal from IPC's Generation Interconnection (GI) queue, a senior-queued GI Request in the electrically relevant area—GI #530—was withdrawn from IPC's GI queue. This withdrawal resulted in a Transitional Cluster Restudy (RTCS) of transitional CA4. An updated draft final Transitional Cluster Restudy Report (RTCSR) was issued September 8, 2025.

In accordance with Section 5.1.1.2 of IPC's Large Generator Interconnection Procedures (LGIP), this final Transitional Cluster Restudy Report (RFTCSR) is specific to the Project and documents the basis for, and results of, the interim RTCS for the Project. The RFTCSR 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 interim RTCSR to connect the Project physically and electrically to the Transmission System. In conjunction with the interim RTCSR dated September 8, 2025, this report satisfies the final RTCS requirements of IPC's LGIP.

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

1.2 Study Assumptions

- For NRIS, additional studies to reduce or eliminate congestion may be required, and these studies may identify the need for additional upgrades. To the extent Interconnection Customer enters an arrangement for long term transmission service for deliveries from the Large Generating Facility at any point outside IPC's Transmission System, such request may require additional studies and upgrades for IPC to grant such request.

- Senior- and equally 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 (B2H) 500kV transmission line (2027)
    - 50% series capacitance compensation on the Kinport to Midpoint 345kV transmission line (2026)
    - Midpoint Substation T502 500:345kV transformer (2026)
    - Bowmont to Hemingway #2 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 RFTCSR is a study of a request for NRIS as defined in Section 1 of IPC's LGIP. This RFTCSR identifies the facilities necessary to provide such service. NRIS in and of itself does not 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 RFTCSR 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] BESS facility in Canyon County, Idaho and interconnect at a single 230kV Point of Interconnection (POI) at IPC's Bowmont Station ([redacted]). The total Project output as studied is 100 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] and are approximately [redacted] away from Transmission Provider's Interconnection Facilities (IPC's Interconnection Facilities). Interconnection Customer will install disconnect switches, distribution collector system, transformers, controllers, appropriate grounding measures, and associated auxiliary equipment. The main step-up transformer is a [redacted] transformer. The proposed [redacted] transformer 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 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.

Point of Change of Ownership

The POCO for the Project will be at the first structure outside IPC's Bowmont 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.

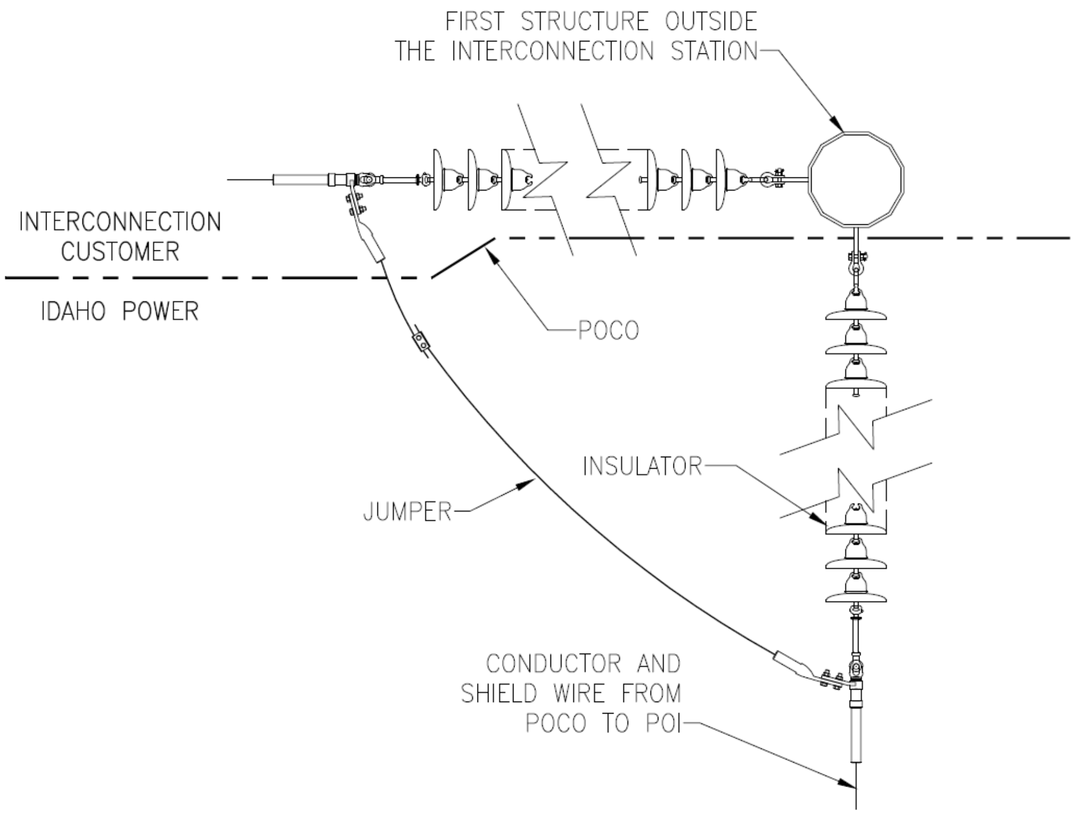

Figure 1
Generic Point of Change of Ownership (POCO) configuration.

Note the following related to the POCO:

- The first structure outside Bowmont Station shall be designed as follows:
    - Vertical construction
    - 90-degree max line angle
    - Steel
    - IPC phase spacing
- Interconnection Customer's OPGW shall terminate at an Interconnection Customer-provided splice box on the POCO structure.
- Interconnection Customer shall inform IPC of the conductor size terminated at the POCO structure.
- IPC and Interconnection Customer shall coordinate phase configuration (e.g., 321, 213, etc.) terminated at the POCO structure.

- 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 the Bowmont Station. Per Interconnection Customer's request, this POI will be shared with GI #723. The preliminary configuration for the POI is 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 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] ION 8650A meter
- [redacted] dead-end structure
- [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.

Table 1
Transmission Provider Interconnection Facilities

Facility Description	Cost Allocation	Unloaded Cost Estimate
Interconnection Facilities	GI #723—50% GI #724—50%	$571,722
	TOTAL Unloaded Costs	**$571,722**
	Share Unloaded Costs	**$285,861**

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. In accordance with Section 4.2.1(a) of IPC's LGIP, costs for Substation Network Upgrades are allocated per capita to each Generating Facility interconnecting at the same substation. 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. Substation SANUs must be required for only a single Interconnection Customer in the Cluster, and no other Interconnection Customer in that Cluster is required to interconnect to the same Substation Network Upgrades.

No Substation SANUs were identified for this Project.

Substation Network Upgrades

The following Substation Network Upgrades are required for this Project:

- Expand the existing Bowmont Station and construct a new [redacted] line terminal
  - Approximately [redacted] yard expansion
  - [redacted] entrance gate and driveway apron
  - Associated relaying, PLC communications, and control equipment in the station yard and building

Table 2
Substation Network Upgrades

Facility Description	Cost Allocation	Unloaded Cost Estimate
Bowmont Station	GI #723—50% GI #724—50%	$750,059

Facility Description	Cost Allocation	Unloaded Cost Estimate
	TOTAL Unloaded Costs	**$750,059**
	Share Unloaded Costs	**$375,030**

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. In accordance with Section 4.2.1(b) of IPC's LGIP, costs for each specific System Network Upgrade are allocated based on proportional impact of each individual Generating Facility in the RTCS. 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. System SANUs must be required for only a single Interconnection Customer in the Cluster, as indicated under IPC's Proportional Impact Method as outlined in Section 3 of IPC's Generation Interconnection Business Practices and Section 4.2.1 of IPC's LGIP.

No System SANUs were identified for this Project.

System Network Upgrades

No System Network Upgrades were identified for this Project.

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 RFTCSR 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, under the terms and subject to the conditions included in any LGIA executed by IPC and Interconnection Customer. Costs for work being performed by Interconnection Customer and/or Affected Systems are not included.

In accordance with Section 11.3 of IPC's LGIP, an LGIA deposit equal to 20% of the estimated Network Upgrade costs identified below (or as updated in the LGIA) must be received or other arrangements acceptable to IPC must be made with IPC's Credit Department upon LGIA execution.

Additional security for the remaining Interconnection Facilities and Network Upgrades is estimated to be required as outlined in the Estimated Milestones section of this RFTCSR.

There are identified contingent facility Network Upgrades and/or 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 RFTCSR. For this and other reasons, the cost estimates included in this RFTCSR 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	$571,722
Contingency 20%		$114,344
Overheads 4%		$27,443
Total		$713,509
50% Share		**$356,755**
Substation Network Upgrades:		
Upgrades to Bowmont Station as described in Section 2.3	IPC	$750,059
Contingency 20%		$150,012
Overheads 4%		$36,003
Total		$936,074
50% Share		**$468,037**
	GRAND TOTAL	$1,649,583

Description	Ownership	Cost Estimate
	#724 SHARE OF GRAND TOTAL[1]	**$824,792**

[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 100 MW at a single POI at 230kV at IPC's Bowmont Substation.

If a senior- or equally queued Interconnection Request that is responsible for constructing Network Upgrades should withdraw from the queue or otherwise be terminated, junior- or equally 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, #590, #605, #632, #636, #639, #640, #665, #666, #667, #669, and #696 are senior-queued Interconnection Requests to the Project. Additionally, as of the date of this report, Interconnection Requests #704, #708, #710, #716, #718, #719, #723, #724, #725, #732, and #737 are in the RTCS with the Project and are therefore equally queued. The recommended upgrades for these senior- and equally queued Interconnection Requests 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 one or more of these senior- or equally 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.

No Contingent Facilities associated with senior-queued projects were identified as being required to be completed prior to the interconnection of this Project, as identified in the interim RTCSR dated September 8, 2025.

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, as identified in the interim RTCSR dated September 8, 2025.

Table 4
Contingent Transmission Provider planned system improvements.

Planned System Improvement	Outage	Estimated In-Service
Rebuild 138kV Bowmont–Mora	[redacted]	2026

Planned System Improvement	Outage	Estimated In-Service
Expand 230kV Bowmont Station	[redacted]	2026
Build new 230kV Bowmont–Hemingway #2	[redacted]	2026
Install Midpoint T502 500/345kV transformer	[redacted]	2026
Build new 230kV Bowmont–Hubbard	[redacted]	2026
Build new Boardman to Hemingway 500kV Project	[redacted]	2027
Rebuild 230kV Mountain Air Wind Park–Rattlesnake	[redacted]	2028
Build new 500/230kV Mayfield Station	[redacted]	2028
Build new 230kV Mayfield–Pleasant Valley Solar	[redacted]	2028
Build new 500kV Hemingway–Mayfield	[redacted]	2028
Loop Boise Bench–Midpoint #2 230kV in-and-out of Mayfield 230kV Station	[redacted]	2028
Build new 230kV Bennett Mountain–Danskin–Rattlesnake 3-terminal line	[redacted]	2029
Loop Boise Bench–Midpoint #3 230kV in-and-out of Rattlesnake 230kV Station	[redacted]	2030
Build new 500kV Mayfield–Midpoint	[redacted]	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.

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.

In the event Interconnection Customer is unable to meet the dates as outlined in the ultimate LGIA, Interconnection Customer may request suspension of up to 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 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 31, 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 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 by the specified date(s) may result in the loss of milestone dates and construction schedules set forth below.

Table 5
Estimated Milestones

Estimated Date	Responsible Party	Milestone
30 Calendar Days following receipt of final LGIA	Interconnection Customer	**LGIA Execution** Provide the following: • Executed LGIA • Demonstration of continued Site Control • LGIA deposit (20% of estimated Network Upgrade costs in cash, or arrangements acceptable to IPC can be made with IPC's Credit Department) • Reasonable evidence to show one or more of the development milestones as per LGIP Section 11.3 has been achieved
10 Business Days following LGIA Execution	Interconnection Customer	Provide Certificate of Insurance
15 Business Days following LGIA Execution	Interconnection Customer	**Project Initiation** IPC receives Notice to Proceed for design, procurement, and construction
24 months following Project Initiation	IPC	Engineering and Design complete
24 months following Project Initiation	Interconnection Customer	Additional security required for Interconnection Facilities and Network Upgrade material
18 months following Project Initiation	IPC	Easements/Property acquisition and permits procured for IPC site; construction will not begin until acquisitions and permits are in place.
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 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 months prior to Initial Synchronization	Interconnection Customer	Provide notification of local Balancing Authority per LGIA Article 9.2

Estimated Date	Responsible Party	Milestone
48 months following Project Initiation	IPC	Construction of IPC's Interconnection Facilities and Network Upgrades Complete
2030	IPC	Contingent Transmission Provider planned system improvements in service (Table 4)
1 month following completion of all previous construction milestones	IPC	Commissioning of IPC's Interconnection Facilities and Network Upgrades Complete Back feed power is available
Any time after Commissioning Complete **Note**: Switching request must be made a minimum of 5 days prior to In-Service Date	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	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 BESS inverter system will comprise of [redacted] BESS inverters.
2. A plant controller will be used to control the inverter system in accordance with the latest version of IEEE 2800.

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 RFTCSR. 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

IPC does not anticipate the need for additional land to be acquired for the Bowmont Station expansion. 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

IPC will perform land clearing and grading for the Bowmont Station expansion and IPC's Interconnection Facilities.

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 POCO. 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 LGIA.

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.

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. The 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

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] 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 RFTCSR.

5.5 Generation Interconnection Supervisory Data Requirements

Interconnection Communications

All supervisory data points described in this Section 5.5 of the RFTCSR 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 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 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 of the RFTCSR.

Table 6
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
12/26/2024	Laura Nelson	Final Transitional Cluster Study Report version 1.0 issued.
1/28/2025	Laura Nelson	Updates to Milestone table, including adjustment of Long Lead Material receipt to be associated with Project Initiation instead of Land Procurement and adding line items for expected completion of Contingent Facilities and Planned System Improvements. Version 1.1.
6/27/2025	Laura Nelson	Draft Final Transitional Cluster Restudy Report version 1.0 issued.
12/8/2025	Laura Nelson	Draft Final Transitional Cluster Restudy Report version 2.0 issued. Incorporates changes due to withdrawal of senior-queued project #530.