GENERATOR INTERCONNECTION
SYSTEM IMPACT RESTUDY REPORT

for interconnection of the proposed

240 MW [redacted] PROJECT

(GI PROJECT #551)

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

in

ELMORE COUNTY, ID

for

[redacted]

Report v1.0

September 8, 2025

Table of Contents

Introduction 2
1.0 Study Assumptions 2
2.0 Description of Proposed Generating Project 3
3.0 Protection and Control 3
4.0 Description of Power Flow Cases 3
5.0 Senior-Queued Interconnections 4
6.0 POI Facilities & Substation Network Upgrades 4
7.0 System Network Upgrades & Contingent Facilities 5
8.0 Battery Charging 5
9.0 Voltage 5
10.0 Transient Stability Analysis 6
11.0 Description of Operating Requirements 6
12.0 Conclusion 6
APPENDIX A 7
A-1.0 Method of Study 7
A-2.0 Acceptability Criteria 7
A-3.0 Grounding Guidance 8
A-4.0 Electrical System Protection Guidance 8
A-5.0 WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements 8
Revision History 9

Introduction

[redacted] has contracted with Idaho Power Company (IPC or Transmission Provider) to perform a Generator Interconnection System Impact Restudy (RSIS) for the interconnection of the proposed 240 MW [redacted] project (the Project) at a single Point of Interconnection (POI) at 230kV at IPC's [redacted] 230kV station. The Project location is in IPC's Capital Region in Elmore County, Idaho approximately [redacted] miles to the [redacted] of [redacted] 230kV station.

The Project is Generation Interconnect (GI) queue number 551 (GI #551) and has an executed Large Generator Interconnection Agreement (LGIA) for Network Resource Interconnection Service (NRIS). The Project restudy was triggered due to the senior project GI #530's removal from IPC's GI queue.

This System Impact Restudy Report (RSISR) documents the basis for and the results of this RSIS for GI #551. The RSISR describes the study assumptions, the proposed Project, the determination of the Project interconnection requirements, and estimated costs for interconnection of the Project to the Transmission Provider's Transmission System. This report satisfies the SIS requirements of IPC's Open Access Transmission Tariff (OATT).

1.0 Study Assumptions

- For NRIS, additional studies to reduce or eliminate congestion may be required and these studies may identify the need for additional upgrades. NRIS in and of itself does not convey Transmission Service.
- The Project has no senior-queued GI requests.
- The need for transmission modifications, if any, that may be required to provide NRIS will be evaluated on the basis of 100 percent deliverability of the interconnection request under study.
- Power flow analysis requires WECC base cases to reliably balance under peak load conditions the aggregate of generation in the local area, with the Generating Facility at full output, to the aggregate of the load in the Transmission Provider's Transmission System.
- IPC will not mitigate thermal or voltage violations with remedial action schemes (RAS) in the GI process.
- The following IPC planned system improvements were assumed in service. Any facility that has been determined to be contingent will be listed in Section 7 of this RSISR.
    - 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)

2.0 Description of Proposed Generating Project

The primary POI for the Project is at the [redacted] 230kV station with a maximum injection of 240 MW.

Project Location	~[redacted] miles to the [redacted] of [redacted] 230kV station
Generator Nameplate Rating	**Solar** – 240 MW **BESS** – 255.75 MW/1023 MWh [redacted]
Total Output Power Rating	240 MW to POI
Number and Type of Inverters	**Solar –** [redacted] inverters **BESS** – [redacted] inverters
Main Power Transformer	[redacted] MVA, 230/34.5/13.2kV Z = [redacted]% X/R = [redacted]
Rated Power Factor	0.95

Table 1. GI #551 Project Specifications

3.0 Protection and Control

For 230kV line protection, IPC's System Protection Department utilizes permissive and line differential protection schemes integrated with digital communication infrastructure. IPC will require optical ground wire (OPGW) in the static wire position for any gen-tie lines and fiber communication between co-located facilities. Interconnection Customer is responsible to provide communication infrastructure between Interconnection's Customer's 230kV collector substation and IPC.

Studies indicate that there is adequate load and short circuit interrupting capability on the Transmission Provider's existing 230kV breakers after this Project is interconnected.

The proposed 230/34.5 kV Wye-Grounded/Wye-Grounded with 13.2 kV delta tertiary transformer specified in the Project's Interconnection Request should provide an adequate ground return path for transmission line protection/relaying.

Grounding requirements and acceptability criteria are found in Appendix A.

4.0 Description of Power Flow Cases

For the NRIS study, two power flow cases were used to study the Transmission Provider's Transmission System with heavy east-to-west power flow and heavy west-to-east power flow conditions to determine the required Network Upgrades.

The WECC 2030 Heavy Summer base case was modified to represent a summer month with high west-to-east (eastbound) transfers across Midpoint West.

The WECC 2030 Light Summer base case was modified to represent a shoulder month condition with high east-to-west (westbound) transfers across Midpoint West.

5.0 Senior-Queued Interconnections

The Project has no senior-queued GI requests.

6.0 POI Facilities & Substation Network Upgrades

Listed below are the required transmission facilities to interconnect the Project at the POI.

The actual station layout and detailed equipment requirements will be determined in the Interconnection Facilities Restudy (RFS) should Interconnection Customer choose to move to that study phase of the GI process. Table 2 provides a summary of the facilities and conceptual costs required to interconnect the Project to the Transmission Provider's Transmission System.

Item of Work	Estimate
A yard expansion[1] and generation interconnection and protection package at the POI with two (2) new 230kV power circuit breakers and one (1) new line terminal at the Substation, associated switches, protective relays, 3-phase potential transformers (PTs) and 3-phase current transformers (CTs), SCADA and remote connectivity	$3,885,466
Contingency 30% (1)	$1,165,640
Total unloaded costs	**$5,051,106**
Overheads (2)	$202,044
Total Conceptual-level Cost Estimate (3)	**$5,253,150**
(1) Contingency is added to cover the unforeseen costs in the estimate. These costs can include unidentified design components, material cost increases, labor estimate shortfalls, etc. (2) Overhead costs cover the indirect costs associated with the Project and are subject to change. (3) This cost estimate includes direct equipment, material, labor, and overheads as shown.	

Table 2. Estimated GI #551 Project's POI Costs

Note the following regarding Table 2:

- These estimates do not include the cost of Interconnection Customer's equipment/facilities or required communication circuits for SCADA, PMU, Protection, and metering.

[1] The cost estimates for the land required for the station expansion will be Interconnection Customer's responsibility and are not included in the report.

- These costs assume the use of contracted resources.
- These are non-binding conceptual level cost estimates that will be further refined upon the request and completion of the RFS; final charges to Interconnection Customer will be based on the actual construction costs incurred.
- These costs include both Interconnection Facilities (direct assigned) and Substation Network Upgrades (reimbursable). These costs will be explicitly broken out in the RFS.

The schedule for designing, procuring, and constructing facilities will be developed and optimized during the RFS should Interconnection Customer choose to move to that study phase of the GI process.

7.0 System Network Upgrades & Contingent Facilities

Power flow solutions for all the N-1 and credible N-2 outage simulations revealed no violations requiring System Network Upgrades other than those already planned on IPC's Transmission System.

The following contingent Transmission Provider planned facilities are required:

Contingent Facility	Outage	Estimated In-Service
Build new 500/230kV Mayfield Station	[redacted]	2028
Build new 500kV Hemingway–Mayfield	[redacted]	2028
Build new 500kV Mayfield–Midpoint	[redacted]	2030

Table 3. Contingent Transmission Provider Planned Facilities

8.0 Battery Charging

The energy storage system (ESS) 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 ESS from the grid at full capacity; for example, a forced outage that would require IPC to curtail grid charging. Should the Project require non-curtailable grid charging, a firm Point-to-Point transmission service from the energy market/source to the battery would be required.

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

9.0 Voltage

A Voltage Stability study was performed using the WECC 2030 Heavy Summer case with Midpoint West west-to-east flows at 105% of the path rating and the WECC 2030 Light Summer case with Midpoint West east-to-west flows at 105% of the path rating. All contingencies solved successfully; there were no voltage stability issues found for the Project.

10.0 Transient Stability Analysis

The WECC 2030 Heavy Summer operating case and PowerWorld Simulator version 24 analysis tool were used to perform the transient stability analysis.

The results showed no transient stability violations. Per NERC Reliability Standards, the Generator Owner is responsible to ensure the modeling data utilized accurately reflects inverter operations, and to provide updates to IPC if testing or real-time observations indicate a need.

11.0 Description of Operating Requirements

The Project will be required to control voltage in accordance with a voltage schedule as provided by IPC's Load Serving Operations. The Project will be required to manage the real power output of their Generating Facilities at the POI. 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 Standard 2800, *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 will be required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 2800 or any subsequent standards as they may be updated from time to time.

Installation of phasor measurement unit devices at the POI and maintenance costs associated with communication circuits needed to stream PMU data will also be required to be provided to interconnect the Project. The specific costs associated with the IPC requirements for Interconnection Customers with aggregate facilities larger than 20 MW to provide PMU data to IPC will be identified in the RFS should Interconnection Customer choose to proceed to that phase of the GI process. Also, it may be beneficial for Interconnection Customer, for their own modeling compliance requirements, to install additional PMU devices at their facilities to monitor the generation sources separately.

12.0 Conclusion

Interconnection Facilities and Substation Network Upgrades detailed in Section 6.0 totaling $5,253,150 are required to interconnect the Project at the POI. Additional Contingent Facilities required by the Project are detailed in Section 7.0.

APPENDIX A

A-1.0 Method of Study

The power flow case for the System Impact Restudy is built using Western Electricity Coordinating Council (WECC) power flow cases as a Base Case in Power World Simulator. The Base Cases are then modified to include the senior-queued generation Interconnection Requests identified in Section 5.0 and their respective Network Upgrades and Interconnection Facilities. The Interconnection Request being studied is then added to the cases with the model provided by the Interconnection Customer at the requested MW injection at the agreed-upon POI. The Base Cases are then rebalanced such that the applicable WECC transmission paths are at their WECC path rating with reasonable pre-contingency energy transfers utilizing the Idaho Power Transmission System. The power flow model is then analyzed using P1, P2, and P7 category contingencies contained in Table 1 of NERC standard TPL-001. WECC and Idaho Power reliability criteria are applied to the results of the contingency analysis and any violations are mitigated with Network Upgrades or Contingent Facilities.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

- The continuous rating (P-0) of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.
- Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. These state, in part, that distribution voltages under normal operating conditions are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.
- Voltage flicker while starting or stopping the generator is limited to 5% as measured at the POI, per Idaho Power's T&D Advisory Information Manual.
- Idaho Power's Reliability Criteria for System Planning was used to determine proper Transmission System operation.
- All customer generation must meet IEEE 519 and ANSI C84.1 Standards.
- All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.
- The stable operation of the system requires an adequate supply of volt-amperes reactive (VAr or VArs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VArs will result in voltage decay or even collapse under the worst conditions.
- Equipment, line, or Path ratings used will be those that are in use at the time of the study or that are represented by Idaho Power upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

A-3.0 Grounding Guidance

IPC requires interconnected transformers on the distribution system to limit their ground fault current to 20 amps at the POI.

A-4.0 Electrical System Protection Guidance

IPC requires electrical system protection per Facility Connection Requirements found on the Idaho Power website,

https://docs.idahopower.com/pdfs/BusinessToBusiness/FacConnReq.pdf

A-5.0 WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements

IPC requires frequency operational limits to adhere to WECC Under-frequency and Over-frequency Limits per the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Requirements available upon request.

Revision History

Date	Revision	Initials	Summary of Changes
09/08/2025	1.0	SWL	Restudy report issued.