

**GENERATOR INTERCONNECTION
SYSTEM IMPACT STUDY REPORT**

for integration of the proposed

500 MW [REDACTED] PROJECT

(GI PROJECT #674)

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

in

ADA COUNTY, ID

for

**[REDACTED]
Report v1.0**

May 8, 2023

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Introduction

██████ has contracted with Idaho Power Company (“Transmission Provider”) to perform a Generator Interconnection System Impact Study (SIS) for the integration of the proposed 500 MW ██████ (the Project) at a single Point of Interconnection (POI) at 230 kV at Idaho Power’s Hubbard. The Project is located in Ada County, ID at approximately ██████. The project is assigned Generation Interconnect (GI) queue number 674 (GI #674). The Project has chosen in the System Impact Study to be studied for Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

This report documents the basis for and the results of this System Impact Study for the GI #674 Generation Interconnection Customer. The report describes the study assumptions, the proposed Project, the determination of the Project interconnection requirements, and estimated costs for integration of the Project to the Transmission Provider transmission system. This report satisfies the SIS requirements of the Idaho Power Tariff.

1.0 Study Assumptions

- For ERIS, the Interconnection Customer’s ability to inject its Large Generating Facility output beyond the Point of Interconnection will depend on the existing capacity of Transmission Provider’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.
- 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 outside Transmission Provider’s Transmission System, such request may require additional studies and upgrades in order for the Transmission Provider to grant such request.
- Senior-queued generator interconnection requests that were considered in this study are listed in Section 5.0. If any of these requests are withdrawn, the Transmission Provider reserves the right to restudy this request, and the results and conclusions could significantly change.
- 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. However, Idaho Power’s balancing authority area has proposed generation in the interconnection queue that far surpasses projected load. To reliably balance the power flow case, it is necessary to assume some portions of other resources are displaced by this Project’s output in order to assess the impact of interconnecting this Project’s generation and that some generation is being transferred regionally through the transmission system.

- The Most Severe Single Contingency (MSSC) is the balancing contingency event, due to a single contingency, that results in the greatest loss (measured in MW) of resource output used by the Balancing Authority at the time of the event to meet firm system load and export obligation. Idaho Power’s MSSC is [REDACTED] MW. An NRIS interconnection request greater than [REDACTED] MW must mitigate single contingencies that would result in the loss of more than [REDACTED] MW. This includes, but is not limited to, single contingencies in [REDACTED] Interconnection Facilities.
- Idaho Power will not mitigate thermal violations with remedial action schemes (RAS) in the generation interconnection process.
- The following Transmission Provider planned system improvements were assumed in service:
 - Boardman to Hemingway 500 kV transmission line (Q2 2026)
 - 50% series capacitance compensation on the Kinport to Midpoint 345 kV transmission line (2025)
 - Midpoint Substation transformer T502 500:345 kV transformer (2025)
 - Hemingway to Bowmont 230 kV transmission line (2025)
 - Bowmont to Hubbard 230 kV transmission line (2025)
 - Midpoint to Hemingway #2 500 kV transmission line (2028)

2.0 Description of Proposed Generating Project

The primary POI for the Project is Hubbard 230 kV with a maximum injection of 500 MW. The Project’s Commercial Operation Date (COD) is [REDACTED].

Project Location	[REDACTED]
Generator Nameplate Rating	[REDACTED]
Total Output Power Rating	[REDACTED]
Number and Type of Inverters	[REDACTED]
Main Power Transformer	[REDACTED]

Table 1. GI #674 Project Specifications

3.0 Protection and Control

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

For 230 kV line protection, the Transmission Provider’s System Protection Department utilizes permissive and line differential protection schemes integrated with digital communication infrastructure. Communication infrastructure between the interconnection’s customer’s 230 kV collector substation and Idaho Power will be the responsibility of the interconnection customer.

The proposed 230 kV [REDACTED] transformer specified in the Project 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 a heavy west to east power flow conditions to determine the required Network Transmission Upgrades.

The WECC 2025 Heavy Summer base case was modified to represent a summer month with high west to east (eastbound) transfers across Idaho Northwest.

The WECC 2022 Light Winter base case was modified to represent a shoulder month condition with high east to west (westbound) transfers across Idaho Northwest.

5.0 Senior-Queued Interconnections

Idaho Power generation interconnection projects GI #530, GI #551, GI #557, GI #567, GI #588, GI #590, GI #604, GI #605, GI #619, GI #621, GI #629, GI #634, GI #636, GI #638, GI #639, GI #640, GI #643, GI #646, GI #649, GI #650, GI #663, GI #665, GI #666, and GI #669 are senior-queued projects in the affected area of Idaho Power's transmission system. Idaho Power studied GI #674 with all Network Upgrades for the identified senior-queued projects as in-service.

Changes to senior-queued projects, including in-service date and withdrawal from the queue, may trigger a restudy associated with GI #674.

6.0 POI Facilities

Due to physical limitations at the Hubbard 230kV substation, it has been determined that it is not feasible to interconnect the project to the proposed POI. Once a new POI has been identified and selected, interconnection facilities and costs can be identified.

7.0 System Upgrades

Preliminary system upgrades were identified using the proposed POI of the Hubbard 230kV substation. When an alternate POI has been identified, a restudy of these upgrades will be required, and additional or different upgrades may be identified for interconnection.

Studies discovered the following overloads in the WECC 2022 Light Winter base case with high East to West flows on the Idaho Northwest path.

Designation	Contingency	Violation
NRIS	Loss of the [REDACTED] 230kV and [REDACTED] 230kV lines	Thermal overload of the [REDACTED] 230kV line
NRIS	Loss of the [REDACTED] 230kV line	Thermal overload of the [REDACTED] 230kV line
NRIS	Loss of the [REDACTED] 230kV line	Thermal overload of the [REDACTED] 230kV line

Table 3. Contingency Violations

The following are preliminary Network Upgrades assigned to GI #674 to mitigate the violations outlined in Table 3 (at the currently proposed POI).

Because of the infeasibility of the proposed POI, no cost estimates have been provided.

Item of Work	Estimate
Reconductor [REDACTED] 230kV line with [REDACTED] miles of [REDACTED] conductor	N/A
Reposition the landing of the [REDACTED] 230kV line at Hubbard	N/A

Table 4. Estimated GI #674 Network Upgrade Costs

In addition to the network upgrades identified above, the following contingent facilities are also required. Again, due to the infeasibility of the proposed POI, many of these contingency facilities are expected to change when an alternate POI is identified.

Designation	Contingent Facility	Estimate	Estimated In-Service
ERIS & NRIS	Adjacent bay (breakers, switches, controls) of [REDACTED] 230kV lines, and [REDACTED] 230kV bus reconfigure for GI #646	\$7,865,705	GI #646 (TBD)
NRIS	Adjacent bay (breakers, switches, controls) of [REDACTED] 230kV line for GI #650	\$1,120,979	GI #650 (TBD)
NRIS	Adjacent bay (breakers, switches, controls) of [REDACTED] 230kV line for GI #665	\$330,600	GI #665 (TBD)

Table 5. GI #674 Contingent Facilities

8.0 Voltage

A Voltage Stability study was performed using the WECC 2022 Light Winter case with Idaho Power network load scaled to 105%. All contingencies solved successfully, there were no voltage stability issues found for the Project.

The Project will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. The Project will be required to manage the real power output of their generation project at the POI. Also, it may be beneficial for [REDACTED], for their own

modeling compliance requirements, to install additional PMU devices at their facilities to monitor the generation source

9.0 Transient Stability Analysis

The WECC 2022 Light Winter operating case and PowerWorld Simulator version 23 analysis tool were used to perform the transient stability analysis.

The results showed no transient stability violations. It is the responsibility (per NERC Standards) of the Generator Owner to ensure the modeling data utilized accurately reflects inverter operations, and to provide updates to Idaho Power if testing or real-time observations indicate a need.

10.0 Description of Operating Requirements

GI #674 will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. The Project will be required to manage the real power output of their generation project at the POI. The Project will be required to operate at 0.95 leading/lagging measured at the high side of the main power transformer to maintain voltage within limits at the POI over the range of real power output.

The Project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*.

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 Facilities Study should the generation interconnection customer choose to proceed to that phase of the interconnection process. Also, it may be beneficial for [REDACTED], for their own modeling compliance requirements, to install additional PMU devices at their facilities to monitor the generations sources separately.

11.0 Conclusion

Due to physical limitations, the Project is unable to interconnect at the proposed Point of Interconnection of the Hubbard 230kV substation. Because of this, interconnection requirements have not been identified. Prospective upgrades and contingent facilities were identified for interconnection of the Project at the proposed POI, and are detailed in Section 7.0, but no cost estimates have been provided.

An alternative Point of Interconnection will need to be identified, and a subsequent restudy of the Project at the new POI will need to be performed in order to identify interconnection requirements, network upgrades, and contingent facilities that will permit the Project to connect for Energy and Network Resource Interconnection Service.

APPENDIX A

A-1.0 Method of Study

The power flow case for the System Impact study 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 projects in Section 5.0 and their respective network upgrades and POI facilities. The generation project being studied is then added to the cases with the model provided by [REDACTED] at the requested 500 MW at the requested 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 and P2 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 listed in Table 3, are mitigated with Network Upgrades or contingent facilities, (see also Section 7.0).

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 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 during starting or stopping the generator is limited to 5% as measured at the point of interconnection, 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/path ratings used will be those that are in use at the time of the study or that are represented by IPC 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 Point of Interconnection.

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.

A-6.0 Storing Energy

The energy storage system (ESS) component of the Project was studied charging from the grid in steady state under N-0 (no contingencies) conditions. The charging of the ESS was assumed to be interruptible. No network upgrades were identified to support charging the ESS. There may be times during the year where system load in the local area will prevent charging of the ESS at full capacity; for example, a forced outage that would require Idaho Power to curtail charging. Should the Project require non-curtailable charging from their energy source then Point-to-Point firm transmission service from the energy market to the battery and from the Project to the point of delivery would be needed.

Revision History

Date	Revision	Initials	Summary of Changes
05/08/23	1.0	CHH	Initial report