GENERATOR INTERCONNECTION

SYSTEM IMPACT STUDY REPORT

for integration of the proposed

23 MW [redacted]

IPC PROJECT QUEUE #536

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

for

[redacted]

REPORT v.0

April, 2019

Revision History

Date	Revision	Initials	Summary of Changes
4/10/2019	0	AV	SISR GI #536 – Original issue.

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1.0 Introduction

[redacted] has contracted with Idaho Power Company (IPC) to perform a Generator Interconnection System Impact Study for the integration of the proposed 23 MW [redacted](the Project). The Project is located in IPC's Western Region along [redacted] in Malheur County, Oregon (See Figure 1: Location of [redacted] – GI # 536 in Appendix B). The Project is Generation Interconnect (GI) queue number 536 (GI #536).

The Project has applied to connect to the IPC transmission system for an injection of 23 MW at a single Point of Interconnection (POI) at a 69-kV voltage. The POI is located at [redacted]. The POI is on IPC's Hope Junction (HPJN) – Harper Junction (HRPJ) 69-kV line approximately [redacted] from the VALE station.

This report documents the basis for and the results of this System Impact Study for the GI #536 Generation Interconnection Customer. The report describes the proposed project, the determination of project interconnection impact and estimated costs for integration of the Project to the Idaho Power System. This report satisfies the System Impact Study requirements of the Idaho Power Tariff.

2.0 Summary

The system impact of interconnecting the 23 MW [redacted] to IPC's HPJN - HRPJ 69-kV line was evaluated.

The Project will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. Therefore, GI #536 will be required to install a plant controller for managing the real and reactive power output of the 23 MW inverter array at the project POI.

Generator interconnection service, either as an Energy Resource or a Network Resource, does not in any way convey any right to deliver electricity to any specific customer or point of delivery.

The total preliminary cost estimate to interconnect the [redacted] to the IPC's HPJN - HRPJ 69-kV line is $18,734,824, and includes the following tasks:

- Transmission upgrades
  - Move approximately 2 miles of the Willis Tap – Caldwell 138 kV line from the shared Langley – Caldwell 230 kV structures near Caldwell. Utilize the old Caldwell – Lansing 69 kV right of way of the re-located line.
- Subtransmission upgrades
  - Rebuild approximately 8.4 miles of the Vale – Sage 69 kV line using [redacted] (or equivalent) conductor.

- Rebuild approximately 12.8 miles of the Vale – Malheur Bute 69 kV line using [redacted](or equivalent) conductor.
    - Rebuild approximately 5.5 miles of the Malheur Bute – Ontario 69 kV line using [redacted](or equivalent) conductor.
    - Rebuild approximately 4.3 miles of the Nyssa – Apple Valley Junction 69 kV line using [redacted](or equivalent) conductor
    - Upgrade 69-kV voltage regulator at VALE substation
- Substation upgrades
    - Yard preparation of fenced yard
    - Prefab control building with AC and DC systems installed
    - Conduits and yard cables run between all yard apparatus/equipment and the control building
    - 69-kV circuit breaker with disconnects
    - Instrumentation transformers for protective relaying and metering
    - Interconnect package
        - SEL 421/411L Protective relaying panels with PMU capability
        - SEL 2506 mirror bit boxes with fiber communications
        - Interconnect metering
- SCADA.

The cost estimate includes direct equipment and installation labor costs, indirect labor costs and general overheads, and a contingency allowance. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred. It should be noted that the preliminary cost estimate of $18,734,824 does not include the cost of the customer's owned equipment to construct the solar generation site or required communication circuits.

3.0 Scope of Interconnection Transmission System Impact Study

The Interconnection Transmission System Impact Study was completed, in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide an evaluation of the system impacts of the interconnection of the proposed generating project to the Idaho Power system. As listed in the Interconnection Transmission System Impact Study agreement, the Interconnection Transmission System Impact Study report provides the following information:

- identification of additional transformer load tap changer operations, voltage fluctuations (flicker) and additional feeder losses.
- identification of required reactive power support.
- identification of islanding conditions.
- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection.

- identification of any thermal overload or voltage limit violations resulting from the interconnection.
- identification of any angular instability.
- description and non-binding estimated cost of facilities required to interconnect the Small Generating Facility to the IPC System and to address the identified short circuit and power flow issues.

All other proposed generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found in the Generation Interconnection folder located on the Idaho Power web site at the link shown below:

http://www.oatioasis.com/ipco/index.html.

4.0 Description of Proposed Generating Project

[redacted], GI #536, consists of a single 23 MW photovoltaic solar plant which requested to be connected to Idaho Power's HPJN - HRPJ 69-kV line. The Project will need to install a plant controller for managing the real and reactive power output. The supplied single line drawing shows the project using [redacted] inverters. Thirteen groups of twenty inverters will be connected to 2.0 MVA transformers to step-up the voltage from 800 V to 34.5 kV. The thirteen transformers will be connected to the GSU 34.5 kV / 69kV transformer with an 18 / 24 / 30 MVA capacity.

Idaho Power does not [redacted]inverters to be connected to the distribution or transmission system. The project will need to propose a different inverter if it chooses to move to the next stage of the interconnection process.

5.0 Description of Transmission Facilities

The Project's impact on the Brownlee East transmission path (WECC Path #55) was evaluated in this Transmission System Impact Study. In addition, the Idaho-Northwest transmission path (WECC Path #14) which is in series with the Brownlee East transmission path was studied at its rated West-to-East transfer capacity.

The Idaho-Northwest transmission path (WECC Path #14) is defined as the sum of the flows on the following five lines:

- Oxbow-Lolo 230kV
- Hells Canyon-Hurricane 230kV
- North Powder-La Grande 230kV
- Hines-Harney 115kV
- Hemingway-Summer Lake 500kV

The Brownlee East transmission path (WECC Path #55) is defined as the sum of the flows on the following seven lines:

- Brownlee-Boise Bench #1 230kV
- Brownlee-Boise Bench #2 230kV
- Brownlee-Boise Bench #3 230kV
- Brownlee-Horse Flat #4 230kV
- Brownlee-Ontario 230kV
- Oxbow-Starkey 138kV
- Quartz-Ontario 138kV

For this generation interconnection Transmission System Impact Study, the flow on the Path 14 Idaho-Northwest transmission path was modeled at [redacted] MW West-to-East and the Brownlee East transmission path was modeled at [redacted]MW West-to-East. The paths were stressed to these specific levels in order to determine if the addition of the Project's 23 MW degraded the existing Brownlee East path's transfer capability.

6.0 Description of Power Flow Case

This study utilized the WECC approved 19hs3a1 Heavy Summer operating case as the starting point of the studies. Two power flow cases were developed:

- The "Base Case" with projects earlier in the queue added, but not the Project.
- The "Second Case" with projects earlier in the queue and the Project added.

The pre-contingency flows across the Idaho-Northwest and the Brownlee East paths/cut-planes were modeled at their respective ratings (see Section 5.0). Flow in each path is modeled in this manner in order to capture the potential impact of the Project on the existing capabilities of the surrounding paths and the interconnected transmission systems. Performing the studies at these levels will ensure that the Total Transfer Capability of the adjacent paths are not impacted by the Project.

In addition to the 19hs3a Heavy Summer operating case, a light-load operating case was developed for the IPC 69 kV sub-transmission system. The limits used for this analysis are as follows:

1. Voltage magnitude during normal operating steady-state must remain between 0.93 per unit and 1.05 per unit. If the post-transient voltage deviates from this range during N-1 conditions and an operating procedure can be taken to return the voltage to the required range without creating a four-terminal line, then network upgrades are not required.
2. Line loading must be less than 100% of line rating during normal steady-state operation. Steady-state line loading above 100% requires network upgrades.

3. Post-transient line overloading that does not exceed the emergency line rating resulting from an N-1 contingency is acceptable if an operating procedure can be taken to reduce the line loading below 100% without creating a four-terminal line.

Post-transient line loading above the emergency line rating resulting from an N-1 contingency requires network upgrades.

7.0 Power Flow Analysis Study Results

Results from the stressed Heavy summer operating case indicate the addition of the GI #536 project will result in contingency violations that would impact the Total Transfer Capability of the adjacent Path 55 Brownlee East transmission path. Five contingencies resulted in critical (Exceeded emergency rating) post-transient contingency violations.

1. [redacted]
   a. This contingency results in a post-transient overload violating the emergency rating of the Nyssa – Apply Valley Junction 69kV line, which requires network upgrades.
2. [redacted]
   a. This contingency results in a post-transient overload violating the emergency rating of the Nyssa – Apply Valley Junction 69kV line, which requires network upgrades.
3. [redacted]
   a. This contingency results in a post-transient overload violating the emergency rating of the Nyssa – Apply Valley Junction 69kV line, which requires network upgrades.
4. [redacted]
   a. This contingency results in a post-transient overload violating the emergency rating of the Nyssa – Apply Valley Junction 69kV line, which requires network upgrades.
5. [redacted]
   a. This contingency results in a post-transient overload violating the emergency rating of the Brownlee – Boise Bench #1 & #2 230kV lines, which requires network upgrades.
   b. This contingency results in a post-transient overload violating the emergency rating of the Emmett – Spring Valley Tap 138kV line, which requires network upgrades.
   c. This contingency results in a post-transient overload violating the emergency rating of the Spring Valley Tap – Hidden Springs 138kV line, which requires network upgrades.

Results from the light load spring operating case indicate the addition of the GI #536 project will result in contingency violations that would impact the 69-kV system. Two contingencies resulted in critical (Exceeded emergency rating) post-transient contingency violations.

i. [redacted]
   a. This contingency results in a post-transient overload violating the emergency rating of the Vale – Malheur Bute - Ontario 69 kV line, which requires network upgrades.

ii. [redacted]
   a. This contingency results in a post-transient overload violating the emergency rating of the Vale – Sage 69 kV line, which requires network upgrades

8.0 Description of Substation Facilities

The HPJN – HRPJ line is radially fed by IPC's 69/12.5 kV VALE substation in Malheur County, Oregon.

9.0 Description of Distribution Facilities

No distribution facilities are affected by the Project.

10.0 Short Circuit Study Results

The Project must be a source of ground current for line relaying. This is typically achieved through the proper selection of transformer configurations. For example, an autobank with a delta tertiary is a source of ground current, (other configurations can and do exist).

The fault duty at the approximate POI (with no Project modeling) is as follows.

Single-Line-to-Ground Fault Duty = [redacted] A

Line-to-Line Fault Duty = [redacted] A

Three-Phase Fault Duty = [redacted]A

The sequence network reductions at the point of interconnection are as follows.

Positive Sequence: [redacted]

Negative Sequence: [redacted]

Zero Sequence: [redacted]

11.0 Description of Required Facility Upgrades

The following upgrades will be required to IPC-owned facilities to facilitate the interconnection of GI #536:

- Transmission upgrades
    - Move approximately 2 miles of the Willis Tap – Caldwell 138 kV line from the shared Langley – Caldwell 230 kV structures near Caldwell. Utilize the old Caldwell – Lansing 69 kV right of way of the re-located line.
- Subtransmission upgrades
    - Rebuild approximately 8.4 miles of the Vale – Sage 69 kV line using [redacted] (or equivalent) conductor.
    - Rebuild approximately 12.8 miles of the Vale – Malheur Bute 69 kV line using [redacted] (or equivalent) conductor.
    - Rebuild approximately 5.5 miles of the Malheur Bute – Ontario 69 kV line using [redacted] (or equivalent) conductor.
    - Rebuild approximately 4.3 miles of the Nyssa – Apple Valley Junction 69 kV line using [redacted] (or equivalent) conductor.
    - Upgrade 69-kV voltage regulator at VALE substation
- Substation upgrades
    - Yard preparation of fenced yard
    - Prefab control building with AC and DC systems installed
    - Conduits and yard cables run between all yard apparatus/equipment and the control building
    - 69-kV circuit breaker with disconnects
    - Instrumentation transformers for protective relaying and metering
    - Interconnect package
        - SEL 421/411L Protective relaying panels with PMU capability
        - SEL 2506 mirror bit boxes with fiber communications
        - Interconnect metering
- SCADA.

See the conceptual-level cost estimate in Table 1.

Table 1 Conceptual-level Cost Estimate for GI #536

Item of Work	Estimate
Generation interconnection and protection package	$1,484,800
Substation upgrades	$92,800

Transmission upgrades	$12,533,800
Unloaded costs	$14,111,400
Contingency 20% (1)	$2,822,280
Total unloaded costs	$16,933,680
Overheads (2)	$1,801,144
Total loaded costs	$18,734,824
Total Conceptual-level Cost Estimate in 2019 dollars (3)	**$18,734,824**

(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.

(3) This cost estimate includes direct equipment, material, labor, overheads, and contingency as shown.

- Note that these estimates do not include the cost of:
  - The customer's equipment/facilities.
  - The land needed for the interconnection yard. This land will be IPC owned but is the responsibility of the interconnection customer to permit and purchase.
  - The cost of the dedicated communications circuits required.
    - Interconnection Customer to provide one dedicated 64 kilo-bit per second DDS leased line communications circuit between the POI and IPC Boise Bench substation for PMU data.
    - Interconnection Customer to provide one dedicated 64 kilo-bit per second DDS leased line communications circuit between the POI and IPC Boise Bench substation for SCADA data.
    - Interconnect Customer to provide one POTS (Plain Old Telephone Service) dial-up circuit for querying the revenue meter at the generation interconnection site. The dial-up circuit should be of sufficient quality to accommodate a dial-up modem connection.

- Any 69 kV connection between the Project and the POI including the line termination apparatus. These facilities will be constructed, owned and operated by the Interconnection Customer.

- The overhead rates are subject to change during the year and tax gross-up percentages vary from year to year.
- These are estimated costs only and final charges to the customer will be based on the actual construction costs incurred, including overheads and tax gross-up.

- These are non-binding conceptual level cost estimates that will be further refined upon the request and completion of Transmission and Distribution Facility Studies.

Cost estimates include direct equipment and installation labor costs, indirect labor costs and general overheads, and a contingency allowance. These are preliminary cost estimates only and final charges to the customer will be based on the actual construction costs incurred

12.0 Description of Operating Requirements

The Project shall be capable of injecting reactive power (over-excited) and absorbing reactive power (under-excited) equal to 44% of its rated capacity at all active power output between 20% and 100%.

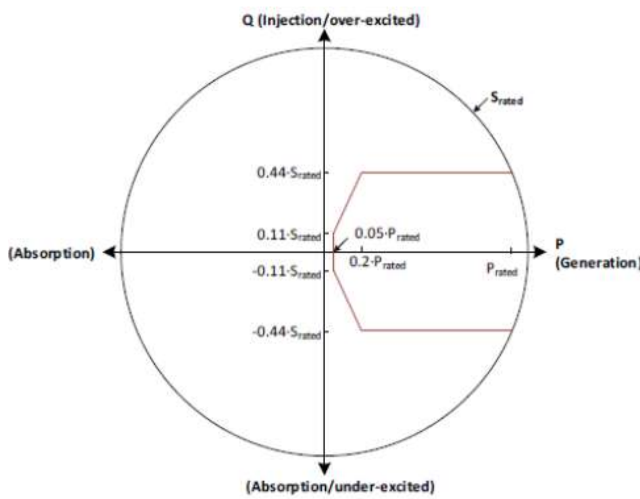

Figure 1 Operating requirements

The inverter(s) will be required to have the UL 1741SA certification prior to the installation and be approved by Idaho Power cybersecurity group.

The Project will be required to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. Therefore, GI #536 will be required to install a plant controller for managing the real and reactive power output of the 23 MW inverter system at the project POI.

Voltage flicker at startup and during operation will be limited to less than 5% as measured at the POI. The allowable voltage flicker limit is further reduced during operation due to multiple voltage fluctuations per hour or minute, per Idaho Power's T&D Advisory Information Manual.

The Project is required to comply with the applicable voltage fluctuation limits found in IEEE Standard 1453-2004 *IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems.*

The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-2014 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*.

Additional operating requirements for the Project may be identified in the System Impact Study when it is performed.

13.0 Conclusion

The requested interconnection of the [redacted], GI #536, to Idaho Power's system was studied for impact to the IPC electrical transmission and distribution system.

The results of this study list the modifications and networks upgrades required to interconnect the [redacted], GI #536, to the existing Idaho Power system. The proposed inverter does not meet Idaho Power criteria and will have to be replaced by an inverter that meets all of Idaho Power requirements.

All generation projects in the area ahead of the Project in the IPC generation interconnection queue and their associated transmission system improvements were modeled in a preliminary power flow analysis to evaluate the feasibility of interconnecting GI #536. The results and conclusions of this System Impact Study are based on the realization of these projects in the unique queue/project order.

The estimated cost to interconnect GI #536 to the IPC system at the 69-kV point of interconnection considered in this study is approximately $18,734,824.

Generator interconnection service, either as an Energy Resource or a Network Resource, does not in any way convey any right to deliver electricity to any specific customer or point of delivery. Transmission requirements to integrate the Project will be determined during the System Impact Study phase of the generator interconnection process.

APPENDIX A

A-1.0 Method of Study

The Transmission System Impact Study plan inserts the Project up to the maximum requested injection into the selected Western Electricity Coordinating Council (WECC) power flow case and then, using Power World Simulator or GE's Positive Sequence Load Flow (PSLF) analysis tool, examines the impacts of the new resource on Idaho Power's transmission system (lines, transformers, etc.) within the study area under various operating and outage scenarios. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. The WECC case is a recent case modified to simulate stressed but reasonable pre-contingency energy transfers utilizing the IPC system. For distribution feeder analysis, Idaho Power utilizes DNV·GL's Synergi Electric software and EPRI's OpenDSS software.

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. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal at each meter or POI 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 the starting or stopping of the generator will be limited to less than 5% as measured at the POI. Allowable voltage flicker limit is further reduced during operation due to multiple voltage fluctuations per hour or minute, 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, IEEE1453, IEEE1547, 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 (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 Requirements for Generation Interconnections found on the Idaho Power Web site,

http://www.idahopower.com/pdfs/BusinessToBusiness/facilityRequirements.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.

APPENDIX B

B-1.0 [redacted] GI Project #536 Site Location

[redacted]