FINAL
Generator Interconnection
Facility Study Report

for the

[redacted] Project #570

for

[redacted]

in

[redacted] and [redacted] Counties, Idaho

1/14/2022

FINAL FACILITY STUDY REPORT (FSR)

[redacted] 500kV 1050 MW

Project GI #570

1/14/2022

1. General Facility Description

[redacted] (Interconnection Customer) has stated that the proposed project will consist of a wind generation and Battery Energy Storage System (BESS) project with a total output of 1050 MW in [redacted] and [redacted] Counties, Idaho. The project will connect to the 500kV system on Idaho Power Company (IPC)'s Midpoint (MPSN) Transmission Station 500kV bus. All capitalized terms in this report, if not defined herein, are defined in IPC's Open Access Transmission Tariff (OATT).

Contact Information for Interconnection Customer is as follows:

[redacted]

A Large Generator Interconnection Agreement (the "LGIA") under IPC's Open Access Transmission Tariff (OATT) between Interconnection Customer and IPC (Transmission Provider) for the [redacted] Project, specifically Generator Interconnection Project # 570 ("Project"), will be prepared for this project. The LGIA will be a definitive agreement that contains terms and conditions that supersedes this FSR.

Project Queue and Affected Systems:

If an earlier queue project that is responsible for providing additional sub-transmission capacity should drop out of the queue, a later queue project that may have been relying on at least a portion of any "surplus" capacity may then be faced with additional project costs for sub-transmission capacity additions of their own. As of the date of this report, there is a project in the queue (GI 530) ahead of [redacted] for which costs related to sub-transmission capacity upgrades or additions could be passed on to [redacted] should changes be made to their queue position or generation output. Details for GI 530 upgrades and alternative upgrade options can be found in Appendix B.

The recommended upgrades for GI number 530 were assumed to be completed prior to the interconnection of the Project. For this and other reasons, the cost estimates included in this FSR are estimates only, are based on currently known or assumed facts that may not be accurate or materialize and are subject to change.

1.1 Point of Interconnection

The Point of Interconnection ("POI") for the Project will be the node on the 500kV bus between air-break switches [redacted] and [redacted]. A drawing identifying the POI is attached as Exhibit 1.

1.2 Point of Change of Ownership

The Point of Change of Ownership for the Project will be on the dead-end structure of IPC's Interconnection Facilities on the Interconnection Customer's side of air-break switch [redacted], as shown in Exhibit 1. The Interconnection Customer is responsible for the material (hardware, insulators, fittings and conductor) and installation to connect to the IPC dead-end structure and the jumpers down to the line side of air-break switch [redacted].

1.3 Interconnection Customer's Facilities

1.3.1 Interconnection Customer's Interconnection Facilities

The Interconnection Customer's Interconnection Facilities are located approximately [redacted] miles from IPC's Interconnection Facilities. The Interconnection Customer will install, at its expense, air-break switches, transformers, breakers, CTs, appropriate grounding measures, and associated auxiliary equipment. The step-up transformers will be 383/510/637 MVA, 3 phase, 500/230kV units (Z=7%). The Project single line does not indicate the winding configuration on the 500kV side of the 500/230kV transformers. Idaho Power requires a wye grounded connection on the high side and delta included in the transformer to create a solid ground path for the transmission system. This can be achieved with autotransformers with a delta tertiary which is a source of ground current, other configurations can and do exist. Interconnection Customer will build the transmission line and required facilities to the Point of Change of Ownership including redundant communication circuits from the Interconnection Customer's Interconnection Facilities to IPC's Interconnection Facilities. Dual fiber optic communication circuits were estimated as part of this study.

To coordinate relaying protection between the Interconnection Customer's Interconnection Facilities and IPC's Interconnection Facilities the Interconnection Customer will need to install redundant [redacted] relays.

1.3.2 Interconnection Customer's Generating Facilities

The Interconnection Customer's generation system consists of five collector systems and will be constructed as follows:

a. 230kV transmission lines and five collector stations with 230/34.5kV transformers ranging from 225 MVA to 285 MVA. Five 103 MW BESS's (108.8 MVA with a power factor of 0.95) will be connected to the 34.5kV bus of the five collector stations.
b. 363 [redacted] wind turbines – 3.189/3.03 MVA/MW with a power factor of 0.95.
c. Total generation output limited to 1050 MW at the POI.

The above referenced equipment, or equivalent that have the same specifications and functionality as stated above must be utilized. If different equipment is utilized that has different specifications and functionality than that which was studied, then additional study and/or equipment may be necessary.

The Project is a combined wind and BESS generation project. It has been assumed the BESS will be charged via the wind output. [redacted] will need to demonstrate the operating procedures and control measures which prevents the BESS from being charged via IPC's transmission system. However, if the intent is also to be able to charge the BESS via

IPC's transmission system, [redacted] will need to make an IPC Large Load Service request.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Telecommunications

The Interconnection Customer is not responsible to provide third party telecommunication circuits for IPC's use.

1.4.2 Ground Fault Equipment

The Interconnection Customer will install transformer configurations that will provide a ground source to the transmission system.

1.4.3 Generator Output Limit Control

The Interconnection Customer will install equipment to receive signals from IPC Grid Operations for Generation Output Limit Control ("GOLC") - see Section 3 Operating Requirements and Appendix A. IPC's recommended method of communication for GOLC is via fiber between IPC's Interconnection Facility and the Project. Redundant digital communication is required.

1.4.4 Local Service

The Interconnection Customer is responsible to arrange for local service to their site, as necessary.

1.4.5 Property

The Interconnection Facilities and Substation Network Upgrades to be installed at IPC's Midpoint Transmission Station will require the existing yard to be expanded. Costs associated with any required land purchase are the responsibility of the Interconnection Customer and fall under Network Upgrade costs. The Interconnection Customer, at its expense, will provide to IPC documents and services as identified below:

Land transaction documents ("Land Transaction Documents") in a form approved by IPC that may include, but are not limited to, the following:

- Easements for transmission power lines;
- Crossing Agreements; and
- Any other Project specific documents deemed necessary by IPC.

Interconnection Customer is advised that IPC review and approval of the Land Transaction Documents may require six to nine months. Interconnection Customer is advised to provide all required Land Transaction Documents at earliest possible time. All recording and mailing fees shall be paid by Interconnection Customer. IPC shall provide to Interconnection Customer electronic copies of all fully executed and recorded Land Transaction documents.

1.4.6 Site Work

The Interconnection Customer is not responsible for site work for any IPC facilities.

1.4.7 Monitoring Information

If the Interconnection Customer requires the ability to monitor information related to the IPC breaker/relay (i.e. Mirrored Bits) of IPC's Interconnection Facilities, they are required to supply their own communications. The fiber communication circuit used for GOLC is acceptable.

1.4.8 Meteorological Data

In order to integrate the wind energy into the IPC system, the Interconnection Customer will provide weather data to IPC from the proposed Project site or from a location within two miles of the Project site consisting of the following near real-time weather parameters that will be collected via each meteorological observation tower at 10 m & 80 m above ground:

Wind Speed (miles/seconds)
Wind Direction
Air Temperature (degrees Centigrade)
Relative Humidity
Barometric Pressure

This data shall be provided to IPC hourly via commonly accepted electronic web service standards or similar communication method. Specific meteorological data must also be sent via the fiber communication circuit as identified in Appendix A. The Interconnection Customer will provide relevant historical meteorological data to IPC. Additionally, the Interconnection Customer shall submit to IPC the physical and technical specifications for all meteorological measurement devices, geographic locations, and technical specifications of all turbines. The associated cost for obtaining this data is the Interconnection Customer's responsibility and therefore not included in the Facility Study estimate.

1.4.9 Generator Technical Information & Drawings

Interconnection Customer shall provide draft design prints during FSR development containing technical information, like impedances, and equipment brand and models. After construction, the Interconnection Customer shall submit to IPC all the as-built information, including prints with the latest approved technical information and commissioning test results.

1.5 Transmission Provider's Interconnection Facilities

Transmission Provider's Interconnection Facilities are referred to hereafter as "IPC's Interconnection Facilities." IPC's Interconnection Facilities are in IPC's Southern region in IPC's Midpoint (MPSN) Transmission Station. IPC's Interconnection Facilities will be installed by IPC.

IPC's Interconnection Facilities will include a dead-end structure, a 500kV air-break switch, CTs, a revenue meter, associated protection/control/communications equipment and required foundations, structures, bus, grounding, conduit, and conductor for such equipment. IPC's Interconnection Facilities will be located in IPC's MPSN Station yard up to the Point of Change of Ownership. IPC will remove an existing 500kV air-break switch and some bus to accommodate the new line terminal.

To coordinate relaying protection between the Interconnection Customer's Interconnection Facilities and IPC's Interconnection Facilities the Interconnection Customer will need to install redundant [redacted] relays.

To meet North American Electric Reliability Corporation's (NERC's) MOD-11 and 13-WECC-CRT-1, R1.2 requirements, IPC will install equipment to collect and transmit Phasor

Measurement Unit (PMU) data to IPC. The data can be made available to the Interconnection Customer on request.

The minimum acceptable PMU message rate is 30 samples per second. The minimum set of PMU measurement channels recorded at the POI is shown below. Additional or substitute channels may be required on a per case basis depending on the interconnection configuration and facility design details.

- Frequency
- Frequency Delta (dF/dt)
- Positive Sequence Voltage Magnitude
- Positive Sequence Voltage Angle
- Positive Sequence Current Magnitude
- Positive Sequence Current Angle

2. Estimated Milestones

These milestones will begin, and the construction 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 below 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 this Study by the date(s) specified below may result in the loss of milestone dates and construction schedules set forth below. In the event that the Interconnection Customer is unable to meet dates as outlined below, Interconnection Customer may request an extension of the Operation Date of up to three (3) years. Interconnection Customer's request will be evaluated by IPC to ensure Interconnection Customer's request does not negatively impact other projects in IPC's Generator Interconnection Queue. Such extension will be allowed only if IPC determines, in its sole discretion, that the extension will not negatively impact other projects in IPC's Generator Interconnection Queue. Estimated milestones, which will be updated and revised for inclusion in the LGIA in light of subsequent developments and conditions, are as follows:

Estimated Date	Responsible Party	Estimated Milestones
[DATE]	*Interconnection Customer*	*IPC receives Notice to Proceed and construction funding or arrangements acceptable to IPC are made with IPC's Credit Department*
12 months after construction funds received	*IPC*	*IPC Engineering and Design Complete*
12 months after construction funds received	*IPC*	*IPC Long Lead Material Procured/Received*
12 months after construction funds received	*Interconnection Customer*	*Easement(s) for Interconnection Customer's Transmission Line through IPC-owned property complete, construction will not begin until easements are in place.*
8 months prior to IPC Commissioning	*IPC*	*New generation must be modeled and submitted to the Western Energy Imbalance Market a minimum of 6 months prior to*

		coming online, failure to submit by given lead time will results in project delay.
22 months after construction funds received	*IPC*	*IPC Construction Complete.*
24 months after construction funds received	*IPC*	*IPC Commissioning Complete (commissioning will not take place until GOLC fiber circuit is operational).*
48 months after GIA Execution of Contingent Queue Project #530		*Contingent Queue Project #530*
5 days after switching request made to IPC Dispatch	*Interconnection Customer*	*Switch at the Point of Interconnection can be closed*
TBD	*Interconnection Customer*	*Interconnection Customer testing begins*
TBD	*Interconnection Customer*	*Operation Date*

IPC does not warrant or guarantee the foregoing estimated milestone dates, which are estimates only. These milestone dates 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 Operation Date. 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 the 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 Operation Date 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.

3. Operating Requirements

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* or any subsequent standards as they may be updated from time to time.

The Project will be subject to reductions directed by IPC Grid Operations during transmission system contingencies and other reliability events. When these conditions occur, the Project will be subject to Generator Output Limit Control ("GOLC") and will have equipment capable of receiving an analog setpoint via DNP 3.0 from IPC for GOLC. Generator Output Limit Control will be accomplished with a setpoint and discrete output control from IPC to the Project indicating maximum output allowed. For more detail see Appendix A.

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 Project must meet or exceed the Low Voltage Ride-Through requirements as set forth in NERC Standard PRC-024.

Frequency Response Requirements: Generator must be capable of providing Fast Frequency Response for both positive and negative frequency deviations from 60Hz (+/- 0.036 Hz) for Bulk Electric System disturbances. The required frequency response will be linear for a deviation of 0 to +/- 0.1 Hz, a response of 0% to 3% of generator capacity, with a maximum required response of 3% of generator's full capacity for as long as the generator is able to provide support or the frequency deviation is reduced to within stated limits, whichever occurs first. Provided that Generator meets the above Fast Frequency Response requirements, Company shall not curtail Interconnection Customer when such curtailments are caused by a need to comply with applicable Frequency Responsive reliability standards.

Momentary Cessation Requirements: Momentary cessation should not be used within the voltage and frequency ride-through curves specified in PRC-024. Use of momentary cessation is not considered "ride through" within the "No Trip" zone curves of PRC-024. 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.*

In digital equipment, frequency should be calculated over a period-of-time (e.g. three to six cycles) and filtered to take control action on the fundamental frequency component of the calculated signal. Calculated frequency must not be susceptible to spikes caused by phase jumps on the Bulk Electric System.

Applicable generation resources should follow NERC's *Reliability Guideline for BPS-Connected Inverter-Based Resource Performance* with respect to Reaction Time, Rise Time, Settling Time, Overshoot, and Settling Band.

Interconnection Customer will be able to modify Interconnection Customer facilities on the Interconnection Customer side of the Point of Change of Ownership with no impact upon the operation of the transmission or distribution system whenever the generation facilities are electrically isolated from the system via the [redacted] air-break switch, and a terminal clearance is issued by IPC's Grid Operator.

4. Reactive Power

It is the generation project's responsibility to provide reactive power capability of the project to have a power factor operating range of at least 0.95 leading (absorbing) to at least 0.95 lagging (supplying) at the POI over the range of real power output (up to maximum output of the project) and for all modes of operations (wind generation only, combined wind/BESS (charging and discharging), and BESS generation only). With only a single 500kV Project line to the POI and with just 1050 MW of wind generation (no BESS on-line), preliminary analysis indicated that approximately 270+ MVAr shunt compensation will be required to be installed to achieve the 0.95 lagging (supplying) power factor. At the combined 1050 MW output from the wind and BESS generation, approximately 70 MVAr shunt compensation will be required to be installed to achieve the 0.95 lagging (supplying) power factor. With only the 500 MW BESS generation (no wind generation on-line), less than 15 MVAr shunt compensation will be required to be installed to achieve the 0.95 lagging (supplying) power factor. No additional reactive shunt compensation was identified to achieve 0.95 leading (absorbing) for the above three operating scenarios.

The Project must have equipment capable of receiving an analog setpoint, via DNP 3.0 from IPC for Voltage Control. The setpoint will be the desired voltage level as measured at the interconnect bus. The range of setpoint will be 499kV to 551kV. For more detail see Appendix A.

5. Distribution and Network Upgrades

5.1 Distribution Upgrades

None required.

5.2 Network Upgrades to Substations

IPC will expand the Midpoint Transmission Station yard to accommodate the new facilities. Upgrades to be installed consist of two single-pole tripping 500kV circuit breakers, five 500kV air-break switches, CCVTs, associated relaying/control/communications equipment in a control building, required site development with fencing, local service equipment and foundations, structures, bus, grounding, conduit, and conductor for such equipment. IPC will replace the protection panel on the adjacent transmission line to accommodate the additional I/O required for the shared breaker. The existing PMU relay does not have enough channels available and will be replaced.

5.3 Network Upgrades to the Transmission System

None required.

6. Estimated Costs

The following good faith estimates are provided in 2021 dollars and are based on several 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 to be performed by IPC and its agents, under the terms and subject to the conditions included in any LGIA executed by IPC and Interconnection Customer.

The estimated cost below is required to be paid in full by the Interconnection Customer, or other arrangements acceptable to IPC are made with IPC's Credit Department, prior to IPC commencing construction on the project.

Estimated Cost of IPC's Interconnection Facilities and Network Upgrades:

Description	Ownership	Funding Responsibility[1]	Cost Estimate
IPC Interconnection Facilities:			
Install Interconnection Facilities as described in Section 1.5 above.	IPC	Interconnection Customer	$1,319,014
Contingency 10%		Interconnection Customer	$131,901
Overheads 7.25%		Interconnection Customer	$105,191
Subtotal			**$1,556,106**
Network Upgrades:			
Install Network Upgrades to Substations as described in Section 5.2 above.	IPC	Interconnection Customer	$5,228,881
Contingency 10%		Interconnection Customer	$522,888
Overheads 7.25%		Interconnection Customer	$417,003
Subtotal			**$6,168,772**
GRAND TOTAL			**$7,724,878**

Note Regarding Transmission Service:

This FSR is a study of a request for an Energy Resource Interconnection Service. This FSR identifies the facilities necessary to connect the Generating Facility to IPC's Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. Energy Resource Interconnection Service does not in and of itself convey any right to transmission service or to deliver electricity to any specific customer or Point of Delivery.

Note Regarding LGIA:

This FSR 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 FSR. Unless and until a 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 FSR.

[1] Funding responsibility is described in the standard LGIA in Idaho Power's OATT (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.

Appendix A

Generation Interconnection Control Requirements

A.1 Generator Output Limit Control (GOLC)

A.1.1 IPC requires Interconnected Power Producers to accept GOLC signals from IPC's energy management system ("EMS").

A.1.2 The GOLC signals will consist of four points shared between the IPC EMS (via the IPC RTU) and the Interconnection Customer's Generator Controller ("SGC"). The IPC RTU will be the master and the SGC will be the slave.

A.1.2.1 GOLC Setpoint: An analog output that contains the MW value the Interconnection Customer should curtail to, should a GOLC request be made via the GOLC On/Off discrete output Control point.

A.1.2.1.1 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.

A.1.2.2 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"), the Interconnection Customer is free to run to maximum possible output.

A.1.2.2.1 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.

A.1.3 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 10 minutes.

A.2 Voltage Control

A.2.1 IPC requires Transmission-Interconnected Power Producers to accept voltage control signals from IPC's EMS when they are connected to IPC's transmission system.

A.2.2 The voltage control will consist of one setpoint and one feedback point shared between the IPC EMS and the SGC.

A.2.3 The setpoint will contain the desired target voltage 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.

A.2.4 The control will always be active, there is no digital supervisory point like the Curtail On/Off control above.

A.2.4.1 When a setpoint change is issued an Analog Input feedback point must be updated (to reflect the voltage control setpoint value) by the SGC upon the SGC's receipt of the voltage control setpoint change, with no intentional delay.

A.2.4.2 When a setpoint change is received by the SGC, the voltage control system should react with no intentional delay.

A.2.4.3 The voltage control system should operate at the voltage indicated by the setpoint with an accuracy of +/- 0.5% of the nominal system voltage.

A.2.5 The 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.

A.3 Generation Interconnection Data Points Requirements

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	FREQUENCY RESPONSE OFF/ON (Control Feedback)	Off/On	Feedback provided by Interconnection Customer
2	52A Interconnection Customer Main Breaker (if present)	Open/Closed	Sourced at substation
3	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	Frequency Response 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	Ambient Temperature	32767	-32768	327.67	-327.68	DEG C	Provided by Interconnection Customer
4	Wind Direction	32767	-32768	327.67	-327.68	Deg from North	Provided by Interconnection Customer

5	Wind Speed	32767	-32768	327.67	-327.68	M/S	Provided by Interconnection Customer
6	Relative Humidity	32767	-32768	TBD	TBD	%	Provided by Interconnection Customer
7	SPARE						
8	SPARE						
9	Number of Turbines In High Speed Cutout	32767	-32768	32767	-32768	Units	Provided by Interconnection Customer
10	SPARE						
11	SPARE						
12	SPARE						
13	SPARE						
14	SPARE						
15	SPARE						
16	SPARE						
17	SPARE						

Analog Outputs to Interconnection Customer (DNP Obj. 41, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint	32767	-32768	TBD	TBD	MW	Control issued by IPC
1	Voltage Control Setpoint	32767	-32768	TBD	TBD	kV	Control issued by IPC
2	SPARE						
3	SPARE						
4	SPARE						
5	SPARE						
6	SPARE						
7	SPARE						
8	SPARE						
9	SPARE						

Appendix B

Contingent Queue Project Upgrades

GI #570 is contingent upon upgrades associated with the senior queued project GI #530. Because GI #530 generation interconnection plan of service is to split the [redacted] 500kV line ([redacted] and [redacted] 500kV lines), the Midpoint 500kV series compensation was required to be replaced, and with part of the existing series compensation in the form of a new 500kV series capacitor bank relocated to [redacted] in the [redacted] 500kV line. If GI #530 in-service date is delayed and/or withdraws their project, GI #570 will be responsible for some or all the Midpoint 500kV series compensation replacement. And, because of GI #570 Midpoint station interconnection, the Midpoint 500kV series capacitor will likely need to be replaced due to its size i.e. current rating.

Alternative Upgrade/Mitigation Options

The following options were evaluated as alternatives to constructing GI #530 500/230kV transformer/transmission interconnection facilities if the GI #530 project withdraws:

- The [redacted] 500/345kV 1800 MVA identified Network Resource Interconnection Service Upgrade (~$38M).
- The [redacted] 230kV integration of [redacted] 500kV ([redacted]) into the [redacted] Project (~$21M). o Second [redacted] 230kV Line. o [redacted] 230kV Line.
- [redacted] Transmission Project interconnection at Midpoint 500kV Station.
- A [redacted] generation tripping Remedial Action Scheme (RAS), which would be required to trip ~500 MW of generation under heavy Idaho to Northwest import conditions (i.e. [redacted] 500kV line flows) and maximum [redacted] Project generation of 1050 MW, was evaluated. Performance was marginally acceptable at 500 MW [redacted] RAS generation tripping. [redacted] generation tripping RAS mitigated overloads in the [redacted] 230kV and 138kV transmission facilities but potentially could result in overloading the [redacted] 230 kV line at higher levels of [redacted] generation than what was studied. The overall lack of effectiveness of the RAS, which requires the large amount of [redacted] generation tripping for mitigation, is due to the Northwest's make-up generation response to the [redacted] generation trip component on the [redacted] 500kV line back filling the relief obtained on the [redacted] 230kV line from the generation trip. In essence, the relief on the [redacted] 230kV line from tripping [redacted] generation is partially erased due to the make-up generation response coming from the Northwest on the [redacted] 500kV line. As an Energy Resource Interconnection Service, the [redacted] RAS generation tripping make-up generation will not be the responsibility of Idaho Power Company and can potentially exceed Idaho Power Company's present contingent operating reserves requirements. If [redacted] generation tripping RAS is selected as the alternative to constructing GI # 530 transformer/transmission interconnection facilities, a System Impact re-study of GI #570 will need to be commissioned to fully vet/determine [redacted] 500kV/[redacted] 230kV line flows versus [redacted] generation tripping arming level and [redacted] generation tripping requirements.
- Project Curtailment.