Generator Interconnection Facility Study Report

for the

[redacted] **Project #567**

for

[redacted]

in

Ada County, ID

5/20/2022

FACILITY STUDY REPORT (FSR)

[redacted]

Project #567

5/20/2022

1. General Facility Description

[redacted] ("Interconnection Customer") has stated that the proposed project will consist of a 200 MW photovoltaic and 150 MW battery energy storage system (BESS) installation in Ada County, Idaho and connect to the 230kV system on Idaho Power Company (IPC)'s Danskin - Hubbard line. The total project output as studied is 200 MW.

Contact Information for Interconnection Customer is as follows:

[redacted]

A Standard Large Generator Interconnection Agreement (the "LGIA") under IPC's Open Access Transmission Tariff (OATT) between Interconnection Customer and IPC – Delivery (Transmission Provider) for the [redacted] Project, specifically Generator Interconnection Project #567 ("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 one 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.

The identified contingent facility upgrades for GI #530 are required to be completed prior to the interconnection of the Project and are estimated to take longer to construct than the interconnection facilities and network upgrades for this Project. Details on the contingent facilities identified from GI #530 are in Appendix D. 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 Interconnection Point

The Interconnection Facilities are located in IPC's Capital region in Township [redacted], Range [redacted] and Section [redacted]. The Point of Interconnection ("POI") for the Project will be the node on the 230kV bus between air-break switch [redacted] and air-break switch [redacted] at the new interconnection switching station. 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 Interconnection Customer's side of air-break switch [redacted]. A drawing identifying the Point of Change of Ownership is attached as Exhibit 1.

1.3 Interconnection Customer's Interconnection and Generation Facilities

The Interconnection Customer's Interconnection Facilities are located immediately south of and adjacent to IPC's Interconnection Facilities. The Interconnection Customer will install solar arrays, batteries, inverters, disconnect switches, distribution collector system, transformers (including a main step-up transformer), controllers, appropriate grounding measures, and associated auxiliary equipment. The main step-up transformer is a 133.3/177.8/222.2 MVA, 230kV/34.5kV wye-grounded/wye-grounded, 3-phase with a delta tertiary and should provide an adequate ground source for transmission line protection. Interconnection Customer will build 230kV facilities to the Point of Change of Ownership.

The Interconnection Customer's system will be constructed as follows:

1. The photovoltaic inverter system will comprise of 61 [redacted] power conditioning systems.
2. Each photovoltaic power conditioning system will comprise of one 3,600 kVA 34.5kV/630V step-up transformer and one 3,600 kVA [redacted] interter.
3. The BESS inverter system will comprise of 41 [redacted] power conditioning systems.
4. Each BESS power conditioning system will comprise of one 3,600 kVA 34.5kV/630V step-up transformer and one 3,600 kVA [redacted] interter.
5. A plant controller will be used to control the inverter system and to implement smart inverter functionality for operating the project within a voltage range and power factor specified by IPC at the point of interconnection.

   The above referenced inverters, or equivalent inverters that have the same specifications and functionality as stated above must be utilized. If a different inverter 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 solar and BESS generation project. It has been assumed the BESS will be charged via the solar output. The Interconnection Customer 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, the Interconnection Customer 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 for any third party communication circuits for the IPC Interconnection Facilities. Any additional telecommunication requirements will be the sole responsibility of the Interconnection Customer.

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 the Interconnection Station and the Project.

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 Customer will acquire and then transfer to IPC, the property for IPC's interconnection station yard, including a year-round access. The interconnection station will be owned and maintained by IPC. The Interconnection Customer, at its sole cost and expense, will provide to IPC documents and services as identified below relating to IPC's land rights required for its interconnection facilities:

1.4.5.1 Land Transaction Documents

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

- Right of Entry Agreement;
- Interconnection Facility fee ownership parcel ("Fee Ownership Parcel") conveyance pursuant to a Warranty Deed.
- Sale Agreement;
- Access Easement;
- Easements for distribution service lines, major distribution power lines, and transmission power lines and related ancillary facilities as determined necessary by IPC at IPC's sole discretion, to support the interconnection facility and Interconnection Customer's development;
- Completed Applications with respective fees for Release of Easements and/or Crossing Agreements that may be required for the Project;
- Crossing Agreements; and
- Any other Project specific documents deemed necessary by IPC.

1.4.5.2 Project Map/Site Plan

A 90% complete informational map or site plan of the Project Property with locations of all easements to be released, new easements proposed for both Interconnection Customer and IPC, existing IPC lines to be crossed by Interconnection Customer's facilities, Interconnection Customer's lease and easement areas (if any), access roads, and any other features or elements requested to be included by IPC to facilitate review and processing of the project documents.

1.4.5.3 Surveyed Legal Descriptions and Maps

Written legal description and map for each Land Transaction Document, stamped and signed by a licensed surveyor. Each legal description and map is to be submitted to and approved by IPC's surveyor. See IPC survey requirements in Appendix B, attached hereto and made a part hereof.

1.4.5.4 Title Insurance

Title report and American Land Title Association (A.L.T.A.) extended owners' pro forma policy of title insurance for the amount of the value of the Interconnection Facility Easement or Fee Ownership Parcel and access easement areas. Interconnection Customer shall provide proof and information to establish the value of the easement or property to be insured. IPC will review the title policy pro forma and will advise of any necessary title mitigation measures to ensure clear and unencumbered title to the Interconnection Facility Easement or Fee Ownership Parcel and access easement areas. Title mitigation measures shall be performed by Interconnection Customer at Interconnection Customer's sole cost and expense. Title policy to include endorsements as required by IPC at Interconnection Customer's sole cost and expense. Interconnection Customer to provide an electronic copy of all exceptions to title insurance for IPC review. Interconnection Customer to provide Idaho Power with a final A.L.T.A. extended owners' policy of title insurance.

1.4.5.5 A.L.T.A. Survey

An A.L.T.A. survey of the Project property with all existing IPC easement rights and facilities identified. The A.L.T.A. survey shall include and identify all proposed land transaction areas. If IPC requires a Fee Ownership Parcel for the Interconnection Facility, Interconnection Customer shall provide an A.L.T.A. survey of the Fee Ownership Parcel to be conveyed to IPC and all Land Transactions. If IPC requires an Easement for the Interconnection Facility, Interconnection Customer may provide IPC with a copy of Interconnection Customer's A.L.T.A. survey or with an A.L.T.A. survey in IPC's name but the A.L.T.A. survey shall include the Interconnection Facility Easement Area, as well as all Land Transactions.

1.4.5.6 Phase I Environmental Analysis

A Phase I environmental analysis ("Phase I EA") of Interconnection Customer's Project property (whether fee-owned, leased, or on an easement premises) for IPC review. The Phase I EA shall provide a map indicating the location of the IPC Interconnection Facilities in relation to any identified areas of concern. If IPC requires a Fee Ownership Parcel for the Interconnection Facility, Interconnection Customer shall provide a Phase 1 EA in IPC's name with warranties for IPC. If IPC requires an Easement for the Interconnection Facility, Interconnection Customer shall provide IPC with a copy of Interconnection Customer's Phase 1 EA but which shall include and reference the Interconnection Facility Easement Area.

1.4.5.7 Land Use Authorizations/Permits

The Interconnection Customer shall secure all necessary local jurisdiction, state, and/or federal land use authorizations and permits for the IPC Interconnection Facilities, access road, new transmission and distribution lines, buildings, and all facilities in support of Interconnection Customer's Project, as required by local, state or federal entities. A copy of each authorization pertaining to IPC facilities shall be provided to IPC.

1.4.5.8 Land Division

Should a division of land be necessary to create a new Fee Ownership Parcel, Interconnection Customer shall submit application to the proper local jurisdiction and complete all requirements to finalize the creation of a new Fee Ownership Parcel in IPC's name. Interconnection Customer shall provide final approval documentation to IPC.

Interconnection Customer is advised that IPC review and approval of the Land Transaction Documents may require six (6) to nine (9) months. Interconnection Customer is advised to provide all required Land Transaction Documents at earliest possible time. Refer to Appendix C for a quick reference guide to Idaho Power Corporate Real Estate Fee Acquisition and/or Easement Parcel requirements. Upon IPC approval of all Land Transaction Documents, IPC will supply to the Interconnection Customer final form documents for signature by the land owner of record. The Interconnection Customer shall return original signed and recorded Land Transaction Documents to IPC. 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 will provide: property, property access and site plan. IPC will perform land clearing and grading for IPC's interconnection station.

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) in the interconnection station, they are required to supply their own communications circuit to the interface area of the interconnection yard. The fiber communication circuit used for GOLC is acceptable.

1.4.9 Meteorological Data

In order to integrate the solar energy into the IPC system and operate IPC's solar forecasting tool, the Interconnection Customer must provide solar irradiation and weather data from the Facility's physical location to IPC via real time telemetry in a form acceptable to IPC. The associated cost for obtaining this data is the Interconnection Customer's responsibility.

The data must be provided at 10 second intervals and consist of:

1. Global Horizontal Irradiance
2. Plane of Array Irradiance
3. Ambient Temperature
4. Wind Speed and Wind Direction
5. Relative Humidity

The installed instruments must equal or exceed the specifications of the following instruments:
Temperature and Relative Humidity: [redacted] Relative Humidity and Temperature Probe Sensors [redacted]
Wind: [redacted] Wind Monitor [redacted]
Pryanometer: [redacted]

1.4.10 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 Providers's Interconnection Facilities

Transmission Provider's Interconnection Facilities are referred to hereafter as "IPC's Interconnection Facilities." At the new 230kV interconnection switching station IPC will install a meter, a dead-end structure, a 230kV air break switch , three CTs, required foundations and fiber communication equipment to allow the Interconnection Customer to interconnect the project. IPC will install facilities up to the Point of Change of Ownership.

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 for design, procurement and construction.* *Construction funding or arrangements acceptable to IPC are made with IPC's Credit Department*
24 months after construction funds received	*IPC*	*IPC Engineering and Design Complete*
24 months after construction funds received	*IPC*	*IPC Long Lead Material Received*
24 months after construction funds received	*Interconnection Customer*	*Fee ownership parcel documents, easements and permits procured for IPC site, construction will not begin until easements and permits are in place.* *Detailed in Appendix C attached.*
6 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.*
36 months after construction funds received	*IPC*	*IPC Construction Complete*
38 months after construction funds received	*IPC*	*IPC Commissioning Complete*
48 to 60 months from the date of this report	*IPC*	*Contingent facilities from GI #530 completed. Based on current milestone estimates. (Appendix D)*
5 days after switching request made to IPC Dispatch	*Interconnection Customer*	*Switch at the Point of Interconnection can be closed*
TBD	*IPC*	*Notification from IPC's Energy Contracting Coordinator confirming First Energy of Non-Firm Output*
TBD	*Interconnection Customer*	*Interconnection Customer testing begins*
TBD	*IPC*	*Notification from IPC's Energy Contracting Coordinator confirming Operation Date (pending all requirements are met) of Firm Network Resource Output*

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

Frequency Response Requirements: The Project 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 the Project meets the above Fast Frequency Response requirements, Company shall not curtail the 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*

Interconnection Customer will be able to modify power plant facilities on the Interconnection Customer side of the Interconnection Point 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] switch and a terminal clearance is issued by IPC's Grid Operator.

4. Reactive Power

It is the Project's responsibility to provide reactive power capability to have a power factor operating range of at least 0.95 leading (absorbing) to at least 0.95 lagging (supplying) at the high side of the generator substation over the range of real power output (up to maximum output of the project) and for all modes of operations (solar generation only, combined solar/BESS (charging and discharging), and BESS generation only).

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 at the time the LGIA is executed. For more detail see Appendix A.

5. Distribution and Network Upgrades

5.1 Distribution Upgrades

IPC will extend the OCHD-042 distribution line approximately 1 mile to the new interconnection switching station. The feeder extension will be installed to provide local service to IPC's new interconnection station and will be of single phase configuration. The feeder route will avoid BLM lands.

5.2 Network Upgrades to Substations

New IPC Interconnection Switching Station

IPC will install a new fenced 350' x 300' switching station yard with a control building, in and out 230kV transmission taps and 3-breaker ring bus to integrate the station into the existing DNPR - HBRD 230kV transmission line. Two 230kV steel dead-end structures, three 230kV circuit breakers, six 230kV air-break switches, nine CCVTs, CTs, PTs and associated bus supports, relaying, PLC communications, and control equipment will be installed in the station yard and building.

Danskin Substation

Install second MPLS multiplex shelf and ethernet switch, SEL-421/311L protection package and 3-phase line CCVTs.

Boise Bench Substation

Terminate PMU circuit via RS232 fiber transceivers and fiber jumper. Terminate SCADA circuits.

5.3 Network Upgrades to the Transmission System

IPC will install one 230kV double circuit dead-end tower with drilled pier foundation to bring in and out transmission lines (500 feet or less per line) and Optical Ground Wire (OPGW) to the new switching station.

6. Estimated Costs

The following good faith estimates are provided in 2022 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 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:

Description	Ownership	Cost Estimate
IPC Interconnection Facilities:		
Facilities between the Point of Change of Ownership and Point of Interconnection as described in Section 1.5	IPC	$417,269
Contingency 10%		$41,727
Overheads 6.25%		$28,687
TOTAL		**$487,683**
Distribution Upgrades:		
7.2kV single-phase line extension as described in Section 5.1	IPC	$100,596
Contingency 10%		$10,060
Overheads 11.75%		$13,002
TOTAL		**$123,658**
Network Upgrades to IPC Substations:		
New 230kV ring bus switching station and upgrades at Danskin and Boise Bench Substations as described in Section 5.2	IPC	$4,107,884
Contingency 10%		$410,788
Overheads 6.25%		$282,417
TOTAL		**$4,801,089**
Network Upgrades to IPC Transmission:		
New transmission structure, lines and OPGW as described in Section 5.3	IPC	$286,527
Contingency 10%		$28,653
Overheads 6.25%		$19,699
TOTAL		**$334,878**
GRAND TOTAL	**$5,747,308**	

Note Regarding Transmission Service:

This FSR is a study of a request for Network Resource Interconnection Service. This FSR identifies the facilities necessary to provide such service. Network Resource Interconnection Service in and of itself does not 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.

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	Global Horizontal Irradiance	32767	-32768	TBD	TBD	W/M^2	Provided by Interconnection Customer
8	Plane of Array Irradiance	32767	-32768	TBD	TBD	W/M^2	Provided by Interconnection Customer
9	SPARE						
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

IPC Survey Requirements

- ❑ Is the Grantor's Deed Instrument No. noted in the Exhibit 'A' Legal Description or Exhibit 'B' Survey Map?
- ❑ Are the Section, Township, Range, and County information clearly stated on the Exhibits?
- ❑ Is the Basis of Bearings between found monuments called out and noted on the Exhibits?
- ❑ Are the Point of Commencement, Point of Beginning and or Point of Terminus shown on the Exhibits?
- ❑ Do all lines have a bearing and distance associated with them on the Exhibits?
- ❑ All lines need bounding calls to Grantor's ownership lines, Rights-of-Way, etc. in Exhibit A.
- ❑ Are the Subdivision names, lot & block, and streets labeled on the Exhibit B?
- ❑ Are any existing Utility Easements adjoining this Easement called out and shown on the Exhibits?
- ❑ Is the map scale noted and is there a North arrow shown on the Exhibit B?
- ❑ On a strip easement is the width given and does it call to form a closed figure in the Exhibit A?
- ❑ Does the Parcel description close?
- ❑ Are the reference surveys of record or CP&Fs used to prepare the easement called out and shown on the Exhibits?
- ❑ A Professional Land Surveyor or Engineer in responsible charge must stamp, sign and date the exhibits for submission.
- ❑ A copy of the current Deed of Record for the Grantor is needed for submission.

Appendix C

Idaho Power Company – Corporate Real Estate Department
Fee Parcel Acquisition and/or Easement Parcel Acquisition Requirements for Developers

1. **Right of Entry Agreement**. A Right-of-Entry Agreement is attached and will allow Idaho Power to conduct necessary studies and review of the property and substation lands to determine feasibility for development. This document is required to be signed by the underlying property owner as soon as possible and will allow the preliminary stages of project development to commence pending completion of the transfer of substation lands to Idaho Power.

2. **Purchase and Sale Agreement – Warranty Deed – Access Easement – Power Line Easements**. Idaho Power requires the substation land be provided in a form of fee ownership acceptable to Idaho Power. A Purchase and Sale Agreement is attached and provides the terms for the fee ownership transaction. The Purchase and Sale Agreement includes a Warranty Deed for the transfer of the substation land to Idaho Power, a form of Access Easement for access to the substation land, and forms of transmission and distribution easements. Individual forms are attached, as well.

3. **Land Division (if needed)**. Should a division of land be necessary to separate the substation parcel from an underlying, larger property ("Property"), Developer will be required to submit application to the County for the land division and to ensure the satisfaction of all conditions to complete the land division.

4. **Title Commitment**. Idaho Power requires that Developer ensure the substation lands and access easement over the Property are free from any encumbrances to title. To meet this requirement, a Title Commitment with A.L.T.A. extended coverage owner's policy in Idaho Power's name is required. All exceptions to title insurance need to be provided with the Title Commitment for Idaho Power review. Upon receipt, Idaho Power will review all exceptions and will advise of any necessary follow-up actions. Importantly, Idaho Power requires a form of ownership that is free and clear from all encumbrances and will require the developer to complete title curative measures as Idaho Power deems necessary.

5. **Survey**. An A.L.T.A survey for the substation parcel, and which includes the access easement is required. The A.L.T.A. survey will be reviewed by Idaho Power's surveyor who will advise of any necessary revisions.

6. **Legal Descriptions**. Written legal descriptions, stamped and signed by a surveyor licensed in the state of Idaho, are required for the substation parcel, access easement area, and all distribution/transmission line easement parcels. The written legal descriptions will be reviewed by Idaho Power's surveyor who will advise of any necessary revisions.

7. **Phase I Study**. Developer shall provide Idaho Power with a Phase I study prepared by an independent environmental site assessment company, in Idaho Power's name, which recognizes Idaho Power as the purchaser of the substation parcel and User of the Phase I report, and which provides warranties to Idaho Power for the substation parcel and access easement areas. The Phase I study will be reviewed by Idaho Power and Idaho Power will advise if a Phase II or other necessary actions or required based on the results of the Phase I study.

8. **Public Lands Permits or Authorizations (if needed)**. Should any agency lands, rights-of-way, etc. be affected by the granting of land and easement rights to Idaho Power, Developer shall be responsible to any secure necessary agency authorizations or permits in Idaho Power's name, at Developer's sole cost and expense. Developer shall be responsible to ensure all conditions of approval are satisfied, fees are paid, etc.

9. **Land Use Permits or Authorizations**. Developer shall be responsible to secure any necessary land use entitlements or authorizations from the local jurisdiction, local agencies, state of Idaho, or Federal or other agencies to allow the development of the substation parcel, access road and ancillary transmission or distribution lines and facilities (example: Conditional Use Permit from city or county). Any such authorizations shall be secured in Idaho Power's name and for the benefit of Idaho Power. Idaho Power will require the Developer to satisfy all conditions of approval and requirements for any such entitlement or authorization.

10. **Costs**. Any costs pertaining to the above items shall be at the Developer's sole cost and expense.

11. **Miscellaneous Documents.** Other miscellaneous documents as necessary for the project – such as Memorandums of Agreement/Understanding, etc.

Appendix D

GI #530 contingent facility upgrades identified in Version 4 of the System Impact Study for GI #567, [redacted] dated January 5, 2022.

GI #530 Project	
Network Resource Transmission Upgrades:	**Estimated Cost**
Boise Bench – Hubbard 230kV Line Loop in-and-out of Dram Station Build 1.25 miles 230kV Double Circuit Line with 1272 MCM ACSR "Bittern" Conductor	$1,040,000
Dram 230kV Station Add two 230kV Line Terminals	$1,775,000
Subtotal	**$2,815,000**
Contingencies (~20%)	$563,000
Subtotal	**$3,378,000**
Overheads (~7.25%)	$244,905
Network Transmission – Total Estimated Cost	**$3,622,905**