Generator Interconnection Facility Study Report

for the

[redacted]

for

[redacted]

in

Bonneville County, Idaho

Rev. 2
February 7, 2023

FACILITY STUDY REPORT (FSR)

[redacted]

Project GI #580

Rev. 2 February 7, 2023

1. General Facility Description

[redacted] ("Interconnection Customer") has stated that the proposed project will consist of a combined 263 MWac wind turbine, solar and battery energy storage system (BESS) plant in Bonneville County, Idaho and connect to the Idaho Power Company (IPC) and PacifiCorp jointly owned [redacted] 161 kV line. This line is operated by PacifiCorp. The total project output studied is 263 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 the Interconnection Customer and IPC (Transmission Provider) for the 263 MW [redacted] Project, specifically Generator Interconnection Project #580 ("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 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 transmission capacity additions of their own. As of the date of this report, there are no projects in the queue ahead of the 263 MW [redacted] Project for which costs related to transmission capacity upgrades or additions could be passed on to the 263 MW [redacted] Project. Regardless, 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 Eastern region in Township [redacted], Range [redacted] and Section [redacted]. Because the Project's requested connection point is on a transmission line jointly owned by Idaho Power and PacifiCorp but fully operated by PacifiCorp, the details of the interconnection station and specific Point of Interconnection ("POI") will be determined by PacifiCorp in a separate Affected System Facilities Study.

1.2 Point of Change of Ownership

The Point of Change of Ownership for the Project is located in IPC's Eastern region in Township [redacted], Range [redacted] and Section [redacted]. Because the Project's requested connection point is on a transmission line jointly owned by Idaho Power and PacifiCorp but fully operated by PacifiCorp, the details of the interconnection station and specific Point of Change of Ownership will be determined by PacifiCorp in a separate Affected System Facilities Study.

1.3 Interconnection Customer's Facilities

The Interconnection Customer will install wind turbines, solar arrays, batteries, inverters, disconnect switches, distribution collector system, transformers (including main step-up transformers), controllers, appropriate grounding measures, and associated auxiliary equipment. The two main step-up transformers are 100/135/170 MVA, 230kV/34.5kV wye-grounded/wye-grounded, delta-tertiary 3-phase units. PacifiCorp will determine if the step up transformer configuration provides adequate ground source for transmission line protection. Interconnection Customer will build 230 kV facilities to the Point of Change of Ownership.

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

1. The wind generation site will comprise of 48 [redacted] 3.4 MW wind turbines.
2. The photovoltaic inverter system will comprise of 35 [redacted] inverter transformer stations rated at 3.43 MVA.
3. The BESS will comprise of 34 [redacted] inverter transformer stations rated at 3.51 MVA.
4. A plant controller will be used to control the turbines and inverter systems and to implement smart inverter functionality for operating the project within a voltage range and power factor specified at the point of interconnection.

The above referenced turbines and inverters, or equivalent equipment 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.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Telecommunications

There are no identified telecommunication upgrades identified as part of the network upgrades contained in this report. Any additional telecommunication requirements will be the sole responsibility of the Interconnection Customer.

Telecommunication requirements specific to an interconnection station and network upgrades under the design and control of PacifiCorp will be determined by PacifiCorp in a separate Affected System Facilities Study.

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 for Generation Output Limit Control ("GOLC") - see Section 3 Operating Requirements and Appendix A.

1.4.4 Local Service

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

1.4.5 Property

There are no property transaction requirements related to the IPC's network upgrades identified in this study.

Property requirements specific to an interconnection station and network upgrades under the authority of PacifiCorp will be determined by PacifiCorp in a separate Affected System Facilities Study.

1.4.6 Site Work

No site work is required.

1.4.7 Monitoring Information

PacifiCorp will provide specific requirements should the Interconnection Customer require the ability to monitor information related to the breakers/relays (i.e. via Mirrored Bits) in the interconnection station.

1.4.9 Meteorological Data

In order to integrate the wind energy, the Interconnection Customer will provide weather data 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), along with Relative Humidity, and Barometric Pressure. This data shall be provided hourly via commonly accepted electronic web service standards or similar communication method. 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.

In order to integrate the solar energy 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: R.M Young Relative Humidity and Temperature Probe Sensors [redacted]
Wind: R.M Young Wind Monitor [redacted]
Pryanometer: Apogee Instruments [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 Interconnection Facilities

Note because the Project's requested interconnection point is on a line jointly owned by Idaho Power and PacifiCorp but fully operated by PacifiCorp, the interconnection facilities will be determined by PacifiCorp in a separate Affected System Facilities Study. The interconnection facilities will be jointly owned by Idaho Power and PacifiCorp and fully operated by PacifiCorp.

2. IPC Network Upgrade 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*
18 months after construction funds received	*IPC*	*IPC Engineering and Design Complete*
24 months after construction funds received	*IPC*	*IPC Long Lead Material Procured/Received*
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*	*Construction Complete for IPC Network Upgrades*
38 months after construction funds received		*Commissioning Complete for IPC Network Upgrades*
TBD	*IPC*	*Contingent facility completed (Appendix C)*
TBD	*PacifiCorp*	*Interconnection Station and Network Upgrades under PacifiCorp's authority completed.*
TBD	*Interconnection Customer*	*Switch at the Point of Interconnection can be closed after switching request made to PacifiCorp's Dispatch.*
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: 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*

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. The specific device and method of disconnection from the transmission system will be determined by PacifiCorp.

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.

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. Upgrades

Note the network upgrades detailed in this section are the identified upgrades to Idaho Power operated substations and transmission lines only. Identified network upgrades to substations and transmission lines jointly owned by Idaho Power and PacifiCorp, but fully operated by PacifiCorp, will be contained in a separate Affected System Facilities Study to be conducted by PacifiCorp. Details on the full list of GI #580 required network upgrades are contained in Appendix B.

5.1 Distribution Upgrades

There are no required distribution upgrades.

5.2 Network Upgrades to Substations

[redacted] Substation

Expansion of the yard at [redacted] Station which will include one new 161-138 kV 200 MVA transformer, one 161 kV and three 138 kV circuit breakers with associated concrete foundations, one 161 kV and eight 138 kV air break switches with associated concrete foundations. Extend out new 138 kV bus for new 138 kV line terminating at [redacted], with the initial 138 kV line to tie into the [redacted] line. Install new relaying packages for protection on new 138 kV bus, 161 kV bus, transformers [redacted] and [redacted] and the new 138kV transmission line. Install six CCVTs and add a second MPLS shelf for protection communications circuits. Install one 138 kV wave trap. Twelve steel support structures will be installed to accommodate the reconfiguration of the substation.

The yard expansion will take place in a parcel of land to the northwest of the existing [redacted] station. The property purchase for the yard expansion is presently being conducted as part of an existing Idaho Power asset replacement project.

[redacted] Substation

Install one new 138 kV line terminal, including one 138 kV circuit breaker and two 138 kV air break switches with associated concrete foundations, allowing the new 138 kV line to tie into the [redacted] line near [redacted] Substation. Install new relaying packages for protection on the AFTS 138 kV transmission line. Install six CCVTs and a second MPLS self for protection communication circuits. Install one 138kV wave trap. Six steel support structures will be installed to accommodate the additional 138 kV line terminal.

A yard expansion, and associated property purchase, is required on the north side of [redacted] Substation to accommodate the new 138 kV line terminal.

[redacted] Substation

Install three CCVTs with associated steel support structures and install one 138 kV wave trap.

5.3 Upgrades to the Transmission System

[redacted] 161 kV Line
Rebuild all 19 miles of the existing 161 kV [redacted] transmission line from single conductor to 2-conductor bundled 715 ACSR design. The new structures will be H-frame construction with direct buried engineered tubular steel poles. Dead end structures will be 3-pole design also with direct buried engineered tubular steel poles and include guying and anchors.

[redacted] 138 kV Line
Rebuild approximately 8.5 miles, between [redacted] Substation and [redacted], of existing 46 kV single circuit transmission line to double circuit 138/46 kV. The rebuild will be double circuit engineered steel mono poles, 5 deadends and 67 tangent structures. Deadend structures will require drilled pier concrete foundations and tangent structures will be direct buried. One 3-way ground operated air-break switch will be installed on IPC's existing 138 kV Line 163, near [redacted] Substation, to accept the new 138 kV line being installed from [redacted].

Install approximately 6 miles of 715 ACSR wire on existing 138 kV insulated available line position between [redacted] and [redacted] Substations. Install optical ground wire (OPGW) for entire 14.5 mile length of new 138 kV line between [redacted] Substation and [redacted].

Ground and LiDAR surveys required for all new line sections. Geotechnical survey required for foundations locations.

6. IPC Network Upgrade 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.

IPC Network Upgrade Estimated Costs:

Description	Ownership	Cost Estimate
Network Upgrades to IPC Substations:		
Upgrades to [redacted] and [redacted] substations as described in Section 5.2	IPC	**$6,798,298**
Contingency 10%		**$678,930**
Overheads 8.25%		**$616,129**

TOTAL		**$8,084,357**
Network Upgrades to IPC Transmission:		
Upgrades to IPC transmission lines as described in Section 5.3	IPC	**$30,631,768**
Contingency 10%		**$3,063,177**
Overheads 8.25%		**$2,779,833**
TOTAL		**$36,474,778**
GRAND TOTAL	**$44,559,135**	

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	Number of Turbines in High Speed Cutout	32767	32767	32767	-32767	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

All identified interconnection facility and network upgrades required for the interconnection of GI #580.

Identified Network Upgrades under Idaho Power's Authority (Detailed in Section 5 of this study)
Rebuild [redacted] 161 kV line with bundled (2) 715 ACSR.
Install new 200 MVA 161/138 kV transformer at [redacted].
Construct [redacted] 138 kV line with 715 ACSR. With a new line bay at [redacted] with PCB, switches and Protective Relay system.
[redacted]
Identified Interconnection Facilities and Network Upgrades under PacifiCorp's Authority (To be detailed in a separate Affected System Facilities Study)
3-Ring 161kV interconnection station (includes interconnection facilities)
Rebuild existing [redacted] 161kV line with 954 ACSR
Rebuild 15.9 miles of the existing [redacted] 161 kV line from the [redacted] station to [redacted] with 1590 ACSR.
[redacted] Substation - update relay settings
[redacted] Substation - update relay settings
[redacted] Substation - update relay settings

Appendix C

The following table C1 is a summary of the GI #580 contingent facility upgrades required and their conceptual costs.

Table C1: GI #580 Transmission Upgrades Required

Network Resources Transmission Upgrades	Estimated Cost
[redacted] 138 kV Line	NA