

Generator Interconnection Facility Study Report

for the



for



in

Sweetwater County, Wyoming

December 30, 2022

FACILITY STUDY REPORT (FSR)

[REDACTED]
Project GI #607

December 30, 2022

1. General Facility Description

[REDACTED] (“Interconnection Customer”) has stated that the proposed project will consist of 312 MW of [REDACTED], 312.96 MW of [REDACTED] and 312.96 MW of [REDACTED] in Sweetwater County, Wyoming and connect to the 345 kV system at Idaho Power Company (IPC)’s and PacifiCorp’s [REDACTED] Substation. The total project output as studied is 300 MW. PacifiCorp is responsible for the operation of [REDACTED] Substation including managing the engineering, design, and construction of projects at the site and as such is identified as an Affected Party to this Project. As an Affected Party and operator of [REDACTED] Substation, PacifiCorp has conducted its own review for this Project and determined the scope, cost estimate and milestone dates for identified Network Upgrades and interconnection facility requirements. PacifiCorp’s Affected System Facility Study Report is attached as an Exhibit to this study. Any changes or modifications to PacifiCorp’s study must be requested directly to PacifiCorp.

In e-mail correspondence with IPC [REDACTED] the Interconnection Customer has affirmed their election to proceed with this Facility Study as an NRIS interconnection. Additionally the Interconnection Customer has acknowledged that coordination with existing customers holding transmission capacity rights on the [REDACTED] 345 kV transmission path will be required to ensure that the major Network Upgrade options identified in the GI #607 System Impact Study, dated January 14, 2022, are not required. This can be accomplished by ensuring existing generation and proposed generation output does not exceed Idaho Power’s [REDACTED] 345 kV path capacity allocation.

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 [REDACTED] Project, specifically Generator Interconnection Project # 607 (“Project”), will be prepared for this project. The LGIA will be a definitive agreement that contains terms and conditions that supersedes this FSR.

1.1 Interconnection Point

The Interconnection Facilities are located near [REDACTED], Wyoming in Township [REDACTED], Range [REDACTED] and Section [REDACTED]. Because the Project’s requested connection point is at a substation jointly owned by Idaho Power and PacifiCorp but fully operated by PacifiCorp, the details of the specific

Point of Interconnection (“POI”) are determined by PacifiCorp in its Affected System Facility Study Report.

1.2 Point of Change of Ownership

The Interconnection Facilities are located near [REDACTED], Wyoming in Township [REDACTED], Range [REDACTED] and Section [REDACTED]. Because the Project’s requested connection point is at a substation jointly owned by Idaho Power and PacifiCorp but fully operated by PacifiCorp, the details of the specific Point of Change of Ownership are determined by PacifiCorp in its Affected System Facility Study Report.

1.3 Interconnection Customer’s Facilities

The Interconnection Customer’s Facilities [REDACTED] are located approximately [REDACTED] Substation. The Interconnection Customer will install a 345 kV tie line, wind turbines, solar arrays, batteries, inverters, disconnect switches, distribution collector system, transformers (including main step-up transformers), appropriate grounding measures, and associated auxiliary equipment. Interconnection Customer will build 345 kV facilities to the Point of Change of Ownership.

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

1. The wind system is comprised of [REDACTED] wind turbine generators (WTG), with each WTG connected to a 2.56 kVA isolating transformer with a 690 V grounded-wye to 34.5 kV delta rating.
2. The solar system is comprised of [REDACTED] inverter stations with each containing a 3.51 kVA isolating transformer with a 645 V grounded-wye to 34.5 kV delta rating.
3. The BESS system is comprised of [REDACTED] inverter stations with each containing a 3.51 kVA isolating transformer with a 645 V grounded-wye to 34.5 kV delta rating.
4. 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 wind, solar, and BESS generation project. It has been assumed the BESS will be charged via the wind and/or 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. The requested ESS grid-charging study will determine the specific requirements for allowing the BESS to charge via IPC’s transmission system.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 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.

1.4.2 Local Service

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

1.4.3 Meteorological Data—Wind

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), along with Relative Humidity, and 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 over the DDS 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 Customers responsibility and therefore not included in any Facility Study estimate.

1.4.4 Meteorological Data—Solar

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:* R.M Young Relative Humidity and Temperature Probe Sensors [REDACTED]
- *Wind:* R.M Young Wind Monitor [REDACTED]
- *Pryanometer:* Apogee Instruments [REDACTED]

1.4.5 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 at a substation jointly owned by Idaho Power and PacifiCorp but fully operated by PacifiCorp, the Interconnection Facilities have been determined by PacifiCorp in a separate Affected System Facilities Study Report attached as an Exhibit to this study. The Interconnection Facilities will be jointly owned by Idaho Power and PacifiCorp and fully operated by PacifiCorp.

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]	<i>Interconnection Customer</i>	<i>IPC receives Notice to Proceed.</i>
TBD	<i>PacifiCorp</i>	<i>Construction Agreement executed between Interconnection Customer and PacifiCorp</i>
6 months prior to Commissioning	<i>IPC</i>	<i>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.</i>
TBD	<i>PacifiCorp</i>	<i>PacifiCorp Construction and Commissioning Complete</i>
5 days after switching request made to PacifiCorp Dispatch	<i>Interconnection Customer</i>	<i>Switch at the Point of Interconnection can be closed</i>
TBD	<i>IPC</i>	<i>Notification from IPC’s Energy Contracting Coordinator confirming First Energy of Non-Firm Output</i>

TBD	<i>Interconnection Customer</i>	<i>Interconnection Customer testing begins</i>
TBD	<i>IPC</i>	<i>Notification from IPC's Energy Contracting Coordinator confirming Operation Date (pending all requirements are met) of Firm Network Resource Output</i>

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 and PacifiCorp 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 or PacifiCorp'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 or PacifiCorp, 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 and a terminal clearance is issued by IPC’s Grid Operator. The specific point of isolation is identified in PacifiCorp’s Facility Study Report for this Project.

4. Reactive Power

The Project must be capable of +/- 0.95 power factor operation, as measured at the high-side of the generator substation, for all MW production levels. 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.

IPC will determine the reactive power required to be supplied by IPC to the Interconnection Customer, based upon information provided by the Interconnection Customer. IPC will specify the equipment required on IPC’s system to meet the Facility’s reactive power requirements. These specifications will include but not be limited to equipment specifications, equipment location, IPC-provided equipment, Interconnection Customer provided equipment, and all costs associated with the equipment, design, and installation of IPC-provided equipment. The equipment specifications and requirements will become an integral part of the LGIA. IPC-owned equipment will be maintained by IPC, with total cost of purchase, installation, operation, and maintenance, including administrative cost to be reimbursed to IPC by the Interconnection Customer.

5. Network Upgrades

IPC has no identified Network Upgrades associated with the Project. Network Upgrades to substations and transmission lines jointly owned by Idaho Power and PacifiCorp, but fully operated by PacifiCorp, are contained in PacifiCorp’s Affected System Facility Study Report.

6. Estimated Costs

All estimated interconnection facility and Network Upgrade costs are identified in PacifiCorp’s Affected System Facility Study Report for this Project.

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 the 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	3276	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						