BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO ESTABLISH TARIFF SCHEDULE 68, INTERCONNECTIONS TO CUSTOMER DISTRIBUTED ENERGY RESOURCES	))))))	CASE NO. IPC-E-20-30

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

Jared L. Ellsworth

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Jared L. Ellsworth. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Transmission, Distribution & Resource Planning Director for the Planning, Engineering & Construction Department.

Q. Please describe your educational background.

A. I graduated in 2004 and 2010 from the University of Idaho in Moscow, Idaho, receiving a Bachelor of Science Degree and Master of Engineering Degree in Electrical Engineering, respectively. I am a licensed professional engineer in the State of Idaho.

Q. Please describe your work experience with Idaho Power.

A. In 2004, I was hired as a Distribution Planning engineer in the Company's Delivery Planning department. My principal responsibilities included developing distribution circuit, substation, and sub-transmission projects to meet growth needs primarily related to equipment capacity and voltage delivered to the customer meter. In 2007, I moved into the System Planning department, where my principal responsibilities included planning for bulk high-voltage transmission and substation projects, generation interconnection projects, and NERC reliability compliance standards. I transitioned into the Transmission Policy & Development group with a similar role, and in 2013, I spent a year cross-training with the Company's Load Serving Operations group. In 2014, I was promoted to Engineering Leader of the Transmission Policy & Development department and assumed leadership of the System Planning group in 2018. In early 2020, I was promoted into my current role as the Transmission, Distribution and Resource Planning Director. I am currently responsible for the planning of the Company's wires and resources to continue to provide customers with cost-effective and reliable electrical service.

Q. How is your testimony organized?

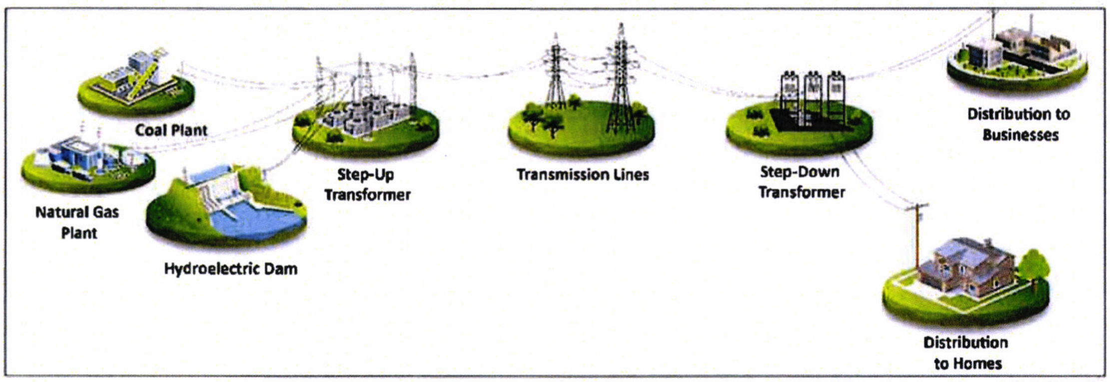
A. I will provide a general overview of the Company's electrical system and how customers with Distributed Energy Resources ("DER" or "DERs") utilize the Company's distribution system. I will then describe the Company's request to implement the functionality of smart inverters in accordance with Commission Order No. 34046 issued in Case No. IPC-E-17-13. Next, I will explain the Company's proposed interconnection requirements for customers seeking to interconnect a non-exporting system to meet a portion of their electricity needs while simultaneously maintaining an electrical connection to the grid ("in Parallel"). Finally, I will provide an overview of the rationale for the Company's proposed process as it relates to interconnecting energy storage devices.

I. IDAHO POWER'S GRID

Q. What is meant by the term "the grid"?

A. The grid, in this context, is the electric power system, including the generation, transformation, transmission, distribution, and delivery of energy in the form of electricity to customers.

Figure 1: The Grid



Generation converts energy contained in reservoirs, fossil fuels, wind, geothermal wells, or solar rays to electricity. Generation stations are often located remote from customers' point of use; therefore, the electricity is transformed to extremely high voltages to reduce electrical losses and moved on transmission lines over long distances. Once the electricity is delivered to communities, it is transformed to a lower voltage at substations and distributed through the local community on distribution lines. A final stage of transformation is used to reduce voltage to deliver electricity to customer's homes.

Q. Which services does the grid offer Idaho Power's customers?

A. The grid offers reliable and dependable electricity delivery across large regions in nearly the instantaneous time of a customer's demand. The grid also provides flexibility by allowing the utility access to a diverse portfolio of resources for power generation, even if those resources are located vast distances from where the power is needed.

Q. What functions does Idaho Power perform in order to maintain a safe and reliable distribution system and grid?

A. In order to provide safe and reliable energy on demand, Idaho Power must perform the following functions: voltage control, system protection, scheduling, dispatching, and load balancing. These functions are commonly referred to, and collectively known as ancillary services.

Q. How does Idaho Power control voltage to maintain a safe and reliable distribution system and grid?

A. Voltage control is achieved by managing the voltage throughout the grid at the generator, transmission system, and distribution system. The voltage regulating devices control the voltage output of the generators to match the voltage requirements established by personnel within the Company's dispatch control center ("System Operator"). At the substations, System Operators also remotely switch substation capacitors and inductors to raise and lower the transmission voltage, respectively. Automatic voltage management occurs at the distribution substation transformers with voltage control based on load, known as load tap changers. For longer distribution circuits, distribution regulators can be added away from the substation for additional voltage control. Additional automatic control signals are sent to switched distribution circuit capacitors based on substation transformer loading. Finally, voltage control occurs at substations that service large commercial and industrial customers.

Q. Does the distribution system provide other services that are specific to a customer with a DER?

A. Yes. The grid provides several services for customers with DERs, but most specific to the scope of this case, the distribution system enables inverter operation.

Q. What is an inverter?

A. An inverter is a power electronics device that converts direct current ("DC") electricity into alternating current ("AC") electricity. Inverters are used in both off-grid and on-grid applications.

Q. What types of DERs require an inverter?

A. Any DER that produces DC energy requires an inverter. An inverter is required for customers who install a solar photovoltaic ("PV") generation system or an energy storage device because solar panels and batteries produce DC electricity, but home appliances require AC power.

Q. How does Idaho Power define a Distributed Energy Resource?

A. In Schedule 68, Interconnections to Customer Distributed Energy Resources ("Schedule 68"), included as Attachment No. 1 to the Application, the Company proposes to define a DER as a source of electric power that is not directly connected to the bulk power system. For purposes of administering the proposed Schedule 68, a DER is any combination of a generation facility or an energy storage device connected in Parallel to Idaho Power's system.

Q. How does the grid enable inverter operation?

A. The majority of inverter-based systems connected to Idaho Power's grid are considered "on-grid" systems. For on-grid systems, the DC electricity generated by the solar PV system is sent directly to an on-grid inverter, which converts the electricity to AC for use by the customer or sent to the grid. Without the grid, the customer's generation system would not operate because these on-grid inverters require an AC voltage grid connection; without this connection, the inverter would not be able to develop voltage or deliver energy. In other words, the grid must be present for customers with on-grid inverters to operate their systems. For the purposes of my testimony, the discussion regarding inverters will be specific to on-grid inverters.

II. IMPACTS OF DER ON IDAHO POWER'S DISTRIBUTION SYSTEM

Q. Please describe a typical distribution circuit.

A. Historically, the distribution system could be characterized as a downhill flow of power from electrical substations, across distribution circuits, to customers. Absent DERs, power comes from centralized generators through the transmission system, and the distribution substation regulates the voltage of distribution circuits to deliver energy to customers. As energy travels across the distribution circuit further from the distribution substation, it is delivered at reducing amounts of voltage. American National Standards Institute ("ANSI") standard C84.1 Range A specifies that voltage provided to customers must be in the range of plus or minus five percent of the nominal voltage, i.e., 0.95 - 1.05 per unit ("pu").

Q. How do DERs affect distribution system operations?

A. DERs add a two-way power flow dynamic to the distribution system, so the historical downhill flow of power may no longer apply. In most installations, this dynamic is inconsequential; however, there are cases where DERs can negatively impact the performance of a distribution circuit. Two such cases are (1) voltage rise causing high voltage and (2) voltage deviations.

Q. Please describe what you mean by the term "voltage rise" that may be caused by DER systems.

A. Voltage rise occurs when customer generation exceeds customer demand, and power flows back toward the substation transformer.

ANSI standard C84.1 Range A specifies that service voltage be delivered to customers within a voltage range of 0.95 to 1.05 of nominal voltage. A typical voltage profile for a distribution circuit begins with a maximum voltage, approximately 1.03 pu, at the distribution substation transformer, and voltage will reduce with the distance from the substation. For distribution circuits with high penetrations of customer-owned DERs, the 0.02 pu difference between the 1.03 at the distribution substation, and the 1.05 ANSI Range A maximum voltage, can provide challenges in integration.

Q. Does the Company typically investigate voltage rise for customer generation applications?

A. Yes. The Company has studied this issue frequently with the Public Utility Regulatory Policies Act ("PURPA") projects connecting to the distribution system. The Company also monitors other utility jurisdictions with higher penetrations of DERs and voltage rise. Voltage rise, in particular, is one of the issues that can be addressed through smart inverters.

Q. What are typical means to address voltage rise?

A. Voltage rise is a function of the conductor size between the generation and the substation. One solution to reduce the voltage rise is to upgrade the conductor with a larger size. This solution is generally an expensive option.

Another solution is to change the settings on the voltage regulator to hold the voltage lower and allow for reverse power flow. This solution is dependent on the distribution configuration and will not work in all situations.

The third option is to use smart inverter settings for reactive power control functions. This is the most economical solution.

Q. Please describe what you mean by "voltage deviations" that may be caused by solar PV.

A. Distribution circuits have devices such as load tap changers, regulators, and shunt capacitors, that are installed to manage the voltage at various points on the distribution circuit. These devices respond to voltage changes over a few seconds. The output from a solar PV system changes more rapidly than can be managed by the distribution devices, impacting other customers in the near proximity.

Q. Why would a reduction of voltage deviation, a power quality issue, be the responsibility of the customer with a DER?

A. In most cases, it is the customer with a DER that creates the voltage deviation, especially in locations with high levels of penetration. Section 4 of Idaho Power's Rule K governing Customer's Load and Operations states "[t]he Customer is solely responsible for the selection, installation, and maintenance of all electrical equipment and wiring (other than the Company's meters and apparatus) on the load side of the Point of Delivery." It is also the customer with a DER that can cost-effectively mitigate the deviation through the installation of a smart inverter. The alternative would be more costly distribution system upgrades required to allow continued or expanded operation of the customer-generators.

III. REQUEST TO IMPLEMENT SMART INVERTER FUNCTIONALITY

Q. What is a smart inverter?

A. A smart inverter is an inverter that provides configurable functions beyond the conversion of DC to AC. A few of the features are voltage/reactive power control, anti-islanding, monitoring, and remote communication.

Q. Does the Company currently require that customers who install an inverter-based DER interconnect to the grid using a smart inverter(s)?

A. No. Section 2 of the current Schedule 72, Interconnections to Non-Utility Generation ("Schedule 72") found in Attachment Nos. 2 and 3 to the Application, requires that on-grid inverters have either a certification with Underwriters Laboratories *Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources* UL 1741 ("UL 1741"), Institute of Electrical and Electronic Engineers *Interconnecting Distributed Resources with Electric Power Systems* Standard 1547 ("IEEE 1547") or be subject to third-party testing performed at the customer's expense.

Q. What is the Company recommending in this filing regarding smart inverters?

A. The Company is requesting authorization to adopt the revised IEEE standards in compliance with Order

No. 34047 issued in Case No. IPC-E-17-13. This filing seeks to include the language in the newly proposed Schedule 68, to require that customers with DERs install a smart inverter that meets the requirements defined in the revised IEEE standards.

Q. What is the purpose of the IEEE 1547 and 1547.1 Standards?

A. The IEEE DER interconnection standards (IEEE 1547 and IEEE 1547.1) comprise the industry's benchmark and definitively establish the functional requirements for the proper interconnection of DERs within an Area Electric Power System (the utility). IEEE 1547 specifies the functional requirements for interconnection, including design, production, and installation commissioning evaluation. IEEE 1547.1 specifies the equipment conformance test and evaluation procedures.

Q. What is the purpose of the adjustable smart inverter variables?

A. The smart inverter variables are adjusted to set the normal operating performance categories (Category A or B) and abnormal voltage and ride-through operating performance categories (Category I, II, or III).

Q. What smart inverter functionality does the Company propose requiring to maintain normal operating voltage within the acceptable range?

A. The Company proposes voltage operational guidelines for inverter-based DERs to be set for normal operating performance Category B. The reactive power control setting will be a voltage-reactive function with a voltage dead band between 0.98 and 1.03 pu. When the voltage falls below the dead band, 0.98 pu, the volt-ampere reactive ("var") requirements will go from 0 to a maximum var requirement of 44 percent of nameplate kilo-volt-ampere ("kVA") injecting at 0.92 pu. When the voltage rises above the dead band, 1.03 pu, the var requirement will go from 0 to a maximum of 44 percent of nameplate kVA absorbing at 1.06 pu.

Q. Why did the company select the 0.98 to 1.03 pu dead band?

A. The Company selected the 0.98 to 1.03 pu dead band to maximize the amount of time inverter-based DERs spend within the dead band, in other words, operating at unity power factor, while still allowing for voltage support during times of need.

Q. Why is the Company recommending minimum (0.92 pu) and maximum (1.06 pu) voltage settings outside of the ANSI C84.1 Range A 0.95 to 1.05 pu service voltage?

A. The 0.92 and 1.06 pu voltages represent approximations to ANSI standard C84.1 Range B. Range B specifies a wider allowable service voltage range to customers; however, service voltages outside the 0.95 to 1.05 Range A limits should be infrequent, per the standard. These lower and higher limits in the smart inverters allow for var support over a wider range of voltages and ensure the need to supply maximum var support, injecting or absorbing, will be infrequent.

Q. What abnormal voltage and ride-through operating requirements does the Company propose?

A. The Company proposes that for abnormal voltage events and ride-through capability, inverter-based DERs be set to Category III.

Q. Did the Company consider requesting additional smart inverter functionalities to be implemented?

A. Yes, but the Company decided not to request additional smart inverter functionality requirements at this time. With the current level of DER penetration on its system, these proposed settings should provide the necessary voltage management capability. The Company recommends all other smart inverter settings be consistent with the most recently approved IEEE 1547 standard (currently IEEE 1547-2018) default settings.

Q. Will smart inverters reduce solar PV system efficiencies and/or increase costs for customers?

A. Any impact will be negligible. As previously mentioned, the Company is proposing the smart inverters have a voltage-reactive function reactive power control setting with a voltage dead band between 0.98 and 1.03 pu. Distribution circuit operation outside of this dead band will be uncommon. Absorbing or providing vars when outside of the dead band will require little to no reduction in the production of the PV Solar system.

The alternative would be more costly distribution system upgrades to allow the operation of the DER without on-site var/voltage support.

Q. What customer generators will be required to install a smart inverter?

A. The Company requests prospective customers that submit an application on or after the effective date of Schedule 68 comply with the smart inverter standard.

Q. Will customers with existing generation be required to retrofit their installations to comply with the new standard?

A. No. However, if a customer replaces an inverter, they would be required to install an inverter that is compliant with the terms of Schedule 68, or a successor schedule, in place at that time.

IV. CUSTOMER GENERATION NON-EXPORT OPTION

Q. What is the Company proposing as it relates to a customer generator that does not export to the grid?

A. The Company is requesting to implement standard interconnection requirements for customers who seek to install DERs but who do not intend to export excess net energy or do not wish to take service under Schedule 6, Residential Service On-Site Generation ("Schedule 6"), Schedule 8, Small General Service On-Site Generation ("Schedule 8") or Schedule 84, Customer Energy Production Net Metering Service ("Schedule 84").

Q. Does the Company have customers who have interconnected generation in Parallel without taking service under Schedule 6, 8, or 84?

A. Yes. I am aware of a few instances where commercial or industrial ("C&I") customers have interconnected either combined heat and power ("CHP") or solar PV systems behind-the-meter, and in Parallel with the Company's system, but whose request did not align with the requirements contained within Schedule 84. Some of those customers take service under the Company's Schedule 45, Standby Service ("Schedule 45"), but at least one opted not to take Schedule 45 service. I am aware of other customers who have inquired about requirements for DERs that exceed the limitations contained within Schedule 84, but who do not desire to export excess net energy to the Company.

Q. What interconnection requirements did the Company require in those cases?

A. In the cases I am aware of, the customers contacted the Company to determine whether any specific interconnection requirements were necessary. The Company studied each case independently to determine whether Company-furnished interconnection facilities would be necessary or whether the customer-furnished interconnection provided adequate system protection, metering, and communications equipment.

Q. Does Schedule 45 contain requirements for interconnection facilities?

A. Yes. Schedule 45 states:

> Parallel operations will only be authorized by the terms of the Uniform Standby Service Agreement with the Customer. At the Company's discretion, the Company will install a system protection package at the Customer's expense prior to the start of parallel operations. The Customer will also pay a Maintenance Charge of 0.59 percent per month times the investment in the protection package.

Q. If the Company has interconnected a few customers on a case-by-case basis, why does the Company believe it is now necessary to have requirements outlined in a tariff schedule?

A. The instances I mentioned have all interconnected in approximately the last two to three years, but the Company has fielded multiple requests more recently from customers desiring this type of service.

Having these requirements defined in the tariff will assist the Company's representatives, installers, and customers, alike who may be involved in discussions regarding interconnecting generation in this manner and will ensure consistent treatment across the service area.

Q. What interconnection requirements does the Company propose for non-export customers?

A. The Company's proposal would require customers intending to interconnect a non-exporting system in Parallel to the Company's system to submit an application and complete the Customer Generator Interconnection Process set forth in the proposed Schedule 68. The same general requirements would apply to net metering exporting systems and non-exporting systems, including disconnection equipment, metering equipment, and smart inverter requirements. For non-exporting systems under 3 megavolt-ampere ("MVA") total nameplate capacity, the application process will also generally be the same as those for exporting systems.

The Company has included additional interconnection requirements specific to non-exporting systems in Sections 3 and 4 of Schedule 68. Non-exporting systems would be required to incorporate one of three listed non-export control system options: (1) advanced functionality, (2) reverse power protection, or (3) minimum power protection.

Q. What is an advanced functionality non-export control system?

A. The use of an internal transfer relay, energy management system, or other customer facility hardware or software system(s) may be used to ensure power is never exported across the interconnection point. Inverter-based generation technologies, such as solar PV or energy storage devices, are particularly likely to utilize this control system. If inverter-based, the generating facility must utilize smart inverters as defined in Schedule 68.

As described in Schedule 68, the non-exporting system must monitor the total inadvertent export, and the DER must disconnect from the Company's distribution system or halt energy production within two seconds after the period of continuous inadvertent export exceeds 30 seconds. The non-exporting system must enter a safe operating mode where inadvertent export will not occur as a result of a failure of the control or inverter system for more than 30 seconds, which results in loss of control signal, loss of control power or single component failure or related control sensing of the control circuitry.

Q. What is a reverse power protection non-export control system?

A. To ensure power is never exported, a reverse power relay protective function must be implemented at the interconnection point. As described in Schedule 68, the default setting for this protection equipment shall be 0.1 percent (export) of the non-exporting systems total maximum nameplate capacity, measured in terms of either kVA or MVA, with a maximum two-second time delay.

Q. What is a minimum power protection non-export control system?

A. To ensure at least a minimum amount of power is imported at all times, and therefore, that power is not exported, an under-power protective function may be implemented at the interconnection point. As set forth in Schedule 68, the default setting for this non-export control system shall be five percent (import) of the non-exporting systems total maximum nameplate capacity (kVA or MVA), with a maximum two-second time delay.

Q. Do you believe these requirements will be burdensome for customers seeking to interconnect non-exporting systems?

A. No. Approximately 99 percent of active net metering systems on Schedule 6, 8, and 84 are inverter-based generation resources. Therefore, the Company would expect that most customers electing for the non-export option would choose to implement the advanced functionality for their non-export control system. As a result, this would not result in an incremental expense for the customer. The other two non-export control options are provided for the rare instances where utilizing the advanced functionality is not a feasible non-export control option.

Q. Does the Company propose limiting the total nameplate capacity for non-exporting systems?

A. Not in most instances. The net metering service available to exporting commercial, industrial, and irrigation ("CI&I") customers under Schedule 84 is limited to 100 kVA. For CI&I customers with non-exporting systems, the total nameplate capacity would not be limited. Customers on Schedules 1 and 7 would be limited to a total nameplate capacity of 25 kVA.

Q. Why is it reasonable to include limitations on Schedules 1 and 7, but not on other service schedules?

A. Generally, customers taking service under Schedule 1 or 7 will not have a load large enough to warrant a system larger than 25 kVA to offset their consumption. Further, placing a system cap on Schedule 1 and 7 will align with the nameplate capacity limits in Schedule 6 and 8 to allow for customers to transition between the applicable net metering and non-export service schedule.

Q. Would CI&I customers be able to transition from a non-export option to Schedule 84?

A. If the CI&I customer has a total nameplate capacity of 100 kVA or less, they would have the ability to transition to Schedule 84 in the same manner as a non-exporting customer generator can transition from Schedule 1 or 7 to Schedule 6 or 8, respectively.

Q. Does the Company propose any other requirements specific to customer generation non-exporting systems?

A. Yes. Rotating machines up to 500 kVA total nameplate capacity and inverter-based DERs up to 3 MVA may not require additional Company-furnished protection equipment but will be evaluated on a case-by-case basis. For systems 3 MVA or larger, the Company will require protection equipment, metering, and communications equipment.

Q. Why does the Company propose protection equipment requirements for larger systems?

A. For rotating machines on the distribution system, these larger systems provide a higher fault current contribution. For inverter-based systems on the distribution system, a DER of 3 MVA or greater represents a significant amount of generation and will make up a minimum of 30 percent of the capacity on a typical distribution circuit. Both types of DERs can affect distribution circuit voltage levels for other customers and can impact operational safety and distribution circuit reliability.

The addition of protection equipment provides a means to coordinate distribution circuit protection, such as circuit breakers, reclosers, and fuses.

Protection equipment will also be utilized to monitor voltage. A DER 3 MVA or greater has the ability to absorb or supply 1.3+ mega-var of reactive power, which can significantly impact the voltage on the distribution system. Protection equipment for these larger projects will ensure other customers on the feeder are protected from issues that may arise with the DER 3 MVA or greater.

Finally, protection equipment provides a means to maintain safety and reliability. Idaho Power operational personnel regularly maintain and operate distribution circuit equipment and must be aware of these larger DER installations when verifying de-energized sections of the circuit, or when transferring load between adjacent distribution circuits.

Q. Why does the Company propose a metering and communications equipment requirement for larger DER systems?

A. The company is proposing a metering and communications equipment requirement due to the system size and the need for operational visibility to complete critical System Operations functions. Visibility is required for the purposes of scheduling, dispatching, and load balancing.

For scheduling, the Company is responsible for forecasting future system loads and resources. Actual data from these customer sites with DERs 3 MVA and larger is critical for maintaining and refining an accurate load and resource forecast.

For dispatching, the Company's System Operators frequently move customers from one distribution circuit to another for operational and maintenance purposes. When shifting these customers, System Operators must consider whether ANSI standard C84.1 can continue to be met if the large DER system suddenly reduces output, for example, during a partly-cloudy day.

Finally, for load balancing, System Operators maintain a real-time balance between system load and system resources. Real-time information about the output of larger system resources, such as DERs 3 MVA or greater, provides important real-time visibility into what may be causing an area control error deviation, and whether a System Operator should take immediate action, or wait for the clouds to pass.

Q. What additional interconnection study requirements does the Company propose specific to non-exporting systems with a total nameplate capacity of 3 MVA and greater?

A. The Company proposes that for non-exporting systems with a total nameplate capacity of 3 MVA or greater, the Company will complete additional studies, as needed, at the customer's expense. In addition to the Feasibility Review completed for all DERs, non-exporting systems 3 MVA or greater may also require one or more of the following: Feasibility Study, System Impact Study, and a Facility Study. This process has been modified from the Generation Interconnection Process for PURPA Qualifying Facilities under Schedule 72 and is described in more detail in Section 4 of Schedule 68.

At the end of each stage of the study process, the Company will provide the customer generator with an increasingly more refined and detailed report that will present a list of necessary interconnection facilities. The report would also include a non-binding, good faith estimate of the customer generator's cost responsibility for the interconnection facilities. The Company expects the need for a System Impact Study will be rare and reserved for the most complex projects.

Q. Why does the Company propose that non-exporting systems 3 MVA or greater complete a full Customer Generator Interconnection Process?

A. Due to their size, they can significantly affect the grid's voltage. The process proposed by the Company for these larger non-exporting systems to complete the full Customer Generator Interconnection Process and sign a uniform interconnection agreement recognizes they must have similar performance characteristics compared to any other generation system interconnected under Schedule 72.

Q. Why must non-exporting systems have similar performance characteristics compared to any other generation system?

A. An example of this is during a transient condition that results in extremely low voltage (down 0.88 to 0.50 pu); the non-exporting system is required to continue operation for up 20 seconds. The non-exporting system operation, combined with other on-grid DERs, is required to remain connected to avoid a sustained system outage.

Q. Will non-exporting systems 3 MVA or greater need to enter Idaho Power's generation interconnection queue?

A. No. These DERs are non-exporting systems and, therefore, will not enter the Company's generation interconnection queue.

Q. When it is determined that system protection is necessary, how does the Company propose those upgrades will be funded?

A. The Company will install a system protection package at the customer's expense, and the customer will pay a maintenance charge of 0.59 percent per month times the investment in the protection package. While general upgrades on the distribution system are funded pursuant to Rule H, in the case of System Protection, the Company proposes the customer will pay the actual installed cost of the system protection equipment. This funding mechanism is similar to what is provided for under the Company's Schedule 45, Standby Service under the Parallel Operations section.

Q. Will the Company require a Customer Generator with a non-exporting system to fund upgrades on the Company's distribution system if the non-exporting system total nameplate capacity exceeds the capacity of the local distribution facilities?

A. No. The Company initially considered requesting tariff language that would require, for example, a Schedule 6 or 8 non-exporting customer to pay for a transformer upgrade if the system size exceeded that of the transformer. After considering feedback received from the Commission Staff and Idaho Clean Energy Association

("ICEA"), the Company opted to instead propose adding clarifying language to the tariff schedule that would require a customer to replace any damaged equipment if failure of the non-export control system resulted in damage to the Company's system.

Q. How does the Company propose to define the failure of the non-export control system?

A. Under the language proposed in Schedule 68, an unauthorized inadvertent export would conclusively indicate non-export control system failure. Unauthorized inadvertent export would be defined as the total exports in any 30-day period exceeding three hours of the total nameplate rating. The total nameplate rating is specified on the System Verification Form for a customer generator system. As an example, a 10 kVA AC system would be limited to 30 kWh of export in 30 days. If more than 30 kWh of export occurs, the non-export control system would have failed.

Q. What process does the Company propose to mitigate cases of unauthorized inadvertent export?

A. The Company would notify the non-exporting customer that their customer generation system has exceeded the inadvertent export limit.

For Schedule 1 and Schedule 7 customers, if not rectified within 30 days after receipt of the notification by Idaho Power, the customer can elect to disconnect the non-exporting system from the grid until the issue that caused the export is remedied. An Idaho Power inspection would be required before the non-exporting system could interconnect to the system again. If the customer instead chooses to take service under Schedules 6 or 8, the customer would complete the application process and be placed on Schedule 6 or Schedule 8, as appropriate. If the customer is placed on Schedule 6 or Schedule 8, the customer will be given the option to submit an additional application and be moved back to Schedule 1 or Schedule 7, as appropriate, after 180 days.

For customers on Schedules other than Schedule 1 or Schedule 7, upon notification from Idaho Power, the non-exporting system will be disconnected from the grid until the issue that caused the export is remedied. A Company inspection will be required before the non-exporting system can safely interconnect to the Company's system.

V. ENERGY STORAGE DEVICES

Q. Why is the Company proposing to define energy storage devices, such as batteries, in Schedule 68?

A. Customer installations of energy storage devices are growing. While energy storage devices are DERs, they are typically installed by customers for the purposes of backup power or time-shifting energy from an on-site generation facility.

Establishing criteria in the tariff will best enable the Company, installers, and customers to understand what interconnection requirements are applicable to batteries, just as it does today for generation facilities.

Q. Is the Company prosing to include additional interconnection requirements for energy storage devices?

A. Under the Company's current proposal, there would be no additional requirements for energy storage devices DC coupled to another generation system (shared inverters). The system size will be determined by the inverter nameplate rating.

Energy storage devices which are AC coupled (separate inverters) with a generation facility on Schedule 6, 8, or 84 will be treated as a separate DER and require a separate application and interconnection review. The total system size will be determined by the aggregate value of all separate inverter nameplate ratings at the customer's premise.

Energy storage devices which are AC coupled (separate inverters) with a non-exporting system or installed on a stand-alone basis would be subject to the provisions of Schedule 68, Section 3 for non-exporting systems. For an energy storage device to not export, it will be required to implement non-export control system Option 1 (Advanced Functionality).

Q. Does this conclude your testimony?

A. Yes.

DECLARATION OF Jared L. Ellsworth

I, Jared L. Ellsworth, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Jared L. Ellsworth. I am employed by Idaho Power Company as the Transmission, Distribution & Resource Planning Director for the Planning, Engineering & Construction Department.

2. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 20th day of July 2020, at Boise, Idaho.

Jared L. Ellsworth