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IDAHO PUBLIC
UTILITIES COMMISSION

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

CONNIE G. ASCHENBRENNER

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

A. My name is Connie G. Aschenbrenner. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Rate Design Senior Manager in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 2006, I received a Bachelor of Business Administration degree in Finance from Boise State University in Boise, Idaho. In December of 2011, I earned a Master of Business Administration degree from Boise State University. In addition, I have attended the electric utility ratemaking course The Basics: Practical Regulatory Training for the Electric Industry, a course offered through New Mexico State University's Center for Public Utilities.

Q. Please describe your work experience with Idaho Power.

A. In 2012, I was hired as a Regulatory Analyst in the Company's Regulatory Affairs Department. My primary responsibilities included support of the Company's Commercial and Industrial customer class's rate design and general support of tariff rules and regulations. In 2015, I assumed responsibilities associated with Residential and

Small General Service rate design, as well as activities associated with demand-side management ("DSM") activities. In 2016, I was promoted to a Senior Regulatory Analyst, and my responsibilities expanded to include the development of complex cost-related studies. In 2017, I was promoted to Rate Design Manager for Idaho Power, and in 2019 I was promoted to my current role as Rate Design Senior Manager. I am currently responsible for the management of the rate design strategies of the Company, as well as oversight of all tariff administration.

Q. What is the Company requesting in this filing?

A. The Company is requesting to establish tariff Schedule 68, Interconnections to Customer Distributed Energy Resources ("Schedule 68"), included as Attachment No. 1 to the Application, and to modify Schedule 72, Interconnections to Non-Utility Generation ("Schedule 72"), to remove only the provisions of Schedule 72 that relate to **retail** customer generation interconnection requirements. Attachment Nos. 2 and 3 to the Application include redline, legislative format and clean copies of Schedule 72, respectively.

Q. What are the primary objectives of the Company's request?

A. The primary objectives of the case are to implement an interconnection tariff schedule applicable only to retail customers who have Distributed Energy Resources ("DER" or "DERs"), establish a smart inverter standard for all new DER interconnections, and establish interconnection requirements for customers with DERs who do not wish to export excess net energy to the Company.

Q. Is Idaho Power requesting any changes to interconnection requirements contained in Schedule 72 applicable to Sellers owning or operating Qualifying Facilities that sign a Uniform Interconnection Agreement?

A. No. The Company's request in this case only addresses interconnection requirements for generation facilities that qualify for 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") and those retail customers of Idaho Power desiring to install a non-exporting system.

Q. Why is the Company proposing to address the interconnection requirements for retail customers with DERs at this time?

A. The Company submits this filing in response to Commission orders issued in Case No. IPC-E-17-13. In Order No. 34046, the Commission found that "smart inverters provide functionality that is beneficial to support the ongoing stability and reliability of the Company's distribution system" and a "smart inverter requirement will mitigate circuit voltage deviation in a cost-effective manner." As such, the Commission ordered the Company to file a tariff advice with the Commission within 60 days of the final adoption of the Institute of Electrical and Electronics Engineers ("IEEE") standards 1547 and 1547.1. The final IEEE 1547.1 Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces was published on May 21, 2020.

Further, in Order No. 34147 issued in the same case, the Commission stated it was "open to the possibility of allowing the customer opportunity to remove himself from the Company's net metering schedules" if that "customer can reasonably and safely eliminate the export of energy to the Company's grid." The Commission ultimately ordered, "a non-export option should be studied for feasibility and vetted for safety and operational concerns by the Company and interested stakeholders in the forthcoming docket."

Q. How is the Company's case organized?

A. My testimony will (1) briefly describe relevant case history related to the existing interconnection requirements applicable to customer generation, smart inverters, and the non-export option, (2) explain the rationale for implementing Schedule 68 and removing retail customer generator interconnection requirements from Schedule 72, (3) outline the proposed changes to existing tariff provisions applicable to retail customer applicants and existing customer generators, and (4) provide a brief overview of customer and installer communication related to this request.

Company witness Jared Ellsworth's testimony will (1) provide a general overview of the Company's electrical system and how customers with DERs utilize the Company's distribution system, (2) describe the Company's request related to incorporating the smart inverter requirement, (3) explain the Company's proposal for requirements for customers who desire to interconnect non-export systems in parallel with Idaho Power's system, and (4) describe the Company's proposed requirements for energy storage devices.

I. BACKGROUND

Interconnection Requirements

Q. When was Schedule 72 initially established, and what was its purpose?

A. On April 12, 1991, the Commission issued Order No. 23631, implementing Schedule 72 to be applicable to small and large non-utility generating facilities seeking to interconnect to Idaho Power's system for the purpose of selling energy.

Q. When was Schedule 72 initially modified to incorporate requirements associated with on-site generation installed by retail rate customers?

A. On November 9, 2001, the Company filed Case No. IPC-E-01-39 seeking approval of a new tariff Schedule 84, Customer Energy Production, Net Metering Service ("Schedule 84"). Concurrent with that filing, the Company filed two additional cases: (1) Case No. IPC-E-01-40 in which the Company sought to eliminate the net metering option language in Schedule 86 (contained in Option B of Schedule 86 at that time), and (2) Case No. IPC-E-01-38 in which the Company sought to establish the interconnection requirements for net metering customers within Schedule 72.

Q. What were the outcomes of those cases?

A. In Case No. IPC-E-01-39, the Commission issued Order No. 28951 approving the Company's request to include a net metering offering in Schedule 84, which would initially be available to residential and small commercial customers seeking to interconnect on-site generation systems 25 kilowatts ("kW") or smaller. In Case No. IPC-E-01-40, the Commission (in Order No. 29093) approved the Company's request to modify Schedule 86 to eliminate the net metering option previously offered under that schedule. Finally, in Case No. IPC-E-01-38, the Commission issued Order No. 29092, approving streamlined interconnection requirements for retail customer net metering projects to be contained within Schedule 72.

Q. Has Schedule 72 been modified subsequently to incorporate necessary revisions for customer generation offerings?

A. Yes. While not an exhaustive list, the Company sought modifications to Schedule 72 in two net metering specific cases, Case Nos. IPC-E-12-27 and IPC-E-17-13.

Q. What changes to Schedule 72 did the Company request in Case No. IPC-E-12-27?

A. The Company requested several modifications to Schedule 72 intended to improve clarity and increase customer understanding. The Company requested to reorganize Schedule 72 to clarify sections applicable to net metering service, expand details around the application process for net metering customers, and outline a new process to be applied to unauthorized net metering installations.

Q. Did the Commission approve the changes to Schedule 72 requested in Case No. IPC-E-12-27?

A. Yes. In Order No. 32846, the Commission approved the proposed settlement of the issues related to interconnection in that case.

Q. What changes to Schedule 72 did the Company request in Case No. IPC-E-17-13?

A. The Company requested revisions to Schedule 72 to incorporate the defined terms necessary to sync the interconnection requirements between Schedule 72 and the newly proposed Schedules 6 and 8.

Q. What position did parties to Case No. IPC-E-17-13 take on the issue of the Company's requested modifications to Schedule 72?

A. Both Commission Staff and the Idaho Clean Energy Association opposed the proposed revisions to Schedule 72. Commission Staff took the position that "the Company's proposed modifications are not minor, and constitute a major revision to Schedule 72" and because "Schedule 72 applies to all energy providers who interconnect with the Company's grid, including its [Public Utility Regulatory Policies Act ("PURPA")] interconnections" the Company's proposed changes should be considered in a separate case that would ensure input from all stakeholders."

Q. Did the Commission ultimately approve changes to Schedule 72?

A. Yes. In Order No. 34046, the Commission directed the Company to meet with Staff and other interested parties before filing conforming tariff language for Commission approval. Following the Commission's order, the Company scheduled a meeting with Staff and other interested stakeholders to walk through its proposed tariff changes, demonstrating the requested changes would not modify requirements applicable to PURPA interconnections. The Company subsequently filed its updated tariff schedule sheets with the Commission's ordered effective date.

Smart Inverters

Q. What was the Company's request in IPC-E-17-13 related to smart inverters?

A. The Company requested the Commission acknowledge that smart inverters provide functionality that is necessary to support the ongoing stability and reliability of the distribution system by ordering the Company to submit a compliance filing (by way of an advice filing) to require a smart inverter that meets the requirements defined in the revised IEEE standard.

Q. Did the Commission approve the Company's request?

A. Yes. In Order No. 34046, the Commission directed Idaho Power to file a tariff advice within 60 days of final adoption of IEEE standards 1547 and 1547.1 for investigation and final approval.

Non-Export Option

Q. Was the Commission's Order No. 34046 establishing Schedules 6 and 8 found to apply to non-exporting customers?

A. In the near term, yes; however, in granting reconsideration in Case No. IPC-E-17-13, the Commission directed interested parties to file briefs discussing whether a customer's ability to export energy should determine if the customer should be included in the newly established Schedules 6 and 8. After reviewing the evidence and arguments presented in the briefs, the Commission issued Order No. 34147 where it ordered that:

> all on-site generation customers classified in Schedules 6 and 8 remain there for now. However, we also find it is reasonable to provide an opportunity for a customer to be an on-site generator and not export its energy, thereby distinguishing himself from a customer who imports and exports energy.

The Commission went on to order that "a non-export option should be studied for feasibility and vetted for safety and operational concerns by the Company and interested stakeholders in the forthcoming docket."

Q. Did the Company and parties evaluate the feasibility of a non-export option in Case Nos. IPC-E-18-15 and IPC-E-19-15?

A. Yes. Over the course of 2019, the Company participated in roughly 13 meetings where parties to Case Nos. IPC-E-18-15 and IPC-E-19-15 engaged in discussions broadly related to the Company's customer generation offerings. Through those discussions, the Company obtained feedback related to a potential non-export option that could be made available to customers who did not want to interconnect generation facilities under the provisions of Schedules 6, 8, or 84.

Q. Generally, what feedback did the Company receive?

A. Parties were supportive of the Company implementing interconnection rules for non-exporting customers. Ultimately, several areas of agreement were reached related to the establishment of a non-export provision in the Settlement Agreement filed in Case No. IPC-E-18-15, which was intended to apply to residential and small general service customers:

- Non-export customers may receive service under Schedules 1 and 7;
- Before exercising the non-export option, a customer must file an application demonstrating the functionality and safety of the non-exporting system;
- Capacity limits for non-export customers will be the same as limitations listed in Schedules 6 and 8; and
- If exports occur and are not rectified, a process to either disable the system or to

transition the customer to the appropriate on-site generation schedule would apply.

Parties agreed on these broad principles and agreed to continue discussions related to specifics of the interconnection requirements in additional workshops.

Q. Did the Company host additional workshops?

A. Yes. The Company hosted two meetings specific to discussing a proposal for a non-export option. The meetings were held at Idaho Power's corporate headquarters building on October 23, 2019, and December 18, 2019. All parties to Case No. IPC-E-18-15 and Case No. IPC-E-19-15 were invited to attend one or both of those discussions.

Q. Did the Company incorporate stakeholder feedback into its recommendations in this case?

A. Yes. The Company's proposal related to the non-export option applicable to all service schedules was influenced by discussions with stakeholders. The Company believes its proposal, as outlined in Mr. Ellsworth's testimony, balances providing enhanced customer optionality while mitigating and monitoring system impacts that may ultimately impact other customers.

II. **REQUEST TO IMPLEMENT NEW TARIFF SCHEDULE 68**

Q. Please summarize the Company's rationale to implement a new interconnection tariff schedule in this case?

A. Establishing an interconnection schedule to be applicable to customer DERs separate from the interconnection requirements for Sellers on the Company's system is intended to distinguish requirements applicable to **retail customers** of Idaho Power who intend to interconnect DERs from requirements applicable to **Sellers** who seek to interconnect generation from Qualified Facilities to the Company's system. The Company believes this will reduce confusion and procedural process when parties are determining whether intervention and participation in a case is necessary to protect or advance their interests.

The Company believes separating the interconnection requirements will also reduce customer confusion; in its experience, some customers confuse which sections of Schedule 72 apply to their applications.

Q. Are there differences in the interconnection requirements for Idaho Power customers with DERs and those Sellers who interconnect under Schedule 72?

A. Yes. While most of the physical interconnection requirements may be consistent, the application process for **retail customers** with DERs is distinctly different from a Seller seeking interconnection. The funding for interconnection facilities is also slightly different; Rule H applies to a **retail customer** whose request for service requires the installation of new or upgraded distribution facilities, where a **Seller** under Schedule 72 pays actual work order costs for necessary upgrades on the distribution system. There are also Federal Energy Regulatory Commission requirements that are only applicable to Sellers and are not relevant to customer generators.

Q. You mentioned earlier that the Company is not proposing any changes to Schedule 72 provisions that are applicable to Sellers as part of this filing. Please explain.

A. The Company is only requesting to remove the provisions contained within Schedule 72 that apply to customer generators. The existing requirements and application of those remain unchanged for Sellers seeking to interconnect. Because of the removal of those sections only applicable to customer generators, the Company's Schedule 72 would be shortened from 34 pages to 28 pages.

Q. Did the Company discuss the proposal to remove the requirements from Schedule 72 applicable to customer generators with stakeholders in advance of this filing?

A. Yes. In both the October 23, 2019, and December 18, 2019 meetings, the Company discussed its plan to create a new service schedule as I have described. The

Company did not receive any opposition or feedback related to this component of the Company's proposal.

Q. When is the Company requesting Schedule 68 be effective?

A. The Company requests Schedule 68 to become effective 14-days after approval by the Commission. This 14-day implementation period is necessary to update communication materials with any approved changes to the interconnection requirements for customer DERs and provide to installers and prospective customers.

III. MODIFICATIONS TO EXISTING INTERCONNECTION REQUIREMENTS FOR RETAIL CUSTOMER DER

Q. Does the Company propose modifications to facilitate and administer the interconnection of customer DERs to its distribution system?

A. Yes. In preparation of the filing to modify the inverter requirements and establish the non-export interconnection requirements, the Company evaluated existing processes to determine whether improvements could be made to streamline existing processes and/or increase operational efficiencies or if changes were necessary to ensure the Company can continue to meet the requirements contained within the tariff schedule.

Through that review, the Company identified several opportunities that it believes will accomplish those goals:

(1) modified or added language intended to improve clarity for the Company in administering and for customers and installers in complying with the tariff schedule, (2) removed the three-year recertification requirement, (3) added flexibility of additional time, only as needed, to complete Feasibility Reviews, (4) modified requirements in the unauthorized systems and expansions section, and (5) implemented a return-trip charge if the Company is unable to complete an inspection.

Q. Is the Company proposing to define any new terms or create new processes in Schedule 68?

A. Yes. Mr. Ellsworth's testimony introduces several new definitions and proposed processes related to incorporating smart inverters and interconnecting non-export systems and energy storage devices. The supporting rationale for each is contained in his testimony.

Improve Clarity

Q. Why is the Company proposing to modify language or provide additional details in certain sections of the tariff schedule?

A. The last major revision to Schedule 72 was proposed in 2013, as part of workshops in Case No. IPC-E-12-27. At that time, the Company had approximately 350 existing and pending net metering customers and, through discussions with installers and customers, identified several modifications that were necessary to better outline expectations of the Company and of customer generators. In the seven years that have passed since that last major revision, the Company has interconnected or processed approximately 6,500 net metering applications (as of June 30, 2020). The Company's customer generation team fields and responds to thousands of phone calls and emails each year, and through those conversations have identified areas where the tariff language could be expanded to enhance understanding. With these language changes, the Company is not intending to implement new or different requirements; rather, it views these modifications as necessary to improve clarity.

Recertification Inspections

Q. What is the requirement in the existing interconnection tariff schedule regarding the recertification of on-site generation systems?

A. Section 2 of Schedule 72 requires the Company to perform a full recertification inspection of all on-site generation systems once every three years at no charge to the customer. In addition to the mandatory recertification, the existing tariff requirements provide that the Company may inspect any net metering system at any time if the Company identifies a condition that may be unsafe or may otherwise adversely affect the Company's equipment, personnel, or service to its other customers.

Q. How long has the Company performed three-year recertifications?

A. Idaho Power has performed three-year recertifications since the net metering interconnection requirements were initially established by the Commission in 2002. At that time, the Company requested the requirement for scheduled, periodic recertifications due to concerns that may arise from a customer generator modifying interconnection equipment in a manner that jeopardizes the integrity of the system.

Q. What is the Company's request in this case regarding periodic recertifications?

A. The Company requests to remove the mandatory three-year recertification requirement, and instead, authorize Idaho Power to conduct periodic inspections as needed.

Q. Why is the Company requesting to remove the mandatory recertification requirement?

A. In its experience, the Company identifies issues, most commonly unauthorized system expansions or disabled systems, in only a small portion of the total systems inspected during a recertification visit. The Company has identified other means it can utilize, at a lower cost for customers, to identify locations where changes have occurred without Company notification.

For example, it is now feasible to rely on reporting from its Automated Metering Infrastructure ("AMI") to identify whether a customer has expanded their system or cases where a system may no longer be online, and this could be done at a significant cost savings as compared to rolling a truck to re-inspect the system. In addition to relying on metering data, the Company may select a sample based on region or resource type to monitor for and identify any potential trends or issues that are identified on re-inspection that could be addressed more broadly.

Considering the significant growth in customer generation, the Company anticipates it would be required to perform approximately 1,800 re-inspections in 2021, which is projected to increase to 2,520 annual re-inspections by 2022. The projected increase is a result of the recent growth in customer generation and assumes no additional growth. Modifying this requirement to provide Idaho Power the opportunity to re-inspect in cases it believes may be warranted and eliminating the mandatory language will result in increased operational efficiencies for the Company and, ultimately, its customers.

Feasibility Reviews

Q. How many days is the Company afforded to complete a Feasibility Review?

A. Currently, the Company is required, per Section 2 of its Commission-approved Schedule 72, to complete the Feasibility Review in seven business days.

Q. What is the Company's request in this case regarding the completion of Feasibility Reviews?

A. The Company requests the Commission allow additional time in limited situations, where the Company identifies that additional studies are needed to complete a Feasibility Review. In those circumstances, the Company requests that it be required to notify the applicant of its need for additional time and be required to complete the Feasibility Review within 15 business days.

Q. Why does the Company believe this additional flexibility is warranted?

A. The Company's existing Feasibility Review is largely automated, and many applications "pass" the review based on studied criteria (transformer size vs. system size, phase compatibility, and project size vs. feeder capacity). In those cases where the automated review indicates an additional review is necessary, the application is forwarded to an engineer in the Company's Distribution System Planning department for further evaluation. As the volume of applications has increased, and as the number of projects tied to the same transformer or feeder increases, a more thorough and time-intensive review is warranted.

The Company's ongoing ability to meet this requirement has recently come into question, particularly as the number of Schedule 24, Agricultural Irrigation Service customers submitting requests for dozens of systems located in the same geographical area has increased. For these projects, the review team is expanded to include multiple engineers, and coordination with engineers from the regional offices is necessary. Modifying the requirement to permit a more thorough review in complex situations will ensure continued compliance with the requirements of the tariff schedule.

Unauthorized Systems and Expansions

Q. What are the current requirements when the Company identifies an unauthorized system or system expansion?

A. Section 2 of the existing Schedule 72 tariff schedule provides for immediate Company inspection without prior notice. At that point, there are three potential outcomes of the inspection:

- If proper disconnection equipment is present (and it is in most cases), the Company will open and lock the disconnect. Within twenty-four (24) hours of the disconnection, the customer will be called, and written notification will be sent.

- If disconnection equipment is not present and the customer's system utilizes a UL 1741 or IEEE 1547 inverter, the customer is contacted and given 15 days to submit an application and an additional 30 days to complete the necessary inspection requirements or must notify the Company within 30 days of their decision to disable their system. Customers who fail to take either action within the allotted timeframe are subject to termination of electric service.
- If no disconnection equipment is present and the Company cannot verify the presence of a compliant inverter, the customer is subject to immediate termination of electric service.

Q. How does the Company seek to modify the requirements for unauthorized systems or system expansions?

A. As part of the newly proposed Schedule 68, the Company recommends eliminating the requirement for Idaho Power to "lock" a customer's system and is also requesting the timeframes for either interconnecting a system under

Schedule 6, 8, or 84 or disabling the system be extended. The proposed Schedule 68 language would permit customers 12 months to either complete the Customer Generator Interconnection process or permanently disable the system.

The Company's proposed tariff language requires that at any point during an installation (whether a new application or a system expansion), a customer must keep the system disconnected to separate the customer's generation from the interconnected load until they have completed the application process.

Q. Why is the Company proposing these changes?

A. The current requirement for the Company to "lock" the system requires an Idaho Power employee to be called back on-site anytime a customer is working with an installer or state inspector to bring the system back into compliance. Often, the Company may be called back multiple times. While locking the system provides for some protection, the Company believes it is reasonable to rely on the customer and installer to keep the disconnect in the open position, just as it does for all new systems that are installed and awaiting inspection.

Through conversations with customers and installers, the Company does not believe the 45-day process outlined in the current tariff schedule provides customers with a reasonable opportunity to rectify the issues. Often, there are factors (e.g., state permitting, electrical inspections, weather) outside the Company or customer's control that prevent these timelines from being met. The Company believes allowing 12 months (as provided for new installations) more reasonably provides customers and installers with an opportunity to rectify the issues.

Return-Trip Charge

Q. What is the Company's proposal regarding a return-trip charge?

A. The Company is proposing to implement a $61.00 return trip charge for customers if the Company is unable to complete the inspection after the customer or installer has submitted a completed System Verification Form certifying the system is ready.

Q. Why is the Company proposing to implement a return trip charge?

A. The final step in the application process occurs when a system has successfully completed the Company's on-site inspection. Prior to the Company dispatching a field resource to complete the inspection, a customer must submit and sign a System Verification Form in which the customer (or in many cases, the installer acting as an agent of the customer) certifies that the on-site generation system is installed and that:

- The system meets all required codes and has passed the city/state electrical inspections;
- The system is operational, breaker and inverter are engaged;
- The AC disconnect is in the open or off position; and
- Required placards are in place.

In approximately 10 percent of inspections between 2018 and year-to-date 2020, the Company has been unable to complete the inspection once on-site due to one or more of these criteria that were incomplete despite certification otherwise.

Q. What is the significance of the Company having to perform multiple trips to perform an inspection?

A. The Company is incurring incremental and unnecessary expenses. In the short term, the Company is allocating resources to perform visits that are avoidable, and ultimately, this cost may be borne by other customers.

Q. What has the Company done to address the issue?

A. The Company's customer generation team communicates with new installers operating in Idaho Power's service area to provide an overview of the application process and interconnection requirements. When the Company identifies a specific issue with an installer, Idaho

Power's customer generation team will contact the installer to offer feedback and discuss the non-compliance, often asking the installer to meet a Company-representative on-site if more than two visits are required. In 2018, the Company updated its System Verification Form to include an affirmative customer acknowledgment that the site was ready to be inspected. Finally, the Company uses an electronic newsletter, provided periodically to installers to communicate about repeat issues.

Q. Have these enhanced communications been effective at reducing the number of return trips in the Company's service area?

A. No. Based on year-to-date 2020 data, the Company has had to return to perform an inspection in more than 10 percent of systems.

IV. CUSTOMER AND INSTALLER COMMUNICATION

Q. How will the Company notify installers and customers of its request in this case?

A. The Company will send a communication directly to installers known to be operating in its service area to notify them of the request regarding smart inverters. Subsequent to this filing, the Company will also update its customer generation webpage to include a summary of Idaho Power's request in this case and will maintain a list of frequently asked questions to address common customer or installer questions. In addition to providing advance notice of its intent to file this case, Idaho Power also served its Application and testimony on the parties of record in Case Nos. IPC-E-18-15 and IPC-E-19-15.

V. CONCLUSION

Q. Please summarize the Company's request in this case.

A. The Company requests that the Commission authorize the Company to implement the proposed Schedule 68 interconnection tariff specific to retail customers with DERs and remove the associated existing interconnection provisions from Schedule 72. The Company requests Schedule 68 become effective 14-days after approved by the Commission. The Company further requests that the Commission approve proposed modifications to the interconnection processes intended to improve efficiencies, adopt the electric industry's smart inverter standard, and outline provisions for interconnecting non-exporting systems to the Company's system.

Q. Does this conclude your testimony?

A. Yes.

DECLARATION OF CONNIE G. ASCHENBRENNER

I, Connie G. Aschenbrenner, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Connie G. Aschenbrenner. I am employed by Idaho Power Company as the Senior Manager of Rate Design in the Regulatory Affairs 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.

Connie Aschenbrenner

Connie G. Aschenbrenner