REDACTED

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF IDAHO AND FOR ASSOCIATED REGULATORY ACCOUNTING TREATMENT.	))))))))	CASE NO. IPC-E-23-11

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

ERIC HACKETT

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

A. My name is Eric Hackett. My business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Projects and Design Senior Manager.

Q. Please describe your educational background.

A. I graduated in 2003 from Boise State University in Boise, Idaho, receiving a Bachelor of Science degree in Civil Engineering. I am a registered professional engineer in the state of Idaho. In 2010, I earned a Master of Business Administration from Boise State University.

Q. Please describe your work experience with Idaho Power.

A. From 2005 to 2007, I was employed as an engineer in Idaho Power’s Transmission Engineering group. In 2007, I became a Project Manager leading transmission and distribution line and station infrastructure projects. In 2012, I was promoted to Engineering Leader where I managed the Cost and Controls group supporting project management. In 2015, I changed leadership roles and managed the Stations Engineering and Design group as an Engineering Leader. In 2018, I was promoted to Senior Manager of Projects overseeing Project

Management and Cost and Controls, which later became my current role of Senior Manager of Projects and Design in 2021, adding Power Production Design and Project Management. In addition, I am currently leading a team of internal employees and consultants in development and evaluation of Idaho Power's Request for Proposals for Peak Capacity and Energy Resources.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to discuss the growth in the Company's generation-related rate base since the completion of the Company's last general rate case ("GRC"), up to and including major projects expected to be complete in the 2023 test year. In my testimony I will discuss the prudent nature of these investments, detailing why they are needed to ensure Idaho Power's generation fleet is robust and well-positioned to provide continued safe, reliable service to customers.

Q. How is your testimony organized?

A. My testimony begins with a background of the Company's generation fleet and the factors that have led to generation-related investment since the conclusion of the Company's last GRC in 2011, Case No. IPC-E-11-08. I will then provide a discussion of proactive investments in Idaho Power's aging hydro fleet to ensure these facilities are well-equipped to continue to provide safe, clean and reliable energy to customers. My testimony will conclude with detail on Idaho Power's investment associated with the addition of utility-scale battery projects included in the 2023 test year, and explain why the Company's investment in these facilities reflects the least-cost, least-risk option to ensure sufficient capacity to meet customer demand in 2023 and beyond.

I. BACKGROUND

Q. Please describe Idaho Power's current generation fleet.

A. The backbone of Idaho Power's current generation fleet consists of the Company's 17 hydroelectric projects on the Snake River and its tributaries. Together, these projects comprise the Company's largest generation source at approximately 1,800 megawatts ("MW") of nameplate capacity. Additionally, the Company is the sole owner of three gas-fired generation facilities: the Danskin and Bennett Mountain simple-cycle power plants located near Mountain Home, Idaho, and the Langley Gulch combined-cycle power plant located near New Plymouth, Idaho, which provide approximately 762 MW of combined capacity. The Company also holds a 33 percent ownership share in the coal-fired Jim Bridger power plant ("Bridger"), which is expected to undergo conversion to natural gas generation at two of four units in the first half of 2024. Idaho Power's share of current coal-fired operations at Bridger provides approximately 706 MW of combined net dependable capacity. The Company also has access to 134 MW of net dependable capacity at the coal-fired North Valmy power plant, reflecting 50 percent of the nameplate capacity at Unit 2 of that facility. Lastly, the Company owns and operates a 5 MW diesel facility near Salmon, Idaho.

Q. How has Idaho Power's generation-related rate base grown since the last GRC in 2011?

A. As discussed in the Direct Testimony of Company Witness Ms. Lisa Grow, over the last decade Idaho Power has placed in service over $3.3 billion in infrastructure. Of this $3.3 billion, approximately $1.3 billion reflects investment in the Company's generation facilities. This investment was largely driven by growth on the Company's system and a proactive approach to addressing aging infrastructure. Because the Langley Gulch plant has already been approved for recovery in customer rates, the remainder of my discussion will focus on investments after Langley Gulch came online in 2012.[1]

Q. How has growth driven investment in Idaho Power's generation fleet since Langley Gulch came online in 2012?

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[1] Order No. 32585

A. For the first time since Langley Gulch came into service in 2012, Idaho Power is adding new Company-owned resources to its generation fleet in the 2023 test year. As discussed in Ms. Grow's testimony, the Company has experienced unprecedented growth over the past decade, adding approximately 117,000 new customers between 2012 and 2022. Over that same time period, normalized energy sales have grown from 14,010,319 megawatt-hours ("MWh") in 2012 to over 15,358,562 MWh in 2022. From a peak load perspective, Idaho Power's system peak load (approximately 95 percent of which is attributable to the state of Idaho) has grown from 3,245 MW in 2012 to 3,568 MW in 2022. As I will detail in the next section of my testimony, this growing load resulted in the Company experiencing a resource deficiency in 2023, thus necessitating the addition of new resources.

Q. How has the age of the Company's existing generation fleet driven investment over the last decade?

A. In addition to growth, Ms. Grow also describes how much of the Company's infrastructure is aging to the extent that replacement or refurbishment is required to maintain safe, reliable operation of the electrical grid. Much of the Company's hydro facilities are decades old, such as the Shoshone Falls power plant, which is over 100 years old, and the Hells Canyon Complex ("HCC"), which was constructed in the 1950s and 1960s. To ensure the Company’s generation fleet can continue to provide safe, reliable service, the Company takes a proactive approach to ensuring a robust and reliable generation fleet, resulting in significant investment over the last decade.

II. <u>HYDRO FACILITIES INVESTMENTS</u>

Q. Please describe the major investments related to the Company’s hydro fleet since the conclusion of the 2011 GRC.

A. Since the Company’s last GRC, Idaho Power has made several major investments in its hydro fleet, notably the refurbishment of all four turbines at the Brownlee hydrogeneration facility (“Brownlee”), upgrades and improvements at Shoshone Falls, and refurbishment of the Lower Salmon Falls hydrogeneration facility (“LSF”).

Brownlee

Q. Please describe the Brownlee hydrogeneration facility.

A. Brownlee is the most upriver dam in the HCC, which is comprised of the largest and most operationally flexible facilities in the Company’s hydro fleet. The HCC consists of three dams: Brownlee, Oxbow, and Hells Canyon, which, prior to the upgrades I will discuss, provided over 1,166.9 MW of nameplate generation capacity. Brownlee consists of five turbines, four with a generating capacity prior to refurbishment of 90.1 MW, for a total of 360.4 MW and one (Unit 5) with a generating capacity of 225 MW.

Q. What drove the need for the turbine refurbishment project at Brownlee?

A. At the time the refurbishment commenced, the four turbines at Brownlee had been in service for over 57 years. The turbines were nearing the end of their useful lives, cavitation damage had accumulated and deterioration was observed on the turbines and wicket gates. To ensure the reliable operation of the plant and the continued availability of this source of low-cost, clean hydropower, refurbishment of the turbines was absolutely necessary.

Q. Did Idaho Power gain any additional benefits from the turbine refurbishment project in addition to reliability?

A. Yes. In addition to improving reliability at the plant, the refurbishment project increased the nameplate capacity of Brownlee, resulting in an increase of 22.4 MW for each of units 1 through 4, or a cumulative increase of 89.6 MW for the entire facility, elevating the total nameplate capacity from 585.4 MW to 675 MW. Additionally, the existing turbine runners were replaced with new aerating runners, which added the ability to aerate the water to meet expected dissolved oxygen requirements associated with the Federal Energy Regulatory Commission ("FERC") license for the HCC.

Q. When was the Brownlee refurbishment project completed?

A. Refurbished Units 1, 3, 2, and 4 went into service in 2016, 2017, 2018, and 2019, respectively.

Shoshone Falls

Q. Please describe Shoshone Falls.

A. Shoshone Falls is a hydroelectric facility outside Twin Falls, Idaho. Prior to the upgrade of this facility, it consisted of three units at a combined nameplate capacity of 12.5 MW.

Q. Please describe the scope of work Idaho Power performed at Shoshone Falls since its last GRC.

A. Between 2018 and 2020, Idaho Power replaced Units 1 and 2, replaced the exterior equipment conveyer, made improvements to the intake structure, and completed significant work to ensure the safe, reliable operation of the plant.

Q. What drove the need for the replacement of these units?

A. Prior to their replacement, both units were over 85 years old. Unit 2 had become inoperable due to cavitation damage and cracking of the turbine runner, while Unit 1 was shut down in 2017 due to a thrust bearing failure. Further, under the existing setup, both units could only be operated manually from the powerhouse, limiting the ability for dynamic dispatch.

Q. Please describe the work Idaho Power performed at Shoshone Falls related to the generating units.

A. Idaho Power replaced Units 1 and 2 with a single horizontal new turbine and generator with a nameplate capacity of 3.2 MW, increasing the plant’s overall nameplate capacity to 14.7 MW. New unit ancillary equipment including a turbine inlet valve and turbine unit controls were also installed.

Lower Salmon Falls

Q. Has Idaho Power performed any other major upgrades or refurbishments at any of its other hydro facilities over the last decade?

A. Yes. For the last eight years, Idaho Power has been upgrading and refurbishing the hydrogeneration facility at Lower Salmon Falls to ensure the safe and reliable production of energy and to enhance the generation capability of this aging plant.

Q. Please describe LSF.

A. LSF was first constructed in 1910 by the Greater Shoshone and Twin Falls Power Company, then acquired by Idaho Power in 1916 and rebuilt in 1946. LSF consists of four generating units that provide a combined 60 MW of clean, reliable hydropower.

Q. What drove the need for investment in LSF?

A. Many components at LSF were aging and in need of replacement. Annual condition-based testing of the coils showed them to be deteriorated and in need of replacement. Various components of the facility were aging and in need of replacement, such as the coils (32 years), core (70 years), and turbine and mechanical components (70 years).

Q. Please describe the scope of work for the LSF refurbishment project.

A. Idaho Power replaced the turbine runners for Units 1, 2 and 3, and the Unit 2 Kaplan runner received new blades and refurbished inner mechanical components. The turbine unit was completely disassembled and mechanical components of the units were refurbished or replaced as necessary. The head cover was replaced on Units 1 and 3 due to cracking. Generator work included a new stator core and new coils for all units.

Q. What benefits will the LSF refurbishment provide?

A. This project is expected to increase unit efficiency by 2 to 5 percent and is anticipated to increase unit operational flexibility. In addition to incremental generation and flexibility, this project should reduce long-term maintenance costs as well. As an added benefit, the increased generation from the project is expected to qualify for tax credits and renewable energy credits (“REC”), which will be sold in accordance with the Company’s REC Management Plan to offset net power supply expenses for all customers.

Q. When is the LSF project expected to be completed?

A. Refurbished Units 1, 2, and 4 went into service in 2022, 2020, and 2015, respectively. Refurbished Unit 3 is scheduled to go into service December 2023.

Q. Do the examples discussed in your testimony reflect a prudent and proactive approach to managing the Company’s hydro fleet?

A. Yes. Over the last decade Idaho Power has completed numerous projects at its hydro facilities to ensure they are able to provide safe, clean, and reliable service to customers.

III. 2023 BATTERIES

Q. What drove the need for the addition of the utility-scale battery projects for which the Company is seeking a prudence determination in this case?

A. As discussed earlier in my testimony, Idaho Power has experienced and expects sustained load growth and transmission import constraints, thereby requiring the addition of new dispatchable resources to meet peak summer demand. As a result of this growth and import constraints, in May 2021, the Company identified a near-term capacity deficit in summer 2023. To meet its obligation to reliably serve customer load and fill this capacity deficiency, in June 2021, the Company issued a competitive solicitation through a request for proposals ("RFP") seeking to acquire dispatchable resources to be online by June 2023. This robust competitive bidding process resulted in the procurement of 120 MW of dispatchable four-hour duration battery energy storage as well as execution of a 20-year Power Purchase Agreement ("PPA") for 40 MW of photovoltaic ("PV") solar, all of which was necessary to adequately address 2023 capacity deficits.

Q. Did the Company file a request for a Certificate of Public Convenience and Necessity ("CPCN") for the 2023 resource procurement?

A. Yes. Idaho Power's request for a CPCN associated with a total of 120 MW of Company-owned battery storage, the Hemingway 80-MW four-hour duration battery energy storage system ("BESS") and the Black Mesa 40-MW four-hour duration BESS, was presented in Case No. IPC-E-22-13. At the conclusion of this case, the Commission granted a CPCN with Order No. 35643, stating that "...the evidence and the record ... demonstrates that the public convenience and necessity requires the Company to acquire 120 MW of dispatchable energy storage." The request for approval of the 20-year PPA for 40 MW of solar was filed in Case No. IPC-E-22-06, which was approved by the Commission in Order No. 35482.

Q. Did the Company request binding ratemaking treatment for the investments in the 120 MW of Company-owned battery storage facilities?

A. No. Due to the urgency of the 2023 capacity deficiency and the issuance of the resulting RFP, Idaho Power was still in the process of negotiating a number of agreements necessary for the construction, installation, and maintenance of the projects and, therefore, binding ratemaking treatment was not requested. The Company's request was that the Commission find Idaho Power had met the requirements of *Idaho Code* § 61-526 and issue a CPCN, which was ultimately granted in Order No. 35643.

Q. Did Order No. 35643 impose any conditions on recovery of costs associated with the procurement of the 120 MW of Company-owned battery storage?

A. Yes. Order No. 35643 approved the acquisition of the 120 MW of energy storage resources but found that "implementing a soft cap of up to $50,228,329 and $100,456,659, for the 40 MW BESS and 80 MW BESS, respectively, is reasonable."[2] This equates to a total soft cap of $150,684,988.

Q. Why did the Commission impose a soft cap on the 2023 battery storage investments?

A. In its Order, the Commission adopted Commission Staff's ("Staff") recommendation to implement the soft cap due to concerns regarding whether the selected resources were least-cost. In comments, Staff expressed concerns about the lead time and certain restrictions associated with the resource procurement process, resulting in its recommendation regarding the soft cap.[3] The soft cap did not foreclose future requests by Idaho Power for recovery of costs above the soft cap, but rather indicated the Company would have to provide justification for any costs above the soft cap when requesting rate recovery.

[2] Order No. 35643 pg. 12.
[3] Order No. 35643 pg. 13.

Q. Was the procurement of the 120-MW Company-owned battery storage facilities least-cost?

A. Yes. The Company's competitive solicitation process was initiated as soon as feasibly possible once the 2023 capacity deficiency was identified, and the project that was ultimately selected was the direct result of this process.

Q. What led to the rapid change in the 2023 capacity deficiency?

A. The Company's rapid change in the 2023 capacity deficiency was the result of several dynamic and evolving factors including: transmission availability, planning reserve margin determinations and reliability methodology modernization, an increasing population, new large customers in the service area and associated emergent load demands on the Company's system, and the ability of demand response programs and variable energy resources to meet load during the Company's highest-risk hours. The updated load and resource balance analysis prepared in May 2021 first identified a 2023 capacity deficit, and the Company immediately began to prepare an RFP, which was issued on June 30, 2021, roughly one month after the load and resource balance was updated.

Q. Was the RFP solicitation as expedient and robust as possible given the urgency of the capacity need in 2023?

A. Yes. Due to the urgency, the RFP solicitation focused on the importance of having a project in service by June 2023; given resource-specific permitting and construction timelines, the RFP solicited energy storage projects, solar PV projects, solar PV plus storage projects, wind projects, and wind plus storage projects. There was only one economic project bid into the RFP that was able to meet the required commercial operation date of June 2023 — the 20-year PPA associated with a 40-MW solar PV facility - which was selected through the RFP process.

The initial proposal also envisioned a build-transfer agreement associated with a 40-MW battery storage facility. However, during negotiations associated with the PPA, the developer indicated they were no longer interested in pursuing a build-transfer agreement and instead coordinated on the Idaho Power-owned battery storage project located at the developer’s solar PV site, ultimately resulting in a self-build option that was lower cost for customers.

Q. Aside from being the only economic project able to meet the required commercial operation date of June 2023, does the Company have any additional support to indicate the 120 MW of Company-owned battery storage facilities were least-cost?

A. Yes. At the time, Idaho Power was performing a parallel investigation into different configurations of Company-owned and constructed BESS, and the indicative pricing received was comparable to the lowest-cost proposals for similar battery storage projects submitted through the RFP process. In fact, pricing on the proposed 40-MW battery storage was based on a BESS from Powin Energy Corporation (“Powin”), one of the suppliers for which the indicative pricing was based. Procuring the BESS from Powin directly resulted in lower BESS costs, further supporting the acquisition of the least-cost, least-risk resource necessary to fill the 2023 capacity deficiency.

Q. Does the Company believe the RFP process was robust and that the resources procured were least-cost resources?

A. Yes. The 40-MW solar facility plus 40 MW of battery storage was identified through the RFP, resulting in a PPA for the solar facility. The decision for Idaho Power to procure the 40-MW battery storage facility directly from Powin was the result of conversations with the solar developer and Powin, ultimately resulting in a self-build option that was lower cost for customers. The remaining 80-MW project was identified through the

Company’s extensive analysis of other configurations to complement the RFP process, ensuring the resulting projects were least cost and least risk.

The lack of sufficient viable projects resulting from the RFP was not an indication that the RFP was inadequate, but rather the result of the requirement for a commercial operation date of June 1, 2023, which other bidding entities would not commit to achieving. During this time, the United States and the rest of the world were also experiencing significant supply chain disruptions and constraints, which impacted in-service dates and costs. The RFP was robust and sufficient, indicating prudent action based on information known at the time.

Q. Did Idaho Power agree with Staff’s quantification of the soft cap?

A. No. In Case No. IPC-E-22-13, the Company expressed concern that the quantification of the soft cap, presented in Staff’s Comments in that case, was flawed. Because Idaho Power did not receive multiple bids through the RFP process, Staff performed a benchmark analysis on which the quantification of the soft cap was based. The analysis, however, was based on a National Renewable Energy Laboratory (“NREL”) study that is intended for long-term planning purposes and ignores current market realities and supply chain disruptions that impact the costs of lithium-ion battery systems, resulting in a flawed analysis. In fact, the NREL study states in its disclaimer: the NREL data is “prepared for reference purposes only,” “based upon expectations of current and future conditions,” and “subject to change without notice.”[4]

While NREL data may be valuable in developing long-term integrated resource plan (“IRP”) forecast cost assumptions over a 20-year time horizon, market realities can vary significantly when contracting near-term resources. This was certainly the case between 2020 and 2022, as the COVID-19 pandemic, inflation, and other factors disrupted markets across the world. As evidenced by actual lithium-ion battery system costs, the downward pricing trend anticipated by NREL reversed into an upward trend starting in late 2021 and continued into 2022. This increasing price trend is well documented by industry reporting firms and will likely be incorporated into upcoming NREL forecasts.

Q. Are there any additional factors that would suggest the NREL study used by Staff is not appropriate for use in a benchmark analysis?

A. Yes. In addition to not factoring in current market realities, which include current real-world supply chain constraints, pricing, and above-normal inflation, the

[4] https://atb.nrel.gov/electricity/2022/disclaimer

NREL study referenced used 2020 as its base year or last historical year, which, at the time, anticipated a decline of 27 percent in costs from 2020 to 2023, as can be seen in the table below.

Table 1
NREL Forecasted Utility-Scale Battery Storage – 4Hr – Moderate

	2020	2021	2022	2023	2024	2025
$/kW	$1,727	$1,475	$1,371	$1,256	$1,167	$1,104
Annual Change		($252)	($104)	($115)	($89)	($63)
Annual Percent Change		-15%	-7%	-8%	-7%	-5%
Change from 2020		($252)	($356)	($471)	($560)	($623)
Percent Ch. From 2020		-15%	-21%	-27%	-32%	-36%

This stale NREL data did not consider recent market realities and should not have been used as a basis for Staff’s soft cap recommendation. Further, in the *Annual Technology Baseline: The 2022 Electricity Update*,[5] NREL notes that it does not track near-term cost variability, and further notes that the baseline is to help in conducting scenario analysis for 5 to 30-year futures.

Q. Did the Company see a decline in battery storage costs as indicated in the NREL study?

A. No, the opposite occurred. Demand for utility-scale BESS projects in the second half of 2021 and into 2022, coupled with supply chain constraints and above-normal inflation, resulted in an *increase* in pricing of

[5] https://www.nrel.gov/docs/fy22osti/83064.pdf, slide 54.

battery storage. Industry information suggested a 10 to 20 percent increase or more from 2020 levels, driven by this high demand, input prices for lithium carbonate, and inflationary pressures on other materials and labor.[6] Utility Dive noted in April 2022 that battery storage costs rose more than 20 percent as compared to 2020 and 2021 installs, stating "crimped supply chains, rising demand for batteries and higher costs of lithium used in ubiquitous lithium-ion batteries make for a steep climb ahead ..."[7] Nearly all battery material costs had increased over the prior year and some major battery module inputs increased significantly.

> The index for nearly every commodity that is required to manufacture lithium-ion batteries, including aluminum, copper, and nickel, has risen across the board. The price of lithium-carbonate has increased 500 percent in the last 12 months. Bloomberg New Energy Finance calculates that each 20 percent increase in the price of lithium-carbonate results in a three percent increase in the total cost of battery modules.[8]

[6] *IHS Markit:* "Multiple factors halt downward trajectory of Li-ion battery costs, with higher prices for energy storage systems set to continue throughout 2022 and 2023" January 6th, 2022.
[7] *Utility Dive:* "Battery storage costs rise more than 20% in New York as state forges ahead with 6 GW goal", April 12th, 2022.
[8] *Utility Dive:* "Navigating the evolving state of the storage industry," April 4th, 2022.

Q. Does Idaho Power have an alternative source of data that it believes would have been a more appropriate basis for a benchmark analysis of battery storage costs?

A. Yes. The most appropriate market guide is actual RFP responses. However, if a benchmark is desired, as part of the IRP process, the Company utilizes Wood Mackenzie, a global research and consultancy business that provides quality data, analytics, and insights for energy, chemicals, metals, mining, and the power and renewables industries, as a data source for battery storage prices. In *Wood Mackenzie's U.S. Energy Storage Monitor – 2021 Year in Review Full Report*, dated March 2022, average utility-scale four-hour battery prices averaged [redacted] per kilowatt ("kW") for the same time period, as compared to the NREL data utilized by Staff that suggested battery storage costs in 2021 would have been $1,475 per kW.

Q. How did the total estimated cost of the battery storage projects compare?

A. Using the Company's estimated project costs at the time Case No. IPC-E-22-13 was filed, the total cost of the 120 MW of battery storage projects, excluding interconnection and transmission upgrade costs analogous to the NREL and Wood Mackenzie cost estimates, was approximately $1,650 per kW. Staff used the outdated NREL data to benchmark Idaho Power's battery storage costs, suggesting that, based on the forecasted 2023 NREL battery storage costs, the Company could have procured the BESS for as little as $1,256 per kW, and therefore Idaho Power's selection of the products was not least cost. Yet, when current market conditions and industry trends are factored into battery storage costs, average costs for procurement in 2022 would range from $1,966 per kW to as high as $2,144 per kW, evidence that the soft cap was inherently flawed and punitive and should not have been imposed on Idaho Power.

Q. Assuming the low range of Idaho Power's estimate of the average cost for procurement of battery storage developed in 2022, what is the Company's quantification of a reasonable benchmark estimate?

A. Using the low end of the range, $1,966 per kW, for average battery storage costs developed in 2022 would suggest that a battery project costing $235.9 million represents a more reasonable benchmark estimate, which is $85.2 million greater than the soft cap imposed by the Commission.

Q. Your discussion of the average battery storage costs focuses on data available during the processing of Case No. IPC-E-22-13, the point at which Staff presented the benchmark analysis. Does Idaho Power have an updated estimate of the average cost of battery storage?

A. Yes. As part of the modeling for the 2023 IRP, Idaho Power is estimating average four-hour duration battery storage costs of $1,600 per kW.

Q. What is the total investment in the 120 MW of Company-owned battery storage included in the Company's 2023 test year?

A. The Company is requesting in this case to include $146.8 million for 120 MW of battery capacity plus an additional $28 million investment to account for performance degradation over time that will ensure the batteries maintain the 120 MW of capacity.

Q. Does the Company's request in this case reflect a cost that is below an appropriately calculated benchmark estimate?

A. Yes. The Company's total request for $174.8 million in rate base for the 120 MW of batteries reflects a cost of $1,457 per kW. Relative to available cost data at the time Case No. IPC-E-22-13 was being processed, the 2023 test year amounts are well below the range of $1,966 per kW to $2,144 per kW based on average costs for procurement in 2022. Further, the Company's 2023 test year costs are nearly 10 percent lower than current battery storage costs based on the Company's forthcoming IRP analysis.

Q. Does the information presented in your testimony support the Company's assertion that the 120 MW of batteries procured by Idaho Power were the least-cost option to meet the 2023 capacity deficiency?

A. Yes. Idaho Power identified a 2023 capacity deficiency in May 2021 and issued an RFP as soon as feasibly possible in June 2021. This robust competitive process ultimately resulted in the procurement of the 120 MW of batteries included in the Company's 2023 test year. The final cost of these batteries is lower than Wood Mackenzie-based pricing available at the time the 2023 CPCN case was being processed and was even less than costs available today. For all these reasons, the 120 MW of batteries included in this case represent the least-cost, least-risk option for customers.

IV. CONCLUSION

Q. Please summarize your testimony.

A. As mentioned in Ms. Grow's testimony, Idaho Power experienced unprecedented growth over the past decade, resulting in the need for the Company to procure its first utility-scale resources since Langley Gulch was placed in service in 2012. The Company's proactive approach to refurbishing and upgrading its existing resource fleet reflects a prudent approach to ensuring the continued provision of safe, clean, and reliable energy to meet the needs of Idaho Power's customers. Idaho Power's investment in the 2023 batteries reflects the least-cost, least-risk option to meet the Company’s resource need, as identified in the 2023 CPCN case and affirmed in Commission Order No. 35643.

Q. Do you believe the inclusion in rates of the generation-related rate base in the Company’s 2023 test year would result in fair, just, and reasonable rates?

A. Yes.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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DECLARATION OF ERIC HACKETT

I, Eric Hackett, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Eric Hackett. I am employed by Idaho Power Company as the Projects and Design Senior Manager.

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 1st day of June 2023, at Boise, Idaho.

Signed: ____________________
ERIC HACKETT