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January 28, 2019

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: Docket LC 68 - Idaho Power Company's 2017 Integrated Resource Plan ("IRP")

Attention Filing Center:

Attached for filing in the above-identified docket is Idaho Power Company's Update Report.

Please contact this office with any questions

Sincerely,

Alisha Till

Alisha Till
Paralegal

Attachment

INTEGRATED RESOURCE PLAN

IDAHO POWER
An IDACORP Company

2017 IRP UPDATE

JANUARY • 2019



SAFE HARBOR STATEMENT

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Glossary of Acronyms

AC—Alternating Current
ACOE—Army Corps of Engineers
AEG—Applied Energy Group
AMI—Advanced Metering Infrastructure
AFUDC—Allowance for Funds Used During Construction
ATB—Annual Technology Baseline
B2H—Boardman to Hemingway
BLM—Bureau of Land Management
BPA—Bonneville Power Administration
DC—Direct Current
EFSC—Energy Facility Siting Council
EIA—Energy Information Administration
EIM—Energy Imbalance Market
EIS—Environmental Impact Statement
EPA—Environmental Protection Agency
GPCM—Gas Pipeline Competition Model
kV—Kilovolt
kW—Kilowatt
IRP—Integrated Resource Plan
IRPAC—IRP Advisory Council
LDC—Load Duration Curve
LNG—Liquefied Natural Gas
LOG—Low Oil and Gas Price Forecast
LTCE—Long-Term Capacity Expansion
MW—Megawatt
MWh—Megawatt-Hour
NEPA—*National Environmental Policy Act of 1969*
NERC—North American Electric Reliability Corporation
NLDC—Net Load Duration Curve
NREL—National Renewable Energy Laboratory
ODOE—Oregon Department of Energy
OFPC—Official Forward Price Curve
OPUC—Public Utility Commission of Oregon
POD—Plan of Development
PURPA—*Public Utility Regulatory Policies Act of 1978*
PV—Photovoltaic
R&D—Research and Development
ROD—Record of Decision
ROW—Right-of-Way

SCR—Selective Catalytic Reduction
TRC—Technical Review Committee
USFS—United States Forest Service
VER—Variable Energy Resource
WECC—Western Electricity Coordinating Council

1. Summary

Idaho Power Company (Idaho Power) filed its *2017 Integrated Resource Plan* (IRP) with the Public Utility Commission of Oregon (OPUC or Commission) on June 30, 2017. Idaho Power's 2017 IRP was designed to identify the least-cost, least-risk set of resources to reliably serve Idaho Power's customers over the 20-year planning horizon. The OPUC acknowledged Idaho Power's 2017 IRP in Order No. 18-176 issued May 23, 2018.

In Idaho Power's final reply comments and during the 2017 IRP public meeting at the OPUC, Idaho Power requested a waiver from IRP guideline 3(f) that requires an annual update on the utility's most recently acknowledged plan on or before the acknowledgement order anniversary date. Idaho Power made this request because the annual update would be due for filing very close to the date on which the company's 2019 IRP would be filed. The Commission granted Idaho Power a waiver of guideline 3(f) on the condition the company report to the Commission providing an update on the following topics:

- A comprehensive update of the Boardman to Hemingway transmission line (B2H) project
- Information about the planned gas price forecast for the 2019 IRP, and any appropriate updates on the natural gas price forecast
- A discussion of portfolio modeling options and preferences for the 2019 IRP
- An update on Jim Bridger environmental control developments and options

In compliance with Order No. 18-176, Idaho Power submits this 2017 IRP report providing updated information on the requested topics. Additionally, the report also addresses changes or enhancements to IRP inputs and methodologies that apply to the 2019 IRP, including resource-cost assumptions, hourly load shaping, changes to planning margins, capacity value of solar, integration charges, and modeling of energy efficiency.

Idaho Power's public involvement process for the 2019 IRP officially began in September 2018. To date, the IRP Advisory Council (IRPAC) has convened for five monthly sessions to discuss various aspects of the 2019 IRP. Stakeholder engagement in the current 2019 IRP process has been robust and has influenced many of the 2019 IRP changes discussed in the report.

2. Boardman to Hemingway Transmission Line

Idaho Power, PacifiCorp, and Bonneville Power Administration (BPA) jointly propose to design, construct, operate, and maintain a new, approximately 300-mile long, 500-kilovolt (kV), single-circuit electric transmission line from the proposed Longhorn Substation near Boardman, Oregon, to the Hemingway Substation near Melba, Idaho—known as the Boardman to Hemingway transmission line. Idaho Power is leading the permitting process for the project.

In January 2018, Idaho Power submitted the 2017 IRP Appendix D: B2H Supplement, which provided comprehensive information on project need, history, benefits, co-participants, costs, risks, and project activities. On May 23, 2018, the Commission issued Order No. 18-176 in Docket No. LC 68 that specifically acknowledged Idaho Power's 2017 IRP's action items to conduct ongoing permitting, planning studies, and regulatory filings for the B2H transmission line, as well as to conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project. The following section details additional activities that have occurred since Idaho Power's 2017 IRP was filed with the OPUC in June 2017.

Federal Permitting

The permitting phase of B2H is subject to federal review and approval by the Bureau of Land Management (BLM), the United States Forest Service (USFS), the Department of the Navy (Navy), the Army Corps of Engineers (ACOE), and certain other federal agencies. The following subsections will provide updates on each of the respective federal permitting processes.

National Environmental Policy Act

BLM, as the lead federal agency on the *National Environmental Policy Act of 1969* (NEPA) review, issued its final Environmental Impact Statement (EIS) for the project in November 2016. The agency-preferred route set out in the EIS would run across approximately 100 miles of federal land, 190 miles of private land, and 2.9 miles of state land. There are no updates since the Commission's order in LC 68 regarding the NEPA EIS.

Bureau of Land Management

On November 17, 2017, the BLM released its record of decision (ROD) for the B2H project authorizing the construction, operation, and maintenance of the B2H project on BLM-administered land. In January 2018, BLM issued a right-of-way (ROW) grant to Idaho Power for the approximately 85.1 miles of transmission line that would be constructed on BLM land. There are no updates since the Commission's order in LC 68 regarding the BLM ROD.

United States Forest Service

On November 13, 2018, the USFS issued its ROD, which approved the B2H project. Idaho Power anticipates the USFS will issue an easement agreement in early 2019 for the approximately 6.8 miles of USFS land the B2H project crosses.

United States Navy

Idaho Power submitted a final revised application to the United States Navy, at Whidbey Island Naval Air Station, on June 1, 2018. The application is a request to locate B2H on approximately 7.1 miles of the Naval Weapons Systems Training Facility Boardman (also known as the

Boardman Bombing Range). The application was originally submitted in 2015 and has been modified since then based upon ongoing dialogue with the Navy.

The revised application minimizes, or avoids, impacts to habitat and cultural areas of significance on the Boardman Bombing Range. The Navy has indicated the B2H project will not impact flight operations and is currently reviewing the application. The Navy is using the BLM EIS for resource information, as well as documentation provided in the application. The Navy expects to issue its ROD in the first quarter of 2019, and to execute an easement agreement in the second quarter of 2019.

Idaho Power's project team continues to work with the Navy and BPA on the details for removal of BPA's existing 69-kV line from the Boardman Bombing Range to clear the ROW for B2H. BPA expects to issue a ROD in early 2019 for the removal of the existing line.

State of Oregon Permitting

On June 19, 2017, Idaho Power submitted its Amended Application for Site Certificate to the Oregon Department of Energy (ODOE) and other reviewing agencies, marking a major milestone in the Oregon permitting process conducted by the Energy Facilities Siting Council (EFSC). This was followed by the submittal of hard copies of the approximately 17,000-page application on July 19, 2017.

In September 2018, ODOE deemed the application complete, and Idaho Power submitted the final version of the application. Public informational meetings were held the week of October 15, 2018, in each of the five Oregon counties directly impacted by the B2H project. ODOE's focus is now on preparing and issuing a draft proposed order, which is expected in the second quarter of 2019. ODOE will accept and consider public comments on the draft proposed order, issue a final proposed order, and hold a contested case proceeding to address the public comments. Following those proceedings, EFSC will issue its final order and site certificate, which Idaho Power expects to occur in 2021. In the meantime, Idaho Power continues to meet with reviewing agencies and other stakeholders to facilitate the ODOE state application process.

Preliminary Construction Activities

The previous sections of this report are categorized as ongoing permitting, planning studies, and regulatory filings. The following activities: title search, Geotechnical Plan of Development (POD), and construction agreements may be considered "preliminary construction activities," but still fall under the scope of the *Amended and Restated Boardman to Hemingway Transmission Project Joint Permit Funding Agreement*. Please refer to pages 63-64 of the 2017 IRP for more information on B2H preliminary construction activities.

Title Search

Idaho Power has requested a formal title search from title companies for all parcels where Idaho Power would seek to obtain a ROW from private landowners for any facilities related to the project. Idaho Power expects all title reports will be completed in 2019.

Geotechnical Plan of Development

Approval of a geotechnical POD and a notice to proceed from the BLM are required before Idaho Power can take core samples along the project route, which are necessary to inform the final design of the project. In the fall of 2018, Idaho Power submitted a draft geotechnical POD to the BLM for review and approval. Dialogue is ongoing with the BLM. Idaho Power expects to finalize the geotechnical POD in spring 2019 and anticipates the BLM will issue a notice to proceed. Geotechnical sub-surface activities are expected to start in 2020.

Construction Agreements

Per the *Amended and Restated Boardman to Hemingway Transmission Project Joint Permit Funding Agreement*, negotiations for reaching definitive development and construction agreements are formally triggered by ODOE’s issuance of the draft proposed order, which is expected in the second quarter of 2019. The parties have 120 days from the date of the draft proposed order to execute development and construction agreements. The parties may mutually agree to extend the negotiation period for an additional period, not to exceed 120 days.

Project Cost Estimate

Idaho Power contracted with engineering and construction firm HDR, Inc., to serve as the B2H project’s third-party owner’s engineer and to prepare the B2H transmission line cost estimate. The cost estimate was updated in fall 2018. The 2017 IRP Appendix D provides additional background on HDR, Inc., and the components of the B2H total cost estimate. The total cost estimate for the B2H project remains at $1.0 to $1.2 billion dollars, which includes Idaho Power’s allowance for funds used during construction (AFUDC) and a 20 percent contingency for unforeseen project expenses.

Within the 2019 IRP modeling assumptions, Idaho Power assumes a 21.2 percent share of the direct expenses, which equates to approximately $223 million. This represents roughly a 9 percent increase in direct expenses compared to the 2017 IRP estimate. Idaho Power also included costs for local interconnection upgrades, which are now estimated to cost approximately $21 million, up from $16 million in the 2017 IRP. Idaho Power is in the process of developing the Idaho Power AFUDC estimate for the project that will be added to these direct expense estimates for purposes of IRP modeling.

Project Schedule

Permitting activities are ongoing. Idaho Power expects EFSC to issue a final order and site certificate in 2021. To achieve an in-service date in the mid-2020s, preliminary construction activities must be conducted in parallel to Oregon permitting activities. Construction activities will begin after permitting and preliminary construction activities conclude. Material acquisition and construction activities are expected to take three to four years. The specific timing of each preliminary construction and construction activity will be coordinated with project co-participants. Given the status of ongoing permitting activities and the length of the construction period, Idaho Power expects the in-service date for the B2H transmission line to be in 2025 or beyond. For 2019 IRP modeling purposes, Idaho Power is assuming a June 2026 in-service date.

3. Jim Bridger Options

One of the primary objectives of Idaho Power's factorial portfolio design for the 2017 IRP was to inform the IRP's action plan with respect to selective catalytic reduction (SCR) investments required for Jim Bridger units 1 and 2 by 2022 and 2021, respectively. The 2017 IRP portfolio analysis indicated a pivot away from making the SCR investments on Jim Bridger units 1 and 2, and the action plan included actions consistent with the planning and negotiations necessary to facilitate the units' continued operation without SCRs and potential early retirement dates of 2028 for Unit 2 and 2032 for Unit 1. The Commission declined to acknowledge the IRP action plan item related to Jim Bridger units 1 and 2 and requested an update on Jim Bridger environmental control developments and options.

Since that time, Idaho Power and PacifiCorp have continued discussions with the state of Wyoming and the federal Environmental Protection Agency (EPA) on the Jim Bridger Regional Haze compliance alternatives and will keep the Commission apprised of any substantive outcomes from these discussions.

In addition, in developing the resource portfolios for the 2019 IRP, Idaho Power will allow the AURORA model to optimize portfolios by adding additional resources and/or retiring existing generation units (including all Jim Bridger units) based on economics to serve the projected load over the IRP planning horizon. Moreover, there are four portfolio runs developed specifically for Jim Bridger units 1 and 2. More detail on the company's portfolio modeling in the 2019 IRP is discussed in Section 5, *Portfolio Modeling*.

4. Natural Gas Price Forecast

To make continued improvements to the natural gas price forecast process, and to provide greater transparency, Idaho Power began researching natural gas forecasting practices used by electric utilities and local distribution companies in the region. The following table provides excerpts from IRP and avoided-cost filings, which gives an indication of the approaches used to forecast natural gas prices:

Table 4.1 Utility Peer Natural Gas Price Forecast Methodology

Utility	Gas Price Forecast Methodology
Rocky Mountain Power 2017 IRP	The October 2016 natural gas OFPC (Official Forward Price Curve), which was used in the 2017 IRP, was based on an expert third-party long-term natural gas forecast issued August 2016.
Avista Electric 2017 IRP	Avista uses forward market prices and a forecast from a prominent energy industry consultant to develop the natural gas price forecast for this IRP.
Avista Gas 2016 Natural Gas IRP	Avista reviewed several price forecasts from credible sources and created a blended price forecast to represent an expected price strip.
Portland General Electric 2016 IRP	PGE derived the Reference Case natural gas forecast from market forward prices for the period 2017 through 2020 and the Wood Mackenzie long-term fundamental forecast for the period 2022 through 2035. A transition from the market price curve to Wood Mackenzie's long-term forecast is made by linearly interpolating for one year (2021).
Northwest Natural 2018 Oregon IRP	NW Natural's 2018 IRP natural gas forecast is of monthly prices developed by a third-party provider (IHS) based on market fundamentals. Cited source extracted from IHS Global Gas service and was developed as part of an ongoing subscription
Cascade Natural Gas Company 2018 Oregon IRP	Cascade's long-term planning price forecast is based on a blend of current market pricing along with long-term fundamental price forecasts. The fundamental forecasts include Wood Mackenzie, Energy Information Administration (EIA), the Northwest Power Planning Council (NPPC), Bentek (a S&P Global company), and the Financial Forecast Center's long-term price forecasts.

Based on the methodologies employed by Idaho Power's peer utilities, as well as feedback received during the current 2019 IRPAC meetings, Idaho Power made the decision to enlist the service of a well-known third-party vendor by subscribing to S&P Global Platts North American Natural Gas Analytics (Platts).

Platts provides energy consulting services for 12,000 companies in over 190 countries worldwide, including eight of the top ten Fortune 500 companies and nine of the top ten FT 500 companies. Over the past several years, Platts acquired energy consulting companies Bentek and PIRA to strengthen its footprint in this industry and is now considered the foremost provider of such services. For natural gas price forecasting, Platts developed a model that it refers to as the Gas Pipeline Competition Model (GPCM).

Idaho Power invited Beth McKay, Manager, North American Natural Gas Analytics at S&P Global Platts, to present to the IRPAC on October 11, 2018. The Platts forecast information below was presented at the October 2018 IRPAC meeting.

Platts' GPCM uses the following inputs/techniques to develop its gas price forecast:

- Supply/demand balancing network model of the North American gas market
- Oil and natural gas rig count data
- Model pricing for the entire North American grid
- Model production, transmission, storage, and multi-sectoral demand every month
- Individual models of regional gas supply/demand, pipelines, rate zones and structures, interconnects, capacities, storage areas and operations (160 supply areas, 272 pipelines, 444 storage areas, and 694 demand centers) and combines these models into an integrated North American gas grid
- Solves for competitive equilibrium, which clears supply and demand markets as well as markets for transportation and storage

Industry events which informed Platts' 2018 natural gas price forecast include:

- Greater regionalization, with Gulf (export) dominance waning
- Status of North American major gas basins
- The emergence of the Northeast as a self-sufficient region, with a risk of periodic surplus and a chronic need for additional markets
- Texas/Southeast flow reversal to accommodate growing exports
- The absence of policy-driven demand growth (carbon), causing the Midwest to act as a "way station" for surplus gas
- The Western U.S. approaches saturation on policy limits, requiring West coast liquefied natural gas (LNG) exports to lift demand
- Projected slowing of ramp in Appalachian pipeline utilization
- Northeast prices increasingly influenced by supply competition and energy transition, rather than pipe congestion
- The Permian basin may be overwhelmed by too much takeaway pipe if all projects are built
- Congestion and competition depress upstream prices in the West, while California ultimately competed with the premium Gulf
- Ample Midwest supply caps Chicago prices, while resource depletion supports the in-basin price of Rockies supply
- West-to-East disconnect in Canada, means that growth opportunities for Western Canadian Sedimentary Basin are tied to LNG aspirations
- Rising midstream costs have enabled diverse sources of supply to compete

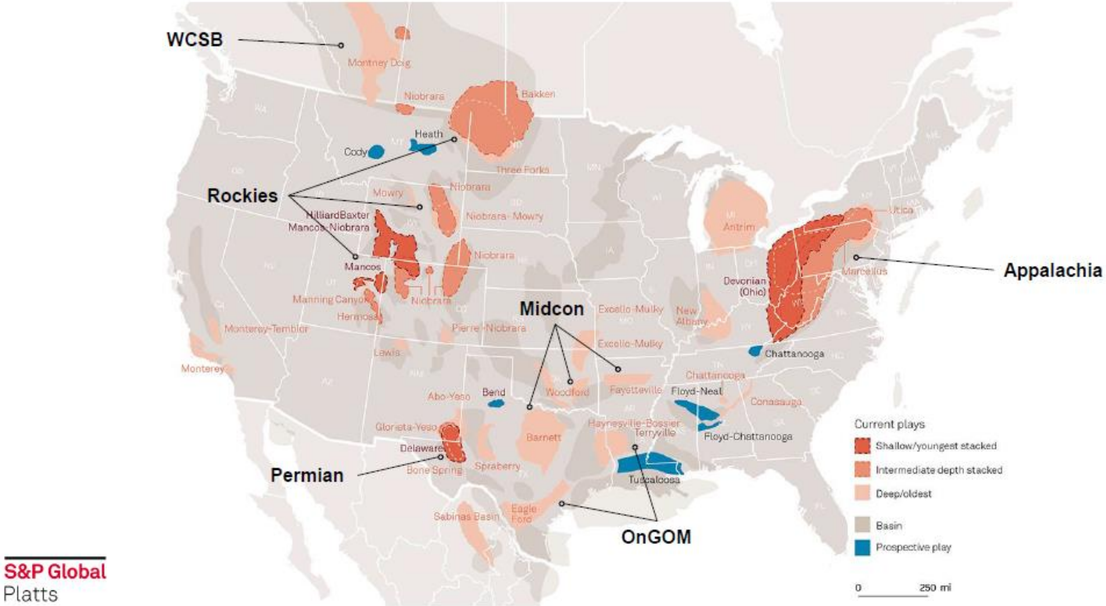

Figure 4.1 **North American Major Gas Basins**

To verify the reasonableness of the Platts forecast, Idaho Power compared Platts' forecast to Moody's Analytics and the NYMEX natural gas futures settlements. Based on a thorough examination of the Platts forecasting methodology and comparative review of these sources led to Idaho Power's conclusion that Platts' natural gas forecast is appropriate for the planning case forecast in the 2019 IRP.

Platts' 2018 Henry Hub long-term forecast, after applying a basis differential and transportation costs from Sumas, Washington (the location where most of the supply is procured to fuel the company's fleet of natural gas generation in Idaho), is the basis by which the company's 2019 IRP planning case natural gas forecast is derived.

5. PORTFOLIO MODELING

Capacity Expansion Modeling

During the 2017 IRP process, stakeholders expressed concern over Idaho Power's manual portfolio modeling technique. Through several sets of reply comments, Idaho Power stated that it would be amenable to evaluating capacity expansion modeling for the 2019 IRP.

Capacity Expansion Modeling in AURORA

Idaho Power began evaluating its long-term capacity expansion (LTCE) modeling capabilities in early 2018. Idaho Power concluded that the AURORA model, which the company currently uses in IRP planning, variable power supply expense regulatory filings, coal studies, *Public Utility*

Regulatory Policies Act of 1978 (PURPA) pricing, and projection valuations, was the best tool to perform the capacity expansion modeling.

For the 2019 IRP, Idaho Power is using the LTCE capability of AURORA to produce a Western Electricity Coordinating Council (WECC) optimized portfolio under various future conditions, such as varying assumptions for natural gas prices and carbon costs. The WECC optimized portfolio includes the addition of supply- and demand-side resources for Idaho Power's system while simultaneously evaluating current generation units for economic retirement. The selection of new resources in the WECC includes maintaining sufficient reserves as defined in the model. Idaho Power presented an overview of the AURORA LTCE modeling at the December 2018 IRPAC meeting.

Portfolio Design

Idaho Power is planning LTCE modeling under three natural gas price forecasts and four carbon price forecasts to develop optimized resource portfolios for a range of possible future conditions.

Natural Gas Price Forecasts

As discussed in Section 4, Idaho Power is planning to use the adjusted Platts 2018 Henry Hub natural gas price forecast as the planning case forecast in the 2019 IRP. Idaho Power will also develop portfolios under two additional gas price forecasts: (1) the 2018 EIA Reference Case and (2) the 2018 EIA Low Oil and Gas (LOG) case.[1]

Carbon Price Forecasts

Idaho Power plans to develop portfolios under four carbon price scenarios for the 2019 IRP:

1. Zero Carbon Costs—assumes that there will be no federal or state legislation that would require a tax or fee on carbon emissions.

2. Planning Case Carbon Cost—is based on a carbon price forecast from a Wood Mackenzie report[2] released in June 2018. The carbon cost forecast assumes a price of $2/ton beginning in 2028 and increases to $26/ton by the end of the IRP planning horizon. A key assumption in the report is that carbon costs would be regulated under a federal program and no state program is envisioned.

[1] EIA Annual Energy Outlook 2018, February 2018: eia.gov/outlooks/aeo/pdf/AEO2018.pdf.

[2] "North America power & renewables long term outlook: Charting the likely energy transition page – the 'Federal Carbon' case."

3. Generational Carbon Cost—is EPA's estimate of the social cost of carbon.[3] The social or generational cost of carbon is meant to be a comprehensive estimate of climate change impacts and includes, among other things, changes in net agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs.

4. High Carbon Costs—is based on the California Energy Commission's Integrated Energy Policy Report (IEPR) "Revised 2017 IEPR GHG Price Projections."[4] Idaho Power plans to use the carbon price stream from the High Price (Low Consumption) scenario and, for the 2019 IRP, assume carbon costs would begin in 2022 under a federal program. No state program is envisioned.

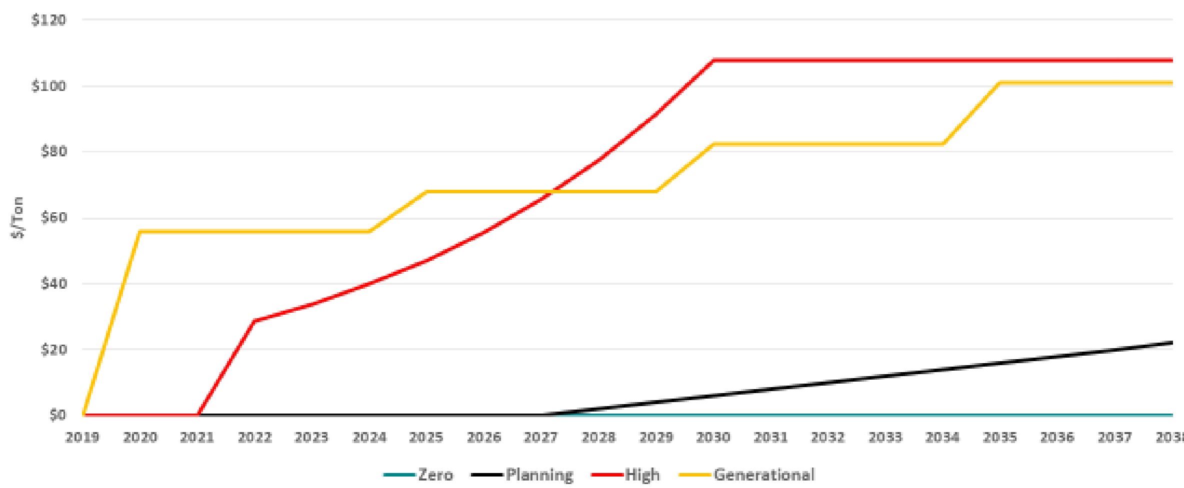

Figure 5.1 Carbon Price Forecasts

Because the AURORA LTCE can evaluate generation units for economic retirement, Idaho Power had to provide baseline retirement assumptions in the AURORA model. The baseline retirement dates for Idaho Power's coal-fired generation is year-end 2034 for all Jim Bridger units and 2019 and 2025 for the North Valmy units 1 and 2, respectively. Any changes to these retirement dates would be determined through AURORA's LTCE process.

Table 5.1 shows the 12 planned non-B2H portfolio designs resulting from the natural gas and carbon price forecasts.

[3] epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf.

[4] https://efiling.energy.ca.gov/GetDocument.aspx?tn=222145.

Table 5.1 Non-B2H Portfolio Design

Non-B2H	Zero Carbon	Planning Carbon	Generational Carbon	High Carbon
Planning Gas	1	2	3	4
EIA Reference Gas	5	6	7	8
EIA LOG Gas	9	10	11	12

To evaluate the B2H project in the AURORA model, Idaho Power will run the same set of 12 portfolios with the inclusion of the B2H transmission line.

Table 5.2 shows the planned 12 B2H portfolio designs resulting from the natural gas and carbon price futures.

Table 5.2 B2H Portfolio Design

Non-B2H	Zero Carbon	Planning Carbon	Generational Carbon	High Carbon
Planning Gas	13	14	15	16
EIA Reference Gas	17	18	19	20
EIA LOG Gas	21	22	23	24

While the LTCE process evaluates units for economic retirement, Idaho Power will also evaluate two specific Jim Bridger defined futures under the planning case for both gas and carbon. The specific defined futures are the retirement of Jim Bridger units 1 and 2 at year-end 2022 and 2021, respectively, and the installation of SCRs at units 1 and 2 in 2022 and 2021, respectively. The Jim Bridger defined futures will also be evaluated with B2H and without B2H, resulting in a total of four additional portfolios.

Table 5.3 shows the portfolio designs for the Jim Bridger defined future scenarios.

Table 5.3 Jim Bridger Defined Future Design

Planning Gas/Planning Carbon	Unit Retirements YE 2021 & 2022	SCR
Non-B2H	25	26
B2H	27	28

Idaho Power plans to evaluate a total of 28 AURORA selected portfolios, resulting from a range of natural gas and carbon price futures. The company then plans to further subject the portfolios to stochastic risk analysis.

Planning Margin in AURORA LTCE Modeling

Historical IRP Methodology

In the 2017 and previous IRPs, portfolio resources were manually selected based on relative cost and reliability. Idaho Power defined reliability as adequate capacity, energy, and flexibility in its portfolio of resources.

Capacity and energy adequacy were evaluated quantitatively under the 95th percentile peak load forecast, the 70th percentile energy forecast, and 90th percentile hydro conditions to evaluate resource needs on a monthly time step. System flexibility adequacy was evaluated qualitatively by ensuring flexible resources were included in the portfolios. System flexibility, for the purposes of IRP evaluation, is considered the capability of dispatchable resources to ramp their output in response to variations in load and intermittent renewable generation. The evaluation of system flexibility adequacy is addressed by the Commission in the IRP Flexible Resource Guidelines, provided as part of Order No. 12-013.[5] Idaho Power designs its analysis of system flexibility to be consistent with the Commission's IRP guidelines.

2019 IRP Planning Margin

The 2019 IRP uses the LTCE capability of the AURORA model to develop portfolios under a range of futures. Idaho Power will use a 50th percentile hourly load forecast for the Idaho Power area in the AURORA model and a 15 percent peak-hour planning margin to develop a 20-year, WECC-wide resource portfolio under a range of futures. The WECC portfolio includes a specific set of new resources and resource retirements to reliably serve Idaho Power's load over the planning timeframe. The LTCE model develops each portfolio based on the peak-hour capacity planning margin and hourly flexibility.

Several factors influenced Idaho Power's decision to move to a 15 percent peak-hour planning margin in the 2019 IRP. First, it is consistent with the use and logic in the AURORA model's LTCE functionality used in portfolio development. Second, it is consistent with the North American Electric Reliability Corporation's (NERC) M-1 Reserve Margin criteria.[6] Lastly, it is like the methodology employed by Idaho Power's regional peer utilities for capacity planning.[7]

To validate the change from the prior IRP methodology, Idaho Power compared the 2017 IRP's 95th percentile peak-hour capacity including the addition of 330 MW of capacity benefit margin

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[5] Order No. 12-013, pages 16-18.

[6] nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

[7] PacifiCorp 13 percent target planning margin (2017 IRP page 10), PGE 17 percent reserves planning margin (2016 IRP page 116), and Avista 14 percent planning margin (2017 IRP 6-1).

(CBM) to the 50th percentile peak-hour forecast with a 15 percent planning margin being used in the 2019 IRP. As shown in Figure 5.2 below, the two methodologies do not result in significant differences. Idaho Power believes the change in methodology aligns with the LTCE modeling and, because the results are similar, Idaho Power believes it is appropriate to use for the 2019 IRP.

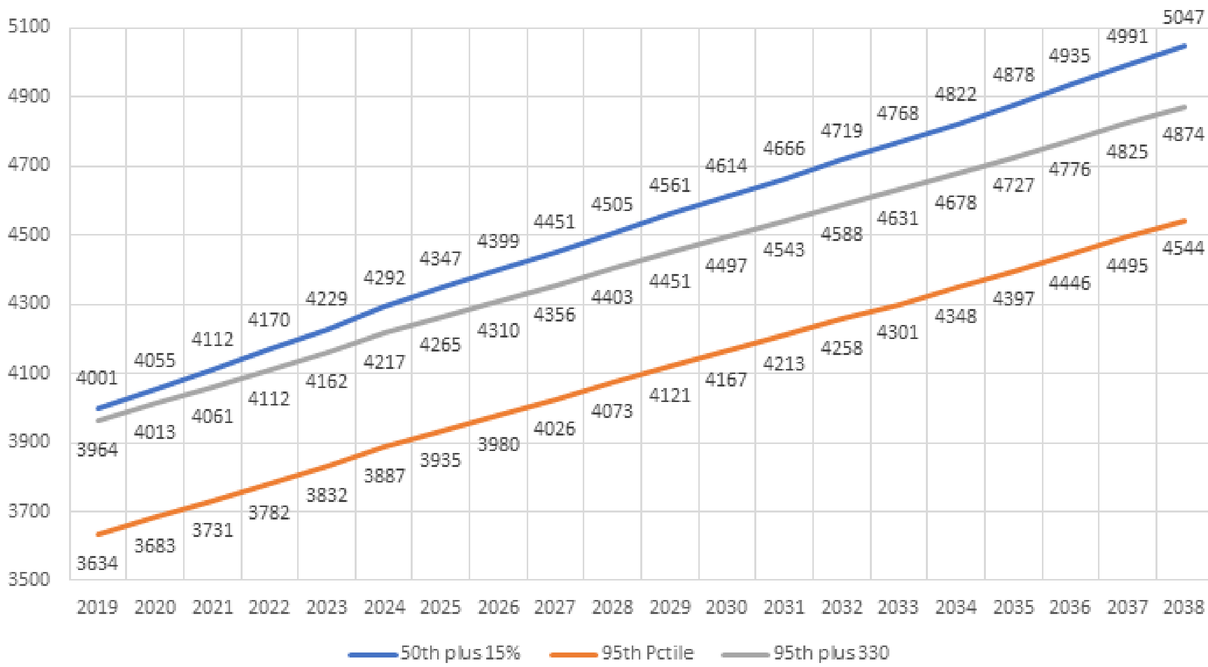

Figure 5.2 2017 vs 2019 IRP Planning Margin Comparison

Resource Costs and Trends

Cost and capacity factor estimates for supply-side resources in the 2017 IRP were primarily sourced from the Lazard Levelized Cost of Energy Analysis—Version 10.0[8] and the Lazard Levelized Cost of Storage—Version 2.0.[9] Cost and capacity factor estimates for resources not reported by Lazard came from other sources, including: internal estimates, vendor responses, and other public sources. While Idaho Power endeavored to use reliable and accurate information in its 2017 IRP, several parties were critical of Idaho Power's resource cost assumptions.

Therefore, in the interim between IRP cycles, Idaho Power evaluated and determined that the information published from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) [10] would provide improved resource cost estimates for the 2019

[8] lazard.com/media/438038/levelized-cost-of-energy-v100.pdf.

[9] lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf.

[10] atb.nrel.gov/.

IRP. NREL data is publicly available, which creates more transparency in the IRP process. Additionally, NREL's reports are published closer to the preparation of the IRP and provide multiple pricing scenarios that span the entire IRP timeframe.

The 2018 ATB released by NREL in July 2018 is the primary source for supply-side resources in the 2019 IRP. Vendor-sourced cost information is used for several resource options not covered by the NREL ATB. The following table provides the summary of cost information sourcing for the 2019 IRP.

Table 5.4 Resource Technology Cost Assumptions and Source

Technology with Capacity in Megawatts (MW)	Source (Capital and O&M Costs)
Boardman to Hemingway (B2H)	IPC (3rd party transmission line estimate)
Geothermal (30 MW)	NREL ATB
SCCT—Frame F Class (170 MW)	NREL ATB
Reciprocating Gas Engine (55.5 MW and 111.1 MW)	Vendor
CCCT (1x1) F Class (300 MW)	NREL ATB
Small Modular Reactor (60 MW)	Vendor
Solar PV—Utility-Scale One-Axis Tracking (40 MW)	NREL ATB
Solar PV—Residential Rooftop (Variable MW)	NREL ATB
Solar PV—Commercial Rooftop (Variable MW)	NREL ATB
Solar PV—Targeted Siting for Grid Benefit (5 MW)	NREL ATB w/ IPC Estimated T&D Benefit
Solar PV (40 MW) Coupled with Lithium Battery (Multiple Battery Capacities)	NREL ATB
Small Hydro (Variable MW)	NREL ATB
Storage—Pumped Hydro (500 MW/4,000 MWh)	Vendor
Storage—Lithium Battery (5 MW/20 MWh and 5 MW/40 MWh)	NREL ATB
Wind—Wyoming and Idaho (100 MW)	NREL ATB

NREL ATB Cost Projections

The NREL ATB provides overnight capital cost projections stated annually through 2050 under three future scenarios: constant, mid-, and low-technology cost. Distinctions noted in NREL documentation[11] between the future scenarios include:

- Constant—No further advancement in research and development (R&D).

[11] atb.nrel.gov/electricity/2018/approach-methodology.html.

- Mid-Technology Cost Scenario—technology advances through continued industry growth, public and private R&D investments, and market conditions relative to current levels that may be characterized as "likely," or "not surprising."
- Low-Technology Cost Scenario—technology advances that may occur with breakthroughs, increased public and private R&D investments, and/or other market conditions that lead to cost and performance levels that may be characterized as the "limit of surprise," but not necessarily the absolute low bound.

For those resources whose capital cost estimates are based on the NREL ATB, Idaho Power has elected to use the mid-technology cost scenario. With respect to solar and wind resources, the mid-technology cost scenario provides cost declines through the IRP's planning period (2019–2038). For example, the overnight capital cost of a single-axis utility-scale solar photovoltaic (PV) is projected to decline under the mid-technology cost scenario from $1,314 per kilowatt (kW) alternating current (AC) in 2019 to the following amounts (costs are in 2016 dollars and assume a direct current to alternating current (DC:AC) ratio of 1.3):

- $1,119/kW$_{AC}$ in 2025
- $1,053/kW$_{AC}$ in 2030
- $1,008/kW$_{AC}$ in 2035
- $980/kW$_{AC}$ in 2038

Lithium-ion battery storage costs provided by the NREL ATB's mid-technology cost scenario project battery pack overnight capital costs to decline in real terms by 21 percent over the 2020 to 2025 period, 9 percent over the 2025 to 2030 period, 5 percent over the 2030 to 2035 period, and 2 percent over the 2035 to 2040 period.

Hourly Load Shaping

Because of stakeholder feedback and comments filed in the 2017 IRP, Idaho Power intends to leverage several years of advanced metering infrastructure (AMI) data and adopt a new hourly load forecasting methodology to be used in the 2019 IRP. The use of AMI data's expanded footprint at Idaho Power is leveraged to inform an hourly load forecast in conjunction with historic billed sales and peak demand.

Historical IRP Methodology

Historically, Idaho Power used metered system generation reads and weather data to build a typical system load factor or hourly system shape based on a previous year that was then applied to the monthly load forecast for the IRP planning horizon. This methodology produced a consistent system shape throughout the load forecast, but it lacked the statistical footing of using individual hourly regressions rooted in AMI data.

2019 IRP Methodology

In the time since the 2017 IRP filing, Idaho Power began exploring potential methodology changes regarding hourly load forecasting relative to what the company currently had in place. While evaluating potential changes, the company believes it is prudent to maintain the integrity of the historic long-term forecasting methodologies previously employed for load forecasting.

Based on the research, the company concluded that the new methodology should be based on a neural network. A neural network utilizes the stability of monthly sales data to calibrate and ground the hourly data via monthly peak regressions. Further, the methodology leverages the control and flexibility of a neural network while still leaning on its more robust statistical underpinnings.

A detailed description of the hourly load forecasting process and the system peak forecast design will be provided with the 2019 IRP.

Updated Capacity Value for Incremental Solar

For the 2019 IRP, Idaho Power updated the capacity value of solar using an 8,760-based method developed by the NREL. The capacity value of solar PV generation is a measurement of solar PV capacity to meet system demand (including planning reserves) and is typically used by power system planners in long-term reliability assessments. The capacity value of the solar PV is expressed as the percentage of nameplate AC capacity that contributes to the top peak net load hours (i.e., contributes to planning margin).

Capacity Value for Solar PV Methodology

The methodology employed by Idaho Power to calculate the capacity value for solar PV uses an Idaho Power system load duration curve (LDC) and a net load duration curve (NLDC) for an entire year. The LDC reflects the total system load sorted by hour from the highest load to the lowest load. The NLDC represents the total system load minus the time-synchronized contribution from solar PV generation. The resulting net load is then sorted by hour from the highest load to the lowest load.

As shown in Figure 5.3 below, the capacity value of existing solar PV generation is the difference in the areas between the LDC (system load) and NLDC (net load) during the top 100 hours of the duration curves divided by the rated AC capacity of the solar PV generation installed. These 100 hours can be a proxy for the hours with the highest risk for loss of load.

$$Capacity\ Value = \frac{\sum_1^{100} LDC - \sum_1^{100} NLDC}{Solar\ PV_{rated}}$$

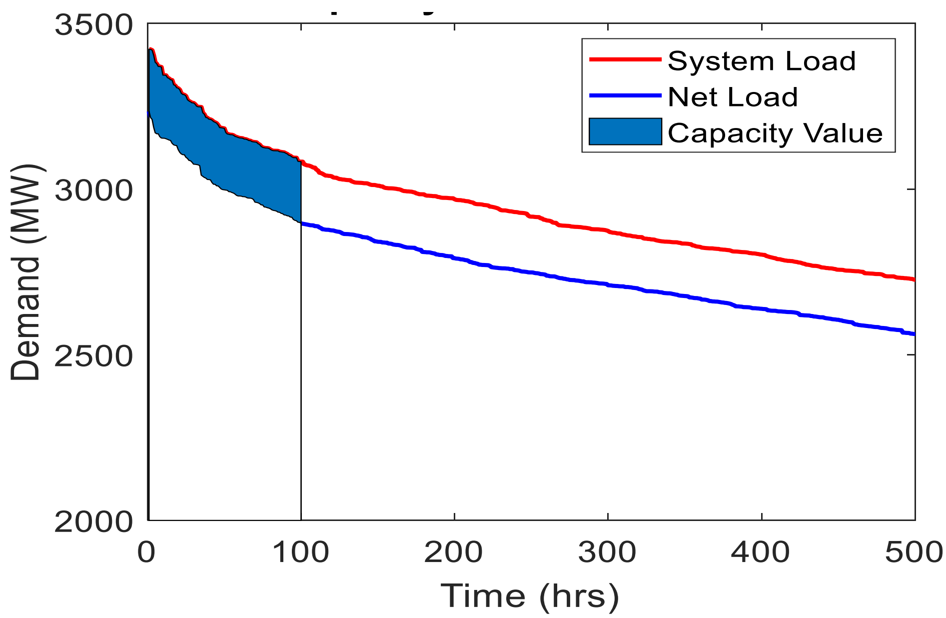

Figure 5.3 Capacity Value of Solar PV

In a similar fashion, the capacity value of the next solar PV plant, or the marginal capacity value (δ) of incremental solar PV, can be calculated using the same methodology. The marginal NLDC(δ) of incremental solar PV is calculated by subtracting the time-synchronized generation of incremental solar capacity from the NLDC. The resulting time series is again sorted by hour from the highest load to the lowest load.

As shown in Figure 5.4 below, the marginal capacity value of incremental solar PV is the difference in the areas between the NLDC and the NLDC(δ) divided by the rated AC incremental solar PV capacity.

$$Marginal\ Capacity\ Value = \frac{\sum_{1}^{100} NLDC - \sum_{1}^{100} NLDC(\delta)}{Solar\ PV_{rated}}$$

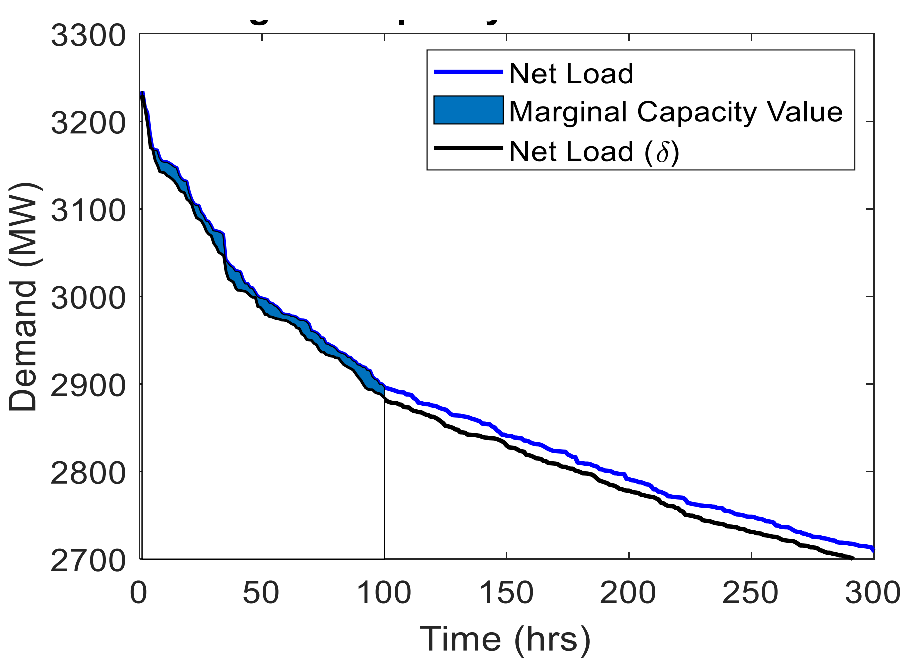

Figure 5.4 Marginal Capacity Value

Results

The capacity value results are divided into three categories: existing operational solar PV, solar PV projects in construction, and the marginal capacity value of incremental solar PV in 40 MW_{AC} increments.

The existing operational solar PV was evaluated as a single solar PV generator of 289.5 MW_{AC}, representing the sum of the rated capacity of existing operational solar PV generation. The capacity value of the existing operational solar PV was calculated by applying the 8,760-based method to the 2017 and 2018 system load. The capacity value of 61.86 percent, shown in Table 5.5 below, is the average of the 2017 and 2018 capacity values for existing operational solar PV.

The capacity value for the 25.5 MW_{AC} of solar PV projects in construction was determined in the same manner as the existing operational solar PV. The capacity value of 47.92 percent, shown in Table 5.5 below, is the average of the 2017 and 2018 capacity values for solar PV projects in construction.

Table 5.5 Summary of Results

	Capacity Value (% of Nameplate Capacity)
Existing Operational Solar PV (289.5 MW)	61.86%
Projects in Construction (26.5 MW)	47.92%

Idaho Power calculated the marginal capacity value of incremental solar PV projects each with a capacity rating of 40 MW_{AC}. As the overall system peak load is decreased by the addition of incremental amounts of solar PV, eventually the top 100 hours of peak load contain fewer and fewer hours where solar PV may contribute to reducing the peak load. Therefore, the incremental capacity value of solar decreases as additional solar is added to the system. Figure 5.5 below shows the resulting capacity value for every 40 MW_{AC} increment of solar PV. Idaho Power will use the resulting capacity factors for incremental solar PV in the LTCE modeling.

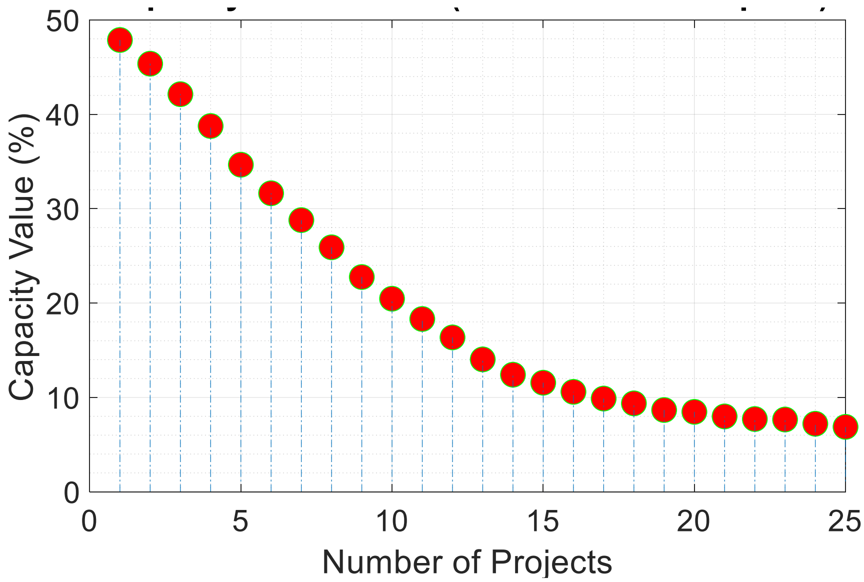

Figure 5.5 Capacity Value of Incremental Solar PV Projects (40 MW_{AC} each)

Integration Charges and Regulating Reserves

As part of its compliance filing with Order Nos. 17-075 and 17-223 in Oregon Docket No. UM 1793,[12] Idaho Power filed the *2018 Variable Energy Resource Integration Analysis*,[13] (VER Study) which described the methods followed by Idaho Power to estimate the amounts of regulating reserves necessary to integrate variable energy resources (VER) without compromising system reliability. Importantly, the methods followed were derived in collaboration with the study's Technical Review Committee (TRC), which included personnel from Oregon Staff.

The methods yielded regulating reserve requirements necessary to balance the netted system of load, wind, and solar (net load). These regulating reserve requirements for net load are expressed in the VER Study as the dynamically varying function of several factors:

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[12] apps.puc.state.or.us/edockets/docket.asp?DocketID=20334.

[13] edocs.puc.state.or.us/efdocs/HAD/um1793had16910.pdf, Attachment A.

- Season (spring, summer, fall, winter)
- Load base schedule (i.e., two-hour ahead schedule)
- Time of day (for load)
- Wind base schedule
- Solar base schedule

Thus, the regulating reserve requirements to balance net load for a given hour can be expressed as dependent on the above five factors. The derivation of the regulating reserve requirements from a net load perspective is considered to capture the tendency of the three elements (i.e., load, wind, and solar) at times when they deviate from their respective base schedules in an offsetting manner. Therefore, the amount of regulating reserve required for net load is *less than* the sum of the individual requirements for each element. The VER Study's regulating reserve requirements were presented to the IRPAC at the January 10, 2019, meeting.

The VER Study suggests that a unified VER integration analysis may be a favored approach for assessing impacts and costs for incremental wind and solar additions going forward. The VER Study also notes that Idaho Power's system is nearing a point where the current system of reserve-providing resources (i.e., dispatchable thermal and hydro resources) can no longer integrate additional VERs without taking additional action to address potential reserve requirement shortfalls. Additional investigation is warranted into the combined effect of wind and solar, in a unified VER integration cost analysis, along with the effects of energy imbalance market (EIM) participation. Idaho Power will continue to work with Staff to determine the best approach going forward regarding VER integration.

It is important to note, however, that for the 2019 IRP, integration charges for variable resources are not utilized as an input into the AURORA model. As described in Section 5, portfolio development for the 2019 IRP is being performed through LTCE modeling in the AURORA model. Under this approach, the model's selection of resources is driven by the objective to construct portfolios that are low cost and achieve the planning margin and regulating reserve requirements. Based on the VER Study's dynamically defined regulating reserve requirements,[14] the 2019 IRP includes hourly regulating reserves associated with *current* levels of load, wind, and solar, as well as *future* portfolios having higher levels of load and potentially higher levels of VERs.

Energy Efficiency

For the 2017 IRP, Idaho Power contracted with a third party, Applied Energy Group (AEG), to conduct an Energy Efficiency Potential Study (Potential Study). This study identified the

[14] Idaho Power is using approximations of the VER study's regulating reserve requirements for the 2019 IRP analysis. These approximations facilitate the calculation of reserve requirements at future levels of load and VERs.

forecast of cost-effective achievable potential for the 2019 IRP study period and the quantity, timing, and cost of the energy efficiency potential. This level of energy efficiency potential was included in all portfolios prior to any supply-side resources selected to meet Idaho Power's forecast load.

Prior to the 2019 IRP, Idaho Power contracted with AEG to conduct a new Potential Study. The new study identified the cost-effective achievable energy efficiency potential for the 2019 IRP timeframe. During the course of the IRPAC meetings for the 2019 IRP, stakeholders provided feedback asking Idaho Power to request AEG identify bundles of like-priced, technical achievable energy efficiency potential. Idaho Power is exploring options for the inclusion of these bundles in the AURORA LTCE model. One option may be for these bundles to be included in the AURORA model as resources to be evaluated and available for selection under the various long-term capacity expansion futures. Another option may be to include all cost-effective achievable energy efficiency potential similarly to the method used for the 2017 IRP. The outcome of this modified modeling approach will be discussed with the IRPAC and presented in the 2019 IRP.

6. CONCLUSION

Idaho Power appreciates the opportunity to present this 2017 IRP report in lieu of a traditional IRP Update. The company is hopeful that this report provides both the Commission and Staff with an update on the information the Commission requested: an update of the B2H project, information on the gas price forecast and portfolio modeling options the company is developing for the 2019 IRP, and an update on environmental control developments and options for the Jim Bridger generation plant. The company looks forward to providing further discussion and clarification as needed at the upcoming public meeting where this 2017 IRP report will be presented.

Idaho Power is actively working on the portfolio modeling for the 2019 IRP and will present preliminary results to the IRPAC in the coming months. The company is hopeful this 2017 IRP report has also provided some insight into the changes and enhancements to IRP inputs and methods that will be applicable to the 2019 IRP, including resource cost assumptions, hourly load shaping, changes to planning margins, the capacity value of solar, integration charges, and modeling of energy efficiency.

Idaho Power appreciates the robust stakeholder involvement, including OPUC Staff, in the current 2019 IRP process. Stakeholder comments and suggestions have influenced many of the 2019 IRP changes discussed in this report. Idaho Power plans to file the 2019 IRP in June 2019.