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PUBLIC WORKS DEPARTMENT
MAYOR: Lauren McLean | DIRECTOR: Stephan Burgos

February 15, 2024

Ms. Monica Barrios-Sanchez, Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Boulevard
Building 8, Suite 201-A
Boise, ID 83714

SUBJECT: Case No. IPC-E-23-23 Idaho Power Company's 2023 Integrated Resource Plan

(Submitted Electronically)

Dear Ms. Barrios-Sanchez,

The City of Boise ("City") submits the following comments on Idaho Power's 2023 Integrated Resource Plan ("IRP"). The City recommends the Commission acknowledge Idaho Power's 2023 IRP.

As a participant on the Integrated Resource Plan Advisory Council ("IRPAC"), the City recognizes the significant efforts by Idaho Power staff to present detailed technical information, incorporate feedback from the committee throughout the plan development, and be responsive to the diverse range of stakeholders. Specifically, the City appreciates and supports the continued refinement of more detailed scenario analyses and the Company's efforts to mitigate long term risk in its resource planning. The City believes the diverse future scenarios, incorporation of fuel price risks, changing climate conditions, and carbon pricing are critical to the development of least-risk resource portfolios that position the Company to serve its growing load cost-effectively and reliably.

The City is encouraged by and supports the 2023 IRP's evaluation and selection of additional demand-side resources that deliver significant benefits to Idaho Power's system, customers, and communities. Additionally, the City supports the Company's incorporation of Inflation Reduction Act incentives and encourages the Company to identify and evaluate federal funding opportunities that may support the implementation of its Near-Term Action Plan.

If you have any questions or need additional information, please contact the Climate Action Division of the Department of Public Works at (208) 608-7150.

cc: Lisa Nordstrom, Idaho Power
Austin Rueschhoff, Holand & Hart LLP

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN	CASE NO. IPC-E-23-23 COMMENTS OF GOLDENDALE ENERGY STORAGE PROJECT ON IDAHO POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN

I. Introduction.

FFP Project 101, LLC, the company working to develop the Goldendale pumped storage hydro project ("Goldendale" or the "Project"), appreciates the comprehensive nature of Idaho Power Company's ("Idaho Power" or "the Company") 2023 Integrated Resource Plan ("IRP") submitted to the Idaho Public Utilities Commission ("Commission" or "IPUC") on September 29, 2023.[1] Goldendale, however, seeks clarification regarding certain methodologies and values as they relate to the IRP's analysis of pumped storage hydro ("PSH") technology. Specifically, the IRP does not appear to reference the Investment/Production Tax Credits ("ITC/PTC") available to PSH. Additionally, it is unclear, or to what degree, the IRP assigns an Effective Load Carrying Capability ("ELCC") value specific to PSH. Confirming that the IRP accurately reflects consideration of the ITC/PTC and ELCC values for PSH will help ensure that Idaho Power is selecting the most cost-effective and reliable resources for its portfolio, consistent with IPUC's regulatory requirements and guidelines.[2]

[1] *In the Matter of Idaho Power Company's 2023 Integrated Resource Plan*, Case No. IPC-E-23-23, Application (Sept. 29, 2023) (hereinafter, "Application").

[2] *See Re Consideration of the Federal Electric Utility Ratemaking Standard Dealing with Integrated Resource Planning in PURPA § 111(d)(7)*, Case No. GNR-E-93-3, IPUC Order No. 25260 (Nov. 29, 1993); *Re Idaho Electric Utility Conservation Standards and Practices,* Case No. U-1500-165, Order No. 22299 (Jan. 26, 1989).

Moreover, given Idaho Power's ongoing transition to cleaner energy resources, it is imperative that the Company identifies and procures PSH resources now*,* in order to meet commercial online dates ("COD") in the early 2030's. Finally, Goldendale requests that Idaho Power implement RFPs that have long lead-time resource-specific considerations in order to enable these PSH resources to fairly compete with all other resource types, thereby ensuring PSH resources can provide the Company the capacity and flexibility that it needs. Pursuant to Order No. 36029 establishing a comment deadline in the above-captioned proceeding,[3] Goldendale hereby submits these comments.

II. Comments.

A. PSH is uniquely positioned to meet the needs of Idaho Power and its customers.

PSH resources such as Goldendale are uniquely positioned to meet the needs of both Idaho Power and its customers over the 20-year forecast period. As explained in further detail below, Goldendale aligns with the 2023 IRP's emphasis on flexibility and adaptability[4] and can support Idaho Power's projected load growth, transition to cleaner energy, and need for reliable resources.

Goldendale is a proposed 1200 MW, 12 hour closed-loop facility located in Klickitat County, Washington. The project is located at a former aluminum smelter site and will interconnect to BPA's system using existing transmission lines/right of way. Goldendale anticipates receiving its full FERC license in 2024 with an anticipated COD in the early 2030's. The project is owned by Copenhagen Infrastructure Partners and being developed by Rye

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[3] *In the Matter of Idaho Power Company's 2023 Integrated Resource Plan*, Case No. IPC-E-23-23, Order No. 36029 (Dec. 15, 2023).

[4] *See* Application at 3 (stating that "[t]he importance of flexibility and adaptability in resource planning is a theme throughout the 2023 IRP…").

Development. The Project will have significant economic impact on the Pacific Northwest, creating 3,000 family wage jobs during its 4-5-year construction, and generating millions of dollars into the local economy year over year. Additionally, the Project can provide Idaho Power flexibility and reliability as the Company serves its growing number of customers and works towards its goal of providing 100% clean energy.

PSH can also support efficient grid management, which will become exceedingly important, as the Company experiences increased customer demand and requests for transmission interconnections.[5] PSH shifting at grid-scale can avoid transmission congestion, reduce energy curtailment, provide quick access to significant and sustained energy ramping, and support uninterrupted electricity supply. For example, the particular location of the Goldendale PSH project, interconnecting at the BPA John Day substation, can benefit Idaho Power by providing greater flexibility in terms of importing (and potentially storing) resources from the Pacific Northwest as well as managing congestion and "shaping" the energy flows over B2H via delivery of excess power to/from Goldendale.

Furthermore, the IRP explicitly acknowledges that additional technological advances will be necessary for Idaho Power to achieve its goal of providing 100% clean energy by 2045.[6] With the Company's preferred portfolio adding 3,325 MW of solar and 1,800 MW wind, PSH can integrate these variable resources by storing the excess renewable energy to balance the intermittent nature of these resources. In addition, the IRP calls for the conversion of multiple

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[5] *See* Application at 5 (projecting the Company's peak load to grow by 80 MW per year over the 20-year forecast period and the average annual number of customers to increase from 639,000 to 855,000 by 2043); IRP at 1 (detailing Idaho Power's near-term transmission investments such as the Boardman to Hemingway ("B2H") transmission line and the Gateway West project).

[6] IRP at 34.

coal-fired generation units to natural gas as the Company seeks to exit coal entirely.[7] PSH's compatibility with various generation sources makes it an optimal bridge technology as the Company transitions its generation mix.

Lastly, given Idaho Power's success with PSH and challenges with small lithium-ion batteries, PSH has proven that it can provide dispatchable, clean capacity at a scale large enough to maintain grid reliability and support customers' energy needs.

B. Idaho Power should clarify certain methodologies and values in the IRP's Analysis of PSH.

Goldendale acknowledges the detailed work the Company has undertaken in developing methodologies and establishing cost values for resources considered in the IRP. For instance, the IRP's analysis of costs using both the Levelized Cost of Capacity ("LCOC") and Levelized Cost of Energy ("LCOE") metrics allows for a fair cost comparison among resources with distinct attributes and economic lives. In particular, reflecting pumped storage's long Economic Life of 75 years and including the LCOEs for storage resources alongside the LCOCs helps to clearly shows the benefits of pumped storage and long duration storage (as illustrated by pumped storage showing as the lowest cost storage resource in terms of Total Cost per MWh in the "Levelized Cost of Energy (costs in 2024$, $/MWh)" table in Appendix C).

However, Goldendale has two open questions regarding the IRP's analysis. First, it is unclear whether the ITC/PTC tax credits were assumed for PSH throughout the IRP. In the IRP's discussion of renewable resources, there is an explicit reference to the Inflation Reduction Act of 2022 ("IRA") tax credits associated with battery storage, but no such reference exists in the subsequent paragraph pertaining to PSH.[8] Goldendale notes that the IRP's Technical Report

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[7] *Id.* at 61.

[8] *Id.* at 64.

generally reflects the IRA tax credits in the capital cost components of the LCOE/LCOC[9] for various resource types but does not specifically state to what extent, if any, PSH is being credited for such tax incentives. Consequently, if the IRA tax credits are not already reflected in the analysis of PSH, Goldendale emphasizes that PSH facilities are eligible for these credits and that Idaho Power should revise the IRP to account for these benefits of PSH. Alternatively, if the IRP already accounts for the IRA tax credits available to PSH, Goldendale requests confirmation as to where this value is reflected in the IRP analysis and what specific assumptions were used in the calculation.

Second, Goldendale requests that Idaho Power confirm that the IRP considers (or will consider) a unique ELCC value for PSH. The IRP references ELCC calculations in its general discussion of battery storage resources but makes no reference of ELCC calculations in the subsequent paragraph dedicated to PSH.[10] Likewise, the table in the Technical Report displaying the average ELCC of existing, expected, and future resources completely excludes PSH. Therefore, it is unclear whether the IRP identified an ELCC value associated with PSH and if so, how it compares to that of other resources. Assuming that an ELCC was not calculated for PSH, Idaho Power should revise the IRP to include a PSH-specific ELCC that exceeds the average ELCC calculated for an 8-hour stand-alone battery (79.2%).[11] If the IRP already includes a PSH-specific ELCC calculation, Idaho Power should explain where this value is reflected in the IRP and what specific assumptions the Company used.

[9] IRP Appendix C- Technical Report at 24, 25.

[10] IRP at 64-65.

[11] IRP Appendix C- Technical Report at 92.

C. **Idaho Power should identify and procure PSH now and make other accommodations for Long Lead-Time Resources.**

Some of the various scenarios analyzed in the IRP, including High Carbon High Gas, 100% Clean by 2035, and Rapid Electrification, include pumped storage in the 2030-2035 timeframe.[12] Under any scenario, whether the base case or an alternative, long lead-time resources (such as PSH) need a roughly seven to eight-year runway in order to procure materials, construct the resources, and come online. Thus, for PSH (like Goldendale) to be available in the early 2030's, procurement decisions must be made no later than approximately 2025. This means that those resources need to be identified, selected, and procured *now*.

Additionally, Idaho Power signaled that it may issue additional RFPs to acquire resources to meet its capacity shortfall.[13] PSH resources require clear market signals further in advance than most, typical resources. These projects need market signals that allow them to make investments in major equipment like the turbines for these projects, which are custom-designed and can take several years to design, construct, and deliver. Because of the unique timing considerations for resources like pumped storage, even pumped storage projects that are well thought out and have a clear pathway to permitting and regulatory approvals (such as Goldendale) still require several years to construct.

Given the longer time required to construct pumped storage resources, Goldendale emphasizes that Idaho Power and the Commission must provide an opportunity for pumped storage projects to fairly compete in future RFPs with all other resources if the Company expects to rely on these resources to meet the looming dispatchable capacity need. For example, a longer online date deadline for long lead-time resources like PSH is necessary to allow full participation

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[12] IRP at 149, 155, and 167-8.

[13] *Id.* at 173.

in the IRP/RFP processes. Additionally, Idaho Power and the Commission should consider the value of issuing a long lead-time resource specific RFP. Such an RFP would allow PSH and similarly-situated resources to be evaluated and potentially placed under contract on a timeline that is more consistent with the realities of these long lead-time resources, which are unlike those faced by conventional, renewable projects.

III. Conclusion.

Goldendale appreciates the opportunity to provide comments on Idaho Power's IRP and contribute to the full development of the factual issues in this proceeding as they relate to PSH technology. Specifically, Idaho Power should confirm whether the IRA tax credits were applied to PSH throughout the IRP or alternatively, revise the IRP to accurately reflect these benefits. To the extent the IRP does not use a PSH-specific ELCC, the Company should also revise the IRP to do so. Lastly, Idaho Power should identify and procure PSH projects *now* given the long lead-time of these resources. Going forward, Idaho Power should implement RFPs that have long lead-time resource-specific considerations. Adopting the foregoing recommendations will ensure that the IRP is selecting the most cost-effective and reliable portfolio, consistent with IPUC's regulatory requirements and guidelines.

Dated this 15th day of February, 2024.

Respectfully submitted,

/s/ Michael Rooney

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Feb 15, 2024

Commission Secretary
Idaho Public Utilities Commission
Via email

Copies via email:
- Idaho Power: Lisa D. Nordstrom, Megan Goicoechea Allen, Timothy E. Tatum, Alison Williams, Docket email
- Micron: Jim Swier
- Holland and Hart: Austin Rueschhoff, Thorvald A. Nelson, Austin W. Jensen

RE: Comments on Idaho Power IRP Case No. IPC-E-23-23

Dear Idaho PUC

I had the honor to participate in the 2023 IRP as a member of the IRPAC. I was very impressed with how Idaho Power ran the IRP meetings, and I congratulate Idaho Power on their success.

This letter is written to provide comments on the two Heat Pump Sensitivity Studies that were run, one for Air Source Heat Pumps (ASHPs) and the other for Ground Source (aka Geothermal) Heat Pumps (GHPs).[1] The results deserve scrutiny and consideration of the implications. The only change between the two scenarios is the use of GHPs instead of ASHPs for residential electrification. This simple switch of heat pump technology reduces the required grid capacity by 3,000 MW. The Portfolio cost is reduced by $1 billion dollars with most of the savings being heavily discounted because they occur so far in the future.

These results are in alignment with a recent study published on the grid impact of mass-deployment of GHPs on the national grid under various grid and economy CO2 objectives.[2] This DOE-funded study conducted by Oakridge and National Renewable Energy Labs (ORNL and NREL) showed a very large reduction in installed capacity and the marginal cost of electricity from the mass-deployment of GHPs.

Figure 1[3] shows the large capacity reduction across the country for the two scenarios of "Base" (business as usual) and "Grid Decarb" (95% grid CO2 reduction by 2035).

[1] The two cases are presented in Appendix C page 60 and 61 and described in the main IRP document on pages 41 and 129.

[2] GRID COST AND TOTAL EMISSIONS REDUCTIONS THROUGH MASS DEPLOYMENT OF GEOTHERMAL HEAT PUMPS FOR BUILDING HEATING AND COOLING ELECTRIFICATION IN THE UNITED STATES. Xiaobing Liu, Jonathan Ho, et al. November 2023. ORNL/TM-2023/2966 https://www.osti.gov/biblio/2224191

[3] Liu Figure 4-2 (page 22)

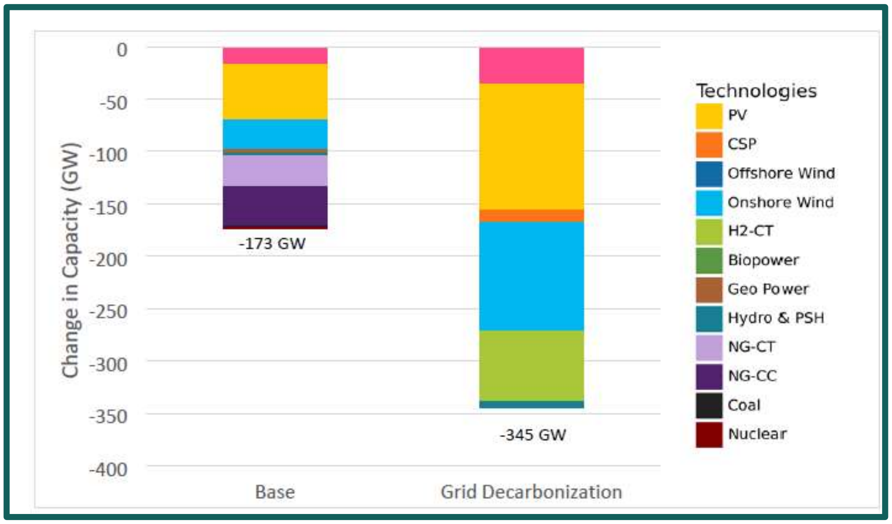

Figure 1: Reduction of nation-wide capacity requirement by deploying GHPs.

There are two reasons why GHPs cut demand even as they electrify heating.

1. Summer peak for A/C is reduced by up to 50% by using cool water instead of hot air.
2. In heating mode, GHPs operate at up to 500% efficiency (5 units of building heat for 1 unit of electricity). Consequently across the system, the grid peak winter electrified heating load is smaller than the current summer air-cooled summer peak load.

This suggests that GHPs are a cost-reduction technology for the existing grid and for efforts to achieve a decarbonized grid in the future, which is an Idaho Power objective on behalf of its ratepayers.

Figure 2[4] shows that GHPs reduce the marginal cost of power (roughly wholesale cost of power). This includes not only the benefits of less new capacity, but also reduced expensive summer peak power.

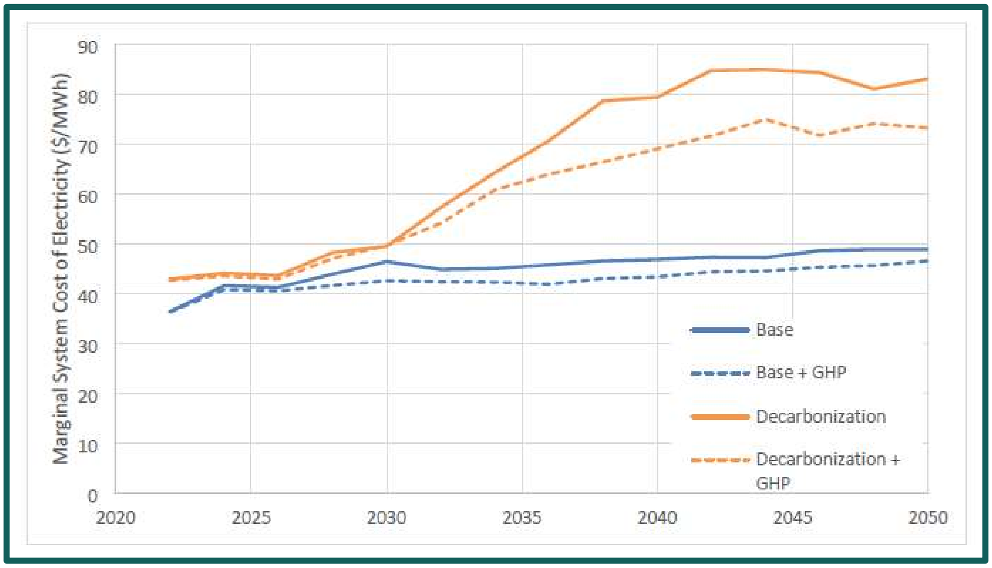

Figure 2: Reduction of nation-wide marginal cost of electricity by deploying GHPs.

[4] Liu Figure 4-8 (page 29)

One important element of Figure 2 is that this study forecasts a nationwide increase in the cost of power for decarbonization (solid blue line to solid orange line). However, the dashed orange line is the cost that results for decarbonization with GHPs and it shows that the cost of decarbonizing the grid can be cut by >30% by using GHPs.[5] This is a highly relevant result for Idaho Power and its ratepayers and shows that encouraging the adoption of GHPs, where appropriate, can lower the cost of power on the grid for everyone. GHPs may be a unique renewable energy resource in that way.

In additional to the study itself, there is summary information via a DOE webinar which presents additional results and interpretation[6].

In summary, the potential implications of this study for Idaho Power and its ratepayers may include the following.

1) The difference in results of the two sensitivity studies may suggest that GHPs deserve a higher incentive than ASHPs. They are currently the same for eligible (electric heating) ratepayers.
2) It could be valuable for Idaho Power to conduct a separate study outside of the IRP process to quantify the benefit of large-scale deployment of GHPs, separating this from the broader vehicle electrification element of the rapid electrification sensitivity studies. This study could be run as an avoided cost analysis, similar to how such studies are run to determine the price for PURPA projects.
3) Assuming that there is a benefit to Idaho Power ratepayers from GHPs, a proportional incentive could be considered to encourage ratepayers to adopt GHPs. GHPs will cross-cut many Idaho Power planning categories, including generation, demand side resources, and efficiency programs.
4) One of the potential values for Idaho Power could be to use the decarbonization emissions credits from buildings as an offset to the gas-fired generation, in the same manner as other standard emissions-trading approaches.

Again, I congratulate Idaho Power on the excellent IRP which they have completed. The observations above are offered to suggest additional ways in which Idaho Power could potentially serve their ratepayers, lower the cost of power, meet their emissions goals. These goals would be met with commercially proven US-manufactured technology installed using a mostly Idaho-based workforce.

Sincerely,

Kevin Kitz, P.E.
KitzWorks LLC

[5] These cost projections should not be interpreted as indicating the cost of decarbonization for the Idaho Power service territory. The forecast includes the eastern US which does not have the variety and abundance of renewable energy options which Idaho Power can access, among other technical modeling reasons.

[6] https://youtu.be/8PUuUO0CRCo

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zanskar

Dear Idaho Public Utilities Commission,

Zanskar Geothermal & Minerals, Inc. is a tech-enabled geothermal exploration and development company focused on increasing the supply of resource de-risked, NTP-ready geothermal power projects. To this end, Zanskar has been exploring geothermal prospects in Idaho. As such, we take a keen interest in the Idaho Power IRP process and the results that come out of it. Given our particular interest in geothermal power, this will be the focus of our two comment areas, which we hope you will consider and act on.

Estimated cost of Geothermal Power in the IRP

The IRP preferred portfolio calls out 30MW of geothermal power in 2030. In other model scenarios, the amount of geothermal varies from a maximum of 120MW to a minimum of 0MW. This wide variance suggests that geothermal power in Idaho Power's IRP model scenarios is at the cusp of being a least cost option and is thus highly sensitive to the estimated power price. The following points suggest that the assumptions made about geothermal power could be conservative, and using more realistic values could increase the amount of clean baseload geothermal power that is developed to serve Idaho Power's rapidly growing baseload demand over the next 7 years and beyond.

The indicative cost of geothermal power (at assumed parameters) given on Page 24 of Appendix C is $78/MWh. However, the NREL Annual Technology Bulletin for Geothermal Power lists some recent geothermal PPA prices. That table is provided here :

Recent Public Geothermal Power Purchase Agreement Pricing

Project	State	Size (MW)	Pricing ($/MWh)	Term (years)
Hell's Kitchen	California	40	74	25
Whitegrass	Nevada	3	67.50	25
Star Peak	Nevada	12.5	70.25	25
Casa Diablo	California	16	68	20
Puna	Hawaii	46	70	30

As can be seen from the table, contracted PPA prices are up to $10/MWh lower than the value reported in the IRP, and raise the possibility that geothermal could be selected at greater levels in the IRP at lower prices. Zanskar recommends a careful evaluation of the cost factors for geothermal power to bring them into alignment with industry best practices.

Capacity Factor

In the LCOE table of Appendix C (page 24), it appears that geothermal power plants use a 90% capacity factor. However, in bank-approved pro-formas used by geothermal developers, including Zanskar, a 95% capacity factor is used for the annual output of the power plant. Using this value as a simple change to the predicted cost of the plant would result in the LCOE going from $78/MWh to $78/.95*.9 = $74/MWh (a >5% cost reduction). Zanskar recommends using a capacity factor for geothermal power of 95%.

When this capacity reduction occurs is an equally important value component. The best practice for geothermal power plants is to perform scheduled maintenance for only a couple of weeks every few years. Those maintenance cycles are scheduled typically for the spring months, when the power is of least value to Idaho Power. Zanskar recommends distributing 3% of the 5% capacity reduction to March, April and May, and the other 2% divided equally between the other months to represent forced outages and temporary partial capacity reductions.

Treatment of the ITC and other tax benefits.

Zanskar did not find a place in the IRP where it was described how the Investment Tax Credit (ITC; from the 2022 Inflation Reduction Act) was applied to each technology. On page 22, it mentions that "elements of the IRA" were incorporated, but it is not clear from the tables on pages 21, 24, and 25 of Appendix C that an ITC was applied to geothermal power capital costs. New geothermal power plants built before 2032 qualify for the 30% ITC and will likely qualify for a 10% bonus for meeting US supply chain requirements. In some cases, they will also receive the additional 10% bonus for being located in an economically disadvantaged area. Geothermal is also eligible for a 5-year accelerated depreciation (MACRS). Geothermal is also unique in that it is eligible for an intangible drill cost (IDC) deduction, which allows a 1-year write-off of a significant portion of the well drilling costs. Zanskar recommends using a 40% effective ITC (splitting the difference between 30% and 50%). Zanskar also recommends inclusion of a method to estimate the effective value of the taxable income deductions for MACRS and IDC.

Future cost projections

As the geothermal industry grows over this next decade, economy of scale factors and experience can be expected to gradually reduce CAPEX costs for binary power plants in real dollar terms, which should be reflected in Idaho Power's cost projections. The industry has already seen these CAPEX costs come down over the last 10 years as more manufacturers compete for binary power plant sales (e.g., Ormat 10-K, 2022). More immediately though are advances in drilling speed and cost which will deliver a substantial cost reduction for geothermal power over the next 10 years. One example of this is a published study about drilling costs at a new project in Utah. In the 4 wells drilled to-date, the cost of the wells has already fallen to the NREL Geothermal ATB Moderate Technology projection for 2035. This indicates that a potential step-change in cost reduction could be justified over the next few years. Zanskar recommends that half of the geothermal power cost be escalated at a reduced rate from that provided in the tables to account for the economy of scale applicable to more geothermal power plants being constructed. Zanskar also recommends that the other half of the geothermal power cost, representing the wells, be de-escalated according to the ATB "moderate" forecast, except accelerated by at least 5 years.

Summary of Cost Recommendations

The following are Zanskar's recommendations for greater technical/financial accuracy in Idaho Power capacity expansion modeling:

1. Consider contracted PPA prices, which have been less than $70/MWh versus $78/MWh LCOE in the IRP
2. Increase geothermal power plant capacity factor to 95%, as this reflects standard industry practice.
3. Adjust monthly capacity factors to reflect that plant overhauls will occur in low-value months. Example:
    a. capacity factor 92% for March-June
    b. capacity factor 97% for all other months
4. Capture all tax benefits for which geothermal power projects are eligible, including a 30% to 50% ITC, MACRS, and Intangible Drilling Cost (IDC).
5. Incorporate demonstrated cost reductions that are already occurring in the industry, especially related to drilling.

Separate study of the avoided cost of geothermal

The IRP does not demonstrate a high need in Idaho Power service territory for geothermal power since the preferred portfolio only acquires 30MW of new geothermal power during the period in which average load increases by almost 800MW. From the data provided, it appears that much of this load growth is for baseload demand. This is a natural fit for the baseload characteristics of geothermal power, especially when air-cooled binary geothermal power plants are integrated with PV, as the two power sources peak power production can complement the other.

Geothermal power development is a high-risk undertaking over several years. Thus, for developers to make this investment, there must be a promising market. One 30 MW project does not, unfortunately, qualify as a promising market. The indications are present that the market may be larger, depending on the price. If Idaho Power were to undertake a short avoided-cost analysis of geothermal power, this would provide a signal to the industry on how large the market could be. Idaho power has conducted other industry-specific studies, such as the wind integration study, and this would have a similar objective, namely to quantify the potential value.

A possible method would be for geothermal power plants to be added to Aurora at a certain rate and frequency. For example, 25 MW every year starting in 2027 through 2034 for a total of 200MW. The avoided cost that these hypothetical plants would produce would be reported. The advantage to Idaho Power and its ratepayers are that if geothermal power has an avoided cost ($/MWh) that is attractive to geothermal developers, it will justify the developers' investment into exploration and drilling. Information about the value of geothermal power can become the mechanism by which such power becomes available.

Avoided Cost Modeling Recommendation

Zanskar recommends that Idaho Power conduct an avoided cost analysis of 200MW of new geothermal power over the next 10 years to encourage investment in the exploration and drilling required to define a new geothermal resource which can serve the needs of Idaho Power's customers.

References

[1] https://atb.nrel.gov/electricity/2023/geothermal
[2] https://pangea.stanford.edu/ERE/db/GeoConf/papers/SGW/2024/Elsadi.pdf?t=1706897516
[3] https://www.power-eng.com/renewables/fervo-energy-claims-70-reduction-in-geothermal-drilling-time-2/#gref