STOP B2H Coalition

“Protect Our Land, Preserve Our Heritage”

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July 7, 2022

Please accept the enclosed Opening Comments from the Stop B2H Coalition pertaining to Idaho Power Company’s 2021 IRP, #LC 78.

Thank You,

Co-Chair, Stop B2H Coalition

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of **Idaho Power Company** **2021 INTEGRATED RESOURCE PLAN**	**Docket LC 78**

Stop B2H Coalition

Opening Comments

Submitted

July 7, 2022

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Introduction

Stop B2H Coalition (STOP), a grassroots, Eastern Oregon citizens' organization, with 955 members and 9 member organizations, hereby submits Opening Comments on Idaho Power's 2021 Integrated Resource Plan – LC 78. STOP is extremely concerned with the accuracy and validity of the data in this IRP, as methods and metrics used in making calculations for this IRP are different from those in the past (e.g.: reserve margins and financial calculations). This behavior began during the protracted delays and extensions throughout the 2019 IRP (5 times) and continues to be rushed with new processes that will again lead to errors in LC78. In addition, the entire IRP process has become less transparent with less stakeholder participation. Albeit, participation has been effected somewhat by the pandemic, however rather than accommodating with *more sensitivity* to virtual participation, the company used it to restrict open participation to Q&A at IRPAC[1] meetings. STOP discussed this with IPC staff and shared a memo of concern with OPUC and IPUC staff. This is STOP's third full IRP (some members' fourth) and we have not experienced this exclusive-type of participation in the past which is concerning given OPUC Guideline 1: Substantive Requirements[2].

STOP is looking forward to engaging in this docket with the hopes that unanswered questions will be answered and that more light will shine on obscured information. STOP will briefly comment in this opening on key questions that pertain to the Boardman to Hemingway Transmission line and reserve our right to comment on other components of this IRP as appropriate in later filings.

B2H Budget

Estimated Costs

In the 2017 and 2019 IRPs the company stated the total cost for the B2H with a 20% contingency was a little over $1.2 billion with a capacity of 350 MW[3]. This included the AFUDC but not the local interconnection costs.[4]

Using the budget numbers in the 2021 IRP it is implausible that the construction of B2H will cost less in 2023 than it did in 2016 when this estimate was done. In fact the 2016 and 2021 budgets--both with a 20% contingency--are very close in costs. When one adds inflation, the pandemic, supply chain issues, etc. it is very difficult to understand how the cost has not gone up. Furthermore, additional substations and transmission reinforcements are being built into the project now and they were not in the 2017 and 2019 IRPs.

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[1] IRPAC = Integrated Resource Plan Advisory Committee
[2] OPUC Guideline 1: ORDER NO. 07-002
[3] The capacity could go to 550MW; but the budget forecasting is based on 350MW.
[4] Public Utility of Oregon Commission ("OPUC") Staff's Data Request No. 56, Confidential Attachment 1 titled "B2H 2017 IRP Cost Estimate."

Confounding the situation, of course is the fact that Idaho Power is absorbing the Bonneville Power Administration (BPA)'s share of the B2H (24%). This increase in share was promised to be reflected in the budget figures for the 2021 IRP. However, there is still **no budget** documentation to review; and therefore not only can these figures not be verified, there is no way to connect the dots or follow the budget build-out from the 2019 IRP to this one.

Additionally, the cost of the B2H varies -- even within this IRP and its Appendix D (the Transmission Supplement). In the IRP-Appendix D. pp. 1-2, the costs are stated as:

> "In the 2021 IRP, Idaho Power estimates that its 45.45% share of B2H costs will be approximately $500 million (with no contingency)[5] and evaluated a high-end cost of $600 million with a 30% cost contingency[6] for future expenses. The B2H cost estimate included Idaho Power's costs for local interconnection upgrades totaling approximately $35 million and additional system upgrades totaling approximately $47 million." [Footnote emphasis added]

Then on page 145 of the 2021 Integrated Resource Plan the B2H Cost Risk Evaluation shows different costs for the B2H than stated above. These range from $485 million ($1,065,934,065) to $607 million ($1,334,065,934) in Table 10.9 B2H Cost Sensitivities, a variation of $7 to $15 million. [Total Cost Column added]

Table 10.9 B2H cost sensitivities

	B2H Cost Idaho Power Share TOTAL	Total Cost	B2H Cost 2021 IRP NPV
B2H 0% Contingency	$485 million	$1,065,934,065	$159.6 million
B2H 10% Contingency	$526 million	$1,156,043,956	$178.4 million
B2H 20% Contingency	$566 million	$1,243,956,043	$197.2 million
B2H 30% Contingency	$607 million	$ 1,334,065,934	$216.1 million

The last budget[7] supplied by Idaho Power is dated October 2016. Using a CPI Inflation Calculator to calculate the Value of $1,200,000,000 from 2016 to 2022 the dollar had an average inflation rate of 3.34% per year between 2016 and today, producing a cumulative price increase of 21.79%. This means that today's prices are 1.22 times higher than average prices since 2016, according to the Bureau of Labor Statistics consumer price index. A dollar today only buys 82.111% of what it could buy back then.

[5] $1,098,901,098 @ 100%
[6] $1,318,681,318 @ 100%
[7] Still a rolled-up budget lacking details, nonetheless more detail than currently.

In STOP's data request No. 5 we asked what cost estimate class the B2H project was rated at on the Advancement of Cost Engineering ("AACE") guidelines. The company stated:

> "HDR did not use Association for the Advancement of Cost Engineering ("AACE") guidelines in developing the cost estimate. The estimate provided is based on the preliminary design. HDR utilized their utility and industry experience with current market values for materials, equipment, and labor to arrive at the Boardman to Hemingway ("B2H") estimate. "

Since the company did not use the AACE guideline rather the estimate was "based on the preliminary design," it would seem that a preliminary design would be equivalent to a class 4 (1% to 15% maturity level) or class 3 (10%-40% maturity level) in the AACE guidelines. That would mean that there is a 50% or less probability that the budget will be as projected.

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

It is clear to STOP, and we hope to the Commission, that the budget has deep fundamental flaws. These foundational errors must be corrected and presented transparently—in this 2021 IRP--and verified by the OPUC, its staff or consultants. The flaws include:

1. A base budget developed in October 2016 for the 2017 IRP continues to be the budget of record.[8] The budget was requested and shared as confidential with interveners, staff, and the commission. A newer version incorporating the commission's budget modeling order has not been shared that STOP is aware of. We tried to request a copy of the revised budget in data requests No. 4 but apparently we were not clear enough. We received a narrative about some of the changes and the spreadsheet with contingency variations, but still no line itemed budget.

> "The attached Excel spreadsheet shows the cost breakdown for B2H as included in the 2021 Integrated Resource Plan ("IRP"). The values in cells E5, E6, E7, and E8 represent the B2H cost estimate for the various contingency amounts evaluated and match Table 10.9 in the 2021 IRP. The $14.4 million represents the net present value cost of Idaho Power purchasing Bonneville Power Administration's ("BPA's") B2H permitting interest.
>
> In the 2019 IRP, the B2H cost estimate was $292 million plus $21 million for local interconnection costs, totaling $313 million.
> Major differences between the 2019 estimate and the 2021 estimate include, but are not limited to, the following:
>
> 1) The Company having a 45.45 percent interest in the B2H project rather than a 21.21 percent interest;
> 2) BPA funding the majority of the Longhorn substation costs;
> 3) The addition of the B2H midline series capacitor; and
> 4) An increase in the cost of the local interconnection projects.
>
> The 2021 IRP was developed throughout 2021 and published in December of 2021. The major inflation, labor, and supply chain issues experienced over recent months in 2022 were not factored into the cost estimates of any of the IRP resources in the 2021 IRP. Financial assumptions are listed in Table 10.1 of the IRP."[9]

2. There is B2H budget inconsistency as mentioned above: the Integrated Resource Plan (published in Dec 2021) and IRP--Appendix D (spring 2022). While some of this could be related to the confirmation of the BPA share, other items mentioned in DR No.4 obviously are part of this too. STOP asks that the Commission require Idaho Power to bring the budget into the current decade and develop "hard" financial numbers from which one can build the "least cost-least risk" portfolio with confidence. Something this IRP (again) does not have. Since 2019, STOP has felt like we are in a shell game: wondering whether or not certain resources maybe misrepresented or certain risks unstated to the commission and ratepayers, while in financial disclosures to the Securities and Exchange Commission and investors/shareholders, different risk scenarios are shared.

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[8] It was exactly the same as provided for in the various 2019 IRPs.
[9] Response to STOP's Data Request No 4.

> "As noted in the 2021 IRP, there is uncertainty surrounding the resource sufficiency estimates and project completion dates, including uncertainty around the timing and extent of third-party development of renewable resources, fuel commodity prices, regulatory requirements, the actual completion date of the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of coal-fired plant conversions and retirements. These uncertainties, as well as others, may result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions in the 2021 IRP."[10]

Therefore, a complete and transparent budget must be provided; so far it has not been.

3. The CPI inflation calculator indicates a cumulative price increase of 21.79% between 2016 and 2022 and this budget does not appear to reflect that.

4. Using the Advancement of Cost Engineering ("AACE") guidelines for the project there is a 50% or less probability that the B2H will come in on cost.

5. The Net Present Values (NPVs) calculated from this 2021 IRP "budget" are also questionable since they were validated with this old budget data. When a newer version of the budget is published the NPV must be vetted by OPUC staff and/or consultant. This should also include a discussion on how B2H revenue goes to reduce the NPV and/or cost to the Idaho Power customer (further discussed below under revenue.)

Revenue

The company states, "... in the 2021 IRP, Idaho Power modeled incremental transmission wheeling revenue from non-native load customers as an annual revenue credit for B2H portfolios, representing a reduction in project costs and ultimately benefiting Idaho Power retail customers."[11] We are unable to see where or how these revenues are being credited to Idaho Power customers and would appreciate an explanation. If B2H is a cost center with O & M and other expenses should not revenues be credited to that cost center? How does IPC determine if a unit is performing as expected in modeling? Is this not done for generation?

The OATT and Point to Point (PTP) revenue that Idaho Power receives will increase between 32-35% if B2H is built. The company's December 2021 SEC 10-K shows Transmission wheeling-related revenues of $67,997,000 in 2021. In the company's discussion of B2H as a resource, it said "When evaluating and comparing alternative resources, two major cost considerations exist: 1) the installation costs of the project (capital and other fixed costs), and 2) the energy costs of the project (variable costs) "[12] What is missing are the wheeling charges to get any generated energy to the Idaho Power border then to the customer. That is the full

[10] 12/31/22 IPC SEC 10K p 15.
[11] 2021 IRP p. 61/72.
[12] 2021 IRP p. 41.

cost of electricity to the customer and that needs consideration. The transmission wheeling charges to the total cost of energy are a significant cost to the customer and a major source of revenue for the company. It would be helpful to know why this cost is not considered and what portion of these wheeling revenues go towards the annual revenue credit for B2H portfolios and reduction of the cost to customers?

STOP asks that Commission direct staff and/or a consultant to conduct a more thorough analysis of this budget **within this IRP cycle** and not "kick the can down the road." Getting the budget correct is vitally important. By the time the company is back for the 2023 IRP construction might have begun and costs will no longer be under control. It would be disappointing (at best) or criminal (at worst) if construction was underway, tearing up the earth across hundreds of miles of eastern Oregon, and the "least cost-least risk" portfolio was hidden under these flawed budget estimates. Eastern Oregon cannot wait for a prudency review or ratemaking to get this corrected.

Transmission Mapping

The transmission scenarios have become more complex in this IRP as has the modeling and following the numbers. It seems that Idaho Power, in vigorously pursuing the B2H transmission line, was caught off guard by the August 2020 energy emergency event in California. The event resulted in a rush by third parties to purchase any additional transmission capacity in the west thus restricting IPC's access to the Mid-C and other markets. STOP is frustrated to learn about this situation since we have commented on this very issue in the last IRP.

To begin to resolve this situation IPC:

1. Issued a Request For Proposal (RFP) for transmission and received no bids; therefore, the company had to search out a complex sequence of transmission rights to meet capacity needs from other markets. **STOP asked in past IRPs that the company look to all available markets, rather than fixating on the Mid-C.**

2. Added 200 MW of transmission import capacity acquired from PAC via the 2022 term sheet but will not use it in planning margin calculations for the summer peaking months. **Why, when summer peaking is so critical for them?**

3. Reinforce Borah west and Midpoint west giving IPC an additional 510 MW.

4. Utilize its Gateway West transmission rights that will give IPC 1/3 of the 3,000 MW capacity (or 1,000 MW.)

5. Build Idaho Power Segments Phase 1 (Partial Segment 8 = 700 MW) and phase 2 (Complete Segment 8 = 800 MW) to pick up 1,500 MW.

6. Examine SWIP-North to add 100 MW in summer and 200 MW in the winter that would count toward meeting the company's planning margin requirements. It would also connect to SWIP South of which **Idaho Power was an original applicant to the BLM for an EIS in 1993with market access farther south on the ON line.**

7. Use CBM and TRM for the first time to serve load. **STOP has asked for this analysis in the past but the company has not been willing to do it. Now they are using it as a resource we would like to see how it is being done.**

8. Build renewables with storage in Idaho. **STOP applauds that this is finally occurring after repeated encouragement from stakeholders and IRPAC members for the past four IRPs (maybe more.)**

9. Increase their planning reserve margin immediately, from 0.1 days per year (2019) to .05 days per year (2021), due to the Northwest Power Planning Council suggestion to do so and issues with hydro and climate modeling. In response to DR 14 which asked, "Please show the difference in megawatt hours and cost related to the company's change in the reliability threshold from 0.1 days per year to 05 days per year for all portfolios." The company responded, "An analysis showing the difference in megawatt hours and costs related to the Company's change in the reliability threshold from 0.1 days per year to .05 days per year for all portfolios was not performed and the information is not available**. It is unfortunate that the difference in megawatt hours and costs related to this change are unknown; again, further obscuring the fiscal implications and budgetary forecasts.**

STOP has discussed for years the value of diversifying the energy markets the company uses, using CBM and TRM, fortifying internal transmission to bring renewables with storage online in Idaho creating jobs and taxes for Idahoans. We are pleased to see that the company is finally looking at options other than the B2H but are disappointed that it took the California event to get the company embrace the new energy model. We think that with a revised B2H budget the true B2H costs will be greater than developing these internal transmission reinforcements and gateway segments with renewables and storage in Idaho.

Useful Comments from Idaho Docket (2021 IRP)

In this section of STOP's comments we will bring in information from the Idaho Public Utilities Commission docket, IPC-E-21-43 Idaho Power Companies 2021 IRP. STOP is sharing these comments, as we did in previous IRP's, to inform the Oregon docket on the Idaho proceedings. The first set of comments is from the Idaho PUC staff, the second from Clean Energy Opportunities (CEO), and the third from Idaho Conservation League (ICL).

IPUC Staff Review

In addition to improvements that the company implemented in the 2021 IRP, Staff identified additional concerns it believes need to be addressed in the 2023 IRP (Items 1-7) and in its current action plan (Items 6 and 7). Staff recommends:

1. Incorporating acceleration of extreme weather events and variability of water availability through its load and resource input assumptions, rather than compensating by changing the LOLE reliability target;
2. Only including market access backed by firm transmission reservations in the Load and Resource Balance ("L&R");
3. Evaluating the risks and inaccuracies from employing a single benchmark year (2023) to determine the LOLE-based Planning Reserve Margin ("PRM");
4. Providing a comprehensive Quality Assurance ("QA") plan to verify and validate its models by describing the purpose of each test, how the test was conducted, and the result;
5. Including a study of the costs and benefits of implementing a flexible resource strategy;
6. Developing a Bridger exit agreement with PacifiCorp that determines potential costs of extending or exiting operations early like the exit agreement developed for the closure of Valmy and incorporate those costs into its coal plant exit costs to properly value different exit dates in the Company's portfolios;
7. Not including acquisition of specific types of resources in its action plan where a broadly-scoped RFP is appropriate. (p. 3 in Staff Review)

III. Development of Portfolios and Selection of the Preferred Portfolio

<u>B Development and Evaluation of Portfolios p 15-16</u>

The Company built six Base portfolios targeting important resource questions that needed to be answered in the 2021 IRP, the most important being whether or not to build the B2H transmission line. The Company included three Base portfolios with B2H and three without B2H. Within those two sets of portfolios, the Company generated portfolio variations on whether it was beneficial to align Bridger exit dates with PacifiCorp, and whether Gateway West was economical. Beyond these resource alternatives being forced into portfolios, all the remaining deficits were filled with resources that were the most economical by using planning conditions for all key inputs such as load growth, natural gas price, and carbon price. The Company then ran each Base portfolio through the production cost model to determine their NPV cost over the 20-year time horizon using different natural gas prices (planning and high) and carbon prices (zero, planning, and high). Staff believes this analysis was appropriate and informs of the need for the B2H transmission line given planning case input assumptions. The NPV results of the Company's Baseline analysis is duplicated from the Company's IRP as shown below.

2021 IRP portfolios, NPV years 2021-2040 ($ x 1,000)

Portfolio	**Planning Gas, Planning Carbon**	**Planning Gas, Zero Carbon**	High Gas, High Carbon
Base with B2H	$7,915,702	$7,186,761	$9,832,001
Base B2H PAC Bridger Alignment	$7,999,347	$7,152,955	$9,932,925
Base without B2H	$8,192,830	$7,784,545	$9,474,983
Base without B2H without Gateway West	$8,441,414		
Base without B2H PAC Bridger Alignment	$8,185,334	$7,588,228	$9,652,891
Base with B2H—High Gas High Carbon Test	**$7,997,339**		**$9,424,935**

The NPV results show that the portfolios with B2H were least cost for planning gas and planning or zero carbon; however, the production cost simulations show that B2H may not be the most economical choice with high natural gas and carbon prices. Based on these results, the Gateway West transmission line without B2H may be more economical because Gateway West would provide better access to renewable energy. To counter this contention, the Company produced additional base portfolios including B2H (as shown on the bottom row of the table).

Instead of using planning gas and carbon to develop the portfolios, it used high gas and carbon. Because of this analysis, the Company concluded:

[The] "Base with B2H—High Gas High Carbon (HGHC) Test" portfolio includes total renewables equivalent to the "Base without B2H" portfolio and was evaluated to test B2H as an independent variable. The results indicate that B2H remains cost effective, independent of gas price and carbon price and that a pivot to even more renewables in a future with a high gas and carbon price would be appropriate.

2021 IRP at 130, fn 36.

However, Staff does not agree with the Company's conclusion since these results are not comparable to any of the results in the table. To make it comparable, the Company would need to generate portfolios for all Base scenarios using the high gas and carbon price inputs and then simulate them through the production cost model using the same planning gas and carbon prices to compare against the $7,997,339 amount and high gas and high carbon prices to compare against the $9,424,935 amount. Until the Company runs this analysis, Staff believes that increasing gas prices and legislating carbon restrictions may make B2H less economical.

C Evaluation and Mitigation of Risk p 17

Based on the scoring of these risk evaluation methods, the Company determined the Base with B2H preferred portfolio has a comparatively low level of risk when compared to the Company's other Base portfolios. However, Staff has two concerns related to risk:

1. How much the Company is relying on B2H to meet its future capacity needs due to it being the largest and most expensive resource in the Company's preferred portfolio; and
2. The lack of risk mitigation and flexibility strategies included in the Company's IRP.

The Company analyzed several sensitivities of risk associated with (1) how much capacity the Company will be able to obtain through the B2H transmission line, (2) increases in B2H construction costs that would make the preferred portfolio no longer economic, and (3) the impact of not being able to meet the B2H in-service date by the end 2026. Because B2H represents the largest and most expensive single resource included in the preferred portfolio, there is additional risk if it does not meet budget and schedule and would likely cause serious impacts to both customer cost and reliability.

Clean Energy Opportunities (CEO)

CEO suggests two areas for careful review before developing the 2023 IRP and shares their concerns about these areas in need of review. They are:

1. Improve the ability of the software used (whether Aurora or some other product) to analyze effects of battery storage on diurnal market price patterns,
   a. Software system limitations produced questionable data: forecast Mid-C hourly price spreads seem unreasonably large. The benefit associated with increased access to Mid-C market may have been overvalued.
2. Improve the method for estimating the present value of various portfolios to remove an existing bias that minimizes out-year costs of inputs that rise in cost over the 20-year forecast period (such as those associated with natural gas prices or carbon emissions charges).
   a. Using an inappropriately high discount rate to calculate present values of forecast costs for various portfolios inserts bias, which could produce “Regrets”

Idaho Conservation League (ICL)

Bridger conversion was late in the process and used speculative inputs

The 2021 IRP process started by building on the 2019 preferred portfolio that included exiting the Bridger units between 2022 and 2030, primarily replaced with wholesale energy via the Boardman transmission and new solar generation. At the May 13, 2021 IRP Advisory meeting, the Company described the future supply-side resource options which did not include any coal to gas conversions. At the June 10, 2021 meeting, the Company described the modeling scenarios, which included manually built portfolios with various coal retirement dates, but no indication of coal to gas conversion scenarios. In a late-breaking plot twist announced during the second to last meeting on October 21, 2021, Idaho Power changed the Bridger coal analysis to include converting Units 1 and 2 to gas. This last-minute change to how a major resource is put into the model hindered stakeholders' ability to collaborate with the Company.

Prior IRPs document that gas conversion is not necessary to create an optimal portfolio without Bridger. The 2017 IRP specifically considered the future of Bridger units 1 and 2 and concluded that early exit, without gas conversion, was the least-cost, least-risk option[2]. The 2019 IRP documented that exiting the entire Bridger plant by 2030 and pivoting to increased wholesale energy through the Boardman transmission line was the preferred option[3]. In both cases neither new gas or gas conversion were tied to the Bridger exits. While ICL recognizes the load forecast has increased since these prior IRPs, we also recognize that Idaho Power continues to assert that increased transmission and wholesale markets are the primary preferred resource and that clean options like solar, wind, and storage show continuing cost declines and performance gains. Probably the strongest evidence that gas conversion is not necessary over the long term is the fact that Idaho Power intends to shutter even this new gas by 2034. One need only look at the overall preferred portfolio to see that expanding the clean options is the primary basis for creating a reliable and affordable resource portfolio.

Even more worrisome is the speculative nature of the modeling inputs to assess the coal to gas conversion. According to Idaho Power's response to ICL production requests, as of April 2022, the Company was still in discussion with plant owner Pacificorp about the necessary permits, infrastructure, and timeline needed to convert Bridger to gas. Without this basic information it is simply not reasonable to conclude Idaho Power rigorously evaluated the model inputs nor collaborated with stakeholders, which this Commission describes as necessary for a worthwhile planning process.4 Because of the speculative nature of the gas conversion costs and last minute nature of the analysis, ICL recommends the Commission instruct Idaho Power to implement a transparent and rigorous process before any further action on the proposed gas conversion.

Conclusion

STOP would like to thank the OPUC staff and Commission for this opportunity to begin comments on this 2021 IRP. As mentioned above, STOP acknowledges the rushed job putting this IRP together before the ink even dried on the prior IRP. This seems to have resulted in confusing figures and what appear to be more questions than answers. As the company searches its cloudy crystal ball, for the right mix of transmission resources, retirements of coal facilities, and renewable resources with storage we wish them clarity. The market is complex and evolving rapidly. STOP looks forward to the inquisitive process where the stakeholders and company question each other to design the best solution for Idaho Powers customers.