"Protect Our Land, Preserve Our Heritage"

STOP B2H Coalition

Date: April 6, 2020

To: OPUC Commissioners, staff, and LC#74 intervenors

From: Jim Kreider, Co-Chair, STOP B2H Coalition

With apologies and respect, the Stop B2H Coalition files its Amended Opening Comments in the OPUC Docket #74, Idaho Power 2019 Amended Integrated Resource Plan.

We are a coalition of volunteers that formed in 2015 for one common purpose: to STOP the B2H! We range the full political and social spectrum and have come to respect each other and our diversity. We are 100% volunteer. Feelings and opinions about the B2H run high; some in our group have been engaged with the project since inception. We have a number of 60-90 year old superstars; some who are ready to stand in front of the bulldozers with pitchforks and others focused on supporting renewable and clean energy as a viable source of power to Idaho Power rate payers. We have accomplished researchers who are dismayed by the way bureaucracies seem to tip the scale in favor of the utilities and their pursuit of profits, and others who are true to every administrative step in the process(es.) We all love eastern Oregon and are working to protect our land and natural resources from an unneeded corporate intrusion.

The research team that put STOP's comments together had not worked together before. We had old, new, and open source software that clashed and battled to destroy the document. We had Google Drive, OneDrive, and DropBox develop black holes. We had the most perfect techno-cyber meltdown in the history of STOP right before the deadline.

In the document submitted on April 2nd, two sections were inadvertently omitted; several sections were overwritten by older versions and formatted out of order, and the Table of Contents needed to be corrected.

We are herewith submitting STOP's Amended Opening Comments. We apologize for any inconvenience this amended filing may have caused fellow readers and especially the Commission staff.

We appreciate your understanding,

Jim Kreider

Jim Kreider, Co-Chair
Stop B2H Coalition

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of Idaho Power Company 2019 AMENDED INTEGRATED RESOURCE PLAN	Docket LC 74

STOP B2H Coalition
Amended and Revised Opening Comments

Submitted
April 7, 2020

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Introduction

Stop B2H Coalition (STOP), a grassroots, Eastern Oregon citizens' organization, with 800 members and ten member organizations, hereby submits its Amended Opening Comments on Idaho Power's 2019 Amended Integrated Resource Plan. STOP presents its case that Idaho Power has the resources available to meet future needs without building the Boardman to Hemingway transmission line (B2H) and without building new thermal generating facilities. The early decommissioning of coal plants planned in the 2019 IRP is supported by STOP. The B2H which is at the core of the company's 2019 IRP preferred portfolio design is not supported by STOP.

OPUC Guidelines,[1] the Prudency test,[2] and STOP's concern for the long-term burden on ratepayers, set an overall tone for our arguments against the B2H. Idaho Power is over-estimating its demand load forecast, under-estimating its energy efficiency and demand-side management capabilities, and the utility has the needed transmission resources to meet its requirements in the future. The cost of the B2H to the ratepayer must be compared to the cost of energy efficiency and the emergence of the emerging class of producer-consumers. As the Commission is well aware, STOP was very dissatisfied with the company's 2017 IRP, as expressed in our opening and closing comments. Today, we are concerned about the company's ability to sustain themselves into the future, given the rapidly evolving business model for electric utilities, changing consumer behavior, and the company's slow adaptation to those conditions.

STOP is also concerned about the powerline in the context of climate change. The current infrastructure of Path 14, as STOP presents in these comments, is able to meet future capacity needs. Nonetheless, given the (drying) climate impacts already apparent in our eastern region and the experience of California's transmission caused wildfires, STOP believes that a more prudent investment would be, to *first* upgrade and fire-harden existing transmission lines in existing corridors. This would result in grid infrastructure improvements and resilience while retaining the forest vegetation with its capacity for carbon sequestration. This has never been modeled and STOP believes it should be.

STOP feels there is serious risk of wildfire. While raised at an IRPAC meeting, it has not been included in the 2019 IRP. The presumed resiliency of brand new transmission infrastructure, to be sited within feet of a parallel transmission system, leaves both vulnerable in our opinion. The proposed B2H powerline does not increase grid security, and it is not in the best interest of the public.

Finally, Idaho Power has forcefully sought to expedite Oregon's review and regulatory processes. STOP asserts that the utility's rush to obtain 2018 OPUC acknowledgment of Action item # 6—to begin construction of the powerline—was premature. We ask that the Commission exercise its third procedural key element[3] in its Order

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1 Guideline 1: Substantive Requirements. a. All resources must be evaluated on a consistent and comparable basis.... b. Risk and uncertainty must be considered.... c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers… and d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

2 "Prudence is determined by the reasonableness of the actions 'based on information that was available (or could reasonably have been available) at the time.'" (In re PGE, UE 102, Order No. 99-033 at 36-37.) See also In re Northwest Natural Gas, UG 132, Order No. 99-697 at 52: ("In this review, therefore, we must determine whether the NW Natural's actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances.")

3 "Opportunity for parties to request supplemental orders to clarify or modify Commission's directives." (ORDER NO. 07-002, ENTERED 01/08/07; referencing Order No. 89-507.)

No. 89-507 (establishing the approach to utility resource planning), and **reconsider, modify or rescind, the 2018 Action Item #6, to construct the B2H (Order No. 18-176)** as identified in multiple sections herein.

STOP Comments: 2019 Idaho Power Integrated Resource Plan

Resource Need Evaluation

Boardman to Hemingway as a Resource

This 2019 Amended IRP is the second Idaho Power IRP that STOP has actively participated in. STOP became especially concerned in 2017 when Idaho Power abandoned the utility's historical justification for the B2H power line, and instead adopted the novel approach of attempting to justify B2H as the lowest cost supply side resource, one that could presumably meet the future peak capacity needs of its customers. This incarnation of B2H – for supplying power – was to be evaluated alongside traditional supply side resources to meet those capacity needs.

STOP did not agree that Idaho Power had adequately evaluated and supported their choice of B2H as a supply side resource in the 2017 IRP. The OPUC, nonetheless, adopted Idaho Power's pivot on the rationale for B2H and that change as justification for selecting the power line as a supply side resource. Ultimately in 2017, the Commission embraced Idaho Power's decision to acquire B2H which action displaces the acquisition of new carbon free resources that would otherwise be acquired in the absence of B2H.

STOP understands that the Commission's IRP Guidelines encourage Idaho Power to consider B2H as a resource option:

> *"…utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability."* [4]

However, STOP does not agree with the OPUC staff assertion that the Commission's IRP Guidelines encourage Idaho Power to consider B2H as a "supply-side" resource option. Such a resource is so labeled because it supplies energy and capacity to the system. A transmission line does not provide either. Specifically, Idaho Power has not identified any quantifiable supply side generating resources that would be transmitted by the power line. Instead the utility has adopted the problematic dogma pioneered during the Enron era: that significant reliance on spot market energy trading is a responsible long-term power supply strategy, one that meets the additional need for capacity resources. We believe history has shown it is not.

STOP still strongly believes that modeling B2H as a supply side resource in an IRP violates best practices and is contrary to the best interests of Oregon and Oregon ratepayers. STOP, however,

4 OPUC Order No. 07-002, Guideline 5, p13

acknowledges the reality that the OPUC's staff has already concluded that B2H is a supply side resource and should be so evaluated in the IRP. We do not wish to revisit the issue in this 2019 IRP.

STOP will, instead, provide comments that seek to improve Idaho Power's analytic re-evaluation of B2H in this IRP – consistent with other supply-side resources. We encourage the Commission to make every effort to ensure adherence to its own rules and regulations as they pertain to the acquisition of a major supply side resource by Idaho Power so that the acquisition does not circumvent Oregon's Competitive Bidding rules.

Does the Commission still agree with Idaho Power that B2H is a Supply Side Resource Acquisition?

Idaho Power proposed B2H as a 350 MW supply side resource in the 2017 IRP and the OPUC staff concurred. Given this determination, STOP believes it is incumbent on the Commission to apply Oregon's rules and regulations governing the review and approval of any Major Resource acquisition by Idaho Power through an IRP. These include:

1. ensuring that Idaho Power has requested and received a waiver of Oregon's Competitive Bidding Rules before acknowledging B2H, which rules require all Major Resource acquisitions to be obtained through a competitive solicitation;
2. requiring at least the same level of analysis, support and documentation around B2H that the Commission typically requires of other supply side resources proposed for acquisition, and;
3. insisting that Idaho Power expand its risk assessment around Idaho Power's dogmatic preference for B2H.

Formal Waiver of Competitive Bidding Required

With both Idaho Power and OPUC Staff having conclusively defined B2H as a 350 MW supply-side resource, B2H clearly falls under the Commission's Competitive Bidding Guidelines. Those guidelines define a major resource as one with a life of at least five years and delivering 80 MW or more. [5]

While STOP acknowledges that Oregon's Competitive Bidding Guidelines provide an exemption from the competitive bidding requirements when a utility is "Seeking to *exclusively* (emphasis added) acquire transmission assets or rights"[6], this does not describe Idaho Power's request. Idaho Power is asking the Commission to approve the acquisition of a 350 MW supply-side capacity resource with a nominal term of 55 years.

STOP respectfully requests the Commission to expand on why it chose to acknowledge the permitting and construction of B2H in Idaho Power's 2017 IRP, when doing so effected a waiver of B2H from Oregon's competitive bidding rules. It is unclear to STOP what authorities the Commission has used to

5 ORS 860-089-0100 (1) (a)
6 ORS 860-089-0100 (B) (3) (d)

exempt B2H – a specific Major Resource Acquisition – from Oregon's supply side competitive bidding rules, absent a formal filing of a request by Idaho Power.

STOP anticipates that Idaho Power could and would identify reasons why B2H should not be subject to Oregon's Competitive Bidding Rules. With their request styled as one that would acquire a 350 MW supply-side capacity resource, STOP questions whether it is appropriate or acceptable for the Commission to reach any such unstated agreement with Idaho Power.

Oregon's Competitive Bidding Rules provide a clear process for Idaho Power to request an exemption, and the Commission has clear authority to approve such a request. We do question, however, whether the Commission has the authority to acknowledge the request for approval to build B2H – as a major supply side resource – while simultaneously bypassing those rules. All major supply-side resource acquisitions (absent a formal waiver from the Commission) must be acquired under a competitive solicitation according to those rules. We ask the Commission to re-evaluate this unstated exemption.

Portfolio NPV cost of B2H is unsupported and appears understated

In this 2019 IRP, Idaho Power maintains that the NPV cost of B2H has fallen by 56% when compared to the NPV cost of the line as stated in the 2017 IRP. Idaho Power has not provided any explanation for this radical downward adjustment.

	Nominal Cost of B2H	Discount Rate Used for NPV Calculations	NPV cost of B2H before credits for Secondary Transmission sales	NPV credits for Secondary Transmission Sales	Total NPV Cost of B2H Portfolios 13-24	Change in NPV Cost of B2H in 2019 IRP
2017 IRP	$ 274,000,000	6.742%	$ 384,000,000	$ (128,000,000)	**$255,000,000**	**N/A**
Initial 2019 IRP	$ 292,000,000	9.490%	$ 112,000,000	N/A	**$112,000,000**	**-56%**
Amended 2019 IRP	$ 292,000,000	7.120%	?	?	**$111,000,000**	**-56%**
	Source: LC074 - Idaho Power Co - 2019 IRP Discovery Non-Confidential Data Response From Idaho Power Co to OPUC Staff Attachment 1 - Response to Staff's Request No 49_Table 9.3					

Figure 1: NPV cost comparison between Idaho Power's 2017 IRP and the 2019 IRP

Figure 1 illustrates this large decline in Idaho Power's estimated NPV cost. There had been a near 7% increase in the nominal cost of B2H – $292 million from the 2010 Amended IRP to the 2017 IRP. Yet the cost of B2H has decreased by 56% in the 2019 IRP compared to the 2017 IRP, dropping from $255 million to $111 million.

The substantial decrease in the modeled NPV capital cost of B2H is even more difficult to understand because Idaho Power did not assume any third-party wheeling revenues as offsets to the B2H costs in the 2019 IRP. Those revenues were included in the 2017 version, a total of $128 million on an NPV basis.

If Idaho Power had made a similar assumption in 2017 and included no incremental third-party wheeling revenue offsets to its B2H costs, the NPV cost of B2H would have been $384 million, based on the figures listed in that IRP.

The Commission should compel Idaho Power to provide a rational explanation of why the forecast NPV cost of B2H has fallen from the projected $384 million in the 2017 IRP to $111 million in the 2019 IRP.

How Can Idaho Power Improve the IRP Analysis of B2H as a Supply Side Resource?

STOP offers the following suggestions for how the Commission can ensure that Idaho Power has conducted a fact-based evaluation of B2H and appropriately evaluated B2H as a supply-side resource:

1. The Commission should require Idaho Power to expand their evaluation of and justification for the underlying energy and capacity resource that the utility claims B2H will supply. This evaluation should remain agnostic as to whether it enables a large increase in rate base (i.e., facilitates B2H). Idaho Power has devoted much of its IRP to B2H, though the power line by itself is only a cost. It does not provide any tangible economic benefits to ratepayers. Yet they devote only 2 pages to a discussion of "Market Power" as a firm capacity resource and the financial parameters around market purchases. Also, and with the lone exception a forecast of "monthly" future gas prices and the uncertainty that revolves around that market, Idaho Power has neglected to conduct any assessment of the risks associated with market purchases. Specifically, they have excluded the risk that a market purchase strategy—even if it looks prudent today (which it does not)—will remain robust over the 20 year IRP planning period, let alone the 55 year period during which ratepayers will be bear the cost of B2H.
2. The Commission should insist that Idaho Power more clearly characterize the "supply-side resource" attributes of market purchases in the Pacific NW. STOP does not believe that the Commission would accept an IRP from Idaho Power based upon the premise that every fossil fuel resource has identical characteristics – with the exception of fuel efficiencies. Likewise, we do not believe that the Commission would accept an IRP from Idaho Power based upon a premise that all renewable resources have identical characteristics – in this case with the exception of their contribution to peak capacity. Yet Idaho Power has submitted its second consecutive IRP where market purchases are characterized as the simple equivalent of a virtual gas-fired plant at MIDC, one that Idaho Power dispatches <u>hourly</u> when needed. The utility contends that the cost is simply a function of the marginal price of market power, all based upon a forecast of <u>average</u> monthly gas prices.

In characterizing the potential value and risks of the MIDC market, Idaho Power should be required, at a minimum, to address the following attributes of the MIDC market:

(a) Depth of the <u>physical</u> market at MIDC

i. STOP understands that the market at MIDC is primarily a financial market, not a physical market. While there is considerable liquidity for financial trading and forward hedging at MIDC, it is apparent that there are many occasions when the liquidity of the <u>physical</u> market is constrained.

ii. While in most cases this does not mean power is not available for purchase at some price, the lack of physical liquidity manifests itself in significant volatility and dramatic price excursions. Those deviations cannot be explained by Idaho Power's simplistic representation of the cost of dispatching available resources at the margin. In the AURORA model, those prices are predicated on a forecast of <u>monthly</u> average gas prices. Idaho Power should be required to analyze and report on the correlation between daily On-Peak prices at MIDC and the days and hours of Idaho Power's capacity needs.

(b) the risk of price uncertainty and price volatility at MIDC.

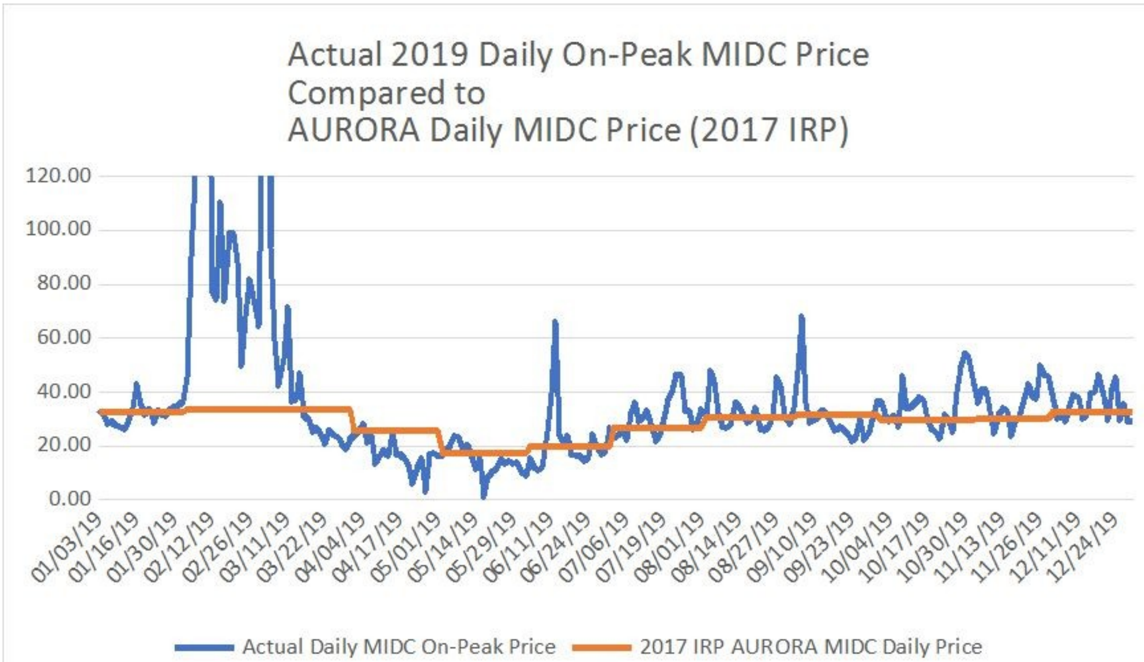

Figure 2: MIDC daily on-peak pricing - daily (2019) and AURORA estimated (2017 IRP)

i. Monthly gas prices are a poor predictor of daily power prices at MIDC, as Figure 2 illustrates. The data in Figure 2 focuses on Calendar Year 2019 and compares the actual daily on-peak price at MIDC to the MIDC price calculated using AURORA (2017 IRP). It clearly shows that the AURORA model is a dismal predictor of power prices at MIDC. The Commission should require Idaho Power to specifically address the risks inherent in their request for ratepayers to incur the large fixed costs of B2H in order to acquire 350 MW of capacity from the PNW markets. That cost cannot be mitigated if the decision later proves to be a bad one for ratepayers.

(c) Depth of Supply at MIDC

i. Idaho Power should be required to identify the generating resource behind each hourly purchase transaction as well as the hourly sales transactions from/to MIDC in their Portfolios, both with and without B2H. This would provide important information and insights including, but not limited to:

1. actual carbon emissions associated with Idaho Power purchases at MIDC as modeled in AURORA;

2. actual carbon emissions associated with Idaho Power sales at MIDC as modeled in AURORA;
3. the distribution of hourly purchases at MIDC across the hours of the day and the seasons of the year using AURORA, as compared to actual purchases from that market using recent data.

ii. an added benefit that further interrogation of AURORA model outputs could uncover data input errors or other hidden problems in the representation of the MIDC market by AURORA – such as inaccurate timing of retiring coal capacity serving that market.[7]

The Commission should seek improvements in Idaho Power's stochastic risk analysis

A Robust Risk Analysis Must Examine Distributions Around Expected NPV

A robust risk analysis must go beyond point estimates of the typical outcomes from scenario analyses. The fundamental approach to risk analysis in any IRP is to evaluate the expected NPV cost of all Portfolios under real world uncertainties, as well as the relative cost exposure uncertainty (that uncertainty is the distribution of outcomes around the expected NVP) of each Portfolio by considering the probability of major risks and unknowns.

From basic statistics we know that the calculation and presentation for the predicted distribution of future NPV Portfolio outcomes – under a specific Portfolio – requires that the distribution be evaluated with reference to the expected value around which the standard deviation is calculated. For example, Portfolio A could have a larger standard deviation in NPV than Portfolio B. That would be an indication that Portfolio A has more downside risk to ratepayers (i.e., a higher standard deviation) than Portfolio B. However, if the expected NPV cost of Portfolio A is much lower than the NPV cost of Portfolio B, then Portfolio A could be the superior choice despite a larger standard deviation.

Idaho Power has curiously avoided any discussion of the <u>expected</u> NPV cost in all of its Portfolio computations, 1 through 24. When calculated, they show that <u>the addition of B2H to nine of the twelve Portfolios INCREASES both the expected NPV cost to ratepayers, and the risk – as measured by the standard deviation — to those customers, when compared to identical Portfolios without B2H</u>.

The increase in both expected NPV and in ratepayer risk from adding B2H is especially relevant for Idaho Power's preferred Portfolio 14. Neither are discussed in the IRP. This lack of any mention of the results from the risk analysis is so complete that the words "mean" and "expected value" appear nowhere in the document.

Idaho Power included a chart in the IRP (Figure 9.1, p 100) with the calculated standard deviation of each Portfolio on the x-axis, and the point-estimate of NPV of each Portfolio – under the Planning Gas

7 For example, Idaho Power distributed information to the 2019 IRP Advisory Council at the March 14 meeting that appears to indicate Idaho Power may have inadvertently operated the Boardman and Centralia #2 coal plants throughout the 20 year planning period in the AURORA, Portfolios that include B2H. See March 14 Presentation to the Advisory Council.

and Planning Carbon scenario – on the y-axis. The comparison of standard deviations around a Portfolio's NPV cost of a discrete scenario, in this case the Planning Gas and Planning Carbon, does not make sense. Statistical rigor requires that a standard deviation be calculated and presented with respect to the expected value <u>of the data for which the standard deviation is calculated</u>.

Had Idaho Power correctly represented the results of their risk analysis as STOP has in Table 1 below, the company would have acknowledged that adding B2H increased the expected NPV cost to ratepayers in nine of the twelve Portfolios. The data also shows that the standard deviation around the expected NPV cost in B2H Portfolios 13-24 increases when compared to Portfolios 1-12, the same portfolios calculated without B2H.

A small increase in expected NPV cost could be seen as an acceptable result from adding B2H to a Portfolio. That would be true if adding B2H reduces the downside risk (lowers the standard deviation) of those Portfolios—those with B2H—to such extent that the higher expected NPV cost is more than offset by the drop in standard deviation around the expected NPV value of the Portfolio. However, in all twelve of Portfolios 13-24, adding B2H <u>increases</u> the standard deviation (downside risk) of the same portfolio without B2H.

The NPV of each Portfolio can be calculated from the same data that Idaho Power used to compute the standard deviation of each Portfolio. STOP has done that in Table 1.

Table 1: Portfolio Costs: the change in mean and standard deviation with the B2H power line.

	Portfolio Costs ($ 000s)									
	Planning Gas - Planning Carbon	**High Gas - Planning Carbon**	**Planning Gas - High Carbon**	**High Gas -High Carbon**		**Mean**	**Standard Deviation**	**Change in Mean with B2H**	**Change in Stamdard Deviation with B2H**	
Minimum	$5,140,799	$5,814,202	$6,330,257	$6,897,190						
Min w/o B2H	$5,193,822	$5,814,202	$6,330,257	$6,897,190						
Portfolio 1	$5,204,987	$5,838,271	$6,764,047	$7,694,476		$6,375,445	$941,990			**Portfolio 1**
Portfolio 2	$5,193,822	$5,912,498	$6,584,945	$7,498,159		$6,297,356	$850,079			**Portfolio 2**
Portfolio 3	$5,721,676	$6,210,619	$6,547,641	$7,061,325		$6,385,315	$488,435			**Portfolio 3**
Portfolio 4	$5,566,119	$6,103,940	$6,330,257	$6,897,190		$6,224,377	$477,414			**Portfolio 4**
Portfolio 5	$5,297,010	$5,814,202	$7,122,079	$8,003,831		$6,559,281	$1,066,763			**Portfolio 5**
Portfolio 6	$5,215,593	$5,833,030	$6,758,198	$7,648,289		$6,363,778	$922,708			**Portfolio 6**
Portfolio 7	$5,954,391	$6,346,565	$6,602,341	$6,996,029		$6,474,832	$379,215			**Portfolio 7**
Portfolio 8	$5,794,846	$6,237,979	$6,470,846	$6,959,605		$6,365,819	$420,109			**Portfolio 8**
Portfolio 9	$5,430,308	$5,888,100	$7,066,370	$7,859,693		$6,561,118	$958,288			**Portfolio 9**
Portfolio 10	$5,571,252	$5,898,554	$7,073,438	$7,730,128		$6,568,343	$872,879			**Portfolio 10**
Portfolio 11	$6,415,595	$6,704,850	$6,940,999	$7,241,029		$6,825,618	$303,555			**Portfolio 11**
Portfolio 12	$6,495,562	$6,815,126	$7,116,717	$7,543,175		$6,992,645	$386,355			**Portfolio 12**
Portfolio 13	$5,186,425	$5,950,205	$7,153,750	$8,055,579		$6,586,490	$1,100,573	$211,045	$158,583	**Portfolio 13**
Portfolio 14	$5,140,799	$5,967,392	$6,833,200	$7,812,743		$6,438,534	$993,768	$141,178	$143,689	**Portfolio 14**
Portfolio 15	$5,574,367	$6,217,075	$6,536,474	$7,223,380		$6,387,824	$593,952	$2,509	$105,518	**Portfolio 15**
Portfolio 16	$5,383,582	$6,128,204	$6,410,119	$7,183,363		$6,276,317	$644,117	$51,941	$166,703	**Portfolio 16**
Portfolio 17	$5,190,226	$5,945,183	$7,203,879	$8,100,650		$6,609,985	$1,121,658	$50,704	$54,895	**Portfolio 17**
Portfolio 18	$5,181,695	$5,943,126	$7,156,143	$8,052,905		$6,583,467	$1,102,521	$219,690	$179,813	**Portfolio 18**
Portfolio 19	$5,588,712	$6,189,823	$6,507,612	$7,151,883		$6,359,508	$564,073	($115,324)	$184,858	**Portfolio 19**
Portfolio 20	$5,524,844	$6,182,985	$6,531,144	$7,229,309		$6,367,071	$615,144	$1,252	$195,035	**Portfolio 20**
Portfolio 21	$5,450,320	$5,936,749	$7,312,706	$8,063,504		$6,690,820	$1,046,239	$129,702	$87,952	**Portfolio 21**
Portfolio 22	$5,471,918	$5,921,624	$7,278,465	$7,992,783		$6,666,198	$1,014,322	$97,855	$141,442	**Portfolio 22**
Portfolio 23	$5,731,414	$6,222,490	$7,014,498	$7,736,676		$6,676,270	$764,449	($149,349)	$460,894	**Portfolio 23**
Portfolio 24	$6,104,508	$6,573,322	$6,843,126	$7,308,401		$6,707,339	$436,199	($285,306)	$49,844	**Portfolio 24**

These results can be represented visually by re-populating IRP figure 9.1 with the corrected expected values of each Portfolio displayed on the Y-axis, while retaining the same standard deviations previously calculated by Idaho Power on the X-axis. The results are shown in Figure 3.

As can be seen in that chart, Idaho Power's own numbers show an almost universal penalty to ratepayers for building B2H when compared to the same Portfolios without the power line. It also shows that Idaho Power's choice of Portfolio 14 as the preferred Portfolio is illogical for several reasons.

First, ratepayers would clearly be better off if Portfolio 2 (Portfolio 14 without B2H) were chosen. It has a lower expected NPV cost than Portfolio 14 and a significantly lower risk in its standard deviation. Remarkably, Portfolio 2 is not even the lowest cost/lowest risk Portfolio among all Portfolios with B2H removed. That honor goes to Portfolio 4, a portfolio optimized by assuming *Planning Gas and High Future Carbon Costs*. Not only does Portfolio 4 show the lowest expected cost to ratepayers, it is significantly lower in cost and in risk than the same Portfolio with B2H added.

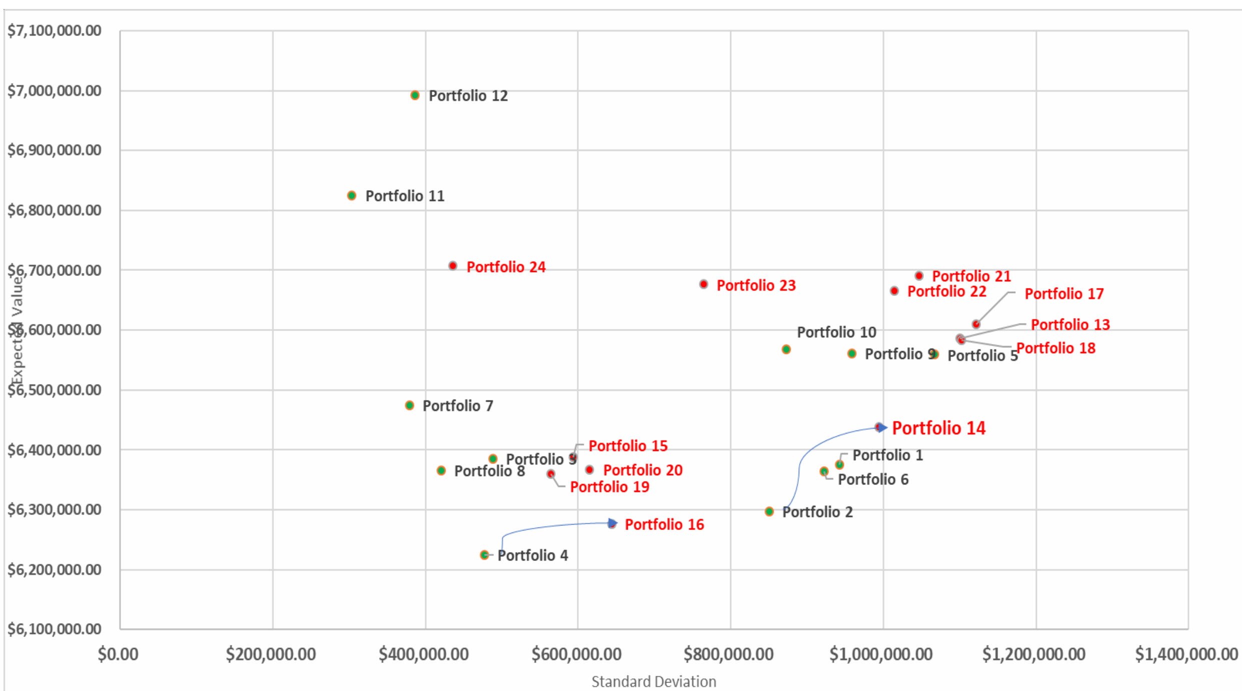

Figure 3: IRP revised Figure 9.1, corrected with expected values on the x-axis.

STOP believes that the Commission should direct Idaho Power revisit their risk analysis and revise the 2019 IRP to clearly evaluate the expected NPV cost for all Portfolios. They must justify their preference for Portfolio 14 with B2H given that Portfolio 2, identical but without the power line, has a lower expected cost and lower expected risk. Idaho Power should also explain why they prefer Portfolio 14 over Portfolio 4, given that the latter has the lowest expected NPV cost of all the Portfolios and significantly less risk than Portfolio 14, again without B2H.

Idaho Power's Stochastic Analysis is Inadequate

STOP commends Idaho Power for performing a stochastic analysis to extend the simple risk analysis discussed above and presented in Figure 3. It can result in a much more robust risk analysis than the simple scenario analyzed in that chart. It can also provide a much greater degree of confidence for the estimated distribution (the standard deviation) derived from the expected NPV cost of each Portfolio. Unfortunately, Idaho Power has not published the numerical results of the stochastic analysis nor has the utility calculated expected values and standard deviations. STOP is therefore unable to understand the underlying expected values and standard deviations that result from the stochastic analysis.

Such an exercise would, in any case, be questionable given how Idaho Power has structured its investigation. To be meaningful, a stochastic analysis must attempt to capture the risks associated with the uncertain cost and revenue drivers that are most important over the planning period. In the context of the 2019 IRP, Idaho Power determined that the primary significant risks to ratepayers revolved around future fuel prices, future carbon costs, hydro conditions, and load growth. Our examination of the risk analysis results (Figure 3) shows that, by any measure, the largest future cost risk among these four uncertainties is the exposure to the downside risk of selecting a portfolio optimized for low future carbon costs if carbon costs increase.

However, Idaho Power only built three of these risks into their stochastic analysis: gas prices; load growth; and hydro conditions. They inexplicably chose to ignore the risk of carbon costs when performing their analyses. Stated differently, they incorporated the risk of future fuel prices, hydro conditions and load growth, but assumed that the risk and uncertainty around the future cost of carbon was immaterial to the stochastic analysis. This assumption of no carbon price risk renders Idaho Power's stochastic risk analysis inadequate and uninformative.

In summary, Idaho Power's own Portfolio analysis shows their preferred Portfolio 14 does not have the lowest expected cost in the future. The addition of B2H also acts to increase the expected cost of all twelve non-B2H Portfolios. Idaho Power's analysis further shows that Portfolio 4, which is optimized to hedge against high future carbon costs, is a superior Portfolio. From the standpoint of cost and risk it is a better choice than Idaho Power's preferred Portfolio 14, where B2H is added to Portfolio 2. Lastly, we note that adding B2H to Portfolio 4 results in a higher expected NPV cost and greater risk than Portfolio 4 alone.

STOP encourages the Commission to request that Idaho Power revise their stochastic analysis to include future carbon costs as a fourth uncertain variable in the Latin hypercube sampling and to present the results of the revised stochastic analysis in terms of expected value and standard deviation for each Portfolio.

Idaho Power may have made unintended modeling adjustments in all Portfolios with B2H

Idaho Power implies that, when optimizing Portfolios 13-24 for the powerline, the only modeling change to Portfolios 1-12 from which they were derived was the addition of B2H in 2026. Logic dictates that the PNW market purchases calculated by AURORA should thus be identical across both sets of Portfolios, with and without B2H, for the years prior to 2026. An examination of Idaho Power's reporting of the AURORA purchases in Portfolios 13-24 clearly shows this was not the case. This indicates that Idaho Power must have made additional modeling adjustments beyond merely adding B2H to Portfolio's 1-12 in order to produce the results for Portfolios 13-24.

Idaho Power's characterization of existing PNW import capacity in Portfolios 1-12 suggests that the import path is constrained and will become increasingly so in the future. Based on data provided by Idaho Power, the AURORA results of Portfolios 1-12 show just the opposite. The AURORA model runs provided by Idaho Power to STOP reveal that, in all Portfolios 1 through 12, purchases from the PNW decline over time without B2H.[8] The conclusion is that purchases from the PNW are expected to become less economic. Consequently, existing capacity to import from the PNW is expected to be utilized less often over time. This results from AURORA's projection that the economic benefits of accessing imports from the PNW will deteriorate over the longer term.

If the economic benefits of importing power from the PNW are expected to decline over time and the transmission path is to be less used—which Idaho Power's Portfolio analysis shows—it follows that adding more import capacity over the path should be of limited value. Strangely, the AURORA model results for Portfolio's 13-24 show a large increase in imports merely by adding B2H, with the increase beginning years before the 2026 addition of B2H to the model.

8 Idaho Power response to STOP data request on the Average Annual Price of Purchases dated April 7, 2019. This response can be found at https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/our-twenty-year-plan/irp-questions-and-responses/

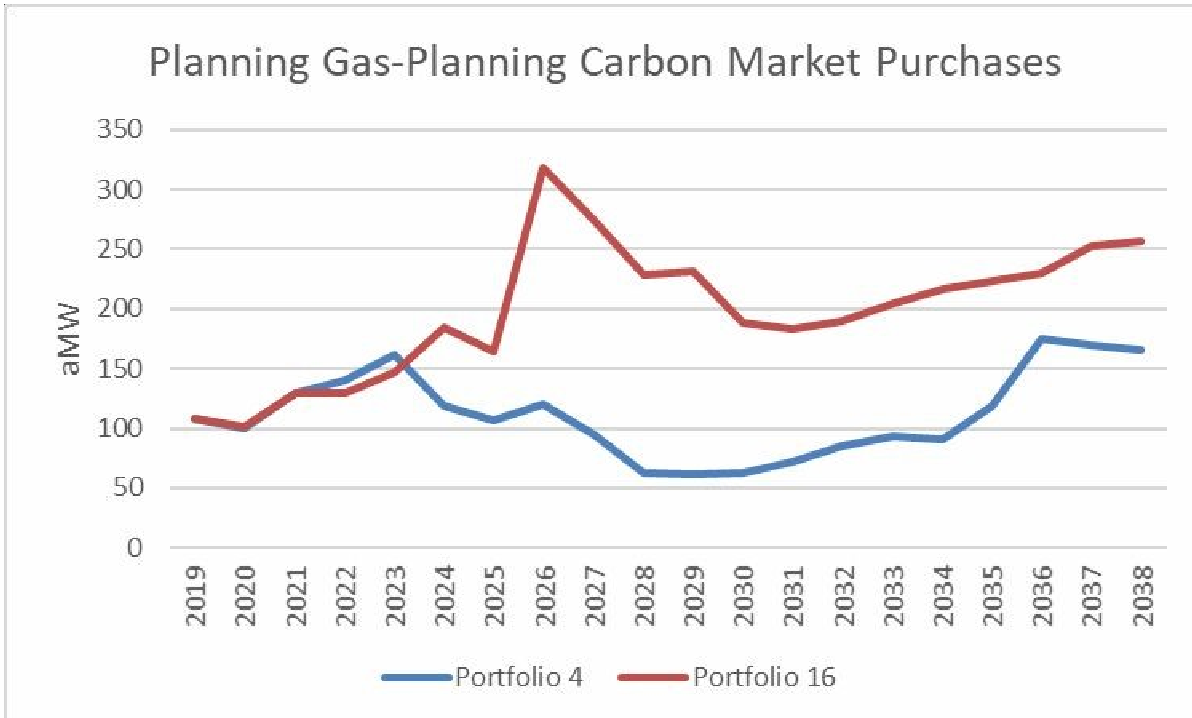

Figure 4: Imports shown increasing in 2024 before B2H comes online in 2026

The increase in imported power in those Portfolios in the early years before B2H comes online implies that existing surplus import capacity becomes more valuable by the mere knowledge that B2H will be built five years in the future. This result defies basic economic principles.

This is illustrated in Figure 4 which displays the annual imports into Idaho Power from the PNW from Portfolio 4, compared to those from Portfolio 16 (Portfolio 4 plus B2H). Market purchases are similar across both in the years 2019-1923. In 2024 however, Portfolio 4 shows a significant decline in imports while its modified twin—Portfolio 16 with B2H added—shows a significant increase in those imports. That happens even though B2H is years away from being in service. STOP encourages the Commission to ask Idaho Power to explain this result and to correct their analysis as necessary.

The same counterintuitive result can be seen when comparing the PNW market purchases in Portfolio 16 and Portfolio 4 with and without B2H. Once again, Idaho Power's own AURORA analysis shows that, under Portfolio 4, future imports from the PNW are expected to decline sharply over time from today's level. This indicates that the market economics of importing power from the PNW are expected to deteriorate over that time. The implication is that the AURORA model expects <u>existing import capacity to become increasingly underutilized in the future</u>. Despite this result, and with no change other than the addition of B2H, there is a dramatic increase of almost 200% in imports the first year B2H enters service.

Idaho Power has stated that, when optimizing Portfolios 13-24, the <u>only change</u> to AURORA modeling was to increase the import capacity from the PNW resulting from the addition of B2H. However, if the value of import capacity from the PNW otherwise declines over time without B2H, as it does in the non-B2H Portfolios, it is unclear why adding more surplus import capacity would result in a tripling of imports as shown in Figure 4.

Idaho Power should explain this anomaly. If there are errors, then the utility should acknowledge them. If on the other hand Idaho Power has made undisclosed changes to the AURORA model concurrent with adding B2H import capacity into the model, Idaho Power should disclose and explain these modeling changes.

Future Supply-Side Generation and Storage Resources

Idaho Power Should Evaluate Real Power Loss Reductions as a Supply Side Resource

Transmission losses (Lost and Unaccounted For) Energy is the single biggest consumer of energy within the Idaho Power System and Idaho Power wastes considerably more energy as a percentage of load than other utilities. In 2018, annual transmission system losses in the Idaho Power BAA averaged 7.3% over the year compared to PacifiCorp's average hourly transmission losses of 5.5% and PGE's average transmission losses of only 3%.[9]

Idaho Power's actual average annual loss factor of 7.2% means that transmission losses on Idaho's peak hours exceed 10%, or more than 400 MW. Losses are a function of the location of generation relative to the load served. Dispatching a resource close to load incurs minimal transmission losses, while dispatching a distant resource to serve the same load can incur a large penalty in the form of high transmission losses. For example, a decision by Idaho Power to turn off Idaho Power's Langley Gulch generating plant and instead buy 300 MW from MIDC on a peak summer day will result in 15% or higher incremental transmission losses (i.e., 45 MW or more of incremental losses). This means that the regional power system must generate 345 MW of power to replace the 300 MW of power that would otherwise have been generated by Langley Gulch on that hour.

Idaho Power is aware of the costly impact of these long-distance market purchase transactions due to their disproportionate impact on real power losses, yet has ignored the consideration of these losses in their IRPs. In fact, Idaho Power expressly denied the existence and/or relevance of these factual real power losses in the 2017 IRP stating, stating that:

> *"STOP B2H suggests that any line loss reductions will be "offset" by grid losses related to "new market power purchases from distant market", which would be enabled by the new transmission line. This statement, while correctly describing a possible impact of transmission development is misleading in this case. Assuming that STOP B2H performed an accurate analysis using its GRIDVIEW software, these "power purchases from distant markets" would already be factored into the 10 aMW line loss reductions calculated by GRIDVIEW. Thus, the benefits of B2H clearly overcome any increases in grid losses, as demonstrated by STOP B2H's own analysis."*[10]

Idaho Power misses the point and misrepresents the detailed dispatch logic built into GRIDVIEW[11]. GRIDVIEW is an hourly model that is capable of accurately representing the most efficient hourly dispatch across WECC for each 8,760 hours of a simulation year. The GRIDVIEW model optimization

9 2018 FERC Form 1 filings for Idaho Power, PacifiCorp and PGE p401a

10 Idaho Power Company's Final Comments, LC-68

11 GRIDVIEW is a Production Cost Model used by both Northern Tier Transmission Group (NTTG) and Columbia Grid to perform regional transmission planning studies.

logic expressly considers the incremental losses of each generator when performing an 8,760 hour production cost simulation. As such, it will only allow the dispatch of a "generator in a distant market" in the simulation if it is the lowest cost resource available, after considering the unique variable cost of dispatching each available resource, including the variable cost of incremental real power losses.

Idaho Power's power trading operations do not consider these incremental losses when making decisions whether to generate power within the Idaho System, or to instead buy distant power at MIDC. In the example above, the GRIDVIEW model optimization would likely run Langley Gulch instead of buying from the PNW, because the model is smart enough to know that the purchase from the PNW transaction is uneconomic due to the large loss penalty that would accrue to such a redispatch decision. Idaho Power real time trading operations are untethered from such economic considerations to the detriment of ratepayers.

In this 2019 IRP, Idaho Power has again ignored consideration of these incremental transmission losses associated with buying power from distant markets. However, it has become clear that while Idaho Power is telling the Commission one thing about real power losses, they are saying something different in other forums. In fact, Idaho power now acknowledges in a pleading to FERC that STOP was right when it called attention to this issue in the 2017 IRP. Stated differently, Idaho Power has independently confirmed that the phenomenon of sharply higher transmission losses will accrue to expanded energy trading over long distances. This education of Idaho Power has come by way of Idaho Power's participation in the EIM.

Just this past week (March 23, 2020 to be exact), Idaho Power alerted FERC to these higher real power losses driven by Idaho Power's participation in the EIM. [12] On March 23, 2020, Idaho Power filed with FERC for permission to assign to transmission customers the cost of sharply increasing transmission losses on the Idaho Power system resulting from Idaho Power's participation in the EIM.[13] Idaho Power explained this to FERC as follows:

> *"Idaho Power began participating in the California Independent System Operator's ("CAISO") Energy Imbalance Market ("EIM") on April 4, 2018. Idaho Power submitted revisions to its OATT to facilitate such participation in 2017 and submitted clarifications to its tariff language in 2019. Idaho Power's existing language states that Unaccounted for Energy ("UFE") will not be sub-allocated to transmission customers.*
>
> *When Idaho Power joined the EIM, it did not anticipate that UFE would be significant. Therefore, like other EIM Entities who had commenced participation before it, Idaho Power did not propose to allocate UFE to transmission customers. Since that time, however Idaho Power*

12 Idaho Power Company, FERC Docket No. ER20-1370-000 Changes to Open Access Transmission Tariff Modification, Attachment O – Energy Imbalance Market, March 23, 2020 https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14844783

13 Idaho Power has been artificially inflating the benefits of the EIM by hiding these high losses imposed by uneconomic EIM transactions. Idaho Power now wants to further hide these losses by assigning them to transmission customers, thereby artificially inflating the reported benefits of the EIM which are shared with stockholders.

has found that UFE can add up to amounts that are not insignificant, and at least one of Idaho Power's customers has requested that UFE be allocated out to transmission customers.

Further, within the past year, EIM participants and CAISO have had many discussions on settlement processes and transparency, and potential improvements. Through these discussions, participants have realized that for EIM Entities, UFE is primarily driven by differences in loss factors based on real time power flow utilized in the EIM and the OATT loss rate used by the Balancing Authority Area, rather than by metering errors or other factors more directly within the EIM Entity's control.

As a result, allocating UFE to transmission customers is consistent with cost-causation principles and will allow transmission customers to receive more accurate price signals from the market. The allocation will reflect market conditions and will ensure both costs and revenues related to UFE are allocated to transmission customers. Allocating UFE to customers is also consistent with the direction other EIM Entities are heading, and the Commission recently approved a similar filing for one other EIM entity."

STOP believes that instead of hiding these extraordinary losses resulting from untethered trading in the EIM by allocating them to transmission customers that don't benefit from the trading activities of Idaho Power, Idaho Power should re-evaluate the true costs of a resource strategy focused on expanding purchases from distant markets, and acknowledge the significant benefits that would accrue to ratepayers of locating resources close to load. Specifically, Idaho Power should calculate and assign an explicit loss reduction credit in AURORA to new resources sited in the Idaho Power BAA when performing capacity expansion modeling in this IRP.

Idaho Power's Transmission System

Capacity Benefit Margin (CBM) as a Resource Option

Idaho Power has correctly identified that taking actions to increase the Average Available Transfer Capacity (ATC) on the PNW to Idaho path is a valid resource alternative to meet Idaho Power's growing capacity needs due to the imminent exit from five regional coal plants. Whether it is the lowest cost/least risk resource for meeting those needs is the focus of this 2019 IRP. Idaho Power has concluded that building B2H is the preferred approach, in fact the only approach, to increasing ATC on the PNW to Idaho path. This is the equivalent to saying that building gas-fired plants is the only way to meet capacity needs, or denying that conservation and demand response can contribute to the goal of meeting Idaho Power's growing peak capacity demands. STOP, however, believes that Idaho Power has inappropriately focused on transmission expansion as the only feasible way to increase capacity on the PNW to Idaho path. We also feel that the utility has ignored actions and investments that would increase the ATC across the PNW to Idaho path by reducing the amount of CBM maintained on the Path. Idaho Power has historically exercised its right under its OATT to designate firm ATC on the PNW to Idaho path as a Capacity Benefit Margin (CBM). Currently, the utility designates 330 MW of existing firm ATC across that path as unavailable for firm use during the summer period (Table 2).[14]

Table 3. Pacific Northwest to Idaho Power import transmission capacity

Firm Transmission Usage (Pacific Northwest to Idaho Power)	Capacity (July MW)
BPA Load Service (Network Customer)	365
Boardman Generation	60
Fighting Creek (PURPA)	4
Pallette Load (PacifiCorp—Network Customer)	1
TRM	280
CBM	330
Subtotal	**1,040**
Pacific Northwest Purchase (Idaho Power Load Service)	240
Total	**1,280**

Table 2: Firm transmission reservation of 330MW by Idaho Power in July (Source: 2019 Idaho Power IRP Appendix D – Amended p14)

14 STOP is unaware of any other Transmission Provider in the Northwest that reserves CBM on any transmission paths.

STOP does not dispute that Idaho Power's designation of CBM is necessary and important for reliability. However, the Commission should recognize that it is a costly requirement for its utility customers. They pay over $9 million/year to reserve CBM, a designation that prohibits any utility, including Idaho Power, from using ATC to move firm power from the PNW to Idaho.[15]

Prohibiting the use of this ATC, for the sole purpose of reserving unused capacity in the event of a system emergency, is also costly to the region, suppressing all of the economic transactions that could otherwise occur. Both of these costs result from Idaho Power's 330 MW ATC set-aside on the PNW to Idaho path.

FERC requires Idaho Power to publicly post information on its use of CBM and STOP has reviewed the last 12 years of data from those postings. Over that period of time, STOP discovered that the utility has never made use of the withheld CBM.[16] This is the economic equivalent of building a 330 MW dispatchable power plant and never deploying it for a dozen years. This suggests that there may be a better way.

By contrast, actions that could reduce the amount of required CBM set-aside—without impairing system reliability—may be the lowest cost capacity resource options available to Idaho Power. It does not appear that Idaho Power has even considered reductions in CBM as a supply-side resource option. That omission is inconsistent with the Commissions IRP Guideline 1-Substantive Requirements. It is also contrary to Idaho Power's position that increased access to ATC on the PNW to Idaho path is a supply side resource.

CBM is defined as:

> ***Capacity Benefit Margin ("CBM")*** *- The amount of firm transmission capability preserved by the Transmission Provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.*[17]

Most transmission providers have sufficient dependable capacity resources within their own Balancing Authority Area (BAA) to meet firm loads, while still holding sufficient reserves at unloaded generating plants physically located within their native BAA. This is not the case for Idaho Power. A significant amount of Idaho Power's firm generating resources are located far from Idaho. This can result in a situation during peak loading conditions, where all of Idaho Power's in-system resources must be

15 Idaho Power customers pay the full Point-to-Point transmission rate to reserve the capacity for Idaho Power, yet are prohibited from actually using the capacity to serve load, except in a narrowly defined system emergency.

16 Idaho Power OASIS under the "Customer Information", "CBM usage" menu

17 Idaho Power OATT, Attachment C, p1

dispatched under those constraints. With all in-system capacity already generating power to serve peak load, there is no generating capacity available in reserve for dispatch during a system emergency. Consequently, if Idaho Power suffers a forced outage during peak conditions, a loss of an in-system resource, the utility's only current resupply alternative is to import power to replace the lost power due to outage.

The reservation of 330 MW ATC on the PNW to Idaho path – through the designation of CBM – is how Idaho Power ensures that ATC will be available for the utility to use during system emergencies. However, CBM is not a fixed amount. It will change over time depending on the resource choices made by Idaho Power. The utility acknowledges this in their OATT:

> "The level of CBM is subject to change if there is a change in the outage performance of the Transmission Provider's Network Resources, or if a new resource larger than the current level is constructed in the Transmission Provider's control area."[18]

Value to Ratepayers of Reducing CBM

If Idaho Power reduced CBM, the value to Idaho Power ratepayers could be substantial. Reducing what is held back for CBM could benefit Idaho Power ratepayers in three fundamental ways.

- It would result in lower transmission costs assigned to Idaho Power customers through their retail rates while simultaneously expanding firm transmission access to the MIDC market (without B2H).
- As Network Integration Transmission Customers, the ATC created on the PNW to Idaho path by reducing the CBM set-aside, would become available exclusively for use by Idaho Power customers at no incremental cost. The utility would then have increased future access to firm imports from the PNW with no additional cost for transmission over what those customers are paying today.
- Reducing CBM, possibly by as little as 25 MW, could defer the need for B2H one or more years into the future. Deferring the construction of, and the energizing date for, B2H by even one year could reward Idaho Power customers with a present value benefit of over $20 million[19]. It would also reduce the stranded cost risk of investing prematurely in B2H during a time of rapid change in the industry.

Idaho Power's native load customers currently pay approximately $9 million/year to reserve 330 MW of CBM on the PNW to Idaho path. This is an existing reservation of firm import capacity that Idaho Power is prohibited from ever using to serve load, except in an emergency. If the need for CBM were eliminated, Idaho Power's native load customers would see a reduction in transmission costs of

18 Idaho Power OATT - 3.3.4 p5 of 8
19 Source: Idaho Power 2017 IRP Attachment 19 - Response to Staff's DR 89

approximately $3.2 million/year[20]. That is equivalent to a reduction in transmission rate base of about $25 million. In addition to these cost savings, as network customers of Idaho Power transmission, native load customers would gain up to 330 MW of additional firm access to the MIDC market at no incremental cost. That would all occur without building B2H.

As new capacity resources are acquired by Idaho Power and sited within the Idaho Power BAA, the need for CBM will decline. Just as savings in reduced real power losses accrue automatically to distributed generation resources and demand response measures, reduced CBM requirements will accrue by default when new long-term capacity resources are acquired in the Idaho Power BAA. The Commission should require Idaho Power to identify and quantify these benefits.

Table 3 shows a generic example of how CBM reductions could be integrated into the AURORA modeling, one based on actual numbers contained in the IRP and in Idaho Power's most recent Transmission Rate Informational filing at FERC.

Table 3: Example of CBM reductions incorporated into AURORA modeling

New Resource A:	Dependable capacity on Peak = 1 MW
Corollary reduction in CBM:	1 MW
Value of CBM reduction @ $9,572 per MW per year:	$9,572 (at current Idaho Power Transmission Rates)
Equivalent reduction in capital investment:	$75,000 ($9,572 divided by 12.7% Capital Recovery Factor)
Value of one year deferral of B2H:	$20 million per year of deferral

STOP encourages the Commission to address this critical issue. Specifically, Idaho Power should be asked to:

- Provide the Commission with Idaho Power's forecast of CBM needs, and the assumptions behind the forecast.
- For each supply side and demand side resource projected by AURORA, Idaho Power should calculate a CBM reduction credit if the resource is located in the Idaho BAA, and incorporate the credit for each resource in the Portfolio analysis. This should be modeled as a reduction in the capital cost per MW of each such resource.

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20 Idaho Power's native load customers are responsible for approximately 65% of Idaho Power's transmission revenue requirement. If Idaho Power eliminates the $9 million/year payment for CBM to Idaho Power transmission services, this reduced revenue will be recovered from all transmission customers through a transmission rate increase but only 65% of the increase will flow back to native load customers. Approximately 35% will flow to other transmission customers, saving native load customers approximately $3.2 million/year.

- Condition the AURORA model to increase the firm capacity of the PNW to Idaho path endogenously over time. This will reflect the reduced need for CBM as the model adds new resources to the Idaho BAA.
- Rerun Portfolios 1-12 using the new logic.
- Rerun Portfolios 13-24 based on the re-optimized Portfolios 1-12.

STOP believes that the insights gained by this extended analysis would be extremely valuable. They may reveal significant positive net benefits to Idaho Power customers from acquiring new in-system generating resources ahead of a perceived "need", given the corollary benefits of increased ATC on the PNW to Idaho path from reduced CBM and the ability to defer the buildout of the B2H.

Least Cost Plan Rule

The OPUC Order # 18-176, acknowledged Idaho Power's 2017 Integrated Resource Plan, specifically action item 6, "Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project." This triggered the State of Oregon's permitting and siting process at the Oregon Department of Energy – Energy Facilities Siting Council. The process is a standards-based process of 36 standards, including Oregon Administrative Rule (OAR) 345-023-0005, "Need Standard For Nongenerating Facilities." On September 10, 2019 Todd Cornett and Maxwell Woods from the Oregon Department of Energy (ODOE) presented the commission with an overview of the least-cost plan rule, OAR 345-023-0020 and the system reliability rule for transmission lines, OAR 345-023-0030, that intertwine OPUC orders.

The STOP B2H Coalition submitted detailed comments on these rules to the Energy Facilities Siting Council (EFSC). **These are shown below, with updated tables from Idaho Powers 2019 IRP highlighted in red.** In essence STOP is saying that the commission acknowledged only Idaho Power's capacity portion, 350 MW average, of the Boardman to Hemingway portion of the transmission line. In 2018, Commissioner Bloom stated:

> *"My concerns are that Idaho power is the 24% participant and the two big parties, BPA which we can't control, and PAC doesn't even have it in their IRP. So if we acknowledge this IRP for Idaho power this is not an acknowledgment for PAC. They are going to have to do all their own work on this to convince us that it's still in the money."*

Since the commission's acknowledgment of action item 6 triggered this process at ODOE we ask that the commission amend its order to rescind the recognition of action item 6, Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project. The following comment to the ODOE-EFSC with updated tables, when available, from Idaho Power's 2019 IRP supports our position that the commission only acknowledged Idaho Power's capacity of the B2H.

Need[21]

The Boardman to Hemingway (B2H) Transmission Project does not meet the "least-cost plan nor the system reliability" standards of the Oregon Energy Facilities Siting Council.

Oregon Administrative Rule (OAR) 345-023-0005, "Need Standard For Non-generating Facilities" states that before EFSC can issue a site certificate for a non-generating facility, the applicant for a site certificate must demonstrate the need for the facility.[22] The Rule further states that *"The Applicant (Idaho Power) shall demonstrate need for electric transmission lines under the least-cost plan rule, OAR 345-023-0020, or the system reliability rule for transmission lines, and OAR 345-*

21 What follows are the Stop B2H comments to the EFSC on 8/23/2019. Red denotes the additions/tables for the current OPUC process.

22 "To issue a site certificate for a facility described in sections (1) through (3), the Council must find that the applicant has demonstrated the need for the facility."

023-0030." We will explain that Idaho Power has failed to meet the Need Standard for the B2H transmission line under either Rule, and that **EFSC cannot find that the this Applicant has met the Need Standard, based upon this Application before the Council**.

1. The Applicant, Idaho Power, has not met the standards under EFSC's Least Cost Plan Rule

The least-cost plan rule, OAR 345-023-0020, states:

> *(1) The Council shall find that the applicant has demonstrated need for the facility if the capacity [emphasis added] of the proposed facility or a facility substantially similar to the proposed facility, as defined by OAR 345-001-0010, is identified for acquisition in the short-term plan of action of "an energy resource plan or combination of plans" adopted, approved or acknowledged by a municipal utility, people's utility district, electrical cooperative, other governmental body that makes or implements energy policy, or electric transmission system operator that has a governance that is independent of owners and users of the system…", if the Council finds that the energy resource plan or combination of plans meets specific criteria outlined in the rule.[23] If, however, the plan or plans have been acknowledged by the OPUC, then the plan or plans are deemed to satisfy the specific criteria outlined in the Least Cost Plan Rule and the Council can rely on the OPUC acknowledgment to find that the energy resource plan satisfies the specific criteria outline in the Least Cost Plan Rule.[24]*

Idaho Power seeks to meet the requirements in the Least Cost Plan Rule based solely upon a single plan: Idaho Power's 2017 IRP. There is no dispute that OPUC acknowledged Idaho Power's 2017 IRP[25] and that therefore, Idaho Power's IRP meets that criteria for an energy resource plan under the Least Cost Planning Rule. The facts are, however, that a single energy resource plan that acknowledged a much smaller transmission line does not meet the need standard under the Least Cost Planning Rule.

It is the Council's responsibility in this proceeding to determine whether the applicant has demonstrated the need for the capacity of the facility under the Rule. Idaho Power's acknowledged IRP alone does not meet requirements under the rule, as Idaho Power's IRP only evaluated a transmission line with a fraction (approximately 20%) of the capacity of the B2H transmission line that is the subject of the application for a site certificate.

Idaho Power has requested and received acknowledgment from the OPUC for their 2017 IRP, including B2H Action Items. This acknowledgment is for Idaho Power's share of B2H, a share that represents only approximately 20% of the total capacity of the B2H project at a cost of less than $300 million, whereas the Applicant, Idaho Power, is requesting that EFSC issue a site certificate for a transmission line with 2,050 MW of capacity at a cost of approximately $ 1 billion. The sections below from Idaho

23 The criteria are specified in OAR 345-023-0020 (1) (a) through (L).

24 OAR 345-023-0020 (2) "The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan.

25 OPUC Order No. 18 176, May 23, 2018

Power's 2017 IRP distinctly show that only a small amount of the capacity of the B2H facility was acknowledged by the OPUC.

Per the terms of the Joint Permit Funding Agreement (see Appendix D-3 of Idaho Power's 2017 IRP), each co-participant (funder) is assigned a discrete share of the bi-directional capacity of the project on a seasonal basis, as shown in Table 4[26] Idaho Power has the smallest share of the project capacity among the three participants in B2H (Table 5).

Table 6.2 B2H capacity and permitting cost allocation

	Idaho Power	BPA	PacifiCorp
Capacity (MW) west to east	350 200 winter/500 summer	400 550 winter/250 summer	300
Capacity (MW) east to west	85	97	818
Permitting cost allocation	21%	24%	55%

Table 4: B2H bi-directional capacity on a seasonal basis (Source: IPC 2017 IRP p. 62)

New – 2019 IRP

Table 5. B2H joint permit funding capacity interests by funder

	Capacity Interest (West-to-East)	Capacity Interest (East-to-West)	Ownership %
Idaho Power	350 MW (Average) 500 MW (Summer) 200 MW (Winter)	0 MW	21.2%
PacifiCorp	300 MW	600 MW	54.5%
BPA	400 MW (Average) 250 MW (Summer) 550 MW (Winter)	0 MW	24.2%
Unallocated	0 MW	400 MW	

Table 5: B2H participants: seasonal capacity allocation & funding (Source: IPC 2019 IRP Appendix D p 28)

As can be seen in Table 4, from 2017 and table 6 from 2019, Idaho Power's capacity interest is seasonally shaped, as are the capacity shares of all three project participants. The details in Table 6, Table 7, and Table 8 derived directly from Table 4 show that Idaho Power's capacity share is 13.9% of total B2H capacity in the Winter season and 28.5% of project capacity in the Summer season. Idaho Powers weighted annual capacity allocation is 21.2% of total B2H capacity.

26 IPC 2017 IRP p. 62

		Winter Capacity Allocation			
		Idaho Power	**PacifiCorp**	**BPA**	**Project Capacity**
		(MW)	(MW)	(MW)	(MW)
West to East		200	300	550	1050
East to West		85	818	97	1000
Participant Shares (MW)		285	1118	647	2050
Participant Shares (%)		13.9%	54.5%	31.6%	100.0%

Table 6: B2H participant capacity allocation in winter

		Summer Capacity Allocation			
		Idaho Power	**PacifiCorp**	**BPA**	**Project Capacity**
		(MW)	(MW)	(MW)	(MW)
West to East		500	300	250	1050
East to West		85	818	97	1000
Participant Shares (MW)		585	1118	347	2050
Participant Shares (%)		28.5%	54.5%	16.9%	100.0%

Table 7: B2H participant capacity allocation in summer

		Annual Capacity Allocation			
		Idaho Power	**PacifiCorp**	**BPA**	**Project Capacity**
		(MW)	(MW)	(MW)	(MW)
West to East		350	300	400	1050
East to West		85	818	97	1000
Participant Shares (MW)		435	1118	497	2050
Participant Shares (%)		21.2%	54.5%	24.2%	100.0%

Table 8: B2H participant annual capacity allocation

Idaho Powers Cost Inputs and Operating Assumptions from their Supply-Side Resource Data in their 2017 IRP Appendix C Page 73 and Appendix C p 23 of the 2019 IRP again demonstrate that their 2017 IRP only evaluated a transmission line that provided 350 MW of eastbound capacity, which is less than 20% of the total capacity of the proposed project.

Cost Inputs and Operating Assumptions

(All costs in 2017 dollars)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital ($/kW)[1,3]	Transmission Capital $/kW	Total Capital $/kW	Total Investment $/kW[2]	Fixed O&M $/kW[3]	Variable O&M $/kW	Other $/MWh	Heat Rate Btu/kWh	Economic Life
Biomass Indirect—Anaerobic Digester (35 MW)	35	6,522	144	$6,666	$7,133	3	16	0	14,500	30
Boardman to Hemingway (250 MW)	350	0	734	$734	$734	0	0	0	0	55
Canal Drop Hydro (1 MW)	1	3,753	70	$3,823	$4,550	2	0	0	0	75
CCCT (1x1) F Class (300 MW)	300	1,246	98	$1,344	$1,574	1	0	0	6,714	30
CCCT (2x1) F Class (550 MW)	550	1,150	109	$1,259	$1,474	1	3	0	6,700	30
CHP (35 MW)	35	2,213	35	$2,248	$2,406	4	5	0	6,060	40
Demand Response—Additional (25 MW)	25	0	0	$0	$0	51	0	0	0	20
Geothermal (30 MW)	35	4,675	144	$4,819	$5,342	18	5	0	0	25
Reciprocating Gas Engine (18.8 MW)	18	775	112	$887	$945	1	7	0	8,370	40
SCCT—Frame F Class (170 MW)	170	878	117	$995	$1,060	1	11	0	10,300	35
Small Modular Nuclear (50 MW)	50	6,126	663	$6,789	$10,279	8	2	0	11,493	40
Solar PV—Rooftop C&I (1 MW)	1	2,925	0	$2,925	$3,040	1	0	1	0	25
Solar PV—Rooftop Residential (0.005 MW)	0	2,400	0	$2,400	$2,495	2	0	1	0	25
Solar PV—Utility Scale 1-Axis Tracking (30 MW)	30	1,375	144	$1,519	$1,579	1	0	1	0	25
Storage—Ice Thermal Storage (10 MW)	10	2,000	0	$2,000	$2,039	3	0	0	0	20
Storage—Li Battery Residential (10 MW)	10	3,114	0	$3,114	$3,175	4	0	0	0	10
Storage—Pumped-Hydro (300 MW)	300	2,352	183	$2,535	$3,017	4	0	0	0	50
Storage—V Flow Battery (10 MW)	10	3,736	0	$3,736	$3,809	6	0	0	0	10
Storage—Zn Battery (10 MW)	10	2,010	0	$2,010	$2,049	3	0	0	0	10
Wind (100 MW)	100	1,475	117	$1,592	$1,700	3	0	16	0	25

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.
[2] Total Investment includes capital costs and AFUDC.
[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

Table 9: Idaho Power supply-side resources – 2017 IRP (Source: Appendix C p 73 of the 2017 IRP)

New – 2019 IRP

Cost Inputs and Operating Assumptions (Costs in 2019$)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital ($/kW)[1,3]	Transmission Capital ($/kW)	Total Capital ($/kW)	Total Investment ($/kW)[2]	Fixed O&M ($/kW-mth)[3]	Variable O&M ($/MWh)	Integration ($/MWh)	Heat Rate (Btu/kWh)	Economic Life (years)
Biomass (35 MW)	35	$3,577	$133	$3,710	$4,614	$3.13	$16.68	$0.00	0	30
Boardman to Hemingway (350 MW)	350	$0	$894	$894	$894	$0.42	$0.00	$0.00	0	55
CCCT (1x1) F Class (300 MW)	300	$1,096	$102	$1,198	$1,401	$0.92	$2.90	$0.00	6,420	30
Geothermal (30 MW)	30	$6,014	$150	$6,164	$7,904	$15.05	$0.00	$0.00	0	25
Reciprocating Gas Engine (111.1 MW)	111	$885	$117	$1,002	$1,067	$1.00	$5.42	$0.00	8,300	40
Reciprocating Gas Engine (55.5 MW)	56	$994	$117	$1,111	$1,183	$1.00	$5.42	$0.00	8,300	40
SCCT—Frame F Class (170 MW)	170	$932	$122	$1,054	$1,122	$1.07	$7.48	$0.00	9,720	35
Small Modular Nuclear (60 MW)	60	$4,292	$165	$4,457	$6,722	$0.70	$2.09	$0.00	11,493	40
Solar PV—Residential Rooftop (.005 MW)	0.005	$3,590	$0	$3,590	$3,730	$1.79	$0.00	$0.00	0	25
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	40	$1,402	$150	$1,552	$1,613	$1.02	$0.00	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (10 MW)	50	$1,658	$150	$1,808	$1,879	$0.97	$0.49	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (20 MW)	60	$1,829	$150	$1,979	$2,056	$0.94	$0.81	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (30 MW)	70	$1,950	$150	$2,100	$2,183	$0.92	$1.03	$0.63	0	30
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	0.5	$1,823	-$62	$1,761	$1,830	$0.93	$0.00	$0.00	0	25
Storage—Li Battery 4 hour (5 MW)	5	$1,973	$52	$2,025	$2,064	$0.78	$2.47	$0.00	0	20
Storage—Li Battery 8 hour (5 MW)	5	$3,277	$52	$3,329	$3,393	$0.78	$2.47	$0.00	0	10
Storage—Pumped-Hydro (500 MW)	500	$1,800	$191	$1,991	$2,315	$0.33	$0.00	$0.00	0	75
Wind ID (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	0	25
Wind WY (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	0	25

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.
[2] Total investment includes capital costs and AFUDC.
[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

Table 10: Idaho Power supply-side resources – 2019 IRP *(Source: Appendix C p 23 of the 2019 IRP)*

The Least Cost Plan Rule requires a finding of fact by the Council that the capacity of the proposed resource is identified for acquisition in an energy resource plan or combination of plans. Idaho Power has supported their application with only a single plan that identifies the acquisition of only approximately 20% of the capacity of the proposed B2H line. Idaho Power has not identified a combination of other participants least-cost energy resource plans that would utilize the remaining 80% of the capacity of the project as required per OAR 345-023-0020(1).

At the April 10, 2018 public meeting at which OPUC acknowledgment of the 2017 was granted Commissioner Bloom clearly stated that he expected the see PacifiCorp's IRP before the OPUC for acknowledgment of B2H. He stated that the action that day was an acknowledgment for Idaho Power and was NOT an acknowledgment for PacifiCorp, a 54% capacity participant of the project. A review of the video of the final 2017 IRP hearing[27] shows Commissioner Bloom at 4:16:18 say:

> *"My concerns are that Idaho power is the 24% participant and the two big parties, BPA which we can't control, and PAC doesn't even have it in their IRP. So if we acknowledge this IRP for*

27 https://oregonpuc.granicus.com/MediaPlayer.php?view_id=1&clip_id=293&meta_id=14009

Idaho power this is not an acknowledgment for PAC. They are going to have to do all their own work on this to convince us that it's still in the money."

Furthermore, an examination of the audio and video record of the April 10, 2018 public meeting clearly shows that the OPUC expressly disclaimed that the Commission's acknowledgment of Idaho Power's IRP meets the Council's requirements for determining the need for B2H under the Council's Least Cost Planning Rule as explained below.

During the OPUC public meeting on April 10, 2018, at which the OPUC Commissioners entered their decision to acknowledge B2H in Idaho Power's IRP, counsel for Idaho Power addressed the Commissioner directly and told the Commissioners that Idaho Power hoped that the OPUC acknowledgement of B2H in the 2017 IRP would meet the EFSC standard for demonstrating need for the capacity of the B2H project.

"Idaho Power intends to rely on the Commission's acknowledgment of the action items regarding B2H to fulfill the need showing that needs to be made at EFSC. The Department of Energy's plan is to issue their draft proposed order either late this Spring or perhaps as late as late summer but it's coming up very soon and at that time our hope is that the draft proposed order will reflect the recommendation on the part of the DOE that the need showing is satisfied by this Commission's Order."[28]

In direct response to this desire expressed by Idaho Power, Commission Chair Lisa Hardie responded with the following:

"I think it is probably fair to say that we'll be, as you know, making a decision into our standards and then it, it will be up to EFSC to say how to interpret that. I think people are, what people are arguing is how they view that. We certainly wouldn't be determining that here."[29]

Indeed, OPUC issued their formal Order acknowledging the B2H Action Items in Idaho Power's 2017 IRP expressly disclaiming that the OPUC acknowledgment of the 2017 IRP met any standards of any other State agency.[30] This is clearly expressed in the first paragraph of the OPUC Order which states:

"This order memorializes our decision, made and effective at the April 10, 2018 Regular Public Meeting, concerning Idaho Power Company's 2017 Integrated Resource Plan (IRP). We acknowledge all but two of the action items proposed in Idaho Power's revised action plan. Although our acknowledgment includes Idaho Power's Boardman to Hemingway (B2H) related action items, we note that our acknowledgment is limited to our interpretation of IRP

28 2:24:20-2:26

29 3:10-3:12

30 Order No. 18 176, May 23, 2018

standards specific to the Public Utility Commission, and does not interpret or apply the standard of any other state or federal agency."[31]

It is the Applicant's responsibility to demonstrate that the 2,050 MW capacity of the proposed B2H transmission line is supported by an acknowledged plan or plans. Idaho Power's acknowledged IRP supports the need for a much smaller and less costly transmission line than that proposed by the applicant (approximately 20% of the project) and therefore, a demonstration of need has not been made by the applicant under the Least Cost Planning Rule, and EFSC cannot issue a site certificate based upon the evidence contained in this Application.

2. The Applicant, Idaho Power, has not met the standards under EFSC's System Reliability Rule

The system reliability rule for transmission lines OAR 345-023-0030 (1) states, "The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that are reasonably expected to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year in the area to be served by the facility."

The DPO at pdf p 532 it states, "The language of OAR 345-023-0030 (Council rules) references that a least-cost plan meets the criteria of an energy resource plan or combination of plans if the OPUC has acknowledged the least-cost plan." The DPO at pdf p 533 further states, "To demonstrate need for the facility under section (1) of the system reliability rule, an applicant must show that the transmission line is needed to meet the firm capacity demands for electricity or firm annual electricity sales anticipated to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a five percent chance of occurrence in any year in the area to be served by the facility.

EFSC rules require that the applicant provide specific information in their application if they choose to support the need for B2H under the System Reliability Rule. These specific requirements are stated in OAR 345-021-0010 (1) (n) Exhibit N:

(F) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule:

(i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility.

(ii) Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility.

31 2019 IRP Appendix D p2 – As in its 2017 IRP, Idaho Power seeks to satisfy EFSC's least-cost plan rule requirement through an acknowledgment of its 2019 IRP.

The applicant shall separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from:

> *(I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility;*
>
> *(II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010;*
>
> *(III) Conservation that results from responses to price; and*
>
> *(IV) Retail customer fuel choice;*

(iii) Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately.

(iv) A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements.

(v) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii).

(vi) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility.

(vii) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table. The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to:

> *(I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility.*
>
> *(II) Construction and operation of electric generating facilities as a substitute for the proposed facility.*

(III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility.

(IV) Adding standard sized smaller or larger transmission line capacity.

(viii) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates.

LOAD AND RESOURCE BALANCE DATA

Monthly Average Energy Load and Resource Balance

	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Load Forecast—included EE	10	11	10	10	12	14	15	15	13	12	11	10
Load Forecast (70th% w/EE)	(1,894)	(1,686)	(1,555)	(1,591)	(1,803)	(2,217)	(2,415)	(2,207)	(1,834)	(1,495)	(1,650)	(1,863)
Adjustment for EE Potential Study Forecast	1	1	1	1	1	1	1	1	1	1	1	1
Net Load Forecast (70th% w/ EE)	(1,893)	(1,685)	(1,554)	(1,590)	(1,802)	(2,216)	(2,414)	(2,206)	(1,834)	(1,494)	(1,649)	(1,862)
Existing Resources												
Total Coal	958	958	926	751	754	958	958	958	958	958	958	958
Total Gas	527	286	280	281	279	511	507	508	277	281	284	527
Hydro (70th%)—HCC	582	647	591	729	870	591	536	367	413	442	347	453
Hydro (70th%)—Other	202	214	211	266	318	328	283	212	223	198	182	189
Total Hydro (70th%)	784	861	801	995	1,187	919	819	578	636	640	529	642
CSPP (PURPA)	230	303	328	411	418	414	397	362	334	291	271	247
PPAs												
Elkhorn Valley Wind	35	35	39	35	33	34	36	32	29	30	42	39
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
Clatskanie Exchange—Take	5	6	7	9	10	11	10	7	4	1	3	4
Clatskanie Exchange—Return	0	0	(20)	(20)	0	0	0	0	0	(20)	(20)	0
Total PPAs	**75**	**75**	**58**	**53**	**65**	**68**	**66**	**59**	**58**	**37**	**57**	**77**
Transmission Capacity available for Market Purchases	203	245	320	285	222	399	313	335	175	290	237	182
Existing Resource Subtotal	**2,777**	**2,728**	**2,713**	**2,776**	**2,925**	**3,268**	**3,060**	**2,801**	**2,439**	**2,496**	**2,335**	**2,634**
Monthly Surplus/Deficit	**884**	**1,043**	**1,159**	**1,186**	**1,123**	**1,052**	**646**	**595**	**605**	**1,002**	**686**	**772**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engines	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Monthly Surplus/Deficit	**884**	**1,043**	**1,159**	**1,186**	**1,123**	**1,052**	**646**	**595**	**605**	**1,002**	**686**	**772**

Table 11: Idaho Power energy load resource balance *(Source: Idaho Power site-certificate application)*

Although the applicant has submitted information as required above when seeking to establish need under the System Reliability Rule, the applicant has failed to meet the standards required because the information provided relates to a transmission line that has only approximately 20% of the capacity of the B2H line, and the information is provided for only a subset of the area to be served by the proposed transmission line. For example, under requirement (A) above, the applicant is required to submit load-resource balance tables for the area to be served by the proposed facility. The applicant has requested a site certificate for a transmission line with a nominal capacity of 2,050 MW between the Pacific Northwest and the eastern Idaho region. Stated differently, the area served by this transmission line as proposed are the service territories of Bonneville Power and PacifiCorp Western Balancing Authority Area in the Pacific Northwest, and the service territories of Idaho Power and PacifiCorp Eastern Balancing Authority Area in the Intermountain (eastern) region of WECC. Despite the clear requirements of [OAR 345-021-0010](), Idaho Power has only supported the application with load-resource balance tables that solely identify the loads and resources of Idaho Power.

The monthly average energy load-resource balance values that are submitted with the application are only for Idaho Power's load and resource data. The first page (Table 11) demonstrates that Idaho Power is ONLY talking about their approximately 20% or 500 MW of capacity to meet their "monthly average energy load-resource balance values."

The monthly peak hour load-resource balance values that are reported (Table 12) in confirm again that Idaho Power is ONLY talking about their approximately 20% or 500 MW of capacity in the project to meet "monthly peak hour load-resource balance values" of the project.

Peak-Hour Load and Resource Balance

	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Load Forecast (95th% w/no DSM)	(2,449)	(2,367)	(2,078)	(2,032)	(2,702)	(3,444)	(3,605)	(3,266)	(2,801)	(2,105)	(2,315)	(2,620)
Load Forecast—included EE	9	9	11	12	16	13	18	18	20	15	8	9
Load Forecast (95th% w/DSM and EE)	(2,441)	(2,358)	(2,067)	(2,020)	(2,686)	(3,431)	(3,586)	(3,248)	(2,781)	(2,091)	(2,307)	(2,611)
Adjustment for EE Potential Study Forecast	1	1	1	1	1	1	1	1	1	1	1	1
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM and EE	(2,440)	(2,357)	(2,066)	(2,019)	(2,685)	(3,040)	(3,195)	(2,910)	(2,780)	(2,090)	(2,307)	(2,611)
Existing Resources												
Total Coal	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	950	900	950	850	1,050	1,000	1,000	800	750	750	650	900
Hydro (90th%)—Other	190	195	172	203	291	301	285	208	215	197	185	189
Total Hydro (90th%)	1,140	1,095	1,122	1,053	1,341	1,301	1,285	1,008	965	947	835	1,089
CSPP (PURPA)	66	69	152	194	234	311	314	307	210	174	151	68
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	9	9	7	8	8	7	9	9	10	10
Neal Hot Springs Geothermal	25	25	23	20	16	15	12	13	16	17	23	25
Clatskanie Exchange—Take	5	6	7	9	10	11	10	7	4	1	3	4
Clatskanie Exchange—Return	0	0	(20)	(20)	0	0	0	0	0	(20)	(20)	0
Total PPAs	45	46	23	23	38	38	35	32	34	12	21	43
Transmission Capacity Available for Market Purchases	203	245	320	285	222	399	313	335	175	290	237	182
Existing Resource Subtotal	**3,190**	**3,190**	**3,354**	**3,291**	**3,571**	**3,785**	**3,684**	**3,420**	**3,120**	**3,160**	**2,979**	**3,119**
Monthly Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2017 IRP Resources												
2026 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2033 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
2030s Reciprocating Gas Engine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	**750**	**833**	**1,288**	**1,272**	**886**	**745**	**489**	**510**	**340**	**1,070**	**672**	**508**

Table 12: Idaho Power peak-hour load resource balance (Source: Idaho Power site-certificate application)

Idaho Power does not meet the system reliability rule for the project.

Idaho Power's monthly average energy load-resource balance values and the monthly peak hour load-resource balance values have demonstrated the need for less than 25% of the service area of the B2H project. The remaining information provided by the applicant under the System Reliability Rule suffers from the same infirmities. The site certificate requested is for a transmission line with a nominal 2,050MW of capacity, yet the information provided by the applicant supporting the project need under the System Reliability rule is for a small sub-area of the total service area to be served by the project and for a sub-area served by less than 25% of the capacity of the project . **<u>The applicant has clearly not met the EFSC requirement for demonstration of need under either the Least-Cost Planning Rule or the System Reliability Rule and must be denied</u>.**

3. Conclusion

EFSC has erred in its Findings Of Fact[32] concerning the applicants attempts to meet Council's Need For Facilities standard. For each and all of the reasons enumerated, Idaho Power has not met the least-cost plan rule, OAR 345-023-0020, or the system reliability rule for transmission lines, OAR 345-023-0030. Nor has Idaho Power filed a complete application, as required by OAR 345-021-0010(1)(n)B(i). The *full* capacity of the proposed facility *has not been* identified for acquisition in the short-term plan of action of an energy resource plan, nor **in a** combination of adopted plans. In light of that situation, the **site certificate should not be approved**.

32 Draft Project Order p 522-529

Thermal Resources

Combined Heat and Power

Distributed Generation – Industrial

As Oregon's Governor Brown works to implement a viable carbon policy for our state, there is industrial steam being wasted. It's going up and out the smoke stack at food processing plants, lumber mills, and other manufacturing facilities. Stace Campbell of Campbell Technical Services estimates that 500MW of Idaho Power's demand could be accommodated by deploying Combined Heat and Power (CHP)[33] and energy efficiency.

Campbell and his client McCain Foods, recently received an energy savings award from Idaho Power. An article in the Magic Valley Times-News[2] states that:

> *"The projects completed at the plant will save 8,856,181 kilowatt-hours of energy per year, which would power about 777 average-sized houses annually, according to a press release issued by Idaho Power."*

Campbell Technical Services also works with IUS Global, a consortium of companies with a mutual interest in developing efficient, sustainable, high-value clean – and green – energy solutions. There is no capital requirement for its clients. The company's fact sheet is attached.

There are advantages and disadvantages to using distributed generation and a well engineered system produces the best results.

What follows is a list of benefits:

- Convenient local positioning which:
  - (a) avoids transmission and distribution losses and
  - (b) enables available sources of energy to be used such as waste products and renewable resources to supplement fossil fuels
  - (c) allows for the use of available single or three phase generation
- Generation adjacent to loads leads to convenient use of heat energy
- Minimizing of disruptions and downtime that are inherent in any large electrical distribution system

33 Combined heat and power systems (also called co-generation) generate electricity and useful thermal energy in a single, integrated system. CHP is not a technology, but an approach to applying technology. Heat that is normally wasted in conventional power generation is recovered as useful energy, avoiding losses that would otherwise be incurred from separate generation of heat and power. While the conventional methods of producing usable heat and power separately deliver a typical combined efficiency of 45%, CHP systems can operate with with an efficiency as high as 80%.

- Displacement of the need for diesel back-up generators at critical facilities such as Hospitals, Prisons, Data Centers, and more
- Enhancement of reliability by having two sources of power:
    (a) distributed generation available in island mode
    (b) the existing power grid
- A ready, low-cost source for heating and/or sterilization at facilities such as: hospitals; large laundries; waste processing, food processing, and pharmaceutical operations – made available by utilizing the hot exhaust gases from distributed generation
- Meeting cooling needs by using exhaust heat as fuel for absorption cooling and thermal energy storage
- Easier incorporation of renewable energy: An example of the use of local resources for distributed generation is using methane generated locally at a municipal facility to supplement natural gas. Both methane and natural gas can be used as fuel in an engine generator connected and supplying power to the utility grid. There is the capability for exchange of power.

On page 52 of its 2019 Integrated Resource Plan, Idaho Power states that CHP:

> *"...would be difficult to model for the IRP because each potential CHP opportunity could be substantially different. While not expressly analyzed in the 2019, Idaho Power will continue to evaluate CHP projects on an individual basis as they are proposed to the company."*

Currently Idaho Power has 20.9 MW of combined heat and power as part of their system. They can and should do more. There is little downside to the company or their industrial customers, with an upside to potentially provide 500 MW to Idaho Power's balancing authority.

IUS Global acknowledges that each potential CHP opportunity is unique, as Idaho Power states, and works with all parties to find the best solution. Existing resources can be used economically to produce energy close to load, eliminating the need for new carbon-emitting power plants. This would align with Governor Brown's Executive Order No. 20-04, directing agencies to take actions to reduce and regulate greenhouse gas emissions. It would also dovetail with Idaho Power's *Clean Today Cleaner Tomorrow* program of 100% clean energy by 2045.

CHP can provide benefits to consumers, to industrial operations, and to Idaho Power. STOP urges the Commission to encourage all load-serving utilities in Oregon to conduct a thorough analysis centered on implementing Combined heat and power systems. CHP can deliver energy savings similar to what was done at McCain Foods in Southern Idaho.

STOP's Review of the Sales and Load Forecast

Forecast Probabilities

It is well understood in the financial[3] and energy sectors[4] that electric demand has undergone a fundamental shift over the last two decades. From 1998 on, what had been a strong correlation between GDP and electric sales started to dissipate[5]. The recession in 2007-2008 then saw flat demand going forward. That trend has carried through to the present. The changes in demand are clearly reflected in Idaho Power's own sales and average load data (Figure 5 and Figure 6)[6].

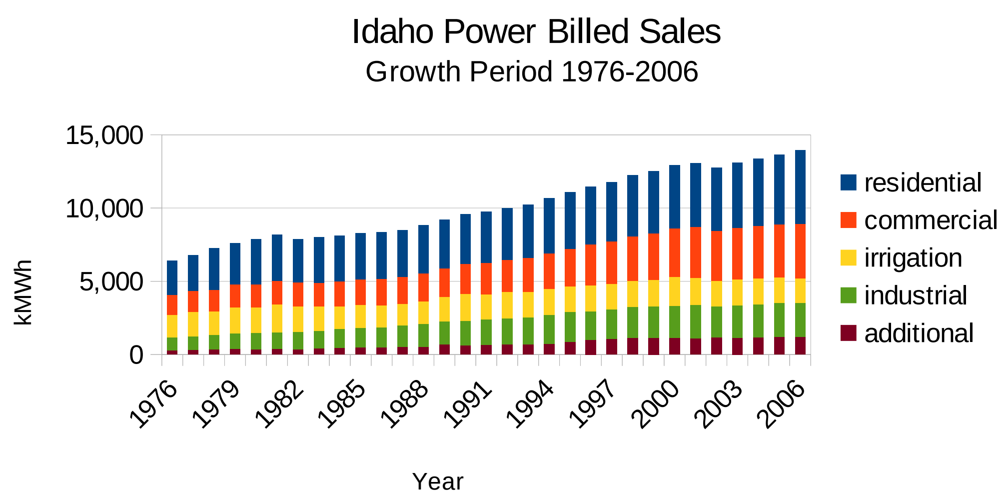

Figure 5: Idaho Power Billed Sales 1997-2006

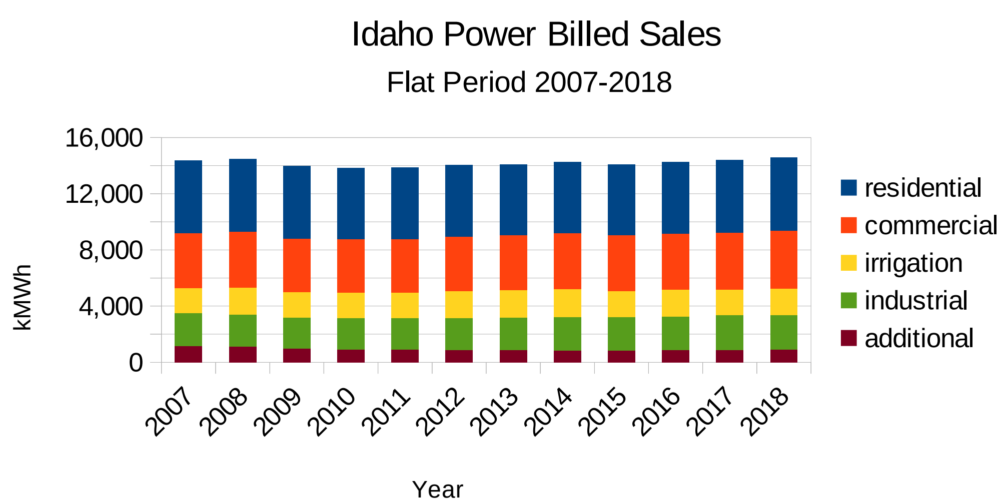

Figure 6: Idaho Power Billed Sales 2007-2018

The reasons for the flattening of the curve are well understood. The Energy Information Administration here in the United States had this to say as part of their analysis of changing electric sales:

> *Total electricity sales in 2015 fell 1.1% from the previous year, marking the fifth time in the past eight years that electricity sales have fallen. The flattening of total electricity sales reflects declining sales in the industrial sector and little or no growth in sales to the residential and commercial building sectors, despite growth in the number of households and growth in commercial building space. Declining rates of electricity demand growth reflect a combination of factors, including the market saturation and increasing efficiency of electricity-using equipment, a slowing rate of economic growth, and the changing composition of the economy, which has reduced the role of electricity-intensive manufacturing.*[7]

That trend is clearly visible in Idaho Power's data for residential electric sales (Figure 7).

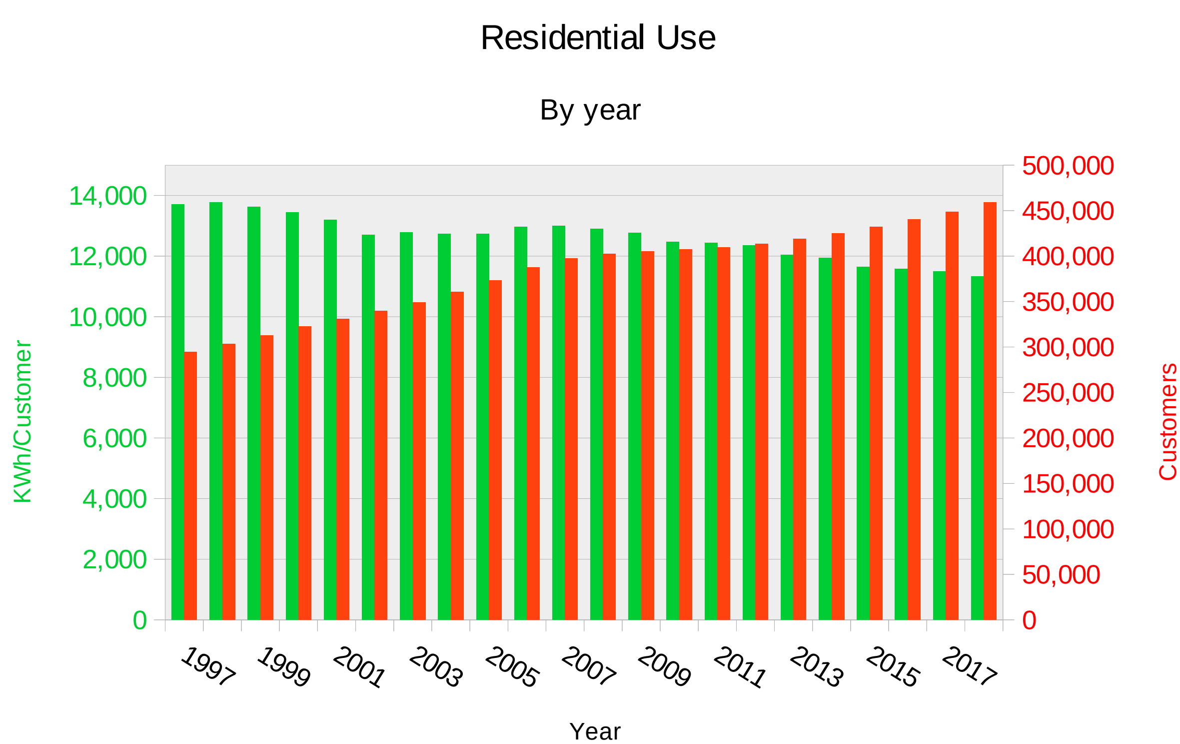

Figure 7: Idaho Power average residential customer use and customer numbers

The drop in average residential demand has compensated for the increase in the number of customers. The result has been flat residential electric sales in that sector. The same is true for Idaho Power's commercial sales: more customers; less average demand (Figure 8).

The result for both sectors is a flat average load over the twelve-year period (Figure 9 and Figure 10). The same is true for irrigation. Those three components represent 77% of Idaho Power electric sales in 2018 resulting in flat sales seen in Figure 6.

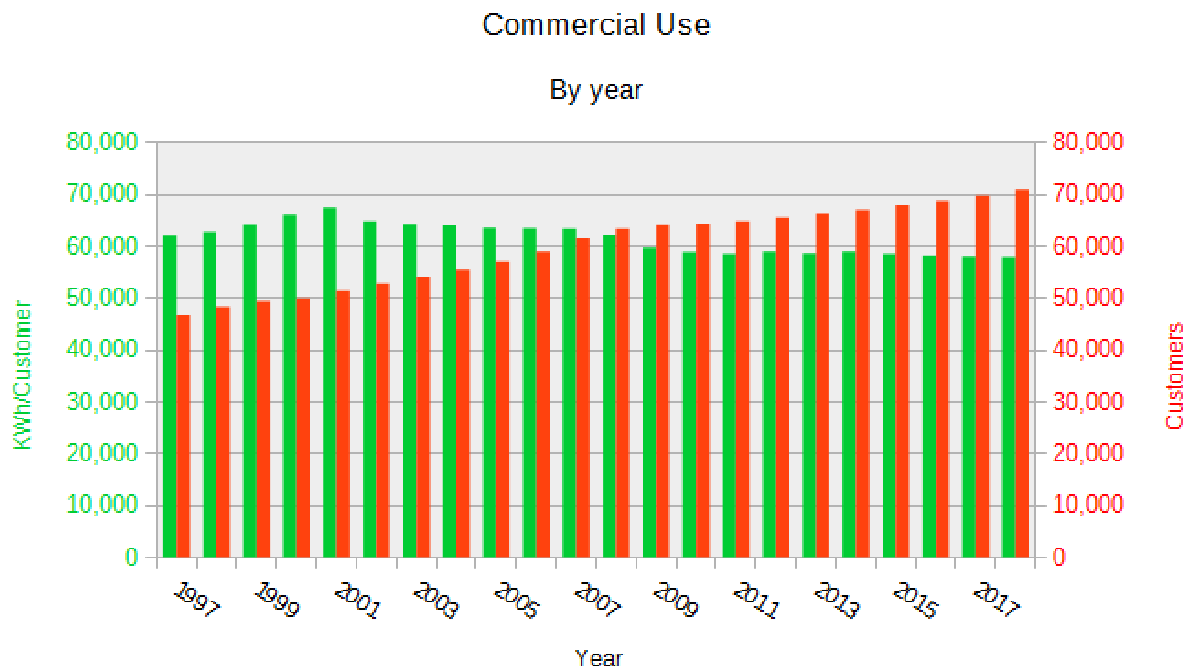

Figure 8: Idaho Power average commercial customer use and customer numbers

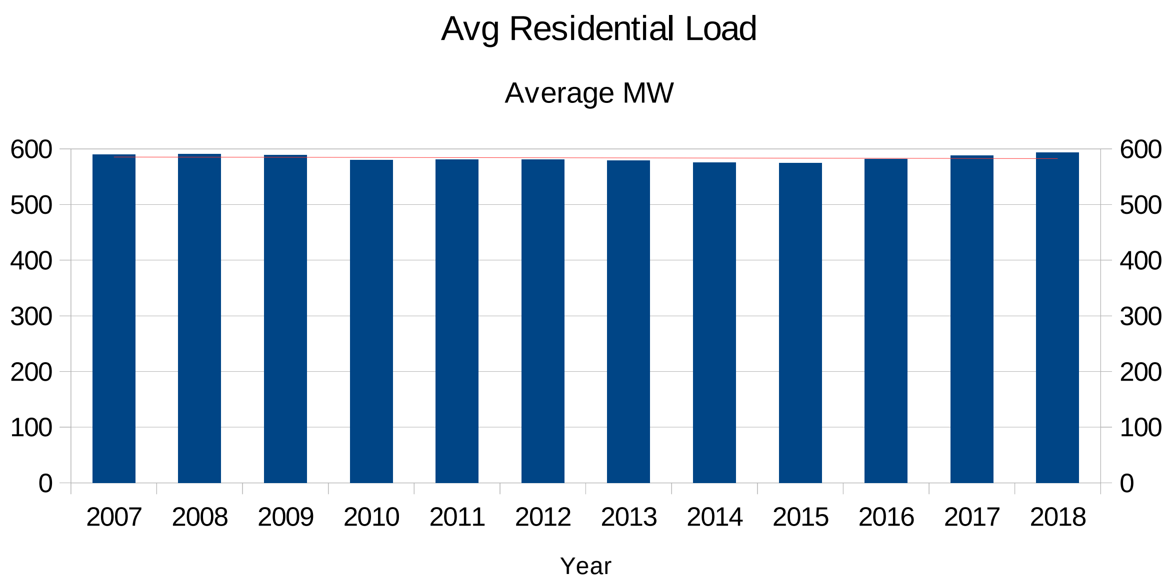

Figure 9: Idaho Power average residential load 2007-2018

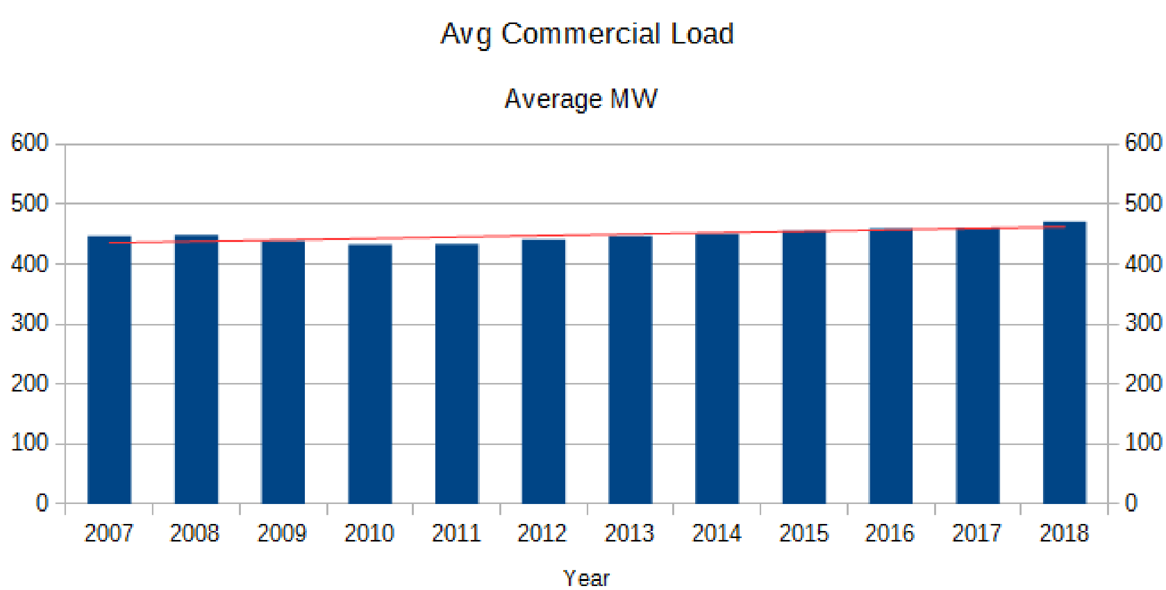

Figure 10: Idaho Power average commercial load 2007-2018

The forecasting employed by Idaho Power in Appendix A has created unnecessary confusion about the data. A simple linear projection, one that uses the data from the 12-year period of flat sales and load gives a straightforward estimate for both in the future (Figure 11).

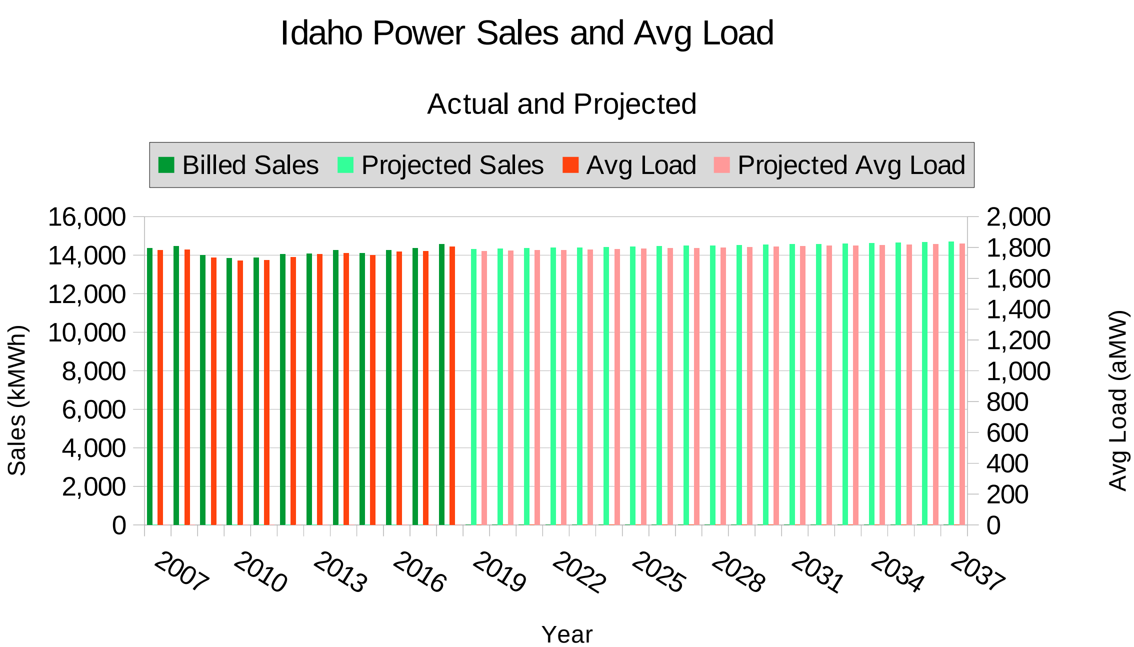

Figure 11: Linear projection of sales and average load from twelve years of Idaho Power data

The twelve-year record of flat growth has not informed Idaho Power's projections of future demand in this Integrated Resource Plan. That poses long-term financial risk to Idaho Power customers[8]. We ask the OPUC and its staff to inquire about the choice of modeling paradigm and why it differs so markedly from Idaho Power sales figures.

The projections also lack any provisions for future incorporation of DERs into the Idaho Power resource mix. Those resources would first be used directly by the DER generator with any excess moved onto the local grid and into a future transactive marketplace[9]. The result would be a decline in the sales provided by Idaho Power onto that local grid. We request OPUC staff to inquire about the projections in light of the omission.

STOP's Review of the DSM Annual Report

Demand Response allows customers:

> *"...to help utilities manage peak electric demand … avoid construction of new power plants, avoid purchases of high-powered electricity, enhance grid reliability, reduce power use from fossil fuels."*[34]

Idaho Power's Energy Savings have remained relatively static since 2015, and have actually declined since 2010—2012. (See Table 13, Table 14 and Table 15) Appendix B demonstrates that Idaho Power has not improved energy efficiency savings or added DSM savings, since 2012 peak savings of 454 MW. That statement is reinforced by examining the Preferred Portfolio's additions and coal exits.[35]

Starting in 2031, by adding 5 MW each year to their committed 390 MW, Idaho Power will have achieved a 420 MW demand response savings by 2036. That level of demand response savings of 420 MW was first achieved in 2011 and in 2012 it peaked at 454 MW. In the past three IRP's the data show declines in DR savings:

- 367 (2015)
- 378 (2017)
- 359 (2109)

There has been a net loss of 95 MW of DR since 2012.

Table 13: Energy Efficiency and Demand Savings 2010-2012

Peak Years of Total Energy Savings kWh		Demand Savings MWW	
2010	193,592,637	2011	420
2011	183,476,312	2012	454

Table 14: Demand Response 2012=21019

	IRP							
	2012		2015		2017		2019	
Program	Demand Response	MWH Saved	Demand Response	MWH Saved	Demand Response	MWH Saved	Demand Response	MWH Saved
A/C Cool*	Homes: 36,454	Peak: 44.9	Homes: 29,000	Peak: 36	Homes: 27,949	Peak: 33	Homes: 25,845	Peak: 29

34 https://www.oregon.gov/puc/utilities/Pages/Energy-Demand-Response.aspx
35 Idaho Power Amended 2019 IRP, Table 1.1, p.13.

	IRP							
	2012		2015		2017		2019	
Program	Demand Response	MWH Saved	Demand Response	MWH Saved	Demand Response	MWH Saved	Demand Response	MWH Saved
Oregon			377	0.5	368	0.4	337	0.4
Flex Peak			Sites: 72	26	Sites: 128	29	Sites: 131	33
Oregon			Sites: 6	14	Sites: 9	13	Sites: 9	2
Irrigation (peak awards)				305		295		288
Oregon				8		7		9
Total Saved w/Oregon		454		367		378		359

Table 15: Energy Efficiency 2015-2019

	2015	2017	2019
Energy Efficiency	**kWh Saved**		
Residential Total	23,818,91	41,208,496	42,322,925
Oregon	712,918	1,060,326	1,328,353
Irrigation Total	13,856,301	12,933,743	18,068,066
Oregon	171,110	2,813,387	3,022,103
Commercial Total	96,653,211	85,960,800	92,736,946
Oregon	5,420,699	7,304.292	6,532,197
Total Saved (w/Oregon)	162,533,155	163,487,859	175,845,637

*Totals also include other programs not listed above

STOP believes that the company, by their long-standing actions in decreasing demand response from 2012 to present—while not adding any DR for another eleven years into the future to 2031—does not comply with OPUC Guideline 7 and 8. STOP requests that OPUC address this issue with the company. We believe their plan is NOT in the best interest of Oregon ratepayers and our planet. Directing the company to pursue more robust DSM would better align with the Governor's carbon policies as well.

Demand Response programs are effective in reducing demands for power and avoiding the cost of adding expensive infrastructure:

> *Holding all else equal, adding demand response and energy efficiency programs [in California] into the system decreased average wholesale electricity prices by about $2.88 (5.4%) and the average system production cost fell by $496,000,000 (5.1%). This is a simple example in one part of the country, but one can easily include additional assumptions about the grid, resources characteristics, and load shape as they desire.*
>
> *Both demand response and energy efficiency programs are intended to be more cost effective and efficient mechanisms of meeting power needs than adding generation. Emphasis on the demand side can lead to lower system production costs, increased grid reliability, and cheaper electric bills; all of which lie in the best interest of governments, utilities, and consumers.*[36]

Utilities across the United States, notably Portland General Electric (PGE) in Oregon, have embraced the savings in energy and money available from demand response and energy efficiency while Idaho Power has avoided them.

What follows are passages from the Amended 2019 IRP (IRP) and Appendix B, with STOP's questions, comments and requests for Commission action below each of those statements.

Statements from Amended 2019 IRP and Appendix B w/Stop Comments

Impact to the Preferred Portfolio (IRP p. 5)

> *[T]he preferred portfolio in Idaho Power's filed IRP included the addition of 5 MW of demand response (DR) in 2026***;** *the Amended 2019 IRP, the procurement of DR shifted later in the planning period, to 2031.*

STOP requests justification for delaying the use of the least polluting, least expensive energy source available. Specifically, how does the above statement comply with OPUC Guideline 7 and Action Item #9 from Order# 18-176[37] acknowledging the Idaho Power 2017 IRP?

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36 The Fundamentals of Energy Efficiency and Demand Response, https://epis.com/powermarketinsights/index.php/2016/05/19/energy-efficiency-and-demand-response-fundamentals/

37 G. Demand Side Management:
With Action Item 9, Idaho Power proposes to continue the pursuit of cost-effective energy efficiency. Staff recommends acknowledgment of this action item with conditions that Idaho Power undertake greater studies of residential savings opportunities and update its transmission and distribution system deferral calculations. Stop B2H argues that Idaho Power has achieved less energy efficiency than other utilities, and argues that the company could do significantly more to achieve demand reduction through more investment in energy efficiency. Stop B2H argues that reductions in peak demand brought on through increased energy efficiency could obviate the near-term need for new transmission facilities. Stop B2H contends that Idaho Power should act to deploy advanced metering infrastructure. Sierra Club argues that Idaho Power's energy efficiency potential is understated, because it's planning uses achievable potential, and Idaho Power has historically out-performed those achievable potential estimates.
We acknowledge Action Item 9, and adopt Staffs recommended conditions.

Variable Energy Resource Integration (IRP p. 22)

> *The 2018 VER Study also identified that, based on the current resources on Idaho Power's system, 173 MW of additional VERs could be integrated before reserve margin violations exceed 10 percent of the operating hours during the year. The study also concluded that at the high relative penetration levels of variable wind and solar that currently exist on Idaho Power's system, additional analysis is warranted, and as Idaho Power gains more experience operating as part of the EIM.*

There are no VERs added to Portfolio 4 between the years 2022 to 2029, a gap of 7 years. STOP does not believe that it will take seven years of additional analysis and experience to further maximize VER integration. The gap is unacceptable given the emerging threat of climate change and the declining price of VERs.

Combined Heat and Power (IRP p. 51-52)

> *The main advantage of CHP is that higher overall efficiencies can be obtained because the steam host can use a large portion of the waste heat that would otherwise be lost in a typical generation process. Because CHP resources are typically located near load centers, investment in additional transmission capacity can also often be avoided. In addition, reduced costs for the steam host provide a competitive advantage that would ultimately help the local economy.*
>
> *…This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different. While not expressly analyzed in the 2019, Idaho Power will continue to evaluate CHP projects on an individual basis as they are proposed to the company.*

The high potential for local Supply Side Generation is excluded from the 20 year plan. Consider the touted benefits mentioned in the IRP, the intervenors' comments in the 2017 IRP, other stakeholders' input during the 2017 and 2019 IRPAC meetings, and the high potential for economic and environmental benefits at manufacturing plants in the Idaho Power territory. With that in mind, STOP encourages the Commission to have the company conduct a thorough analysis of the benefits to be gained from implementing Combined Heat & Power (CHP) systems and energy savings, so that societal benefits are on equal footing with company revenue.

Technically Achievable Supply Side Bundling (IRP p. 57)

> *Idaho Power makes every effort to ensure all cost-effective energy efficiency potential is fully accounted for in resource planning. Because Idaho Power's load forecast includes a level of cost-effective energy efficiency expected to occur during a given forecast period, an important step in this process was to compare the level of future cost-effective energy efficiency included in the 2019 IRP load forecast to bundled levels of efficiency represented in Table 5.1.*

Idaho Power is not committed to researching and utilizing new developments in energy saving technologies. A search of Idaho Power Energy Efficiency programs dating from 2002-2018 shows a total of three pilot programs:

- Air Care Plus Pilot 2003 – 2004 (no savings)
- Ductless Heat Pump Pilot in 2009 – 2014, (142 average participants over 6 years; .05 aMW savings)
- Residential Economizer Pilot 2011-2013 (no participants, no savings.)

Idaho Power's most recent chart of Historical Expense and Performance 2002–2016 lists three small energy savings programs since 2015:

- Multifamily Energy Savings Plan (3 projects, saved 149,760 kWh in 2016)
- Green Motors programs (saved 196,617 kWh)
- Community Solar (cancelled for lack of interest).[38]

STOP assumes that requiring potential Community Solar customers to pay a lump sum in advance of receiving any economic benefits explains why only 15% of the allotted subscriptions were purchased. In an article in the Idaho Mountain Express, Mark Dee had this to say:

> *"The disparity between the payback time on a community solar field and a private array comes down to how the company reimburses customers for the energy generated. Only about a third of the cost per kilowatt hour people see on their power bill covers the actual generation of the electricity. The rest is for the service—distribution, overhead, paying employees, etc. While Idaho Power rebates customers using private systems the full retail cost, it would pay community solar subscribers roughly the cost of generating an equivalent amount of power—considerably less."*[39]

This is yet another example of Idaho Power's pricing discouragement of policies for green energy. Those costs could be rightfully shared across the entire customer base as they are for private customers. All would benefit from the load shifting and ancillary services delivered to the system by the project.

This is in marked contrast to Vermont's Green Mountain Power which provided 2,000 customers with Tesla Powerwall home battery systems for $15/month over 10 years or a one-time payment of $1500. [10]

Instead of having an impact, Idaho Power's energy savings programs amount to public relations. They do not compare with other utilities' serious and measurably successful efforts to save energy. The lack

38 Idaho Power 2017 IRP Appendix B pp. 177–193.
39 Talks show problems, prospects for Idaho Power

of meaningful implementation of digital smart meters and Advanced Metereing Infrastructure (AMI), described below, is one example. Moreover, PGE's successful programs serve as a counterpoint.

In 2009, Idaho Power installed Smart Meters in customers' homes explaining that:

> *Smart devices, sensors, and switches deliver their full value only when they are connected to a supporting backbone of advanced communications, control, and information systems.*[40]
>
> *Billing is the first step of smart meter utilization. Following AMI installation, utilities interested in energy efficiency and peak demand savings can install communication software for direct load control devices, programmable communication thermostats, and smart appliances.*[41]
>
> *Smart thermostats are the leading smart energy technology installed in US homes, with 11% of households having one. Smart thermostats communicate with other connected devices through the home's wireless network. They use programming algorithms for seamless heating and cooling and autonomously respond to inputs from other systems in the home as well as local weather data. Smart learning thermostats heat or cool the home according to learned household behavior patterns and preferences. Smart thermostats have proved to reduce HVAC energy consumption; average savings of 8% in heating costs and 10% in cooling costs can be expected.*[42]

While this was a good start, in 2015, the utility reported that:

> *"Idaho Power cannot communicate directly with any customer's 'smart' appliances. The load control functionality of the Company's AMI system is based on installing an AMI switch in the appliance circuit and opening or closing that switch."* [43]

In the 2015 IRP, in response to significant *"...issues raised by Staff and other parties...",* Idaho Power organized an Energy Efficiency Working Group which held two public meetings in December 2014. *"The second meeting focused on how energy efficiency as a resource should be treated in the IRP."* At that meeting AEG presented *"potential studies from other regional utilities."* Idaho Power staff presented a comparison of how Idaho Power's inclusion of energy efficiency in the IRP related to that of other utilities (p. 47.) STOP questions whether the outcome of Energy Efficiency Meetings satisfied OPUC Staff concerns.

It is now 2020, and Idaho Power is still using AMI only for billing and tracing power outages. More lost opportunities to conserve energy and reduce loads.

The U.S. Final Report from the Smart Grid Investment Grant Program (2015) states that:

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40 https://www.smartgrid.gov/document/us_doe_office_electricity_delivery_and_energy_reliability_sgig_final_report.html p. 30

41 https://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems.html

42 Jen King Impacts of Smart Home Technologies 4/20/18, Report American Council for an Energy-Efficient Energy Efficient Economy

43 Michael Breish, Idaho Power Company's response to informal comments from OPUC Staff on Idaho Power's Draft 2015 Smart Grid Report, 9/4/15

Customers participating in demand-side management programs piloted at 10 utilities that participated in Consumer Behavior Studies reduced their peak demand by up to 23.5 percent, with annual savings for customers ranging from $5 to more than $500, depending on the type of rates offered. … empowering customers with PCTs often enabled them to achieve higher peak demand reductions of 22–45 percent. …

Oklahoma Gas & Electric (OG&E) averaged annual savings of $191.78 for residential customers and $570.02 for commercial customers and reduced load by offering variable peak pricing to about 4,670 participating customers. Based on this success, OG&E expanded the rollout of its time-based rate and PCT program to about 18% (116,000) of its customers, which are achieving 147 MW of peak demand reduction and helping to defer capital investment in peaking generation.[44]

Closer to home we have this development:

In 2015 PGE (1/3 larger customer base but similar rate pricing) initiated a pilot project, initially involving 14,000 customers. A variety of opt-in/opt-out incentives and TOU programs were developed and compared with eventual customer participation goals of 60%. The program, which also included a Direct Load Control pilot with installation of more than 15,000 DLC thermostats, was authorized to expand to 100,000 residential customers in 2019.[45]

When PGE filed their 2019 IRP in July, PGE's president, Maria Pope wrote that:

"This is the first resource plan developed since we expanded our commitment to cut PGE greenhouse gas emissions, It proposes measured steps we can take today to address climate change, while allowing flexibility for adjustments as technology and policies continue to evolve."

Developed through a multi-year research and engagement process that included the construction and testing of 43 different portfolios to identify resource actions needed between now and 2025, the plan calls for:

- 150 average megawatts of additional renewable resources by 2023
- a similar amount (157 average megawatts) of additional cost-effective energy efficiency measures
- increased reliance on demand response to help balance sources and uses of electricity during peak months including:
  - 141 megawatts during winter months
  - 211 megawatts during summer months, and

44 Smart Grid Investment Grant Program Final Report p. 30
45 OPUC Order 18 381, 10/11/18

- ○ 4 megawatts of customer battery storage
- ○ additional actions to help meet capacity needs resulting from expiring contracts and the retirement of baseload coal plants like PGE's Boardman Generating Station[46]

PGE's commitment to utilizing state-of-the-art energy efficiency programs is in marked contrast to Idaho Power:

> *As part of the IRP's* *<u>rigorous examination of the potential for expanded demand response</u>* *(emphasis added)… based on this analysis, the company made available 5 MW incrementally [starting in 2031] new demand response each year.* [47]

In 2017 IRP, Idaho Power addresses changes from the 2015 IRP:

> "… over the last seven years of the IRP planning period (2030-2036), no adjustments to forecast loads were required to reflect incremental energy efficiency savings potential ..."

Incremental may be too generous a term. Considering the rapidly expanding sources of distributed electric power, attached storage resources, and the plummeting price for both, STOP considers the company's efforts to have been measurably inadequate.

To return to the opening quote from the Oregon Public Utilities Commission:

> *Demand Response allows customers "to help utilities manage peak electric demand … avoid construction of new power plants, avoid purchases of high-powered electricity, enhance grid reliability, reduce power use from fossil fuels."*

STOP asks how two utilities, each serving Oregon ratepayers, could respond to the same energy-saving opportunities so differently? The contrast between the 2019 PGE IRP and the 2019 Idaho Power Amended IRP is extraordinary. PGE is obviously a utility committed to utilizing new technologies to save energy and address the challenges of climate change. Idaho Power is obviously a utility committed to constructing a new transmission line, the B2H.

STOP questions whether Idaho Power's failure to progress beyond their 2012 level of energy savings is explained by their commitment to preserving *'need'* for the B2H. Significant energy savings would alter selection of the B2H as a preferred portfolio.

Demand Response Resource Potential (IRP p. 61)

> *As part of the IRP's rigorous examination of the potential for expanded demand response … The company considered achievability and operability to properly model the potential expansion of demand response. Based on this analysis, the company made available 5 MWs of incremental new demand response each year for selection in AURORA starting in 2023.*

46 Presentation by Portland General Electric on their IRP and Grid Modernization Planning, including Demand Response

47 Idaho Power 2019 Amended IRP, p. 61

This additional demand response, beyond the 390 MWs the company considers a committed resource, was used in various amounts by the AURORA model in 23 of the 24 potential portfolios for a total of 420 MW available in the preferred portfolio. This expanded DR will require additional customer participation and was modeled in AURORA at a cost of $60 per kW-year.

First, STOP believes that there is an error in the first paragraph above, as the Preferred Portfolio shows incremental new demand response starting in 2031, not 2023. (See Table 1.1 p. 13)

Second, this rigorous examination of the potential for expanded demand response is an example of confirmation bias. Additional increments totaling 30 MW over the next 20 years will achieve only 420 MW of total savings, still well below the 2012 demand response savings of 454 MW (Table 14). With such an insignificant goal, incentives for "additional customer participation" are expected to be minimal**.** STOP would like to see further justification for the modeled cost.

Demand Response (IRP p. 126)

The company acknowledges that under the amended preferred portfolio, some demand response was shifted into future years outside of the action plan window in comparison to the 2019 IRP preferred portfolio filed in June 2019. The company examined the cost associated with accelerating demand response within the amended preferred portfolio and found accelerating demand response added nearly $900,000 to the preferred portfolio NPV. In moving forward with the amended preferred portfolio as least-cost, least-risk, the company acknowledges the benefit of demand response and will continue to evaluate the cost and risk associated with accelerating demand response to earlier years.

STOP asks the commission to examine the company's halfhearted measures towards meeting Guidelines 6, 7, and 8. The above instances demonstrate, using the company's own words, that programs thought to reduce sales to customers and reduce company revenues will be resisted as forcefully as possible.

Another question: is this another tactic to preclude reduced demand? This would seem seem to justify the company's interest in building B2H. That powerline would, if built, become a revenue stream for the company and its shareholders at an increased cost to ratepayers. Those costs would be best allocated to demand response, conservation, carbon reduction, or the fire-hardening of existing infrastructure. The commission must find a way to persuade the company that Oregon's policies on conservation, clean energy, carbon reduction—all part of climate change mitigation—are serious.

STOP's Review of the B2H Supplement (Amended)

Executive Summary

Paragraph 2 (Page 1)

Idaho Power must include a timeframe in their IRP during which the company assumes the Boardman-to-Hemingway line is the most cost-effective choice. Both PacifiCorp[11] and Portland General Electric[12] have now acknowledged their planned transition to distributed generation and storage components. That disconnect signals a conflict in vision among the investor-owned electric utilities serving Oregon. Idaho Power's 20-year projection should be predicated on a rational plan, one for adapting to what is understood in the industry to be a rapidly changing business environment for electric utilities[48]. The advent of digital controls operating over ubiquitous broadband networks insures that will happen here in the Northwest. It has already started to penetrate much of the country. Without such a timeframe, the IRP lacks any coherent basis for a 20 year projection. The OPUC and its staff should ask Idaho Power why the utility has a different anticipated trajectory than those two utilities, and how that informs the analysis of cost-effectiveness for the B2H power line.

Paragraph 3 (Page 1)

The Obama Administration's designation of B2H as a nationally significant transmission project, a choice made many years ago, has been rendered obsolete given the on-going threat from climate change, something made clear when hurricane Sandy made landfall[49]. He and his advisors also under-estimated the speed of the energy transformation now underway[15]. That transformation is what has galvanized PacifiCorp and PGE. They see the enormous possibilities for energizing their regional grids internally, using digital controls, DERs and storage.[50] It would also be to their great advantage in providing firm power on demand while delivering valuable ancillary services to the larger grid. DERs and storage are now emerging in a transactive marketplace[16].

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48 "*The growth in volume and diversity of distribution-connected, distributed energy resources (DERs) is driving an evolutionary process that is reshaping infrastructure planning, grid operations, energy markets, regulatory frameworks, ratemaking, and utility business models across the nation.*"[13]

49 "*A continued reliance on centralized generation and the relative fragility of high voltage transmission lines is completely out of alignment with the growing acknowledgment amongst regulators, political leaders and industry that grid resiliency is not addressed this way.*"[14]

50 The development of an Imbalance Market for the Western Grid is predicated on the perception that moderately rapid sub-hourly response to imbalances will be increasingly needed. The arrival of battery storage brings into question the use of high-voltage lines to provide that service. The response from battery storage mediated by smart inverters is, for all practical purposes, instantaneous with no delay at all. Given properly provisioned distributed generation, it will emanate locally and it can be propagated through the existing electric regional grid.

The America First Energy Plan was poorly thought out from its inception[17]. It was predicated on a rebound in demand for coal and on the abundance of cheap fracked oil. But financial support for coal has been and remains non-existent, while investment in fracked oil has bordered on fraud[18].

Coal continues to lose market share in the United States, supplanted by natural gas. There have been a large number of coal company bankruptcies and there will be more[19]. The fracked oil boom was dependent on extreme leveraging[20]. That has turned many in the industry into zombie firms[21]. The pool of debt is very deep, and it now threatens to drown the larger economy[22].[51]

With this as background, it is difficult to understand why Idaho Power would embrace the acknowledgment by the BLM of a role in the America First Energy Plan. The utility's reliance on that plan as a justification for building the B2H line is highly problematic financially which puts the utilities customers at risk. It is also in direct opposition to Oregon's stated climate goals. The OPUC should ask why the utility is unable to support those goals and how that may affect its financing of B2H.

Paragraph 4 (Page 2)

The commitment of both the BPA and of PacifiCorp to financing 78.2% of the project needs reaffirmation. PacifiCorp has not included B2H in any of its modeling scenarios in its most recent IRP[11]. OPUC staff has expressed concern about this. The reasons for the omission need to be fully explored given the potential for a greatly increased financial commitment on the part of Idaho Power if partners are no longer be willing to participate. This would increase both the risk and the cost to Idaho Power consumers. We ask the OPUC to please investigate this discrepancy.

Paragraph 5 (Page *2*)

It is reasonable for the OPUC to ask if the lack of co-participant estimates for *funds used during construction* is acceptable given the estimated cost of the power line. As full an accounting as possible should be made so that the OPUC has the information it needs to make a decision.

Energy Cost (Page 6)

Idaho Power states a case for additional capacity requirements from the Mid-Columbia trading hub as a justification for the B2H power line[52]. As mentioned previously, Idaho Power's sales and load data do not justify any need for additional capacity (see Figure 5 through Figure 11) and the resulting cost to its customers.

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51 Fracked oil has been of marginal profitability with the market for oil volatile and prices fluctuating wildly. That has made the process dependent on borrowing at the near-zero interest rates available since the *Great Recession*. Investment has been an enormous financial gamble, and the fracking industry a casino. The junk bond markets are now demanding very high rates for any additional leveraging and there has been a precipitous drop in the price of oil. That will bankrupt many companies given the debt load they are carrying:

> "*Though investors always demand higher returns to buy bonds issued by financially shaky companies, the premium they demand on U.S. junk debt has nearly doubled since mid-February. By last week the premium they demand on the junk debt of oil companies was nearing levels seen in a recession.*"[18]

52 This section of Appendix D references Table 7.6 in the Amended IRP which does not exist. The reference should instead be to Figure 7.6.

There is also a question of whether the line is really for additional capacity as is implied in this section, or as a wager that renewable power can be pushed onto the line and marketed through the EIM for additional profit. The resource planning and operations director for Idaho Power has recently written that:

> *...B2H will act as a clean-energy pipeline transporting energy to customers across the western United States — not just Oregon and Idaho.*[23]

OPUC staff should inquire about the contrast between the Idaho Power IRP and the utility's public statements. Customers should not be subsidizing a line needed only to make money for Idaho Power.

B2H Comparison to Other Resources

Table 2 (Page 11)

In the 2007 OPUC Order 007-02[24], the Commission found it impractical to have utilities – in their Integrated Resource Plans – analyze the deferral of investments made possible through demand response, alternative power sources, and other options. The Commissioners did, nonetheless, state:

> *[W]e believe that utilities should have processes in place outside the IRPs to examine demand- and supply-side options for delaying upcoming distribution investments*

This request is germane to the selection criteria for the elements listed in Table 2 on page 11 of Appendix D. The addition of battery storage to *1-axis solar PV* would:

- negate the intermittency
- render the produced power dispatchable
- provide regulated energy on demand

with the added benefit of no variable costs – as mentioned in Table 2 of the Supplement.

Strategically located and properly provisioned, the combination also provides for the delivery of valuable ancillary services including:

- reactive power and voltage control
- loss compensation
- load following
- system protection
- energy imbalance

The value of those services must be part of the calculations for all listed options in this 20-year planning effort. The OPUC and its staff should ask that they be included.

The effect of these potential supply-side options for dealing effectively with the need for and management of peak load cannot be overstated. The OPUC felt that this might allow the utility to forego distribution investments. We ask the Commission to revisit their order with this as context.

The Definitive Development and Construction Agreement for Boardman to Hemingway Transmission Project

PacifiCorp Energy Gateway Segment H

The Definitive Development and Construction Agreement between Idaho Power (IPC), PacifiCorp (PAC), and Bonneville Power Administration (BPA), joint owners subject to the terms of the agreement, has expired. The partners had 300 days from the issuing of the Draft Proposed Order by ODOE to come to an agreement.

It was STOP's understanding that the 2nd 120 negotiation period was not to exceed 120 days but it appears that the parties have agreed to an additional 120 days.

This extension raises concerns on several levels. First, once the BPA completes its "business case" there will be a public process. We have been unable to get information on the steps involved in this process, nor the timeframe in which it will occur. The Energy Facility Siting Council (EFSC) is expected to issue its Proposed Order (PO) in April or May 2020. If EFSC's PO is in the affirmative, this may allow actual construction to begin. This is well before the extension to the Development and Construction Agreement expires on July, 15, 2020 and we see this as problematic.

Second, we do not believe Idaho Power is confident that the BPA's business case will be in the affirmative. On November 5, 2019, IDACORP INC published the Securities and Exchange Commission (SEC) announcement that includes an additional $324M for a hypothetical doubling of ownership of the Boardman to Hemingway powerline (Figure 12). If this were to happen the entire IRP will need to be amended to include this doubling of ownership. If Idaho Power's share of the project is $648M the least cost portfolio will change.

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Nov 05, 2019
Current report filing

To read the announcement, go to:
http://www.idacorpinc.com/investor-relations/financial-information/sec-filings
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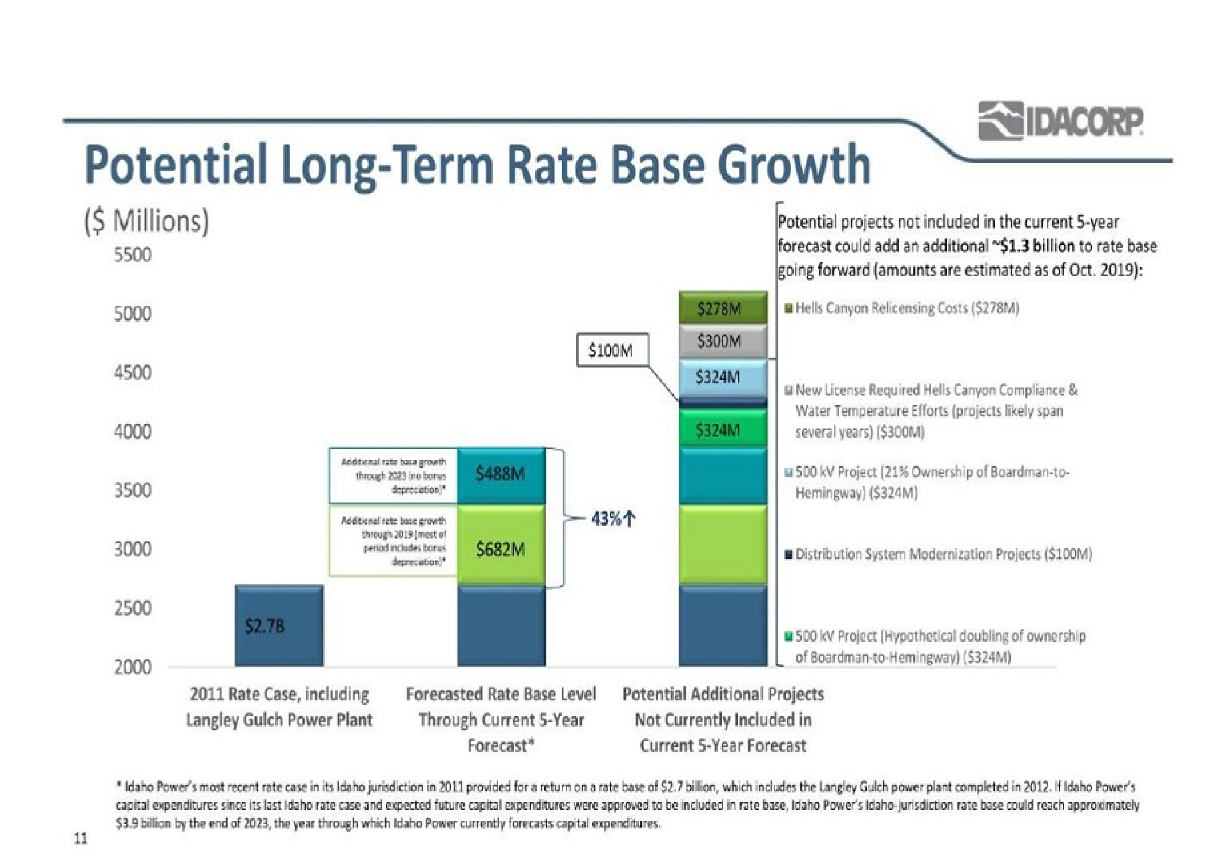

Figure 12: Potential rate-base growth from IDACORP SEC filing, Nov 05, 2019

Third, PacifiCorp does not have PacifiCorp's Energy Gateway Segment H, Boardman to Hemingway, as a short term action item in their 2019 IRP. Instead they are prioritizing their Energy Gateway South (EGS), proposed to be built in 2023. As Commissioner Bloom stated in 2018, the Commission expected to see the Boardman to Hemingway Transmission Project—PacifiCorp Energy Gateway Segment H—in PacifiCorp's in short term action plan for 2019.

These facts further support our request that the Commission modify its order No. 18-176 by rescinding action item 6: conduct preliminary construction activities; acquire long-lead materials; and construct the B2H project; as it is premature to be allowing construction.

Conclusion

"Idaho Power, a company culture out of step with Oregon"

STOP reiterates one last point in the Substantive Requirements of *OPUC Guideline 1d*, that the:

> *"the plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies."*

In the 2019 Amended IRP, Idaho Power maintains a traditional utility model for building new and having a high rate of return on investment: over 10% on a 21% share of a $1.2 billion plus transmission line—all at the expense of ratepayers. Meanwhile, emerging utility business models embrace new technologies including renewable resources, battery storage with ancillary services, distributed grids, and greater energy efficiencies. Idaho Power and its corporate culture are not in step with today's industry vision, or with our state's long history of energy conservation and innovation, such as the Energy Trust of Oregon.

These trends—distributed generation, storage, and local distribution—have many advantages, including "reliability," which is one of Idaho Power's values on their Vision, Values and Mission page. Increasing and expanding reliance on a centralized transmission system is not in the best long-term interest of the public.[53] Sparking or an act of terrorism could result in a catastrophic wildfire caused directly or indirectly by a large powerline—one sited directly next to an existing 230MW corridor such as B2H. Microgrids, while providing for distributed generation, could still function if they were equipped to disengage from the larger grid and they were provisioned with storage. This could be especially important for hospitals, local governmental units, emergency responders, our military bases and preparedness in general. There is too much at stake for Eastern Oregon. The $1.2 billion proposed B2H investment, STOP contends, should be directed elsewhere, or eliminated altogether.

BPA has not committed any resources other than the initial environmental and permitting studies for the B2H. BPA appears more in step with the long-term public interests of the citizens of the northwest and Oregon, as they found other solutions to their I-5 Corridor Reinforcement Project and are carefully evaluating their B2H business case. When completed, they may choose not sign the construction agreement thus changing the entire "least-cost" model as Idaho Power absorbs their cost which the SEC filing points out. This is one reason why we have suggested that the commission rescind action item #6 in the 2017 IRP.

If the BPA goes forward with the B2H when the business case is completed, there will be a series of public meetings which will take more time and still could see the BPA withdrawing from the project. There is also a federal NEPA lawsuit pending on the federal ROW, which could further delay permitting

53 https://microgridknowledge.com/grid-security-tenuous-microgrids-dg-needed-says-former-ferc-chairman/

and construction. Putting the B2H on hold, saving the ratepayer additional permitting costs would be a prudent move.

Pacific Corps' has not included the B2H in their 2019 action plan; and has also not committed any resources other than allowing their ratepayers to fund their portion of the initial environmental and permitting studies for the B2H. In the final OPUC hearing on the 2017 IRP, Commissioner Bloom stated[54] emphatically:

> *"My concerns are that Idaho Power is the 24% participant and the two big parties, BPA which we can't control, and PAC doesn't even have it in their IRP. So if we acknowledge this IRP for Idaho Power this is not an acknowledgment for PAC. They are going to have to do all their own work on this to convince us that it's still in the money."*

And in the final order, the Commission reiterated:

> *"…Transmission must be developed with very long lead times. Because circumstances may change in the future, and new information may be presented at a later date, the ultimate development of the B2H project is not a foregone conclusion. We agree with Staff that a host of changed circumstances could require Idaho Power to reevaluate its course, including but not limited to significant changes in co-participant shares and commitments, project costs, load needs, power market liquidity and depth, and capabilities and costs of alternative technologies. Idaho Power should be prepared for such reevaluation and to change course should such information or circumstances emerge."*[55]

STOP agrees that PacifiCorp and Idaho Power need to BOTH have commission acknowledgment before the hugely expensive and environmentally risky, B2H project moves forward.

STOP has identified many errors and misstatements by Idaho Power in this Amended 2019 IRP, but most important, Idaho Power has grossly under-represented the level of existing transmission capacities in the Aurora model, mentioned nothing of the cost of transmission line loss to the rate payers, and is holding more CMB in reserve than needed thus creating a large modeling bias in favor of the B2H transmission line. If this nefarious bias were corrected, B2H would likely not be the "least cost/lowest risk" portfolio. The Commission should not acknowledge the 2019 IRP as it stands, based upon the deficiencies raised by STOP and other intervenors.

54 https://oregonpuc.granicus.com/MediaPlayer.php?view_id=1&clip_id=293&meta_id=14009 at 4:16:18 in the hearing video.
55 Order No. 18-176, pp. 10-11.

STOP requests the Commission:

1. Modify the 2018 Order 18-176, eliminating the phrase, "…and to construct the B2H.

And, direct Idaho Power to:

2. Reevaluate and improve its energy efficiency and demand response programs bringing them more up-to-date with most utilities.
3. Remove the bias in favor of B2H that Idaho Power has engineered into the AURORA model, and perform a new Portfolio analyses that utilize increasing VERs (such as the Franklin solar project), battery storage, energy efficiencies and demand response.
4. Re-evaluate qualitative analysis, incorporating fire risks and liability; and re-evaluate the qualitative risk of losing investment partners, such as BPA and PAC.
5. Model two additional scenarios for a possibly more conservative and prudent approach given the rapidly changing environment:
   i. Upgrade (digitizing) and fireharden the existing 230 lines in Path 14.
   ii. Upgrade (per 1.) and re-conductor the existing 230 lines to 245MW, in the same corridor, on Path 14.

It does not seem prudent to rush construction approval for the B2H transmission line while Idaho Power has yet to convincingly demonstrate that it is "needed" and that partners are on-board. A clear and reasonable doubt has been raised about the facts in this docket. Based on the information that is available and supplied by the intervenors, what Idaho Power should have reasonably known about emerging new technologies, and what other utilities are adopting, it appears that Idaho Power is not being prudent. Their constant repetition that the B2H has been in every portfolio since 2005 doesn't mean that it still is a good idea. Prudency requires an assessment of the present and an analysis of the future.

STOP offers many alternatives rooted in Oregon's innovation and pioneering spirit. It's time for Idaho Power to get on board—Wagons Ho!

STOP believes that our vision of the energy future is more in alignment with the long-term interest of Oregonians and the public at large. We believe that the Commission will agree. Idaho Power can do a better job at developing residential and commercial conservation programs including smart metering, investing in renewables and battery storage, and partnering with industrial customers before building new transmission lines. New green energy jobs and careers can be created rather than temporary road building and construction of transmission towers.

Help us blaze the trail – toward a new energy future!

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No Capital Required for Clean and Green Energy Solutions --An IUS Global Program

Objective

IUS Global was established as a consortium of companies with mutual interest in developing efficient, sustainable, high-value clean and green energy solutions with ***No Capital Required*** from its clients. Many private sector companies have a desire to become environmentally-friendly, yet clean and green solutions don't bring a profitable return when compared with core business investments. We have developed a program that makes these high-value solutions available to the private sector without impacting their capital budget.

How does it work?

Our team conducts a **No Cost** evaluation of the client's current energy consumption, operating cost and environmental goals. Upon completion of this evaluation a solution which will improve efficiency, reduce operating cost, lower environmental impact is proposed to the client. The proposed solution will also include the standard terms of our ***No Capital Required*** program as it relates to the solution proposed.

The Agreement

The agreement is structured similarly to public-private partnership agreements but rather than engaging the public sector we are offering the program to stable organizations in the private sector. Depending on the project size, geographic location, and regulations the agreement will follow one or a combination of the following ***standard formats***.

- *PPA – Power and Energy purchase agreement*
- *ESA - Energy Services Agreement*
- *Financial Lease Agreement*
- *Operating Lease agreement*
- *Tolling Agreement*

(All the solutions are offered with no budgetary expenses to the client until the supply of energy and/ or derivatives are provided to the client.)

All agreements can be structured to allow for complete ownership transfer to client.