BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 78

In the Matter of	)
	)
IDAHO POWER COMPANY,	)
	)
2021 Integrated Resource Plan.	)
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OPENING COMMENTS OF THE

OREGON CITIZENS' UTILITY BOARD

July 7, 2022

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I. INTRODUCTION

The Oregon Citizens' Utility Board (CUB) files these opening comments on Idaho Power Company's (the Company or IPC) 2021 Integrated Resource Plan (IRP). CUB appreciates the opportunity to participate in this IRP. The 2021 IRP shows a major and rapid shift in the Company's load and resource balance from a resource sufficient to a significantly resource deficient status. The shift, on one hand, demonstrates the uncertainties utilities face as they work towards providing clean, reliable, and affordable energy to utility customers. On the other hand, this shift demands innovative measures from the utilities to account for these unforeseen forces that may rapidly alter the load and resource balance.

Idaho Power's 2021 IRP identifies a capacity deficit of 101 MW in 2023 that keeps growing in the next few years.[1] This is a major departure from the 2019 IRP, in which the first capacity deficit of only 42 MW was detected in July 2029.[2] The 101 MW is also an increase

[1] LC 78: 2021 IRP, page 170. Near term capacity deficiencies identified are 101MW in 2023, 186MW in 2024 and 311MW in 2025.
[2] LC 74: Idaho Power Second Amended 2019 Integrated Resource Plan – Appendix C, page 28.

from the 78 MW deficit identified in the Company's 2022 Request for Proposal.[3] This large and rapid change in the Company's projected capacity shortfall demands scrutiny to ensure that a least cost, least risk plan to meet this need is followed.

According to the 2021 IRP, transmission constraints, reduced ability of existing demand response (DR) programs to serve peak load hours, planning margins and methodology modernization, and higher than expected load forecast have jointly contributed to this newly identified deficit. CUB's comments will discuss some of these factors that have contributed to significant near-term capacity deficiencies and future implications in light of Idaho Power's resource procurement strategy. CUB will also comment on the Company's readiness in bringing significant quantities of renewables on its system as established in the preferred portfolio, and its estimated future demand response capacity.

II. NEAR-TERM CAPACITY DEFICIT

Idaho Power's 2021 IRP identifies near-term capacity deficits of 101MW in 2023, 186 MW in 2024 and 311 MW in 2025. CUB briefly discusses the drivers behind these newly identified capacity deficits and recommends that the Company act on it.

1. *Transmission*

One of the driving factors behind Idaho Power's imminent capacity deficiency is a loss in transmission availability. Idaho Power lists several events that took place during 2021 that forced the Company to change its ability to make energy purchases using third-party transmission.

[3] The Oregon Public Utility Commission had rejected Idaho Power's December 9, 2021, application for a waiver from all of Oregon's Competitive Bidding Rules. *See* UM 2210: Order No. 22-081.

Idaho Power's 2019 IRP outcome showed increased consumer benefits from retiring Valmy Unit 2 in 2022 as opposed to 2025. This result was dependent on transmission availability from the south that would enable capacity purchases from that region during high demand hours. Idaho Power could not import capacity as planned owing to transmission congestion following the California heat wave in August 2020. This heat wave also triggered pre-emptive reservation of "unprecedented" amounts of firm transmission just outside of Idaho Power service area and reduced the Company's access to the Mid-C capacity market significantly.

As a result, the 2021 IRP assumes a reduced transmission availability of 710 MW from the earlier 900 MW for the years 2022-2025. This in turn contributed to the short-term capacity needs that was not there in the 2019 IRP. Idaho power provides the following information on the components of the 710 MW of transmission availability assumption for market purchases.

Table 1[4]

Table 3. Third-party secured import transmission capacity

Third-Party Provider	Market	Capacity (MW)
Avista via Lolo	Pacific Northwest	200
PAC via Walla Walla	Pacific Northwest	80
BPA via La Grande	Pacific Northwest	50
PAC via Red Butte (Utah/Nevada border)	Desert Southwest	50
Subtotal		**380**
Emergency Transmission (CBM)	Pacific Northwest	330
Total		**710**

CUB has the following concerns:

[4] 2021 IRP, Appendix D, page 14.

a. This table does not show the changes made from the previous IRP that accounts for the 200 MW (900MW minus 700MW) shortfall in transmission availability. Identifying specific sources of congestion and the resulting loss in transmission capacity that led to a change in assumption in this IRP is useful to accurately estimate transmission availability.

b. Out of the 710 MW of assumed transmission, 330 MW is Emergency Transmission (CBM). CBM allows Idaho Power to obtain replace generation needs to meet unplanned generation outages or energy emergencies.

Idaho Power mentions: "The company anticipates this third-party transmission will be available during an emergency event."[5] However, there is no further information on what ensures this emergency transmission availability in the 2022-2025 timeframe as this constitutes more than 50% of the assumed transmission capacity. CUB requests that Idaho Power explain the rationale behind the current transmission availability assumption along with an explanation of how the Company plans to utilize emergency transmission resources.

CUB finds no reason to believe that there will be no repetition of the congestion events that the Company faced and is concerned that there may not be adequate transmission availability for similar reasons. As we move towards more extreme weather conditions resulting from climate change, heat waves could become more common, and pre-emptive third-party reservations could become more widespread. Idaho Power is a summer peaking system. How does the Company plan to account for transmission congestion risks stemming from weather related events going

[5] 2021 IRP, Appendix D, page 140

forward? The Company must present sufficient analysis showing that it has accounted for such risks and the current revision to 710 MW of available transmission is justified. Further, relying on a significant portion of future transmission on an emergency basis places a significant level of risk onto customers. If the Company is indeed facing such a significant capacity shortfall, it seems that firm transmission capacity would be needed to ensure an adequate load and resource balance. Finally, CUB notes that the Company is enrolled in the Western Power Pool's Western Resource Adequacy Program (WRAP). CUB anticipates that participation in the WRAP will bring with it capacity benefits that can be accrued from the WRAP's relatively large geographic footprint. CUB would appreciate the Company detailing how participation in the WRAP is likely to affect both its anticipated capacity shortfall and the transmission needs it points to.

2. ***Capacity Contribution of Demand Response***

Idaho Power has modernized its planning margin approach by introducing a Loss of Load Expectations method to determine system needs. This method evaluates the capacity contribution of a generation resource at the highest risk hours (as opposed to system peak hours) by assigning an Effective Load Carrying Capability (ELCC) percentage to the resource. According to the Company, this helps in accounting for generation profile of renewable resources like wind and solar. However, introduction of this new methodology and using ELCC to measure capacity contribution resulted in reduced capacity contribution of Idaho Power's DR programs. The ELCC of DR was found to be only 17%, which was much lower than the previously used value for DR capacity contribution. Idaho Power had applied for approval at both Idaho and Oregon Commissions a change in its existing DR programs, aligning event hours with solar generation by shifting these hours later in the day. This has increased the ELCC of DR to 55%.[6] The changed DR program was approved by Oregon Public Utility Commission (Commission) in February 2022.

CUB believes that ELCC is becoming more of an industry practice to measure risk-based capacity contribution of variable energy resources. The WRAP also discusses using ELCC for resource capacity accreditation for wind and solar resources in the Forward Showing Program (FSP). Idaho Power is a participating utility in the WRAP. CUB found that while the FSP suggests using ELCC for wind and solar, it suggests using "operational testing and historical performance" for DR capacity accreditation. Does Idaho Power foresee any potential conflict between the methodology in the WRAP versus using ELCC for DR in its IRP? How does the Company plan to reconcile the two? Further, how does the change the Company is proposing align with the true capacity contribution of DR resources in recent years? If the ELCC methodology results in a significantly diminished capacity contribution for DR resources compared to how they have historically performed, whether to use the ELCC should be revisited. CUB would appreciate a narrative response from the Company in its forthcoming comments in this proceeding.

3. ***Load Forecast***

Idaho Power has assigned part of its near-term capacity needs to "higher than expected load growth." CUB requests an account of model improvements that Idaho Power has planned to improve its peak load forecast model. The 2021 IRP uses a neural network to forecast hourly

[6] https://edocs.puc.state.or.us/efdocs/UAA/uaa17029.pdf.

system load. However, it is unclear what modeling improvements the neural network has brought to the analysis.

Neural network is a more complex model compared to a linear regression. It is easier to understand the underlying assumptions and outputs of a linear regression model. It is therefore an open question whether to put more weight on model accuracy (for instance, based on size of the mean squared error) or on ease of understanding of assumptions and output of a regression model. A simple regression analysis shows the strength of relationship between dependent and independent variables, it is more transparent in showing statistical significance of predictors, and also provides a confidence interval for each regression coefficient that is estimated in the model. A regression model is less of a black box compared to a complex neural network model. CUB requests that Idaho Power provides more information on how the neural network model is an improvement over the linear regression model in its load forecast analysis.

It is also CUB's understanding that the neural network model used in Idaho Power's load forecasting uses historical weather data. Idaho Power recognizes that its current capacity need is partly triggered by more than expected load growth. Idaho Power also acknowledges that there is growing in-migration to its service area from high EV owning states like California. As climate change could also result in increased in migration, there could be new load arising on the grid from community resilience efforts, and others. The hourly load forecasting model should be able to account for unusual conditions arising from these factors to avoid future surprises in capacity needs growth. CUB therefore requests the Company to provide a narrative explanation of how the neural network model accounts for unusual conditions that could impact hourly electricity load forecast in the long term.

Further, the forecasted load growth on the Company's system appears to be a significant driver of the near-term capacity shortfall identified in the IRP. On June 15, 2022, the Idaho Public Utilities Commission granted the Company's application to establish a new rate schedule to serve "speculative high-density customers—specifically, large-scale cryptocurrency mining operators."[7] It is CUB's understanding that a number of cryptocurrency mining operations have sprung up in the Company's service territory. These operations require a significant amount of energy and capacity to meet their needs. However, with the granting of a new rate schedule for these customers, the Company is able to serve them with interruptible service. Moving these customers to interruptible service has large implications for both the Company's load forecast and anticipated capacity shortfall. Now that these customers are capable of being served with interruptible service and special contracts, CUB would appreciate an explanation from the Company regarding how this impacts its anticipated capacity shortfall. CUB encourages IPC to explore all solutions to defer the need for new capacity investments, including interruptible service, special contracts, DR, the WRAP, and energy efficiency.

III. PREFERRED PORTFOLIO ANALYSIS

Idaho Power's 2021 IRP Preferred Portfolio includes a staggering amount of renewable resource additions throughout the planning period. In sharp contrast to the 2019 IRP, the current IRP includes 700 MW of wind resources, 1,405 MW of solar resources, 1,658 MW of battery storage, some of which are paired with solar and an additional 100 MW of demand response resources. The Company also plans to exit from all coal resources by 2028, two years earlier from the date identified in the 2019 IRP.

[7] Idaho Public Utilities Commission Order No. 35428 (Jun. 15, 2022) *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2137/OrdNotc/20220615Final_Order_No_35428.pdf.

CUB believes these changes are progressive and welcomes them. At the same time, CUB is concerned about the Company's ability to support these significant quantities of variable energy resources (VERs) with adequate transmission and demand side measures that are necessary to reliably serve customers using VERs.

1. ***Transmission***

According to the Company's filing, the 700 MW of new wind resources and the 1,405 MW of new solar resources will be added to its transmission system east of the Treasure Valley. The standalone battery storages are assumed to be sited near the Treasure Valley load center or co-located with solar and wind facilities. To integrate these planned resources, Idaho Power would need the Gateway West transmission line that would transport these new resources to the Treasure Valley load center.[8] However, Gateway West is not selected in the preferred portfolio. There are several reasons that could explain this. According to the analysis, the 700MW of wind and 1,405 MW of solar can be integrated using the Company's transmission system to the east of Treasure Valley. Battery storage, whether standalone near the Treasure Valley load center or co-located with wind and solar is not expected to use any transmission across southern Idaho to the Treasure Valley. Idaho Power expects to gain a net capacity of approximately 400 MW from upgrades to its east-west transmission lines and capacity gained from exits from Valmy Unit 2 and Jim Bridger Unit 3 in 2025.[9]

Idaho Power also analyses a situation in which the Bridger exit does not happen as planned. For instance, if there is no alignment with PacifiCorp on Bridger exit in 2025, more wind and solar shows up on Idaho Power's system necessitating Gateway West partial segment 8 coming online in 2027 and completed segment 8 being online in 2033. As we have seen in the

[8] LC 78: 2021 IRP, Appendix D, page 54.
[9] LC 78: 2021 IRP, Appendix D, page 55.

current IRP, Idaho Power is now converting Jim Bridger 1 and 2 to natural gas plants, rather than exiting these. Given the dynamic nature of current utility planning, this may happen in future with the other Bridger units (3 and 4). Hence, the scenario in which Gateway West becomes an important component of the portfolio is not unlikely.

Similarly, if the Valmy exit gets pushed into the future due to transmission unavailability or other reasons, there would also be a need for Gateway West in the earlier years. CUB requests a scenario in which transmission capacity gains from both Bridger and Valmy exits together are not realized. Idaho Power should provide updates on expected construction timeline of segment 8 of Gateway West.

2. ***Demand Response Potential***

IPC estimated 584 MW DR potential using NWPCC's assessment of DR potential in its service area. Existing DR accounts for 300MW (revised down from 380 MW due to program changes; IPC believes participation will decline due to these changes). Hence, the Company will plan for approximately 280 MW of new demand response over the next twenty years. IPC divides the 280 MW in bundles of 20MW. Unlike the NWPCC assessment, IPC's DR potential estimates do not include potential associated with pricing programs. CUB comments on two aspects of DR potential estimation in Idaho Power's Preferred Portfolio:

a. Existing DR capacity: Idaho Power revised existing DR nameplate capacity from 380 MW to 300 MW starting in 2022. This has also contributed partly to the 101MW of capacity deficit arising in 2023. According to IPC, the changes introduced in the existing demand response program for certain schedules in both Oregon and Idaho may lead to a decline in customer participation. The specifics of the programs can be found in Oregon PUC Docket ADV 1355 and Idaho PUC Case No. IPC-E-21-32.[10] The Company's hypothesis regarding the reduction in participation is based on a survey of its customers regarding the modified DR program. The modified program shifts the event availability start and end time by 2 hours from the original 1pm-9pm to 3pm-11pm. The survey results imply a reduction in rate of participation if the event time window is moved to later hour of the day. Participation rates are highest in the 5-9pm window, less for the 6-10pm window and least for the 7-11pm window.[11] It is not clear to CUB how this survey was utilized in the change in DR availability from 380 to 300 MW.

Idaho Power's updates show that there has indeed been a reduction in capacity availability from these programs compared to last year, but as of June 2022 this capacity is about 320 MW.[12] Also, despite an increase in enrollment in the Flex peak program, there is an estimated reduction in program capacity. Therefore, enrollment may not be the best indicator of capacity availability. Idaho Power must explain clearly how it used decreased participation or enrolment to revise assumptions about existing demand response capacity.

CUB suggests that Idaho Power keep monitoring program contribution towards its peak capacity needs in the months of July and August and provide an update to the Commission.

b. Future DR potential: CUB appreciates the analysis around estimating DR potential for IPC's service area. Demand response is a cheap resource that can replace

[10] Idaho Power provided the docket information in response to OPUC Staff Data Request No. 56.
[11] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2021/2021_IRP_DR_Update_0821.pdf, slide 11.
[12] Idaho Power's Response to Staff IR 94.

expensive generation resources in the highest need hours. As more renewables are brought on to Idaho Power's system, demand response will play a greater role in complementing renewable generation. Therefore, a holistic approach to estimating demand response potential will be useful to effectively integrate variable energy resources in its energy system.

Idaho Power did not include potential from its price-based demand response programs. CUB agrees that currently the Oregon Time of Use program is not significant enough to provide any real capacity benefits to the system. Idaho Power needs to expand this program by leaps and bounds, given that less than five customers are enrolled in the Oregon program. The Idaho program has about 1000 customers, which is also quite low given that Idaho power is the largest electric utility in the state of Idaho. Idaho Power should proactively work towards expanding participation in these programs. This is true for both residential customers as well as other customer classes.

CUB had provided a description of the evolving practices around valuing price-based demand response programs in the LC 77, PacifiCorp 2021 IRP. CUB believes that there should be holistic approach to demand response, and that there is value in modeling price and behavior-based demand side programs as competing resources along with direct load control programs. FERC Order No. 719 defines demand response as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy."[13]

[13] https://www.ferc.gov/media/order-no-719, p309.

Studies establishing best practices towards evaluating DR also include price based and behavioral programs (e.g., critical peak pricing or real time rates).[14] Research shows that, with appropriate price signals, utilities could induce the desired consumption behavior on the customer side and obtain optimized levels of demand response based on price based programs.[15]

CUB realizes that there are both modeling and implementation challenges of voluntary demand response programs that constrain its capacity value, but there are ways to overcome some of these challenges. In terms of modeling, several utilities apply a derate factor to the estimated avoided cost from a DR program to account for these constraints. In California, for instance, "day-ahead programs with voluntary load reductions have been derated by 60 percent whereas technology-enabled air-conditioning load control programs and aggregator-managed C&I [commercial and industrial] programs with short response time could be derated by less than 20 percent. In Colorado, Xcel Energy estimated that the capacity value of DR programs with a four-hour dispatch limit per day and a 40-hour dispatch limit per year should be derated by around 30 percent while unconstrained DR programs that could be dispatched up to 160 hours per year (a large number of hours for a DR program) should only be derated by five percent."[16]

In terms of implementation, CUB realizes that there are barriers to establishing price and behavior-based DR programs that would guarantee meeting capacity and

[14] Ryan Hledik amd Ahmand Faruqi (2015), "Valuing Demand Response: International Best Practices, Case Studies and Applications", the Brattle Group. http://files.brattle.com/files/5766_valuing_demand_response__international_best_practices__case_studies__and_applications.pdf.
[15] Haiyan Shu et. al, (2014), Demand Response based on Voluntary Time-dependent Pricing Scheme.
[16] *Supra,* note 30.

energy needs but believes that there are ways to overcome these barriers. One requirement for such programs is deploying AMI meters. Idaho Power has close to 100% deployment of AMI meters in its service territory. These should be used to their full potential.[17] Another way to overcome barriers regarding certainty around customer participation and responsiveness to price changes would be providing customers with smart systems including in-home displays and home-area-networks.

IV. HELLS CANYON RELICENSING

Idaho Power is awaiting multi-year relicensing from FERC for the Hells Canyon Complex (HCC). The process is ongoing since 2003 with FERC continuing to issue annual licenses to Idaho Power. At present, the HCC accounts for 30% of the Company's total generating capacity. Idaho Power expects that the multi-year license to be issued in 2024 or soon after that. Apart from the cost of the license itself, the multi-year license will come with additional costs of compliance to new terms of the license.

Although, due to lack of sufficient information around the final terms of relicensing, Idaho power cannot include long-term costs associated with the HCC multi-year license, it does introduce a cost and risk component in the IRP, given that it accounts for 30% of its total generation capacity.

CUB believes that additional analysis is needed in this context as we start to see more renewable investments by the Company to meet its resource needs as well as its clean energy goals. Will the new resource strategy lessen the dependence on HCC and can customers save money from diverting Company resources from relicensing efforts to more productive areas?

[17] https://www.idahopower.com/accounts-service/understand-your-bill/meter-information/.

CUB would like to hear the Company's thoughts on this.

V. CONCLUSION

CUB looks forward to Idaho power's responses to CUB's comments. CUB appreciates Idaho Power's effort to adapt to changing energy environments. The Company has introduced new methodologies to capture the value of granular data in its load forecast as well as account for generation patterns of variable resources. As seen in this IRP, accommodating these elements has changed the utility's load resource balance to a large extent and generated previously unrecognized capacity needs on the system. CUB appreciates these modeling and methodological changes and hopes the Company keeps educating and updating stakeholders of the outcomes and implications of these changes.

As this IRP shows, the changing energy policy climate and Idaho Power's clean energy goals call for significant investments in renewable energy over the next planning horizon. CUB wants to be assured that the Company has available transmission to integrate these clean energy resources. CUB also urges Idaho Power to work towards expanding its demand response programs, including price-based programs, as these are also complementary to effective integration of clean energy resources.

Dated this 7th day of July 2022.

Respectfully submitted,

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