BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 77

In the Matter of	)
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PACIFICORP, dba PACIFIC POWER,	)
	)
2021 Integrated Resource Plan.	)
	)

REDACTED OPENING COMMENTS

OF THE

OREGON CITIZENS' UTILITY BOARD

December 3, 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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I. INTRODUCTION

The Oregon Citizens' Utility Board (CUB) files these Opening Comments on PacifiCorp's (PAC or the Company) 2021 Integrated Resource Plan (IRP or Plan) filed on September 1, 2021. CUB will continue to conduct discovery and review the Company's plan prior to submission of Final Comments on March 11, 2022.

CUB appreciates the Company's continued effort to integrate clean energy resources in its portfolio. The 2021 IRP has several new features to it. PacifiCorp includes in its preferred portfolio, for the first time, an advanced nuclear demonstration project with a small fast reactor and storage capable of generating up to 500 MW of electricity for 5.5 hours. Several coal plants are up for early retirement or gas conversions within the next few years. CUB is also appreciative of the Company's conservation targets of achieving 603 MW of energy efficiency and 549 MW of demand response resources between 2021-2024. PacifiCorp also includes two new scenarios in its load forecast analysis including climate change and electrification. CUB believes that modeling both climate change and electrification will be critical to resource procurement for electric utilities in the light of current policies and state clean energy goals.

CUB provides comments on the following:

1. Natrium Advanced Nuclear Demonstration Project.
2. Climate Change and Electrification Modeling.
3. Defining and Valuing Demand Response.

II. NATRIUM ADVANCED NUCLEAR DEMONSTRATION PROJECT

PacifiCorp's 2021 IRP includes, for the first time, a nuclear resource in its preferred portfolio. PacifiCorp views the concept of the Natrium advanced nuclear reactor as a reasonable and cost-effective addition to its portfolio of clean energy resources. Moving forward, electric utilities in Oregon must reduce their dependence on fossil fuels to meet the state's clean energy goals and mandates. While wind and solar are the two most dominant resources being evaluated to meet these goals, nuclear energy has started to appear frequently in recent clean energy conversations.

Some arguments favoring nuclear energy as a clean fuel are compelling. Nuclear resource generation is firm and has a much higher capacity factor compared to wind and solar resources. Dependence on variable resources poses reliability challenges. Many studies on the future clean energy electric grid include nuclear power in the resource mix of clean electricity. Modern nuclear power plants can complement and firm renewables by filling in when solar and wind generation drop during certain times of the day. There is, however, a clear divide between nuclear advocates and skeptics. While nuclear energy generation is free of carbon dioxide or methane emissions, the capital costs are significant, inordinate delays and rising costs put customers at risk, nuclear disasters are still a possibility, and long term federally licensed storage facilities for highly radioactive wastes from nuclear plants are still absent. In short, nuclear energy poses a unique combination of both cost and risk that should be thoroughly examined in IRP processes.

PacifiCorp's resource optimization model considers, among other resources, two new non-emitting thermal resource options that include advanced nuclear projects and non-emitting peaking units. The advanced nuclear project Natrium, with a nameplate capacity of 345 MW, is projected to come online in 2028. The associated storage can provide electricity up to 500 MW for 5.5 hours. PacifiCorp's preferred portfolio analysis shows that excluding the Natrium project would increase the top performing portfolio (PO2MM) cost by $133 million through 2040 in present value terms.[1]

CUB is supportive of exploring clean energy resources including nuclear power in this IRP. However, CUB believes that any resource in an IRP should be allowed to compete with alternative and comparable resources, and all possible costs and risks of a resource should be accounted for. CUB finds PacifiCorp's analysis of the nuclear project as presented in the IRP to be missing some of these elements.

A. Risks to PacifiCorp Customers

In response to CUB's discovery, PacifiCorp presented an account of the various risks that the Company believes this project presents. PacifiCorp's explanation of these risks is appreciated; CUB elaborates on these risks below and identifies a few additional risks associated with the Natrium project.

1. *Fuel Supply Risk* – As PacifiCorp acknowledges, there is a risk associated with the supply of the high-assay low-enriched uranium (HALEU) that the small modular reactor

[1] LC 77 PacifiCorp 2021 IRP, p 280.

(SMR) would be depending on to generate electricity.[2] CUB would like to add to this. While conventional nuclear plants use 5% enriched uranium, the majority of SMR developers, including TerraPower, are reliant on the more efficient HALEU for which the uranium is enriched to 10-20% level. Currently, the only country that produces HALEU at a commercial level is Russia. There is a pilot project in the works in the US that is set to start production of the fuel in 2022, but that could only provide 20% of what the reactors would need in that year alone.[3] Uncertainty surrounding the main fuel for the SMRs is well acknowledged in the industry and currently there are more questions than answers. If more SMRs are developed, there will be increased demand and competition for HALEU, which will increase both the cost and risk of the plant in the future.

2. *Regulatory Risk* – In identifying regulatory risks associated with the project, PacifiCorp states that this is a "first of a kind sodium fast reactor. There are expected design and Nuclear Regulatory Commission (NRC) review challenges that will need to be addressed by PacifiCorp before constructing this project."[4] CUB would like to expand on this. Certification by the NRC is a prerequisite to any SMR coming online. In the absence of any experience from real-life advanced nuclear plants, regulators must issue licenses based on proposals from the developers. This is a time-consuming and resource-intensive process. Changes to the plant's projected operation may need to be made to comply with NRC licensing processes, which may delay and add costs to the project. Oregon-based NuScale Energy's recent experience with NRC licensing demonstrates how protracted the process can be. "NuScale only passed the fourth of a six-phase [NRC] design certification application review last December, almost 12 years after

[2] LC 77 CUB DR 3, CUB Opening Comments Appendix A.
[3] https://www.utilitydive.com/news/nuclear-reactors-of-the-future-have-a-fuel-problem/604707/.
[4] *Supra*, Note 2.

initiating the process. No other SMR maker has undergone the U.S. regulator's design certification review."[5]

3. *Project Management Risk* – PacifiCorp realizes that there could be unforeseen delays related to the design, construction, and commissioning of the demonstration plant due to its novel nature.[6] CUB found that these delays can contribute significantly to cost overruns as seen in the case of the Vogtle power plant in Georgia, where costs have more than doubled from a projected $13 billion to about $28 billion. This cost is expected to go up further due to some recent delays. There is data to measure costs already incurred by customers due to this project's delay. "Georgia Power's 2.6 million customers have already paid more than $3.5 billion toward the cost of Vogtle units 3 and 4 under an arrangement that's supposed to hold down borrowing costs. Public Service Commission staff members earlier estimated that the typical customer will have paid $854 in financing costs alone by the time the Vogtle reactors are finished."[7]

In another instance, NuScale Energy of Oregon announced last year that their project will be delayed by 3 years, until 2030, and that costs would increase from $4.2 billion to $6.1 billion.[8] Eight companies out of a 36-utility consortium backed out from the deal to build the plant. A recent MIT paper analyzes sources of cost escalation for nuclear plants and concludes that factors like low labor productivity, engineering design changes, and related delays contribute significantly to cost escalation.[9]

While there is the potential for technology and project management systems to mature and mitigate the risk for project delays, recent examples demonstrate that the risk of delay is

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[5] https://www.greentechmedia.com/articles/read/so-what-exactly-are-small-modular-nuclear-reactors.
[6] *Supra,* Note 2.
[7] https://www.wabe.org/new-delay-for-georgia-nuclear-reactors-as-costs-mount/.
[8] https://www.science.org/content/article/several-us-utilities-back-out-deal-build-novel-nuclear-power-plant.
[9] https://www.greentechmedia.com/articles/read/mit-study-lays-bare-why-nuclear-costs-keep-rising.

prevalent. This has the potential to add costs to the project and is a risk that must be adequately considered in this IRP setting.

Beyond risks highlighted by the Company, CUB identifies additional risks with this project.

4. Financing/Cost Share Risk – Nuclear projects require a considerable amount of capital investment, and reliable and sufficient funding is crucial towards completion of the projects. The initial costs of the Natrium project are estimated to be around $4 billion.[10] The plant is being partly financed by the Department of Energy's Advanced Reactor Demonstration Program and the rest is financed privately. In the absence of any other information, CUB assumes that PacifiCorp and its customers would be responsible for the rest of the cost, which means PacifiCorp customers are looking at a starting cost of at least $2 billion[11] (if not more due to potential cost overruns) and an exposure to multiple risks including those discussed above. In discovery, CUB requested the financing structure of the plant from the Company. The Company's response to CUB DR 1 shows **[Begin Confidential]** [redacted] **[End Confidential]** and would like additional information on how the Company proposes to finance this project. It is also unknown what share of these costs would fall on Oregon customers under the prevailing multi-state allocation methodology. However, currently, as this resource is projected to come online as Oregon is phasing out of coal, Oregon's resource needs will be greater than other states. This

[10] https://www.reuters.com/business/energy/bill-gates-4-bln-high-tech-nuclear-reactor-set-wyoming-coal-site-2021-11-17/.
[11] *Id*.
[12] LC 77 CUB DR 1 Attach A Confidential, CUB Opening Comments Appendix B.

project could be used to fill Oregon's energy needs which means the cost of this project could largely be assigned to Oregon. Depending on whether the resource is brought on to serve a system-wide need or an Oregon-specific need, Oregon customers may be exposed to a greater level of cost and risk than other PacifiCorp states.

CUB also points out that there is at present no federally licensed long-term waste facility for highly radioactive wastes from the Natrium plant. If the project is completed and PacifiCorp requests cost recovery, it will be the first time a utility would have sought recovery since the codification of ORS 469.595 and ORS 469.599. ORS 469.599 provides, in part:

> The Public Utility Commission shall not authorize the issuance of stocks, bonds or other evidences of indebtedness to finance any nuclear-fueled thermal power plant . . . until the Energy Facility Siting Council has made the finding required under ORS 469.595 [that there is an adequate repository for the disposal of high-level radioactive waste before issuing a site certificate].

While I am not an attorney, there appears to be uncertainty regarding the legal framework for cost recovery in Oregon that should be explored. Further, it remains unclear how PacifiCorp is modeling the long-term costs of storing nuclear waste from the project. These issues should be vetted in this proceeding.

5. *Technology and Safety Risk* – The Natrium technology is based on the GE-Hitachi PRISM[13] modular reactor concept. The Department of Energy has judged the PRISM technology to be mature and commercially viable since its design was based on a small test reactor in Idaho, now operating for three decades. Hence, the Natrium technology is proceeding on the assumption that it would be allowed to skip the performance demonstration test. However, the Union of Concerned Scientists points out that proceeding with the construction of the Natrium "...without conducting any prototype testing could pose unacceptable risks to public health,

[13] https://nuclear.gepower.com/build-a-plant/products/nuclear-power-plants-overview/prism1.

safety, and security, as well as to the success" of the project.[14] Small reactors also tend to have higher capital costs compared to larger ones due to diseconomies of scale. Given the nascent nature of this technology, these risks must be thoroughly analyzed in this process.

CUB believes that there are likely alternative cost-effective and lower risk ways to add emission free resources to PacifiCorp's portfolio, especially given the nascent nature of this technology. The Company must explore those options before burdening its customers with a high-risk project that costs billions of dollars just to start with. CUB looks forward to seeing additional analyses by the Company on the Natrium project.

6. *TerraPower and PacifiCorp Agreement Uncertainties* – There are considerable uncertainties regarding the agreement between PacifiCorp and TerraPower at present. A recent news article suggested that the Natrium project will be financed by the DOE for $1.9 billion[15] **[Begin Confidential]** [redacted] **[End Confidential]**[16] and that PacifiCorp and its customers are completely shielded from any kind of financing risk. PacifiCorp's subsidiary company Rocky Mountain Power will own and operate the plant once it is complete, and the only costs the utility will incur are those of energy and storage priced at the market rate.[17] CUB seeks clarification on the financing arrangements for this project. The Company currently has no agreements with TerraPower to share that could help CUB understand the details associated with the transaction between PacifiCorp and TerraPower.[18] It is essential for CUB, stakeholders, and

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[14] "Advanced" Isn't Always Better – Assessing the Safety, Security, and Environmental Impacts of Non-Light-Water Nuclear Reactors, p-55, Edin Lyman, Union of Concerned Scientists, March 2021.
[15] *Supra,* Note 11.
[16] *Supra,* Note 12.
[17] Clearing Up, November 19, 2021, No. 2031, p 6.
[18] LC 77 CUB DR 12, CUB Opening Comments Appendix C.

the Commission to review the terms of any agreements in this proceeding in order to provide an informed recommendation.

B. CUB's Recommendation

CUB recommends the following regarding the Natrium project:

1. PAC should do a portfolio sensitivity analysis accounting for possible cost escalation of the Natrium plant (for instance, 5%, 10%, 25% and 50% cost increase scenarios). The current IRP shows that the portfolio without the Natrium plant addition costs $133 million more compared to the top-performing portfolio. That is about 3% of the plant's starting cost of $4 billion. Evidence on cost overruns and looming uncertainties with the nuclear plant could result in a much higher increase in the plant's cost in future. PacifiCorp should also conduct modeling to determine what level of initial capital investment, what level of cost overruns during construction, and what level of operating costs would make the plant uneconomic to customers.

2. PAC should perform additional risk analyses for this project and provide evidence to ensure that PAC customers will not be unduly burdened by unforeseen costs and risks of the project.

3. PAC should consider exploring alternatives to the nuclear plant. The Natrium plant has a 345 MW nameplate capacity, and a maximum capacity of 500 MW for 5.5 hours if the storage is in use. That amounts to less than 5% of PacifiCorp's system coincident peak forecasts.

The Company should look at other new or mature resources that could serve this energy and capacity need at a more reasonable cost. For instance, Xcel Energy in Colorado is looking at molten salt energy storage to repurpose a coal plant set for early retirement.[19] Offshore wind is a

[19] https://denvergazette.com/news/environment/xcel-energy-looking-at-preserving-hayden-plant-as-molten-salt-energy-storage-facility/article_ec5214b4-1711-11ec-b906-572e9935def7.html.

known technology gaining prominence. If PacifiCorp had included more alternative resources in its supply side table, the Company may have ended up with a different preferred portfolio. There could be a combination of supply and demand side resources that could reliably provide the 345 – 500 MW of clean energy without burdening customers with excessive costs and risk.

At present CUB cannot recommend acknowledgement of Action Item 2c, the Natrium Demonstration Project. PacifiCorp should provide more information and analyses on this project to put it up for acknowledgement as a part of its near-term Action Plan.

III. LOAD FORECAST SCENARIOS: CLIMATE CHANGE AND ELECTRIFICATION

A. Climate Change

Climate change related events impact customers' electricity consumption as well as utility resources. Any resource plan designed to serve customers reliably and affordably must account for these impacts. CUB appreciates PacifiCorp's inclusion of climate change impact in its load forecast analysis. Including climate change impact explicitly in utility IRPs is a relatively recent development, and few utilities have incorporated an exclusive climate change analysis in their IRPs. There is no standardized way to appropriately model these impacts. Climate change can directly influence temperatures and hence intensity and timing of usage of air conditioning and heating equipment. Climate change effects hydrological cycles through changes in temperature, timing, and volume, which in turn impacts the availability of water for thermal electric cooling and hydropower generation. There could also be indirect impacts of climate change as reflected in evolving policies regarding electrification, in or out migration triggering changes in loads, and so on. It is therefore important to incorporate these impacts in utility planning.

A well accepted principle in modeling climate change seems to be downscaling global climate models (GCM) to regional levels to capture the direct effects of climate change. PacifiCorp uses data from the United States Bureau of Reclamation Hydroclimate Projections that calculated temperature ranges for several river basins in western US by downscaling GCMs. PacifiCorp finds daily average temperatures and peak producing temperatures that correspond to the mid-point of these temperature ranges to project energy and peak needs in specific service territories. CUB appreciates this method, but questions whether the modeling could be improved to better reflect climate change impacts in the jurisdictional load forecasts and in other parts of the IRP.

The 2021 Northwest Power Plan (Power Plan), for instance, models both direct and indirect effects of climate change. The direct impact is captured by downscaling three GCMs to the regional level. That amounted to examining changes in the number of heating degree days (HDD) and cooling degree days (CDD) over time for the northwestern states.[20] CUB believes that looking at HDDs and CDDs is a better approach to capture seasonal load impacts of climate change. The Power Plan also looks at changes in regional precipitation to account for direct impact of climate change.

As stated earlier, climate change can have indirect or secondary impacts. These indirect impacts could be increases in electrification or other reactive policies, or even a change in demographics that could potentially lead to a change in electric load. The Power Plan considers these indirect effects by considering a rise in population due to in-migration and an increase in the use of air-conditioning.

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[20] The states are for which the Power Plan estimates the heating and cooling degree days are Oregon, Washington, Idaho, and Montana.

A recent white paper prepared for the Department of Energy by the Pacific Northwest National Laboratory (PNNL) has a survey of 30 electric utility IRPs on the inclusion and modeling of climate change. The study reveals that 8 out of 30 utilities included climate change scenarios in their IRPs. Most climate change scenarios were modeled as an impact on the hydroelectric resources, only Tennessee Valley Authority (TVA) also modeled the impact of climate change on its thermal resources. The PNNL study pointed out that "TVA's IRP noted that they have derated individual plants in the past and invested in additional cooling at others because of water temperature issues.[21] In their case, TVA identified possible summer capacity derating of coal and nuclear plants in response to hotter, dryer summers, with changes in the resource portfolio (more solar, earlier installation of combustion turbines) to compensate for the reduced capacity (TVA 2019)."[22]

CUB believes there is potential for PacifiCorp to explore the nuances in impacts of climate change on its thermal as well as hydro resources. As the Company moves forward with transitioning to a cleaner energy resource portfolio accurate climate change modeling will prove to be imperative for least cost and risk resource acquisition practices.

B. Electrification

PacifiCorp accounts for electrification in its load forecast, but it only considers electric vehicles in all its service territories and building electrification in Utah only. As stated earlier, the NWPP includes an electrification scenario analysis as an indirect effect of climate change. The Power Plan adjusts for air conditioner saturation in new construction based on the observation that there is an increase in air conditioner installations in residential constructions in

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[21] TVA IRP 2019, Vol. II, p. F-88.
[22] A Review of Water and Climate Change Analysis in Electric Utility Integrated Resource Planning, p 9-14. https://epe.pnnl.gov/pdfs/Water_in_IRP_whitepaper_PNNL-30910.pdf.

the Pacific Northwest. Accordingly, the Power Plan adjusted the demand forecasts to grow to a 98% penetration by 2050.

CUB believes the increased penetration of air conditioners is a phenomenon that may be observed in Oregon, especially after recent unprecedented heat waves. The most recent Residential Building Stock Assessment (2016 -2017) report from Northwest Energy Efficiency Alliance (NEEA), for instance, shows an increase in mechanical cooling especially in air source heat pumps for manufactured homes and mini split air conditioners in single family homes in the Northwest.[23] As climate change accelerates, the frequency and intensity of extreme weather events like heat waves will likely increase and the electric system has to account for customers' changing needs for cooling or heating their homes. The demand or load forecast should be reflective of these changes.

PacifiCorp's electrification scenario for Oregon should also consider building electrification along with electric vehicle adoption. In response to CUB DR 24, asking for the status of building electrification in Oregon as considered by the Company in its load forecast for Oregon, PacifiCorp pointed out that, in the absence of any mature legislation in Oregon on such an initiative, PacifiCorp is only considering a vehicle electrification scenario for Oregon (as opposed to Utah, where building electrification legislation is at a more mature stage).[24] Although there is currently no legislation formalizing building electrification for Oregon, several cities and counties around the state are adopting their own electrification goals. For instance, on November 17, Eugene City Council passed two motions requiring investigation and action to revise code changes for new construction by 2023 to mandate 100% electrification for new commercial,

[23] Residential building stock assessment II (2016-2017), Single Family Homes Report p. 6, Manufactured Homes Report p. 4,
[24] LC 77 CUB DR 24, Appendix D,

residential, and industrial buildings and to chalk out a road map towards equitable electrification of all buildings by 2045.[25] While PacifiCorp does not serve Eugene, it is not difficult to imagine a city such as Corvallis following the lead of Eugene. Earlier this year the Multnomah County Commission unanimously voted for 100% fossil free energy for all new county buildings.[26]

C. CUB's Recommendation

CUB recommends the following:

1. PacifiCorp should review best practices in climate change modeling by peer utilities and consider more a comprehensive modeling of climate change in their load forecast analysis.

2. PacifiCorp should consider increases in air conditioner saturation in Oregon load forecast analysis.

3. The Company should consider both building and transportation electrification for the electrification scenario for Oregon. Specifically, for building electrification, PacifiCorp should consider Oregon Public Utility Commission Staff's (Staff) guidelines regarding alternative scenarios analysis as a part of the Climate protection Program compliance model development by natural gas companies in the Natural Gas Fact Finding docket, UM 2178.

Staff suggests that the gas utilities include two different electrification scenarios. The following is a direct excerpt from Staff's guidelines in UM 2178.

a. Electrification:

- Fraction of new buildings (residential and commercial) using gas goes from its present share to zero in 2030 and stays zero thereafter;

[25] https://www.registerguard.com/story/news/2021/11/20/eugene-climate-change-natural-gas-electrification-nw-natural/8657640002/
[26] https://www.climatesolutions.org/article/2021-04/new-multnomah-county-public-buildings-will-be-100-clean-and-fossil-free

- Existing buildings converting to electricity goes from its present share to 90 percent in 2050;
- Light industry converts to 90 percent electricity by 2050

b. Very Rapid Electrification:

- The fraction of new buildings (residential and commercial) using gas goes from its present share to zero in 2025 and stays zero thereafter.
- Fraction of existing buildings converting to electricity goes from its present share to 90 percent by 2040.[27]

IV. DEFINING AND VALUING DEMAND RESPONSE

Flexible demand response must become a more integral part of utility resource planning as utilities integrate greater amount of variable energy resources, including solar and wind energy, as well as distributed generation resources to its system. Demand response (DR) resources are also among the most cost-effective tools to reduce power sector emissions, balance demand and supply, and generate ancillary services for utilities. Most studies that analyze economic benefits of DR programs consider both involuntary (or utility controlled) and voluntary (or price-based) demand response resources in the mix.

PacifiCorp defines DR to include direct load control or involuntary DR alone and considers this as a competing resource in its portfolio optimization analysis. The price or rate-based demand response programs are defined as demand side rates (DSR) and are included as adjustments to the system load forecast, rather than a competing resource. PacifiCorp explains that price and behavior-based programs cannot provide firm resources and hence modeled differently

[27] https://edocs.puc.state.or.us/efdocs/HAH/um2178hah163319.pdf.

from the more controllable and reliable DLC programs and excluded from the IRP's definition of demand response.

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."[28] The 2021 Northwest Power Plan, for instance, recommends two demand response resources, time varying rates and demand voltage reduction, for utilities to consider in resource plans.[29] Studies establishing best practices towards evaluating DR also include price based and behavioral programs (e.g., critical peak pricing or real time rates).[30] 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.[31]

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

[28] https://www.ferc.gov/media/order-no-719, p309.
[29] 2021 Northwest Power Plan Draft, p.6-41.
https://www.nwcouncil.org/sites/default/files/2021powerplan_2021-5.pdf.
[30] 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.
[31] Haiyan Shu et. al, (2014), Demand Response based on Voluntary Time-dependent Pricing Scheme.

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."[32]

In terms of implementation, CUB realizes that there are barriers to establishing price and behavior-based DR programs that would guarantee meeting capacity and energy needs but believes that there are ways to overcome these barriers. One requirement for such programs is deploying AMI meters. PacifiCorp's 2021-2040 Conservation Potential Assessment Study shows that the utility plans to have 100% AMI deployment in its Oregon and California service territories by 2021, followed by Idaho and Utah (2023) and Washington and Wyoming (2026).[33] CUB appreciates the Company's move in the right direction. 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.

A. CUB's Recommendation

CUB recommends the following:

1. PacifiCorp should use a more holistic approach to defining demand response.

2. PacifiCorp should update its assumptions for customer participation in dynamic pricing options with more recent data. The 2021-2040 participation assumption in the current CPA study is largely based on the 2015 CPA study.

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[32] *Supra,* note 30

[33] https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/2021-irp-support-and-studies/cpa-final-report-and-appendices/PacifiCorp%20DSM%20Potential%20Report%20-%20Vol%201%20-%20FINAL_2-26-2021.pdf, p.24

3. PacifiCorp should work towards modeling both direct load control and price and behavior-based demand response programs as a competing resource in its future resource plans, as it expands AMI deployment.

V. CONCLUSION

CUB appreciates the opportunity to participate in PacifiCorp's 2021 IRP process. CUB applauds the Company's efforts in developing a portfolio that reflects a move away from fossil fuels towards clean energy resources. PacifiCorp's 2021 IRP includes several new elements, including climate change and electrification scenarios. The IRP also includes for the first time a small-scale nuclear plant in the preferred portfolio.

In these opening comments CUB recommends ways in which the modeling of some of these elements, namely, climate change and electrification could be improved to better capture their impact on resource acquisition plans as utilities also prepare towards meeting state climate goals. CUB also advocates for a more holistic approach towards measuring demand response and treating demand side resources in its entirety as a competing resource in portfolio optimization.

CUB is concerned that the Company has not presented sufficient analysis regarding risk implications of the Natrium nuclear reactor in this IRP. The nuclear plant is a completely new resource in the PacifiCorp's portfolio and very little information is currently available on the ownership, financing, and possible cost overruns of this plant. CUB wants to ensure that Oregon customers are not taking on unnecessary and unforeseen risks from this project. CUB urges the Commission to require the Company to present sufficient information regarding the proposed nuclear resource and consider alternative generation or storage resources that are not currently included in the IRP but are likely to impose lower cost and risk. Due to these concerns, at present

CUB cannot recommend acknowledgement of PacifiCorp's Action Item 2c, the Natrium Demonstration Project.

Dated this 3rd day of December 2021.

Respectfully submitted,

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LC 77– CERTIFICATE OF SERVICE

I hereby certify that, on this 3rd day of December, 2021, I served the **Confidential Opening Comments of the Oregon Citizens' Utility Board** in docket LC 77 upon the Commission and each party on the service list designated to receive confidential information pursuant to Order 21-271 through a secure, encrypted attachment to an e-mail.

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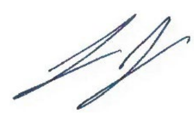
Respectfully submitted,



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LC 77 / PacifiCorp
November 9, 2021
CUB Data Request 3

CUB Data Request 3

Natrium™ Advanced Nuclear Demonstration Project
Please provide a narrative on the potential risks of this project as perceived by PacifiCorp and explain how the Company plans to address these risks.

Response to CUB Data Request 3

Identified risks include:

- Fuel Supply – specifically high-assay low-enriched uranium (HALEU) supply.
- Regulatory – specifically this is a first of a kind sodium fast reactor (SFR). There is expected design and Nuclear Regulatory Commission (NRC) review challenges that will need to be addressed.
- Project Management - unforeseen delays related to the design, construction, and commissioning of a "first of a kind" demonstration reactor.

PacifiCorp will work closely with TerraPower to identify, minimize, address, and provide solutions to the risks that come up throughout the project. Further, PacifiCorp intends to negotiate terms and conditions in future definitive agreements with TerraPower to minimize these risks for our retail customers.

CUB Appendix B is Confidential and has been served upon the Commission and each party on the service list designated to receive confidential information pursuant to Order 21-271.

LC 77 / PacifiCorp
November 9, 2021
CUB Data Request 12

CUB Data Request 12

Natrium™ Advanced Nuclear Demonstration Project
Please provide a copy of the agreement between TerraPower and PacifiCorp related to this facility.

Response to CUB Data Request 12

There is no agreement related to the facility between TerraPower and PacifiCorp.

LC 77 / PacifiCorp
November 22, 2021
CUB Data Request 24

CUB Data Request 24

Load Forecast, Electrification and Climate Change
For the electrification scenario in Appendix A – Load Forecast, page 15, PacifiCorp states

> "Given the status of building electrification initiatives in PacifiCorp's service territory, only the expected impact of these programs for Utah have been incorporated into the sales forecast".

Please clarify what the status of initiatives for building electrification looks like for PacifiCorp's service territory in Oregon and what does it look like in Utah?

Response to CUB Data Request 24

At the time the forecast was created, there was legislation in Utah that was sufficiently mature in the legislative process to warrant inclusion of building electrification in the Company's forecast. There was no similarly mature legislation in Oregon at the time the forecast was completed.