**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

LC 80

In the Matter of
PORTLAND GENERAL ELECTRIC,
2023 Integrated Resource Plan and
Clean Energy Plan.

**ROUND 1 COMMENTS OF
RENEWABLE NORTHWEST**

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I. Introduction

Renewable Northwest ("RNW") is grateful for the opportunity to submit these comments on Portland General Electric Company's ("PGE") 2023 Integrated Resource Plan ("IRP") and Clean Energy Plan ("CEP") (collectively, "Plan"). In our Round 0 Comments, we discussed the novel regulatory context for review of the Plan following the passage and implementation of HB 2021 (2021) and our expectation that the review process would be iterative. We provided high-level responses to certain elements of the Plan, but also indicated that our initial comments were preliminary and that our Round 1 Comments would be substantially more thorough. This document attempts to make good on that expectation.

To go into a little more depth, our Round 0 Comments expressed our view that "PGE's IRP and CEP present a meaningful first step toward the type of wholesale transformation envisioned by those involved in passing HB 2021" and represented "real progress in updating the planning paradigm to account for the mandates and values enshrined in HB 2021." However, we also observed that "additional scrutiny or updating by the company" was in order at least for "the plans' greenhouse gas ("GHG") impacts, their approach to PGE's interest in Colstrip Units 3 & 4, and their approach to modeling resources using conditional firm transmission," as well as a number of other less-developed issues including: hybrid resources; offshore wind; post-2030 planning; and issues relating to HB 2021's community lens.

These Round 1 Comments build on the issues identified in Round 0 and, as expected, add some new ones as well. In fact, **RNW recommends that PGE adopt, or that the Oregon Public Utility Commission (the "Commission") direct PGE to adopt, an alternative preferred portfolio** developed by RNW using PGE's model. This least cost and least risk preferred portfolio reduces costs and lowers risks for Oregon ratepayers, and is included as Attachment A to these comments.

To summarize the remainder of our Round 1 Comments, as to building on Round 0:

- Regarding GHG impacts, we express concern about the extent to which PGE's approach effectively relies on offsetting fossil generation allocated to off-system sales, and we encourage PGE to work on increasing the temporal granularity of its GHG modeling;
- Regarding Colstrip, we highlight how a later retirement date paired with PGE's emissions approach runs the risk of generating significant emissions that could be lost in the accounting;
- Regarding conditional firm transmission, we provide an updated analysis from Grid Strategies that responds to PGE's critiques and maintains our recommendation that PGE assume zero hours of curtailment for modeling purposes;

- Regarding hybrid resources, we appreciate the change that PGE has already implemented and offer no further comments;
- Regarding offshore wind, we provide new modeling demonstrating that offshore wind is a least-cost, least-risk resource post-2030 that should be included in PGE's preferred portfolio, and we recommend that PGE undertake a long-lead time RFP in 2025 aimed at identifying economic resources whose development timelines do not interact well with Oregon's current RFP structure;
- Regarding post-2030 planning, we continue to recommend more concrete planning since some of the resource candidates most likely to meet PGE's needs at the least cost and risk in the 2030s are likely to be long-lead time resources; and
- Regarding the Plan's community lens, we respond to PGE's May 31, 2023 Response to Initial Comments with additional clarity and direction that we believe would be helpful based on our regular dialogue with community organizations.

As to new issues, we also address the following:

- Regarding resource adequacy ("RA"), we recommend that PGE work toward a multi-metric approach that incorporates economic factors, to align with emerging best practices;
- Regarding effective load carrying capability ("ELCC"), we recommend certain changes to PGE's analytical approach, including accounting for portfolio effects rather than relying on resource-specific ELCCs;
- Regarding emerging resources, we recommend that PGE incorporate additional factors in its analysis of hydrogen, including electrolyzer load and potential leakage; and
- Regarding the Western Resource Adequacy Program ("WRAP"), we recommend that PGE continue work to align its Plan with the WRAP, including by incorporating the WRAP into its modeling.

RNW staff are grateful to have had the opportunity to work with a number of outside technical consultants on these comments, as we have worked to understand and respond to the details of PGE's Plan. We continue to appreciate PGE's work on developing a forward-looking Plan that incorporates new values and constraints. We offer these comments in the hope that they will result in a stronger Plan that accomplishes Oregon's GHG policy as robustly as possible -- as is increasingly necessary to respond to the climate emergency -- while also ultimately lowering costs and risks for PGE's customers. We hope that PGE will take up the challenge, and we otherwise appreciate the Commission's consideration of these comments when it meets to address acknowledgement in January.

II. Comments

While there is still significant process to come in this docket, we begin with a brief recitation of the standard the Commission will ultimately apply in reviewing PGE's IRP / CEP. This discussion begins with the traditional framework the Commission applies in deciding whether to acknowledge an IRP and then discusses the additional factors the Commission is required to consider in deciding whether to acknowledge a CEP.

The Commission will acknowledge a utility's IRP if the Commission determines the utility's preferred portfolio and action plan are reasonable at the time of acknowledgment and align with the applicable IRP guidelines.[1] If a preferred portfolio is not least cost, least risk, then the Commission can direct the utility to revise the IRP or not acknowledge the IRP.[2] IRP Guideline 1(a) states "[a]ll resources must be evaluated on a consistent and comparable basis" that includes using "[c]onsistent assumptions and methods[.]"[3] IRP Guideline 4 states the preferred portfolio must also represent "the best combination of cost and risk for the utility and its customers" or be least cost, least risk.[4] Utilities must also consider all resources that are expected to become available during the planning horizon, not just resources that are commercial or near-commercially viable.[5]

The landscape for acknowledgement of utility resource plans changed following the legislature's passage of HB 2021 (2021). HB 2021 built on the traditional IRP process but added new planning requirements -- reflected in a CEP -- and new acknowledgement standards for the CEP. Specifically, HB 2021 provides that:

> (2) The Public Utility Commission shall acknowledge the clean energy plan if the commission finds the plan to be in the public interest and consistent with the clean energy targets set forth in ORS 469A.410. In evaluating whether a plan is in the public interest, the commission shall consider:
>
> > (a) Any reduction of greenhouse gas emissions that is expected through the plan, and any related environmental or health benefits;
> >
> > (b) The economic and technical feasibility of the plan;
> >
> > (c) The effect of the plan on the reliability and resiliency of the electric system;

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[1] *See In re Idaho Power Company 2021 Integrated Resource Plan*, Docket No. LC 78, Order No. 23-004 at 3 (Jan. 13, 2023); *see also In re Commission Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order Nos. 07-002 (Jan. 8, 2007) and 07-047 (Feb. 9, 2007).
[2] Docket No. LC 78, Order No. 23-004 at 3 (Jan. 13, 2023); OAR 860-027-0400(8)-(9).
[3] Docket No. UM 1056, Order No. 07-047, Appendix A at 1 (Feb. 9, 2007).
[4] Docket No. UM 1056, Order No. 07-047, Appendix A at 5 (Feb. 9, 2007).
[5] Docket No. UM 1056, Order No. 07-002 at 4 (Jan. 8, 2007).

(d) Availability of federal incentives;

(e) Costs and risks to the customers; and

(f) Any other relevant factors as determined by the commission.[6]

Briefing regarding the precise meaning of some of HB 2021's language as applied to CEP acknowledgement is currently taking place before the Commission in Docket No. UM 2273.

In addition to the acknowledgement standards, the Commission temporarily waived and modified IRP Guideline 1(c) in Docket No. UM 2225 earlier this year. Specifically, for the current planning cycle, in reviewing IRPs for acknowledgement the Commission will also consider "the pace of greenhouse gas emissions reductions, and community impacts and benefits."[7] Additionally for the current cycle, "[t]he pace of greenhouse gas emissions reductions should be evaluated, **at a minimum**, in a manner consistent with the methodology approved by the Oregon Department of Environmental Quality."[8]

RNW recommends that the Commission bear these standards in mind when reviewing the following comments.

A. Renewable Northwest Recommends PGE Update its Resource Adequacy Methodology by Revising its Need Determination Process and Publishing Additional Information on Loss-of-Load Events

PGE provides a clear description of its seasonal capacity needs for future years in the IRP planning horizon. As a part of its Portfolio Analysis Refresh addendum, the utility updated its capacity needs and included a graphical depiction of its summer and winter capacity needs by year in Figure 7.[9] In 2028, PGE has a need for 944 MW and 827 MW of firm capacity in the summer and winter seasons, respectively.

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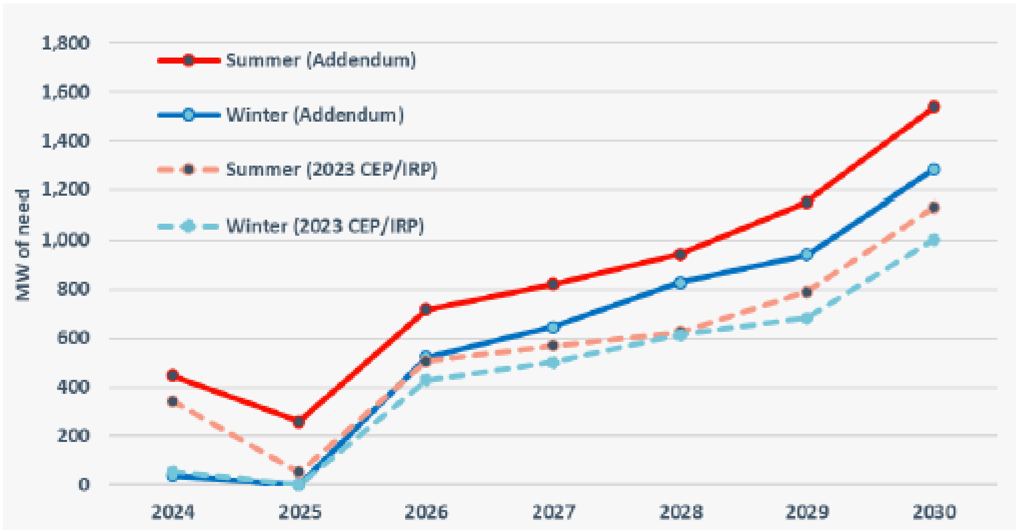
[6] ORS 469A.420(2).
[7] *See In re OPUC House Bill 2021 Investigation into Clean Energy Plans*, Docket No. UM 2225, Order No. 23-060, Appx. A at 5 (Feb. 23, 2023).
[8] *Id.* at Appx. A at 6 (emphasis added).
[9] 2023 Clean Energy Plan and Integrated Resource Plan Addendum: System Need & Portfolio Analysis Refresh at 18 (July 7, 2023) (hereinafter "2023 CEP/IRP Addendum").

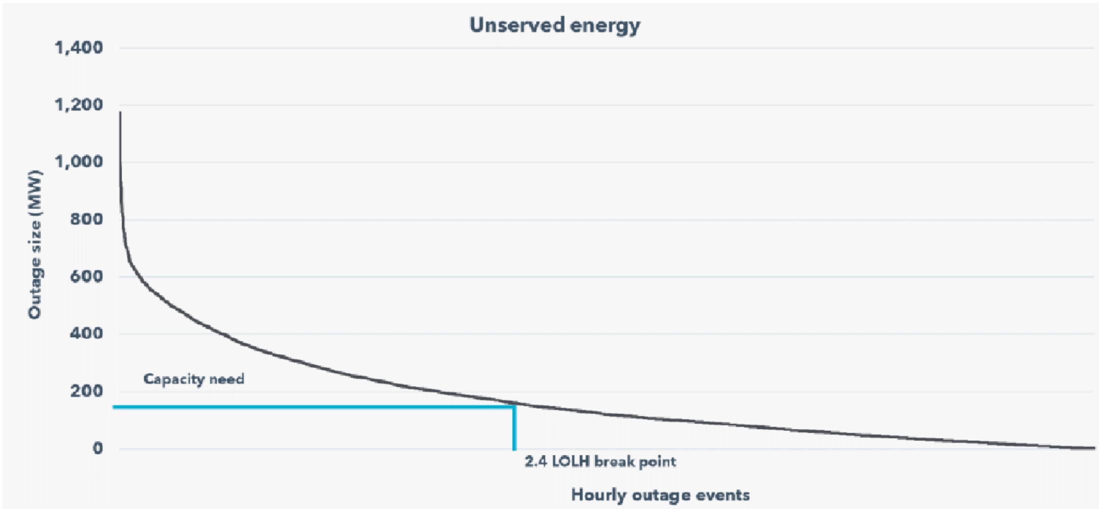
Figure 7. Capacity need comparison



PGE provides a clear explanation of its RA methodology in its IRP by providing readers with a detailed description of Sequoia, its proprietary loss-of-load probability ("LOLP") model that determines system needs and firm capacity accreditation for proxy resources. To account for the variability of weather and hydro years on the RA supply-demand equation, Sequoia conducts 50,000 weekly simulations for both winter and summer seasons for a 20-year horizon. Moreover, by modeling 168 hours of continuous timesteps, Sequoia can identify shortfalls in capacity that are related to time sequential constraints.

Whenever Sequoia detects that PGE's portfolio of defined resources is insufficient to meet the demand, it logs the outage and proceeds to the next weekly trial. Upon completion of the weekly simulations, Sequoia arranges the identified outages for each season-year (e.g., summer 2026) in descending order, essentially creating an outage duration curve. It then applies PGE's LOLP reliability target of 2.4 loss-of-load hours ("LOLH") to determine the incremental need for firm capacity.[10] The figure below from PGE's Plan summarizes this approach.[11]

[10] PGE March 2022 IRP Roundtable Meeting, available at: https://youtu.be/eo4e1r5cNUE?t=3870.
[11] Clean Energy Plan and Integrated Resource Plan 2023, Appendix H at 527 (July 6, 2023) (hereinafter "2023 CEP/IRP").



As described in PGE's 2019 IRP Update, for each weekly trial run, Sequoia generates a time series of unserved energy in PGE's portfolio that can be used to derive a suite of LOLP metrics along with other outputs such as heatmaps and outage distributions that characterize the timing, frequency, magnitude, and duration of loss-of-load events.[12]

RNW would like to commend PGE for conducting a robust analysis of its RA needs, which helps the utility address the impact of uncertainty on this complex topic. The utility conducts multiple detailed studies to explore the functional relationship between the portfolio's capacity needs and different input variables. As a result, the utility not only understands its probable capacity needs but also how those needs can vary for various scenarios. In its 2023 IRP, PGE analyzes the sensitivity of its RA needs to the following variables:

- Capacity Needs Futures;
- Planning reserve margin ("PRM") levels for the regional spot capacity market; and
- Interannual variability in load and hydro availability due to weather, both from historical records and the going-forward estimated impacts of climate change.

Despite the acknowledgements listed above, RNW has identified multiple issues with PGE's current RA methodology.

1) The methodology is predicated on using a single LOLP metric: LOLH.
2) PGE inaccurately applies the LOLH metric by arranging the Sequoia-generated outages in descending order from the largest to smallest.

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[12] *In re PGE 2019 IRP*, Docket No. LC 73, PGE's IRP Update, Appendix K at 81 (Jan. 29, 2021), available at: https://assets.ctfassets.net/416ywc1laqmd/1PO8IYJsHee3RCPYsjbuaL/b80c9d6277e678a845451eb89f4ade2e/2019-IRP-update.pdf.

3) PGE publishes limited LOLP-related information on its unserved energy risk and omits discussion on any additional insights gleaned from analyzing the characteristics of critical, individual outages.
4) Sequoia does not account for any economic considerations as part of its formulation for PGE's incremental firm capacity needs, precluding the utility and outside stakeholders from obtaining the necessary information to properly evaluate the cost-benefit tradeoff for varying levels of resource adequacy.
5) Inadequate temporal granularity of spot market availability.

Below, RNW suggests updates to PGE's approach that would respond to these identified issues. RNW recognizes that updating RA methodology may be too much to do in too little time this planning cycle, so the following recommendations are likely best implemented in the next planning cycle.

<u>Point of Contention #1:</u>
It's not possible to adequately characterize the RA risk profile of any portfolio using a single LOLP metric. LOLH is a 'necessary but not sufficient' metric because it only tracks the frequency (and potentially duration) of loss-of-load events. It excludes, however, the magnitude of outages as well as the expected amount of unserved energy, both of which are key parameters in determining the appropriate level of RA.

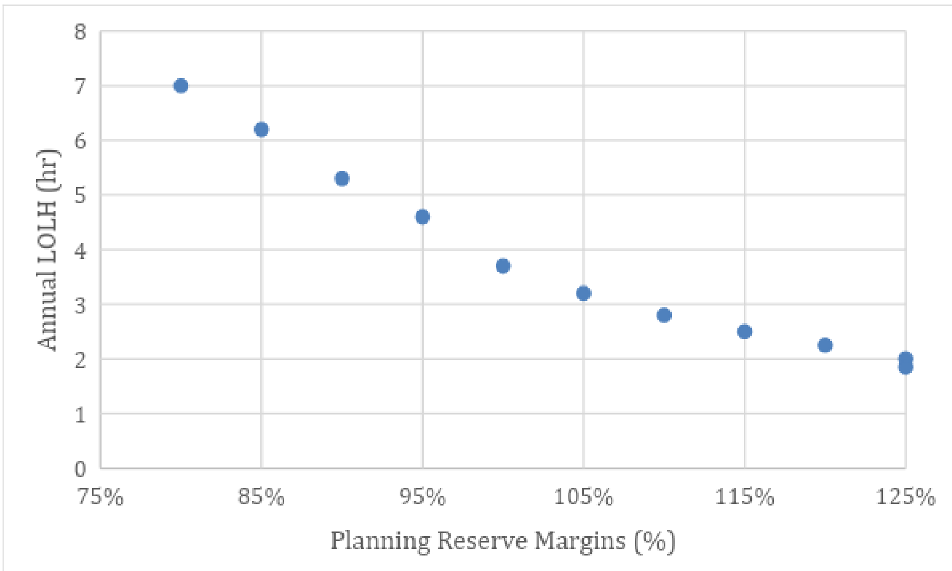
<u>Recommendation:</u>
PGE should incorporate a suite of LOLP metrics as a part of its official needs determination process in order to better understand its unserved energy risk profile and to identify the best resource option that addresses its marginal need for firm capacity. RNW refers PGE to analysis conducted by the Northwest Power and Conservation Council that discusses the importance of measuring multiple probabilistic metrics independently specifying unique threshold values for each.[13]

<u>Point of Contention #2:</u>
There is the risk of PGE misinterpreting the amount of capacity required to satisfy its ex-ante reliability target of 2.4 hours per year. Because there is no direct connection between LOLH and outage size, outages should not be arranged in any pre-specified order. RNW believes loss-of-load events should be arranged assuming a uniform distribution where each outage, independent of size, has an equal probability of occurrence.

[13] Fazio and Hua, *Three Probabilistic Metrics for Adequacy Assessment of the Pacific Northwest Power System* (May 2019), available at: https://www.researchgate.net/publication/335530163_Three_probabilistic_metrics_for_adequacy_assessment_of_the_Pacific_Northwest_power_system.

Recommendation:
Presuming PGE continues to use LOLH as the sole driver of investment in new resources, it should not arrange Sequoia-generated outages in descending order. Rather, it should model varying amounts of a generic resource of perfect capacity to determine the amount necessary to achieve its stated reliability target. In Figure 1 below, RNW provides an illustrative example of the general relationship it would expect to see between reserve margins and reliability in a well-designed RA methodology.

Figure 1



Point of Contention #3:
Although RNW believes that a suite of LOLP metrics is valuable, a comprehensive resource adequacy methodology also includes going beyond calculated averages. LOLP metrics synthesize a complex, stochastic process into a single statistic. As a result, sole reliance on these metrics can increase the risk of grid planners overlooking additional, useful information related to system reliability. This risk increases as the level of uncertainty in both demand and supply parameters also increases.

Recommendation:
Detailed investigations on the "tail events" to ascertain the characteristics of key periods with unserved energy can lead to additional insights into critical risks and mitigation opportunities afforded to PGE. A comprehensive analysis of any outage will include documentation on the size, frequency, duration, and timing of the event. Given the growing importance of the electric grid on the economy as more loads electrify, it will be critical to conduct this analysis on low-probability, high-impact events. This new paradigm of resource adequacy planning is

encapsulated well in a recent Energy Systems Integration Group ("ESIG") report on resource adequacy.[14]

Point of Contention #4:

By ignoring economic considerations, PGE's Sequoia model is unable to weigh the incremental costs of investing in additional reserve margins against its incremental benefits. These benefits come from not only reduced periods of expected unserved energy but also reduced market exposure during scarcity pricing. There is no guarantee that sole reliance on the industry reliability standard of "1-in-10" (or any interpretations thereof) will result in the most cost-effective level of planning reserves.

Recommendation:

RNW advocates for PGE to begin incorporating economic considerations into its Sequoia model to determine the most cost-effective level of planning reserves. In doing so, PGE and interested parties can be more informed to balance the costs of procuring new resources with the additional benefits afforded by greater reliability. RNW refers PGE to a report from the National Regulatory Research Institute for a detailed overview on the importance of expanding resource adequacy planning to include economic considerations.[15] RNW would also like to highlight how industry thought leaders are now advocating for reliability criteria to be transparent and economic.[16] Resource adequacy is just one aspect of system reliability and sits alongside other drivers such as distribution reliability, transmission stability, and security measures to protect against cyber and physical attacks. Consequently, understanding the tradeoffs in costs and benefits for varying levels of resource adequacy will enable more efficient allocation of capital spending across all investments intended to improve system reliability.

Point of Contention #5:

As discussed above, PGE utilizes the Sequoia model to perform reliability analysis, including its determination of capacity needed to maintain system reliability. Central to this analysis is the modeling assumption regarding import availability from neighboring balancing authorities during different periods of the year, which are used to fill any reliability gaps left by PGE's resource fleet. In this Plan, PGE estimates import availability for light- and heavy-load periods

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[14] Stenclik, et al., Electric Systems Integration Group, *Redefining Resource Adequacy for Modern Power Systems* (2021), available at: https://www.esig.energy/wp-content/uploads/2022/12/ESIG-Redefining-Resource-Adequacy-2021-b.pdf.

[15] National Regulatory Research Institute, *The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On* (Apr. 2011), available at: https://www.brattle.com/wp-content/uploads/2021/08/The-Economics-of-Resource-Adequacy-Planning-Why-Reserve-Margins-Are-Not-Just-About-Keeping-the-Lights-On.pdf.

[16] Stenclik, et al., Electric Systems Integration Group, *Redefining Resource Adequacy for Modern Power Systems* (2021), available at: https://www.esig.energy/wp-content/uploads/2022/12/ESIG-Redefining-Resource-Adequacy-2021-b.pdf.

during summer and winter months, differentiated by pre- and post-2025 periods.[17] PGE assumes no availability of spot market power during summer heavy-load periods, meaning the Sequoia model must rely strictly on PGE resources to meet load from 6:00AM to 10:00PM on all summer days. This assumption is consistent across the low-, medium-, and high-reference market capacity sensitivities.[18]

Recognizing tightening energy markets throughout the west, it is likely that reducing the assumption regarding spot market availability during summer peaks is directionally correct – however, it is also likely that a blanket assumption over the 16-hour heavy load period may obscure critical reliability dynamics that may inform resource valuation and portfolio development. Specifically, it is likely that significant energy will be available to PGE during peak solar hours – including hours reflecting loss of load risk, at least as reflected in its 2026 capacity need heatmap[19], which shows reliability risk prior to sunset from June through September.

Recommendation:
Improving the granularity of PGE's import constraint may result in a re-shaping of PGE's reliability risk, reducing modeled events during the solar window and concentrating reliability risk into a narrower band of evening hours. The corresponding narrower net load peak (when accounting for available imports) may result in increased effectiveness of 4-hour energy storage, demand response, or other resources capable of serving narrower peaks, as fewer megawatt-hours can address more megawatts of net load peak.

RNW appreciates the efforts of PGE and the Northwest Power and Conservation Council to proactively identify and address resource shortfalls across jurisdictions[20], and recommends PGE modify its import availability constraint to reflect more hourly variability in subsequent IRP modeling. Recently conducted modeling studies are now highlighting some of the potential reliability benefits of regionally coordinated transmission operations to Western utilities and regional planning organizations.[21]

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[17] 2023 CEP/IRP at 74.
[18] 2023 CEP/IRP at 505-12.
[19] 2023 CEP/IRP at 125.
[20] 2023 CEP/IRP Addendum at 13-14.
[21] Hart and Mileva, GridLab, *Advancing Resource Adequacy Analysis with the GridPath RA Toolkit: A Case Study of the Western US* (Oct. 2022), available at: https://gridlab.org/wp-content/uploads/2022/10/GridLab_RA-Toolkit-Report-10-12-22.pdf.

B. Renewable Northwest Recommends PGE Update its ELCC methodology To Include Additional Industry Best Practices

As described in their IRP filing, PGE's ELCC accreditation methodology consists of running Sequoia to assign firm capacity values for proxy resources[22]:

> *PGE uses the Sequoia model to calculate resource ELCC values, using the following steps:*
> - *The model runs once to establish a base system capacity need*
> - *The model runs again with a new resource added and produces a new capacity need*
> - *The difference in capacity need between the base system and the system with the new resource added determines how much effective capacity the resource contributes*
> - *The effective capacity value is divided into the resource nameplate value to calculate the ELCC*

RNW acknowledges that ELCC calculations are complex and that the industry is still working on identifying what constitutes best practice. Along those lines, RNW would like to commend PGE for incorporating several factors into their ELCC methodology to improve their estimate of each resource type's contribution towards system reliability. The following is a list of examples referenced in the IRP that showcase PGE's multifaceted approach towards ELCC accreditation:

- Calculating seasonal ELCCs, rather than annual values, to more accurately assess the ability of proxy resources to deliver firm capacity during the time period of need;
- Accounting for the "saturation effect" commonly associated with intermittent renewables (e.g., wind and solar) and energy-limited resources (e.g., storage) by reflecting decreasing marginal reliability benefits as Sequoia adds in additional capacity of a given resource type;
- Including the effects of geographic location (e.g., onshore wind vs. offshore wind) and project configuration (e.g., varying levels of inverter loading ratio) on the ELCC calculation; and
- Investigating the relationship of ELCC factors as a function of the system configuration (i.e., "tuned" vs. "untuned").

However, RNW recommends that PGE update its current ELCC methodology because it omits the following aspects, all of which are key when determining the effective capacity contribution of resources:

[22] 2023 CEP/IRP, Appendix H at 527.

- The "portfolio effect" associated with ELCC calculations;
- ELCC calculations based on the system configurations for multiple calendar years; and
- A "round-trip" LOLP modeling run along with any necessary adjustments to ELCC values or reserve margins to ensure sufficient resource adequacy.

Also referred to as "interactive effects," portfolio effects capture the interdependent relationship between various resources on the system, which can either be synergistic or antagonistic in nature. An example commonly provided to illustrate a synergistic relationship between two resource types is the symbiotic interaction between storage and solar.[23] Conversely, an example of an antagonistic relationship is the interaction between storage and demand response since these two resources commonly compete to provide reliability service during the same hours of critical need.[24]

The importance of including portfolio effects was discussed during the August 2022 IRP Roundtable.[25] However, based on the recently filed IRP, PGE has yet to update its planning process with a more rigorous ELCC methodology. While RNW acknowledges PGE conducted a preliminary investigation looking at the relationship between the availability of charging energy for storage and incremental amounts of wind and solar, a more comprehensive approach is warranted, especially given the downstream effects it has on the planning process. PGE runs the risk of overinvesting in the system if it inaccurately underestimates the ELCC effects of renewable and energy-limited resources by excluding portfolio effects. In a world where supply chains are still strained and interconnection queues are getting longer, it is imperative to minimize the risk of overbuilding the system. RNW refers PGE to a recent example of how utilities in other regions are incorporating ELCC surfaces into their ongoing planning responsibilities.[26]

The 2023 IRP calculates ELCC values based on the assumed configuration for the untuned system in 2026.[27] However, ELCC values are a function of both the resource mix and the load profile, neither of which are constant. Therefore, a robust ELCC accreditation method will

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[23] Schlag, et al., E3, *Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy* (Aug. 2020), available at: https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.
[24] Stenclik, Welch, and Sreedharan, GridLab, *Reliably Reaching California's Clean Electricity Targets: Stress Testing Accelerated 2030 Clean Portfolios* (May 2022), available at: https://gridlab.org/wp-content/uploads/2022/05/GridLab_California-2030-Study-Technical-Report-5-9-22-Update1.pdf.
[25] PGE August 2022 IRP Roundtable Meeting, available at: https://youtu.be/jKbuy7y6Ky0?t=6082.
[26] Carden, et al., Astrapé Consulting and E3, *Incremental ELCC Study for Mid-Term Reliability Procurement (January 2023 Update)*, (Jan. 2023) available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20230210_irp_e3_astrape_updated_incremental_elcc_study.pdf.
[27] 2023 CEP/IRP, Appendix J at 543.

calculate the effective capacity contributions of proxy resources for multiple future calendar years to account for yearly changes in both supply-side and demand-side variables. Given forecasted changes from resource mixes, electrification levels, and secular weather trends, it is critical for grid planners to account for the evolving LOLP risk profile. Such a methodology is not only likely to improve accuracy but also yield more consistent, predictable results.[28]

Finally, in recognition of the importance of resource-specific ELCC valuation in PGE's solicitation and selection process following the IRP, RNW strongly encourages PGE to include a validation process to ensure the ELCC values it ultimately assigns to proxy resources are reasonable and accurate. PGE can refer to a recent ESIG publication for a description of an illustrative example.[29] This final step can help validate that the ELCC accreditation process is accurately accounting for all the determinants that make up the calculation of firm capacity values.

In a planning environment where the role of intermittent renewables and storage provide a larger share of the capacity and energy needs of the system, it is paramount to account for the portfolio effect as accurately as possible. To properly assess the effective capacity contribution from a proxy resource, Sequoia must use an ELCC "surface" rather than an ELCC "curve" to capture the dependency of ELCC values on other facilities. If the portfolio effect is excluded from the analysis, the reported ELCC values that are passed on to ROSE-E will be inaccurate, and the results of the capacity expansion modeling exercise will be sub-optimal.

As with RNW's recommended changes to PGE's RA methodology, RNW's recommended changes to PGE's ELCC methodology may be too significant to implement this planning cycle. Accordingly, RNW suggests that PGE work to incorporate them for the next planning cycle.

C. PGE's Emerging Resource Analysis Provides an Interesting Starting Point

RNW appreciates the analysis conducted by PGE to understand the impact of emerging technologies, including offshore wind, long-duration storage, and green hydrogen-fueled combined-cycle combustion turbines ("CCCT"). It is interesting to understand where the $/kW-year inflection point is for these technologies to become competitive within PGE's Preferred Portfolio, noted to be between $250 and $500/kW-year.[30] Given the current cost constraints of these resources, PGE found there to be minor impacts on near-term resource builds

[28] Stenclik, Energy Systems Integration Group, *Ensuring Efficient Reliability: New Design Principles For Capacity Accreditation* (Feb. 2023), available at: https://www.esig.energy/wp-content/uploads/2023/02/ESIG-Design-principles-capacity-accreditation-report-2023.pdf.
[29] *Id.*
[30] 2023 CEP/IRP at 297.

across the Emerging Technology portfolios but more potential beyond 2030 for these technologies to displace other costly investments.[31] Relatedly, because PGE's post-2030 Preferred Portfolio resource pathway includes nearly 2,500 MW of generic non-emitting capacity resources, we would like to further explore PGE's treatment of hydrogen for its potential to meet these forecasted capacity needs. We will address offshore wind in significantly more detail in a separate section below.

PGE notes that nearly all of its "existing thermal fleet is capable of combusting a blend of hydrogen or renewable natural gas at present."[32] However, the 2040 zero-emission requirement would require significant investments in PGE's thermal fleet to retrofit the infrastructure for 100% green hydrogen fuel usage. We understand that the incorporation of hydrogen into portfolio modeling will be an iterative process as more information on this resource's viability becomes available. Still, there are details missing from PGE's narrative around and modeling of green hydrogen that RNW would find valuable in understanding the projected path toward resource deployment.

First, PGE relies on hydrogen production and storage costs derived from Mongrid and Hunter, though it is unclear what component costs (*e.g.*, from Hunter et al., low-, moderate-, or high-2020 or 2030 values[33]) have been applied, whether inflation was accounted for (values are presented in 2019 dollars), and how the Inflation Reduction Act tax credits have been applied.[34] Further, because green hydrogen is produced via electrolysis powered by a renewable energy source, PGE should take measures to model hydrogen availability in vicinities where there is a renewable energy surplus (*e.g.*, via a grid-powered electrolyzer with a renewable power purchase agreement) to make clear that average ("dirty") grid power is not driving the electrolysis and artificially deflating the cost estimates for this resource. The IRP is not clear on this locational aspect of the modeling, nor on the electrolyzer load requirements generally. On this point, RNW recommends that PGE consider our comments below on renewable energy curtailment as it relates to the company's treatment of GHG accounting, as this excess emissions-free generation would be the ideal power source for an electrolyzer modeled to produce green hydrogen.

The impact of this pairing (excess emissions-free generation powering the electrolyzer) is significant when considering that the hourly production for PGE's modeled electrolyzer is "approximately 38 percent of the fuel needed to operate the CCCT at full load for one hour."[35] In other words, 1 MWh of power into an electrolyzer outputs 0.38 MWh of power from a CCCT.

[31] 2023 CEP/IRP at 283.
[32] 2023 CEP/IRP at 36.
[33] Hunter, et al., *Techno-Economic Analysis of Long-Duration Energy Storage and Flexible Power Generation Technologies to Support High Variable Renewable Energy Grids* (Oct. 28, 2020), available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769.
[34] 2023 CEP/IRP at 632.
[35] 2023 CEP/IRP at 630-31.

While this conversion efficiency is quite low (losses occur in both the power-to-gas and the gas-to-power conversions), the effective efficiency would be higher if the power into the electrolyzer would otherwise be curtailed.

Finally, if PGE more seriously considers hydrogen in the future, we would like the company to explicitly address the importance of leakage detection with this technology, as hydrogen has its own warming potential. Hydrogen is a much smaller molecule than carbon dioxide, requiring more sensitive leakage detection, and by some estimates hydrogen has a relative warming impact that is 100x more potent than carbon dioxide emissions.[36] To limit the potential for leakage, we recommend that PGE limit its modeling of this resource to locations where the fuel can be produced and used in close proximity. We also recommend that PGE incorporate the cost of equipment capable of measuring hydrogen concentrations at the parts-per-billion level in its capital expenditures for this resource.

D. Robust Emissions Accounting is Critical for Successful Implementation of HB 2021

House Bill 2021 (2021)[37] sets Oregon utilities on a course to providing 100% greenhouse gas emissions-free energy to retail customers by 2040, and further establishes requirements for PGE and other utilities to elevate equity, resilience, and community benefits into their long-term decarbonization goals.[38] While RNW commends PGE's efforts within this initial CEP to incorporate the requirements of HB 2021 with a focus on 2030, there are a range of policy questions embedded within PGE's modeling decisions that must be addressed through the regulatory process to ensure an effective and positive implementation process to 2030 and beyond.

PGE's proposed framework for implementing HB 2021's climate and clean energy requirement centers around an annual clean energy constraint determined by netting its retail load against its permissible fossil emissions, summarized below[39]:

- First, PGE establishes an annual schedule of permitted portfolio emissions through 2040 indexed to the requirements in HB 2021.

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[36] *See, e.g.*, Ocko and Hamburg, *Climate consequences of hydrogen emissions* (July 20, 2022), available at: https://acp.copernicus.org/articles/22/9349/2022/acp-22-9349-2022.pdf. This research supported by the Environmental Defense Fund finds that continuous emissions from hydrogen leakage, which is more representative of real-world conditions than pulsed emissions, would result in a relative warming impact that is 100x more potent than continuous carbon dioxide emissions over a ten-year period.
[37] https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.
[38] We recognize that there is some question about whether HB 2021 is in fact a load-based standard, as this language suggests. RNW has addressed that question in more detail in the July 24, 2023 brief in Docket No. UM 2273, available at: https://edocs.puc.state.or.us/efdocs/HBC/um2273hbc152834.pdf.
[39] 2023 CEP/IRP at 96-97, 255.

- Second, PGE utilizes a proprietary tool, the Intermediary Greenhouse Gas Model (Intermediary GHG Model), to differentiate between the share of energy and emissions used to serve retail from the energy and emissions used for sales in the wholesale market, which are excluded from HB 2021.
- Third, the results of the Intermediary GHG Model are passed to ROSE-E, PGE's capacity expansion model, to define the portfolio's annual carbon budget constraint. When this constraint binds in ROSE-E, the model adds additional non-emitting resources to the portfolio to fill the open energy position in the load resource balance without adding any incremental carbon emissions.
- Finally, PGE's progress toward meeting its clean energy requirement is assessed on the basis of meeting its clean energy development target, rather than specific annual energy production or emissions targets, to address year-to-year fluctuations in load and clean energy output from hydroelectric and other weather-dependent resources.

Several related but discrete policy questions are embedded within this process:

- **Accounting Framework:** Over what time horizon should PGE's clean energy procurement be aligned with its retail sales (e.g. annual, monthly, hourly)? While reporting under ORS 468A.280 is annual, to eliminate emissions associated with serving PGE's customers will likely require more granular alignment.
- **Net Clean Energy:** To the extent PGE produces excess clean energy -- meaning clean energy that would not be needed to meet load but for PGE's emissions cap, given PGE's expectation that it will still be operating its thermal fleet -- how should it be applied toward its climate and clean energy requirements? How should the benefits of energy storage and risk of curtailment be modeled?
- **Thermal Fleet Emissions:** To what extent should the energy and emissions of PGE's thermal fleet be applied to its retail load as specified energy?
- **Unspecified Energy:** Should Oregon Department of Environmental Quality ("ODEQ") revisit the default emissions factor applied to market purchases?

Separate from these analytical questions, PGE also makes several probing references to the emissions rate applied to unspecified market purchases, purchases that are made through bilateral transactions or market purchases (e.g. the California Independent System Operator ("CAISO") Energy Imbalance Market) for energy which is not directly associated with a known resource.

RNW recognizes that some of these policy questions are being reviewed in-depth in Docket No. UM 2273 and provides the following comments in support of contextualizing the broad policy questions in that docket to a specific, in-depth utility CEP. In summary:

- Hourly and operations-based analysis of PGE's emissions will likely be foundational to effective implementation of HB 2021 and should be tracked within the IRP regardless of current ODEQ rules;
- Allocating PGE's thermal generation to non-PGE load runs the risk of becoming effectively an annual offset program that masks on-going reliance on fossil resources and embeds operational risk associated with excess energy;
- Selective retention and exclusion of PGE thermal fleet emissions in its retail load emissions analysis embodies resource shuffling concerns related to Colstrip; and
- Despite a rapidly growing share of clean energy on the western grid, the subset of resources that are unspecified are likely growing dirtier as legacy hydroelectric resources are shifted from unspecified to specified.

Each of these issues, discrete but interrelated, are articulated in further detail in the sections below. While some of these issues -- i.e. hourly granularity -- may not need to be addressed in the 2023 IRP / CEP, all of them would benefit from the company's and the Commission's attention and should likely be addressed in future plans, at a minimum.

a. Decarbonization Planning Requires Sub-Annual Emissions and Clean Energy Analysis and Reporting

PGE's current emissions and clean energy modeling constraint is deployed on an annual basis, limiting the amount of energy available from its resources and market purchases to a defined emissions threshold and backfilling the remainder with clean energy.[40] While this method of analysis is consistent with HB 2021 and ODEQ's rules implementing ORS 468A.280[41], it is also founded on the assumption that megawatt-hours produced throughout the year are fungible products with equivalent climate costs and benefits, traded at the rate of unspecified market purchases. As PGE plans ahead for a deeply decarbonized future, it will be essential for PGE to directly analyze the emissions implications from the operations of its clean energy and thermal resource fleet on a more granular basis to identify integration needs, curtailment risk, and operational emissions.

While PGE has identified improved temporal granularity as an improvement in this IRP cycle, it is unclear to RNW that this initiative included the temporal granularity of emissions reductions.[42] All parties involved in developing and passing HB 2021 agreed that ODEQ's annual reporting paradigm would be an appropriate foundation for ultimately driving emissions out of PGE's system. After all, a 100% emissions reduction target means zero emissions, and zero emission on an annual basis means zero emissions on an hourly basis (provided no netting or offsets are

[40] 2023 CEP/IRP at 96-101.
[41] *See* OAR 340-215.
[42] 2023 CEP/IRP, Appendix I at 530.

permitted). Nevertheless, all parties involved in passing HB 2021 also agreed that getting from 90% to 100% emissions reductions would be challenging and that the path to achieving 100% clean energy is not yet clear. A more temporally granular assessment of emissions within the IRP modeling workflow may help identify the true sticking points in getting to 100%.

In contrast to the relative simplicity of annual emissions accounting, the reality of the situation is far more complex: in any given hour, month, or season, PGE may be long or short on emission-free energy based on the hourly and seasonal patterns of its customers' load shapes and the composition of its resource fleet, a reality that will become far more textured as additional solar, wind, and storage resources are added to its portfolio. As it does today, PGE will manage this textured load-resource balance with its thermal, hydroelectric, and battery storage fleets as well as through transactions with other market participants. In any given hour, PGE may be selling thermal energy, buying unspecified power, or exporting renewable energy – all actions with concrete emissions implications that cannot be reasonably simplified to an annual accounting framework.

In recognition of these complex operating dynamics, PGE's IRP workflow should analyze and report on the emissions associated with serving its load from an operational perspective -- including the emissions from thermal resources needed to meet load. This will require a more specific analysis of PGE's hourly clean energy position, how its thermal fleet would be dispatched to meet short hours, and how its storage fleet would be used to integrate periods of excess renewable resources.

This is in contrast to PGE's current modeling of its thermal fleet operations and renewable curtailment risk, both performed on a region-wide basis within the Aurora PZM model and applied to all portfolios, rather than executed as a modeling analysis specific to each portfolio.[43] As discussed below, the current approach may fail to identify critical operational dynamics which could inform resource planning and risk mitigation in PGE's resource planning process.

b. PGE's Emissions Framework Should Include Expanded Analysis of Overgeneration and Curtailment Risk

As discussed above, PGE's current emissions analysis is performed at an annual level, a method that -- if PGE is permitted to assign thermal generation to non-PGE load -- allows netting clean energy produced in excess renewable periods against thermal generation produced in low-renewable periods. The netting strategy, which PGE permits within its model to meet HB 2021 emissions targets at least until 2039[44], assumes that PGE will have trading partners willing

[43] 2023 CEP/IRP at 96-97, 649-651
[44] 2023 CEP/IRP at 123.

to purchase its excess energy during periods of peak renewable generation in which its clean energy production exceeds its demand and storage charging capability. Specifically, RNW is concerned that PGE's modeling of renewable resource curtailments may not sufficiently assess the risk that the sale of these excess resources may not be feasible if other trading partners in the region are, for similar reasons, long on energy at the same time. While PGE models the risk of curtailment on a regional basis, it does not assess how the risk of curtailment changes either as a function of the portfolio under consideration (i.e. ratio of renewables and storage resources) or as an uncertainty given a range of potential development trajectories for the broader region.

As the grid penetration of wind and solar energy continues to increase, production cost modeling studies will need to be run at the appropriate spatiotemporal resolution in order to fully capture the full extent of curtailment risk for a given portfolio of resources. As already exhibited by CAISO, variable energy resource curtailments in 2022 were 4.4% of the total supply of wind and solar energy generated and continue to increase as more solar and wind facilities come online.[45] Because these curtailment levels are material in the calculation of annual GHG emissions, it's important to adequately account for this risk factor in the GHG reduction strategy. Recognizing this risk, PGE estimates the level of curtailment of wind and solar resources across its portfolio using a WECC-wide pricing model[46], identifying significant resource curtailment during spring months after thermal and hydroelectric resources are ramped down. However, RNW is concerned that PGE's current curtailment methodology may not be sufficient, given the outsized role wind and solar energy will play in both the company's decarbonization plan but the plans of other utilities throughout WECC as well.

To the extent PGE's strategy for offsetting its thermal emissions relies on excess generation during peak renewable generation periods, it is likely that its strategy will conflict with parallel strategies from other utilities, all of which are long on resources during these same correlated periods of high renewable production. Among other examples, utilities in California[47], Nevada[48], and New Mexico[49] anticipate significant excess generation during key solar periods in coming years; this trend is likely to grow with new incentives, declining costs, and tightening climate policies.

Utilities have approached this question in several ways. NV Energy, which uses a similar annual clean energy requirement as is proposed by PGE here, assumes only approximately 1/3 of its

[45] *See* http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.
[46] 2023 CEP/IRP, Appendix N at 649.
[47] California Energy Commission, *2021 SB 100 Joint Agency Report: Achieving 100 Percent Clean Electricity in California: An Initial Assessment* at 76 (Mar. 2021), available at: https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.
[48] NV Energy, 4th Amendment to the 2021 Joint Integrated Energy Resource Plan, Volume I at 158.
[49] PNM 2020-2040 Integrated Resource Plan at 57-59 (Nov. 4, 2021), available at: https://www.pnm.com/documents/28767612/31146374/PNM-2020-2040-IRP-REPORT-corrected-Nov-4-2021.pdf/7f2f46c4-f0a9-b936-715c-4b02e3586ce9?t=1648479305606.

excess energy in excess of retail sales could be effectively utilized, including both charging and export.[50] For California load-serving entities ("LSEs"), an algorithm is embedded in the hourly emissions filing template that assesses the share of energy each LSE may reasonably be assumed to use for storage, export, or curtailment based on the LSE's load and portfolio mix.[51]

Relative to these approaches, PGE's approach appears relatively generous in its curtailment assumptions, and places PGE at risk should the underlying assumptions across WECC change. Further, its modeling workflow does not provide for identification of increased integration needs, such as storage resources or a different portfolio mix, to better align its generation fleet with load in order to mitigate curtailment risk.

Improved analysis and transparency regarding curtailment and overgeneration risk may identify portfolio alternatives that better directly address PGE's emissions and reduce curtailment risk, such as portfolios with higher levels of complementary renewables, long-duration storage, or improved load flexibility. Given the long-lead time to develop these complementary resources, it will be critical to model this dynamic explicitly through improved representation of PGE's load-resource balance.

c. Selective Retention from the Thermal Fleet Raises Resource Shuffling Concerns

As a vertical utility operating in a regional (albeit not integrated) western market, the lines between PGE's roles and responsibilities as a provider of retail energy and as an owner and operator of transmission and generating resources can be difficult to parse, yet they are critically important to PGE's GHG emissions assessment. The mechanics of PGE's Intermediary GHG Model, which attempts to assess the share of emissions from PGE's generating capacity to its retail load, is at the heart of this discussion.

In its 2023 IRP / CEP, PGE introduced the Intermediary GHG Model, a tool for determining the quantity of energy it may allocate to retail customers from its thermal resource and market purchases while remaining in compliance with HB 2021.[52] In sum, PGE pro-rates the energy and associated emissions from its thermal fleet in each year until the emissions are below the requirement established by HB 2021, and 'unspecifies' the remaining energy and emissions as transactions to non-PGE customers. Additionally, emissions for certain resources, notably Colstrip, are pre-adjusted to remove certain categories – energy not wheeled to PGE retail

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[50] NV Energy, 4th Amendment to the 2021 Joint Integrated Energy Resource Plan, Volume I at 157.
[51] California Public Utilities Commission Clean System Power Calculator Documentation at 3-5 (June 6, 2022), available at:
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/clean-system-power-calculator-documentation_beta_060622.docx.
[52] 2023 CEP/IRP at 532.

customers, energy sold into the Energy Imbalance Market, and specified energy sales to California.[53] Following these adjustments, the resource fleet is adjusted pro rata until the emissions target is met.

This issue is particularly impactful because of the expected retention of Colstrip through 2029. Colstrip's emissions rate, 1.00 MT CO2e/MWh, is over twice that of PGE's other resources and the default emissions rate for market purchases[54], 0.428MT CO2e/MWh[55], a number initially developed by the California Air Resources Board to reflect the emissions rate of a reasonably efficient natural gas power plant[56].

This process raises several important policy questions. First, to the extent PGE's thermal resources are needed by PGE retail customers to meet reliability needs, should the emissions associated with providing those reliability services be assigned to PGE customers? If PGE customers pay for the fixed costs of thermal resources that sell power at marginal cost but below average cost, should emissions associated with those resources be assigned to PGE customers? To the extent PGE-owned thermal resources generate emissions that are not assigned to PGE customers, to whom and through what mechanism should they be allocated? These questions may not go to the accounting methodology that HB 2021 requires for assessment of its 80%, 90%, and 100% emission-reduction targets, but the questions are relevant to the Commission's determination of whether PGE's plan is in the public interest, particularly with regard to the statutory public-interest criterion of greenhouse gas emission reductions.[57]

Of these, the question of how to assess the share of emissions that should be 'specified' to PGE retail customers is likely the most significant and most tangible, and should certainly be contemplated in PGE's IRP given its potential for resource shuffling. As an example, under PGE's proposed approach, PGE may operate Colstrip for energy as a sale into the Energy Imbalance Market while simultaneously purchasing energy for retail load through the same market, selling 1.00 MT / MWh energy into the EIM pool while buying back .428 MT / MWh energy from the same pool. Similarly, energy which is produced at Colstrip and not wheeled to Oregon load may be sold bilaterally to another party as a financial hedge against a parallel transaction for energy to serve retail load. These transactions, which appear to be contemplated (or at least not prohibited) within the current framework, would result in PGE shuffling a

[53] 2023 CEP/IRP at 93.
[54] 2023 CEP/IRP at 98.
[55] 2023 CEP/IRP at 98.
[56] Singh, California Air Resources Board, *Imported Electricity in California's Cap-and-Trade Program* at 14 (Sept. 2021), available at: https://www.commerce.wa.gov/wp-content/uploads/2021/09/CARB-slides-CETA-workgroup-September-2021-Final.pdf.
[57] HB 2021, section 5(2)(a).

high-emissions resource into the broader market while purchasing back nominally moderate-emissions power from the same power pool.

Evidence of this type of strategy - which only reduces emissions on paper - may have occurred in PGE's recent Portfolio Analysis Refresh. In the refresh, PGE's higher load forecast required a shift in retained energy and emissions from its thermal fleet to remain compliant with HB 2021. As indicated in Table 4[58], PGE appears to swap the emissions from Beaver, one if its higher-emitting facilities[59], for unspecified market purchases. Specifically, in 2024, reduces retention of Beaver by 34 [MWa?] while increasing unspecified purchases by 39, noting the "changes associated with Beaver … are mostly balanced by market unspecified purchases." To RNW's knowledge, this does not correspond with any changes to Beaver's operations, PGE customers' reliance on Beaver for energy and reliability services, or any other real-world emissions reductions. Rather, it simply represents a reallocation of specified emissions from Beaver into the unspecified pool, while returning a comparable level of energy to PGE customers from the same pool.

In addition to resource shuffling concerns, PGE's current approach may underestimate operating emissions from its resource fleet associated with cycling, ramping, ancillary services, and other operational requirements. Given the role PGE's thermal fleet plays in meeting PGE's net load peaks and flexibility requirements, it will be important to better understand how the fleet will operate based on PGE's future portfolio, and it is unreasonable to assume these emissions should strictly be associated with an unspecified third-party who may be a willing buyer in the future.

To address this risk, PGE should perform hourly operational analysis that identifies the specific resources needed to meet the reliability requirements of PGE's retail load, including energy needs, capacity needs, flexible ramping needs, and other ancillary services. Like PGE's probabilistic reliability modeling, it may be reasonable for PGE to reflect imports and exports in this analysis, but it would not be reasonable for market purchases to displace PGE's owned and contracted resources during hours in which they operate. Likewise, while it is reasonable to assume that PGE's thermal fleet may provide economic exports beyond PGE's native load, it would not be reasonable for PGE to 'assume away' its thermal fleet operations based on a need to shift these resources' emissions out of its portfolio.

d. The Unspecified Emissions Rate Is Not Likely to be Declining

Throughout the IRP / CEP, PGE makes several suggestions that the emissions rate currently applied to market purchases, set by ODEQ at 0.428 MT / MWh[60], should be reconsidered in light

[58] 2023 CEP/IRP Addendum at 12.
[59] 2023 CEP/IRP at 198.
[60] 2023 CEP/IRP at 16, 95, 122, 137.

of the growing share of clean energy resources on the electric grid. This culminates in a sensitivity analysis to determine how modifications to the default emissions rate would shift PGE's total clean energy need.[61] RNW recognizes that the ODEQ value is a simplification of a very complex regional energy market intended to, in one value, represent the emissions associated with energy purchased at many diverse locations at any time throughout the year. The ODEQ unspecified emissions rate, modeled after similar regulatory input used by California Air Resources Board, is intended to represent the "marginal generation that would be needed for an additional MWh of electricity imported to California."[62]

PGE's interest in modifying the unspecified emissions rate appears to be rooted in a belief that the pool of unspecified power is growing cleaner as more solar, wind, and other clean energy resources are added to the regional grid. However, this macro observation fails to recognize significant underlying selection bias between resources that are specified, typically low-emitting resources, and resources that are unspecified, typically high-emitting resources. First, while clean resources are deploying rapidly, nearly all of these clean resources are specified resources – resources for which the offtaker (or another party) is claiming the environmental attributes associated with the resource's energy production. Second, with the proliferation of climate policy into Oregon and Washington, as well as voluntary interest from regional utilities, previously unspecified hydroelectric facilities are being newly specified in the portfolios of utilities and load-serving entities that were previously transacted as unspecified power. Finally, newly emissions-regulated utilities such as PGE are exploring opportunities to 'unspecify' coal resources within their portfolios and shift these into the pool of unspecified resources. This selection bias may be seen firsthand, as discussed above, in PGE's selective retention of its thermal fleet for retail customers in the Intermediary GHG Model.

While PGE is correct that available exports during solar hours are increasing[63], the environmental benefits of these resources have already been specified in their offtakers' respective jurisdictions, and may be being utilized to offset their offtakers' residual fossil emissions. To apply a clean energy emissions rate to these resources would result in a double-counting of their zero-emissions attribute across jurisdictions, meaning that emissions associated with residual fossil operations will be lost in the accounting math. This is not to state a claim about the direct relevance of environmental attributes to the ORS 468A.280 accounting framework, but rather to point out that, in order to carry out the policy of HB 2021, we do not want to lose track of emissions through seams or faulty accounting.

[61] 2023 CEP/IRP at 137.
[62] Singh, California Air Resources Board, *Imported Electricity in California's Cap-and-Trade Program* at 14 (Sept. 2021), available at: https://www.commerce.wa.gov/wp-content/uploads/2021/09/CARB-slides-CETA-workgroup-September-2021-Final.pdf.
[63] 2023 CEP/IRP at 16.

As discussed, RNW appreciates the value of introducing additional temporal granularity into the emissions accounting process – and it may be reasonable to re-evaluate the default emissions rate of unspecified power as part of a broader in-depth analysis of the emissions impacts of PGE's imports and exports. However, at this time, there is limited evidence to indicate that the true unspecified emissions rate is declining, and anecdotal evidence suggesting that the true unspecified emissions rate may be increasing as resources are shifted between specified and unspecified pools.

e. Comparative Analysis with Other Jurisdictions

Major utilities and jurisdictions throughout the west are grappling with these same policy questions. For utilities implementing aggressive decarbonization targets, a rising best practice is to utilize a dispatch-based analysis, in which the utility models how the system operates on an hourly or sub-hourly basis, reflecting thermal operations as well as renewable resource utilization and curtailment explicitly linked to native load. Examples are provided below from other western jurisdictions, including the California Public Utilities Commission ("CPUC"), the Los Angeles Department of Water and Power ("LADWP"), the Sacramento Municipal Utility District ("SMUD"), and PacifiCorp.

The CPUC, which regulates and establishes clean energy procurement requirements for investor-owned utilities, community choice aggregators, and electric service providers serving load in California, executes a systems-level emissions analysis with a binding emissions constraint implemented through a combination of capacity expansion and production cost modeling. The CPUC utilizes RESOLVE, a capacity expansion model, to determine the portfolio of resources necessary to achieve California's reliability, renewable energy, and GHG emissions constraints, and stress tests the emissions limit through the Strategic Energy & Risk Valuation Model (SERVM) model, a production cost model that models resource operations within the CAISO footprint as well as the broader WECC footprint.[64] The CPUC's method is a dispatch-based method that directly assesses a load-serving entity's net dependency on system power, which is a combination of thermal generation -- both natural gas and cogeneration facilities -- and unspecified imports. Any dependency on 'Net System Power' incurs an emission penalty based on defined hourly emission rates. Annually, the emission profile of Net System Power averages ~0.428 tonnes of CO2e per MWh, the same rate used by PGE.[65] The CPUC has required LSEs, as part of their biennial IRP filings, to include hourly load-resource balance

[64] *In re Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes*, CPUC Rulemaking Docket No. 20-05-003, CPUC Decision Adopting 2021 Preferred System Plan at 104 (discussion of GHG analysis in RESOLVE and SERVM), available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M449/K173/449173804.PDF.
[65] CPUC, *Inputs & Assumptions: 2022-2023 Integrated Resource Plan (IRP)* at 157-158 (June 2023), available at; https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/draft_2023_i_and_a.pdf.

showings illustrating their progress towards the state's emissions goals[66], and is in the process of developing a framework to establish clean energy procurement targets calibrated using the dispatch-based analysis.[67]

While the CPUC approach is similar in concept to the approach utilized by PGE, which also incorporates both capacity expansion and production cost modeling, the application of the binding emissions constraint is very different. PGE's approach to emissions, as discussed above, simply analyzes PGE's annual energy needs, without explicit modeling of thermal operational requirements, storage operations, or renewable resource utilization, export, or curtailment. While thermal resource operations and renewable curtailment are modeled at a high-level through PGE's WECC-wide Aurora model, these operations are not analyzed with an explicit linkage to PGE's native load or how each portfolio's renewable output and integration solutions aligns with PGE's retail needs. Moreover, as discussed, PGE's method may permit the reshuffling of higher-emissions coal generation into the pool of unspecified resources while withdrawing (perhaps simultaneously) ostensibly lower-emissions generation from the same pool of resources. This approach fails to capture key operational dynamics and risks associated with meeting PGE's long-term emissions requirement.

LADWP and SMUD, California's two largest municipal utilities, both applied an hourly, dispatch-based emissions framework in recent studies informing their long-term resource plans. LADWP's 2022 Strategic Long-Term Resource Plan assesses the operations of its resource fleet needed to serve native load as an islanded system, with direct, dispatch-based analysis of thermal fleet emissions and renewable resource curtailment risk.[68] Similar to LADWP's approach, SMUD uses an hourly, dispatch-based accounting methodology which directly assesses the emissions from its thermal fleet (tied to its native load) and applies the same default emissions as PGE to its imports and exports to CAISO.[69]

In contrast to PGE, LADWP and SMUD's methods attempt to directly measure the relationship between their customers' load and reliability requirements with their retail portfolios, serving

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[66] CPUC, *CPUC Fact Sheet on Clean Net Short Emissions Intensities from the RESOLVE Model Used in Integrated Resource Planning* (June 2018), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/utilitiesindustries/energy/energyprograms/electpowerprocurementgeneration/irp/2018/cpuc-fact-sheet-on-cns-emissions-intensities-for-irp.pdf.
[67] CPUC Energy Division, *Staff Options Paper for the Reliable and Clean Power Procurement Program* at 24-27 (Sept. 2022), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/procurement-program-staff-options-paper_09122022.pdf.
[68] LADWP, *Power Strategic Long-Term Resource Plan 2022* at 4-60 through 4-65 (2022), available at: https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB794970&RevisionSelectionMethod=LatestReleased.
[69] SMUD, *2030 Zero Carbon Plan* at 63 (Apr. 2021), available at: https://www.smud.org/-/media/Documents/Corporate/Environmental-Leadership/ZeroCarbon/2030-Zero-Carbon-Plan-Technical-Report.ashx.

their customers' needs first with clean energy, then with their thermal fleet, and (for SMUD only) with unspecified market purchases. This approach ensures the modeling workflow accounts for customers' real, temporally-specific needs (peaking, ramping, etc.) and also eliminates opportunities for the utility to shuffle unwanted, high-emissions resources out of the customer portfolio. In doing so, the approach is more robust and is likely to lead to better insights and strategic decision-making for long-term planning.

E. Planning for 2040

RNW appreciates the strong focus within PGE's IRP on achieving Oregon's rapidly approaching 2030 climate target, and commends the resource procurement, transmission development, and community programs articulated in PGE's action plan.[70] RNW also appreciates PGE's intent to articulate some of the challenges and necessary actions to achieve the 2040 policy requirement of eliminating greenhouse gas emissions associated with serving Oregon retail electricity consumers, including its discussion of post-2030 resource options. However, in this and future IRP cycles, RNW encourages PGE and the Commission to center the long-term transformation to a decarbonized grid, a project which must be completed under Oregon law in 17 years.

a. Integrating Policy Requirements into the Planning Framework

To achieve this end, it will be critical for PGE's planning process to evolve such that the full range of today's fossil resource needs are smoothly transitioned out of the portfolio over time, including hourly energy needs, capacity, flexibility, and ancillary services. Currently, PGE's transitional focus is on the clean energy requirement needed to offset PGE's fossil fleet on an annual basis, as discussed above, as well the removal of Colstrip in 2030 and the removal of remaining gas resources in 2040.

The impact of this stepwise transition in 2040, visualized in PGE's Figure 45[71], reflects the importance of incorporating planning frameworks that will remove the need for fossil resources in an orderly manner. Under the current planning framework, resource exits in 2030 and 2040 result in significant (1-3GW) increases in PGE's net capacity need. While RNW recognizes that PGE is not indicating literally that it intends to replace 2GW of gas capacity in the year 2040 (approximately half of its peak load) [72], it is critical to recognize that the deadline to remove these resources is fast approaching and significant efforts will be required to develop clean replacement resources over the next decade.

[70] 2023 IRP/CEP at 302-12, Chapter 12 Action Plan.
[71] 2023 IRP/CEP at 126.
[72] 2023 IRP/CEP at 194, 285.

In addition to specific recommendations regarding long-lead resources discussed in the offshore wind section below, RNW has three recommendations to ensure the transition is embedded in the planning process. First, PGE should adopt an hourly or systems-level analysis of its emissions target, as discussed in Section 2, which will better align PGE's clean energy resource investments with its customer load. Second, PGE should incorporate a clean capacity glidepath within its capacity expansion model that prevents the risk of 'hockey stick' transitions at critical milestones. Third, PGE should analyze the ancillary services role currently served by its thermal fleet and identify the investments necessary to reduce reliance on thermal resources for voltage, frequency, inertia, and other power flow requirements.

b. PGE Appropriately Identifies Transmission as a Significant Need, but More Robust Analysis Is Likely Necessary To Support Immediate Actions

RNW appreciates PGE's acknowledgement that "the identification and development of transmission solutions are long lead activities that often take longer than the Action Plan window…" and that "it is necessary to engage in transmission planning and development on a forward-looking basis beyond the Action Plan window."[73] However, given the IRP has identified a need of 905 MW of non-emitting energy and 1,136 MW of capacity needs by 2030 – less than seven years from today – and considering transmission projects may take a double-digit number of years to develop, we encourage PGE to consider its projected transmission needs in finer detail than is outlined in the IRP. PGE points to a number of studies being conducted by NorthernGrid and the Western Power Pool ("WPP") to better understand regional transmission forecasts, but we would appreciate a more detailed analysis of PGE's transmission needs and creative solutions considering the company is attempting to wean off its reliance on Bonneville Power Administration ("BPA") transmission. This recommendation is further colored by the offshore wind section below, which discusses how PGE will need to take concrete steps now to meet its post-2030 needs, and those steps should be informed by robust analysis.

Also later in these comments we discuss the analysis by Grid Strategies regarding PGE's treatment of conditional firm transmission services. The findings indicate that a more detailed look at PGE's hours of curtailment may allow for more innovative solutions to transmission congestion, some of which are discussed in more detail in the analysis. Along the same lines, PGE should be actively pursuing non-wires alternatives including grid-enhancing technologies ("GETs") to provide congestion relief while longer-lead transmission projects are under development. GETs, including dynamic line ratings ("DLR"), power flow controllers ("PFCs"), and topology optimization, improve the real-time operation of the system and increase grid resilience and reliability. A 2022 study released by the U.S. Department of Energy found that the deployment of GETs on a region in NYISO produced an annual avoided curtailment savings

[73] 2023 IRP/CEP at 217.

ranging from $1.7 million to $9.1 million, depending on the technology deployed.[74] Another study conducted by the Brattle Group found that the use of GETs could enable Kansas and Oklahoma – two of the most wind-rich states in the U.S. – to integrate more than double the renewable energy generation possible without the technologies.[75] We encourage PGE to take proactive steps to better understand how these technologies can relieve the company's potential mid-term congestion issues.

RNW also recommends that PGE consider merchant transmission projects as it works to develop a more concrete assessment of its transmission needs and a related action plan. Merchant projects such as the Cascade Renewable Transmission System, a proposed 320-kV high-voltage transmission line currently under review by the Oregon Department of Energy,[76] can help address a number of the transmission planning constraints the company outlines while facilitating the integration of diversified non-emitting resources.

c. Post-2030 Resource Set

The next section of these Round 1 Comments features an extensive discussion of potential post-2030 resources, focused on offshore wind but including other considerations as well. We offer specific recommendations for an updated preferred portfolio, but perhaps the greater takeaway is the likely need for near-term actions to enable post-2030 resources.

F. Post-2030 Resources and Offshore Wind

a. Summary Regarding Post-2030 Resources and Offshore Wind

The IRP's preferred portfolio does not represent the least cost, least risk portfolio with respect to offshore wind and long-lead time resources. Regarding offshore wind and long-lead time resources, RNW recommends that the Commission conditionally acknowledge PGE's preferred portfolio with the following modification and one additional directive:

1. The preferred portfolio should be modified and acknowledged to reflect that the least cost, least risk solution to achieving PGE's resource needs and carbon targets involves at least 2 GW of offshore wind, as reflected in the portfolio summarized in Attachment A, but likely more than 2 GW as presented in Attachment A to these comments.[77]

[74] U.S. Department of Energy, *National Transmission Needs Study* at 76 (Feb. 2023), available at: https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.
[75] The Brattle Group, *Unlocking the Queue with Grid-Enhancing Technologies* (Feb. 2021), available at: https://watt-transmission.org/unlocking-the-queue/.
[76] *See, e.g.*, Oregon Department of Energy, *Cascade Renewable Transmission System* (accessed July 26, 2023), available at: https://www.oregon.gov/energy/facilities-safety/facilities/Pages/CRT.aspx.
[77] In the alternative to modifying and acknowledging the preferred portfolio, the Commission should not acknowledge PGE's preferred portfolio, and direct PGE to refile its preferred portfolio within six months to more accurately model offshore wind and other resources per the recommendations in these comments.

2. Offshore wind, extended interregional transmission, and other resources have long development periods. PGE's transmission action items only enable a subset of the least cost, least risk long-lead time resources. PGE's action items should be broadened to include an all-source long-lead time request for proposals ("RFP") and PGE should be directed to develop and issue a long-lead time RFP in late 2025.

i. PGE's Preferred Portfolio Should Include At Least 1 GW of Offshore Wind

PGE's preferred portfolio is the result of multiple resource constraints and forced resource additions that prevent it from selecting the least cost, least risk portfolio that has the best combination of cost and risk. The constraints underlying the preferred portfolio include limits on long duration battery storage, offshore wind, Nevada solar, and Wyoming wind. When these constraints are lifted PGE's capacity expansion model selects a mixture of offshore wind and other resources. Offshore wind is selected as an economic resource in *every price, technology, and hydro condition*. This remains true when the assumed cost of offshore wind is increased to be 50 percent above industry expectations, which is not realistic as the costs of offshore wind are expected to decline rather than increase.

PGE's preferred portfolio has an expected net present value revenue requirement ("NPVRR") of $37.4 billion.[78] The least cost, least risk portfolio that PGE's model identifies when resource constraints are removed includes a mixture of offshore wind and other non-emitting resources and has a net present value of $26.5 billion. PGE's preferred portfolio costs $10.9 billion more than the least cost, least risk portfolio, a premium of 40 percent. PGE's preferred portfolio is costly because it relies on "generic" resources rather than specific resources. Because PGE's portfolio consists of generic resources, PGE's proposed action plan will not lead to a least cost, least risk outcome for PGE's customers.

ii. PGE Should Issue a Long-Lead Time RFP

PGE's own offshore wind analysis shows that offshore wind is economic and that the earlier the availability of offshore wind, the greater the benefits.[79] Because offshore wind has a long development time, action must be taken now to secure these benefits. However, PGE's action plan includes acquisition of only a single long lead resource, transmission. This action should be complemented with an additional action item to issue a long-lead time RFP in late 2025.

Issuing an RFP serves two functions. First, it provides a signal to developers that PGE recognizes the potential value of long lead resources. This signal will help PGE to retain the option of securing long lead resources on a time horizon that is most economic. If the Commission waits to send this signal until PGE's next IRP, then developers may not take the necessary actions today to ensure that these resources are available as early as possible. Taking action now is also important because the value of offshore wind increases when it is acquired in

[78] PGE's 2023 CEP/IRP Addendum finds the preferred portfolio costs $36.96 billion. However, in our modeling we found it appropriate to add $58.80 per kW-year to the cost of offshore wind and pumped hydro storage. These changes increased the cost of the preferred portfolio to $37.4 billion.
[79] PGE's response to RNW DR 001 Attachments A and B (Attachment B).

early years relative to later years. This means that to obtain maximum value from this resource PGE should begin the acquisition process as early as possible because offshore wind has a relatively long lead time.

Second, the RFP will set the stage for PGE to appropriately allocate resources between transmission and generation. PGE's models and our analysis show that offshore wind offsets the need for transmission access to remote regions such as Nevada and Wyoming. PGE is in the process of securing transmission access to these regions. While some transmission access may be appropriate, PGE will not have sufficient information to quantify the amount of eastern transmission to acquire without properly pricing offshore wind through an RFP. PGE should use the results of the long-lead time RFP as part of its transmission planning process. This is consistent with CAISO's recent long term planning process that included analysis of transmission needs for integrating 21 GW of offshore wind in California.[80]

The Commission should not wait for the conclusion of other proceedings to require PGE to issue a long-lead time RFP. The Commission is engaged in other regulatory proceedings evaluating whether and what regulatory changes may be necessary to meet Oregon's carbon reduction mandates, and will take up potential revisions to the integrated resource planning and procurement processes sometime in 2024, if not earlier.[81] Modest changes are already underway, including ensuring harmony and consistency between clean energy plans and integrated resource planning, and PGE simultaneously processing its current RFP and IRP.[82] The Commission may need to change its traditional approach to resource procurement to be more involved in procurement decisions to provide more certainty to developers and help Oregon reach its 2040 emissions targets.

RNW's recommendation provides a first step towards aligning PGE's procurement process with the challenges of achieving Oregon's emissions targets. The Commission may not need to radically alter its current regulatory processes and paradigms to allow least cost and least risk long-lead time resources to help meet PGE and other utilities' energy and capacity needs in the early 2030s.

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[80] CISO, *2021-2022 Transmission Plan* (Mar. 17, 2022), available at: http://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf; CAISO, *20 Year Transmission Outlook* (May 2022), available at: http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

[81] *In re Investigation into House Bill (HB) 2021 Implementation Issues*, Docket No. UM 2273, Order No. 23-194 at 9 (June 5, 2023) ("One area of work anticipated for 2024 is planning and procurement procedures. This potentially includes, among other things, evaluating ways to streamline and modernize planning and procurement rules to reflect today's context and the needs of HB 2021; incorporating small-scale and community-based renewable energy procurement; maintaining or improving opportunities for competition; and revising administrative rules to incorporate modernized IRP guidelines that address HB 2021 and the Climate Protection Program.").

[82] *See In re PGE Request for Waiver of 2023 RFP Process*, Docket No. UM 2274, Order No. 23-146, Appendix A at 8-12 (Apr. 21, 2023).

b. Offshore Wind Is a Least Cost Resource for PGE

Oregon sited offshore wind is a least cost resource for meeting PGE's mandatory greenhouse gas emission-reduction targets. The net present value of portfolios that include offshore wind is lower than that of portfolios without offshore wind. We determined this by reviewing PGE's offshore wind study and by using PGE's cost models to evaluate a variety of portfolios and cost assumptions, including cost assumptions with conservatively high estimates of offshore wind costs. Every variant that we analyzed showed offshore wind to be least cost. We found that offshore wind displaces onshore wind, solar, remote market transmission, storage, and generic capacity and energy resources. This outcome is reasonable when considered in light of the unique properties of offshore wind. Namely that its diversity in generation relative to other Pacific Northwest resources brings high value to PGE without excessive transmission construction and line loss costs.[83]

i. PGE's IRP Does Not Test the Economic Value of Offshore Wind

PGE's preferred portfolio meets resource needs after 2030 through "generic capacity" and "generic energy" resources. These resources are selected because all other resources are either directly prevented from being selected,[84] or indirectly prevented from being selected by limiting transmission expansion.[85] These limits have the practical impact of converting a 20 year portfolio analysis into a 7 year portfolio analysis because no information or conclusions are made regarding what types of resources are economic to acquire after 2030.[86] Given the complexity of meeting PGE's mandatory greenhouse gas emission-reduction targets, PGE should move toward more comprehensive analysis of the out years of the IRP rather than more general analysis.[87]

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[83] PGE's 2023 CEP/IRP Appendix J shows Offshore Effective Load Carrying Capability of offshore wind exceeds all non-storage renewable resources in the summer and exceeds nearly all non-storage renewable resources in the winter. Wyoming Wind, which marginally exceeds the Winter ELCC of Offshore Wind, has transmission costs of $435 per kW-year relative to Offshore wind's transmission cost of $58.80 per kW-year. *See* "fixed_cost_futures.txt" in PGE's response to AWEC DR 039 Attachment B (Attachment B).

[84] PGE's response to OPUC DR 7 Attachment A "2023 IRP final inputs\p_40\max_build.txt" (Attachment B) shows that offshore wind, pumped hydro, 24 hour battery storage, and hydrogen have a maximum build quantity of 0 MW in every year for every future. "2023 IRP final inputs\default\potential.txt" shows that 2-, 6-, 8-, and 16- hour batteries have maximum total build quantity of 0 across all years (Attachment B).

[85] PGE's response to AWEC DR 13 Attachment A file "LC 80_AWEC DR 013_Attach A.gms" (Attachment B) constraints the sum of new gorge wind, Montana wind, southeast Washington wind, Christmas valley solar, McMinnville solar, Wasco solar, and corresponding hybrid facilities are restricted to total incremental South of Alston transmission. The same file shows that Nevada solar is constrained to incremental Nevada transmission and Wyoming solar is constrained to incremental Wyoming transmission. PGE's response to OPUC DR 7 Attachment A (Attachment B) "2023 IRP final inputs\default\potential.txt" shows that these incremental transmission on these three paths are constrained to 400 MW each. Most of this transmission and the associated resources are built out prior to 2030 in PGE's preferred portfolio.

[86] PGE's 2023 CEP/IRP page 37 table 3 shows resource additions post 2030. The only material additions are "Solar and Wind", and "Capacity". These are the "Generic Energy" and "Generic Capacity" resources respectively. *See* PGE's response to OPUC DR 7 Attachment B referencing "2023 IRP final inputs\p_40\new_resources.txt" (Attachment B).

[87] The Commission's planning guidelines require a 20-year planning horizon. *See* Docket No. UM 1056, Order No. 07-047, Appendix A at 2. For this guideline to be satisfied the preferred portfolio should include specific resources.

Furthermore, the comparator portfolios[88] that the preferred portfolio was evaluated against prevented access to two key low cost resources, Wyoming wind and Nevada solar.[89] Because all comparator portfolios excluded these two key resources, the costs and risks associated with all of PGE's comparator portfolios are artificially increased so that they appear to have greater cost than PGE's preferred portfolio.[90] When PGE's resource constraints are relaxed to optimally select offshore wind, long duration storage, and transmission access, PGE's capacity expansion model ROSE-E replaces generic capacity and energy resources with a mixture of specific storage and variable energy resources, including offshore wind. Removing these constraints results in the acquisition of 3 GW of offshore wind.[91] PGE's IRP does not provide a reasonable evaluation of the economic value of offshore wind because PGE did not evaluate it under an appropriate and comparable set of conditions. Additionally, PGE did not comply with IRP Guideline 1 to evaluate all resources on a consistent and comparable basis with consistent assumptions and methods.

PGE's IRP analysis of offshore wind is reported in Figure 100.[92] This figure compares offshore wind against a set of "emerging technologies" and shows that offshore wind results in the lowest cost portfolio among the different technologies that are considered. The cost of the emerging technology offshore wind portfolio is $39 billion,[93] which is higher than PGE's proposed preferred portfolio, at $37 billion. A cursory review of this result therefore suggests that, while offshore wind is the most economic "emerging technology" resource, it is less economic than the resource in the preferred portfolio. However, this conclusion is incorrect because PGE's emerging technology portfolios did not allow for the selection of transmission assets.

When PGE's capacity expansion model is re-run using identical inputs to the preferred portfolio, but modified to allow for the selection of offshore wind, the model selects 3 GW of offshore wind.[94] PGE did not need to create a specific offshore wind portfolio, but only needed to allow the model to run without constraints. Removing only the offshore wind constraint from the set of assumptions used to develop the preferred portfolio results in a net present value revenue requirement of $29 billion.[95]

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[88] A comparator portfolio is an alternative portfolio used to evaluate relative cost and risk.
[89] PGE's response to OPUC DR 7 Attachment A "2023 IRP final inputs\default\ max_build.txt" (Attachment B).
[90] 2023 CEP/IRP section 11.4 Portfolio Analysis.
[91] Attachment A.
[92] 2023 CEP/IRP at 286.
[93] Based on PGE's response to AWEC DR 039 (Attachment B) which updates the wind sensitivity to be consistent with the addendum.
[94] *See* Attachment A. For consistency across portfolios this model adds $58.80 per kW-year in transmission cost to offshore wind and pumped hydro storage.
[95] This model included revisions to transmission costs. When similar changes are made to PGE's preferred portfolio it costs $37.4 billion. Removing additional constraints on Nevada and Wyoming resources reduces the NPVRR further to $26.5 billion.

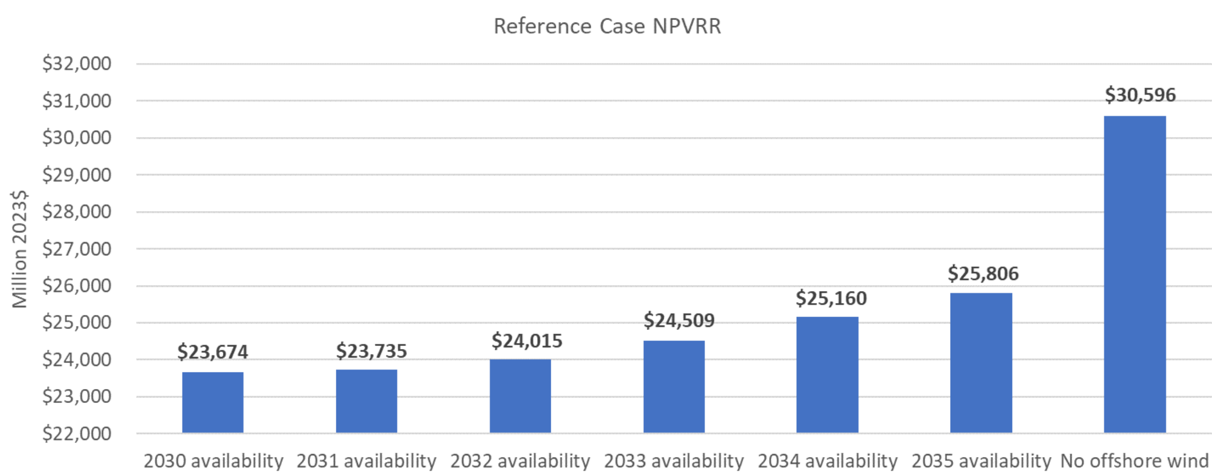
ii. PGE's Post IRP Analysis Shows Benefits of Offshore Wind Increases for Earlier Acquisitions

PGE performed analysis outside the IRP that demonstrates portfolios with offshore wind are more economic than PGE's preferred portfolio and that the benefits of offshore wind increase with earlier acquisition.

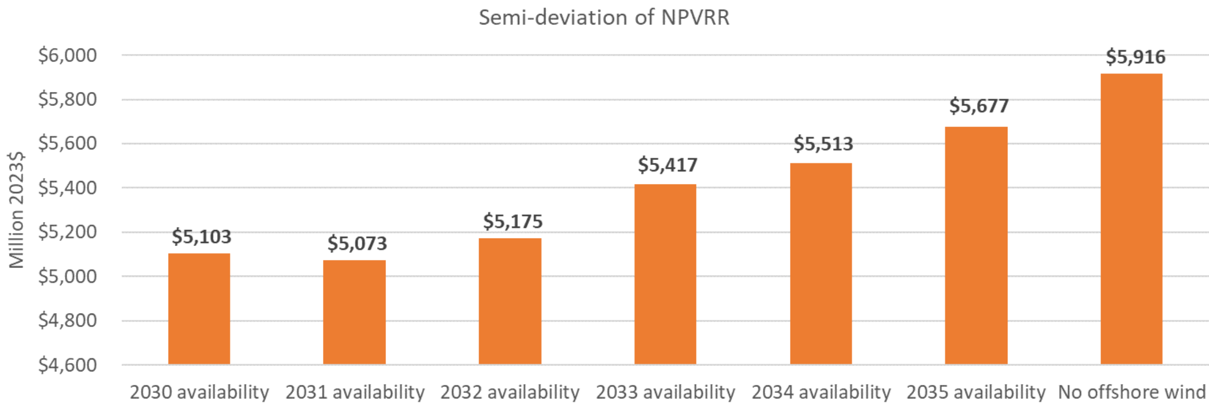
The Oregon Department of Energy ("ODOE") requested that PGE perform a number of sensitivities to evaluate the potential value of offshore wind.[96] PGE responded to ODOE's request by allowing the ROSE-E model to select an optimal amount of offshore wind additions.[97] PGE included assumptions and constraints similar to those used in the preferred portfolio, but with the following key modifications:

1. In the preferred portfolio constraints offshore wind was not an available resource addition while in the ODOE models offshore wind could be optimally selected by ROSE-E.
2. In the ODOE study the cost of selecting offshore wind was increased from the level used in PGE's offshore wind study by $58.80 per kW-year for every year and vintage. This increase was to account for the cost of transmission necessary to receive energy from Oregon's offshore wind resources off the southern coast of Oregon.
3. The first year of availability was varied between 2030 and 2035 to test the impact of timing on resource selection.[98]

PGE found that even with the added cost of transmission, the ODOE offshore wind portfolios were more economic than PGE's preferred portfolio, as shown in the table below.[99]



[96] PGE's response to RNW DR 001 Attachment A at 2 (Attachment B).
[97] PGE's response to RNW DR 001 Attachment B at 3 (Attachment B).
[98] PGE's response to RNW DR 001 Attachment B at 3 (Attachment B).
[99] PGE's response to RNW DR 001 Attachment B at 9 (Attachment B).



All six variants of the ODOE wind studies showed offshore wind to be significantly less costly and less risky than PGE's preferred portfolio. The variants also show that the lowest cost resource is associated with a 2030 acquisition date and costs increase monotonically with the first year of availability.

PGE's summary of these results is cautious and offers the following conclusion regarding offshore wind:

> In the transmission-constrained system modeled in this analysis, after the available Tx capacity is fully utilized, offshore wind is competing economically only against the high-cost generic resources. Large additions of offshore wind reveal that it is generally a more cost-effective source of energy than the generic VER. Results show that offshore wind has the potential to fill a substantial part of the GHG-free energy need in the post-2030 time-horizon. However, other technologies may emerge to compete to fill that role and there is substantial uncertainty about the relative rate at which these technologies will develop technologically and economically. There is also uncertainty regarding the cost projections used for offshore wind in this study given that there is no offshore wind development in Oregon today. This study does not compare offshore wind to other emerging technologies like hydrogen, small modular nuclear reactors, long duration storage, enhanced power markets, and others. Because of the substantial uncertainty associated with the cost, availability and performance of emerging technologies, PGE conducted a detailed qualitative review of a variety of emerging technologies, in addition to the emerging technologies portfolio group analysis.[100]

PGE appears to have the following reasons for proposing a preferred portfolio with generic resources rather than offshore wind:

1. In PGE's ODOE models offshore wind is the only unconstrained resource other than "generic" resources.

[100] PGE's response to RNW DR 001 Attachment B at 4 (Attachment B).

2. Cost for offshore wind and offshore wind enabling transmission are uncertain.
3. Oregon has no offshore wind facilities in operation.
4. Offshore wind needs to be tested and compared against other technologies.

PGE's caution regarding other emerging technologies and cost uncertainties warrants consideration. However, consideration of these issues shows that offshore wind remains a least cost, least risk resource.

iii. Offshore Wind Is Competitive Against a Variety of Resources

PGE asserts that "after the available [transmission] capacity is fully utilized, offshore wind is competing economically only against the high-cost generic resources." However, this misrepresents the economic value of offshore wind. PGE's observation is that, in the ODOE models, when all other resources are constrained and the only options are offshore wind and generic resources, offshore wind is found to be economic. This finding by itself is supportive of offshore wind but not particularly interesting or relevant. What is more relevant and interesting is whether offshore wind is selected when other non-generic resources, such as pumped hydro storage or other variable energy resources ("VER") are available for selection. The table below shows the reduction in certain proxy resources for RNW's proposed preferred portfolio when offshore wind is added as a resource option. This table shows that offshore wind displaces non-generic resources such as southwest solar and Wyoming wind.

Figure 2

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Offshore Wind	244	479	728	974	1263	1645	1965	2290	2491	2824	3000	3000
Generic Capacity	0	0	0	0	-61	-57	-81	-81	-81	-81	-81	-81
Nevada Solar	104	47	-33	-141	-75	-75	-75	-75	-100	-100	-100	-100
Wyoming Wind	-381	-633	-887	-1117	-1527	-2002	-2401	-2807	-3043	-3456	-3675	-3675

iv. While PGE's Cost Assumptions for Offshore Wind and Offshore Wind Transmission are Conservatively High, the Least Cost and Least Risk Selection of Offshore Wind Is Not Sensitive to Transmission or Capital Expenditure Costs

One caveat that PGE has offered with respect to offshore wind is that capital costs are uncertain. However, the costs included in the IRP for commercial operation dates after 2030 PGE are conservatively high. Thus, cost risk is primarily upside risk, meaning that wind costs are likely to be less than modeled, which is favorable for offshore wind. However, even if offshore wind is 50 percent more costly than PGE assumes, the ROSE-E model still selects a material amount of offshore wind as economic. The table below illustrates the impact of removing constraints on offshore wind in ROSE-E when $58.80 per kW-year in transmission costs are added to PGE's original price curves and the combined amounts are scaled up by 50 percent.

Figure 3

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Offshore Wind	244	479	722	918	1166	1548	1869	2194	2194	2527	2702	2858
Generic Capacit	0	0	0	0	-127	-124	-127	-127	-127	-127	-127	-127
Wyoming Wind	-307	-558	-812	-1042	-1452	-1927	-2326	-2732	-2672	-3084	-3304	-3498
Nevada Solar	0	-58	-126	-148	-11	-11	-11	-11	-100	-100	-100	-100

PGE's estimated levelized cost of energy for offshore wind with a COD of 2030 is $71 per MWh.[101] However, the NREL estimate of the levelized cost of energy for offshore wind in southern Oregon is much lower, at $51 per MWh for a COD of 2032.[102] NREL's cost estimates form the basis for PGE's offshore wind assumptions.[103] However, PGE appears to not be fully accounting for all the factors considered by NREL, such as either the geographic specificity of southern Oregon or the changes in cost over time. NREL's cost estimates were generated prior to the announcement of the Offshore Wind Shot, a recent initiative by the US Department of Energy to reduce the cost of offshore wind by more than 70 percent by 2035.[104]

PGE's transmission cost assumptions also appear to be relatively high and conservative. NorthernGrid has recently issued a study of the cost to deliver 3 GW of offshore wind to load centers.[105] The study found that 3GW of wind could be integrated into the existing system with a capital investment ranging from $820 to $1,231 million.[106] This translates to a levelized cost of $18 to $27 per kW-year.[107] PGE's ODOE studies assume transmission costs of $58.80 per kW-year.[108] PGE's estimate is a generic estimate based on mileage rather than a targeted transmission study such as the one performed by NorthernGrid. Thus, cost risk associated with transmission is primarily another upside risk that favors the selection of offshore wind.

While PGE's offshore wind cost assumptions are conservatively high, it is reasonable to evaluate the sensitivity of offshore wind economics to increased costs. The sensitivity of offshore wind to capital costs was evaluated by generating a portfolio under the assumption that offshore wind and transmission costs 50 percent more than PGE's base assumption, without modifying costs of other resources.

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[101] PGE's response to RNW DR 001 Attachment B page 2 (Attachment B).
[102] Walt Musial et al., NREL, *Updated Oregon Floating Offshore Wind Cost Modeling* at 30 (Sept. 24, 2021), available at: https://www.nrel.gov/docs/fy22osti/80908.pdf.
[103] PGE's 2021 IRP at footnote 220.
[104] *See* U.S. Department of Energy, *Floating Offshore Wind Shot* (accessed July 26, 2023), available at: https://www.energy.gov/eere/wind/floating-offshore-wind-shot.
[105] NorthernGrid, *NorthernGrid Economic Study Request Offshore Wind in Oregon* (2023), available at: https://www.northerngrid.net/private-media/documents/DraftforPostingNGESROSW.pdf (Attachment C).
[106] *NorthernGrid Economic Study Request Offshore Wind in Oregon* at 9 (Attachment C).
[107] This levelized cost assumes a depreciable life of 75 years, cost of equity of 10%, cost of debt of 4%, equity ratio of 50%, tax rate of 31 percent, property tax rate of 1.5%, and no book tax difference.
[108] PGE's response to RNW DR 001 Attachment B at 3 (Attachment B).

Even under this aggressive and unlikely price curve, which greatly exceeds the expected cost of offshore wind, the ROSE-E model selects 244 MW of offshore wind in 2032 and adds 2.9 GW of offshore wind by 2043.[109]

v. Offshore Wind Is an Established Technology that Is Viable in Oregon

PGE has characterized offshore wind as an emerging technology and raises specific concern with floating offshore wind.[110] However, offshore wind is relatively mature globally, and the floating substructures expected for use in Oregon have evolved from the platforms that have a long history of use in the oil and gas industry. Globally, there are over 200 MW of floating offshore wind operating today; however, with the de-risking of floating offshore wind technology that has been underway for over a decade, we anticipate a significant ramping up in global floating offshore wind deployments in the short- and long-term. In 2022, U.S. Department of Energy projected that over 8 GW of floating offshore wind will be deployed by 2027, with 264 GW of deployment by 2050.[111] There is significant capital ready to make investments in Oregon, and what could hold it back is not technological risk, but the risk of not having a viable purchaser. It is unreasonable to equate this technology with hydrogen peaking facilities, modular nuclear, or "generic capacity".

vi. Offshore Wind Can Be Tested Against Other Technologies

PGE appropriately notes that there is uncertainty associated with costs and offshore wind has not yet been compared to other emerging technologies like hydrogen, small modular nuclear reactors, long duration storage, enhanced power markets, and others. As explained in Section II(F)(c) below, now is the time to test offshore wind against other technologies with a long-lead time RFP.

vii. PGE's Reliance on "Generic" Resources Disadvantages Long-Lead Time Resources

PGE's preferred portfolio is heavily reliant on generic resources. PGE's portfolio begins selecting "generic capacity" and "generic energy" in 2035 and 2032 respectively and includes a total of 2,470 and 3,801 MW by 2043. PGE appears to prefer presenting this need as generic rather than highlighting specific least cost resources. PGE presents generic resources as resources that require transmission access, and PGE relies on the IRP's selection of generic resources to support transmission action items.[112] This is problematic because transmission is not generic, it is specific.

It is certainly likely that transmission will play an important role in achieving PGE's emission targets. However, PGE has not demonstrated which transmission projects are most economic

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[109] Attachment A.
[110] The geography of Oregon's coast is such that floating platforms will likely be used for most offshore wind developments.
[111] U.S. Department of Energy, *Offshore Wind Market Report: 2022 Edition* (Aug. 16, 2022), available at: https://www.energy.gov/eere/wind/articles/offshore-wind-market-report-2022-edition.
[112] 2023 CEP/IRP at 270.

because PGE has not demonstrated which VER regions or technologies are most economic. PGE's action plan includes the acquisition of transmission capacity at South of Alston ("SoA") and upgrading the Bethel to Round Butte transmission line. These transmission upgrades enable resources in specific regions and thus favor development of resources in these specific regions. Oregon offshore wind is a viable alternative to SoA and Bethel to Round Butte because its energy can be delivered to Portland without these specific transmission upgrades. By focusing on generic resources, PGE has failed to develop an economic basis for favoring transmission to one region over another. Conversely, making decisions to invest in substantial transmission now may result in sunk costs that bias the results of future RFPs and IRPs in favor of more costly and risky procurements simply because the sunk costs cannot be recouped.

In addition to transmission, by characterizing resources as "Generic," PGE is failing to send appropriate signals to developers of long-lead time resources. Long-lead time resources need signals now for development if Oregon is going to meet its 100 percent clean energy goals in the least cost, least risk manner. If the Commission and utilities wait too long to send these signals to developers, then PGE would need to invest in these "Generic" resources, which as explained above are more expensive than developing long-lead time resources such as offshore wind, long duration storage, pumped hydro, and more tailored transmission.

viii. PGE's Least Cost, Least Risk Portfolio Includes Offshore Wind and Other Specific Resources

The Commission should approve an action plan based on a portfolio with specific resources rather than generic resources. The use of specific resources is important to provide proper signals to developers, to appropriately select transmission options, and to allow for economic decisions when evaluating the results of RFPs. This can be accomplished by approving a portfolio that is developed with a more reasonable set of resource restrictions than the ones used for the preferred portfolio. Attachment A contains the portfolio that RNW recommends be supported by the Commission. This portfolio was developed using PGE's ROSE-E model and default addendum model assumptions with the following adjustments:

1. Allow a maximum of 3000 MW across all study years for the following resources:
    a. Offshore wind,
    b. Wyoming transmission, and
    c. Nevada transmission.
2. No restrictions on annual maximum annual build file (max_build.txt) for the following resources and years:
    a. Offshore wind from 2032 to 2043,
    b. Wyoming transmission from 2026 to 2043, and
    c. Nevada transmission from 2026 to 2043.

3. Add a $58.80 per kW-year in transmission costs for offshore wind and pumped hydro storage,[113] and
4. Modify the capacity contribution of market transmission to reflect the IRP's ELCC findings.

The post 2032 buildout of this portfolio is summarized below.

Figure 4

Year	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
4 Hour Battery	0	100	200	300	400	500	600	700	800	800	800	800
Pumped Hydro Storage	0	0	0	0	0	0	0	0	2000	2000	2000	2000
CV Hyb	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Gorge Wind	778	778	778	778	778	778	778	778	778	778	778	778
SEWA Wind	150	150	150	150	150	150	150	150	150	150	150	150
CBRE	155	155	155	155	155	155	155	155	155	155	155	155
Generic Capacity	0	0	0	0	66	202	642	1,142	1,642	1,642	1,642	1,642
McMinnville Solar	10	10	10	10	10	10	10	10	10	10	10	10
Nevada Solar	104	104	104	134	200	200	200	200	600	600	600	600
Offshore Wind	244	479	728	974	1,263	1,645	1,965	2,290	2,491	2,824	3,000	3,000
Wyoming Wind	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,278	1,472
Montana Wind	200	200	200	200	200	200	200	200	200	200	200	200

Relaxing the preferred portfolio's constraints results in the identification of specific least cost resources. The total cost of this portfolio is substantially lower than PGE's preferred portfolio even though it includes modeling changes that increase costs. Enabling offshore wind provides the bulk of these savings. The table below compares the NPVRR and PGE's risk metric under PGE's preferred portfolio and portfolios developed with combinations of offshore wind and additional remote market and VER access.

Figure 5

	Reference NPVRR	Mean NPVRR	Semi-deviation
PGE Preferred Portfolio (Repriced)	37,365	38,861	11,232
Allow Offshore Wind	28,784	29,980	9,231
Allow Remote Market Transmission	29,424	29,941	9,209
Allow Both Offshore and Remote Markets	26,454	26,996	8,200

It is worth noting that, while this portfolio still includes a substantial amount of Generic Capacity, the portfolio's more diverse resource set would likely pair well with emerging storage technologies such as a 100-hour iron-air battery to meet PGE's future capacity need. However, this scenario was not modeled.

[113] This modeling adjustment is based on assumptions around proxy pumped hydro projects requiring new transmission to interconnect to PGE's system; some pumped hydro projects in development may not require this level of transmission investment and therefore may out-perform the proxy resource in an actual long-lead time RFP.

A portfolio with offshore wind is the least cost, least risk and best combination of cost and risk. The Commission should acknowledge a modified PGE preferred portfolio aligned with Attachment A that indicates offshore wind as a least cost, least risk resource. In the alternative, the Commission should not acknowledge PGE's current preferred portfolio and direct PGE to refile its preferred portfolio within six months consistent with these comments that demonstrate other resources, including offshore wind, are least cost, least risk.

ix. Offshore Wind Alleviates SoA and Bethel to Round Butte Congestion

PGE proposes two transmission related action items:

1. Alleviate congestion at the SoA flowgate.[114]
2. Upgrade Bethel to Round Butte. [115]

If PGE's second transmission action item was modified to "Alleviate congestion along Bethel to Round Butte" in line with the first action item, both action items would be satisfied by pursuing offshore wind.

The NorthernGrid offshore wind study shows that the development of offshore wind alleviates congestion at SoA[116] and westbound flows at West of Cascades South.[117] Of particular note is that offshore wind reduces peak load on SoA and on West of Cascades South by approximately 250 MW each. This could have the same economic impact as adding 500 MW of transmission to enable resources in southeast Washington, the gorge, and eastern Oregon. The potential value of this can be estimated within PGE's IRP models by making an incremental 500 MW of new low-cost SoA transmission available in ROSE-E. This reduces NPVRR by $600 million.

c. *Long-Lead Time RFP*

The Commission should direct PGE to issue a long-lead time RFP in late 2025 for the potential acquisition of resources in the early 2030s, or, in the alternative, direct PGE to develop and issue a broader RFP that fairly and accurately compares long-lead time resources to shorter-term resources.

For Oregon to reach its 100 percent clean energy goals, the utilities will need to acquire new, diverse resources many of which will likely be long-lead time resources, including offshore wind. In the near future, PGE is expected to conduct numerous RFPs that could determine whether PGE meets its long-term energy and capacity needs. The current RFP rules and processes and the specific RFP designs have not been and are not sufficient to properly value long-lead time resources. Modest modifications to the RFP process could remove these barriers. This should occur as soon as practicable because a long-lead time resource, specifically offshore wind, is now part of the least cost and least risk portfolio. Thoughtful and deliberative changes

[114] 2023 CEP/IRP at 309.
[115] 2023 CEP/IRP at 310.
[116] *NorthernGrid Economic Study Request Offshore Wind in Oregon* at 23 (Attachment C).
[117] *NorthernGrid Economic Study Request Offshore Wind in Oregon* at 25 (Attachment C).

should be made to ensure that PGE can select the least cost, least risk mix of short- and long-lead time resources and transmission build out. An RFP should be designed to ensure that the IRP preferred resource portfolio can be tested in the market. PGE has proposed securing transmission access to specific regions without assessing whether these regions offer the most economic resources. We have found offshore wind to be more economic than the Wyoming and Nevada resources that are enabled by PGE's proposed transmission action items. PGE appropriately raises concerns about cost uncertainties regarding offshore wind. However, rather than dismissing offshore wind despite its demonstrated benefits, PGE should alleviate the cost risk by issuing a long-lead time RFP.

i. Developers Need a Market Signal to Invest in Long-Lead Time Resources, Which Could Be a Long-Lead Time RFP

Due to the long-lead times and large upfront capital investments required to develop these technologies, developers need more certainty from the utilities and the Commission before investing in resources such as offshore wind. If Oregon is going to meet its binding clean energy targets in 2035 and 2040, then developers of long-lead time resources need to start making decisions now about development of these resources. For example, the Bureau of Ocean Energy Management has an anticipated offshore wind auction in the second half of 2024, and prices for a lease could be similar to California that ranged from $135 million to $174 million, which represents only a portion of the individual developer's investment needed for offshore wind. Investment is also needed in the ports in Southern Oregon, supply chain infrastructure, and more. In order to make these investments, many developers and coastal communities will need some market signal now from the utilities and the Commission that Oregon is interested in pursuing these long-lead time resources.

Our recommendation is that the Commission help to send this market signal by requiring utilities to issue long-lead time RFPs. This may help overcome any limitations of Oregon's current RFP rules and process, which are based on a two- to four-year IRP action plan, and will help create momentum for the long-lead time resources PGE recognizes as essential for meeting the goals of HB 2021.[118]

ii. Current RFPs Are Not Well Suited for Long-Lead Time Resources and Changes Would Need To Be Made to the Procurement Process for Long-Lead Time Resources

The timelines in current RFPs are not well suited for these long-lead time resources. One issue is that the Commercial Operation Dates ("COD") are not sufficiently far out into the future to allow for any offshore wind facilities to be eligible. No RFPs included a COD in the 2030s, which would be necessary for offshore wind. A related issue is that the time between contract execution

[118] As discussed in these comments, PGE represents these resources as "generic." However, PGE is more explicit about the need to look outside the Action Plan window to consider planning and development of transmission, another long-lead activity (see 2023 CEP/IRP at 216-17). We think PGE should be taking more concrete steps to create momentum for all long-lead projects.

date in the RFPs and the CODs in those contracts is generally 5 to 5.5 years.[119] Five years may not be enough time for development of long-lead time resources, especially if the project would need the commitment of a contract before investing in capital for the project. Offshore wind for example may need development timelines of 5-10 years depending on the project. The Independent Evaluator in PacifiCorp's 2020 RFP noted this issue and stated, "[a] resource with a long lead time simply does not fit an evaluation geared towards projects with shorter construction times, which has a relatively short-term reliability target."[120] Thus, long-lead time resources need a separate RFP designed to accommodate their long development timelines.

There are other RFP changes that may be necessary, in addition to accounting for the later COD and longer time to develop the resources. Some other changes that may need to be made include: 1) providing form contracts for long-lead time resources;[121] 2) sufficient time from bid submission to initial shortlist for due diligence in evaluating a long-lead time resource;[122] 3) allowing a long-lead time resource to submit a reasonable transmission plan instead of requiring firm transmission at time of bid;[123] 4) developing modeling and evaluation tools that ensure long-lead time resources are evaluated fairly;[124] 5) ensuring scoring is fair among all resources;[125] and potentially more. These issues do not need to be addressed now, but they are something to consider when developing a long-lead time RFP.

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[119] A review of recent RFPs illustrates the COD and development period issues. In PGE's proposed 2023 RFP, the COD for long-lead time resources is December 31, 2029 with contracts for all resources likely negotiated and executed in Q2 2024 (Docket No. UM 2274, PGE's Reply Comments at 4 and Updated Draft 2023 All-Source RFP at 7 (June 28, 2023)). This only provides 5.5 years for development of a long-lead time resource. PGE's 2021 RFP had a COD of December 31, 2027 with contracts expected to be executed in June 2022, but contracts were not executed until late 2022 and early 2023, which would have only provided around 5 years for development of a long-lead time resource (*In re PGE 2021 All-Source RFP*, Docket No. UM 2166, PGE's 2021 All-Source RFP – Final Draft at 8, 11 (Oct. 15, 2021); Docket No. UM 2166, PGE's Independent Evaluator's Final Report on Contract Negotiations Filing at 5, 14 (June 30, 2023) (explaining negotiations for the projects selected ended in October 2022, April 2023, and May 2023)). In PacifiCorp's current RFP, long-lead time resources must have a COD of December 31, 2028 with contracts expected to be executed at the end of 2023, but the schedule has already been delayed, which again only provides at most 5 years for development of a long-lead time resource (*In re PacifiCorp 2022 All-Source RFP*, Docket No. UM 2193, PacifiCorp's Informational Update to PacifiCorp's 2022 All Source Request for Proposals at 2-3, 13 (Oct. 25, 2022)). In PacifiCorp's 2020 RFP, long-lead time resources were allowed a COD by December 31, 2026 with contracts executed at the end of 2021, which provided 5 years for development of a long-lead time resource (PacifiCorp, *2020 All-Source Request for Proposals Resources* at 5, 9 (July 7, 2020), available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/suppliers/rfps/2020-all-source-request-for-proposals/documents/main-documents-appendices/2020AS_RFP_Main_Document_July_7_2020.pdf). Long-lead time resources have not been selected in these RFPs even with the extended CODs.
[120] *See In re PacifiCorp Application for Approval of 2020 All-Source RFP*, Docket No. UM 2059, Independent Evaluator's Updated States Report on PacifiCorp's 2020AS RFP at 28 (Nov. 20, 2020).
[121] *See* Docket No. UM 2059, Comments of Swan Lake North Hydro, LLC at 8-9 (May 22, 2020); *see also* Docket No. UM 2059, PacifiCorp's Reply Comments at 12-13 (June 1, 2020).
[122] *See* Docket No. UM 2059, Independent Evaluator's Updated States Report on PacifiCorp's 2020AS RFP at 28-29 (Nov. 20, 2020).
[123] *See* Docket No. UM 2166, Comments of Swan Lake North Hydro, LLC and the Goldendale Energy Storage Project on PGE's 2021 All-Source RFP – Final Draft at 3-6 (Nov. 1, 2021).
[124] *See* Docket No. UM 2059, Comments of Swan Lake North Hydro, LLC at 2-4 (Dec. 4, 2020).
[125] *See* Docket No. UM 2166, Comments of Swan Lake North Hydro, LLC and the Goldendale Energy Storage Project on PGE's 2021 All-Source RFP – Final Draft at 2-3 (Nov. 1, 2021).

The recommendation to have a long-lead time RFP is not a change to the current regulatory scheme, and it is consistent with Commission precedent in IRP acknowledgement proceedings. In past IRPs, the Commission has directed utilities to issue an RFP or make specific changes to an upcoming RFP.[126] Similarly, it is a more modest recommendation than the Commission's reasonable decision to waive competitive bidding rules in PGE's 2023 RFP to run concurrently with the IRP.[127] RNW, however, recommends that the Commission, PGE, and interested stakeholders also review whether there should be substantive changes to the competitive procurement regulatory scheme when developing the long-lead time RFP. For example, the Commission could consider whether greater assurance of cost recovery than the traditional acknowledgement of a final shortlist (rather than a specific resource) would be warranted. RNW looks forward to additional discussions on this topic.

iii. A Long-Lead Time RFP Would Provide Certainty to Developers to Invest in Offshore Wind in Oregon

The Commission should direct PGE to issue a long-lead time RFP in late 2025 for resources with commercial operation dates in the early 2030s. RNW proposes a late 2025 RFP because it will be a year after the expected Bureau of Ocean Energy Management offshore wind auction in the second half of 2024. This will provide project developers with enough time to develop a bid, and the utilities with sufficient time to complete more analysis of all the long-lead time resources. This also allows the Commission, PGE, and interested stakeholders the time to work collaboratively to design a long-lead time RFP with meaningful changes as suggested above to accommodate long-lead time resources. In the alternative, the Commission should direct PGE to develop and issue a broader RFP in late 2025 that fairly and accurately compares long-lead time resources to shorter-term resources. With a broader RFP, it is equally important to address the long-lead time RFP issues that have been raised in numerous RFP dockets before.

Directing the utilities to issue a long-lead time RFP provides certainty and confidence to developers of long-lead time resources that Oregon has interest in these resources and that these developers should be looking to Oregon. It will also be the first step in providing price certainty to developers when the contracts are negotiated. By issuing a long-lead time RFP and executing contracts with the resources, PGE would signal that the resource and its costs at that time are reasonable. The Commission would still have the opportunity to review the prudence of the acquisition and costs at a rate case, but the RFP provides certainty to the developers. It also

[126] *See e.g.*, Docket No. LC 73, Order No. 21-129 at 5 (May 3, 2021) (directing Staff to ensure the RFP for the IE includes stakeholders' desired IE criteria, a discussion in the RFP on the RFP design and how long-lead time resources may participate, and PGE to report on low market price futures and tax credit sensitivities on the final shortlist); *see also e.g., In re PGE 2016 IRP*, Docket No. LC 66, Order No. 18-044 at 1-2 (Feb. 2, 2018) (directing PGE to provide updates to it needs in the RFP docket, update its assumptions on qualifying facilities and renewable energy certificates and incorporate those assumptions in its RFP analysis as sensitivities, address RFP design and scoring elements relevant to Montana wind in a workshop, and include a description of the cost containment mechanism in the RFP); *see also e.g., In re PacifiCorp 2019 IRP*, Docket No. LC 70, Order No. 20-186 at 18-20, 23 (June 8, 2020) (explaining several conditions related to updated load and market forecasts, off-system sales sensitivities, and customer impacts/revenue requirement analysis on the all-source RFP and directing "PacifiCorp pursue demand response acquisition with a demand response RFP.").

[127] Docket No. UM 2274, Order No. 23-146 (Apr. 21, 2023).

provides upfront reassurances to the utilities that, at the time of issuing the RFP and executing the contracts, investing in the long-lead time resource is reasonable and that the original decision will not be revisited. The market signals to developers from a long-lead time RFP, price certainty of contract negotiations, and upfront reassurance to the utilities regarding the reasonableness of the resource will help ensure that Oregon meets its 100 percent clean energy goals. Thus, the Commission should direct PGE to issue a long-lead time RFP in late 2025.

G. IRP Integration with Western Resource Adequacy Program

RNW appreciates PGE's thoughtful introduction of Western Resource Adequacy Program ("WRAP") issues into the 2023 IRP.[128] PGE highlights the need to better reflect the WRAP within its IRP planning, while identifying potential incongruencies between PGE's and WRAP's analytical results and corresponding requirements. RNW provides the following comments and recommendations to support PGE's and the Commission's further integration of WRAP into PGE's resource planning initiatives.[129] As an overarching theme, it is likely that PGE and WRAP's reliability analysis and resource adequacy frameworks are likely to remain parallelized, rather than integrated, for the foreseeable future. While convergence is a beneficial long-term goal, it is useful to think of PGE's and WRAP's programs as providing complementary analyses to inform long-term planning -- PGE's analysis is more specific to PGE's system and can provide a longer-term planning horizon, while WRAP will ensure each participant pulls its fair share of the weight toward reliability for the broader region.

RNW identifies three critical workstreams for WRAP integration. First, WRAP, like any compliance obligation, should be incorporated as a section within the IRP, articulating PGE's current and anticipated position and its action plan to resolve any long or short position within its portfolio. Second, PGE should incorporate WRAP into its resource planning framework, which will include incorporation of WRAP as a resource planning constraint as well as leveraging data from WRAP to inform inputs and assumptions within its production cost modeling. Third, PGE, along with Commission representatives, should continue to engage within the WRAP governance framework to support continued evolution of the program to better integrate with long-term state utility planning.

a. Reporting WRAP as a New Compliance Obligation

As a compliance obligation, PGE's next IRP should include a narrative and action plan regarding its near- and mid-term compliance needs in the same manner PGE reports on other compliance

[128] 2023 IRP/CEP at 63-66, Section 3.2: Regional Planning: Resource Adequacy.
[129] *In re Commission Investigation into Resource Adequacy in Oregon*, Docket No. UM 2143, Staff's Process Proposal and RA Solution Straw Proposal, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2143hah145744.pdf.

obligations, such as the Renewable Portfolio Standard requirements.[130] This section will fill a critical regulatory oversight need for the Commission and stakeholders to understand what resources PGE may need to fill its open position for near-term WRAP compliance. Given the on-going development of WRAP compliance parameters, it is reasonable that this was not included in detail in the 2023 IRP; however, the Commission should require PGE to provide preliminary analysis prior to the next IRP filing for stakeholder review and comment, and may wish to require PGE to report at significant compliance milestones, such as entering into contracts exceeding specific thresholds or at the time of compliance submissions to the WRAP program operator.

b. Integrating WRAP into Long-Term Planning

Integrating WRAP into long-term IRP processes is a critical yet complex task, with some near-term actions PGE can implement and others that may need to be addressed through WRAP governance. Although PGE's reliability framework and WRAP's reliability framework share many common conceptual threads, such as a 1-day-in-10-years loss of load expectation standard and the use of effective load carrying capability to assess resource value, there are many methodological and practical differences that will almost certainly result in different requirements between the two programs, though it is too early to determine whether these will be subtle or significant. As a result, it is likely necessary for PGE's and WRAP's reliability frameworks to co-exist until further WRAP program development enables better long-term convergence. In the comments, below, RNW highlights the current limitations and potential areas for improved alignment moving forward.

The first key difference between PGE and WRAP is the analytical region. PGE analyzes reliability at the level of the PGE balancing authority, with critical simplifying assumptions regarding import availability from the broader region, while WRAP analyzes reliability across the entire WRAP footprint. This analysis may result in subtle differences in the reliability risk profile, which can have downstream implications for Planning Reserve Margin and Effective Load Carrying Capability values. PGE's analysis, with its simplified regional methodology, may model regional risks with less precision than does WRAP; conversely, WRAP's zonal analysis may miss reliability risks specific to PGE's system (for instance, WRAP's methodology does not include power flow modeling to identify topology-specific contingency risk, which PGE should continue to perform regardless of future WRAP integration).

The second key difference is in how PGE and WRAP will apply their resource accreditation methods. While both PGE and WRAP utilize ELCC for solar, wind, and storage resources, the applications of the methodologies are different, with WRAP utilizing a seasonal, zonal, average

[130] 2023 IRP/CEP at 126-127, Section 6.7 RPS Need.

ELCC methodology, and PGE utilizing a seasonal, vintaged marginal ELCC methodology. While the sum of PGE's marginal ELCCs should approximate average ELCC, other practical limitations will prevent this. Most significantly, WRAP and PGE are unlikely to be precisely aligned on their ELCC curves -- it is unlikely that the saturation and interactive effects observed on PGE's system will align precisely with the same level of saturation and interaction observed on the WRAP system. This is further complicated by WRAP's plan for monthly adjustments to ELCC values to determine resource-specific accreditation.[131] As a result, it is unlikely that WRAP's resource accreditation results will overlay precisely with PGE's resource accreditation results.

The third key difference, which is the crux to better long-term integration, is the difference in planning horizon between WRAP and state-level planning. WRAP's Forward Showing program is currently envisioned as a near-term compliance framework, with binding compliance parameters limited to one forward year and advisory requirements three years beyond the binding year[132], effectively five years beyond the date of analysis. To the extent the portfolio, load profiles, or other conditions change in the ensuing years between the issuance of the advisory PRMs and the finalization of binding PRMs, it is likely that PRMs and resource accreditation values may shift in subtle or significant ways, limiting PGE and other participants' ability to rely on these values for planning. Beyond the advisory values, there will not be data available from WRAP to inform PGE's process. As discussed in the subsequent section, RNW sees this as a key area for improved long-term coordination within the WRAP governance framework, and one that may enable the use of a single resource adequacy framework in the future.

Despite these differences, there are likely opportunities for PGE to integrate insights and analysis from WRAP into its planning ecosystem. WRAP's regional analysis will generate significant input data, including a range of weather and resource operational data (e.g. wind resource profiles), which may be useful as either a direct input to PGE's data needs or as a benchmark against its data. WRAP's modeling outputs will provide significant data regarding the regional reliability risk profile, and PGE would do well to benchmark the reliability profile generated by Sequoia against that identified in WRAP. For example, this could include ensuring the seasons and hours of risk identified across the two programs are comparable. WRAP modeling results could inform spot market availability hours and magnitudes, as discussed above, likely one of the most critical input assumptions to PGE's reliability analysis. PGE can utilize WRAP insights to understand the net resource position within WRAP, which will be useful in identifying the degree

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[131] Western Power Pool, *WRAP Business Practices Manual* at 23-27, available at: https://www.westernpowerpool.org/private-media/documents/BPM_105_Forward_Showing_Qualifying_Resources_for_Comment_rar2CLS.pdf.

[132] Western Power Pool, *WRAP Draft Detailed Design Document* at 85 (Mar. 2023), available at: https://www.westernpowerpool.org/private-media/documents/2023-03-10_WRAP_Draft_Design_Document_FINAL.pdf.

to which PGE may be able to leverage transactions with neighboring utilities for specific resource needs rather than needing to build new resources. Finally, with material impacts for this IRP, WRAP regional modeling could be very useful in calibrating the risk of transmission curtailment of candidate resources without firm transmission.

c. Improved Alignment through WRAP Program Evolution

PGE is not alone among utilities in confronting the need to integrate WRAP with state-level planning, and it is likely that many western utilities and regulators will be confronting parallel challenges. As PGE moves deeper into WRAP implementation, it would be beneficial for PGE, the Commission, and stakeholders to engage in dialogue regarding potential areas for WRAP evolution to better facilitate integration with state-level planning. Most significantly, WRAP has established a tremendous platform for reliability analysis and coordination that has significant long-term potential -- but potential that can only be unlocked should participants (and their regulators) determine that WRAP's outlook and coordination frameworks be extended beyond the current limited time frame.

G. Conditional Firm Transmission

In our Round 0 Comments, RNW provided a preliminary analysis, performed by Michael Goggin and Zachary Zimmerman from Grid Strategies, of conditions under which BPA's conditional firm transmission product might be curtailed. Our comments expressed an interest in working with PGE to improve and refine the analysis. The comments also explained the regulatory context underlying the analysis, which is familiar to the Commission and is not repeated here.[133]

PGE's May 31, 2023 Response to Initial Comments raised a number of concerns about our preliminary analysis, including the following:

- Recommendation that a power flow analysis would be more appropriate than a spreadsheet analysis;
- Critique of the analysis's focus on the West-of-Cascade-South path rather than South-of-Alston;
- Critique of the analysis's adopting only new builds associated with PGE, PacifiCorp, and Bonneville Power; and
- Critique of the analysis's allocation of new PacifiCorp resources between PACE and PACW.

[133] RNW Round 0 Comments at 6-7 (May 2, 2023), available at: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac74848.pdf.

Attached to these comments as Attachment D is an updated analysis from Grid Strategies responding to PGE's analysis. The updated analysis includes two main conclusions: first, we continue to recommend that PGE assume zero hours of curtailment corresponding with peak hours for purposes of capacity accreditation; second, we recommend that to better understand this issue PGE perform a power flow analysis along the lines the company discusses in its May 31 Response.

As matters stand today, Grid Strategies has performed a public-facing analysis of conditional firm curtailment and PGE has not. Accordingly, RNW continues to recommend that either the company work to refine its approach to conditional firm transmission or the Commission acknowledge the IRP conditioned on a modification to PGE's ELCC analysis in line with Grid Strategies' conclusion.

H. Community Engagement and Inclusion

a. Thorough and Direct Incorporation of Energy Justice Principles and Conversations

RNW requests that PGE incorporate energy justice throughout the CEP. RNW believes PGE should add actions to its action plan that pertain to outcomes related to environmental and energy justice. Energy justice should be considered throughout the CEP and within other actions beyond the Community-Based Renewable Energy ("CBRE") actions. While PGE acknowledged that CBIs will be improved upon over time, the action plan should also include a commitment to improving community benefit indicators. Throughout the CEP and in PGE's response to comments, PGE often points to other venues or forums where environmental justice conversations may take place. While RNW supports engaging in multiple venues and community forums, we are concerned about the many outside venues PGE defers to in their response to comments critiquing community input strategies. RNW stresses the importance of direct engagement with communities related to accomplishing goals and specific actions of the CEP.

Like the Energy Advocates, RNW believes that the instrument of a CEP is intended to be a drastic departure from the traditional IRP, where community benefits and community stakeholders are central to the process, and energy justice is considered and thoughtfully applied throughout from the goals to specific actions. The intent of the CEP is to create a plan to accomplish reductions in GHG emissions *and* environmental justice principles such as resilience, community benefits, health and other environmental advantages. The latter are not a secondary priority, but an equally important facet to be considered in every aspect of the CEP.

In Round 0, RNW agreed with PGE that engaging communities that have been historically excluded and underserved is important. RNW recommended supplying a plan with more information for how reaching the historically excluded communities will occur, such as what communities would be contacted, how the company plans to do this, and when. PGE responded with information on Tribal engagement and near- and long-term goals for community engagement. RNW would still like to see a specific plan to ensure that historically excluded and underserved communities (both Tribal and non-Tribal) will be included in future engagement.

b. Tribal Engagement

RNW appreciates the response to our comments in Round 0 regarding Tribal engagement and the explanation of the other efforts PGE is taking to engage Tribes such as the Strategic Tribal Engagement Plan and the near- and long-term goals. This engagement plan is another outside venue that is not tied directly to the CEP. RNW recommends that PGE directly engage the Tribes in conversations relevant to CEP goals and actions, and develop goals with Tribal partners. RNW also recommends continuing to provide information on the progress of Tribal engagement as well as any other efforts beyond the Strategic Tribal Engagement Plan that PGE may pursue in working with Tribes. RNW would like to see actions described that will be taken to achieve each of the near- and long-term goals and desired outcomes. For example, how does PGE plan to "build awareness, inform and provide learning opportunities to communities" and "increase community participation, including Tribal and EJ communities?" Also, what steps is PGE taking in searching for a Tribal representative for the Community Benefits and Impacts Advisory Group ("CBIAG")? Because the inaugural CBIAG meeting has already taken place, RNW recommends prioritizing finding a Tribal representative for the group.

c. Community Benefit Indicators

RNW appreciates the response to our questions regarding the valuation of CBREs and the resource Community Benefit Indicator ("rCBI") adder establishing a 10% cost reduction for CBREs. For informational Community Benefit Indicators ("iCBIs"), RNW requested more information on how the baselines will be determined for energy, equity, health and community wellbeing, and economics. PGE responded that they expect to *continue* to work on that with stakeholders in the Community Learning Labs and other venues. RNW would like to understand what work has been done to establish baselines so far.

PGE also states that the attribution of benefits from the CEP will not be differentiated from that of other PGE efforts. RNW would then stress the importance of maintaining an understanding of the effectiveness of certain actions taken to achieve CEP goals, to be able to conclude whether actions identified in CEPs can be improved upon for community benefit. Otherwise, it may be difficult for interested parties to understand the benefits that occur from CEP actions and which occur as a result of other processes. Therefore, RNW requests more information to understand how the CEP may be used as a tool for supporting community benefits. This request also ties to the necessity of having engagement forums that are directly linked to the CEP, to better understand the origin of intended community benefits and how successful (or otherwise) the CEP's results may be.

In response to RNW's and the Energy Advocates' Round 0 suggestion of creating an additional environmental CBI (because GHG reduction is expected already) such as one developed in partnership with Tribes, PGE states that it will not modify the existing list of iCBIs. PGE essentially states (with the example given) that consideration of Tribal indicators can be accomplished through other venues. RNW strongly recommends revisiting the idea of creating additional environmental CBIs in collaboration with Tribal partners.

d. Community-Based Renewable Energy

RNW appreciates PGE's plans to create a workgroup including community members and environmental justice community representatives in developing the CBRE-RFP scoring matrix. We are further pleased to hear PGE plans to engage communities in developing multiple parts of the acquisition process. We would like to reiterate our comments from Round 0, "To create community-owned projects with community feedback, we believe that many under-resourced communities will need further capacity building and resources to gain experience and ability to engage in planning and building CBRE projects." While CBRE action can achieve some energy justice goals, energy justice principles should be considered and applied throughout the CEP. Other actions, besides CBRE, should more directly address environmental justice as well.

III. Conclusion

For the foregoing reasons, RNW respectfully requests that either PGE agree or the Commission direct PGE as Plan acknowledgement conditions to do the following:

1. For future plans, develop a multi-metric RA approach that incorporates economic factors, to align with emerging best practices;
2. For future plans, develop an updated ELCC approach that accounts for portfolio effects;
3. For future plans, incorporate additional factors in its analysis of hydrogen, including electrolyzer load and potential leakage;
4. For future plans, develop and transparently present more granular GHG modeling with a non-regulatory goal of planning for hourly matching of clean energy to load;

5. For the current Plan, adopt the updated preferred portfolio presented in Attachment A or a similar portfolio developed without artificial constraints on the selection of offshore wind;
6. For the current Plan, establish as an action item a long-lead time RFP in 2025 aimed at identifying economic post-2030 resources whose development timelines do not interact well with Oregon's current RFP structure;
7. In line with recommendations 5 and 6, for the current Plan and future plans, continue to develop more concrete post-2030 planning;
8. For future plans, continue work to align utility-specific resource planning with the WRAP, including by incorporating the WRAP into its modeling.
9. For the current Plan, change its ELCC modeling for resources relying on conditional firm transmission to assume zero hours of curtailment;
10. For the current Plan, continue to add clarity on PGE's work to effectuate HB 2021's policies that support integrating community input and benefits into resource plans.

Again, RNW appreciates PGE's and the Commission's consideration of our comments and looks forward to the remainder of the Plan-review process. We conclude, however, by zooming out to the broader context driving the work of Clean Energy Plans and the motivation for our comments -- science tells us that we must eliminate all GHG emissions as quickly as possible.[134] Research published this month shows that in 2022, heat waves killed over 60,000 people in Europe,[135] and that climate change is likely a contributing factor to recent heat waves.[136] And that's just to pick recent, top-of-mind studies. The Commission has the authority -- indeed, a legislative mandate -- to "ensure that an electric company … is taking actions as soon as practicable that facilitate rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers."[137] We strongly believe that these comments will help to facilitate that deeply necessary outcome.

[134] *See*, *e.g.*, Intergovernmental Panel on Climate Change, *Climate Change 2023: Synthesis Report, Summary for Policymakers* at B.3 (2023) (discussing the suite of risks associated with climate change and explaining that "future changes are unavoidable and/or irreversible but can be limited by deep, rapid, and sustained global greenhouse gas emissions reduction"); Intergovernmental Panel on Climate Change, *Synthesis Report of the IPCC Sixth Assessment Report* at 3.4.2 (2023) ("The cumulative scientific evidence is unequivocal: climate change is a threat to human well-being and planetary health (*very high confidence*). Any further delay in concerted anticipatory global action on adaptation and mitigation will miss a brief and rapidly closing window of opportunity to secure a liveable and sustainable future for all (*very high confidence*).").
[135] François Herrmann et al., 29 Nature Medicine 1857–1866, *Heat-related mortality in Europe during the summer of 2022* (July 10, 2023), available at: https://www.nature.com/articles/s41591-023-02419-z.
[136] Mariam Zachariah et al., Imperial College London, *Extreme heat in North America, Europe and China in July 2023 made much more likely by climate change* (July 25, 2023), available at: https://spiral.imperial.ac.uk/handle/10044/1/105549.
[137] ORS 469A.415(6).

Respectfully submitted this 27th day of July, 2023,

/s/ Max Greene
/s/ Katie Ware
/s/ Emily Griffith

Renewable Northwest
421 SW 6th Ave., Suite 1400
Portland, OR 97204
503-223-4544
max@renewablenw.org
katie@renewablenw.org
emily@renewablenw.org

/s/ Irion Sanger
/s/ Ellie Hardwick

Sanger Law, PC
4031 SE Hawthorne Blvd.
Portland, OR 97214
Telephone: 503-756-7533
Fax: 503-334-2235
irion@sanger-law.com
ellie@sanger-law.com

/s/ Nick Pappas

NP Energy
Nick@NPEnergyCA.com

/s/ Lance Kaufman

Western Economics
lance@westernecon.com

/s/ James Himelic

First Principles Advisory LLC
jhimelic@firstprinciples.run

Attachment A

RNW's Proposed Preferred Portfolio

RNW Preferred Portfolio

Technology Future:	Reference_Te
Price Future:	RRRR
Need Future:	Reference

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Bat_4hr	0	0	0	0	0	0	0	0	0	100	200	300	400	500	600	700	800	800	800	800
bCV_Hyb_1	0	0	0	0	69	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
bCV_Hyb_2	0	0	0	0	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310	310
bWind_Gorge	0	0	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
bWind_SEWA	0	0	112	112	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
CBRE_hydro	0	0	1	1	3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
CBRE_micro	0	0	43	56	71	85	100	100	100	100	100	100	100	100	100	100	100	100	100	100
CBRE_solar	0	0	22	28	36	43	50	50	50	50	50	50	50	50	50	50	50	50	50	50
CV_Hyb_1	0	0	299	299	299	299	299	299	299	299	299	299	299	299	299	299	299	299	299	299
CV_Hyb_2	0	0	0	0	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191
Generic_Cap	0	0	0	0	0	0	0	0	0	0	0	0	66	202	642	1142	1642	1642	1642	1642
MCMN_Hyb_1	0	0	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PSH_10hr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2000	2000	2000	2000
Solar_NV	0	0	0	0	0	0	0	104	104	104	104	134	200	200	200	200	600	600	600	600
Tx_SOA	0	0	0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
txSolar_NV	0	0	0	0	0	0	0	104	104	104	104	134	200	200	200	200	600	600	600	600
txWind_WY	0	0	0	0	0	516	911	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1472
Wind_Gorge	0	0	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
Wind_Off	0	0	0	0	0	0	0	0	244	479	728	974	1263	1645	1965	2290	2491	2824	3000	3000
Wind_WY	0	0	0	0	0	516	911	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1278	1472
xWind_Gorge	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
xWind_MT	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200

2043 Offshore Wind Instalations By Scenario

			Installed Capacity	
Need Future	Price Future	Technology Future	Base OSW Cost	150% OSW Cost
Average			2699	2546
Minimum			3000	3000
Maximum			2008	1513
Reference	RRRR	Reference_Te	3000	2858
Reference	RRRR	Low_Tech	3000	2966
Reference	RRRR	High_Tech	3000	2494
Reference	NRHR	Reference_Te	3000	2871
Reference	NRHR	Low_Tech	3000	2927
Reference	NRHR	High_Tech	3000	2589
Reference	NRRR	Reference_Te	3000	2846
Reference	NRRR	Low_Tech	3000	2990
Reference	NRRR	High_Tech	3000	2521
Reference	RLHR	Reference_Te	3000	2879
Reference	RLHR	Low_Tech	3000	2964
Reference	RLHR	High_Tech	3000	2555
Reference	RLLR	Reference_Te	3000	2924
Reference	RLLR	Low_Tech	3000	2970
Reference	RLLR	High_Tech	3000	2501
Reference	RLRR	Reference_Te	3000	2929
Reference	RLRR	Low_Tech	3000	2976
Reference	RLRR	High_Tech	3000	2505
Reference	RRHR	Reference_Te	3000	2875
Reference	RRHR	Low_Tech	3000	2925
Reference	RRHR	High_Tech	3000	2556
Reference	RRLR	Reference_Te	3000	2917
Reference	RRLR	Low_Tech	3000	2964
Reference	RRLR	High_Tech	3000	2495
Reference	RSHR	Reference_Te	3000	2906
Reference	RSHR	Low_Tech	3000	2765
Reference	RSHR	High_Tech	3000	2569
Reference	RSLR	Reference_Te	3000	2893
Reference	RSLR	Low_Tech	3000	2932
Reference	RSLR	High_Tech	3000	2483
Reference	RSRR	Reference_Te	3000	2897
Reference	RSRR	Low_Tech	3000	2935
Reference	RSRR	High_Tech	3000	2551
Reference	SRHR	Reference_Te	3000	2862
Reference	SRHR	Low_Tech	3000	2929
Reference	SRHR	High_Tech	3000	2569
Reference	SRRR	Reference_Te	3000	2848
Reference	SRRR	Low_Tech	3000	2969
Reference	SRRR	High_Tech	3000	2497
High	RRRR	Reference_Te	3000	3000
High	RRRR	Low_Tech	3000	3000

High	RRRR	High_Tech	3000	3000
High	NRHR	Reference_Te	3000	3000
High	NRHR	Low_Tech	3000	3000
High	NRHR	High_Tech	3000	3000
High	NRRR	Reference_Te	3000	3000
High	NRRR	Low_Tech	3000	3000
High	NRRR	High_Tech	3000	3000
High	RLHR	Reference_Te	3000	3000
High	RLHR	Low_Tech	3000	3000
High	RLHR	High_Tech	3000	3000
High	RLLR	Reference_Te	3000	3000
High	RLLR	Low_Tech	3000	3000
High	RLLR	High_Tech	3000	3000
High	RLRR	Reference_Te	3000	3000
High	RLRR	Low_Tech	3000	3000
High	RLRR	High_Tech	3000	3000
High	RRHR	Reference_Te	3000	3000
High	RRHR	Low_Tech	3000	3000
High	RRHR	High_Tech	3000	3000
High	RRLR	Reference_Te	3000	3000
High	RRLR	Low_Tech	3000	3000
High	RRLR	High_Tech	3000	3000
High	RSHR	Reference_Te	3000	3000
High	RSHR	Low_Tech	3000	3000
High	RSHR	High_Tech	3000	3000
High	RSLR	Reference_Te	3000	3000
High	RSLR	Low_Tech	3000	3000
High	RSLR	High_Tech	3000	3000
High	RSRR	Reference_Te	3000	3000
High	RSRR	Low_Tech	3000	3000
High	RSRR	High_Tech	3000	3000
High	SRHR	Reference_Te	3000	3000
High	SRHR	Low_Tech	3000	3000
High	SRHR	High_Tech	3000	3000
High	SRRR	Reference_Te	3000	3000
High	SRRR	Low_Tech	3000	3000
High	SRRR	High_Tech	3000	3000
Low	RRRR	Reference_Te	2078	1949
Low	RRRR	Low_Tech	2008	1950
Low	RRRR	High_Tech	2145	1799
Low	NRHR	Reference_Te	2098	1969
Low	NRHR	Low_Tech	2213	1970
Low	NRHR	High_Tech	2152	1603
Low	NRRR	Reference_Te	2102	1973
Low	NRRR	Low_Tech	2034	1976
Low	NRRR	High_Tech	2133	1633
Low	RLHR	Reference_Te	2076	1947

Low	RLHR	Low_Tech	2008	1950
Low	RLHR	High_Tech	2168	1603
Low	RLLR	Reference_Te	2084	1955
Low	RLLR	Low_Tech	2014	1957
Low	RLLR	High_Tech	2159	1810
Low	RLRR	Reference_Te	2089	1960
Low	RLRR	Low_Tech	2019	1961
Low	RLRR	High_Tech	2154	1813
Low	RRHR	Reference_Te	2078	1949
Low	RRHR	Low_Tech	2010	1952
Low	RRHR	High_Tech	2158	1553
Low	RRLR	Reference_Te	2078	1949
Low	RRLR	Low_Tech	2008	1950
Low	RRLR	High_Tech	2158	1806
Low	RSHR	Reference_Te	2067	1906
Low	RSHR	Low_Tech	2206	1940
Low	RSHR	High_Tech	2046	1513
Low	RSLR	Reference_Te	2070	1941
Low	RSLR	Low_Tech	2011	1939
Low	RSLR	High_Tech	2179	1542
Low	RSRR	Reference_Te	2072	1943
Low	RSRR	Low_Tech	2030	1944
Low	RSRR	High_Tech	2180	1543
Low	SRHR	Reference_Te	2086	1957
Low	SRHR	Low_Tech	2196	1956
Low	SRHR	High_Tech	2143	1557
Low	SRRR	Reference_Te	2081	1952
Low	SRRR	Low_Tech	2011	1953
Low	SRRR	High_Tech	2134	1707

Attachment B

PGE Responses to Data Requests in LC 80

May 30, 2023

To: Sudeshna Pal
Public Utility Commission of Oregon

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
LC 80
PGE Response to OPUC Data Request 007
Dated May 8, 2023

Request:

Please provide all modeling inputs and outputs for each portfolio considered in the IRP. Please provide the data in electronic, Excel format.

Response:

PGE objects to this request on the basis that it is overly broad, unduly burdensome, and requires significant new analysis. Subject to and without waiving its objections, PGE responds as follows:

There are numerous data inputs that flow into portfolio analysis. Many of these inputs are generated by one of multiple upstream models and flow through one or more intermediate steps before ultimately being used as inputs to portfolio modeling. Other inputs are simply text files used to define values of variables that have not come from upstream models and which were not created in Excel workbooks. Portfolio analysis generates outputs in .txt file format.

Attachment 007-A is a compressed file containing the .txt files that are direct inputs to portfolio analysis. All portfolios utilize the inputs in the "default" folder. Portfolio-specific modifications are made in the portfolio-specific folders identified with "P_" followed by the portfolio number. Portfolio numbers are shown in Table 1.

Attachment 007-B is a compressed file containing the .txt files that are direct outputs from portfolio analysis. Outputs for each portfolio are in individual folders identified with "P_" followed by the portfolio number. Portfolio outputs are identified using the numbers shown in Table 1.

Table 1. Portfolio list

Portfolio Number	Portfolio Name
P_1	Linear decline
P_2	Front-loaded decline
P_3	Back-loaded decline
P_4	100% emissions reduction by 2035
P_5	2-yr forward shift in targets
P_6	Optimize NCE DERs

Portfolio Number	Portfolio Name
P_7	Zero NCE
P_8	60 MWa EE
P_9	Default CBREs
P_10	CBRE - 75%
P_11	CBRE - Unavailable
P_12	CBRE - Microgrid
P_13	CBRE - Optimize
P_14	No Tx constraints
P_15	No Upgrades
P_16	Unconstrained SoA
P_17	Unconstrained SoA Plus
P_18	SoA in 2027
P_19	SoA in 2029
P_20	WY in 2026
P_21	NV in 2026
P_22	WY in 2028
P_23	NV in 2028
P_24	Oregon-only resources
P_25	Physical RPS
P_26	Hydrogen blending
P_27	Hydrogen building
P_28	Offshore wind
P_29	Long Duration Storage
P_30	Pumped hydro
P_31	RTO
P_32	Min Avg LT cost
P_33	Min Avg ST cost
P_34	Min Ref ST cost
P_35	SoA in 2027 Plus
P_36	50 Mwa NCE EE
P_37	25 Mwa NCE EE
P_38	70 Mwa NCE EE
P_39	Optimized
P_40	Preferred Portfolio

June 8, 2023

To: Corinne Olson
Alliance of Western Energy Consumers

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
LC 80
PGE Response to AWEC Data Request 013
Dated May 18, 2023

Request:

Please refer to PGE's 2023 IRP Appendix H.4.

a. Please provide all inputs to each capacity expansion developed with ROSE-E.
b. Please provide all constraints used in each ROSE-E model run at the most granular level available.
c. Please provide all outputs of each ROSE-E model run in their native format.
d. Please provide all instructions, user guides, and other written documentation of the ROSE-E model.
e. Please provide access to a functional version of ROSE-E with all reference case inputs, parameters, and constraints.

Response:

a. Please see attachment A of PGE's response to LC 80 OPUC DR 007.
b. Following a conversation with AWEC, PGE's response is as follows: ROSE-E constraints are described in the following sections of the CEP/IRP: Section 11.1 Portfolio design requirements; Appendix H.4.2 ROSE-E Constraints; and Appendix H.7 BPA transmission in ROSE-E.
c. Please see attachment B of PGE's response to LC 80 OPUC DR 007.
d. PGE does not have a user guide for ROSE-E. For description of ROSE-E's functionality, see Appendix I.6 from the 2019 IRP and for key improvements and modifications made since the 2019 IRP, see Appendix H.4 of the 2023 CEP/IRP.
e. Attachment "LC 80_AWEC DR 013_Attach A_HighCONF.gms" contains the GAMS modeling software code that is the series of equations and constraints of which the version of ROSE-E that was used in the 2023 CEP/IRP is constructed. In order to run ROSE-E, one must hold a license for GAMS software and for the Gurobi Optimizer software that is used to solve for optimal solutions. The inputs needed in conjunction with the code to run ROSE-E are referenced in part (a) above. If one does not hold a GAMS license, the series of equations and constraints that comprise ROSE-E can be viewed by opening attachment A in a text editing application (i.e., Notepad). Highly Confidential attachment "LC 80

AWEC DR 013_Attach A_HighCONF” contains highly protected information and is subject to Modified Protective Order No. 23-193.

July 13, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
LC 80
PGE Response to AWEC Data Request 039
Dated July 11, 2023

Request:

Please provide all workpapers supporting PGE's Addendum Filing filed on July 7, 2023.

Response:

All tables and figures (containing quantitative information) from the July 7th Addendum are included in LC 80_AWEC DR 039_Attachment_A.

Additionally listed in the table below are the different models and their confidentiality designation and description of component that changed in the July 7th Addendum. There are two attachments (LC 80_AWEC DR 039_Attachment_B, LC 80_AWEC DR 039_Attachment_C) that corresponded to non- confidential and highly confidential, respectively, with all applicable work files contained in a zip file for each model. Highly Confidential Attachment 039-C contains highly protected information and is subject to Modified Protective Order No. 23-193. The models, their level of confidentiality, and component(s) changed in the Addendum are listed below. Models that are not listed below (e.g., LUCAS) are not included in this DR as they have not been changed from the filed 2023 CEP/IRP.

Model	Confidentiality	Addendum Change
DER forecast	Not confidential	June 2023 updated DER forecast. Reflects updated Transportation Electrification, Solar PV, and Building Electrification market forecasts. No changes to Demand Response forecast, including distributed storage.
Load forecast	Not confidential	June 2023 corporate load forecast

Model	**Confidentiality**	**Addendum Change**
QFs	Not confidential	New snapshot date of June 2023.
Sequoia	Highly Confidential	Light load hour correction, new load forecast, update to 2021 RFP resources, update to QF resources, update to DER forecast, changes to resulting outputs.
Aurora	Highly confidential	Corrected thermal characteristics for select PGE plants which led to different thermal outputs for those plants.
Intermediary GHG	Not confidential	New Aurora inputs, minor adjustment to non-PGE resource balancing, all resulting outputs are changed.
ROSE-E	Not confidential	Updated system need inputs, hybrid and pumped storage settings, Aurora thermal dispatch costs and revenues, RPS obligation (from change in load forecast), REC generation (from changes in portfolio of existing resources), and existing system costs (from changes in portfolio of existing resources). Updated portfolio analysis for all portfolios.
ART	Not confidential	Updated portfolio analysis inputs, iGHG inputs, 2021 RFP inputs, price impact projections

July 7, 2023

To: Irion Sanger
Renewable Northwest

From: Erin Apperson
Assistant General Counsel III

Portland General Electric Company
LC 80
PGE Response to RNW Data Request 001
Dated July 3, 2023

Request:

At PGE's Office Hour held on April 26, 2023, PGE mentioned that Oregon Department of Energy ("ODOE") asked PGE for a study on offshore wind. Please provide:
a. the current draft of the ODOE offshore wind study,
b. previous drafts exchanged with ODOE on the offshore wind study, and
c. a summary of the issues, concerns, and positions PGE has expressed to ODOE related to offshore wind and the offshore wind study.

Response:

a. See Attachment RNW DR 001_Attach A for the current draft of the study.
b. See Attachment RNW DR 001_Attach B for the one previous draft of the study exchanged with ODOE.
c. Offshore wind (OSW) offers promising potential to help PGE meet resource needs. However, some key caveats to consider in the interpretation and extrapolation of results from PGE's supplemental offshore wind study are:

- PGE's portfolio analysis is predicated on the use of proxy resources. Proxy resources are meant to represent the type of projects that may become available for acquisition rather than specific projects. Resource buildout results therefore represent a generalized resource mix. The cost-competitiveness of specific projects will be evaluated through the RFP process.
- There is substantial uncertainty surrounding the cost of OSW.
- There is also substantial technological uncertainty around the development of OSW, especially given that there are currently no OSW developments in Oregon to serve as examples.
- The sources of uncertainty in the previous two bullet points are especially true of floating offshore wind, which is less-developed than fixed-bottom offshore wind.
- Transmission cost and availability estimates used in this analysis are generic assumptions and actual costs of Transmission needed for OSW may differ substantially.

- After transmission-constrained resources are fully utilized, offshore wind is competing economically only against the high-cost generic resources.
- There is substantial uncertainty about the availability and cost of other potential technologies and this study does not compare offshore wind to other emerging technologies like hydrogen, small modular nuclear reactors, long duration storage, enhanced power markets, and others.
- Because of the uncertainty in assumptions regarding costs of emerging technologies and transmission, resource buildout results with regards to these resources provide directional information about the potential role for these resources, rather than prescriptive findings about quantities and cost impacts.

Portland General Electric

2023 Supplemental Analysis of Offshore Wind

1. Introduction

PGE conducted the following analysis in response to a request from staff at Oregon Department of Energy (ODOE) regarding portfolio analysis focused on offshore wind resources. The request asked that PGE conduct analysis beyond the offshore wind focused portfolio in the 2023 IRP.[1]

Consistent with the approach to modeling of other emerging technologies, the offshore wind portfolio in the 2023 IRP forced the addition of a certain amount of the resource at a specific point in time and the impacts on portfolio cost and risk were analyzed. The offshore wind portfolio added 500 MW of offshore wind to PGE's portfolio in 2032. The offshore study request asked for portfolio analysis with offshore wind available for optimized selection in portfolio modeling, with no limit on total MW selected. The request also asked to include transmission costs in the total resource cost of offshore wind (this was not a component of offshore wind modeling in the 2023 IRP). The request also asked that alternative timing of commercial availability be considered in the analysis.

Results of the study reveal optimized selection of offshore wind as early as 2030 and reduced portfolio cost and risk metrics associated with the availability of offshore wind. Results also show that earlier availability of the resource has the potential to reduce portfolio costs. PGE has large resource needs over the coming decades and these results illustrate the potential value of offshore wind if it becomes available. However, care should be taken with the extrapolation of these results due uncertainty in key assumptions including offshore wind Transmission costs and the availability of alternative proxy resources for selection in the model. As such, there are some key caveats to consider in the interpretation and extrapolation of results:

- PGE's portfolio analysis is predicated on the use of proxy resources. Proxy resources are meant to represent the type of projects that may become available for acquisition rather than specific projects. Resource buildout results therefore represent a generalized resource mix. The cost-competitiveness of specific projects will be evaluated through the RFP process.
- There is substantial uncertainty surrounding the cost of offshore wind.
- There is also substantial technological uncertainty around the development of OSW, especially given that there are currently no offshore wind developments in Oregon to serve as examples.
- The sources of uncertainty in the previous two bullet points are especially true of floating offshore wind, which is less-developed than fixed-bottom offshore wind.
- Transmission cost estimates used in this analysis are generic and actual costs of Transmission needed for OSW may differ substantially.
- After transmission-constrained resources are fully utilized, offshore wind is competing economically only against the high-cost generic resources.
- There is substantial uncertainty about the availability and cost of other potential technologies and this study does not compare offshore wind to other emerging technologies like hydrogen, small modular nuclear reactors, long duration storage, enhanced power markets, and others.

[1] Details on the offshore wind and other emerging technology portfolios in Chapter 11 of PGE's 2023 IRP are available here: https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf

- Because of the uncertainty in assumptions regarding costs of emerging technologies and transmission, resource buildout results with regards to these resources provide directional information about the potential role for these resources, rather than prescriptive findings about quantities and cost impacts.

The subsequent sections of this report summarize PGE's resource needs, provide the performance characteristics and resource economics of the offshore wind proxy resource, describe portfolio analysis study design, and present results.

2. Resource Needs

Due to factors including load growth, expiring non-GHG emitting resource contracts and decreasing retail sales from existing thermal resources, PGE has a need for additional non-GHG emitting resources. Resource needs can be expressed in terms of required capacity and energy. Based on analysis from the 2023 CEP/IRP, under reference case conditions, absent any incremental resource additions PGE has a forecasted 2026 capacity need of 506 MW in summer and 430 MW in winter, growing to 4173 MW in summer and 3912 MW in winter in 2040. PGE has a forecasted Reference case energy need of 59 MWa by 2026, growing to 2235 MWa in 2040. The large needs that arise by 2040 necessitate substantial resource additions and there are a variety of resources that may emerge to fill them.

3. Offshore Wind Performance Characteristics

PGE's offshore wind proxy resource has a relatively high annual average capacity factor of 55% and provides diversity in generation profiles compared to onshore wind resources, which increases both, its energy value and capacity value. In 2023 IRP modeling, at an incremental addition of 100 MWa offshore wind has an annual average effective-load-carrying-contribution of 56%.

4. Resource Economics

Net cost analysis is a commonly used method to compare the relative economics of alternative resource options. The net cost of a resource is the sum of all associated costs, net of any benefits it provides. Results of the net cost analysis of offshore wind are shown in Figure 1. The net cost of offshore wind is $28/MWh for a 2030 COD at a 100 MWa (182 MW of nameplate). As seen in Figure 1, offshore wind costs are driven by fixed costs, with transmission costs making up a relatively small portion in this modeling exercise.

For comparison, the net cost analysis of the other wind + transmission expansion resource option in the analysis (WY wind) is shown in Figure 2. An important difference between these resources is that the WY wind resource includes costs and benefits of market access and as a result provides 100% capacity contribution. While offshore wind provides higher levels of capacity contribution relative to other stand-alone VER resources, the capacity benefits are lower than for the WY wind resource because it does not provide access to regional markets. Thus, offshore wind + transmission expansion option does not include costs or benefits of market access and only includes the benefits are provided by the offshore wind resource.

Net costs of WY wind are larger than offshore wind at $53/MWh at 100 MWa. For WY wind, transmission costs (which include embedded market access costs) make up a substantially larger share of net costs than fixed costs ($92/MWh in Transmission cost vs $41/MWh in wind fixed costs). The difference in transmission costs between offshore wind and WY wind in this analysis are driven mainly by distance and more detailed cost estimates of transmission costs may reveal different dynamics.

Figure 1. Net costs for 100 MWa of offshore wind (2030 COD)

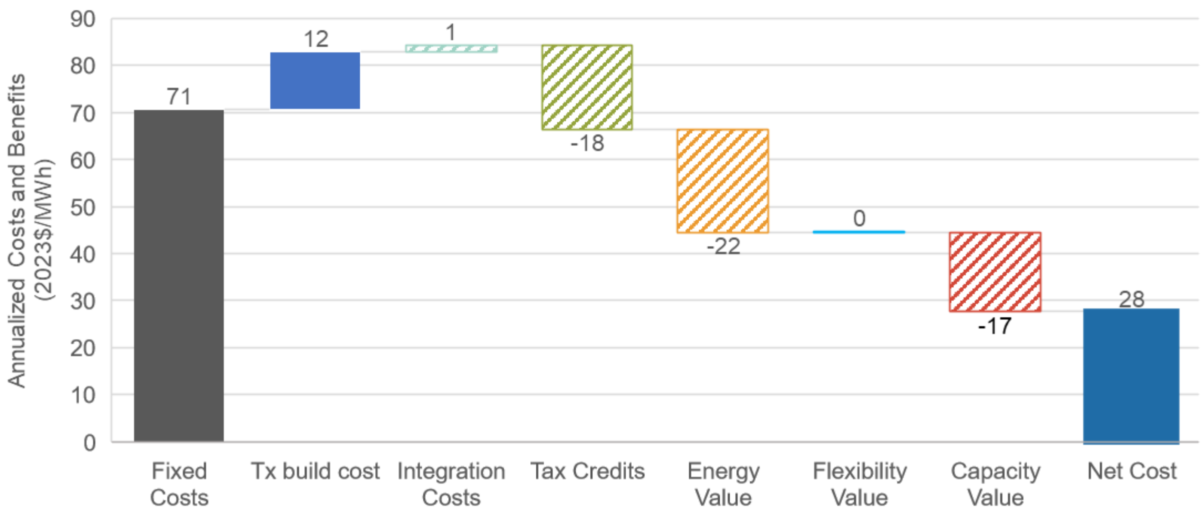
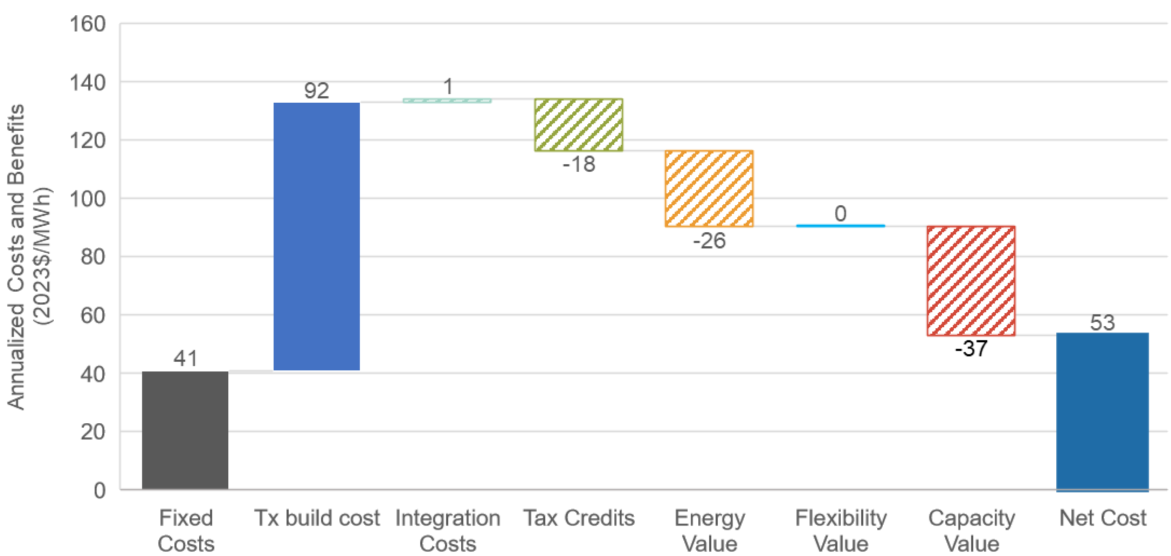


Figure 2. Net costs for 100 MWa of WY wind + Transmission expansion (2026 COD)



5. Portfolio Analysis Design

PGE designed and analyzed six offshore wind portfolios and compared them to a portfolio in which offshore wind is not available for selection. Portfolios are subject to the same constraints and default assumptions used in the 2023 IRP Preferred Portfolio. For more detail on these assumptions, see Chapter 11 of the 2023 IRP (available at the location provided in Footnote 1). Key assumptions that align with the Preferred Portfolio are:

- **Transmission constraints**: Access to PNW proxy resources is limited to the amount that can be accessed through a constraint representing transmission available in the contractual transmission landscape.
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- **Transmission resources**: Portfolios add 400 MW of SoA upgrade in 2027 and have access to 400 MW of WY transmission, and 400 MW of NV transmission starting in 2026.
- **Contract extension**: Portfolios include 200 MW of contract extension in the years 2026 – 2030.
- **CBREs**: Portfolios include 155 MW of CBREs acquired by 2030.

Key design components of the of the offshore study that differ from assumptions in the 2023 IRP include:

- **Offshore wind resource availability**: The offshore wind proxy resource is made available for optimized selection with no constraint on the total quantity available.
- **Timing of availability of offshore wind**: Six portfolios are analyzed, varying the first year of availability of offshore wind from 2030 to 2035 to test the effect on portfolio outcomes. No annual build limit on offshore wind is imposed.
- **Offshore wind transmission costs:** Total costs of offshore wind are defined using the values from the 2023 IRP, with additional costs for transmission added (combined costs shown in Table 1). Transmission costs for offshore wind are estimated using the same transmission cost data and methodology used to derive costs estimates of WY and NV transmission expansion proxies in 2023 IRP.[3] Costs of offshore wind transmission are estimated to be $58.80/kW-year.[4] This cost is included in the total offshore wind costs shown in Table 1 along with tax credit impacts and integration costs.

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[2] Generic resources have total costs equal to 105 percent of the highest-cost proxy resource option (NV Transmission).
[3] Costs of WY and NV transmission expansion proxies are shown in Chapter 9 of the 2023 IRP, available here: https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf

4 With the methodology used, transmission cost is a function of distance. Therefore, because the length of a transmission line from PGE's load center to the Southern coast of Oregon is shorter than to WY or NV, the fixed costs of transmission for offshore wind are lower than for WY wind or NV solar. In reality, there are likely to be other differences between alternative transmission projects that will influence costs.

Table 1. Offshore wind total costs (Reference technology cost future), including transmission costs

COD	Total costs (2023$/kW-year)
2024	383.70
2025	370.36
2026	357.14
2027	344.95
2028	336.43
2029	328.19
2030	319.85
2031	311.10
2032	302.61
2033	298.61
2034	294.60
2035	290.84
2036	287.36
2037	284.12
2038	280.81
2039	277.65
2040	274.70
2041	271.92
2042	269.15
2043	266.47

6. Results and Insights

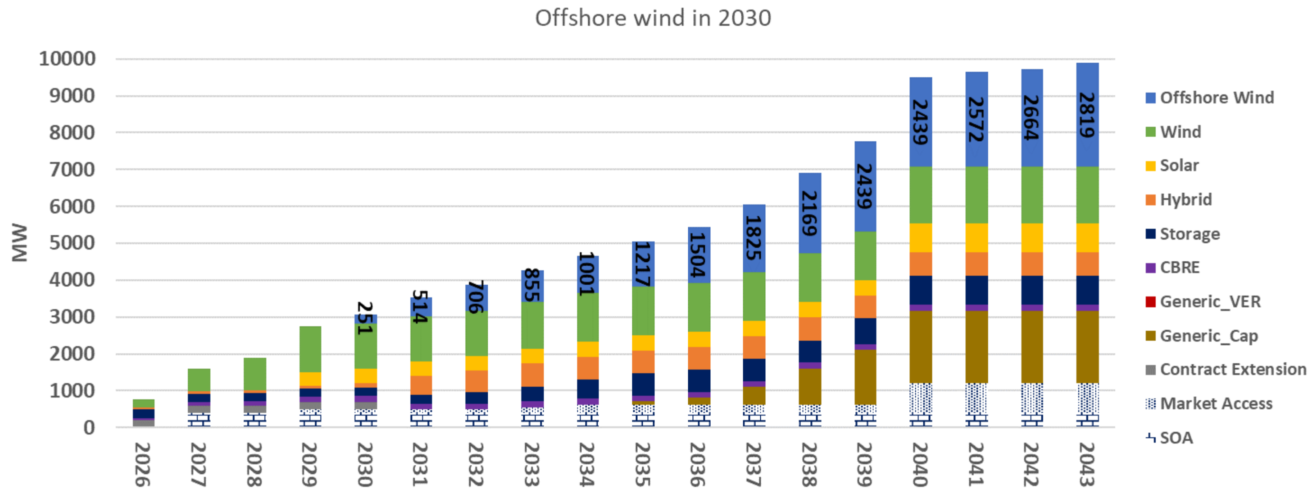
In the transmission-constrained system modeled in this analysis, after the available Transmission capacity is fully utilized, offshore wind is competing economically only against the high-cost generic resources. Large additions of offshore wind reveal that it is generally a more cost-effective source of energy than the generic VER. Results show that offshore wind has the potential to fill a substantial part of the GHG-free energy need in the post-2030 time-horizon. However, other technologies may emerge to compete to fill that role and there is substantial uncertainty about the relative rate at which these technologies will develop technologically and economically. There is also uncertainty regarding the cost projections used for offshore wind in this study given that there is no offshore wind development in Oregon today. This study does not compare offshore wind to other emerging technologies like hydrogen, small modular nuclear reactors, long duration storage, enhanced power markets, and others. Because of the substantial uncertainty associated with the cost, availability and performance of emerging technologies, PGE conducted a detailed qualitative review of a variety of emerging technologies, in addition to the emerging technologies portfolio group analysis.[5]

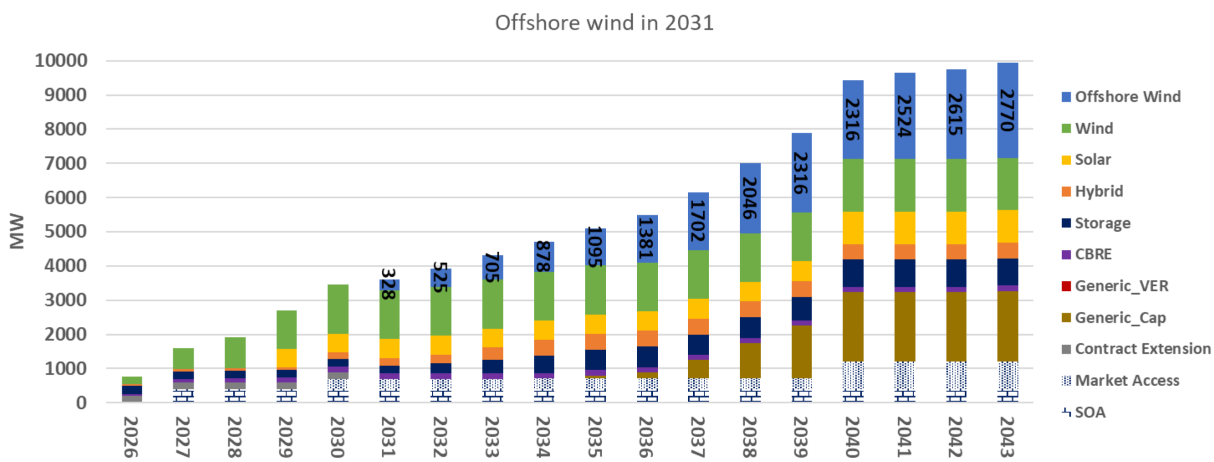
Reference case resource buildouts from 2026 through 2043 for each of the portfolios are shown in Figure 3. Results show that offshore wind is added in the first year of availability in all cases and is added in amounts up to 2819 MW through 2043 (when offshore wind becomes available in 2030). The earlier offshore wind becomes available, the greater the total amount of offshore wind that is added throughout the modeling time-horizon (Reference case incremental additions of offshore wind in each portfolio are shown in Table 2). Offshore wind additions for High and Low need cases are shown in Tables 3 and 4, respectively. In the High need case, up to 3694 MW of offshore wind is added through 2043. In the Low need case, the first year that offshore wind is added is 2031 and thus is not always added in the first year of availability. Substantially less offshore wind is added in the Low need case, with a maximum of 1790 MW added through 2043.

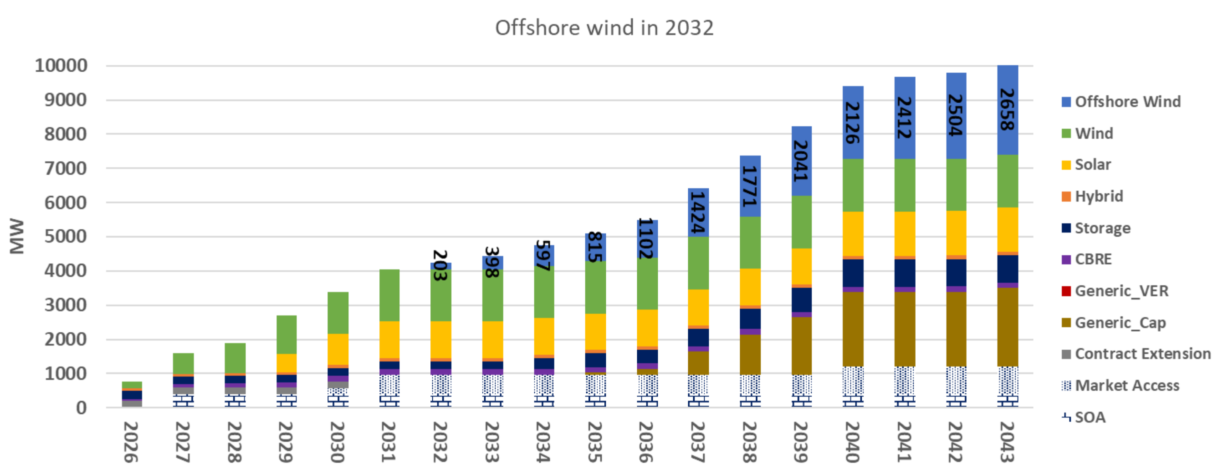
Results show all portfolios that have access to offshore wind have lower portfolio cost and risk compared to the portfolio in which offshore wind is not available (cost and risk metrics for each portfolio are shown in Figure 4). Earlier availability of offshore wind results in lower portfolio costs. The reduction in portfolio cost is driven by the ability to offset additions of the expensive generic resources. When offshore wind becomes available in 2030 – 2032, the need to build Generic VER is reduced to zero in the Reference case. When offshore wind doesn't become available until 2035, 615 MW of Generic VER is added through the planning horizon (Reference case). While the difference is less stark, earlier availability of offshore wind also reduces the need for Generic Capacity (1977 MW in the Reference case of 'Offshore wind in 2030' and 2265 MW in the Reference Case of 'Offshore wind in 2035').

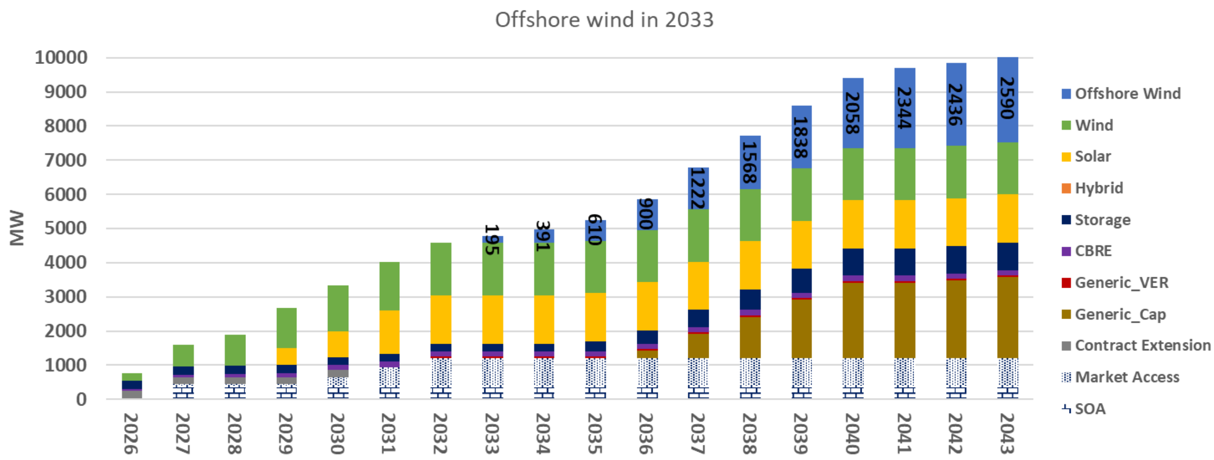
[5] Analysis of post-2030 resource options in Chapter 8 of PGE's 2023 IRP are available her: https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf

Figure 3. Reference Case resource buildout in offshore wind portfolios (cumulative MW)








Offshore wind in 2033
MW
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
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2030
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2040
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2042
2043
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900
1222
1568
1838
2058
2344
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Offshore Wind
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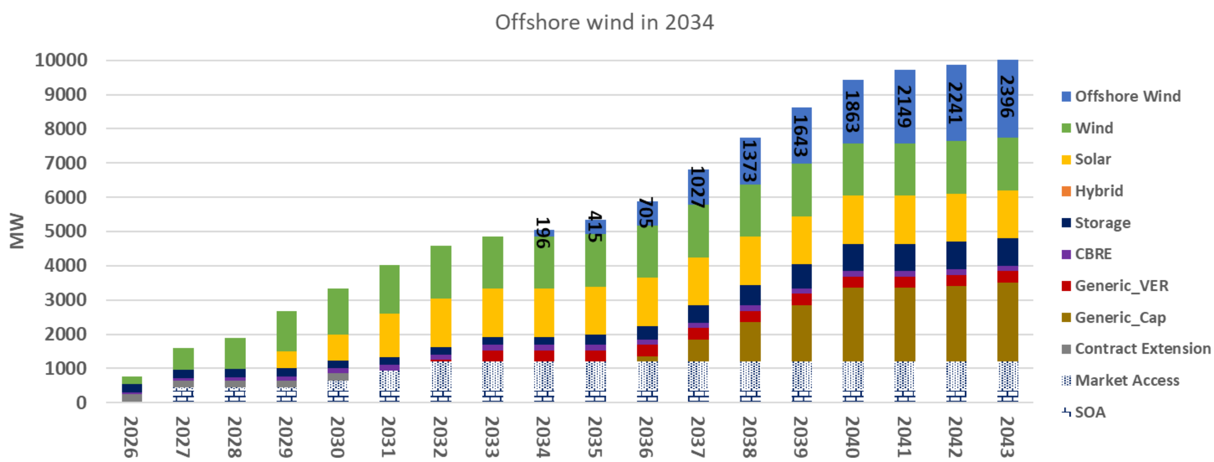
CBRE
Generic_VER
Generic_Cap
Contract Extension
Market Access
SOA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MW
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Offshore Wind
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Generic_VER
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Contract Extension
Market Access
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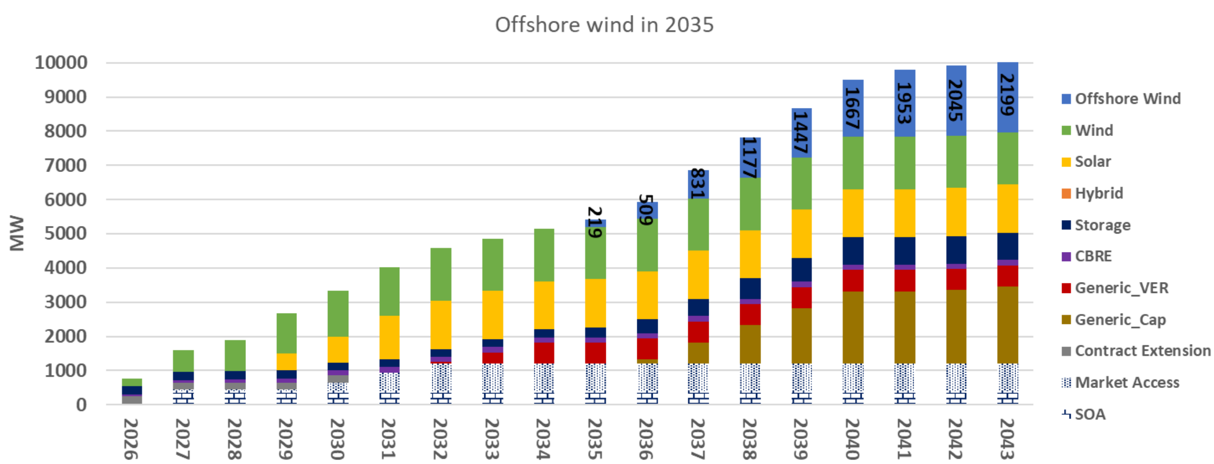
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MW
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Offshore Wind
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Table 2. Reference Case incremental offshore wind additions (MW), by year of first availability

First year Available	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
2030	251	263	191	150	146	216	286	321	344	270	0	134	91	155
2031	0	328	197	179	173	217	286	321	344	270	0	208	91	155
2032	0	0	203	195	199	218	287	322	346	270	85	286	91	155
2033	0	0	0	195	196	219	290	322	346	270	220	286	91	155
2034	0	0	0	0	196	219	290	322	346	270	220	286	91	155
2035	0	0	0	0	0	219	290	322	346	270	220	286	91	155

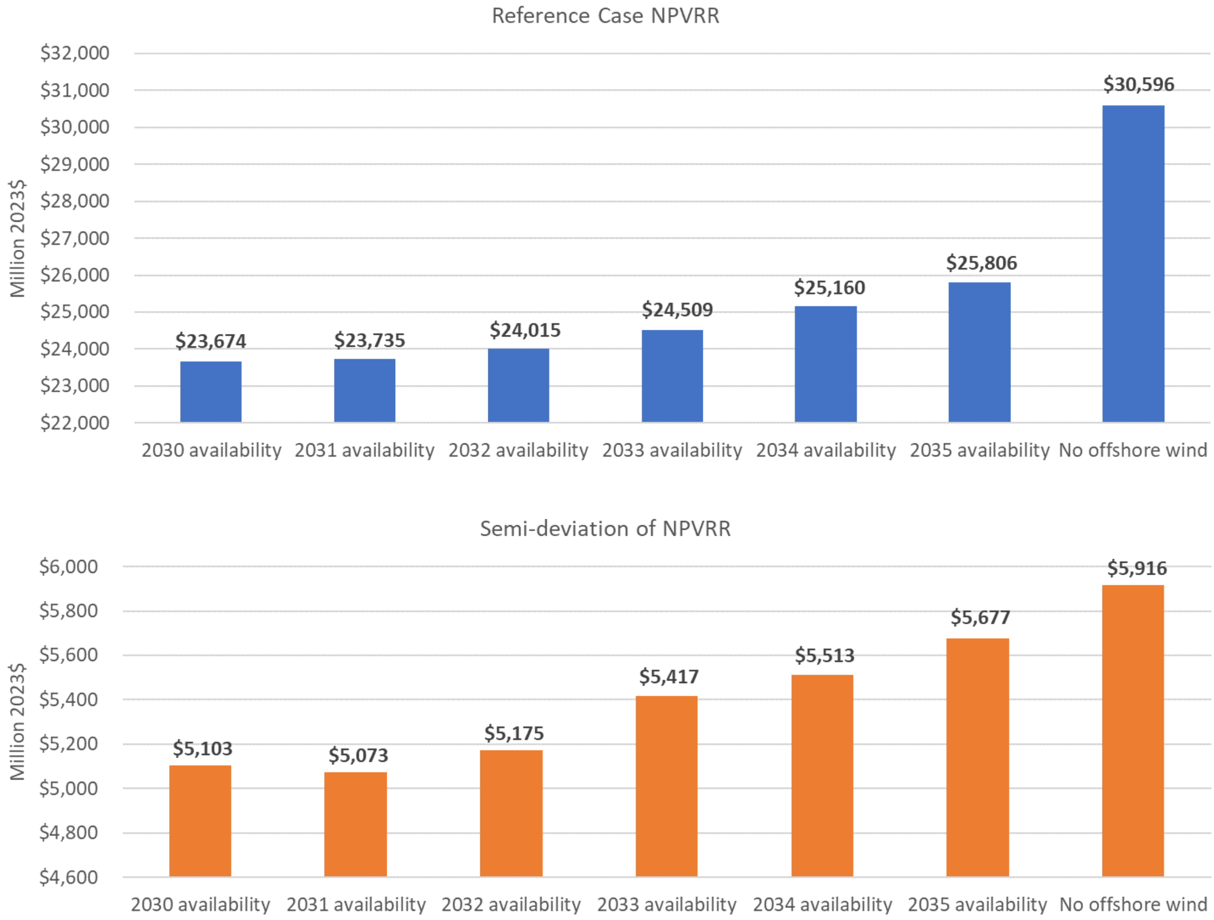
Table 3. High Need case incremental offshore wind additions (MW), by year of first availability

First year Available	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
2030	320	290	219	254	254	268	344	366	386	309	72	320	109	182
2031	0	390	258	254	253	269	345	366	389	308	161	320	109	182
2032	0	0	267	254	253	270	345	368	389	308	253	320	109	182
2033	0	0	0	259	253	270	345	367	389	308	253	320	109	182
2034	0	0	0	0	262	270	346	365	389	308	253	319	109	182
2035	0	0	0	0	0	276	346	365	389	308	253	319	109	182

Table 4. Low Need case incremental offshore wind additions (MW), by year of first availability

First year Available	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
2030	0	263	147	141	134	154	197	234	290	25	0	57	51	97
2031	0	263	147	141	134	154	197	234	290	25	0	57	51	97
2032	0	0	157	141	142	165	226	265	291	98	0	56	51	96
2033	0	0	0	148	142	163	226	266	291	208	0	56	51	96
2034	0	0	0	0	148	163	226	266	291	212	0	182	51	96
2035	0	0	0	0	0	163	226	266	291	212	92	237	51	96

Figure 4. Cost and risk metrics of offshore wind portfolios



2023 Supplemental Analysis of Offshore Wind

1. Introduction

PGE conducted the following analysis (offshore study) in response to a request from staff at Oregon Department of Energy (ODOE) regarding portfolio analysis focused on offshore wind resources. The request asked that PGE conduct analysis beyond the offshore wind focused portfolio in the 2023 IRP.[1]

Consistent with the approach to modeling of other emerging technologies, the offshore wind portfolio in the 2023 IRP forced the addition of a certain amount of the resource at a specific point in time and the impacts on portfolio cost and risk were analyzed. The offshore wind portfolio added 500 MW of offshore wind to PGE's portfolio in 2032. The offshore study request asked for portfolio analysis with offshore wind available for optimized selection in portfolio modeling, with no limit on total MW selected. The request also asked to include transmission (Tx) costs in the total resource cost of offshore wind (this was not a component of offshore wind modeling in the 2023 IRP). The request also asked that alternative timing of commercial availability be considered in the analysis.

Results of the study reveal optimized selection of offshore wind as early as 2030 and reduced portfolio cost and risk metrics associated with the availability of offshore wind. Results also show that earlier availability of the resource has the potential to reduce portfolio costs. Care should be taken with the extrapolation of these results due uncertainty in key assumptions including offshore wind Tx costs and the availability of alternative proxy resources for selection in the model. The subsequent sections of this document will describe the performance characteristics and resource economics of offshore wind, present the portfolio analysis study design, and provide results.

2. Offshore Wind Performance Characteristics

PGE's offshore wind proxy resource has a relatively high annual average capacity factor of 55% and provides diversity in generation profiles compared to onshore wind resources, which increases both, its energy value and capacity value. In 2023 IRP modeling, at an incremental addition of 100 MWa offshore wind has an annual average effective-load-carrying-contribution of 56%.

3. Resource Economics

Net cost analysis is a commonly used method to compare the relative economics of alternative resource options. The net cost of a resource is the sum of all associated costs, net of any benefits it provides. Results of the net cost analysis of offshore wind are shown in Figure 1. The net cost of offshore wind is $28/MWh for a 2030 COD at a 100 MWa (182 MW of nameplate). As seen in Figure 1, offshore wind costs are driven by fixed costs, with transmission costs making up a relatively small portion in this modeling exercise.

For comparison, the net cost analysis of the other wind + transmission expansion resource option in the analysis (WY wind) is shown in Figure 2. An important difference between these resources is that the WY wind resource includes costs and benefits of market access and as a result provides 100% capacity

[1] Details on the offshore wind and other emerging technology portfolios in Chapter 11 of PGE's 2023 IRP are available here: https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf

contribution. While offshore wind provides higher levels of capacity contribution relative to other stand-alone VER resources, the capacity benefits are lower than for the WY wind resource because it does not provide access to regional markets. Thus, offshore wind + transmission expansion option does not include costs or benefits of market access and only includes the benefits are provided by the offshore wind resource.

Net costs of WY wind are larger than offshore wind at $53/MWh at 100 MWa. For WY wind, transmission costs (which include embedded market access costs) make up a substantially larger share of net costs than fixed costs ($92/MWh in Tx cost vs $41/MWh in wind fixed costs). The difference in transmission costs between offshore wind and WY wind in this analysis are driven mainly by distance and more detailed cost estimates of transmission costs may reveal different dynamics.

Figure 1. Net costs for 100 MWa of offshore wind (2030 COD)

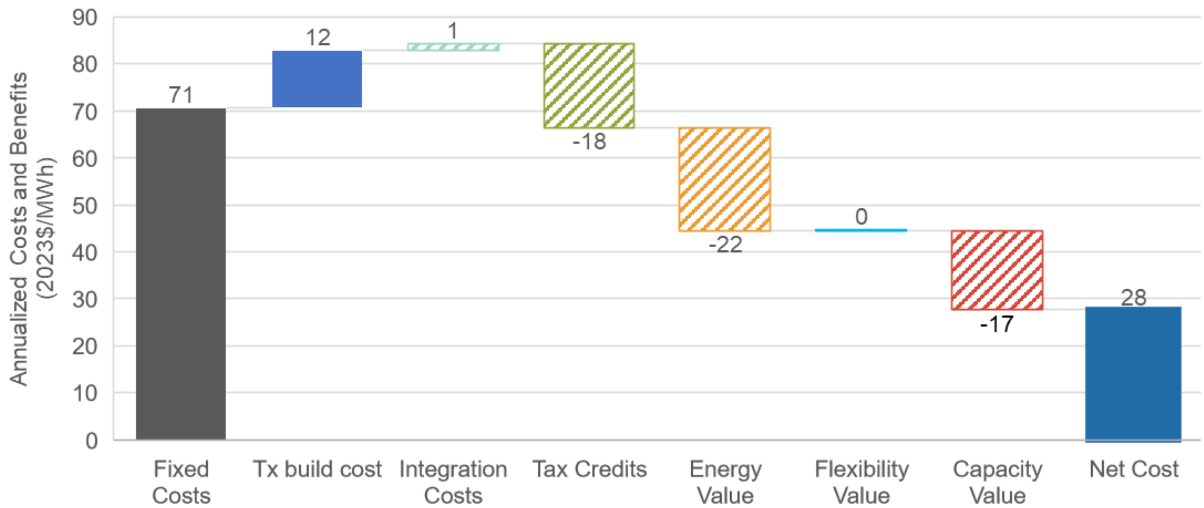
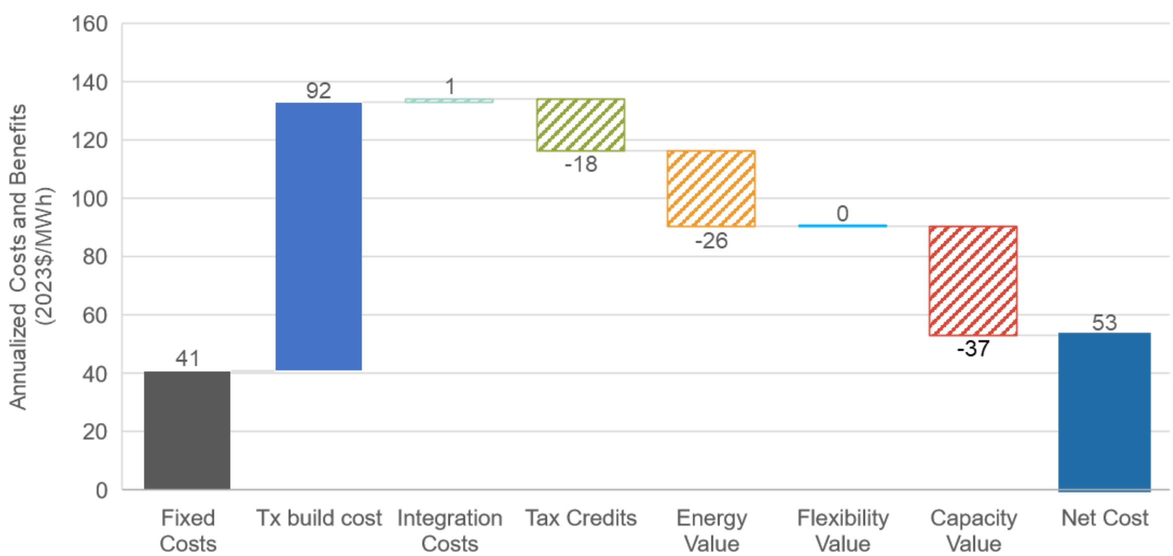


Figure 2. Net costs for 100 MWa of WY wind + Tx expansion (2026 COD)



4. Portfolio Analysis Design

PGE designed and analyzed six offshore wind portfolios and compared them to a portfolio in which offshore wind is not available for selection. Portfolios are subject to the same constraints and default assumptions used in the 2023 IRP Preferred Portfolio. For more detail on these assumptions, see Chapter 11 of the 2023 IRP (available at the location provided in Footnote 1). Key assumptions that align with the Preferred Portfolio are:

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Key design components of the of the offshore study that differ from assumptions in the 2023 IRP include:

- **Offshore wind resource availability**: The offshore wind proxy resource is made available for optimized selection with no constraint on the total quantity available.
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4 With the methodology used, transmission cost is a function of distance. Therefore, because the length of a transmission line from PGE's load center to the Southern coast of Oregon is shorter than to WY or NV, the fixed costs of transmission for offshore wind are lower than for WY wind or NV solar. In reality, there are likely to be other differences between alternative transmission projects that will influence costs.

Table 1. Offshore wind total costs (Reference technology cost future), including transmission costs

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5. Results and Insights

In the transmission-constrained system modeled in this analysis, after the available Tx capacity is fully utilized, offshore wind is competing economically only against the high-cost generic resources. Large additions of offshore wind reveal that it is generally a more cost-effective source of energy than the generic VER. Results show that offshore wind has the potential to fill a substantial part of the GHG-free energy need in the post-2030 time-horizon. However, other technologies may emerge to compete to fill that role and there is substantial uncertainty about the relative rate at which these technologies will develop technologically and economically. There is also uncertainty regarding the cost projections used for offshore wind in this study given that there is no offshore wind development in Oregon today. This study does not compare offshore wind to other emerging technologies like hydrogen, small modular nuclear reactors, long duration storage, enhanced power markets, and others. Because of the substantial uncertainty associated with the cost, availability and performance of emerging technologies, PGE conducted a detailed qualitative review of a variety of emerging technologies, in addition to the emerging technologies portfolio group analysis.[5]

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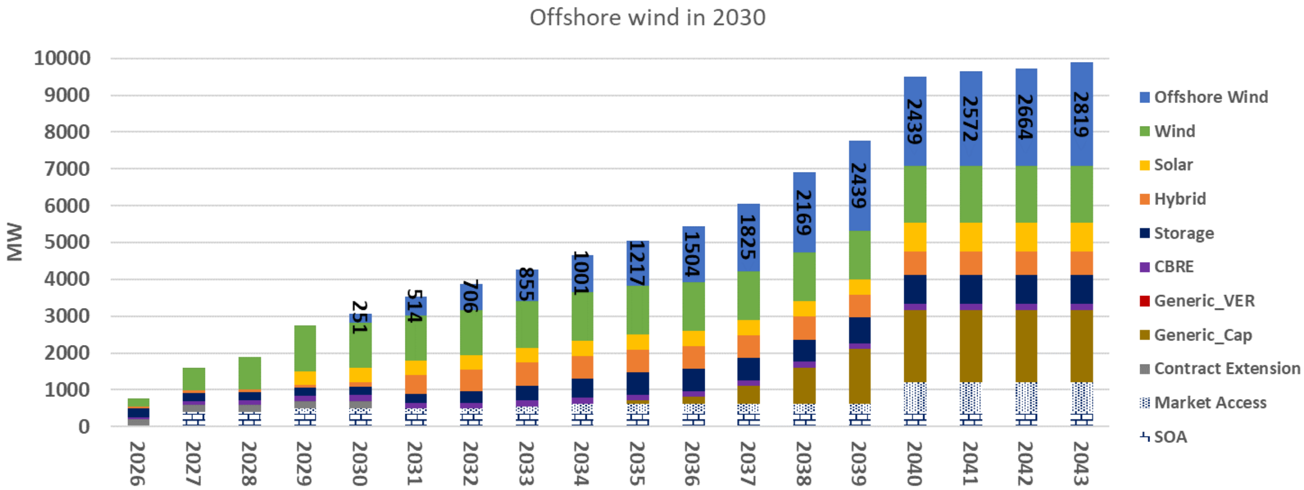
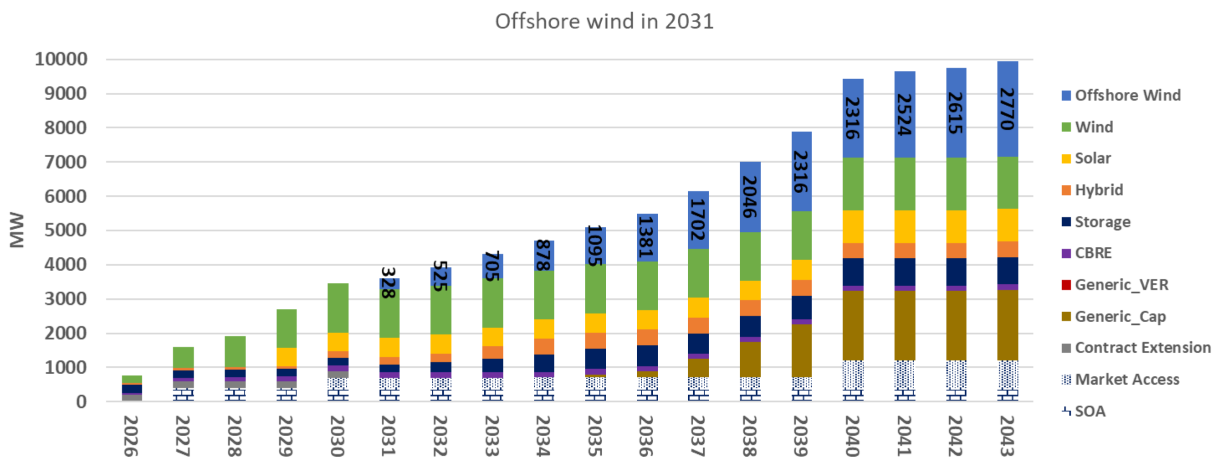
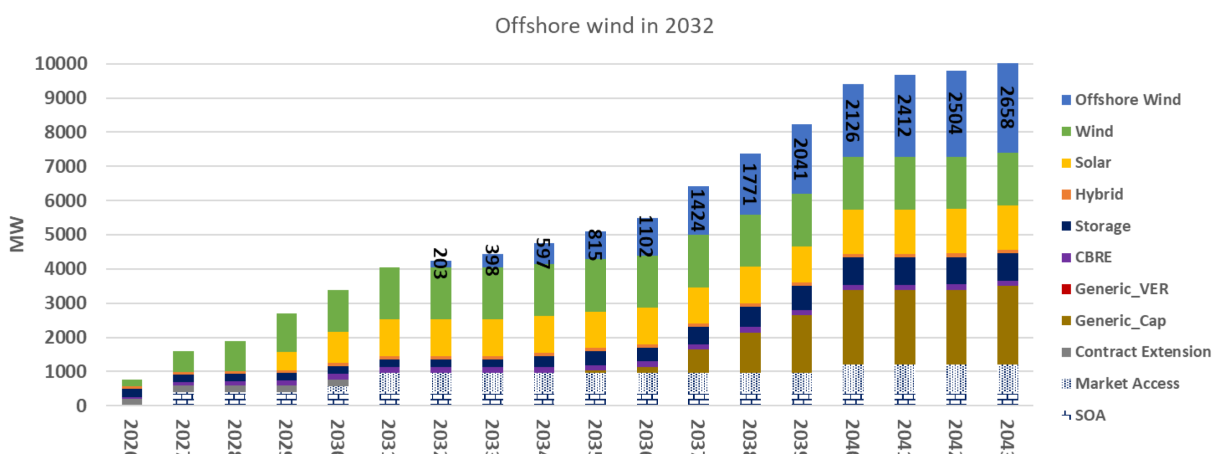
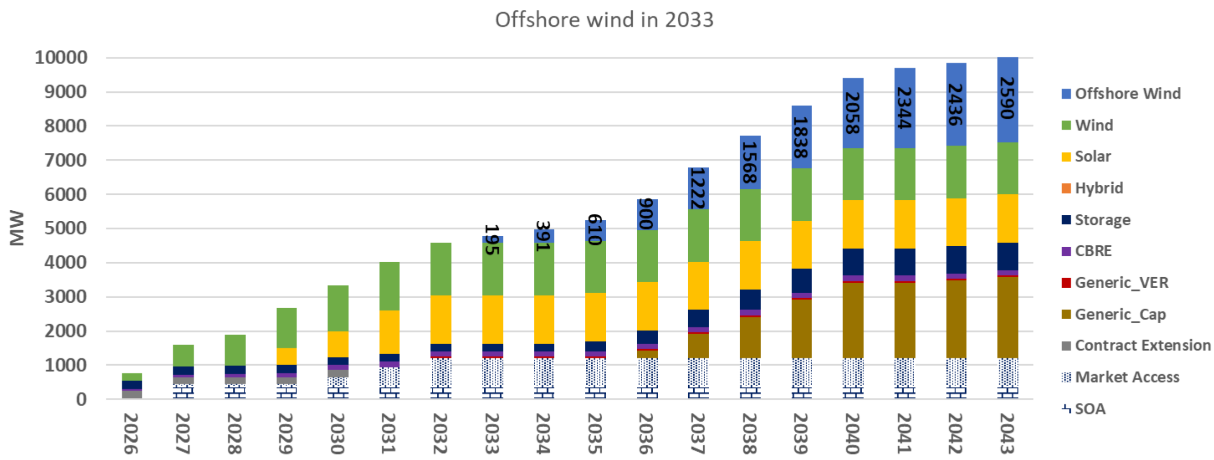
Figure 3. Reference Case resource buildout in offshore wind portfolios (cumulative MW)





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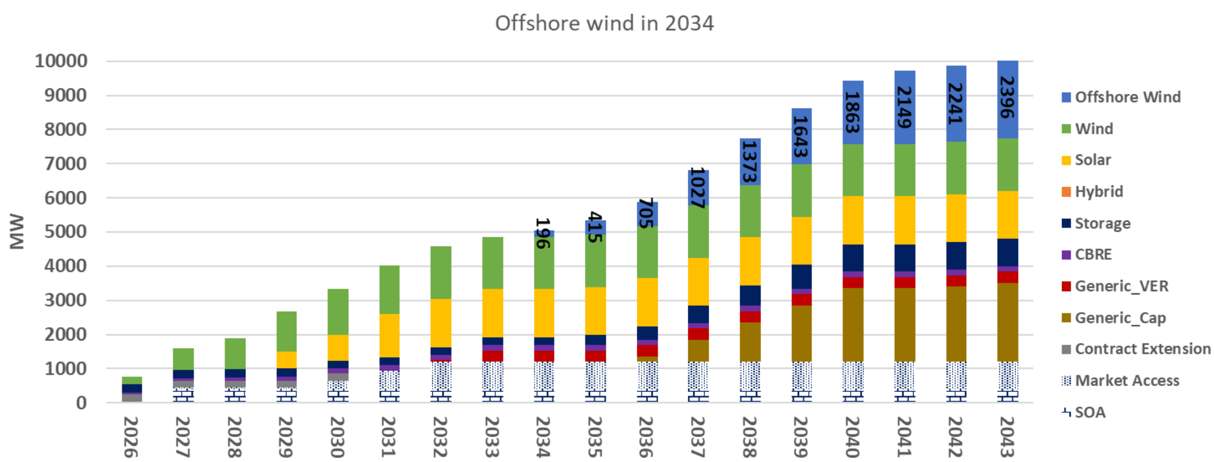
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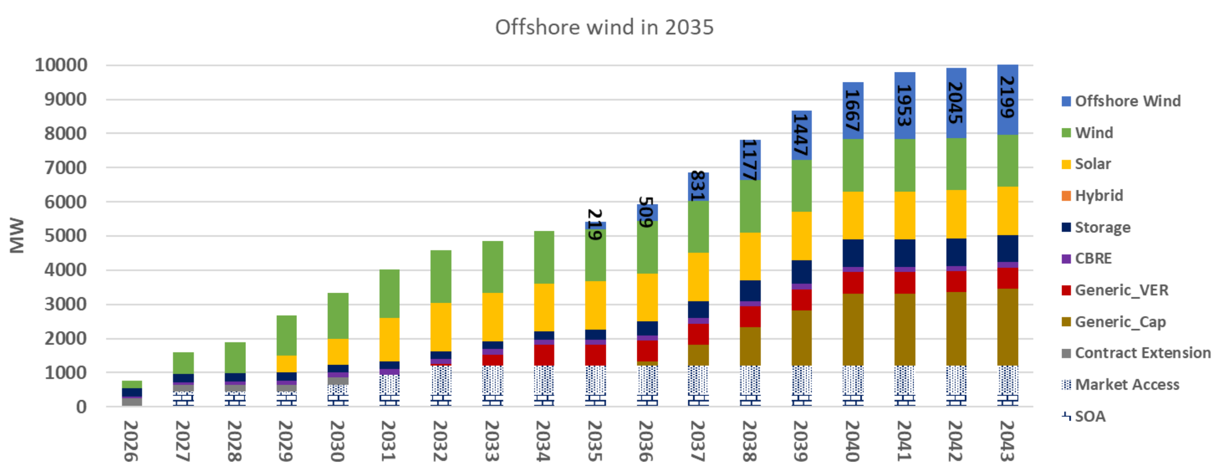
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Table 2. Reference Case incremental offshore wind additions (MW), by year of first availability

First year Available	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
2030	251	263	191	150	146	216	286	321	344	270	0	134	91	155
2031	0	328	197	179	173	217	286	321	344	270	0	208	91	155
2032	0	0	203	195	199	218	287	322	346	270	85	286	91	155
2033	0	0	0	195	196	219	290	322	346	270	220	286	91	155
2034	0	0	0	0	196	219	290	322	346	270	220	286	91	155
2035	0	0	0	0	0	219	290	322	346	270	220	286	91	155

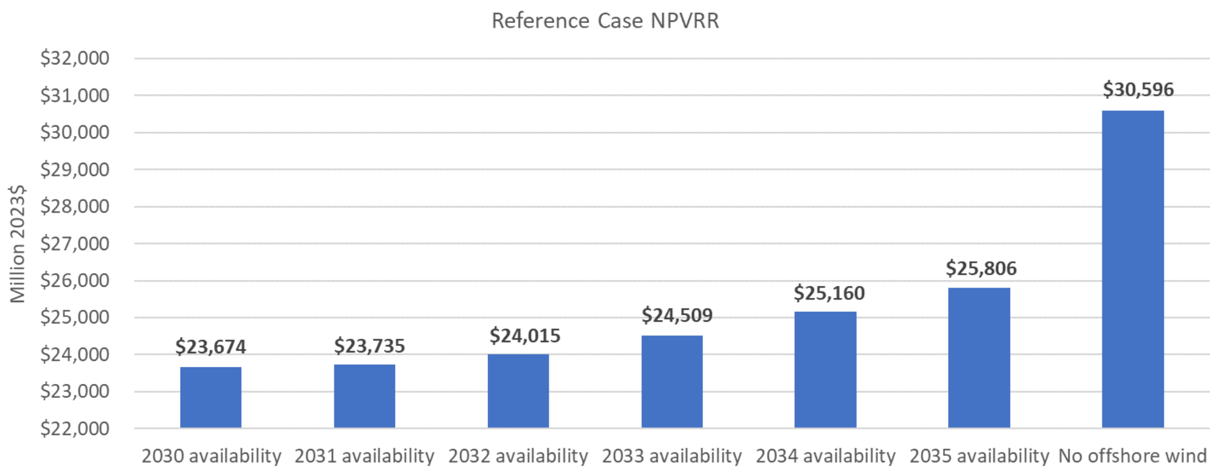
Table 3. High Need case incremental offshore wind additions (MW), by year of first availability

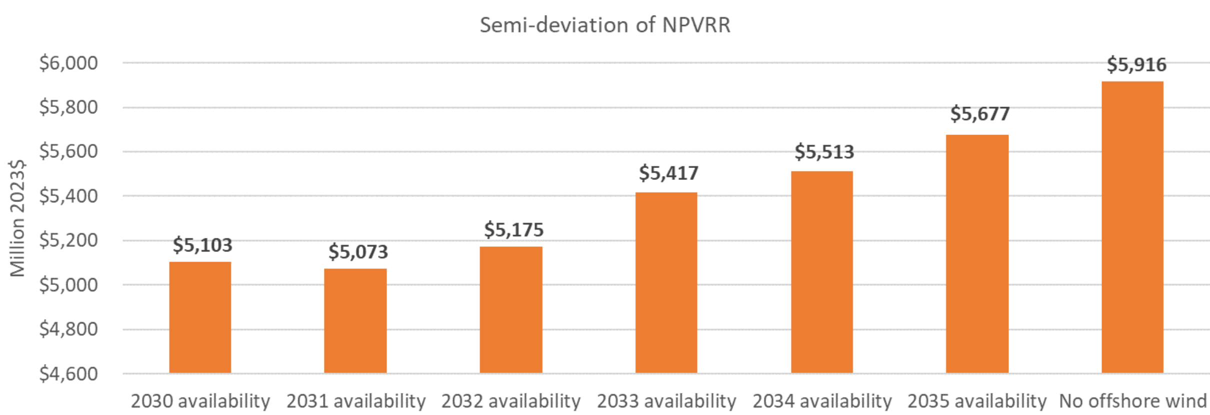
First year Available	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
2030	320	290	219	254	254	268	344	366	386	309	72	320	109	182
2031	0	390	258	254	253	269	345	366	389	308	161	320	109	182
2032	0	0	267	254	253	270	345	368	389	308	253	320	109	182
2033	0	0	0	259	253	270	345	367	389	308	253	320	109	182
2034	0	0	0	0	262	270	346	365	389	308	253	319	109	182
2035	0	0	0	0	0	276	346	365	389	308	253	319	109	182

Table 4. Low Need case incremental offshore wind additions (MW), by year of first availability

First year Available	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
2030	0	263	147	141	134	154	197	234	290	25	0	57	51	97
2031	0	263	147	141	134	154	197	234	290	25	0	57	51	97
2032	0	0	157	141	142	165	226	265	291	98	0	56	51	96
2033	0	0	0	148	142	163	226	266	291	208	0	56	51	96
2034	0	0	0	0	148	163	226	266	291	212	0	182	51	96
2035	0	0	0	0	0	163	226	266	291	212	92	237	51	96

Figure 4. Cost and risk metrics of offshore wind portfolios





Attachment C

NorthernGrid Economic Study Request
Offshore Wind in Oregon (2023)

NorthernGrid

Economic Study Request

Offshore Wind in Oregon

2023

Contents

Request

In March of 2022, The Oregon Public Utility Commission along with the Oregon Department of Energy jointly submitted to the NorthernGrid planning region a request for both economic and reliability analysis of the regional impacts to the transmission system resulting from the modeling of the installation of 3 GW capacity (nameplate)along Oregon's southern coastline. The high-level details of the request are listed below.

1. 3.0 GW of wind split with 1800 MW interconnected at the Fairview substation near Coos Bay, OR and 1200 MW at the Wendson substation near Florence, OR.

2. Planned in-development date of December, 2032

"This evaluation should also include an identification of transmission system upgrades necessary to accommodate the power flow capacities of key existing transmission corridors and paths (e.g., 230 kV to 500 kV) to enable the full deliverabilty of the power to load with minimal curtailment of generation due to transmission constraints."

Basis for 3 GW and the Selection/Split Across Two Coastal Substations in Southern Oregon

Through adoption of HB 3375 in 2021, the Oregon legislature established a state policy goal to plan for the development of up to 3 GW of floating offshore wind energy projects within federal waters off the Oregon coast by 2030 (see Chapter 376, Oregon Laws 2021). This policy goal is guiding Oregon's state agencies in their exploration of the potential impacts from integrating up to 3 GW of offshore wind into Oregon's electric grid, and is not a commitment to developing offshore wind.

Subsequently, on April 29, 2022, the federal Bureau of Ocean Energy Management (BOEM) identified two "Call Areas" in proximity to the Southern Oregon coast, one near Coos Bay, Oregon, and the other near Brookings, Oregon (see Federal Register, Vol. 87, No. 83. Call Areas are delineated for the purposes of BOEM's call for information and feedback on site conditions, resources, and ocean uses within the call areas; and for nominations of smaller areas of interest within the call areas for potential leases. As of April 2023, BOEM has not yet determined which areas, if any, within the Oregon Call Areas may be offered for lease.

- **Coos Bay Call Area** - BOEM estimates the entire Coos Bay Call Area is approximately 873,000 acres and could accommodate approximately 10.6 GW of offshore wind power capacity; and
- **Brookings Call Area** - BOEM estimates the entire Brookings Call Area is approximately 286,500 acres and could accommodate approximately 3.5 GW of offshore wind power capacity.

The combination of Oregon's state policy goal to plan for up to 3 GW of floating offshore wind, and the two Oregon Call Areas identified by BOEM, formed the basis for studying the economic and reliability effects of interconnecting a total of 3 GW split across two southern Oregon coastal substations located in proximity to the two Oregon Call Areas. The Fairview and Wendson substations were selected for this transmission study because previous Oregon offshore wind transmission studies identified these two existing coastal substations as having the largest capacity to potentially receive new injections of offshore wind power. [1]

[1] PNNL, Exploring the Grid Value Potential of Offshore Wind Energy in Oregon, May 2020, https://www.osti.gov/servlets/purl/1618872; NREL, Evaluating the Grid Impact of Oregon Offshore Wind, Oct. 2021, https://www.nrel.gov/docs/fy22osti/81244.pdf.

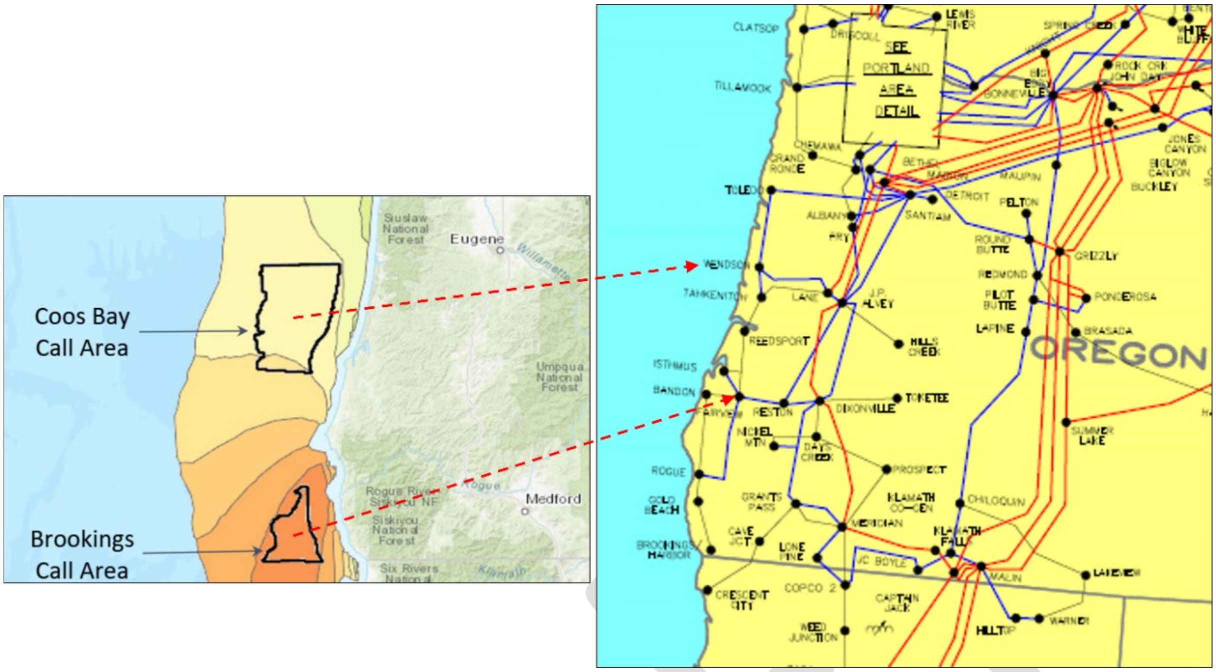


Figure 1: Call Area

BOEM's Oregon Call Areas (left) - yellow to orange color gradient correlates to offshore wind/energy quality in those locations. Wind/energy quality is highest in dark orange, and decreases from lighter orange to yellow. Southern Oregon's Transmission System (right) – Wendson and Fairview substations indicated. Blue transmission lines = 230 kV, red lines = 500 kV, black lines = less than 230 kV.

Given the more energetic resource to the south, the NorthernGrid study request was formulated as 1,800 MW at Fairview and 1,200 MW at Wendson for a total of 3,000 MW. This request sought to investigate more significant power flows through these substations than had been observed in preceding work.

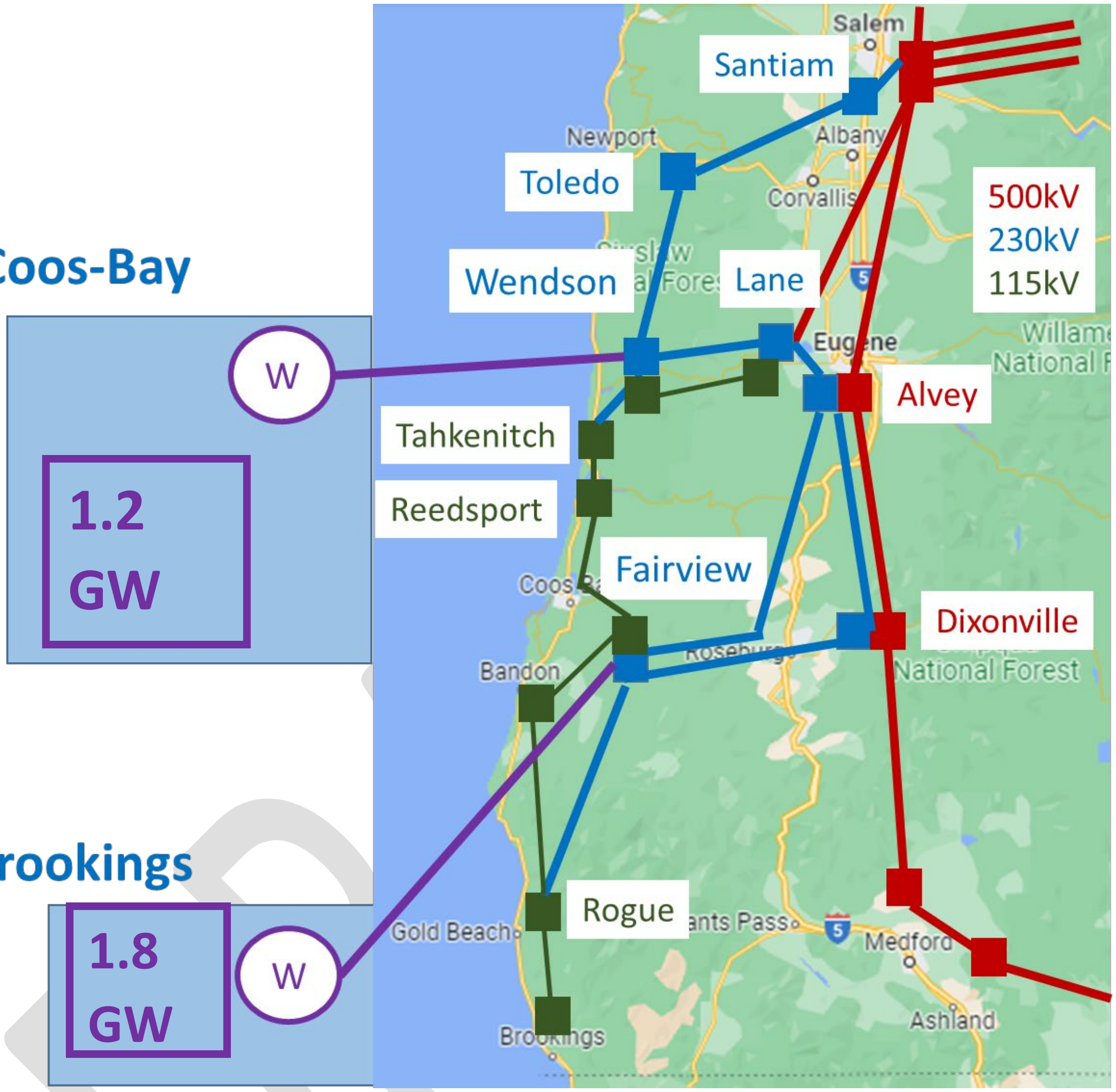


Figure 2: Offshore wind request

Figure 2: Offshore wind request is a pictorial representation of the offshore wind request. 1.2 GW of the wind will be modeled in the Coos Bay wind pocket with interconnection to the existing 230 kV bus at Wendson. The remaining 1.8 GW of wind will be modeled in the Brookings wind pocket with interconnection to the 230 kV bus at Fairview.

Study Scope

The study scope was developed with input from both the technical committee at NorthernGrid as well as the requesters. The two groups coordinated a set of analyses that addressed the feasibility of the proposed offshore wind project from both reliability and production cost perspectives. The group included subject matter experts from the Bonneville Power Administration (BPA), PacifiCorp, and Portland General Electric throughout the process. The Study Scope was ultimately approved by the Member Planning Committee and is posted publicly.

Analysis

All findings in this report are informative in nature and conclusions from this analysis should be limited to the assumptions built into the base cases used for the analysis. These findings do not represent a definitive future. The findings help to illustrate the possible reliability needs of the transmission system on a regional level in a potential ten-year future and do not address the myriad of impacts to the local transmission system. Nothing in this report should be interpreted as a construction plan or a replacement for any local transmission planning process.

The technical team supporting the analysis of this offshore wind request collectively identified that both steady state reliability and production cost analyses would be necessary to understand the impacts of the installation three gigawatts of offshore wind in the Oregon coast.

Steady state reliability analysis was performed first. The technical team used the 2032 Western Electric Coordinating Council (WECC) Heavy Summer base case as a starting point. Per agreement amongst the technical team and the requesters, the base cases were also stressed in both the north and south directions so as to fully capture the reliability concerns that may arise in either direction on the I-5 corridor.

Initially, the technical team identified a process that would allow for the three gigawatts of offshore wind to be analyzed on the expected 2032 transmission system before transmission upgrades were identified, per the process depicted in Figure 2.

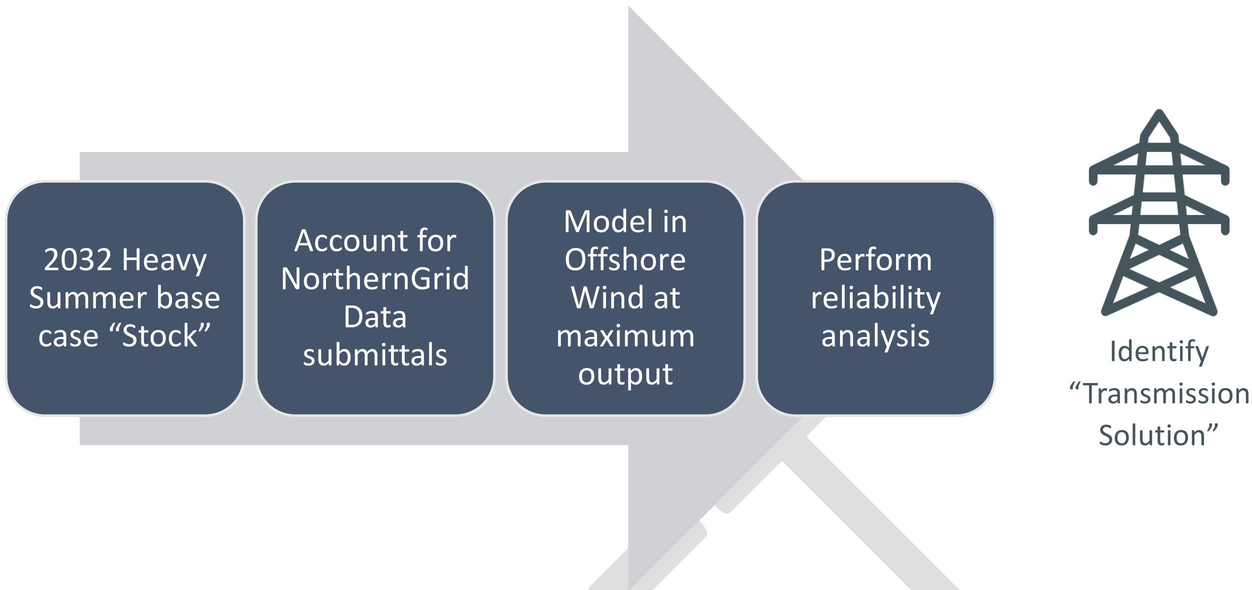


Figure 3: Proposed reliability analysis

In practice, the installation of three gigawatts on the 230 kV system in Oregon turned out to cause violations on the surrounding system, upwards of 200%, that the "Transmission Solution" as well as supporting solutions were needed before reliability analysis could be performed.

The existing 115 kV and 230 kV systems along the west coast of Oregon were not designed to pass through a large influx of energy from the coast along to the I-5 corridor. There are many known constraints that would necessarily restrict the output of the proposed wind farms-to a point that the analysis would be limiting. The technical team agreed on a set of supporting transmission solutions that was implemented in all the cases used for the analysis and are listed in Table 1: Transmission system improvements proposed to reinforce connectivity to the I-5 corridor.

Table 1: Transmission system improvements proposed to reinforce connectivity to the I-5 corridor

Improvements to existing system to allow for improved connectivity to the I-5 corridor	Upgrade Fairview-Alvey 230 kV
	Upgrade Wendson-Toledo 230 kV
	Rebuild Fairview-Reedsport-Tahkenich 115 kV

These 115 kV and 230 kV transmission system upgrades are assumed to be "in-service" for this analysis. Figure 4: Areas with notable overloads and generation at the 230 kV level provides a high-level depiction of areas impacted, and related facilities overloaded, upon the installation of the three gigawatts offshore wind on the 230 kV system. Despite the assumed upgrades on the 115 kV and 230 kV transmission system between the coast and the corridor, the facilities were loaded upwards of 200% of their improved ratings.

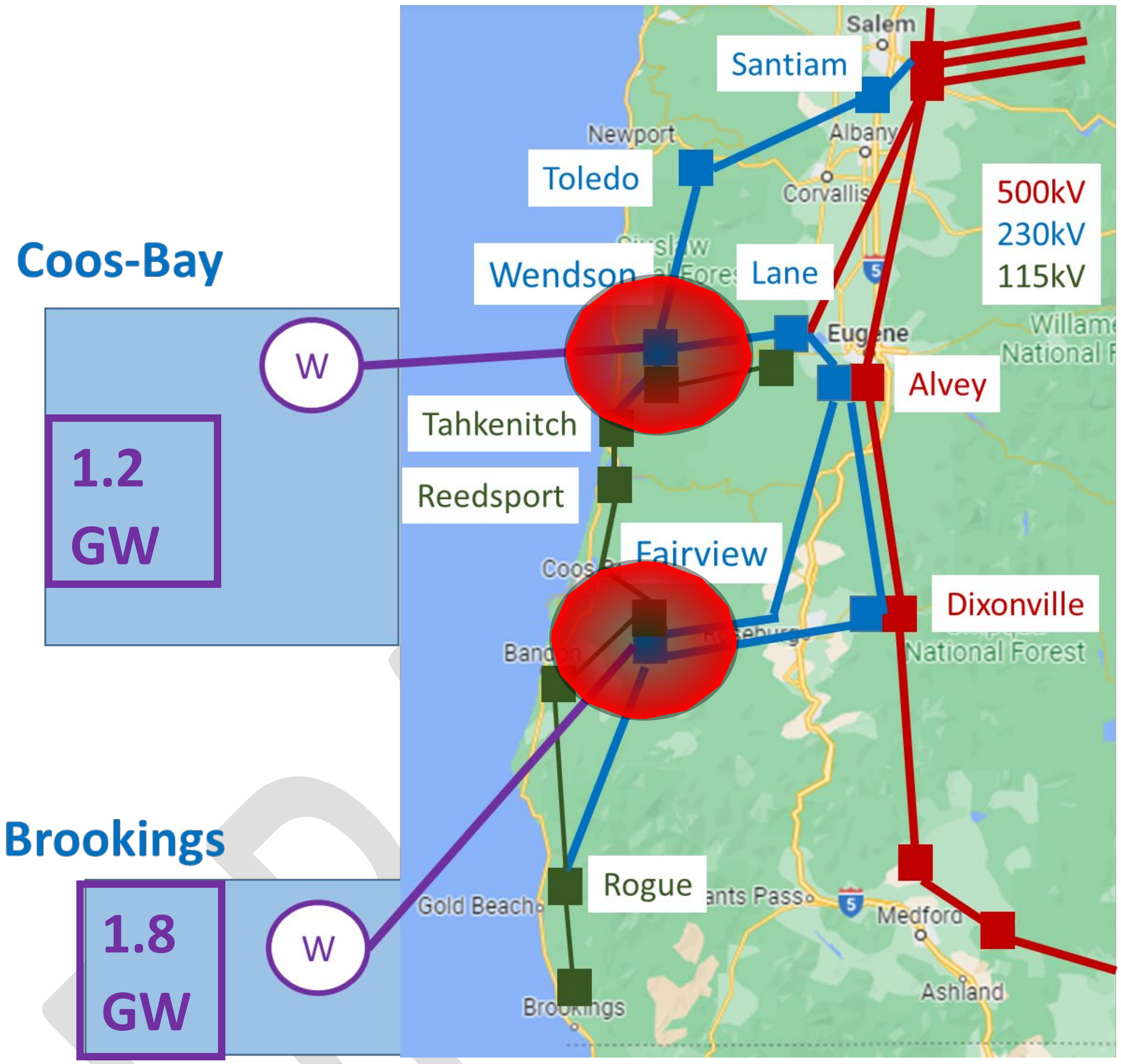


Figure 4: Areas with notable overloads and generation at the 230 kV level

For either northbound or southbound flows on the I-5 corridor, the injection of 1.2 GW and 1.8 GW of offshore wind at Wendson and Fairview, respectively, caused reliability violations that needed mitigation before further reliability analysis could be performed. The technical team coordinated on a transmission solution that was modeled into the base cases before the contingency analysis portion of the reliability analysis was performed.

The technical team implemented a “500 kV loop” solution. The “500 kV loop” consists of new 500 kV lines from Alvey to Lane, Lane to Wendson, Wendson to Fairview, and Fairview to Dixonville. The existing 500 kV line between Alvey and Dixonville closes the loop. The “500 kV loop” solution also assumes that the offshore wind farms are interconnected at the 500 kV level instead of 230 kV. This “500 kV loop” was modeled into the base cases that have the proposed upgrades for the 115 kV and 230 kV system, and then contingency analysis was performed.

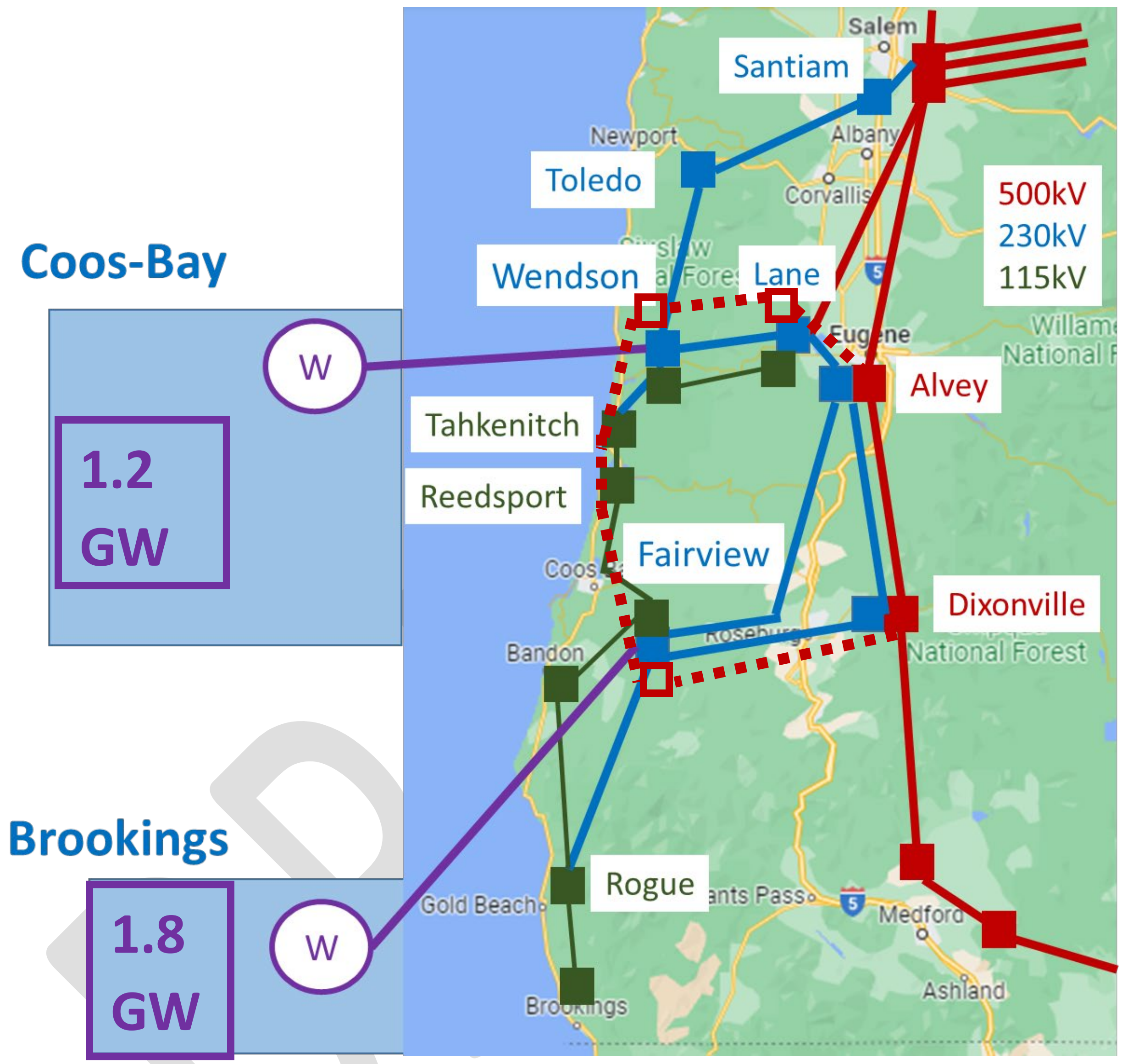


Figure 5: Proposed "500 kV loop"

With the "500 kV loop" modeled into the base cases, and along with the "supporting" transmission upgrades that were identified in Table 1: Transmission system improvements proposed to reinforce connectivity to the I-5 corridor, and the wind farms connected at the 500 kV level, the steady state contingency analysis concluded that the installation of three gigawatts of offshore wind interconnected at the 500 kV level is reliable with all pieces of equipment in service (N-0), or with the outage of any one piece of equipment (N-1). The single outages included either individual line or generation outages. The reliability finding for this analysis holds true for both northbound and southbound flows on the I-5 corridor.

Cost

High-level, non-binding costs were developed for the upgrades. The costs were developed with input from the entities involved and are not reflective of a full-blown estimation process. The costs reflect estimates of the equipment only and do not reflect the funds needed to procure the land, acquire the permits, or in any way account for the myriad of financial commitments needed to support a construction build. The costs were produced through internal reviews of recent projects and the source information is not available publicly. The "Existing System" upgrades are needed for both the 230 kV and 500 kV interconnection levels, as shown in Table 2.

Table 2: High-level, non-binding Estimates for the transmission facilities

	230 kV		500 kV	
	High-level Estimate ($M)	**High-level Estimate +50% ($M)**	**High-level Estimate ($M)**	**High-level Estimate +50% ($M)**
"500 kV Loop" transmission line			$501	$752
500 kV Supporting upgrades			$274	$411
Proposed 115 kV and 230 kV System Upgrades (Table 1)	$45	$68	$45	$68
Total	**$45**	**$68**	**$820**	**$1,231**

1. The costs in Table 2: High-level, non-binding Estimates for the transmission facilities only reflect the transmission equipment needed to support the transmission system and do not include any costs of the actual offshore wind farms or their associated infrastructure.
2. The estimates provided in Table 2: High-level, non-binding Estimates for the transmission facilities reflect high-level, non-binding estimates of the equipment needed for the physical facilities including the communications and labor. They do not include the permitting, right-of-way, land acquisition, or anything beyond the physical facilities needed for the transmission lines.
3. The "500 kV Supporting upgrades" line item represents the collective total substation cost estimates. In some instances, a new substation is needed and in others, the existing substation needs substantial infrastructure support.
4. "Existing System Upgrades (Table 1)" are those listed in Table 1: Transmission system improvements proposed to reinforce connectivity to the I-5 corridor of this report.
5. The costs in Table 2: High-level, non-binding Estimates for the transmission facilities assume there are no major "hurdles" such as the ability to acquire the land easily and quickly, no litigation concerns, no public pushback, or no Endangered Species concerns. Experience has shown that any one of these hurdles, or setbacks, can double or even triple the overall cost of the project.
6. Substation improvements are also needed for interconnection at the 230 kV level, and those costs are not reflected in Table 2: High-level, non-binding Estimates for the transmission facilities.

Production Cost Modeling

The production cost analysis started with adding the "supporting" transmission upgrades to the 2032 Anchor Data Set (ADS) produced by WECC. The 2032 ADS topology is the same as that of the 2032 Heavy Summer base case. The ADS produced by WECC is a data set that puts together the ability to perform reliability and production cost analyses on cases that represent the WECC system in its totality. The program used to model the production cost analysis, GridView, allows for a simulation of all 8784 hours in 2032 (2032 is a leap year) where the generation in the transmission system gets dispatched for each hour of the year. This variation in generation dispatch changes and how those changes impact the transmission system allows for investigation into how the offshore wind project and the different transmission solutions impact the overall transmission system.

The offshore wind projects were modeled into the 230 kV system in the initial production cost run, and then again in a second production cost analysis with the "500 kV loop" added and the offshore wind projects at the 500 kV interconnection level. Both production cost runs included the system upgrades identified in Table 1: Transmission system improvements proposed to reinforce connectivity to the I-5 corridor. The following figures depict how certain components of the production cost analysis change as a function of the wind being interconnected to the different voltage levels.

In the following graphics below, there will be reference to the following cases.

- ADS Anchor Data Set. The ADS case does not have the updates listed in Table 1, and there are no offshore wind projects modeled.
- 230kV The 230kV case represents the offshore wind projects being modeled at the 230 kV level in the ADS. The case includes the upgrades in Table 1: Transmission system improvements proposed to reinforce connectivity to the I-5 corridor.
- 500kV The 500kV case represents the offshore wind projects being modeled at the 500 kV level in the ADS. The case has the upgrades in Table 1: Transmission system improvements proposed to reinforce connectivity to the I-5 corridor as well as the "500 kV loop".

Production Cost Modeling Results

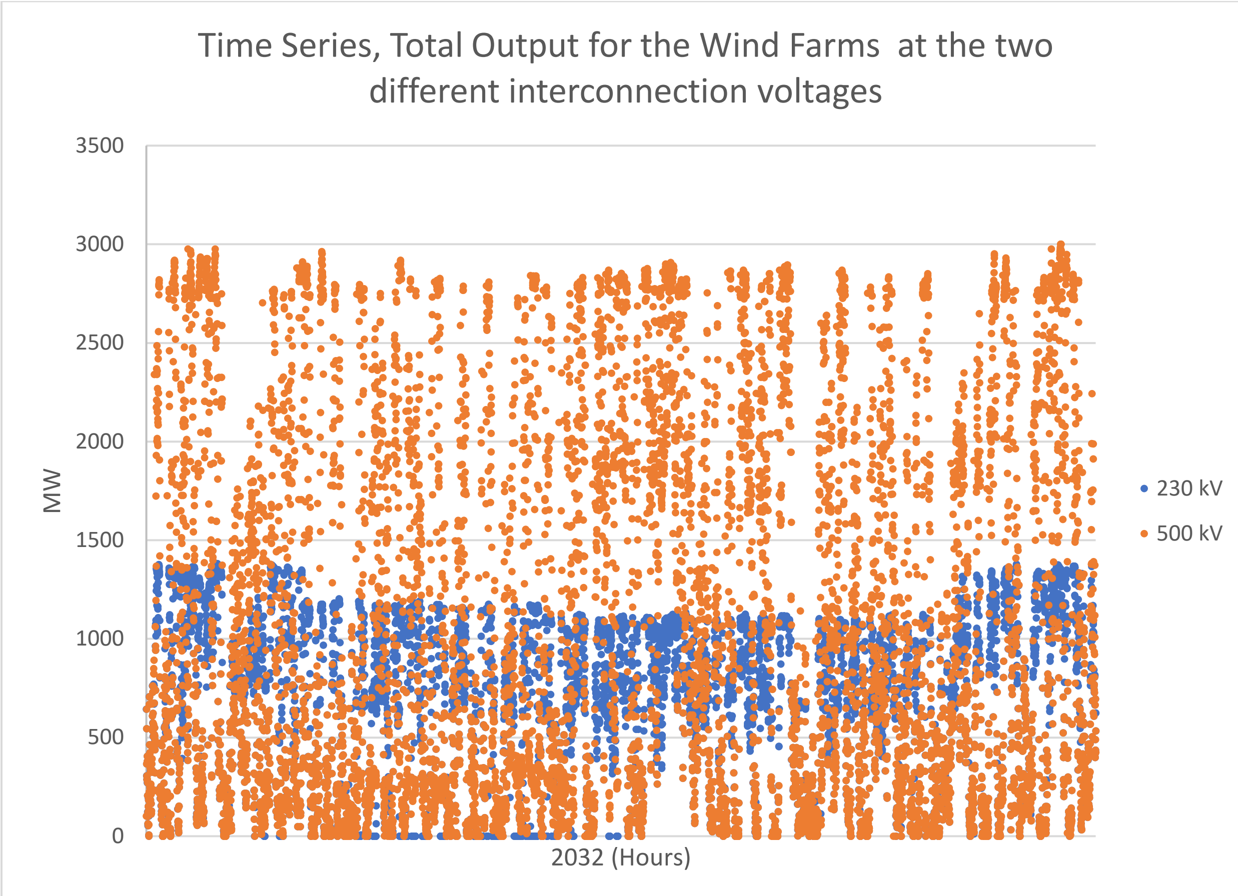


Figure 6: Offshore wind output for year 2032, time series

Figure 6: Offshore wind output for year 2032, time seriesshows the time series combined megawatt output for the two offshore wind farms. The 500 kV interconnection allows for the full output of the wind farms whereas the 230 kV interconnection is seasonally limited. The seasonal limitations observed in the 230 kV output are due to seasonal ratings on associated cut planes. These cut planes were introduced by the technical team to measure the output of the offshore wind farms as well as to honor the physical limitations of the associated branches. A cut plane is a collection of transmission lines that has a collective rating; this rating was established by the technical team and did not undergo the scrutiny and review that would be required of a formal path.

Table 3: Path limits proposed

	Path	Summer (MW)	Spring (MW)	Winter (MW)
230 kV	Wendson	444	481	549
	Fairview	453	484	561
500 kV	Wendson	1630	1730	1883
	Fairview	1534	1687	1974

Figure 7: Megawatts through the 230 kV Wendson and Fairview cut planes shows the collective megawatts across the Wendson and Fairview cut planes.

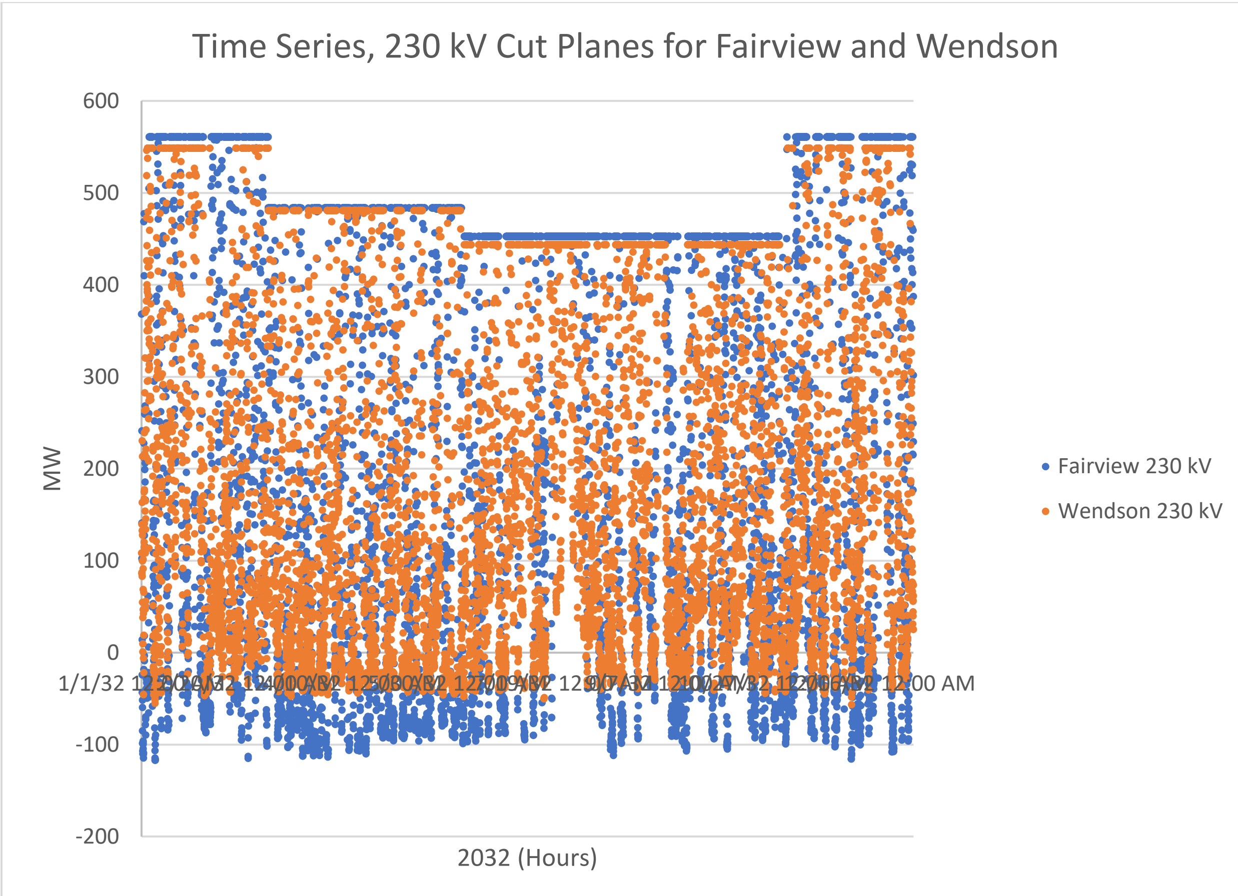


Figure 7: Megawatts through the 230 kV Wendson and Fairview cut planes

The 230 kV Wendson and Fairview cut planes limit the output of wind farms at the 230 kV level. This can be observed by the seasonal flat lines that are depicted in Figure 7: Megawatts through the 230 kV Wendson and Fairview cut planes. The cut plane limits are not exactly one to one with the output of the wind farms as the transmission system is a network of lines, and these cut planes only capture the bulk of the output. When interconnected at the 230 kV level, the output of the windfarms was curtailed a significant portion of the year.

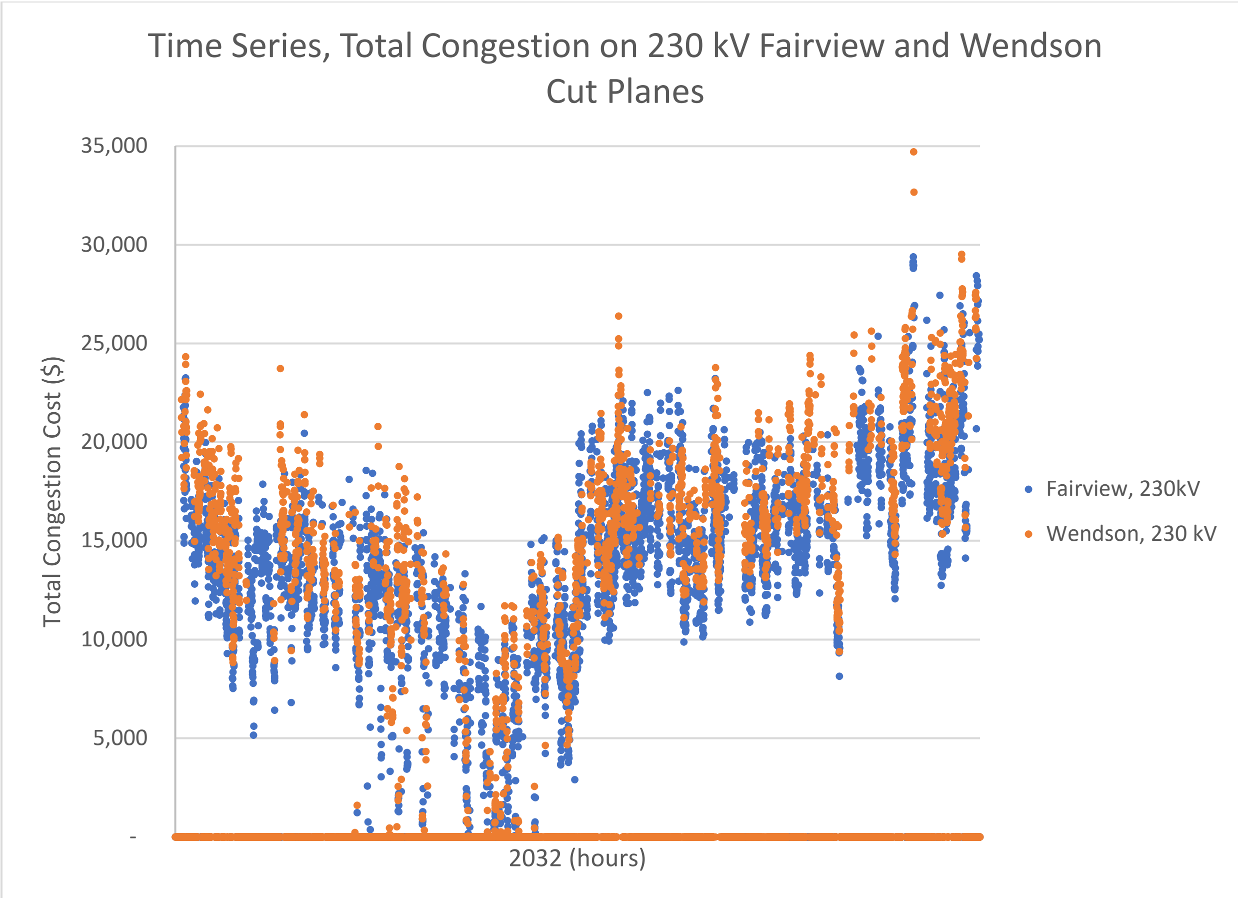


Figure 8: Fairview cut plane congestion

The congestion through the Fairview and Wendson 230 kV cut planes occurs regularly throughout the year. Congestion is generally reflective of the money that is lost due to a generator not being able to inject its generation onto the transmission system at a time when the generation is available to output onto the system. For example, if the wind is blowing and the wind turbines have the ability to send all three gigawatts onto the transmission system, the congestion of the cut planes translates into the amount of money lost because the transmission system was not able to accept the output and the offshore wind generators were curtailed.

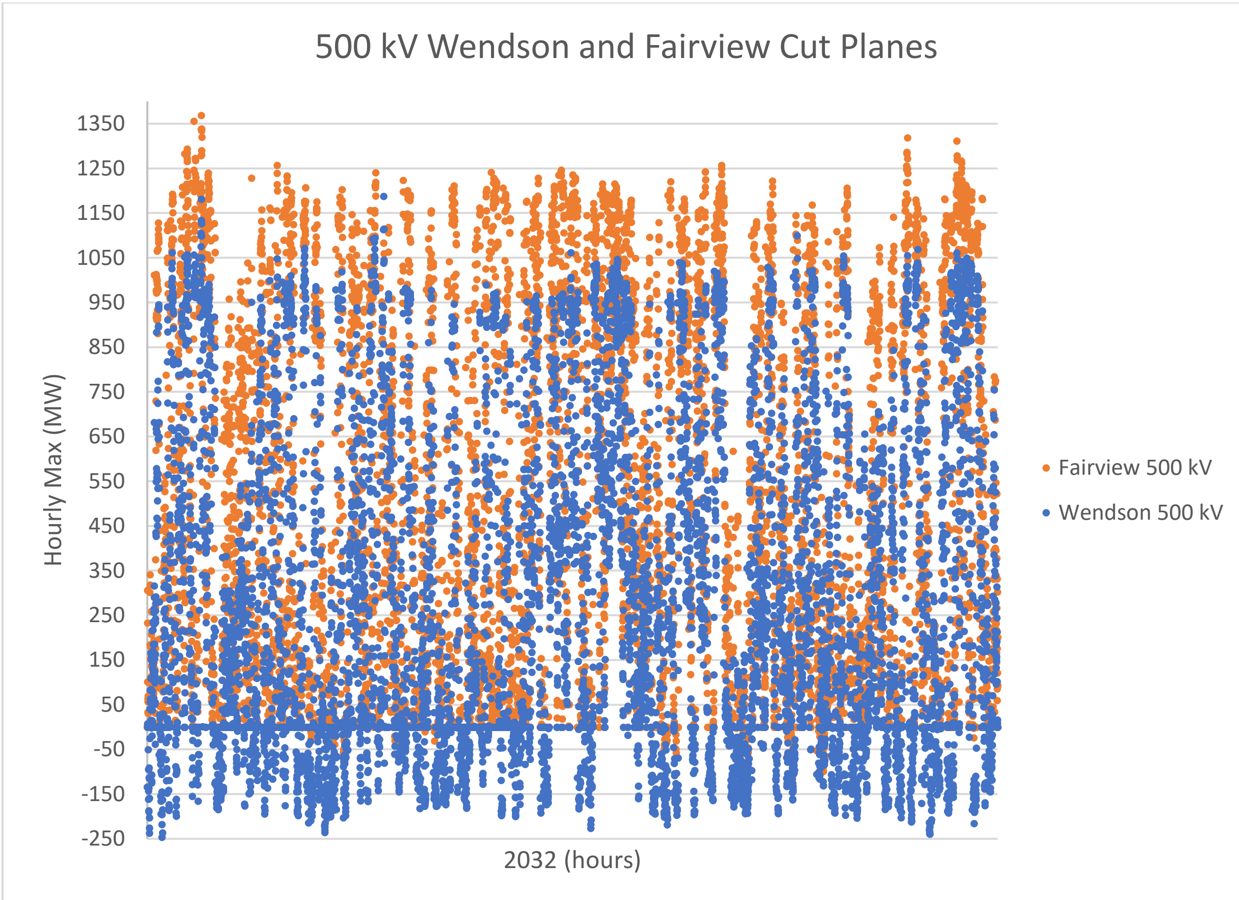


Figure 9: 500 kV Wendson and Fairview cut planes

The 500 kV cut planes for Wendson and Fairview allow for full output of the wind farms; there are no curtailments when the "500 kV loop" is modeled.

Because the "500 kV loop" assumes interconnection at the 500 kV level, it also assumes that the associated 500 kV substations have either been built or improved to handle the output from three gigawatts of offshore wind. Altogether, the "500 kV loop" allows for both the reliable operation of the wind farm under stressed operating conditions as well as relatively congestion-free generation opportunities. The biggest hurdle for the generation is to get from the coast to the I-5 corridor. The "500 kV loop" enables generation to reach the I-5 corridor and also acts as a new "backbone" for the coastal transmission system. The existing system upgrades listed in Table 1: Transmission system improvements proposed to reinforce connectivity to the I-5 corridor are required for interconnection at the 500 kV level.

Interconnection at the 230 kV level is possible. However, interconnection at the 230 kV level results in congestion that generally limits the total generation to less than half its total capability. The existing system upgrades listed in Table 1: Transmission system improvements proposed to reinforce connectivity to the I-5 corridor are required for interconnection at the 230 kV level. Interconnection at the 230 kV level would also require significant upgrades to the 230 kV Fairview and Wendson buses and would still result in significant congestion.

The following plots explore some of the larger, more regional, impacts of the installation of the offshore wind projects. The three cases used for the plots were the unmodified Anchor Data Set (ADS), the offshore wind interconnected at the 230 kV level (230 kV) , and the offshore wind interconnected at the 500 kV level (500 kV). The first set of plots will focus on four Western Electric Coordinating Council (WECC) paths:

1. South of Allston
2. "WOCS" West of Cascades South
3. Idaho to the Northwest
4. "COI" California Oregon Intertie

Figure 10: Western Interconnection with graphical depiction of main Paths

The green stars in Figure 10: Western Interconnection with graphical depiction of main Paths generally show the location of the two wind projects as well as their proposed cut planes which are dashed to indicate they are not formal WECC paths.

The California-Oregon Intertie (COI) portion of the transmission system connects California and Oregon and typically flows in the southbound direction. With the COI depictions, positive values indicate southbound flows.

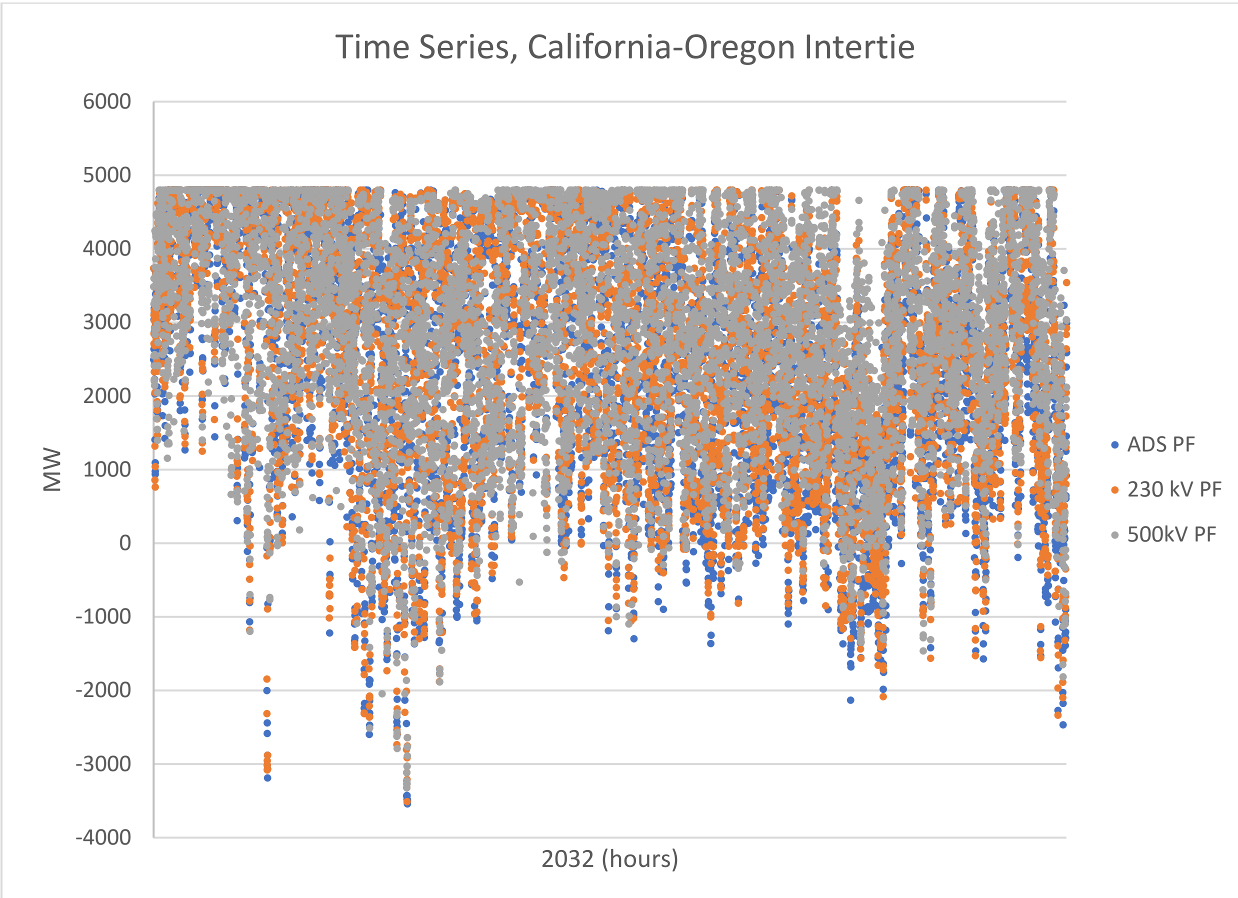


Figure 11: COI flows, time series

While it is clear that the majority of the time, the COI is flowing in a southbound direction, Figure 11: COI flows, time series does not provide an opportunity to understand how the COI differed for the three different cases that were examined.

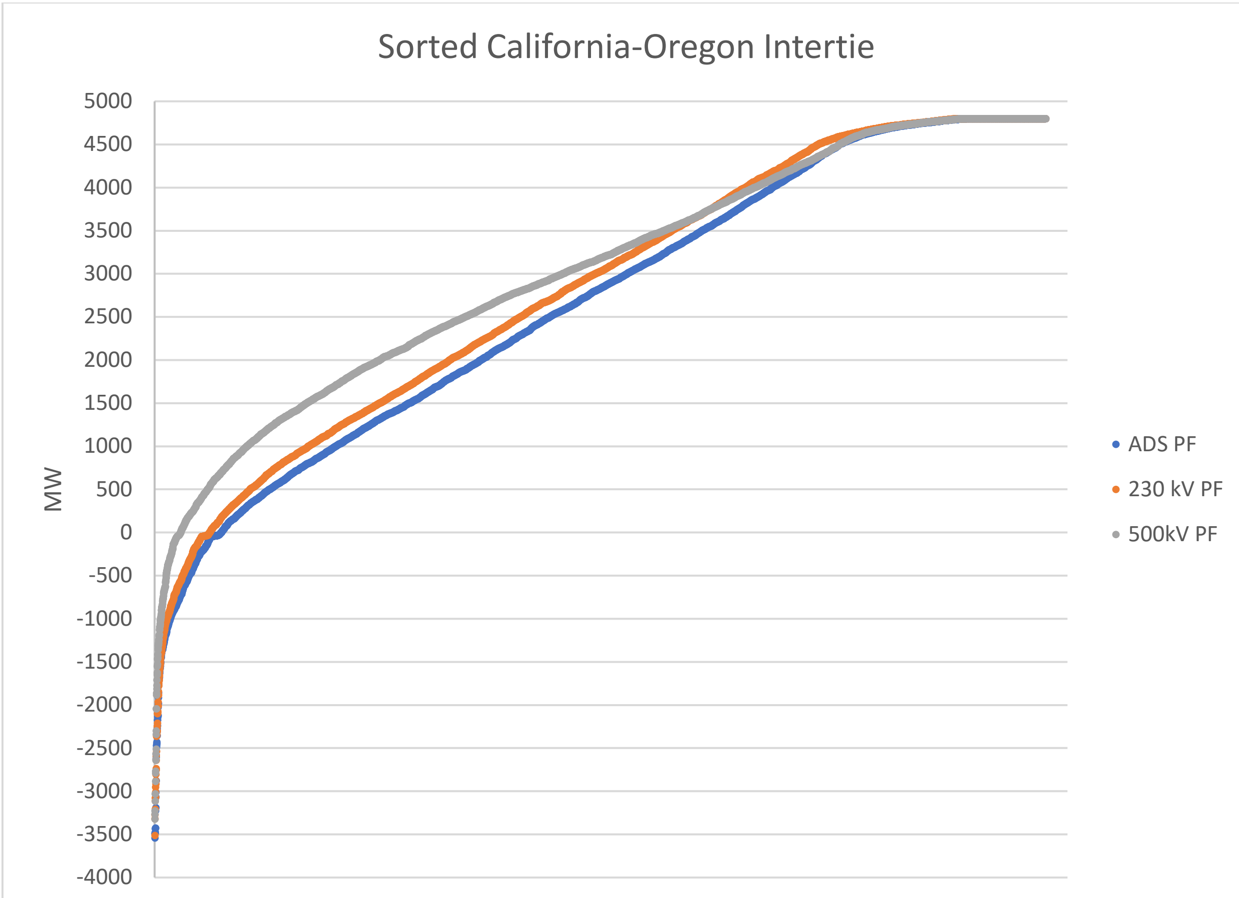


Figure 12: Sorted COI output, sorted by MW

Figure 12: Sorted COI output, sorted by MW demonstrates that the COI was impacted by the introduction of the wind farms. Using the ADS as the “baseline” for comparison, the sorted output indicates that there were more southbound flows on the COI as a result of the 230 kV interconnection and yet again more southbound flows for the 500 kV interconnection.

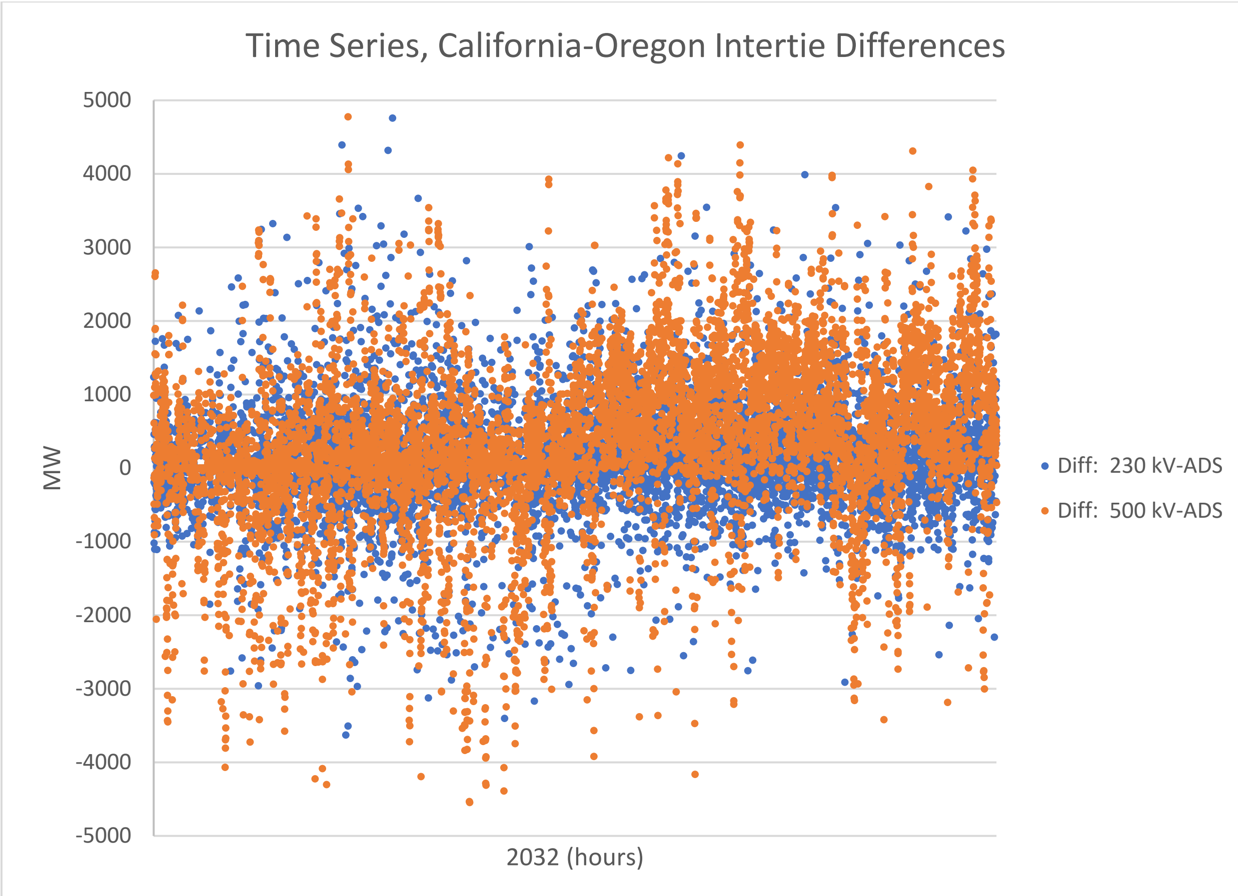


Figure 13: COI differences, time series

Another way to consider how the COI gets impacted by the installation of offshore wind is by looking at the difference between the COI flow on the ADS case versus the COI flows on the 230 kV and 500 kV cases. The difference was taken with ADS leading; positive values indicate that the southbound flows on the COI in the ADS case are less than the other cases, and negative values indicate that the southbound flows in the ADS case are more than that of the other cases. While it appears that the differences are larger between the ADS case and the 500 kV case than they are for the differences between the ADS and the 230 kV case, further examination is warranted.

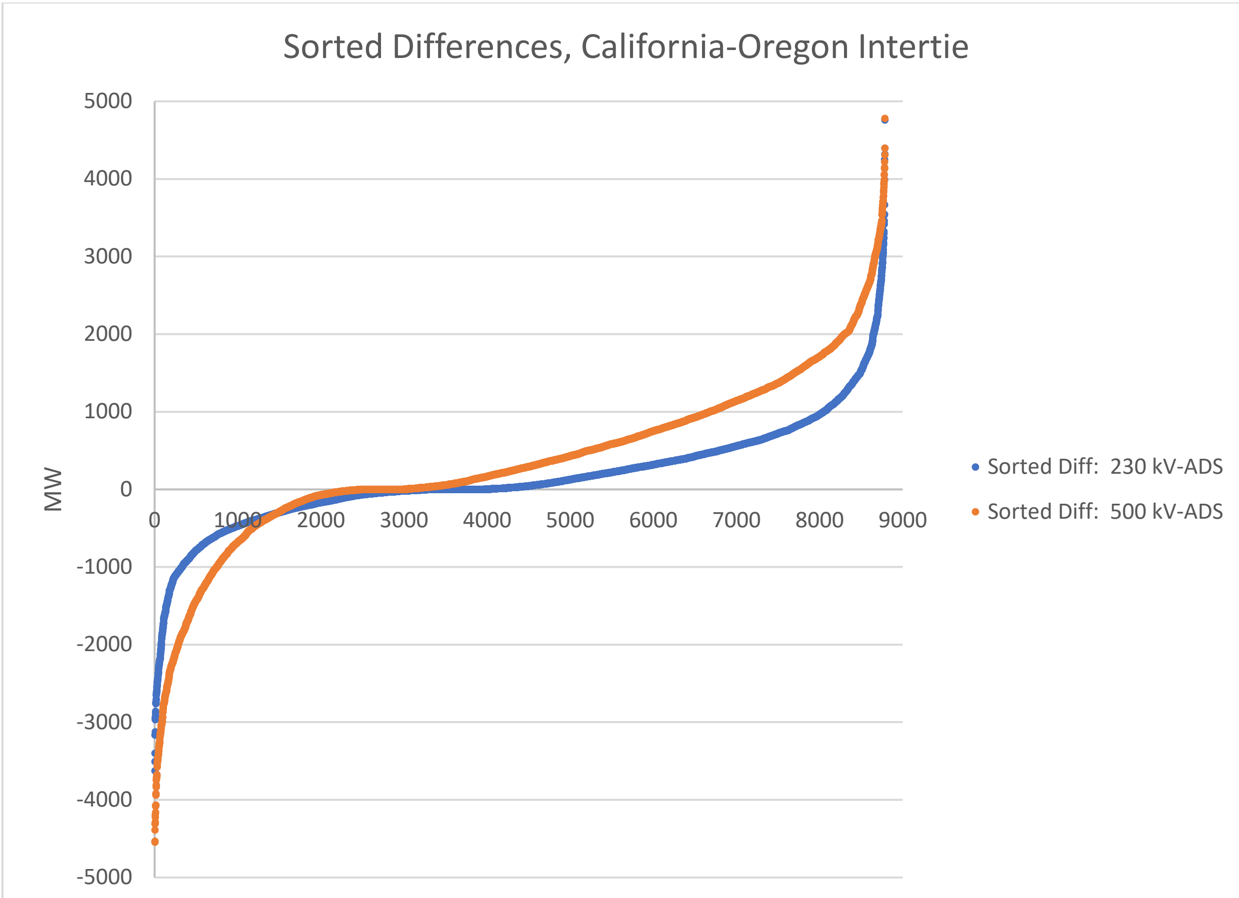


Figure 14: Sorted Differences, COI, sorted by MW output

Figure 14: Sorted Differences, COI, sorted by MW output shows the sorted differences for the three cases on the COI. The differences were consistently greater between the ADS and the 500 kV than the differences between the ADS and the 230 kV.

Figure 15: Idaho to the Northwest Westbound MW flows, time series has predominately westbound MW flows. With the Idaho to the Northwest depictions, positive values indicate westbound flows.

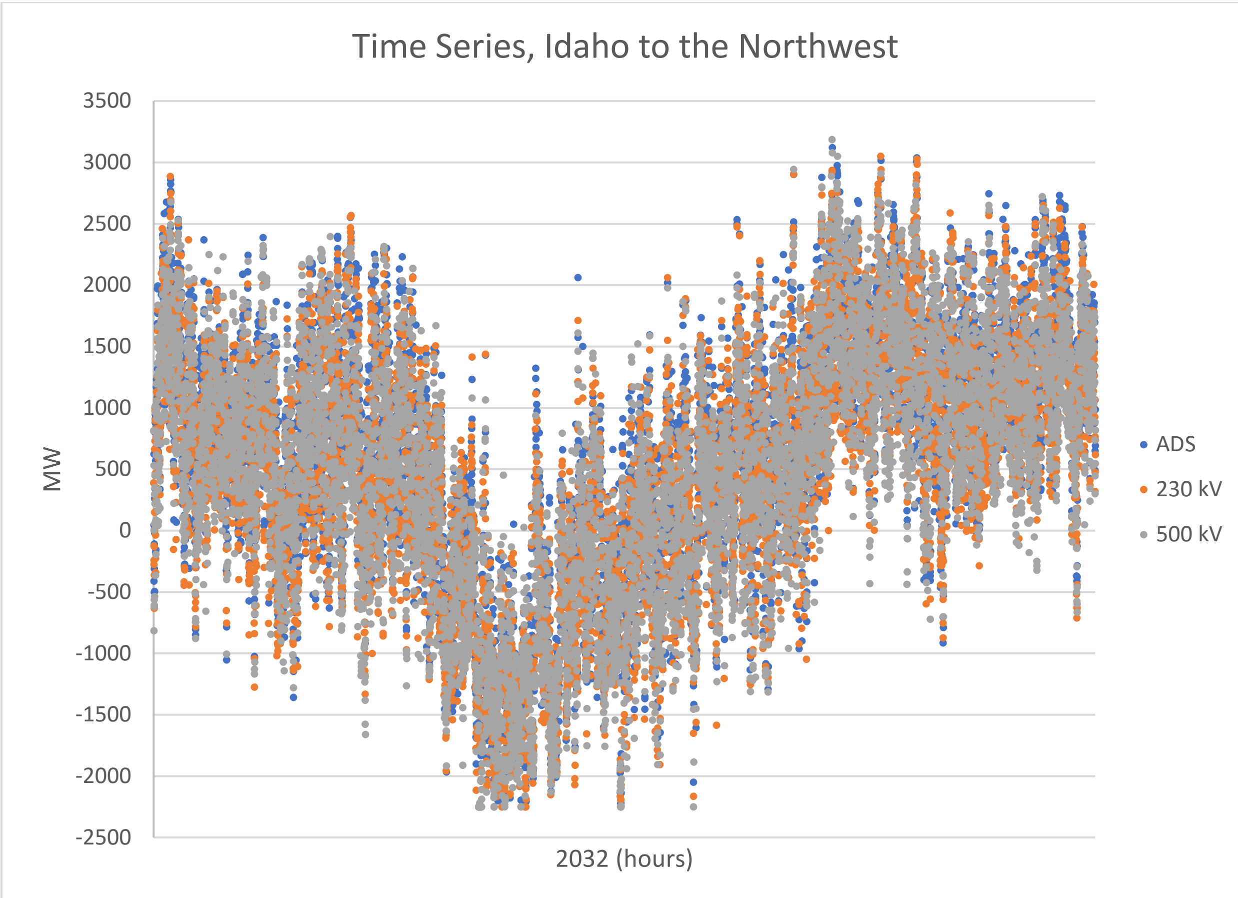


Figure 15: Idaho to the Northwest Westbound MW flows, time series

It is unclear from the time series how Idaho to the Northwest is impacted by the presence of the offshore wind projects and further scrutiny is warranted.

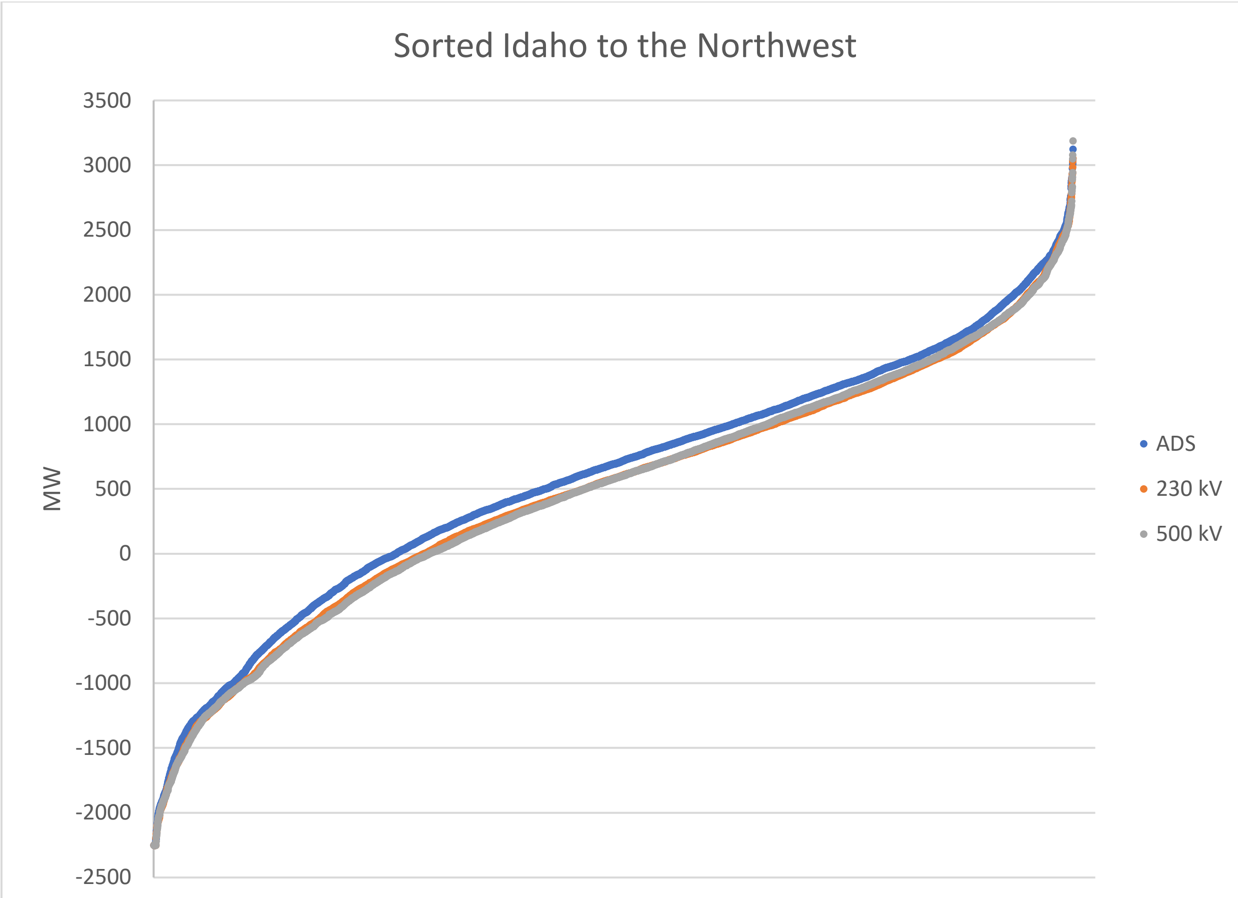


Figure 16: Path 14, sorted by MW

Figure 16: Path 14, sorted by MW depicts the sorted values for westbound Idaho to the Northwest MW. The 230 kV and 500 kV cases show fewer westbound flows on Idaho to the Northwest than the ADS case; this indicates that the presence of the offshore wind projects reduces the loading on Idaho to the Northwest.

The South of Allston path is predominately westbound in nature. With South of Allston depictions, positive values indicate westbound flows.

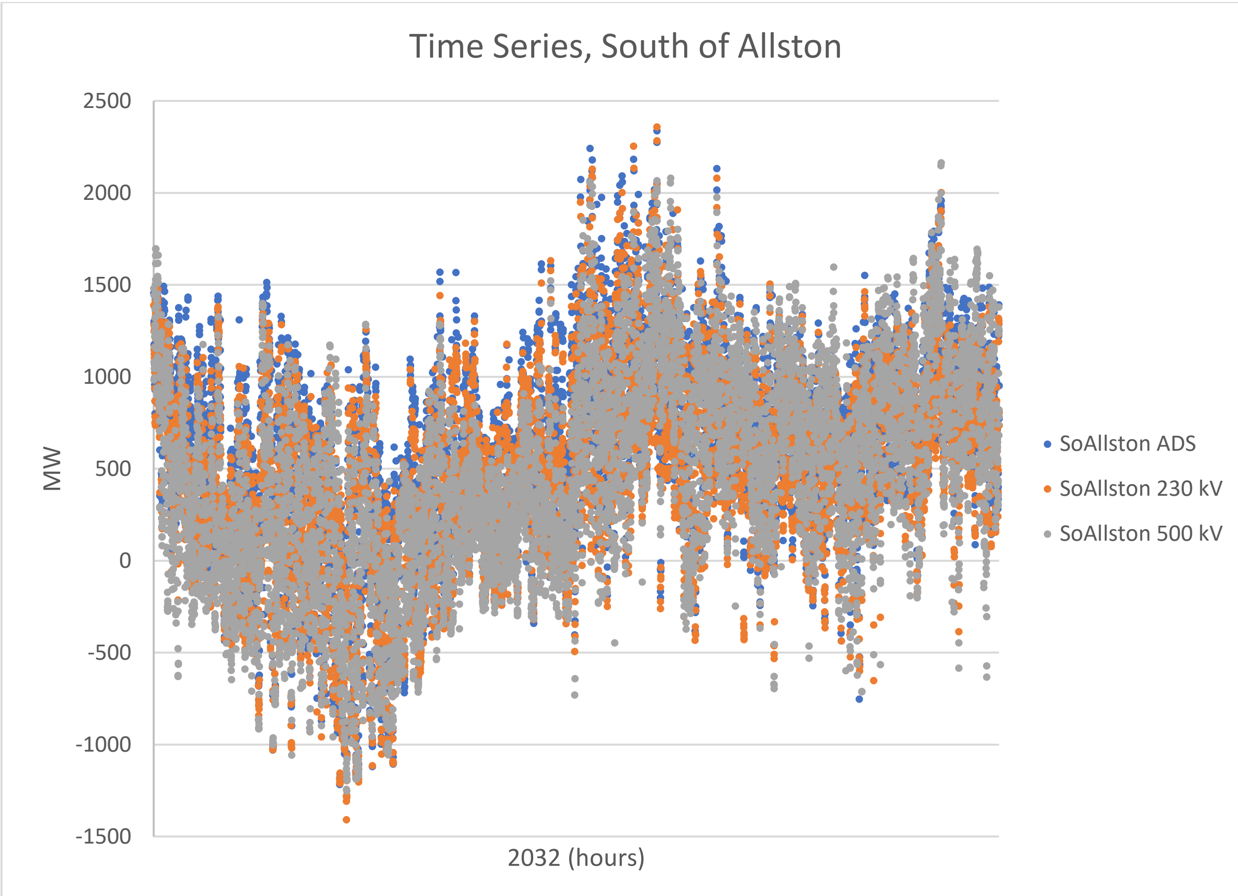


Figure 17: South of Allston, time series

Figure 17: South of Allston, time series suggests that the offshore wind project reduce the loading on South of Allston.

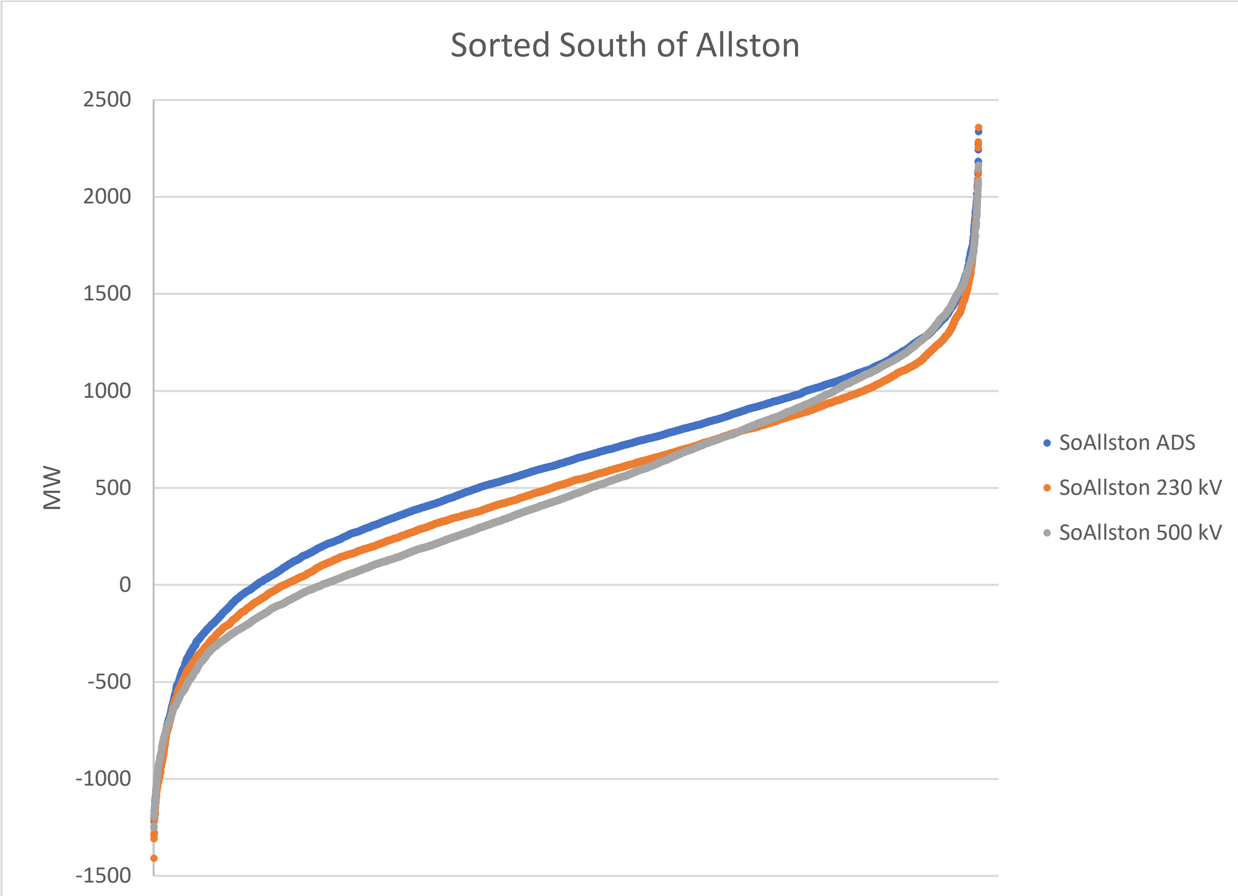


Figure 18: South of Allston, sorted by MW output

The sorted South of Allston output confirms that with the introduction of offshore wind in the Oregon area, the loading on South of Allston is generally reduced.

The last of the four WECC paths that were explored is the West of Cascades South (WOCS) path. For WOCS depictions, positive values indicate westbound flows.

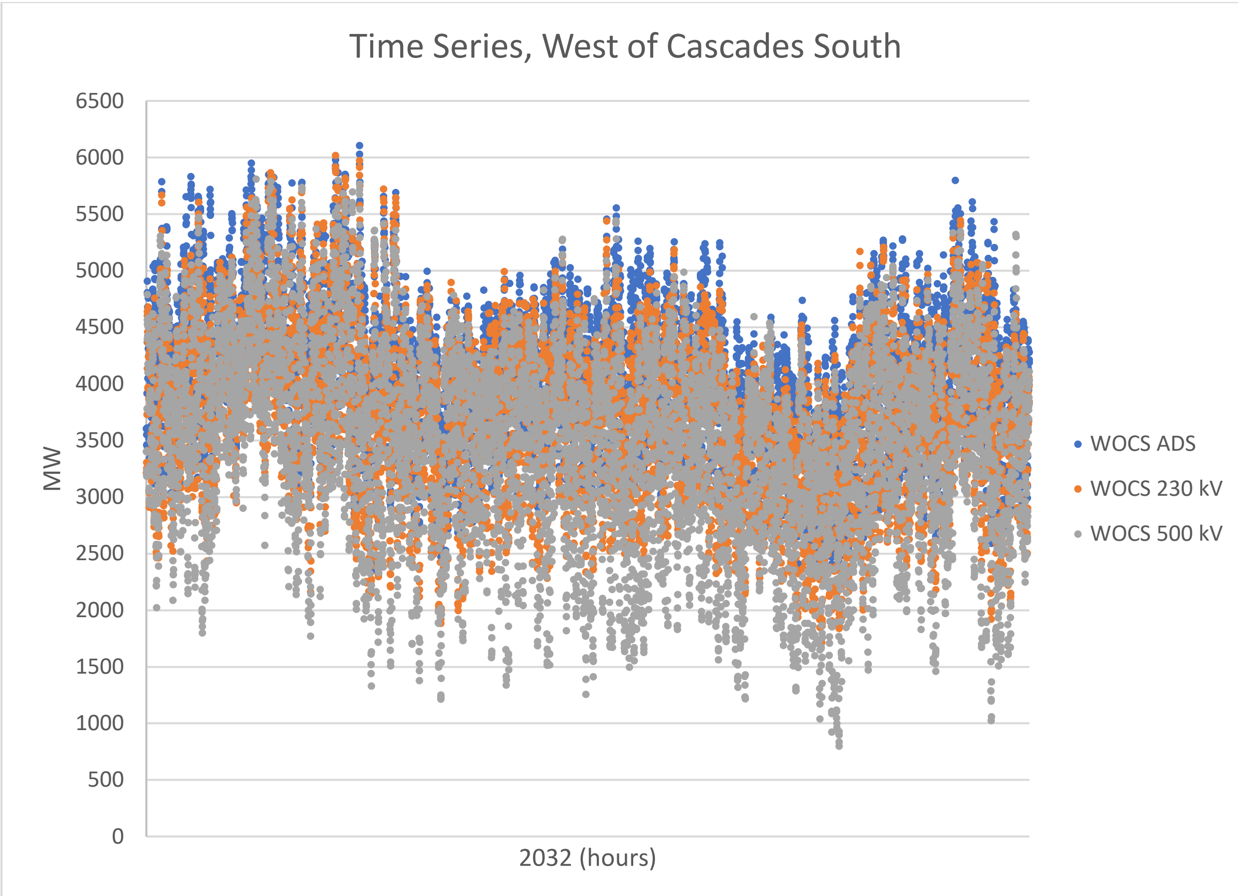


Figure 19: West of Cascades South, time series

It appears that the loading on West of Cascades South is less in the cases with the offshore wind.

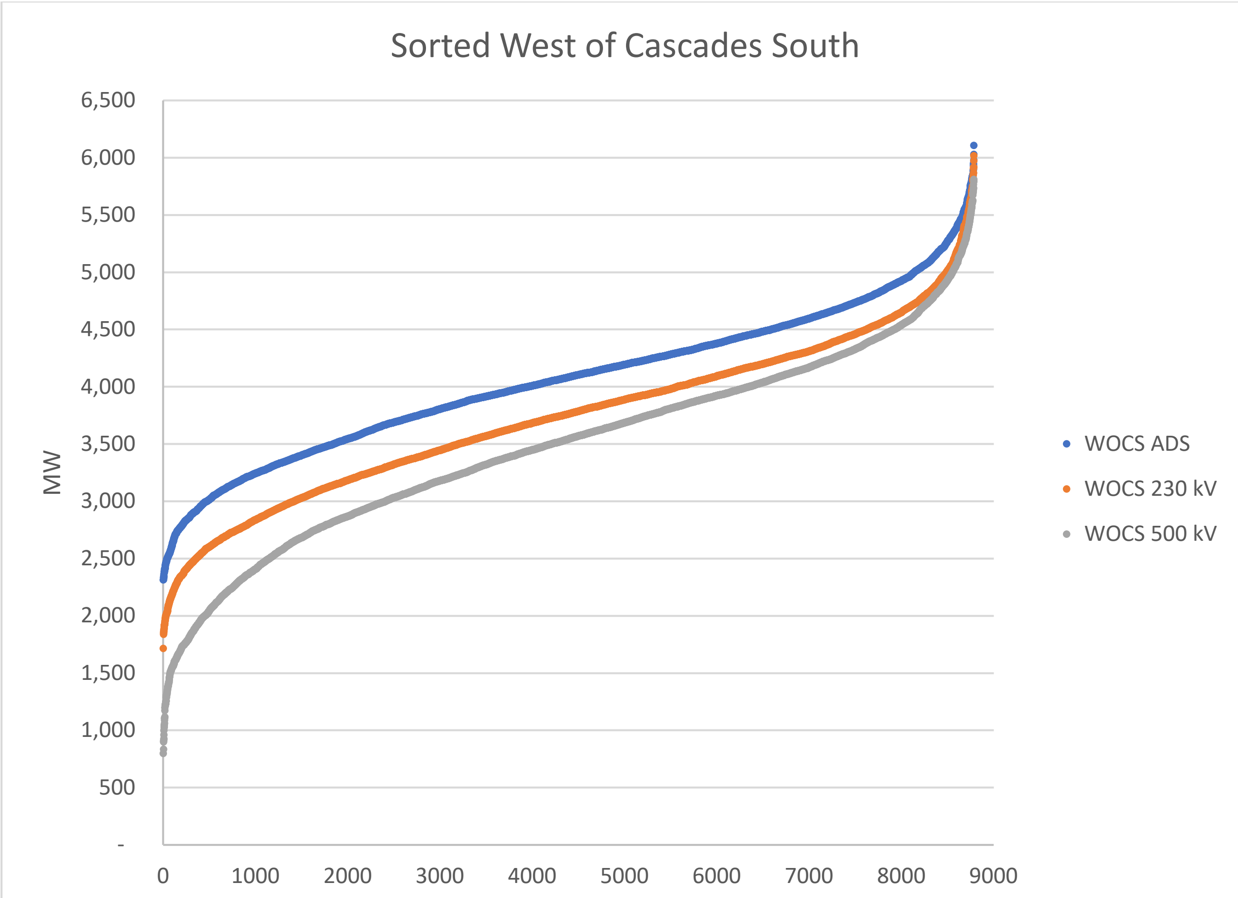


Figure 20: WOCS westbound flows, sorted by MW

Figure 20: WOCS westbound flows, sorted by MW demonstrates that the westbound flows on West of Cascades South are decreased in the presence of offshore wind in Oregon.

Interface Summary

Of the four paths that were examined in this paper, the following observations were made.

1. Paths that generally moved power into the Oregon area (Idaho to the Northwest, South of Allston, and West of Cascades South) experienced reduced loading.
2. The southbound flows on the California Oregon intertie increased.

These four paths do not represent the entirety of the western interconnection and should not be interpreted as the only paths that are impacted by the offshore wind installations; they were chosen to generally represent the possible regional impact of the offshore wind as modeled in Oregon.

Another point of interest is how the installation of three gigawatts of offshore wind impacts carbon-based resources. The following figures and table explore the output all facilities in the NorthernGrid region.

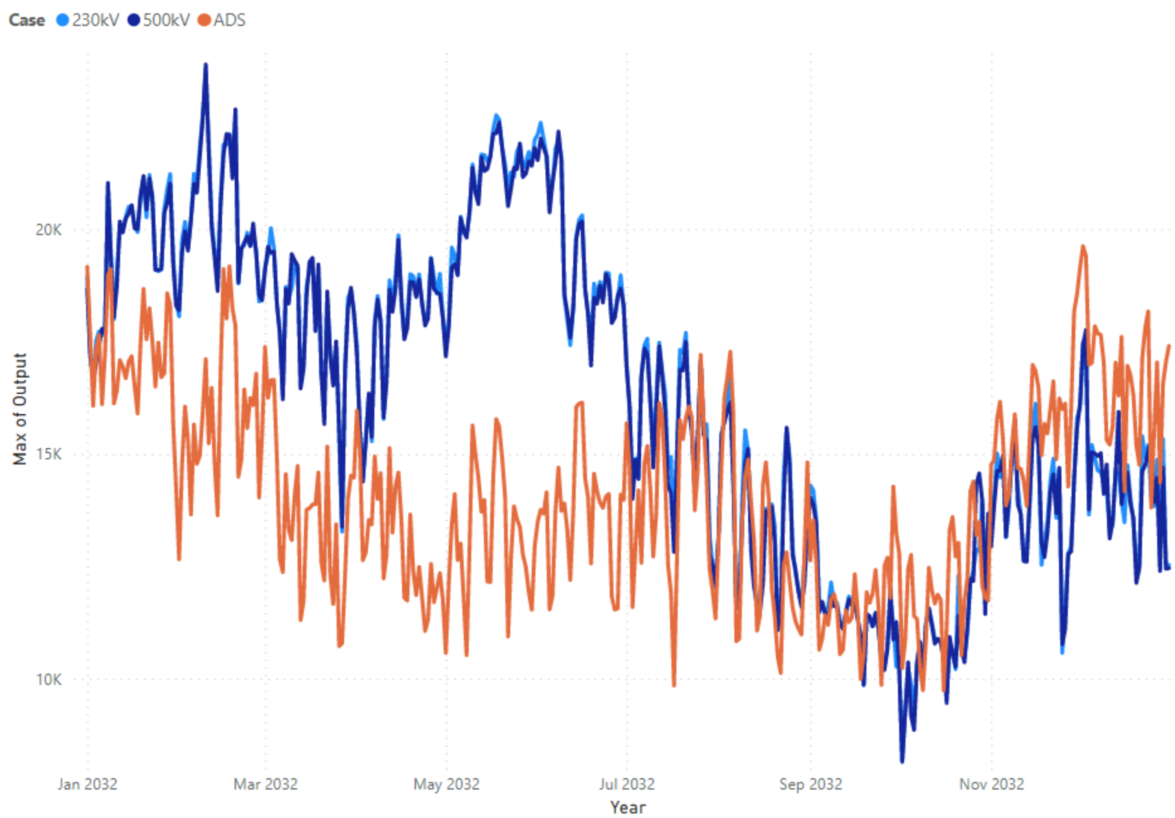
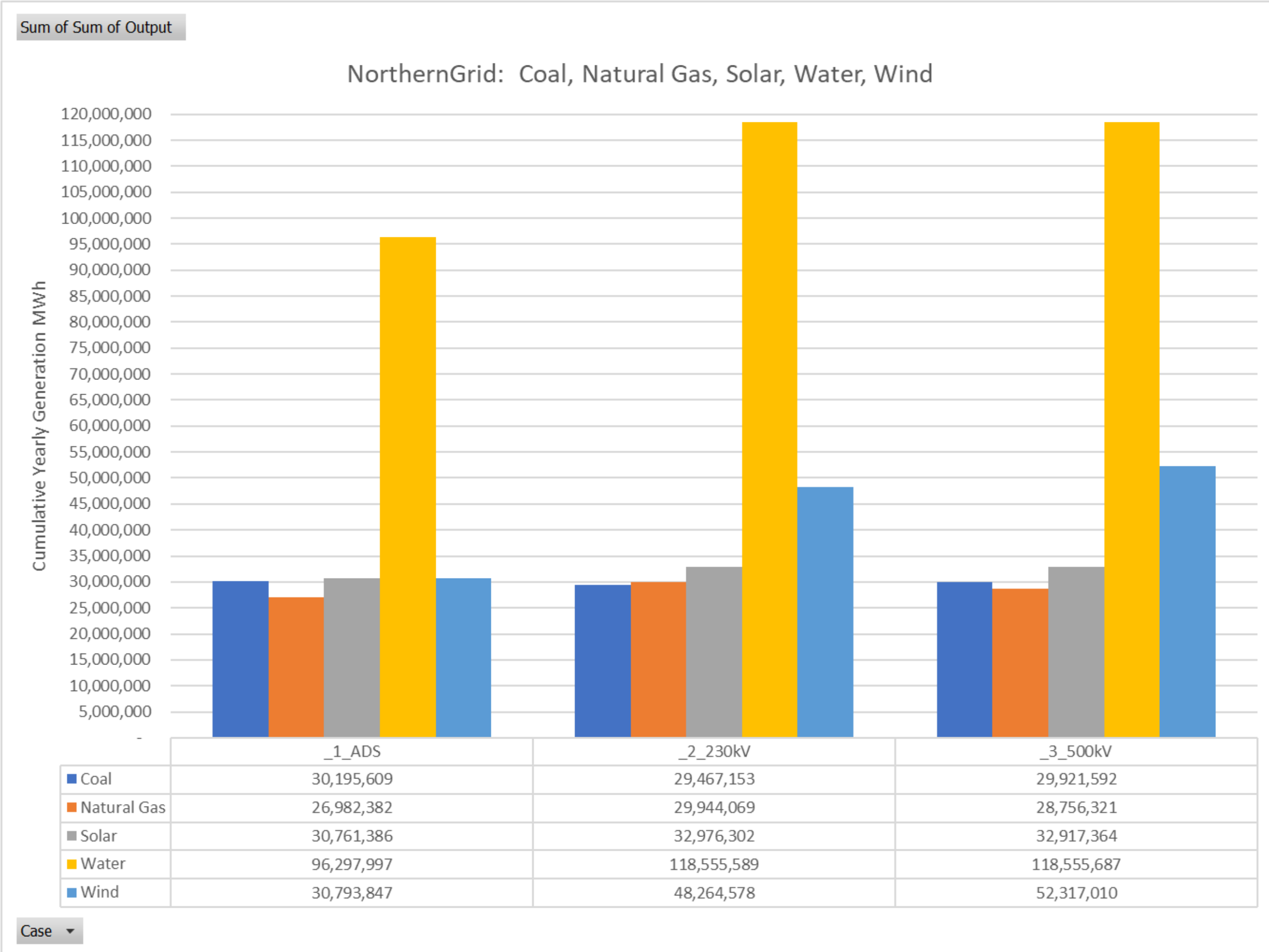


Figure 21: All generation in the NorthernGrid region

Figure 21: All generation in the NorthernGrid region suggests that with the addition of offshore wind, at either the 230 kV or 500 kV level, there is additional generation on the system. The figure represents the entire collection of different generation resources in the entirety of the NorthernGrid region. With the offshore wind resources present, there is more generation overall within the NorthernGrid region and Figure 21: All generation in the NorthernGrid region suggests that the offshore wind changed the overall dispatch of generation within the NorthernGrid region.



	_1_ADS	_2_230kV	_3_500kV
Coal	30,195,609	29,467,153	29,921,592
Natural Gas	26,982,382	29,944,069	28,756,321
Solar	30,761,386	32,976,302	32,917,364
Water	96,297,997	118,555,589	118,555,687
Wind	30,793,847	48,264,578	52,317,010

Figure 22: NorthernGrid broken down by Coal, Natural Gas, Hydro, Solar, and Wind, daily total output

Figure 22: NorthernGrid broken down by Coal, Natural Gas, Hydro, Solar, and Wind shows these selected fuel types in the NorthernGrid region. For the NorthernGrid region and with this offshore wind request modeled in, the following observations can be made:

- In the NorthernGrid Region, there is less total coal output in the cases with the offshore wind modeled.
- In the NorthernGrid Region, there is less total Natural Gas output in the cases with the offshore wind.
- In the NorthernGrid Region, there is more solar output in the cases with the offshore wind modeled.
- In the NorthernGrid Region, there is more total water output in the cases with the offshore wind projects modeled.
- In the NorthernGrid Region, there is more total wind output in the cases with the offshore wind projects modeled.

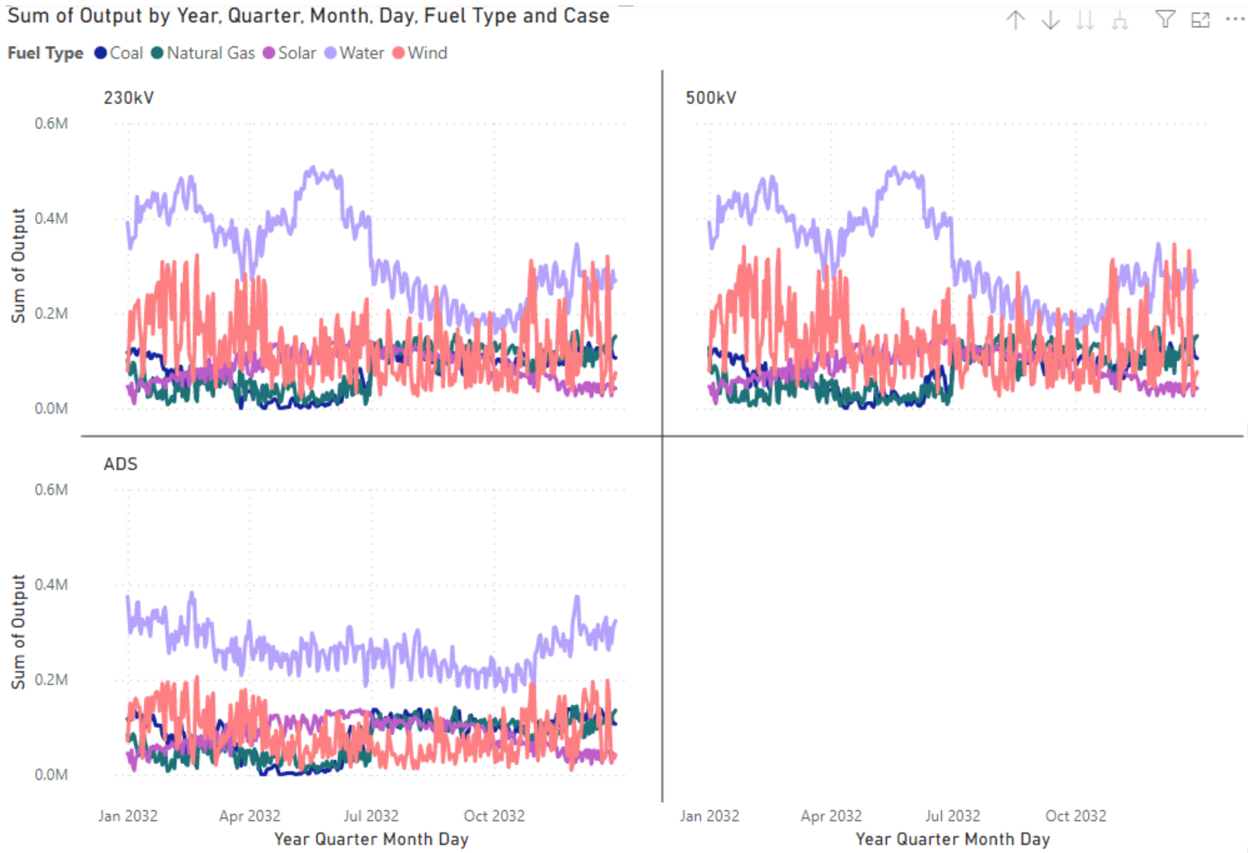


Figure 23: Total daily output for Coal, Natural Gas, Solar, Water, and Wind for the NorthernGrid Region

The colors in Figure 23: Total daily output for Coal, Natural Gas, Solar, Water, and Wind for the NorthernGrid Region do not match those of Figure 22: NorthernGrid broken down by Coal, Natural Gas, Hydro, Solar, and Wind, daily total output, but they do represent the same data. Visual examination of Figure 23: Total daily output for Coal, Natural Gas, Solar, Water, and Wind for the NorthernGrid Region allows for visual confirmation that the resources are behaving similarly for the three different cases.

The results herein this report represent the outcome of the results of a simulation that does not take into account the myriad of different outcomes that may have come about as a result of human intervention and operation. This report lacks a comprehensive review of every aspect of the output of production cost modeling and as such, there may be other characteristics that may more fully explain some of the changes observed between cases.

Table 4: Emissions

	Total SO2	Total NOx	Total CO2
ADS	502,951	36,514,565	69,920,966,237
230kV	489,133	34,966,414	67,430,741,789
500kV	491,841	34,574,063	66,627,837,531

Table 5 shows the overall emissions for the region; the introduction of offshore wind resources helps to reduce regional emissions.

Table 5: Regional Production Cost

Case	Total
ADS	$ 2,287,783
230kV	$ 2,204,824
500kV	$ 2,184,426

The regional production cost reduces with the offshore wind.

Summary

All the statements in the summary below assume that the existing system upgrades listed in Table 1 have been constructed. The statements pertain to the output of the offshore wind from the steady-state, post-transient power flow and production cost modeling analyses performed specifically for this request. This summary only addresses the impacts to the transmission system as a result of successful interconnection, and does not address anything needed to obtain that successful interconnection. The following were observed from this analysis:

1. Offshore wind in Oregon modified the flows on the WECC paths
    a. California to Oregon experienced increased southbound (export to California) flows
    b. Idaho to the Northwest, West of Cascades South, and South of Allston all experienced decreased flows
    c. South of Allston path experienced reduced north to south utilization
2. Carbon-based resources
    a. Regionally, the natural gas and coal generators were dispatched less when offshore wind was modeled
3. Interconnection at the 230 kV level
    a. Requires all Existing System upgrades listed in Table 1
    b. Offshore wind generators experienced congestion as a result of the transmission system limitations between the coast and the I-5 corridor
    c. Reduces the overall production cost compared to the ADS
4. Interconnection at the 500 kV level
    a. Requires all Existing System upgrades listed in Table 1
    b. Requires a new “500 kV loop” that connects the I-5 corridor with both wind facilities
        i. This “500 kV loop” may be constructed in phases as the offshore wind projects get developed; it only needs to be complete upon the complete installation of the additional wind.
    c. The output from the offshore wind generators was delivered to the I-5 corridor congestion-free
    d. The “500 kV loop” allows for other potential interconnection points along the Oregon coast
    e. The “500 kV loop” reinforces the existing transmission system in Oregon
    f. Further reduces the overall production cost from the 230 kV interconnection level

This report is for informational purposes only. The findings in this report may inform the NorthernGrid regional planning process.

Attachment D

Grid Strategies, Round One Comments for 2023 PGE IRP Presenting Analysis on Conditional Firm Assumptions in the Preferred Portfolio Results (July 2023)

MEMORANDUM

To: Renewable Northwest
From: Grid Strategies, LLC
Date: July 2023
Re: Round One Comments for 2023 PGE IRP Presenting Analysis on Conditional Firm Assumptions in the Preferred Portfolio Results

I. Comments

We appreciate Portland General Electric's (PGE) serious engagement with our initial comments, including the statement that "PGE is open to discussion on how conditional firm transmission is modeled."[1] These comments respond to their thoughtful feedback on our initial analysis of the impact of conditional firm curtailment on renewable capacity value. After incorporating many of their suggested revisions to our methodology and assumptions, the analysis still supports our conclusion that curtailment of renewables delivered via Bonneville Power Administration's (BPA) Conditional Firm Transmission Service will not significantly reduce those resources' capacity value. We continue to recommend that PGE update their modeling to reduce the hours of on-peak curtailment of conditional firm transmission service assumed in the Reference Case to zero. In addition, PGE should conduct its own power flow analysis to better understand the conditional firm transmission product.

As background, PGE is modeling transmission in its Integrated Resource Plan (IRP) process for the first time, which is a positive development. However, the draft 2023 IRP uses conservative assumptions for the risk of curtailment during peak demand periods of resources delivered via BPA's Conditional Firm Transmission Service. PGE assumes that renewable resources delivered using Conditional Firm Transmission Service will be curtailed during PGE's highest 100 hours of peak demand.[2] This assumption significantly reduces the contribution of these resources to meeting PGE's peak capacity needs, which PGE discusses in Appendix J of its IRP,[3] and likely limits the amount of renewable resources PGE is able to procure for its preferred portfolio.

After modifying our analysis in response to comments from PGE and their July 2023 Addendum, our results still indicate that PGE's curtailment assumptions are unduly conservative, and thus understate the capacity contributions of renewable resources towards meeting PGE's peak demand needs. For the summer and winter peak demand time periods identified by PGE in their 2023 IRP, we show that with updated estimates of expected growth of renewable resources and if no mitigating actions are taken, in 2030 there could be up to 127 hours in which actual flows exceed the transfer capacity of the West of Cascades South Path, which is the

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[1] Portland General Electric, "Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan Response to Initial Comments," May 31, 2023, 38, available at https://edocs.puc.state.or.us/efdocs/HAC/lc80hac102443.pdf. ("PGE Responses")

[2] PGE, "2023 Clean Energy Plan and Integrated Resource Plan: Appendix J ELCC sensitivities," 545-547, March 2023, https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/db59c8b594a3c380b9d42e90ec9a35aa/2023_PGE_CEP-IRP.pdf.

[3] Id., 545-546.

primary path for delivery of new wind and solar resources to PGE's service territory. 109 of those hours with exceedances occur in the summer and exceed the transfer capacity by an average of 785 MW, while the 18 winter hours saw an average of 273 MW exceedance of the available transfer capacity.[4]

More importantly, nearly all of these events result from short-duration peaks in solar production. In reality, grid operators, utilities, and other generation owners would almost certainly alter the dispatch of other resources in response to market signals, including the locational prices for every 5-minute interval provided by the Energy Imbalance Market, to avoid contributing to transmission overloads. Those peaks would almost certainly be absorbed by the large amount of battery capacity PGE and other utilities are planning to locate near new renewable resources, or by continued increases in the flexible dispatch of hydropower and other existing resources to avoid triggering congestion during peak solar output hours. The interactivity between potential transmission curtailment and storage, which can be located and operated in a manner to reduce curtailment risk, speaks to the importance of ensuring PGE's modeling workflow incorporates portfolio effects between resources in the context of the portfolios under consideration, as RNW recommends in Section IIB of its Round 1 Comments.

For our analysis, the storage capacity PGE and PacifiCorp are planning to add by 2030 exceeds the maximum MW of curtailment in our model (2414 MW of storage vs. 2129 MW max curtailment). Moreover, all but one event in the winter in which modeled flows exceed available transmission capacity last less than four hours, indicating typical 4-hour duration battery installations are more than sufficient to fully absorb this excess generation and prevent curtailment resulting from transmission overloads. As a result, we continue to recommend PGE assume 0 hours of curtailment during peak load for the Reference Case when modeling conditional firm transmission service, instead of its proposed assumption of 100 hours of curtailment.

II. Updated Analysis

This section presents the methodology and results from our updated analysis. Our updated analysis adopts two suggested revisions from PGE's responses, adds additional detail around hybrid resources, and otherwise retains the assumptions and methodologies from our earlier analysis.

First, PGE notes that our initial analysis only relied on 2022-2023 data for available capacity on the West of Cascades South path, despite there being multiple years of data available on the BPA website.[5] To remedy this we reviewed 2018-2023 data to determine the periods of highest and lowest hydropower generation during the hours PGE uses for peak capacity in its IRP. We updated our analysis accordingly to create two scenarios, one with high hydropower generation

[4] Our previous analysis estimated there would be 37 hours of curtailment, 36 hours in the summer and 1 hour in the winter.

[5] "PGE Responses," 38.

and one with low hydropower generation, to bookend the potential major generation variation on the West of Cascades South Path.

These updated scenarios did not significantly change the results of our analysis. Therefore, we retained the years of data from our initial analysis to determine our final results as it provided slightly more conservative results and reflects the current levels of new renewable generation, particularly solar, which is likely the limiting element on the West of Cascades South Path.

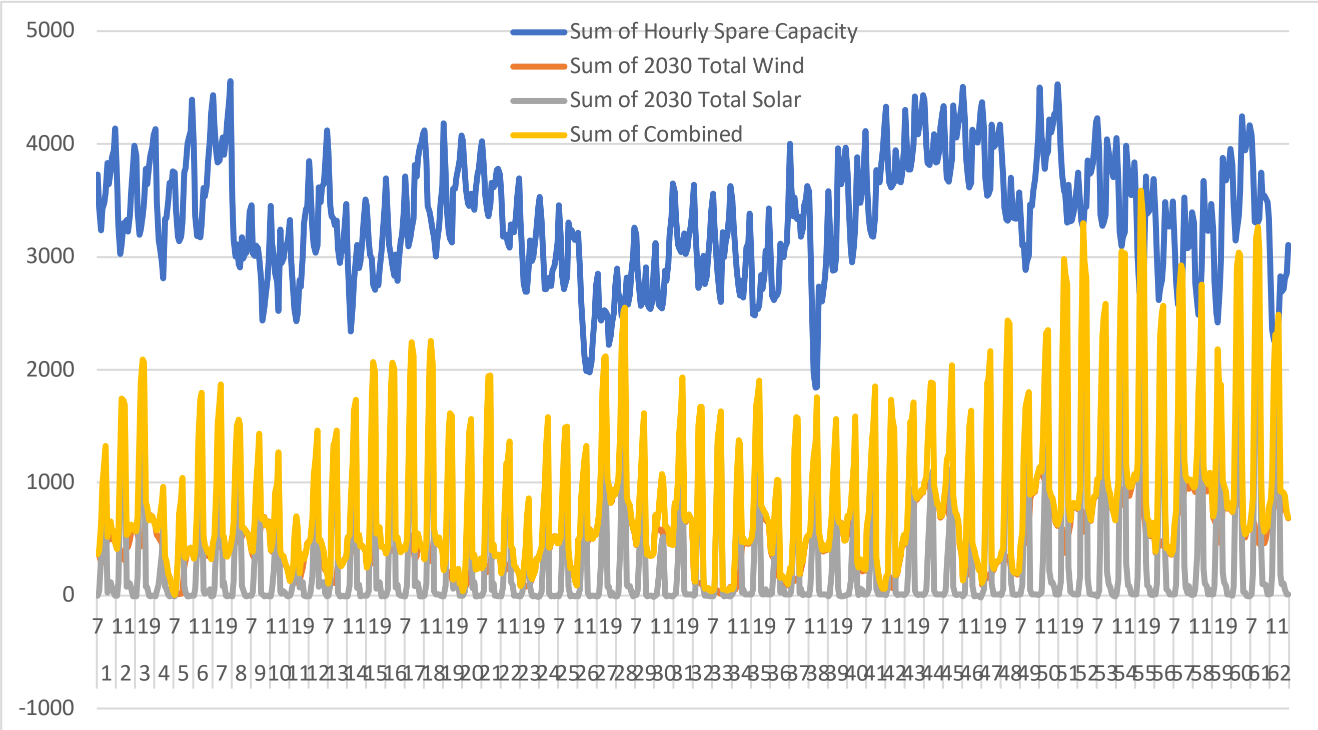
The hydropower generation for each year during PGE's peak hours is summarized in the table below. The highest hydropower year for the summer was July-August 2022, which was already used in our initial analysis, while the lowest hydropower summer was July-August 2021. The highest hydropower year for the winter period was Dec. 2021-Jan. 2022 and tied for the lowest was Dec. 2022-Jan. 2023, which was also already used in our analysis.

Table 1. BPA Hydropower Generation (million MWh)

Year	**Summer (July-August)**	**Winter (December-January)**	**Total**
2022-2023	**4.2**	**6.4**	10.6
2021-2022	**3.2**	**8.6**	11.8
2020-2021	3.7	7.5	11.2
2019-2020	3.0	6.4	9.4
2018-2019	3.4	6.4	9.8

Using these years of high and low hydropower generation in our scenarios actually lowered the hours of curtailment in our analysis. In the high hydropower scenario, the West of Cascades South Path in December 2021-January 2022 had half the curtailments and a similar average hourly spare capacity when compared to the lower hydropower year of December 2022-January 2023 we used in our initial analysis (see figure below). This difference lowered the total hours of curtailment from 127 hours to 118 hours in our high hydropower scenario. As we stated above, these results suggest new renewables are likely a bigger factor as the limiting element on the West of Cascades South path than hydropower generation.

Figure 1. Dec. 2021 - Jan. 2022 curtailments on West of Cascades South Path during high hydropower year



Second, PGE noted that our 18% estimate of resource procurements in 2030 between PacifiCorp's East and West footprints was low,[6] and provided a citation to PacifiCorp's 2023 IRP where PGE states the breakdown was 31% of the resources would be in PacifiCorp's Western footprint.[7] Using the MW of Summer Capacity PGE cites, we were able to replicate that same percentage breakdown between PacifiCorp's East and West footprints at 31% for installed solar and solar + storage capacity; however, the breakdown for installed wind capacity is actually lowered from 18% to 4% using the updated numbers. We also updated PGE's wind and solar capacity additions based on the filed July IRP addendum.[8] Given the much larger increase in solar and solar + storage resources compared to the decreased installed wind capacity in PacifiCorp's Western footprint, the number of overload hours in our analysis does rise from 37 hours to 127 hours.

A significant amount of the additional resources added for our updated analysis from PGE's IRP addendum and in PacifiCorp's Western footprint are solar + storage resources. To account for this increased operational flexibility, we added an assumption to our model that any curtailments less than 4 hours and less than the new installed storage capacity in 2030 could be

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[6] *Id.*, 39.

[7] PacifiCorp, "2023 Integrated Resource Plan (Amended Final)," May 31, 2023, 325-328, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I_Final_5-31-23.pdf. ("PacifiCorp IRP")

[8] PGE, "Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan Addendum: Portfolio Analysis Refresh," 25, July 7, 2023, https://edocs.puc.state.or.us/efdocs/HTB/lc80htb16164.pdf.

mitigated. In 2030, the installed storage capacity between PGE and PacifiCorp West in our model was just over 2400 MW[9] and the maximum curtailment capacity in our 2030 summer scenario was 2129 MW. This means that all of the hours of curtailment in our model can be mitigated through use of short-duration storage during peak periods, as well as increased flexible dispatch of the hydropower fleet.

The following table compares the results of our updated analysis against our initial results, with the scenario we used in our final analysis bolded. As noted above, adopting PGE's suggested revisions does not change our conclusion that adding renewable resources using conditional firm transmission service incurs minimal risk of curtailment during PGE's peak load periods. This is particularly true if new batteries as well as existing flexible resources are dispatched to avoid exacerbating congestion, as they would be in response to market prices and typical operating practices.

Table 2. Summary of initial and updated model scenarios in analysis

Scenario	Hours and MWs of Curtailment (Summer)	Hours and MWs of Curtailment (Winter)	Total Hours of Curtailment
Initial Scenario (2022-2023 Data)	36 hours (386 MW)	1 hour (79 MW)	37 hours (did not account for solar + storage resources)
Updated Scenario (2022-2023 Data w/updated PGE/PacifiCorp West Resources)	**109 hours (785 MW)**	**18 hours (273 MW)**	**0 hours with storage (2129 MW max curtailment)**
High Hydropower Year (July-August 2022 & Dec. 2021-Jan. 2022 w/updated PGE/PacifiCorp West Resources)	109 Hours (785 MW)	9 hours (234 MW)	2 hours with storage (2702 MW max curtailment)
Low Hydropower Year (July-August 2021 & Dec. 2022-Jan. 2023 w/updated PGE/PacifiCorp West Resources)	68 hours (845 MW)	18 hours (273 MW)	0 hours with storage (2702 MW max curtailment)

Our updated analysis is provided in the attached spreadsheet.

III. Qualitative Responses to Other PGE Comments

In its "2023 Clean Energy Plan and Integrated Resource Plan Response to Initial Comments" ("PGE's Responses"), PGE provided comments on the assumptions of our initial analysis. We

[9] We assumed a 1:1 ratio of storage to solar for PacifiCorp's planned hybrid additions, based on page 192 of PacifiCorp's IRP, and a 0.6:1 ratio of storage to solar for PGE based on the assumption in 2023 NREL ATB. NREL, "Annual Technology Baseline: Utility-Scale PV-Plus-Battery," accessed July 24, 2023, https://atb.nrel.gov/electricity/2023/utility-scale_pv-plus-battery.

addressed many of PGE's comments in our updated analysis presented above. In this section we qualitatively respond to PGE's other comments.

In Section 7.11 Conditional Firm Transmission Approach of PGE's 2023 Response to Initial Comments,[10] PGE suggests that a power flow analysis would be a more appropriate approach to modeling conditional firm transmission service. We agree, and suggest that PGE should be conducting its own power flow analysis of these potential constraints.

In Section 7.11 of PGE's Responses, they suggest assuming "0 hours of curtailment" is not a realistic assumption, adding that this assumption suggests that all resources in PGE's preferred portfolio should rely on short-term transmission products to deliver generation.[11] We are not advocating for all resources to rely on conditional firm transmission products, as there is admittedly some uncertainty about the location and quantity of the regional expansion of renewable and storage resources. As a factual matter, BPA has not curtailed conditional firm resources to date, and our analysis shows there is significant spare capacity on the West of Cascades South Path. In addition, our analysis indicates that in 2030 most of the modeled overloads that occur on the West of Cascades South Path are caused by solar generation and only occur for a couple of hours at a time. Because solar peaks are more consistent and easier to forecast, battery and battery hybrid resources, as well as the flexibility of hydropower and other dispatchable resources can be used to prevent or at least mitigate these overloads.

PGE's responses also noted that the RNW analysis does not include the impact of contingencies, which prevent lines from being operated at their limits due to N-1 operational constraints.[12] However, there is insufficient publicly available data for us to analyze N-1 operational constraints, in part because the assumptions for what constitute credible contingencies are not public, adding further reason why PGE should be conducting its own power flow analyses to better understand those potential limitations. In addition, our updated analysis shows that for 82% of the peak hours considered (913 out of 1,116 hours), the West of Cascades South Path is operating well below its limit, which we define as less than 85% of the total rated line capacity. This means that for only 203 hours, or 18% of the peak hours, flows are greater than 85% of the line capacity. This includes the 127 hours of potential curtailment. However, this does not include a majority of the line's operating hours, which occur in non-peak times and are unlikely to approach operating limits regularly. We also note that newer technologies and operating practices can be used to respond to system contingencies, including the use of fast-acting batteries to maintain stability and prevent overloads during contingencies, allowing lines to operate at higher short-term emergency ratings during contingencies, and Grid-Enhancing Technologies like dynamic line ratings, topology optimization, and power flow control devices.

[10] "PGE Responses," 38.
[11] *Id.*
[12] *Id.*

PGE's CEP/IRP highlights the South of Alston Path as a primary constraint on their system.[13] PGE adds that it discusses congestion relief on the South of Alston Path in its Action Plan and that the South of Alston flow gate, and likely other pathways, must be considered when analyzing the ability for resources to provide power to PGE.[14] Since we are not doing a power flow analysis there are some simplifying assumptions we made to our analysis. Our study assumes the West of the Cascades North and South paths will be the limiting factor for new renewables getting to load centers in the Northwest. A presentation by the Northwest Power and Conservation Council ("Council") shows that the West of Cascades North path is a winter peaking path that primarily serves Northwest Washington.[15] Based on this information, we assumed all new renewables and demand on the West of Cascades North path will be used by the utilities in the Puget Sound Area. With the West of Cascades North path serving the Puget Sound Area, we assumed the West of the Cascades South line is the primary transmission path delivering new renewables to Oregon and PGE.

We did not include the South of Alston path in our analysis for two reasons. First, the same Council presentation on transmission utilization indicates that while there may be constraints on the South of Alston path, most of the power on the South of Alston path is Canadian Hydropower, and not the new renewable resources Oregon utilities are adding to meet clean energy and climate goals.[16] British Columbia Hydropower is highly flexible and thus can be dispatched to avoid causing transmission overloads, as can be seen by operational adjustments already being made to accommodate solar generation flowing to the Northwest from California. In addition, any renewables that make it to the South of Alston path and get curtailed would first have to make it over the West of Cascades North path and not be used by utilities in the Puget Sound Area. We feel this scenario means a limited amount of renewables will be entering PGE's system through the South of Alston path and the bigger concern for curtailment of new renewable generation under conditional firm contracts lies with the West of Cascades South path, which is why it is the focus of our analysis. Second, PGE in its IRP models and recommends upgrades to the South of Alston path, suggesting PGE could achieve those upgrades as early as 2027.[17] We assume PGE would be able to make those upgrades, which would further focus the limits on new renewable generation imports to PGE's system on the West of Cascades South path.

PGE also added that the analysis does not incorporate load growth, which could result in a greater need for power and more power flowing over the pathway.[18] We feel that if the utilities

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[13] *Id.,* 38-39; PGE, "2023 Clean Energy Plan and Integrated Resource Plan: Chapter 9," 207, March 2023, https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/db59c8b594a3c380b9d42e90ec9a35aa/2023_PGE_CEP-IRP.pdf. ("PGE IRP"

[14] "PGE Responses," 38-39.

[14] *Id.*

[15] Mike Starrett, "Electric Transmission in the Northwest," Northwest Power and Conservation Council, Slide 13, March 2019, https://nwcouncil.app.box.com/s/sxz0klomm4tyzdx7gjpzfz3y41nmsivo.

[16] *Id.*, slide 34.

[17] "PGE IRP," 227-229.

[18] *Id.*

in the Pacific Northwest are properly planning for and developing resources to meet future load growth in their IRP processes, then our analysis should approximately account for potential load growth simply by modeling additional generation resources in 2030. In addition, a large share of projected load growth is related to data centers, which are often located outside of urban areas and in areas with low-cost generation and minimal transmission congestion, so this load growth may actually reduce and not increase congestion.

PGE also suggested that RNW should take into account "broader anticipated changes resulting from renewable generation buildout from any other utilities, including Washington utilities."[19] As discussed above, we believe it is a reasonable assumption that most of the new renewables procured by utilities in Washington will flow over the West of Cascades North path. If we were to take a more regional look at renewable development, our analysis would still require an assumption about what percent of new renewable development would flow over the West of Cascades South path. Either method requires an assumption to be made. As stated above, the best course of action would be for PGE to conduct its own power flow analysis.

Finally, in PGE's Responses Section 11.6 Hybrid Resources PGE found an error in their calculation of capacity factors for hybrid resources, which was significantly understating the capacity factor of those resources.[20] We appreciate the model refresh that now adds 1010 MW of hybrid resources, and believe this is a more accurate reflection of the value hybrid resources can provide.[21]

[19] "PGE Responses," 39.
[20] *Id.,* 55.
[21] PGE, "Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan Addendum: Portfolio Analysis Refresh," 24-25, July 7, 2023, https://edocs.puc.state.or.us/efdocs/HTB/lc80htb16164.pdf.