BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 394

In the Matter of	)	
	)	
PORTLAND GENERAL ELECTRIC COMPANY,	)	OREGON CITIZENS' UTILITY BOARD'S REDACTED EXHIBITS
	)	
Request for a General Rate Revision.	)	
	)	

The Oregon Citizens' Utility Board ("CUB") CUB submits the following Exhibits for inclusion in the administrative record in this proceeding, not previously filed in this case:

- CUB Exhibit 500 – *Joint Application of the Alliance of Western Energy Consumers and the Oregon Citizens' Utility Board for an Accounting Order Requiring Portland General Electric Company to Defer Expenses and Capital Costs Associated with the Boardman Power Plant* in the docket number UM 2119, filed October 8, 2020.
- CUB Exhibit 501 – *Joint Reply Comments of the Alliance of Western Energy Consumers and the Oregon Citizens' Utility Board* in the docket number UM 2119, filed November 12, 2020.
- CUB Exhibit 502 – *Staff's Opening Comments* in the docket number LC 73, filed October 11, 2019.
- CUB Exhibit 503 – *Opening Testimony of Scott Gibbens* in the docket number UE 359 (PGE 2020 AUT), filed June 25, 2019.
- CUB Confidential Exhibit 504 – 2020 AUT, *Minimum Filing Requirement* in the docket number UE 359, filed April 1, 2019.

- CUB Confidential Exhibit 505 – 2022 AUT, Email from PGE staff Allison Lawler in the docket No. UE 391, filed November 15, 2021.
- CUB Confidential Exhibit 506 – 2020 AUT, *Minimum Filing Requirement* in the docket No. UE 391, filed November 15, 2021.
- CUB Confidential Exhibit 507 – 2022 AUT, *Minimum Filing Requirement* in the docket number UE 391, filed April 1, 2021.

Dated this 7th day of February, 2022.

Respectfully submitted,

Michael P. Goetz, OSB #141465
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UE 394– CERTIFICATE OF SERVICE

I hereby certify that, on this 7th day of February, 2022, I served the **Confidential Exhibits of the Oregon Citizens' Utility Board** in docket UE 394 upon the Commission and each party designated to receive confidential information pursuant to Order 21-206 through a secure, encrypted attachment to an e-mail.

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October 8, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem, OR 97301

Re: In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS AND CITIZENS' UTILITY BOARD OF OREGON,
Application for an Accounting Order Requiring Portland General Electric Company to Defer Expenses and Capital Costs Associated with the Boardman Power Plant.
Docket No. UM _____

Dear Filing Center:

Please find enclosed the Joint Application of the Alliance of Western Energy Consumers and the Oregon Citizens' Utility Board for an Accounting Order Requiring Portland General Electric Company to Defer Expenses and Capital Costs Associated with the Boardman Power Plant.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM ___

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS and OREGON CITIZENS' UTILITY BOARD, Application for an Accounting Order Requiring Portland General Electric Company to Defer Expenses and Capital Costs associated with the Boardman Power Plant.	)))))))))))	JOINT APPLICATION FOR DEFERRED ACCOUNTING OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS AND OREGON CITIZENS' UTILITY BOARD

I. INTRODUCTION

Pursuant to ORS § 757.259 and OAR § 860-027-0300, the Alliance of Western Energy Consumers ("AWEC") and the Oregon Citizens' Utility Board ("CUB") jointly apply to the Oregon Public Utilities Commission ("Commission") for an order requiring Portland General Electric Company ("PGE" or "Company") to defer PGE's expenses and capital costs associated with the Boardman Plant ("Boardman") currently included in the Company's base rates established in its 2019 general rate case, beginning on the date that Boardman ceases operations. A deferral is required in order for customers to adequately capture the reduction in rate base and O&M expenses that will occur as a result of PGE discontinuing operations at Boardman in 2020. In support of this Joint Application, AWEC and CUB state:

1. AWEC is an incorporated, non-profit association of large energy consumers in the Western United States, with offices in Portland, Oregon. Many members of AWEC are customers of PGE.

2. Legislation creating CUB was enacted into law in 1984. CUB was created to ensure that utility consumers have an effective advocate to reflect their needs and interests when it comes to public policies affecting the quality and price of utility services.[1/]
3. Communications regarding this application should be addressed to:

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II. OAR 860-027-0300(3) REQUIREMENTS

The following is provided pursuant to OAR 860-027-0300(3):

A. Description of Expense and Revenue

PGE owns 90 percent of the Boardman 575 MW coal-fired generating plant, resulting in a 518 MW net base capacity for the Company.[2/] The Commission acknowledged the shutdown of Boardman by no later than the end of 2020 through Order No. 10-457.[3/] On February 15, 2018, PGE filed a general rate case for rates effective January 1, 2019.[4/] This was the Company's most recent general rate case. Accordingly, PGE's investment in Boardman is currently included in the Company's base rates established in the 2018 general rate case and will continue at the same level until the rate-effective date of PGE's next general rate case in the absence of a deferral.

1/ ORS § 774.020.
2/ Portland General Electric, Boardman Plant Air Emissions, available at: https://www.portlandgeneral.com/corporate-responsibility/environmental-stewardship/air-quality-emissions/boardman-plant-air-emissions (last accessed Oct. 8, 2020).
3/ Docket No. LC 48, Order No. 10-457 (Nov. 23, 2010).
4/ Docket No. UE 335, Request for a General Rate Revision (Feb. 15, 2018).

B. Reasons for Deferral

Deferral of PGE's expenses and capital costs associated with Boardman currently included in PGE's base rates is authorized pursuant to ORS § 757.259(2)(e) which specifies that the Commission may authorize deferral of "[i]dentifiable utility expenses or revenues, the recovery or refund of which the [C]ommission finds should be deferred in order to…match appropriately the costs borne by and benefits received by ratepayers" for "later incorporation in rates."[5/] Upon the retirement of Boardman by the end of 2020, customers will no longer receive a benefit from the plant and therefore, deferral is necessary to appropriately match costs and benefits.[6/]

Specifically, with respect to rate base amounts associated with Boardman, an appropriate matching of costs and benefits through the deferral of PGE's investment in Boardman included in rate base is further evidenced by the statutory prohibition against a utility earning a return on plant that is no longer used and useful. Specifically, ORS § 757.355(1) states that "a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer." The Court of Appeals of Oregon has affirmed that ORS § 757.355(1) ensures that "property that is not 'reasonably necessary to and actually providing utility service' is ineligible for either inclusion in the rate base or for a rate of return payable by utility customers," and that this

5/ ORS § 757.259(2)(e).

6/ The Company has been recovering decommissioning costs associated with the Boardman Power Plant under its Schedule 145. From 2011 to 2013, the Company was allowed to collect accelerated depreciation through Schedule 145. Beginning on January 1, 2014, accelerated depreciation amounts were incorporated into base rates and only amounts related to decommissioning were subsequently collected through Schedule 145. Through Schedule 145, the Company also has been able to recover expenses associated with severance and retention of PGE employees outside of base rates at Boardman power plant. This Joint Application does not seek deferral of any costs currently being collected under Schedule 145.

prohibition applies to "property that has ceased being used for the provision of services as well as property that has never been so used."[7/] Consequently, a deferral of amounts attributable to Boardman in PGE's rate base is necessary to ensure PGE does not continue to earn a return on property that is no longer providing utility service.

C. Proposed Accounting

AWEC and CUB recommend that PGE record the deferred amounts as a regulatory liability to the appropriate FERC account.

D. Estimate of Amounts

AWEC and CUB do not currently have the information necessary to provide a precise accounting of the amount to be deferred pursuant to this Application but estimate that the amount currently included in PGE's base rates is approximately $50 million.

E. Notice

A copy of the Notice of Application for Accounting Order Requiring PGE to Defer Expenses and Capital Costs Associated with the Boardman Power Plant and a list of persons served with the Notice are attached as Attachment A to this Application.

III. ADDITIONAL FILING CONDITIONS

A. Earnings Review

The refund of costs associated with Boardman will be subject to an earnings review in accordance with ORS § 757.259(5).

[7/] Citizens' Util. Bd. v. PUC, 154 Or. App. 702, 708-710, 962 P.2d 744, 747 (1998).

B. Prudence Review

Because this Joint Application seeks to defer a reduction in expense and rate base, a prudence review will not be performed when the amounts in this deferred account are eligible for amortization.

C. Sharing

All refunds are to be returned to ratepayers of PGE with no sharing mechanism.

D. Rate Spread/Rate Design

The rate spread/rate design will be consistent with the prevailing rate spread/rate design determined at the time of amortization, unless otherwise agreed by the parties to the applicable proceeding or ordered by the Commission.

IV. CONCLUSION

For the foregoing reasons, AWEC and CUB respectfully request that the Commission order PGE to defer expenses and capital costs associated with Boardman currently included in the Company's base rates, beginning on the date Boardman ceases operations.

Dated this 8th day of October, 2020

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

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Attachment A

Notice of Application for Accounting Order Requiring Portland General Electric Company to Defer Investment in the Boardman Plant Included in Rate Base

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM ___

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS and OREGON CITIZENS' UTILITY BOARD Application for an Accounting Order Requiring Portland General Electric Company to Defer Expenses and Capital Costs associated with the Boardman Power Plant.	)	NOTICE OF JOINT APPLICATION FOR DEFERRED ACCOUNTING OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS AND OREGON CITIZENS' UTILITY BOARD

Pursuant to OAR 860-027-0300(6), on October 8, 2020, the Alliance of Western Energy Consumers ("AWEC") and the Oregon Citizens' Utility Board ("CUB") jointly applied to the Oregon Public Utilities ("Commission") for an order requiring Portland General Electric Company ("PGE" or "Company") to defer PGE's investment and expenses associated with the Boardman Plant ("Boardman") currently included in the Company's base rates established in its 2019 general rate case, beginning on the date that Boardman ceases operations.

This Application is on the Commission's website. Persons who wish to obtain a copy of PGE's application will be able to access it on the Commission's website, and "any person may submit to the Commission written comment on [this Application] by the date set forth in the notice, which date may be no sooner than 25 days from the date of [this Application]."[8/]

[8/] OAR 860-027-0300(6)(d).

The granting of AWEC and CUB's Application "will not authorize a change in [PGE's] rates, but will permit the Commission to consider allowing such deferred amounts in rates in a subsequent proceeding."[9]

Dated this 8th day of October, 2020

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[9] OAR 860-027-0300(6)(e).

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the attached **Application for Deferred Accounting Order on behalf of the Alliance of Western Energy Consumers and the Oregon Citizens' Utility Board** by electronic mail upon each of the parties on the attached service list for Oregon Public Utilities Commission Docket No. UE 335.

DATED this 8th day of October, 2020.

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch
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OREGON PUBLIC UTILITIES COMMISSION
Docket No. UE 335

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2119

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS and OREGON CITIZENS' UTILITY BOARD, Application for an Accounting Order Requiring Portland General Electric Company to Defer Expenses and Capital Costs Associated with the Boardman Power Plant.	)	JOINT REPLY COMMENTS OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS AND OREGON CITIZENS' UTILITY BOARD

I. INTRODUCTION

Pursuant to OAR 860-027-0300(8) and OAR 860-001-0150, the Oregon Citizens' Utility Board (CUB) and the Alliance for Western Energy Consumers (AWEC) jointly submit these Reply Comments to the Public Utility Commission of Oregon (Commission) in the above-captioned proceeding. CUB and AWEC respond to issues raised by Portland General Electric Company (PGE) in its November 2, 2020 Comments.

PGE's comments request that CUB and AWEC's application for an accounting order requiring PGE to defer costs associated with the closure of its Boardman power plant (Application) be denied, citing various legal and policy concerns. PGE also makes a number of fact-based assertions in its Comments. In order to thoroughly examine these issues, the Commission should grant CUB and AWEC's Application to provide an adequate venue to do so.

PGE's comments raise several issues that the Commission should take up when this Application is eligible for potential amortization at the end of the 12-month tracking period. The Commission should not pre-judge these fact-based issues, and, instead, should only render a decision based upon a robust evidentiary record.

For the reasons discussed herein, CUB and AWEC respectfully request that the Commission grant the Application.

II. DISCUSSION

PGE opposes CUB's and AWEC's Application through a mixture of legal, policy, and factual arguments. Each of these arguments are either incorrect or irrelevant to the task currently before the Commission—to consider whether to approve the deferral Application and begin to track, not whether to amortize deferred amounts that do not yet exist.

PGE, through its non-attorney sponsor, claims that "CUB's and AWEC's Application reflects a novel an unsupported change in the interpretation of Oregon law …"[1] As CUB and AWEC noted in the Application, however, the Court of Appeals has held that ORS 757.355 prohibits the inclusion of plant that is not used and useful in a utility's rate base.[2] Thus, far from being a "novel and unsupported" interpretation, CUB and AWEC's Application reflects clear and well-settled law. As these Comments will discuss, the Application also matches the Commission's regulatory treatment for Idaho Power Company's share of Boardman.[3]

Meanwhile, PGE's citations to state decisions stemming from the *Trojan* lineage fail to tell the entire story of the Commission and courts' discussion of the potential inclusion of the return of and on an investment in rates beyond its cessation date. Regardless, however, PGE's legal arguments are premature. The issue addressed by the Commission in the *Trojan* decisions was whether PGE's rates were just and reasonable overall. That is a factual issue for

[1] PGE Comments at 1.
[2] Application at 3-4.
[3] Chief Administrative Law Judge Nolan Moser's letter indicating the Commission adopted Staff's recommendation in ADV 1179 (Oct. 20, 2020) *available at* https://edocs.puc.state.or.us/efdocs/UBF/adv1179ubf115034.pdf.

consideration when deferred amounts are proposed to be amortized. CUB and AWEC will appropriately address this issue when the Application is eligible for potential future amortization.

Because the removal of plant no longer in service is statutorily mandated, PGE's reference to the Commission's discretionary deferral criteria is similarly off-base. This deferral is not being filed hurriedly to address oncoming costs or benefits from an unexpected event. PGE and its customers have known about Boardman closing since the Company made an agreement with the Oregon Department of Environmental Quality almost ten years ago. From a deferred accounting perspective, responding to a regulatory requirement is more akin to responding to a change in federal tax law or complying with a statutory mandate. When a change in costs is mandated—such as due to regulatory, legislative, or statuary direction—the Commission frequently does not require that traditional deferral criteria be met or an earnings test be applied. PGE itself has sought deferral of numerous statutorily or Commission mandated or authorized costs, and their approval has not been subject to the Commission's discretionary criteria.[4]

The Commission should also grant the Application because it is supported by several policy considerations. For one, the Application is a reasonable means to capture the regulatory lag associated with Boardman's closure. Regulatory lag represents the delay between rate cases when rates are frozen until a new rate is approved.[5] Regulatory lag significantly impacts customers where it appears on the back end of a capital

[4] *See, e.g.*, Docket UM 2078 (Residential Battery Storage Pilot); Docket UM 1977 (Community Solar Start-Up Costs); Docket UM 1976 (Demand Response Test Bed)
[5] OPUC Order No. 12-493 at 17 (citing LEONARD SAUL GOODMAN, THE PROCESS OF RATEMAKING (Vol. I), 44 (Pub. Util. Rpts., Inc. 1998)).

investment's useful life. In between rate cases, customers continue to pay the rates set during a prior rate case for a capital investment that is continuously depreciating.

PGE, perhaps more so than any other Commission-regulated utility, has historically gone to great lengths to avoid any regulatory lag on the front-end of its capital investments. PGE was able to track the capital and fixed costs associated with its Coyote Springs plant into base rates 90 days prior to the expected in-service date.[6] It received immediate cost recovery provided its Port Westward plant became operational within 60 days of its March 1, 2007 online date.[7] The Company received similar treatment with phase 1 of Biglow Canyon.[8] PGE received special tariff riders for its Port Westward 2, Tucannon,[9] and Carty generating plants.[10] The Company is also able to avoid regulatory lag on all Renewable Portfolio Standard investments through its Renewable Resources Automatic Adjustment Clause. Since utility shareholders have avoided the costs of all regulatory lag on the front end of these investments, enabling customers to avoid regulatory lag for a plant that is no longer serving them would be an equitable and principled result. CUB and AWEC offer this Application to better match the precision with which PGE seeks to eliminate regulatory lag.

Further, by tracking the costs associated with Boardman for potential later amortization, ratemaking will better match the power costs customers will pay in 2021 and beyond. PGE's power costs are currently anticipated to increase by over $65 million in

[6] *In re Portland General Electric Company*, OPUC Docket No. UE 88, Order No. 95-322 (Mar. 29, 1995).
[7] *In re Portland General Electric Company*, OPUC Dockets Nos. UE 180, UE 181, and UE 184, Order No. 07-015 at 49-50 (Jan. 12, 2007).
[8] Order No. 07-573.
[9] *In re Portland General Electric Company*, OPUC Docket No. UE 283, Order No. 14-422 (Dec. 4, 2014).
[10] *In re Portland General Electric Company*, OPUC Docket No. UE 294, Order No. 15-356 (Nov. 3, 2015).

2021, relative to 2020 power costs.[11] Approximately $23 million of this increase is directly attributable to the cessation of operations at Boardman.[12] Customers should avoid the capital and O&M costs associated with the Boardman closure to appropriately match the additional power costs they will incur from this closure.

Deferring these costs for potential later amortization would also match the Commission's treatment of Idaho Power Company's share of the plant. There, the utility was authorized to "track and recover the incremental costs and benefits associated with the early shutdown of Boardman."[13] The Commission ultimately approved a removal of $276,316 from customer rates, which explicitly included similar revenue requirement amounts that are the subject of this Application.[14] Contrary to the Company's assertion that "the Commission has not to [their] knowledge ever required the removal of retired assets between rate cases," the Commission did just that on October 20th of this year. Since the Commission found it reasonable to pass costs back to customers in that setting, it stands to reason that it may here. The Commission should grant CUB and AWEC's Application to preserve that possibility at later amortization.

Further, approving the Application would match cost allocation methodologies for closing thermal plants used by a different Commission-regulated utility. As part of PacifiCorp's Multi-State Process (MSP) 2020 Protocol, the Company is obligated to propose ratemaking treatments that match costs and benefits when a state chooses to leave

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[11] Docket UE 377, PGE November 6, 2020 MONET Update (showing forecasted power costs of $459.1 million, $65.6 million over the $393.5 million in 2020 power costs). Power costs are subject to a final update on November 15th.
[12] Docket UE 377, PGE/100, Seulean-Kim-Batzler/43:15-17.
[13] *In re Idaho Power Company*, OPUC Docket No. UE 239, Order No. 12-235 at 3 (Jun. 26, 2012).
[14] Chief Administrative Law Judge Nolan Moser's letter indicating the Commission adopted Staff's recommendation in ADV 1179 (Oct. 20, 2020) *available at* https://edocs.puc.state.or.us/efdocs/UBF/adv1179ubf115034.pdf.

its share of a coal unit.[15] That is, when a state is no longer receiving the benefits (power) from a facility, it should not be responsible for its costs. The same fundamental ratemaking principle applies here. Since PGE's customers are no longer receiving Boardman's benefits, the matching principle is furthered by ensuring they are not subject to the costs.

Finally, PGE's discussion of the applicability of an earnings test and its reference to various investments it has made that have not been reviewed for prudence is also premature, and is a demonstration of exactly why the Commission should approve the Application to explore various issues. While the Application specifically identified that an earnings test would apply, it is ultimately an issue to be considered when amortization is proposed. The Company's earnings are entirely unknown at this time, as are the incremental investments it has made that are not yet in customer rates. Nevertheless, CUB and AWEC believe the avoided costs from closing Boardman should be passed back to customers, and look forward to addressing these issues at the appropriate time.

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[15] OPUC Order No. 20-024 at Appx. B, p. 14, 2020 Protocol.

III. CONCLUSION

For the foregoing reasons, CUB and AWEC urge the Commission to approve the Application to require PGE to defer and track the O&M expenses and capital costs associated with early cessation at the Boardman power plant.

Dated this 12th day of November, 2020.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 73

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2019 Integrated Resource Plan.	Opening Comments

Contents

1. Executive Summary

Staff of the Public Utility Commission of Oregon (OPUC or Commission) submits these Opening Comments on Portland General Electric's (PGE or Company's) 2019 Integrated Resource Plan (IRP or Plan), filed on July 17, 2019 and Interim Transmission Solution Addendum filed on August 30, 2019. Staff will continue to evaluate the Company's Plan, conduct discovery, and review stakeholders' comments prior to submitting its Final Comments, currently scheduled to be filed on December 3, 2019.

Staff's goal for this first round of comments is to raise questions and identify areas of the Plan where additional analysis, clarification, or coordination with the Company will help Staff in making a recommendation on acknowledgement by the Commissioners.

Staff begins these comments by recognizing the Company's transparent and collaborative planning process. This IRP presents a range of new considerations, models, and strategies. In light of this complexity, Staff is grateful for the Company's openness and the time spent working with Staff to date. In addition, Staff commends the PGE for developing a suite of new tools to improve upon gaps in previous IRPs and the Company's efforts to be responsive to stakeholder feedback, reflect its customers' values, and decarbonize its system.

While comprehensive and innovative, the Company's analysis makes it difficult for Staff to determine whether the Action Plan is the appropriate path forward. Staff is unclear about the extent to which PGE's Plan adheres to the IRP Guidelines and whether the Company's analysis aligns with its conclusion that the Action Plan is least cost, least risk. In summary, Staff has the following major concerns at this stage of the process:

- **The Action Plan is disconnected from portfolio analysis.** Staff is concerned that the proposed renewable and capacity resource acquisition strategy doesn't reflect the key attributes of the current preferred portfolio.
- **Portfolio selection does not adequately reflect portfolio modeling.** Staff is concerned that PGE's approach to selecting its preferred portfolio is too removed from the underlying analysis. This includes non-traditional screens and the development of the Mixed Full Clean portfolio based on some of the "the commonalities in resource additions across each of the best performing portfolios"[1]. Staff is also concerned that PGE did not assign probabilities when considering the wide range of futures.
- **The projected resource need may be skewed by major omissions.** Staff is concerned that PGE requires physical Renewable Portfolio Standard (RPS) compliance without accounting for unbundled and banked Renewable Energy Certificates (RECs). Further, PGE should account for important developments in its resource mix related voluntary customer programs and Colstrip.
- **A narrow approach to decarbonization clouds the analysis.** Staff appreciates the Company's goals to decarbonize its system. However, PGE's approach to addressing the risks of greenhouse gas emissions does not provide a solid jumping-off point for the Commission to compare a traditional least cost, least risk portfolio that considers all resources equally against an alternative least cost, least risk decarbonized portfolio.

Staff's intention in providing this feedback is not to prevent PGE from planning in line with evolving customer and stakeholder values. Rather, Staff is concerned that these deviations from the IRP's fundamental requirements could be obscuring the least cost, least risk path and

[1] 2019 PGE IRP, p. 193.

harming ratepayers. Staff looks forward to continued review and discussion with PGE and stakeholders.

2. Overarching Concerns

Overall, Staff is concerned that several elements of PGE's analysis could be out of line with IRP requirements. Without changes or clarification, Staff cannot fully determine if the proposed Action Plan is the right choice for customers. Staff's major concerns fall within the following categories:

- The Action Plan is disconnected from portfolio analysis.
- Portfolio selection does not adequately reflect portfolio modeling.
- The projected resource need may be skewed by major omissions.
- A narrow approach to decarbonization clouds the analysis.

This section summarizes Staff's primary concerns and requests additional analysis and information. PGE should update its analysis in line with the recommendations proposed in these comments and submit an updated Action Plan as necessary.

2.A. Action Plan

The Company's IRP analysis culminates in three action items: 1) seek all cost-effective energy efficiency and demand response; 2) conduct an RFP in 2020 for up to 150 MWa of RPS eligible resources that "enter PGE's portfolio" by the end of 2023; and 3) pursue all cost-competitive agreements for existing capacity in the region and conduct an RFP for non-emitting resources in 2021 to meet any remaining capacity needs.[2] Staff is concerned that PGE's renewable energy action item (Action Item 2) is disconnected from the preferred portfolio such that that it could result in entirely different resource acquisitions and calls into question consistency with the IRP guidelines. Staff is further concerned that the Company's capacity actions (Action Item 3), while driven by more pressing need, are inconsistent with the "reality" of the resources selected in the preferred portfolio and the approach taken for Action Item 2.

Action Item 2 – Renewable Request for Proposals (RFP)

PGE's conventional load-resource balance shows a projected average energy need beginning in 2025 (109 MWa) and an estimated capacity shortage beginning as early as 2021 (190 – 432 MW) or as late as 2025 (309 MW).[3] The preferred portfolio developed to meet the Company's long term needs contains specific supply-side actions during the Action Plan timeframe (2023 – 2025). These include the acquisition of 41 MWa of Columbia Gorge wind and 109 MWa of Montana wind per year from 2023 through 2025, and 77 MWa of Washington Wind in 2025.[4] This represents 527 MWa of wind resource additions between 2023 and 2025. In addition, the preferred portfolio selects 37 MW of 6-hour batteries and 200 MW of pumped storage per year in 2024 and 2025.[5]

[2] 2019 PGE IRP, pp. 213 – 219.
[3] 2019 PGE IRP, pp. 288 – 289.
[4] In its response to OPUC Information Request 50, PGE notes that each resource identified in the preferred portfolio is a 'proxy' resource, with generalized characteristics of expected resource performance by location. But, the Action Item 2 RFP may include bids that meet the Company's minimum requirements that have different characteristics.
[5] 2019 PGE IRP, pp. 196 – 196.

Resource Additions in the Preferred Portfolio[6]

TABLE 7-8: Cumulative renewable resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Wind Resources									
Gorge Wind (MWa)	41	41	41	41	41	41	41	41	41
WA Wind (MWa)	0	0	77	0	0	77	0	0	77
MT Wind (MWa)	109	109	109	109	109	109	109	109	109
Total Renewables (MWa)	150	150	227	150	150	227	150	150	227

TABLE 7-9: Cumulative dispatchable capacity additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Storage Resources									
6hr Batteries (MW)	0	37	37	0	37	37	0	37	37
Pumped Storage (MW)	0	200	200	0	200	200	0	200	200
Total Storage (MW)	0	237	237	0	237	237	0	237	237
Capacity Fill (MW)	123	79	358	0	0	0	425	423	739
Total Dispatchable Capacity (MW)	123	316	595	0	237	237	425	660	976

However, in its Action Plan, PGE chose to conduct an RFP for RPS-eligible resources that is agnostic to technology and location.[7] Staff appreciates PGE's efforts to reflect flexibility and optionality in its Action Plan, but questions whether this is in line with IRP Guideline 4. This guideline directs that the action plan include the identified resources in the selected portfolio and shall have key attributes specified as stated in portfolio testing.[8]

Staff is concerned that specifying the MWa, commercial operating year, and RPS eligibility may not sufficiently capture key attributes. Staff is also unsure whether this allows the "alignment of the electric company's resource need addressed by the RFP with an identified need in an acknowledged IRP," as required by the competitive bidding rules found in Oregon Administrative Rules (OAR) 860-089-0250(3)(g).

PGE is asking the Commission to acknowledge a renewable resource acquisition in 2023 without certainty that the resources participating in the RFP will capture the tax incentives driving the 2023 acquisition. Staff agrees that PGE's proposed cost containment screen is a useful tool to mitigate some of this risk. However, Staff is unclear if this will consider whether resources that can't capture the Production Tax Credit (PTC) provide enough benefit to justify an earlier than necessary procurement.

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[6] 2019 PGE IRP, p. 196.
[7] 2019 PGE IRP, p. 216 and PGE response to OPUC Information Request (IR) 50.
[8] Order No. 07-047, Appendix A, Guideline 4, pp. 4-5.

Recommendation 1: As PGE adjusts its action plan analysis in accordance with Staff's comments, the Company should explain how its Action Plan conforms to the IRP Guidelines, including Guideline 4 and competitive bidding rules.

Action Item 3 – Capacity Actions and Pumped Storage
Staff appreciates the discussion of regional capacity concerns and uncertainties throughout the IRP. Staff is intrigued by the potential of pumped storage as a zero-emission, flexible capacity resource—particularly given the region's possible capacity shortfall due to coal retirements and the west's increasing reliance on a less diversified, but also less emitting, pool of generation resources discussed in Section 2.4.2 Regional Capacity Changes.[9] However, the IRP's approach to pumped storage does not align well with the actual process to permit and construct this long lead-time resource.

PGE states that in terms of clean technology procurement, "If, despite our other actions, we still forecast a potential reliability shortage in the mid-2020s, we plan to conduct a competitive solicitation for new non-emitting resources that support reliability. This could include battery storage, pumped hydro, renewable resources, or combinations of renewables and storage. The solicitation would exclude new fossil fuel-based generation." [10]

Based on statements from National Grid and Rye Development, the IRP's proposed timing does not support their pumped storage project coming on line in time to meet PGE's projected capacity need in 2025 or the Mixed Full Clean Portfolio's 200 MW of pumped storage resource in 2024.[11] PGE's Action Plan indicates pumped storage will be included in the potential 2021 RFP, but PGE's proposed timing may be too late for pumped storage to serve as a viable longer-term capacity solution. Staff finds merit in exploring how to accelerate the simultaneous evaluation of new and existing capacity resources ahead of PGE's forecasted capacity need in 2025.

Pumped storage represents a unique generation product that can address both PGE and the region's capacity needs with no direct emissions. This resource could also assist with the integration of more renewables as part of a long-term decarbonization plan. Given the potential risk that capacity from federal system hydro resources may not be available post 2025 in the same quantity as today because of additional fish recovery measures or a more lucrative California capacity market, the timing to secure additional capacity is important. Therefore, Staff is intrigued by National Grid and Rye Development's proposal that PGE conduct an "all-encompassing RFP" by adjusting its Action Plan to run two RFP's simultaneously: one for renewables, the other for non-emitting capacity capable of coming online by 2025.

This action would be more in line with the Company's renewable RFP approach to provide, "flexibility across renewable technologies and locations while leveraging the analytical methodologies in the IRP to fairly evaluate benefits to the system will allow us to identify those resources that provide the best value for customers."[12]

[9] 2019 PGE IRP, pp. 64 – 67.
[10] 2019 PGE IRP, p. 22.
[11] See National Grid & Rye Development comments on LC 73, June 7, 2019.
[12] 2019 PGE IRP, p. 21.

Recommendation 2: PGE should discuss in its reply comments the potential to run a second, concurrent RFP for non-emitting capacity resources, while continuing to pursue bilateral contracts, such as their existing hydro contracts.

2.B. Portfolio Scoring and Selection

Staff is concerned that, despite the rigorous analytical tools introduced, PGE's overall approach to scoring and selecting a preferred portfolio is too removed from the results of the portfolio modeling. Staff recommends that the Company correct the following issues, so that Staff can evaluate whether the resulting Action Plan is the best path forward for ratepayers.

Use of non-traditional scoring metrics

Staff is concerned that the manner in which PGE implemented the "non-traditional scoring metrics" inappropriately skews its otherwise rigorous portfolio selection methodology. PGE's non-traditional scoring metrics act as screens that rule out portfolios prior to consideration of traditional risks and costs. These screening metrics are new in the 2019 IRP, and reject portfolios from consideration based on their relative performance in *one* future or on *one* criterion, compared to the other portfolios PGE analyzed in its IRP. [13] The scoring criteria are applied before the portfolios are scored for traditional cost and risk. These metrics include greenhouse gas (GHG) emissions, Criteria Pollutant emissions, cost in a carbon-constrained future, cost in a high-tech future, near term cost, and energy additions through 2025. Some of PGE's metrics are used to reject multiple portfolios without ever quantifying cost impacts.[14] For example, PGE's criteria pollutant screen is based on NOx and SOx levels. It rejects several portfolios without quantifying costs to customers.[15] This is unfortunate because it doesn't account for the potential to reduce criteria pollutants using pollution-reduction technologies.

Additionally, the risks considered by many of these metrics are already included in PGE's portfolio modeling. For example, PGE includes a low, medium, and high carbon price in its IRP analysis.[16] Staff finds the consideration of three potential carbon prices to be a reasonable way to address the risk of GHG policy. However, the application of an additional GHG screen seems to duplicate the GHG portfolio risk analysis, and PGE does not specify what type of additional risk the screen is meant to address. Four portfolios are ruled out by the second GHG screen. Staff wonders if additional GHG screens are more appropriately used in characterizing the best performing portfolios for cost and risk for selection.

IRP Guideline 8 provides direction for analyzing the risk of potential strict-GHG-regulation futures. Guideline 8 directs utilities to consider specific potential high future GHG regulation scenarios, and identify whether a substantially different portfolio might become cost-effective due to a "turning point" in environmental regulations. The "turning point" portfolio should then be compared to the Company's preferred portfolio.[17]

In general, PGE's non-traditional metrics address important and interesting considerations of cost and risk to customers. These screening tools are a result of valuable stakeholder discussion and reflect PGE's understanding of its stakeholders' and customers' evolving interests.[18] However, Staff is concerned that PGE may have been too blunt in implementing the

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[13] The 2016 IRP screened out only those portfolios that were performed to investigate possibilities, but were not actionable and so not eligible for preferred portfolio.
[14] 2019 PGE IRP, pp. 188 – 189.
[15] 2019 PGE IRP, p 189.
[16] 2019 PGE IRP, p 75.
[17] Order No. 08-339, Appendix C, p. 2.
[18] See PGE Integrated Resource Planning Roundtable Presentations. During Roundtable 18-4 on September 26, 2018 where PGE first proposed the use of these additional scoring metrics and

screens. Staff finds that, in assessing the Company's planning outcomes, it is important to better understand the scope impacts of the screens.

Recommendation 3: PGE should provide additional portfolio analysis:

- Provide a report on PGE's 2019 IRP portfolios without the use of its non-traditional screens, so that the impacts of applying these screens before traditional costs and risks analysis can be better understood.

- PGE should also review its IRP for compliance with IRP Guideline 8 and provide a summary of its findings.

Construction of the preferred portfolio
After evaluating more than 40 portfolios and applying the non-traditional screens, PGE identified several commonalities between the seven top performing portfolios and combined them into a set of constraints called the "Mixed Full Clean" portfolio. This portfolio allows 150 MWa of additional resources in 2023 or 2024 and capacity additions that do not emit greenhouse gasses before 2025. In the IRP, PGE explains that,

> [T]he relative economics of specific resources is uncertain, suggesting that preserving the flexibility to pursue various technologies and resource locations may yield cost savings for customers. The preferred portfolio in the 2019 IRP is therefore designed not to identify a specific set of resources, but to reflect a set of reasonable actions that would allow PGE to capture the cost and risk benefits of the best performing portfolios.[19]

This approach to constructing a new preferred portfolio based on "reasonable actions" from other well performing portfolios is somewhat puzzling, and may present another blunt instrument in portfolio selection. Staff finds this approach particularly curious given that the Mixed Clean Full is outperformed by others in terms of cost and risk, as shown by PGE's graphics:[20]

FIGURE 7-13: Cost versus variability for the preferred portfolio

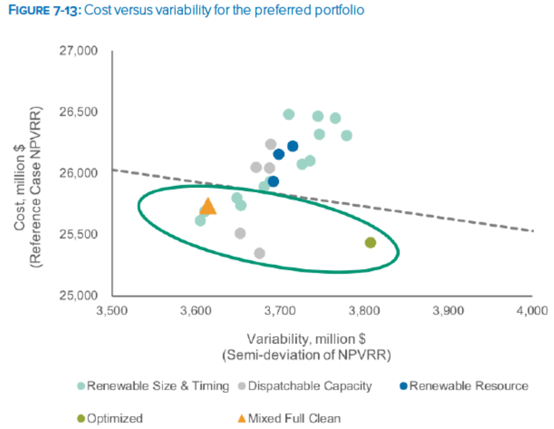
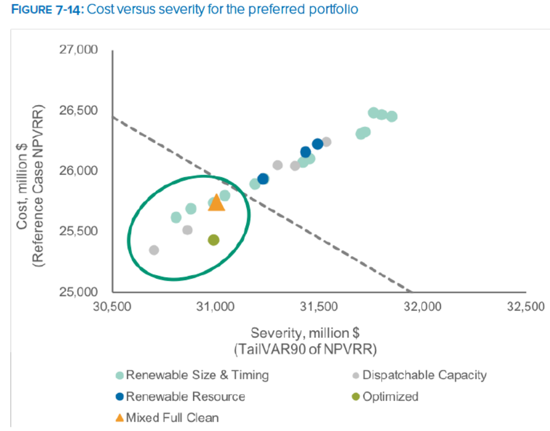


FIGURE 7-14: Cost versus severity for the preferred portfolio



Roundtable 18-6 on November 28, 2018 when the straw proposal to use non-traditional screens was first proposed. https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings.
[19] 2019 PGE IRP, p. 194.
[20] 2019 PGE IRP, p. 197.

PGE's Mixed Full Clean portfolio is among the top performing of those that remain after PGE's non-traditional screening metrics are applied. However, Mixed Full Clean is not the top-performing portfolio for cost and risk. Staff is concerned about the decision to pick a portfolio other than the top-performing portfolio. The Commission's IRP guidelines state that, "The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[21]

PGE should provide an analysis comparing its preferred portfolio to other top-performing portfolios for cost and risk, and explain why the Company believes it has chosen a portfolio with the best balance of cost and risk, as required by the IRP guidelines.

Recommendation 4: As PGE adjusts its IRP analysis in accordance with Staff's comments, including the removal on non-traditional screens, PGE should provide additional information:

- Provide a quantitative comparison of its preferred portfolio to other well-performing portfolios in terms of NPVRR cost and risk.

- Explain why the Company believes its preferred portfolio has the best balance of cost and risk for customers.

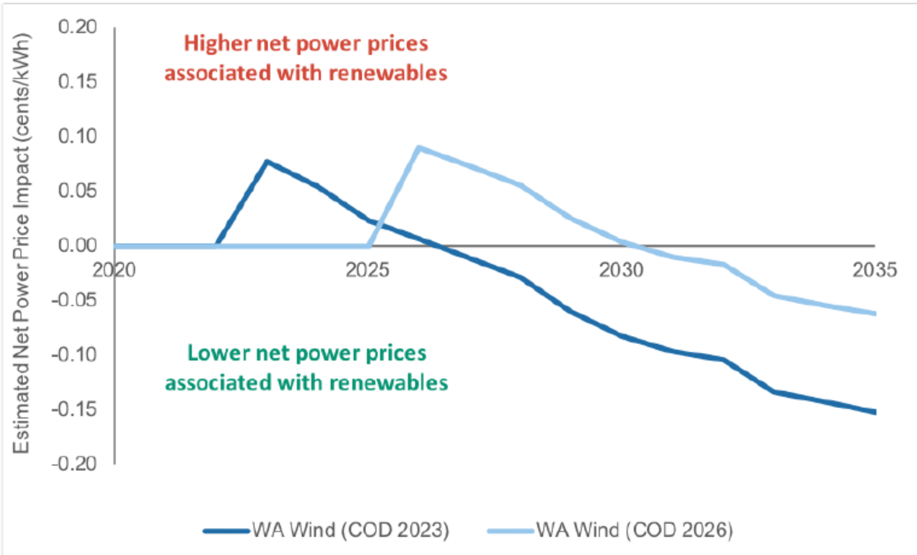
Intergenerational equity analysis
Staff appreciates PGE's inclusion of an analysis of the intergenerational equity implications of its plan to acquire renewable energy in the near-term to capture the expiring PTC An informed discussion of this issue is important to Staff, as near-term renewables may be part of a least-cost portfolio.

PGE's analysis compares the rate effects of acquiring a PTC-eligible wind project in 2023 versus a non-PTC-eligible wind project in of the same size in 2026. The 2023 acquisition would save money for customers in the long term, according to PGE's modeling, but would result in ratepayers experiencing a rate increase three years sooner. The 2023 wind project, PGE calculates, would cause a rate increase of about .04 cents/kWh from 2023 to 2026. However, the acquisition would reduce rates starting in 2027, four years later. The 2026 project would lead to a rate increase of about .05 cents/kWh from 2026-2030, and would result in a rate reduction by 2031, five years later:

[21] Order No 07-047, Appendix A, pp. 1-2.

PGE's Intergenerational Analysis[22]

FIGURE 7-16: Estimated net impacts to retail power prices of Washington Wind additions



To place additional context on the analysis of a 2026 wind addition, PGE's Appendix G Load Resource Balance indicates that PGE may have an energy deficit by 2025.[23] Staff will conduct additional analysis to consider how the 0.01 cent difference in customer rates compares to the risk of an energy need in 2025, given other assumptions about load growth, voluntary programs, and new Qualifying Facility (QF) contracts that are discussed elsewhere in Staff opening comments.

Many factors could change the effect that a new resource will have on rates, including resource cost and performance, future market conditions, and future customer demand. Staff will continue to assess the inputs and assumptions behind PGE's intergenerational equity analysis. For example, the intergenerational equity analysis may utilize some of the same modeling inputs and assumptions that Staff finds concerning or problematic in the 2019 IRP. Staff hopes PGE will participate in a robust assessment and discussion of the intergenerational equity risks of near-term procurement of renewables.

Recommendation 5: PGE should assist stakeholders in gaining an in-depth understanding of the intergenerational equity analysis by holding a workshop.

Probability of futures in PGE's portfolio analysis
Each of the price futures modeled in Aurora is assigned an equal probability in PGE's ROSE-E capacity expansion modeling. Staff is concerned that this will result in portfolios that place too much weight on unlikely futures, and do not acquire the appropriate resources for the most likely futures.

Staff proposes that, while for some futures an equal probability weighting may be appropriate, some combinations of variables are less probable than others. For example, a future with a high

[22] 2019 PGE IRP, p. 199.
[23] 2019 PGE IRP, p. 289.

WECC renewable buildout and high hydro generation may increase the likelihood of lower natural gas prices due to lower demand. Similarly, a future with a high carbon price would likely incentivize more renewable energy, resulting in a higher WECC Renewable buildout.

Recommendation 6: PGE should provide an updated portfolio analysis and Action Plan based on an estimate of the comparative likelihood of each potential future and combination of futures.

2.C. Modeling Resource Need

Staff identified a few key issues with PGE's approach to modeling resource need. First, Staff struggles to find a compelling rationale for PGE's characterization of its RPS compliance need, and is concerned about the costs and risks of ignoring the Company's sizable REC bank in its long-term planning. In addition, Staff highlights developments related to PGE's VRET and Colstrip that need to be considered within the 2019 IRP. Staff requests that PGE update its analysis to account for these issues so that Staff can adequately weigh the costs and risks of the resource acquisition strategy proposed in the Action Plan. Additional feedback on the Company's characterization of its need is provided in Section 3.

RPS compliance need

In Chapter 4 of the 2019 IRP, PGE explains that the Company defines physical Renewable Portfolio Standard (RPS) compliance as, "a year in which the volume of RECs generated by RPS-eligible resources in PGE's resource portfolio meets or exceeds the RPS obligation in that year."[24] PGE's 2019 IRP analysis requires physical RPS compliance in all portfolios from 2027 through 2050.[25] In Chapter four of the 2019 IRP, the Company states, "PGE believes that it is appropriate to apply a minimum standard of physical RPS compliance in its long-term planning process and to use the REC bank to mitigate compliance risks."[26]

Staff finds two major problems with PGE's decision to require physical RPS compliance in the 2019 IRP. First, by requiring physical compliance with the RPS, PGE fails to acknowledge the possibility of substantial ratepayer savings from retiring up to 20 percent of its compliance requirement as unbundled RECs. PGE's 2019 IRP does not provide any analysis around the possibility of achieving savings through the use of unbundled RECs, despite this being a regular practice by the Company and the year-over-year low cost of unbundled RECs. Second, requiring 100 percent physical RPS compliance also prevents any reliance on banked RECs to reduce costs in PGE's portfolio analysis, regardless of how large PGE's REC bank might grow.

Unbundled RECs: In its 2016 IRP Reply Comments, PGE argued that the availability of low-cost unbundled RECs was due to "a temporary misalignment in timing between resource procurement and increasing RPS obligations."[27] PGE argued that as California and Oregon approach a 50 percent RPS, "an assumption of persistently low unbundled REC prices in the West would be highly speculative." PGE continued to explain:

> […]the theoretical long-run cost of an unbundled REC is equal to the cost difference between the most cost effective qualifying renewable resource and the cost of providing the same amount of capacity and energy with a non-qualifying resource. This is effectively the premium associated with the environmental attributes (in this case the RECs) of the qualifying resource.

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[24] PGE 2019 IRP, p. 179.
[25] PGE 2019 IRP, p. 179.
[26] PGE 2019 IRP, p. 113.
[27] See Docket No. LC 66, PGE Reply Comments, p. 28.

While the Company may be correct that unbundled REC prices are currently low compared to their potential value, the lack of any consideration of unbundled REC purchases as a potentially least-cost RPS compliance option is troubling to Staff and goes against Commission direction in the 2016 IRP.

PGE is imposing substantial risk on customers by failing to consider unbundled RECs in its long-term planning. There is no reason provided in the 2019 IRP as to why ratepayers would be better off with PGE's plan to comply with the RPS using 100 percent bundled RECs from PGE-owned or -contracted resources. Further, PGE's recent RPS compliance filings show that it has been retiring unbundled RECs to meet the RPS each year since at least 2013 at very low costs.[28]

Additionally, the Commission has repeatedly requested PGE include unbundled RECs in its IRP planning. In the 2009 IRP and 2013 IRP, the Commission guided PGE to look at alternatives to physical compliance.[29, 30] In the 2009 IRP, the Commission wrote that PGE must, "evaluate alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective, least risk manner…"[31]

In PGE's 2013 IRP, the Commission wrote:

> We adhere to this requirement and expressly direct PGE to develop and evaluate multiple RPS compliance strategies – including alternatives to physical compliance – and recommend a least-cost strategy in its next IRP Update and future IRPs.[32]

Further, in the Commission's acknowledgement order in PGE's 2016 IRP, the Commission directed PGE to "Continue to evaluate non-physical compliance with Oregon's RPS."[33] The Commission continued:

> In its continued evaluation of non-physical compliance with the RPS, we direct PGE to demonstrate it has followed industry best practices for incorporating unbundled REC market projections into its least-cost, least-risk RPS compliance strategy.[34]

Given previous Commission direction on RPS physical compliance alternatives, including direction to consider unbundled REC market projections, PGE's lack of consideration of alternatives in the 2019 IRP is problematic.

REC Bank: In addition to disallowing unbundled REC use in its portfolio analysis, PGE also does not allow its REC bank to be used to reduce the need for physical RPS compliance through PGE-owned or -contracted generation. Staff agrees with PGE that it is appropriate to use the REC bank "to mitigate compliance risks and achieve cost reductions on a year-to-year basis depending on loads, renewable generation, and market conditions."[35] However, PGE should update its IRP modeling so that the REC bank can avoid some of the need for new resource procurement, subject to maintaining a reasonably-sized REC bank as a buffer for

[28] See PGE filings in dockets UM 1699, UM 1740, UM 1783, UM 1847, UM 1958, and UM 2016.
[29] Order No. 10-457, p. 24.
[30] Order No. 14-415, p. 13.
[31] Order No. 10-457, p. 29.
[32] Order No. 14-415, p. 13.
[33] Order No. 17-386, p. 20.
[34] Order No. 17-386, p. 20-21.
[35] 2019 PGE IRP, p. 113.

contingencies. The current assumption of 100 percent physical RPS compliance does not allow for this use of the REC bank.

PGE's portfolio modeling requires physical compliance in 2027, a point at which it forecasts to still have over 10 million infinite-life RECs and 3.5 million 5-year RECs. In addition, PGE's current REC bank contains nearly 10 million infinite life RECs and it expects to generate more than 70 million infinite-life RECs prior to the 2027 physical compliance constraint without pursuing additional renewable resources.[36] By planning to meet future RPS needs only through physical compliance, the rationale behind the size and timing of all of PGE's prior investments in renewable assets is called into question. It also calls into question the 2016 IRP renewable glidepath for the updated action item. This glidepath was used to justify PGE's recent acquisition of renewables in the near-term and called for some use of banked REC's as a reasonable strategy for RPS compliance.[37]

Staff appreciates that PGE is seeking to act in the spirit of Oregon's greenhouse gas reduction goals and the desire of some of its customers for more renewable energy. However, the Commission's IRP guidelines direct the Company to identify a portfolio that best balances cost and risk to customers. In order to comply with the IRP Guidelines, PGE must focus solely on cost-effective greenhouse gas reduction measures. Reducing customer energy use through efficiency, reducing energy use at peak times through demand response, and providing customers a robust set of options to voluntarily select low-carbon energy are among the options for reducing system greenhouse gas emissions that can also provide least cost/risk service for customers (this is discussed further in Section 2.D.)

To comply with the IRP Guidelines, PGE should remove its requirement for potentially costly physical RPS compliance. Removing the 100 percent physical compliance requirement will be essential to Staff's evaluation of PGE's action items, since Staff finds it impossible to evaluate whether the near-term acquisitions in the 2019 Action Plan result from the 100 percent physical RPS compliance requirement, or from energy and capacity need in IRP portfolios.

Recommendation 7: Staff recommends that PGE provide the following analysis related to its RPS compliance strategy:

- Per previous guidance, PGE must model 20 percent unbundled RECs in RPS compliance in all portfolios. REC costs can be based on the historical average with the same rate of inflation used in the most recent rate case.
- PGE should also run its preferred portfolio and several top performing and optimized portfolios in ROSE-E while allowing the model to choose a reasonable number of banked RECs. PGE should provide justification for why these quantities were selected as reasonable.
- In future IRPs, PGE must consider the use of 20 percent unbundled RECs and a reasonable amount of banked RECs in years when they are available and less expensive than 100 percent physical compliance. Any unbundled REC price forecast(s) should include one or more reasonable trajectories from current unbundled REC prices to one or more potential unbundled REC price futures.

[36] See PGE response to Staff IR No. 022 and 022 Attachment A.
[37] *See* Docket No. LC 66 – Portland General Electric Company 2016 Integrated Resource Plan Addendum, November 9, 2017.

Green Energy Affinity Rider

PGE's IRP includes sensitivities around potential subscription levels in its new VRET referred to as Green Energy Affinity Rider (GEAR). For resource planning purposes, the initial tranche of GEAR subscriptions translate into a 15 year PPA that was entered into because of specific customers' demand for the program—not a direct result of the Company's long-term planning process. The sensitivity analysis shows that when the GEAR is subscribed at 100 MW and community solar is subscribed at 93 MW, PGE's energy need is reduced by 55 MWa and its capacity need is reduced by 38 MW in 2025.

Since PGE developed the 2019 IRP needs assessment and voluntary program sensitivities, the Company executed agreements with customers for 160 MW of nameplate capacity[38] PGE informed Staff in discovery that "Green Future Impact, PGE's GEAR product, has a total of 16 customers enrolled with a total of 43.54 MWa."[39] Staff notes the contracting process is at an advanced stage, but the contract needs to be signed and the facility built. In addition to this 42.54 MWa, and contemporaneous with this IRP, PGE submitted an application to expand the size of this program by an additional 200 MW of nameplate capacity, which is under review.

Because of the range of potential near-term resource acquisition in the Action Plan, Staff finds that it is critical that PGE update its modeling to reflect the additional PPA's resulting from the first phase of GEAR and the proposed GEAR expansion. Further, Staff is concerned that the IRP does not discuss how the GEAR energy is being delivered to its system and what these transmission considerations mean for the availability of transmission for other resources considered in portfolio modeling.

Staff notes that it has similar, and important, concerns related to the Company's assumptions about direct access load and the likelihood that QF's beyond what are currently in queue will come online. These related concerns are discussed in Section 3.

Recommendation 8: Staff requests that PGE provide additional analysis and information related to the developments within the GEAR program:

- PGE should update the portfolio analysis and, as necessary, the Action Plan to reflect the impact of the recent successful launch and subscription of the GEAR. Alternatively, PGE could reduce its renewable energy resource acquisition in its Action Plan proportionate amount to the GEAR subscription.

- PGE should also report on the transmission arrangements for its first phase of GEAR resources and the impacts of these resources on the availability of transmission for resources modeled in the IRP.

Colstrip resource availability

Staff appreciates PGE's inclusion of two Colstrip sensitivities on the preferred portfolio in the 2019 IRP Action Plan with Colstrip 3 and 4 retirement in 2027 instead of 2034. In Sensitivity A, Colstrip is fully depreciated and exits PGE's portfolio by the end of 2027. In Sensitivity B, Colstrip is fully depreciated and exits PGE's portfolio by 2027, and is replaced specifically with a 296 MW Montana wind resource.

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[38] https://www.prnewswire.com/news-releases/sustainability-leaders-claim-pges-green-future-impact-in-record-time-300905340.html

[39] *See* PGE's First Supplemental Response to Staff IR 015.

The results of PGE's "Sensitivity A" analysis show a potential savings of over $230 million (about one percent of total revenue requirement over the planning timeframe) from exiting Colstrip in 2027. The analysis also showed that exiting Colstrip in 2027 could reduce risk for customers as measured by PGE's severity metric, also by about one percent. The variability risk metric, however, shows an increase of about one percent.

Sensitivity B shows less benefit from early retirement as compared to Sensitivity A, although the benefit is still substantial at $198 million. Sensitivity B shows improved scores for variability and severity, as compared to both Sensitivity A and the Base Case. [40]

	Scoring Metric (million 2020$)		
	Cost	Variability	Severity
Base Case	25,740	3,614	31,004
Colstrip Sensitivity A 2027 Exit	25,507	3,652	30,834
Colstrip Sensitivity B 2027 Exit w/ MT Wind	25,542	3,585	30,761

Staff also notes that, on June 11, 2019, Puget Sound Energy announced early closure of Colstrip Units 1 and 2. This is referenced in the 2019 IRP, but Staff is unclear whether the potential effects of this early retirement affect PGE's consideration for early retirement of Colstrip.[41] Finally, Staff sees a risk to ratepayers if PGE is the last utility involved in Colstrip. Beginning to explore dates and costs of an early exit from Colstrip may be in the best interest of ratepayers and least-cost, least-risk planning.

Recommendation 9: Staff requests that PGE provide additional analysis and updated information related to the closure of Colstrip:

- Staff suggests PGE perform a rate impact analysis of advancing the depreciation dates of these units to 2027. PGE should report on the potential rate impacts of accelerated depreciation at Colstrip in the 2019 IRP docket.
- PGE should provide information in its reply comments explaining the drivers behind the increase in the variability risk metric in the Colstrip sensitivity.
- PGE should report in its reply comments any steps it has taken or could take to work toward negotiating an early exit date from Colstrip. And, if these actions are affected by early closure of Units 1 and 2.
- Additionally, Staff requests that PGE provide an updated Colstrip Analysis in the 2019 IRP docket demonstrating the effects of any updated information on the variable costs of generation at Colstrip.

[40] 2019 PGE IRP, p. 209, Table 7-10.
[41] 2019 PGE IRP, p. 65.

2.D. Decarbonization approach

In its IRP, PGE provides helpful context about its priorities for the 2019 planning process. Specifically, the Company indicates a goal to decarbonize its energy supply as cost-effectively as possible, stating that:

> To reach our long-term decarbonization goal, we will need additional renewable resources, like wind and solar, to drive greenhouse gases out of our generation portfolio. Specifically, we estimate that we will need to add at least 50-60 MWa of new renewables every year for the next thirty years. To make meaningful progress while taking advantage of continued cost declines and the limited remaining availability of federal tax credits, our plan calls for additional renewables in the near term. These renewables will expand our renewable portfolio and complement the voluntary options, like our Green Tariff, that allow customers who so choose to decarbonize even faster.[42]

Ultimately, Staff understands challenges PGE faces aligning the Commission's long-term planning process with its decarbonization goals. This will be a complex undertaking until the State provides the OPUC with a specific policy directive to decarbonize. With that said, it is important to note that Staff does not reject these values or PGE's desire to develop a long-term plan that meets these goals as cost-effectively as possible. Staff also highlights its three main difficulties related to PGE's discussion of decarbonization in its 2019 IRP.

The first is simple: decarbonization goals, while laudable, do not exempt PGE from the existing IRP Guidelines. The Public Utility Commission has not been authorized by the legislature to pursue decarbonization as a policy goal, and without such an authorization it is difficult to justify a substantial diversion from the current least-cost and least-risk. The Company must identify a traditional least cost, least risk long term plan that considers all resources equally and adheres to the other guidelines. Then, PGE can present alternatives that limit the addition of emitting resources and provide a pathway to reach PGE's decarbonization goals in the most cost-effective manner. Through this, the Commission can clearly weigh the costs and risks of a decarbonized IRP against a traditional least cost, least risk long term plan that considers all resources equally.

Second, Staff is concerned that the 2019 IRP's approach does not present a comprehensive strategy to "decarbonize [its] energy supply as cost-effectively as possible".[43] This is apparent in the disconnection between the Company's urgency to secure a good deal on near-term energy resources, while not committing to take the same steps to identify low-emission storage technologies selected in the preferred portfolio and "preserv[ing] any potential" for repurposed uses of Boardman, which may include emitting resources, in the future where capacity may be needed.[44]

From Staff's understanding of decarbonization, a more holistic approach would move beyond simply acquiring wind resources when they may be a good deal, but rather develop and compare portfolios that consider:

- Additional energy efficiency and demand response above what is identified as cost-effective in the current model;

[42] 2019 PGE IRP, p. 22.
[43] 2019 PGE IRP, p. 22.
[44] 2019 PGE IRP, p. 22.

- The potential for any additional non-utility distributed renewable energy and storage resources that may be lower cost than acquiring new PGE resources;
- Pairing the exit of existing emitting generation resources early, such as Colstrip, logically with new resources coming online; and
- Any other technology or strategy that PGE thinks is a part of a least cost, least risk decarbonization plan.

Finally, Staff's comments to the 2013 IRP requested that PGE perform a climate adaptation analysis.[45] In the Company's 2016 IRP, PGE included a study of projected climate impacts.[46] The Climate Change Study was an informative and helpful exercise in planning for the expected impacts of potential changes in temperature, precipitation, streamflow, storm frequency and intensity, wind speed, cloud cover, and wildfire risk.

In its 2019 IRP, PGE focuses its discussion of climate change on mitigation and decarbonization, but does not directly discuss this issue of climate adaptation and system impacts. Climate change, and the region's understanding of expected future changes in the Northwest, have progressed since 2016.[47] It is increasingly evident that utilities need to incorporate expected future changes, such as peak load characteristics, resource generation operations and escalating wildfire risk, in long-term planning. Staff proposes that PGE develop and submit an updated climate adaptation and system impact plan in the 2019 IRP docket. The adaptation plan should build on the foundation of the 2016 Climate Change Study by describing specific actions the Company will take to adapt and respond to the risks presented by climate change.

The adaptation plan should include the risks PGE expects to face from climate change in the long-term planning timeframe, as well as an explanation of how these risks interact with one another and with PGE's operations. For example, factors such as population growth, severe weather, hydro flows, temperature increases, and air conditioning penetration could interact to change the costs, risks, and strategies associated with reliably serving peak load. Staff proposes that updates to the Company's climate adaptation plans should become a regular part of the long-term planning process moving forward.

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[45] *See* Docket No. LC 56, Initial Staff Comments, p. 7 – 10.
[46] *See* Docket No. LC 66, 2016 PGE IRP, Appendix E: Climate Change Projections in Portland General Electric Service Territory.
[47] Staff recommends reviewing the Oregon Global Warming Commission's 2018 Biennial Report to the Legislature, in particular Section 1, for a discussion of the state's current understanding of climate change impacts and ways in which they have evolved over time. https://www.keeporegoncool.org/s/2018-OGWC-Biennial-Report.pdf.

Recommendation 10: Staff requests that PGE provide additional analysis and information related to its approach to climate change:

- Staff recommends PGE adjust its methodology as recommended in these comments and identify a least cost, least risk portfolio that considers all resources equally. Then, PGE can present an alternative portfolio that is targeted at least cost, least risk decarbonization for the Commission to compare costs and risks.

- Staff proposes that PGE develop and submit a climate adaptation plan as part of the 2019 IRP Update.

<u>2.E. Conclusion</u>
In summary, Staff requests that PGE take the following steps to address these overarching concerns and allow Staff to make a recommendation on acknowledgement:

1. Explain how its Action Plan conforms to the IRP Guidelines, including Guideline 4 and competitive bidding rules.
2. Discuss the potential to run a second RFP for non-emitting capacity, while continuing to pursue bilateral contracts in its reply comments.
3. Provide additional portfolio analysis:
    a. Conduct an additional portfolio analysis without the use of its non-traditional screens so that the impacts of screening for non-traditional impacts before traditional costs and risks can be better understood.
    b. PGE should also review its IRP for compliance with IRP Guideline 8 and provide a summary of its findings.
4. As PGE adjusts its IRP analysis in accordance with Staff's comments, including the removal on non-traditional screens, PGE should provide additional information:
    a. Provide a quantitative comparison of its preferred portfolio to other well-performing portfolios in terms of NPVRR cost and risk.
    b. Explain why the Company believes its preferred portfolio has the best balance of cost and risk for customers.
5. Hold a workshop on the intergenerational equity analysis.
6. Provide an updated portfolio analysis and Action Plan based on an estimate of the comparative likelihood of each potential future and combination of futures.
7. Provide the following analysis related to its RPS compliance strategy.
    a. Model 20% unbundled RECs in RPS compliance in all portfolios.
    b. Model the preferred portfolio and several top performing and optimized portfolios in ROSE-E while allowing the model to choose a reasonable number of banked RECs.
    c. In future IRPs, PGE must consider the use of 20% unbundled RECs and a reasonable amount of banked RECs in years when they are available and less expensive than 100 percent physical compliance.
8. Provide additional analysis and information related to the developments within the GEAR program in reply comments:
    a. Update the portfolio analysis and, as necessary, the Action Plan to reflect the impact of the recent successful launch and subscription of the GEAR. Alternatively, PGE could reduce its renewable energy resource acquisition in its Action Plan proportionate amount to the GEAR subscription.
    b. Report on the transmission arrangements for its first phase of GEAR resources and the impacts of these resources on the availability of transmission for resources modeled in the IRP.

9. Provide additional analysis and updated information related to the closure of Colstrip in reply comments:
    a. Perform a rate impact analysis of advancing the depreciation dates of these units to 2027. PGE should report on the potential rate impacts of accelerated depreciation at Colstrip in the 2019 IRP docket.
    b. Provide information in its reply comments explaining the drivers behind the increase in the variability risk metric in the Colstrip sensitivity.
    c. Report any steps it has taken or could take to work toward negotiating an early exit date from Colstrip. And, if these actions are affected by early closure of Units 1 and 2.
    d. Provide an updated Colstrip Analysis in the 2019 IRP docket demonstrating the effects of any updated information on the variable costs of generation at Colstrip.
10. Provide additional analysis and information related to PGE's approach to climate change:
    a. As PGE adjusts its IRP analysis in accordance with Staff's comments to identify a least cost, least risk portfolio that considers all resources equally, PGE can present an alternative portfolio that is targeted at least cost, least risk decarbonization for the Commission to compare costs and risks.
    b. Staff proposes that PGE develop and submit a climate adaptation plan as part of the 2019 IRP Update.

Staff finds that once these steps have been taken, it will be possible to appropriately compare the costs and risks of PGE's preferred portfolio and Action Plan. Staff has additional questions and feedback that are important to this assessment. The remainder of Staff's comments highlight areas throughout the IRP where different or additional steps are required to identify whether PGE's planning outcomes appropriately balance costs and risks.

3. Characterization of Need

In its 2019 IRP, PGE considered a more robust range of futures and uncertainties, conducted several supplemental studies, and changed the way the Company discusses its energy need in terms of, "evolving market dynamics and the associated uncertainties."[48] Staff commends these efforts, but highlights a few initial concerns with the way that PGE performed its resources needs assessment.

<u>3.A. Load Forecast</u>
Staff appreciates the greater load forecast detail compared to the 2016 IRP. Staff continues to work with PGE to evaluate its load forecasting methodology and is in the process of independently replicating the Company's econometric work to ensure the problems identified in PGEs 2016 IRP have been resolved and new issues have not emerged. Staff briefly summarizes its initial feedback on the load forecast and expects to provide a more detailed analysis in subsequent discussions and in its final comments.

Load forecast methodology
An accurate load forecast is a critical component of prudent resource planning. Building a long-term plan based on an inaccurate load forecast can make uneconomic portfolios look reasonable, which can pose real consequences for ratepayers. Therefore, Staff is closely

[48] 2019 PGE IRP, p. 110.

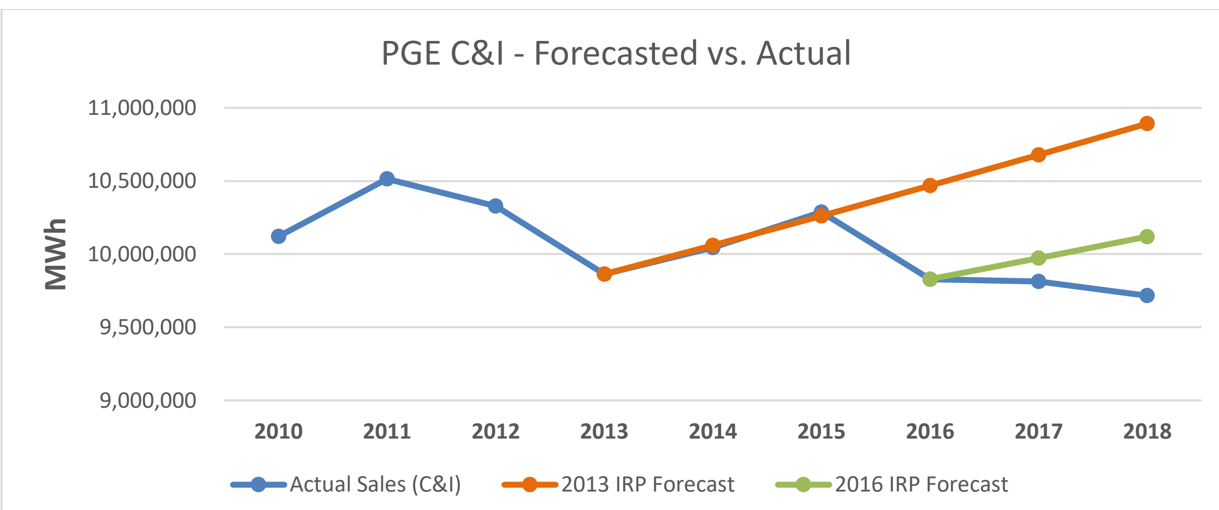
evaluating PGE's load forecast modeling and comparing the Company's specification choices to alternatives.[49]

For example, Staff is looking into the use of different and additional variables, such as, unemployment. In addition, Staff is evaluating PGE's use of historical data. Load growth in the region has decreased since the 1990s.[50] Staff is concerned that utilizing data from past decades with higher load growth could be upwardly biasing the forecast.

As Staff works with the company on this reconstruction of PGE's work, Staff is has noted a few new issues with its load forecast. PGE's rates of projected load growth by customer class in this IRP are modest:

Customer Type	**Reference Case, Forecasted Average Load Growth** [51]
Residential	0.1 %
Commercial	0.5%
Industrial	1.9%

Yet, based on recent trends, Staff is unsure of the accuracy of this IRP's commercial and industrial load forecasts. Below is a comparison of actual load since 2010 and previous IRP forecasts:[52]



[49] Staff is checking to make sure the maximum likelihood estimator with an outer product gradient and a Bernt Hall Hall Housman algorithm was the most appropriate specification. And going back to 1990's data might be biasing PGE's forecasts upward. When this reproduction process is finished, Staff expects to have a step-by-step understanding of all the company's econometric modeling decisions made in the load forecast so that the prudence of the statistical methods can be fully weighed.
[50] Northwest Power and Conservation Council, Seventh Northwest Conservation and Electric Power Plan, Chapter 7, pp. 7-4 – 7-5.
[51] 2019 PGE IRP, pp. 90 – 91.
[52] Sources: Load is based on sales in OPUC Stat Books, 2010 – 2018. IRP forecasts are extrapolated from the growth rates found in the 2013 and 2016 IRPs.

Another concern Staff is evaluating is the freshness of population and employment data inputs used by PGE.

Energy efficiency assumptions
For the 2019 IRP, Energy Trust of Oregon (ETO) provided PGE two energy efficiency scenarios:

- A "Cost-effective EE" scenario using avoided costs circa 2017, which represents ETO's best estimate of what it can achieve within these cost-effectiveness limits; and
- An "Incremental High EE" scenario which is intended to represent the "Achievable Potential". Achievable Potential is 85% of "Technical Potential", or 85% of all possible known equipment options that could save energy regardless of the cost. This is what the industry considers the absolute highest possible adoption rate.[53]

PGE chose the "Incremental High EE" for the Low load future and "Reference EE" for Reference and High as illustrated in PGE's Table 4-5.[54]

TABLE 4-5: Load components for each load scenario

	Low Load	Reference Case	High Load
Top-down Load Forecast	Low Growth	Reference Case	High Growth
Energy Efficiency	High EE	Cost-effective EE	Cost-effective EE
Electric Vehicles	Low Adoption	Reference Case	High Adoption
Dist. Solar and Non-dispatchable Battery Storage	High Adoption	Reference Case	Low Adoption

Staff questions whether it is appropriate to use the same "Cost-effective EE" scenario it uses in the Reference load future as it does in the High load future. The value of energy efficiency should be greater in the High future than in the Reference future, and Staff is concerned that PGE is understating its acquisition of energy efficiency in the High need future.

Staff also has questions about how PGE is working with ETO to attain energy efficiency forecasts. If PGE models three major load scenarios, it should also work with ETO to create three energy efficiency forecasts that reflect those load scenarios.

Recommendation 11: Staff intends to work with PGE and ETO to see if there are opportunities to apply more appropriate input selection for energy efficiency, and potentially for other demand-side and load forecast inputs to scenarios.

Electric vehicle (EV) forecast
Staff notes that one of the assumptions in the Company's distributed energy resource forecast may exaggerate electric vehicle load. It appears that Navigant extrapolated adoption rates across all light duty vehicles in the Company's service area. Staff notes that light-duty vehicles

[53] 2019 PGE IRP, External Study B. Energy Trust of Oregon Methodology, p. 8.
[54] 2019 PGE IRP, p. 101.

can include vehicles upwards of 8,000 or 10,000 pounds.[55] According to manufacturers' data, this category is inclusive of heavier vehicles, such as the Ford F-150 pickup truck.[56]

The majority of electric vehicles currently listed in the U.S. Department of Energy Alternative Fuels Data Center's dataset of Alternative Fuel and Advanced Technology Vehicles are sedans and wagons with a small number of sport utility vehicles (SUVs) and vans, and no pick-ups.[57] Given the current nature of the EV market, Staff is concerned that the methodology used in the 2019 IRP overestimates EV load.

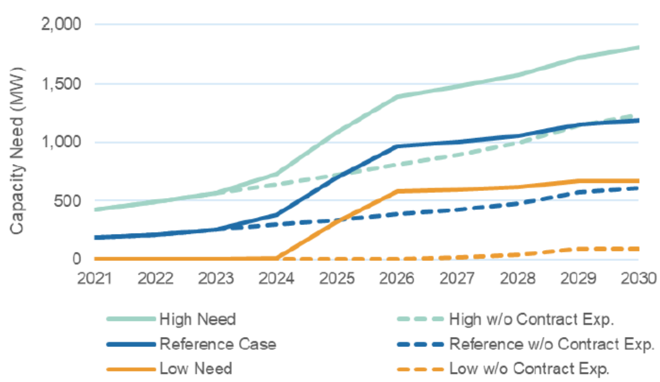
Electric Vehicle Models Available[58]	
Vehicle Type	**2019 Models**
Sedan/Wagon	28
SUV	7
Van	2
Pickup	0

Recommendation 12: PGE should explain in its reply comments how the Company accounted for consumer vehicle preferences and availability of heavier electric vehicles in its load forecast.

3.B. Capacity Needs Assessment

Staff is currently reviewing the forecasted range of capacity needs in the 2019 IRP, which it finds is strikingly broad. Staff is motivated to ensure that the Company gives adequate considerations to capacity adequacy, particularly given the robust discussions in Chapter 3 Futures and Uncertainties and the regional capacity need shown by recent studies evaluated in the Market Capacity Study.[59]

PGE forecasts wide "jaws" of capacity need by 2025, ranging from a low of 0 MW to a high of nearly 1,100 MW of new capacity. The graphic below captures the wide range of possible need.[60]



[55] *See* the U.S. Department of Energy Alternative Fuels Data Center's Vehicle Weight Classes and Categories Chart found at https://afdc.energy.gov/data/10380.
[56] *See* https://www.ford.com/trucks/f150/models/f150-xl/.
[57] *See* U.S. Department of Energy Alternative Fuels Data Center's Alternative Fuel and Advanced Vehicle Search, spreadsheet of vehicles, https://afdc.energy.gov/vehicles/search/.
[58] *See* the U.S. Department of Energy Alternative Fuels Data Center's Vehicle Weight Classes and Categories Chart found at https://afdc.energy.gov/data/10380.
[59] 2019 PGE IRP, External Study E: Northwest Loads and Resource Assessment.
[60] 2019 PGE IRP, p. 108.

Staff appreciates the thoroughness of PGE's capacity assessment in the 2019 IRP. Most notably, PGE's 2019 IRP analysis proactively models capacity need with and without contract expirations. Staff is also happy with PGE's modeling of the impact of demand response on future capacity need, although Staff would like to better understand the assumptions behind this analysis.

PGE's forecasted range of capacity need is influenced by a variety of factors. Other sections of Staff's comments discuss drivers of uncertainty that impact PGE's 2025 capacity, such as the EV forecast, the integration of QFs into PGE's system, and load-growth methodology. Staff hopes to work with PGE and stakeholders during the IRP to understand how changes or improvements to these assumptions can change or shift PGE's final forecasted capacity need.

Staff finds one key takeaway to PGE's capacity adequacy analysis that is worth exploring in these initial comments. Notably, contract expirations in 2025 constitute the main driver of capacity need, except in the "high need" future scenario.[61] In the reference case, with all contracts expiring, PGE's loss-of-load expectation (LOLE) grows to 125 hours,[62] which is well above the industry standard 2.4 hours used in the 2016 IRP.[63] This is also happening against the backdrop of Pacific Northwest energy leaders asserting that a regional capacity shortfall is on the near-term horizon[64] ***and*** a rather dire market capacity forecast from E3 in this IRP.[65]

The extent of the reliability shortfall calls into question PGE's prioritization of near-term action items. The Company would appear to be more focused on acquiring renewables by 2023 than investigating zero-carbon approaches to meeting its potential capacity needs in 2025. Staff thinks it would be more prudent for the Action Plan to place greater emphasis on not only contract renegotiations but also in steps to make PGE more resilient to capacity shortfalls such as exploring higher levels of DR acquisition, better utilization of transmission assets to increase imports, and taking actions to better understand the financing and timing associated with new, potential low-emission capacity products, such as distribution-scale batteries and utility-scale pumped hydro. Waiting until the next IRP Action Plan to explore a more holistic set of capacity options may leave PGE with less ability to avoid the addition of new fossil-fuel thermal generation in the mid-2020's, something PGE is currently saying they want to avoid.

At one level, Staff is concerned that there is not sufficient analysis on the probability of capacity contract renewal or non-renewal; they are all equally weighted probabilities. Staff would like to explore with PGE the possibility of incorporating probabilities into potential contract renewals.

In short, Staff is concerned that PGE is prioritizing near term renewables and the potential savings they may bring, over a real need for capacity to serve load within the action plan timeframe. In addition to reproducing the Company's load forecast, which informs the capacity needs assessment, Staff is also in the process of reproducing the RECAP model, which drives the capacity needs modeled in portfolio evaluation. Staff will carefully weigh each assumption and the formulas in which they are inputted, engage with PGE to confirm modeling results, and provide additional feedback in the next round of comments as warranted.

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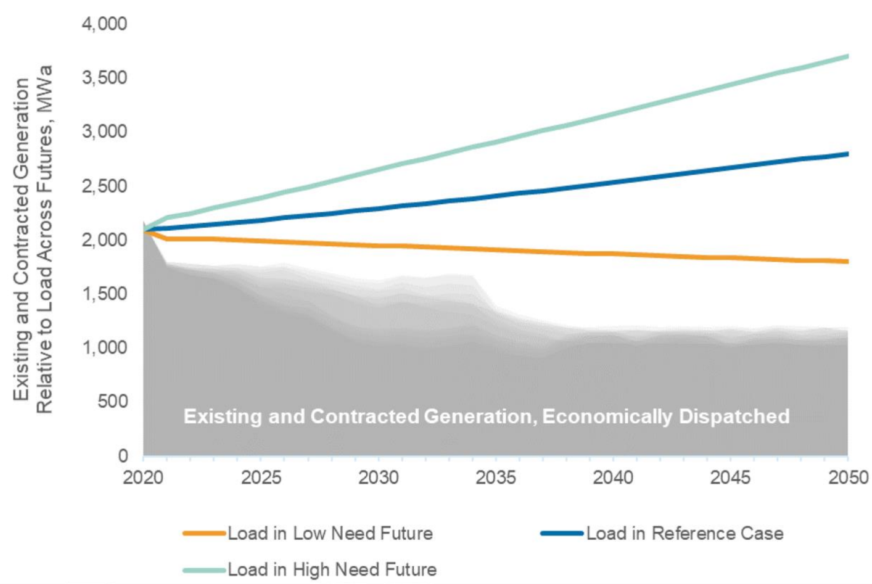
[61] 2019 PGE IRP, p. 110.
[62] 2019 PGE IRP, p. 106.
[63] 2019 PGE IRP, p. 104.
[64] For example, see Northwest Power Pool's recent resource adequacy conference, Oct. 3, 2019 https://www.nwpp.org/private-media/documents/2019.10.02_Resource_Adequacy_Symposium_ALL_SLIDES.pdf
[65] 2019 PGE IRP, External Study E: Northwest Loads and Resource Assessment.

Finally, Staff would like to note its appreciation for the Flexibility Adequacy Study. Staff finds it a helpful explanation of the need to plan for and operate batteries differently than other generating resources. Staff is continuing to consider PGE's findings in the Flexibility Adequacy Study, and what the implications are for PGE's resource planning.

3.C. Market energy position analysis

PGE's new market energy position analysis provides an interesting evolution of the Company's traditional load-resource balance. Through this analysis, PGE models economic dispatch and compares it to three need futures to demonstrate what it describes as an "energy shortage" (See Figure 4-17).[66]

FIGURE 4-17: Load and existing and contracted generation



Yet, when PGE's resources dispatch economically and market purchases meet the rest of PGE's load, this is not necessarily an indication that PGE needs to acquire more energy resources. It may simply indicate that market prices are low. PGE's 'Market Energy Position' analysis tells how much energy the company may choose to buy on the market, but in no way should it be used to justify any amount of new resource acquisition.

In a data response to Staff, PGE clarified that its portfolio modeling uses the market energy position to constrain overbuilding of new resources and to calculate GHG emissions, but not to identify when there is a need to add a new resource.[67] Staff appreciates the Company's clarification. Staff would have serious concerns with portfolio modeling that bases its energy need on its market price forecast and resulting economic dispatch model.

Recommendation 13: In future IRPs, PGE should be careful not to imply that the Market Energy Position analysis represents an energy shortage or a need to acquire new resources.

3.D. Direct Access impacts

As with PGE's GEAR program, Staff appreciates that the Company has provided sensitivities and discussion related to the impact of various voluntary actions and QFs. However, additional

[66] 2019 PGE IRP, p. 110.
[67] PGE response to Staff IR 138.

information and analysis is required to understand if PGE's resource needs assessment accurately captures these loads and resources.

Direct Access adequacy
One component of PGE's 2016 IRP Action Plan, as acknowledged in Order No. 17-386, was to conduct an enabling study on the risks associated with Direct Access to inform the next IRP (2019). Though Staff continues to evaluate whether the Company has completed a full study on the risks associated with Direct Access, PGE has incorporated a sensitivity analysis on the capacity adequacy impacts associated with LTDA load.

In PGE's sensitivity analysis, the Company notes its belief that excluding LTDA customers from capacity planning, while still being required to serve as the provider of last resort (POLR), shifts reliability risks from LTDA participants to cost-of-service customers. As shown in the table below, PGE notes that according to its sensitivity analysis, there would be an incremental capacity need of 526 MW in the event that PGE must serve LTDA customers.[68,69] From its sensitivity analysis, PGE also concludes that the additional 419 MWa of LTDA load would increase its loss-of-load expectation (LOLE) to 53.7 hours per year, significantly higher than the 2.4 hours per year LOLE reliability target.

	Incremental Capacity Need
300 MWa Long-term Direct Access (existing load program)	373 MW
419 MWa Long-term Direct Access (existing + new load programs)	526 MW

Staff appreciates PGE's work to include the LTDA sensitivity analysis in this IRP, and recognizes the challenges PGE faces in regards to Direct Access. However, Staff notes that the issues of planning and risks associated with Direct Access, such as PGE being required to serve as the provider of last resort (POLR), but not directly plan for LTDA customers, are being considered by the Commission in other dockets.

In Docket UE 358, PGE's proposed new load direct access program (NLDA) is currently under review. Additionally, in Docket UM 2024 the Commission recently approved a petition to open an investigation into LTDA that may materially affect PGE's LTDA programs.[70]

As these dockets are ongoing, and the outcome is unlikely to be determined in time for this IRP acknowledgement, Staff ask the Company to provide additional discussion of how these uncertainties are reflected in the analysis and Action Plan.

[68] 2019 PGE IRP, p. 108.
[69] Staff notes that the 526 MW represents the capacity to meet both the LTDA and NLDA program caps of 300 MWa and 119 MWa, respectively.
[70] Order No. 19-271.

Recommendation 14: In its reply comments, PGE should discuss how the resource needs assessment and Action Plan should be altered, if at all, in response to the potential outcomes of current Commission activities related to Direct Access.

Direct Access load
IRP Guideline 9 states that PGE's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.[71] In practice, this means an electric utility such as PGE should not plan for resources for the purpose of meeting Long Term Direct Access (LTDA) customers' load.

In LC 66, Staff raised its concern regarding PGE's load forecasting assumption that there will be no change in additional long term opt outs of cost of service rates, noting that changes to Direct Access load will likely have an impact on industrial load forecasts, and asking PGE to justify its assumption of no new Direct Access customers in its load forecast.[72] PGE noted in response to Staff's concern that the assumption was consistent with Guideline 9, and that it did not have access to information to inform any predictions of new, future direct access customers.[73]

In the 2019 IRP, Staff is again concerned that PGE appears to have made the same assumption with respect to Direct Access. While PGE has appropriately excluded current LTDA load from its load forecast, Staff remains concerned that PGE's choice not to forecast changes to its current level of LTDA load could be upwardly biasing the industrial load forecast, and by extension, its capacity needs. This is particularly concerning given the ongoing discussions under other dockets noted in the previous section.

Recommendation 15: Staff requests that PGE provide additional analysis and information related to the impact of LTDA on its resource needs:

- Staff asks PGE to provide further justification for its assumption that it could not use historical direct access participation data, knowledge of changes in the Direct Access landscape, or another method to update its load forecast

- Alternatively, PGE could update the portfolio analysis and, as necessary, the Action Plan to reflect the impact of including a forecast of additional LTDA participation in its load forecast.

<u>3.E. Future of Existing and Contracted Resources</u>
Similar to the voluntary customer actions described in these comments, Staff questions whether the future of certain existing and contracted resources should be more directly reflected in the Company's planning outcomes. In this section, Staff notes where additional information is required to understand if PGE's resource needs assessment accurately captures the long-term availability of these resources.

QF forecast
PGE's 2019 IRP forecasts that no new QF contracts will be added throughout the entire planning horizon. The result of this assumption is that QF generation decreases from 121 MWa in 2020 to 15 MWa in 2037.[74] Staff strongly recommends PGE amend its QF forecast in the 2019 IRP and in future IRPs to include a forecast of future QF contracts. While Staff recognizes

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[71] Order No. 07-047, Appendix A, Guideline 9, p. 8.
[72] See Docket No. LC 66, Staff's Initial Comments, p. 9.
[73] See Docket No. LC 66, PGE Reply Comments, p. 36.
[74] PGE Response to Staff IR 020, Attachment A.

the uncertainty surrounding future QF generation, assuming no new contracts is unjustified by historical trends.

The 2019 IRP includes a sensitivity analysis for high and low forecasts of QF generation.[75] However, even the high forecast does not include any contracts except those that are already in progress toward execution.

The QF forecast is important because QF generation has a substantial impact on IRP results. In the high QF sensitivity, PGE's analysis shows 67 MW less capacity need and 119 MWa less energy need in 2025, as compared to a low QF future. The unrealistic lack of incremental QF contracts in PGE's long term planning may be contributing to PGE's finding that near-term renewable acquisition is cost-effective. Staff is currently reviewing QF trend data provided in response to several data requests, but finds that this sensitivity analysis points to a likelihood that the capacity and energy needs assessment is likely overstating the Company's energy and capacity needs.

Staff understands that PGE models QF contracts similarly to the way it models other contracts.[76] However, QF generation is unique in that PGE does not choose to acquire it. PGE is required to accept new QFs contracts at avoided cost prices. For this reason, failing to include QF contract forecasts in the IRP modeling causes the appearance of greater resource need than is likely to exist on PGE's system in the future. Including a QF forecast in the portfolio analysis and load resource balance will provide a more realistic view of PGE's position and the resources it may need to acquire.

Staff appreciates the QF sensitivity performed by the Company and understands that QF contracts can be difficult to forecast. However, Staff strongly recommends that PGE amend its QF sensitivity, as well as any IRP modeling that includes a forecast of future QF generation, to include a forecasted level of QF generation based on past QF generation levels and reasonable expectations for the future. Including a reasonable QF forecast will be essential to showing whether the need for a 150 MWa renewable acquisition action item is driven by real need or by inaccurate modeling assumptions in the 2019 IRP.

Recommendation 16: Staff requests that PGE provide additional analysis and information related to the expectation that there will be no new QFs beyond those currently in the contracting process:

- PGE should update the load-resource balance and, as necessary, portfolio analysis and Action Plan to reflect a reasonable QF forecast.

- Alternatively, PGE could reduce its 150 MWa energy resource acquisition in its Action Plan by an amount of QF capacity forecast to come online before 2025.

Boardman availability
Staff appreciates PGE's consideration of biomass as an alternative fuel at the Boardman coal plant. Staff is interested in the potential for sustainably harvested biomass to help reduce wildfire risk while providing capacity in an increasingly capacity-constrained market.[77] Staff is

[75] 2019 PGE IRP, p. 121.
[76] PGE Response to Staff IR 020.
[77] California Energy Commission. Biomass to Energy: Forest Management for Wildfire Reduction, Energy Production, and Other Benefits. 2010. Page 3. Available at: https://ww2.energy.ca.gov/2009publications/CEC-500-2009-080/CEC-500-2009-080.PDF.

supportive of the Company continuing to consider options for using an alternative fuel at Boardman after it retires as a coal plant in 2020.

Staff is continuing to investigate PGE's assumptions and analysis regarding emissions from a potential biomass plant at Boardman, including assumptions around NOx emissions. Under the federal Regional Haze rule, the EPA sometimes requires generators to install Selective Catalytic Reduction (SCR) technology when the operation of a plant detracts from air quality. Staff will continue to investigate PGE's assumptions about whether emissions control technology would be required at a Boardman biomass plant, which could be operated significantly fewer hours in a year than the Boardman coal plant historically operated.

Staff is aware that biomass generation in other parts of the world has received criticism for unsustainable practices. However, Staff is interested in working with PGE and stakeholders to discuss parameters that could ensure that sustainably harvested biomass would truly reduce greenhouse gas emissions, wildfire risk, and electric system capacity need in Oregon.

Recommendation 17: Staff requests that PGE provide additional analysis and updated information related to the future of Boardman:

- Staff recommends a stakeholder workshop within the IRP docket to discuss the potential for sustainably harvested biomass capacity at the Boardman plant.
- Staff requests that PGE report in its replay comments whether SCR technology would be required on a plant that only ran a few months out of the year to meet peak capacity.

Conservation voltage reduction (CVR)
CVR is a strategy of lowering consumer power demand by operating distribution feeders within the lower portion (114V – 120V) of the American National Standards Institute (ANSI) acceptable voltage bandwidth. PGE completed feasibility studies and two CVR pilot projects in 2014 at Hogan South substation in Beaverton and at Denny substation in Gresham. By reducing voltage 1.5 - 2.5 percent in the pilot project, PGE was able to reduce customer demand (MW) and energy consumption (MWh) by 1.4 - 2.5 percent. The pilots yielded customer energy savings of 768 MWh in 2014. A preliminary evaluation has identified 94 transformers as potential CVR candidates with an annual customer energy savings potential of 16 MWa or 142,934 MWh.

Currently, PGE uses manual intervention in the form of data spreadsheets to maintain customer voltage information. In order for PGE to progress its system-wide CVR program, the Company has put a hold on CVR, to allow for the planning and implementation of an advance distribution management system (ADMS).[78]

PGE is in the process of planning ADMS with functions to be implemented by the end of 2020, with full system advanced application to be completed by the end of 2022. This software platform integrates numerous utility systems and provides automated outage restoration and optimization of distribution grid performance. ADMS functions can include automated fault location, isolation, and service restoration, conservation voltage reduction, peak demand management, volt/volt-ampere reactive optimization, conservation through voltage reduction, peak demand management, support for microgrids, and electric vehicles. In essence, an ADMS transitions utilities from paperwork, manual processes, and siloed software systems to systems with real-time and near-real-time data, automated processes, and integrated systems.

[78] *See* Docket No. UM 1657, PGE's 2019 Smart Grid Report, pp.54-55.

Staff commends PGE's ongoing efforts to build and maintain a flexible and integrated grid as explained in its 2019 Smart Grid Report, Staff would still like to see PGE describe this flexibility plan in far more detail moving forward.

Recommendation 18: As part of distribution system planning efforts, PGE should consider the value of CVR and study its value on additional substations. If additional CVR is implemented, it should be included in IRP portfolio modeling.

3.F. Conclusion
Staff recommends PGE do the following related to the resource needs assessment:

11. Work with Staff and ETO to see if there are opportunities to apply more appropriate input selection for energy efficiency, and potentially for other demand-side and load forecast inputs to scenarios.
12. Explain in its reply comments how the Company accounted for consumer vehicle preferences and availability of heavier electric vehicles in its load forecast.
13. In future IRPs, PGE should be careful not to imply that the Market Energy Position analysis represents an energy shortage or a need to acquire new resources.
14. In its replay comments, discuss how the resource needs assessment and Action Plan should be altered, if at all, in response to the potential outcomes of current Commission activities related to Direct Access.
15. Provide additional analysis and information related to the impact of LTDA on its resource needs:
    a. Provide further justification for its assumption that it could not use historical direct access participation data, knowledge of changes in the Direct Access landscape, or another method to update its load forecast
    b. Alternatively, PGE could update the portfolio analysis and, as necessary, the Action Plan to reflect the impact of including a forecast of additional LTDA participation in its load forecast.
16. Provide additional analysis and information related to the expectation that there will be no new QFs beyond those currently in the contracting process:
    c. Update the load-resource balance and, as necessary, the portfolio analysis and Action Plan to reflect a reasonable QF forecast.
    d. Alternatively, PGE could reduce its 150 MWa energy resource acquisition in its Action Plan by an amount of QF capacity forecast to come online before 2025.
17. Provide additional analysis and updated information related to the future of Boardman:
    e. Hold a stakeholder workshop within the IRP docket to discuss the potential for sustainably harvested biomass capacity at the Boardman plant.
    f. Report in the replay comments whether SCR technology would be required on a plant that only ran a few months out of the year to meet peak capacity.
18. As part of distribution system planning efforts, consider the value of CVR and study its value on additional substations. If additional CVR is implemented, it should be included in IRP portfolio modeling.

4. Characterization of Supply-side Options

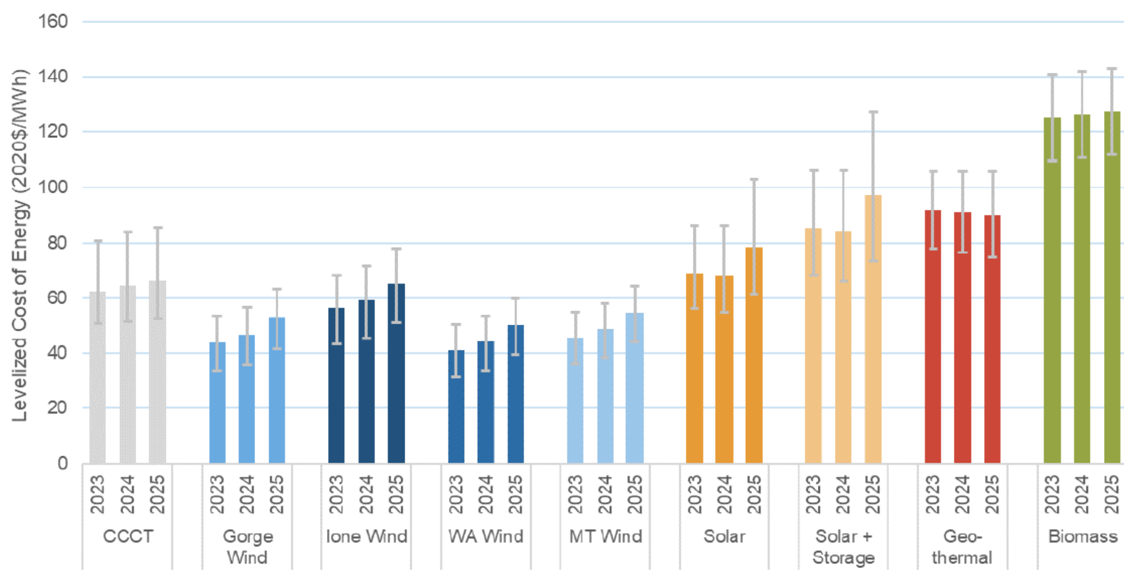
Staff is reviewing the Company's consideration of all resources available to meet the need described in the previous section, as required by IRP Guideline 1.[79] Staff review includes analysis of the resource characteristics and economic assumptions, the third-party studies underlying these assumptions, and a wide range of discovery related to the resources

[79] Order No. 07-047, Appendix A, Guideline 1, pp. 1-2.

considered in its 2019 IRP. In its description of the renewable energy acquisition in its Action Plan, PGE states that, "we found that renewable resources that qualify for federal tax credits are expected to be the lowest costs resource options on a real-levelized basis."[80] Further, the Company states that, "The net cost of wind resources (levelized costs net of capacity and energy value) is negative in the Reference Case and most of the futures, indicating that renewable resources are likely the lowest cost option for securing long-term energy."[81]

Staff finds this statement generally true and believes the IRP does a good job of demonstrating the production risk associated with capacity factor sensitivity in Section 6.5.[82] However, Staff would like to better understand how the many assumptions underlying this conclusion were captured in the portfolio modeling and selection. Given that the main driver for the near-term acquisition of wind resources is not energy, capacity, or an RPS need, but rather the time-limited economic opportunity associated with expiring PTCs, Staff's review is focused on understanding the Company's assumptions around the federal tax incentives and overall performance of renewable energy resources compared to conventional resources (See Figure 6-2 below).[83]

FIGURE 6-2: Levelized cost of energy (LCOE) of energy resource options



Further, PGE's explains that:

> The region is experiencing congestion and uncertainties related to the availability of firm transmission during certain times of the year. This situation is of growing concern to PGE, as many of the future resource alternatives being explored will be off-system and will generally require BPA transmission. This situation is of growing concern to PGE, as many

[80] 2019 PGE IRP, p. 216.
[81] 2019 PGE IRP, p. 155.
[82] 2019 PGE IRP, pp. 174 - 177
[83] 2019 PGE IRP, p. 161.

of the future resource alternatives being explored will be off-system and will generally require BPA transmission.[84]

Therefore, Staff is additionally focused on understanding whether the IRP and Interim Transmission Solution adequately account for transmission costs and availability for the various supply side resources modeled.

4.A. Generating Resources

Federal tax incentives

As noted above, PGE cites the PTC as a driver of wind's performance in the 2019 IRP. Staff has several questions about the IRP's consideration of the risks related to the PTC.

First, Staff continues to have concerns about PGE's ability to utilize the acquired tax credits any time before 2030. Staff raised this concern in the 2016 IRP and it remains an issue. Currently, PGE is sitting on over **[begin confidential]** [redacted] **[end confidential]** in unused PTCs, on which PGE is earning a rate of return paid for by ratepayers. Staff estimates the Wheatridge project add nearly $8 million annually in new PTCs to the current stockpile.[85] From the perspective of IRP modeling, Staff is unclear as to how PGE's ability to utilize tax credits in "real world" is modeled and represented in the cost and risk metrics of portfolios that add PTC eligible wind resources and whether it may skew results toward near-term acquisitions. Before recommending acknowledgement of Action Item 2 – which we assume will be Washington wind based on the preferred portfolio, although its not clear – Staff would like PGE to better explain how it modeled the unapplied tax credits (i.e., the rate of return penalty) and provide a forecasts of the anticipated PTCs and the year of their application to PGE's federal tax filings.

Further, Staff understands that PGE can only capture the PTC for facilities that commence construction or have purchased five percent of equipment in 2019, and can be placed in service by 2023.[86] Staff is curious about the "real world" risk that the market will not present a wind facility or facilities that provide 150 MWa in service before the end of 2023 or that cost overruns, schedule delays, and etc., of such a facility will mitigate the economic opportunity that identified this resource acquisition path as least cost, least risk in PGE's portfolio scoring.

Based on PGE's last procurement, Staff finds that it is important to assess the "reality" of interconnection queue position and transmission reservations as it relates to the results of an agnostic resource procurement. To accomplish this, Staff is in process of reviewing the Bonneville Power Administration (BPA), PacifiCorp (PAC), and PGE OASIS interconnection queues of to identify possible resources in a position to meet the 2023 in service date. Staff is also reviewing transmission reservations prior to the next round of comments. Staff would like PGE to explain whether it has performed a similar analysis and to share their findings with stakeholders, within the next round of comments.

Finally, Staff is investigating the cost and risk metrics for renewable size and timing portfolios because the portfolios that add 50 – 250 MWa in 2024 appear similar under the cost metric to the performance of the renewable size and timing portfolios that add 50 – 250 MWa of

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[84] 2019 PGE IRP, p. 145.

[85] Staff's back of the envelope math: 100 MW capacity at Wheatridge x 38% capacity factor x 95% availability x 8,760 hours/year x $25/MWh. Staff's analysis of the addition to PGE tax credit stockpile does not take into account the Investment Tax Credit PGE may earn on the solar portion of the Wheatridge project.

[86] *See* Congressional Research Service, The Renewable Electricity Production Tax Credit: In Brief, November 27, 2018. https://fas.org/sgp/crs/misc/R43453.pdf.

renewables in 2023. As Staff reviews the Company's resource assumptions and portfolio modeling, it will continue to evaluate the overall impact of PTCs on the value of near-term acquisition to more acutely understand the costs and risks of rushing to acquire resource with a COD of 2023.

Comparison of top performing portfolios[87]

TABLE 7-5: Best performing portfolios, traditional scoring metrics

Portfolio	Category	Cost	Variability	Severity
Min Avg LT Cost, No Energy	Optimized	25,436	3,808	30,987
SCCT	Dispatchable Capacity	25,351	3,675	30,699
LMS100	Dispatchable Capacity	25,515	3,652	30,863
200 MWa in 2023	Renewable Size & Timing	25,744	3,653	30,987
250 MWa in 2023	Renewable Size & Timing	25,620	3,605	30,807
200 MWa in 2024	Renewable Size & Timing	25,804	3,648	31,043
250 MWa in 2024	Renewable Size & Timing	25,693	3,611	30,879

Recommendation 19: In its reply comments, PGE should provide the following additional information about its PTC risks and assumptions:

- Clarify how the Company captured the risks associated with PTC expiration in its analysis.
- Explain the modeling of the unapplied tax credits (i.e., the rate of return penalty) and provide a forecasts of the anticipated PTCs and the year of their application to PGE's federal tax filings.
- Explain what market analysis or other research the Company conducted to understand the availability of PTC eligible resources.
- Analyze the OASIS interconnection and transmission queues for PGE, BPA and PAC to develop an understanding of the pool of possible resources able to compete and come online by 2023
- Provide additional analysis of the difference in performance between renewable size and timing portfolios that add 50 – 100 MWa in 2024 versus the renewable size and timing portfolios that add renewables in 2023, and how that relates the Company's strategy to release a renewable RFP that will capture 2023 wind resources.

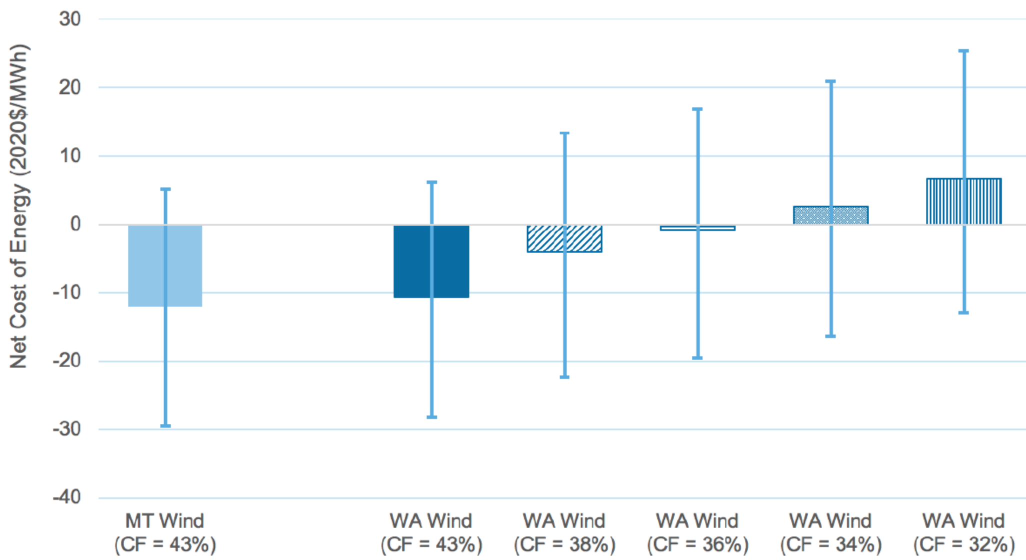
[87] 2019 PGE IRP, p. 192.

Wind capacity factor
Staff appreciates the Company's description of the wind generation profiles assumed in its 2019 IRP, based on supplemental analysis found in the HDR reports provided in External Study D. As PGE notes:

> [T]he long-term annual net capacity factors vary by location, ranging from 32.7 to 42.9 percent. The wind resources vary in seasonal and diurnal timing of their generation, as well as their probability of generation under high load conditions. [88]

Staff particularly appreciates the sensitivity analysis for wind capacity factors provided in Section 6.5 and Figure 6-15 below.[89]

FIGURE 6-15: Net cost sensitivities for wind

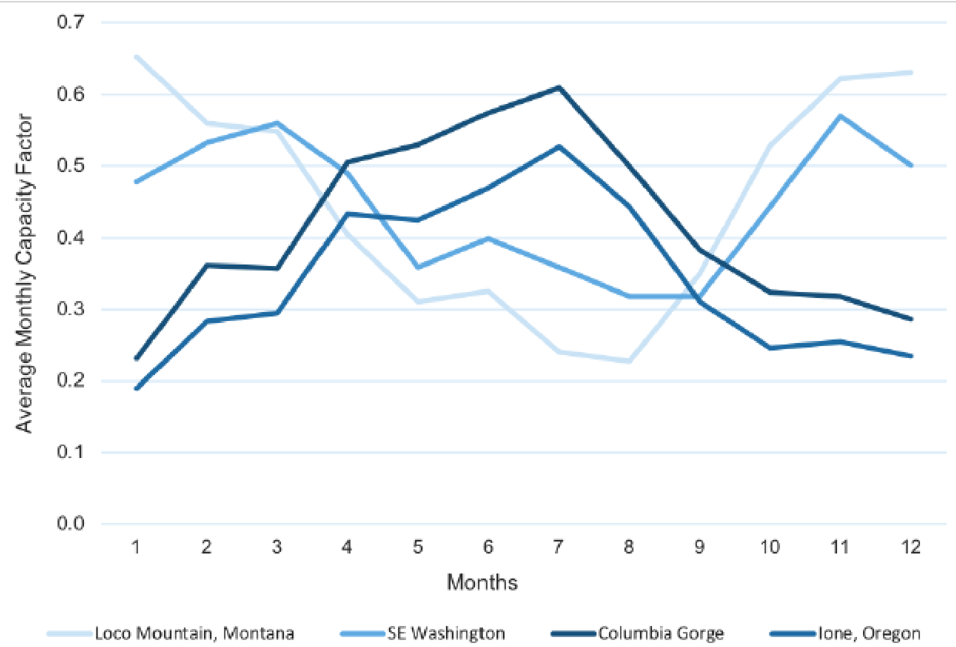


Staff notes the impact that capacity factor assumptions have on the economic performance of wind resources in PGE's sensitivity and questions whether the Company's sensitivity analysis should have been performed on the Mixed Full Clean portfolio to help characterize the risk of acquiring near-term wind assets based primarily on economic performance.

Further, Staff is curious about the relationship between the capacity factor shape of different wind resources modeled in the IRP and PGE's projected capacity needs. For example, PGE provided a helpful characterization of different wind resources' capacity factor shapes in Figure 5-4. [90] Staff notes that the performance of Columbia Gorge and Ione, Oregon wind follow the reverse shape to that of Montana and Washington wind.

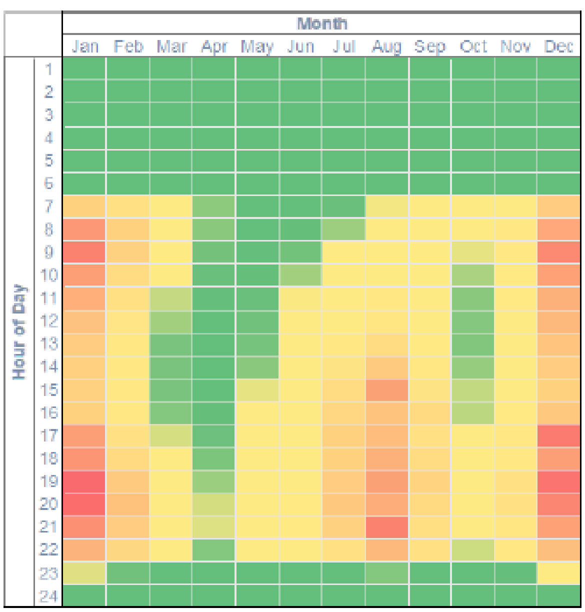
[88] 2019 PGE IRP, p. 135.
[89] 2019 PGE IRP, pp. 172 – 174.
[90] 2019 PGE IRP, p. 136.

FIGURE 5-4: Average monthly wind capacity factors by location



Given the Action Plan's lack of specificity regarding resources in the renewable RFP and the future capacity actions, it is particularly interesting to note the relationship between the wind shapes and PGE's characterization of its capacity need found in figure 4-14.[91]

FIGURE 4-14: Reference Case loss-of-load expectation in 2025



[91] 2019 PGE IRP, p. 107.

Therefore, Staff is evaluating the underlying assumptions for wind capacity factors modeled in the 2019 IRP against the actual performance of PGE's wind fleet, the modeling assumptions in previous IRPs, and the Company's forecasted capacity needs. As Staff continues to evaluate the reasonableness and risks associated with the Company's wind capacity factor assumptions, additional information related to the impact of capacity factors will be helpful.

Recommendation 20: Staff requests that PGE provide a sensitivity analysis of the Mixed Full Clean portfolio assuming proportionate changes to the capacity factor of each resource as the assumptions behind the capacity factor sensitivity analysis in Figure 6-15 above.

Energy value of wind
Staff is concerned the Company's analysis may be overstating the energy value of wind. The company describes energy value as representing "the market revenues or the value of avoided market purchases when the resource dispatches."[92] When the Company's wind resources are generating, so are many of the other local wind resources. Staff is concerned that the Company's modeling may not be capturing the dynamic relationship between regional wind production and market prices. To test these initial concerns, Staff has used historical market prices and historical generation to estimate the energy value of Tucannon wind by cross-referencing hours when Tucannon was generating with the Mid-C market prices at those times.

In its IRP, PGE suggests that levelized energy value of Washington wind in the Reference Case is 2020$ is 46.51/MWh.[93] Using the data PGE shared with Staff on historical hourly output from the Tucannon River Wind Farm from January 1, 2015 through December 31, 2018, and day-ahead Mid-C prices, Staff finds that the observed energy value has been **[begin confidential]** [redacted] **[end confidential]**, which is significantly lower than the Company's bottom range forecast of 2020$ 32.35/MWh.[94,95]

Recommendation 21: PGE should explain in reply comments how it is considering the coincidence of market prices and the times when the various wind resources modeled are likely to generate.

Wind integration costs
In its discussion of the value of curtailment in calculating renewable integration costs, PGE explained that curtailment could have either operational or economic causes:

> High production from renewable resources can result in periods of time where the system has an oversupply of renewable energy, which may be curtailed. Curtailment may occur for economic or operational reasons, and the cost and amount of curtailment depends on a variety of factors including market prices, system conditions, and resource constraints.[96]

The Company noted that in the ROM simulation of PGE's system used to calculate wind integration costs, the lost value of PTCs from curtailed wind is not accounted for. Staff is concerned about the potential for this approach to overestimate the value of resources that

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[92] 2019 PGE IRP, p. 162.
[93] 2019 PGE IRP, p. 162.
[94] PGE Response to OPUC Data Request No. 056.
[95] Platts S&P Global Mid-C Day Ahead.
[96] 2019 PGE IRP, p. 159.

secure the PTC. This could impact the Company's estimate of wind integration costs. Staff will provide any additional findings in its final comments.

Solar integration costs
While Staff continues to conduct its evaluation of wind integration costs, it is also evaluating data responses related to solar integration costs. Staff has not formed any conclusions but notes that the solar integration costs listed in the IRP do not align with Staff's understanding of the value provided by the increased predictability in scheduling solar resources. Staff will provide any additional findings in its final comments.

TABLE 6-2: Renewable integration costs for new renewable resource options

	Renewable Integration Cost (2020$/MWh)
Gorge Wind	0.33
Ione Wind	0.33
MT Wind	0.07
WA Wind	0.31
Central OR Solar	1.36
Solar + Storage	0.00
Geothermal	0.00
Biomass	0.00

Resource cost trajectories
Staff appreciates the Company's efforts to model the uncertainty surrounding long-term technology costs, particularly given the risks and benefits associated with near-term resources that are eligible for expiring federal incentives. However, Staff notes that questions remain related to this methodology.

First, in explaining how it developed its low, reference, and high technology curves, PGE states that it used the HDR estimate of fixed wind costs for its reference case wind "fixed cost scenario." Staff appreciates this explanation, but would find similar information about the PGE's methodology for deriving the low and high fixed cost scenarios from the reference case very helpful in understanding how PGE modeled the tradeoffs between near and long term resource acquisition.

Second, in the technology cost trajectories, the Company explains that a Bloomberg NEF solar learning rate was used for the learning rate of solar, but EIA's Annual Energy Outlook assumptions were used as the source for the learning rate of wind. Staff would like more explanation on why Bloomberg NEF was not also used as a source for wind learning rates.

Finally, Staff appreciates the Company's discussion of emerging technologies in section 5.6, and notes that building a resource too early in its learning curve can result in risks for ratepayers. Staff agrees that hydrogen, SMR nuclear, and hydrokinetics are too early in their technological development to be put into a portfolio, but they serve as a reminder that it's not just the learning curve of proven technologies, but the uncertainty surrounding emerging technologies, that should be considered when evaluating near-term resource acquisition to serve longer-term needs.

Recommendation 22: Staff requests that PGE provide additional clarity on its technology cost trajectories in its reply comments:

- Staff requests further explanation of PGE's methodology for deriving the low and high fixed cost scenarios wind.
- Staff requests further explanation of the differences in learning rate methodologies between solar and wind resources.

Thermal resources
Staff's initial understanding is that PGE's 2019 IRP rules out thermal resources in all portfolios after 2025, without including an adequate justification as to why this is a beneficial modeling decision. The IRP models allow capacity need to be met with a generic "capacity fill" resource.[97] Although the 'capacity fill' resource could be said to implicitly include some types of thermal, in general the exclusion of thermal resources in the IRP is concerning from a least-cost, least-risk planning perspective.

The first IRP guideline directs utilities that "all resources must be evaluated on a consistent and comparable basis", and that "consistent assumptions and methods should be used for evaluation of all resources."[98] PGE identifies no justification in terms of customer benefits that would cause Staff to believe the Company should not be required to follow the IRP guidelines to consider all resources on a consistent basis. PGE will need to provide a thorough explanation and justification for why its decision to exclude a category of resources from consideration is in the best interest of ratepayers, or else change its portfolio analysis to allow for the selection of thermal resources.

Staff notes that it in no way opposes a planning process that does not result in the selection of thermal resources. However, utilities are still required by the IRP guidelines in Order Nos. 07-047, 07-002, and 08-339 to meet need in the most cost-effective manner while considering risk and uncertainty.

Recommendation 23: PGE should provide a thorough justification of why its decision to exclude thermal resources from its long term planning is consistent with the best interest of ratepayers, or else update its analysis to consider all resources available to meet its long-term needs.

Capacity fill resource
Staff is intrigued by the introduction of the capacity fill resource to capture the uncertainties and risks surrounding its bilateral capacity contracts. As PGE notes:

> The portfolio optimization allows use of a generic Capacity Fill resource to meet a portion of its capacity needs. The Capacity Fill resource is priced at just above the net cost of capacity of a simple cycle combustion turbine (SCCT) derived in Section 6.2.3 Capacity Value ($103/kW-yr). In the near term (through 2025), Capacity Fill can be used for up to the portion of PGE's capacity needs associated with the expiration of contracts.
>
> […]After 2025, portfolios are allowed unconstrained access to the Capacity Fill resource. If none of the resource options provide capacity at a cost lower than the

[97] 2019 PGE IRP, p. 178.
[98] Order No. 07-047, Appendix A, Guideline 1, pp. 1-2.

net cost of a SCCT, the portfolio will meet its remaining capacity needs beginning in 2026 with the Capacity Fill resource.[99]

While Staff appreciates the Company's efforts to capture optionality in the IRP, Staff does not believe that PGE has sufficiently justified the near-term constraint on access to the capacity fill resource. Further, the 2019 IRP is unclear whether the "capacity fill" resource matches the expected costs of capacity contracts. Staff would like to understand how this 'just above the net cost of capacity of an SCCT' cost compares to the cost of bilateral purchases. In general, Staff finds discussion of the expected costs of capacity contracts is lacking in the 2019 IRP, which it can address further in its final comments.

Recommendation 24: PGE should provide further justification for costs and constraints on the capacity fill resource in its reply comments.

4.B. Consideration of Transmission

Staff found the PGE's detailed discussion of the regional transmission environment helpful and appreciates the Company's efforts to develop and Transmission Interim Solution. However, Staff is concerned that the analysis pertaining to transmission in the IRP is lacking. The following section describes Staff's initial concerns and questions related to PGE's consideration of transmission in the IRP.

Current level of detail provided in the IRP

In Order No. 17-386, the Commission issued only one requirement pertaining to transmission for PGE's 2019 IRP. The order required that PGE hold a workshop to explore the issue of transmission and the potential access to higher capacity wind resources in Montana and Wyoming. PGE complied by hosting this workshop on December 19, 2018, as part of its IRP stakeholder process.[100] The transmission presentation consisted of an overview of the Montana Renewable Development Action Plan (MRDAP),[101] the Colstrip transmission system (CTS), and a high-level overview of the Federal Energy Regulatory Commission (FERC) standards of conduct. While PGE met the requirement of the order, as Staff elaborates below, overall transmission assumptions in the IRP are opaque and worthy of additional investigation.

PGE indicates that for all new resources expected to require BPA transmission (such as wind in the Columbia River Gorge), PGE assigned BPA tariff rates in the Company's preferred portfolio.[102] In other words, the Company assumed that certain wind resources would require BPA transmission capacity, assumed that the capacity would be available, and assigned a standard tariff to estimate costs. For Montana wind resources in the preferred portfolio, PGE incorporated information from the MRDAP and additional data from Puget Sound Energy tariff filings.

While the Company explains its constraints and concerns well, the IRP does not provide evaluate of future transmission capacity or its impact on the resources considered in portfolio analysis. Staff was also surprised by the limited description of the interim solution or associated process and is concerned that the Company proposes to address this "within the context of a

[99] 2019 PGE IRP, p. 178.
[100] See PGE's December 19, 2018 presentation. Accessible at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2018-12-19-irp-roundtable-18-7.pdf?la=en.
[101] The MRDAP included a process that was jointly sponsored by BPA and the State of Montana governor's office. The process lasted between 2017 and 2018 and was intended to explore barriers in renewables development in Montana. PGE used information from the MRDAP to calculate transmission costs and losses in the 2019 IRP.
[102] 2019 PGE IRP, p. 148.

Renewables RFP docket," because it would require the Commission to make an Action Plan determination prior to acquiring sufficient detail in the RFP process.[103]

Concerns and questions related to PGE's consideration of transmission in the IRP
In the IRP, PGE assumed transmission capacity would be available for resources in the preferred portfolio and assigned a standard BPA tariff rate, along with additional costs to deliver Montana wind.[104] In the IRP and discovery, PGE explained that, for the purposes of creating proxy estimations in its portfolio analysis, the Company limited wind resources to four locations: Columbia Gorge, Southeastern Washington; and Central Montana (near Loco Mountain), and Ione, Oregon.[105, 106] Using these assumptions, PGE developed its action plan, including an RFP to procure energy resources identified in its preferred portfolio that will not limit its search based on geography or resource type.[107] The Company also confirmed in discovery that adding new wind resources did not preclude building additional transmission capacity.[108]

Staff can appreciate the uncertainty in modeling where the next least cost, least risk resource will be located. Because the cost and availability of transmission capacity is closely related to location, Staff is concerned about its ability to evaluate the transmission-related costs or risks associated with this action item.

Staff has also reviewed PGE's Interim Transmission Solution. The Company has introduced a five-year provisional program for renewable resource procurement processes conducted between 2019 and 2024. The key restrictions on the renewable resources in this provisional program are the following:

- Applicable only to newly procured variable renewable resources pursuant to an IRP Action Plan or in support of voluntary renewable programs.
- "Eligible transmission service" consists of one or a combination of the following products:
    - Long-Term Firm (LTF) transmission service,
    - Conditional Firm Bridge (CFB) transmission service with a Number of Hours curtailment option.
    - Conditional Firm Reassessment (CFR) transmission service with a Number of Hours curtailment option.
    - Eligible transmission service for at least 80 percent of the maximum output of the facility.
    - PGE continues to require that output be delivered to PGE's system.[109]

Staff appreciates the Company's creativity in constructing additional transmission proposals that could potentially expand the diversity of bids in a renewables RFP. However, Staff has some preliminary concerns. In the interim proposal, the Company explains that it will implement a scoring methodology when it submits an RFP, but specifics about this methodology are not given. Rather, the Company gives generic concepts about how it intends to structure the scoring framework. In particular, PGE explains that a project could receive a lower score depending on the type of transmission it has paired with the project. PGE explains that it will "adjust the RECAP model to reflect the impacts of curtailment and long-term transmission," and that "the scoring will generally reflect the higher likelihood of curtailment and reduced delivery certainty

[103] 2019 PGE IRP, p. 217.
[104] PGE's response to NIPPC IR 016.
[105] 2019 PGE IRP, p. 134.
[106] PGE's response to Staff IR 050.
[107] PGE's response to Staff IR 048.
[108] PGE's response to Staff IR 049.
[109] PGE's 2019 IRP Addendum – Interim Transmission Solution, p. 5.

associated with using conditional firm or long-term transmission for less than full output."[110] While it is theoretically possible that a lower-cost project will perform better than a project with a higher quantity of long-term firm transmission, it is difficult to tell without additional information about the scoring framework. PGE seems to have attempted to push the details about this framework to the RFP process, leaving the Commission with limited information on which to make a major acknowledgement decision about resource need in the IRP.

Additionally, PGE confirms that it will employ its scoring methodology based on non-quantifiable aspects centered on risk and uncertainty, such as the difference in long-term availability between CFB and CFR service, and states that transmission will play a role in the determination of capacity value.[111] The Company will adjust the RECAP model to reflect curtailment impacts and long-term transmission for less than the full output depending on the type of transmission service paired with the project, in addition to what appears to be coincidence with peak.[112]

PGE's methodology will also "assume that the curtailment occurs in those hours in which PGE experiences the greatest capacity need as it is reasonable to assume that the curtailment occurs during the periods of greatest system stress also experienced by PGE."[113] The Company does not provide any evidence for this assumption. Further, the Company will weigh the scoring based on PGE's determination of capacity value, which will ultimately be tied to the type of transmission service included in the project offer. The Company also explains that it will introduce a non-price scoring assessment that will assign higher non-price scores to bids that have greater shares of long-term service and long-term firm service.[114]

Staff appreciates that the Company has tried to introduce flexibility while attempting to balance and score the role of reliability. Staff questions whether the interim solution proposed is specific enough about scoring. It is concerning to attempt to push major decisions like this to the RFP process, such information is required for review of the IRP. [115] Additional detail should be provided in order to give the Commission a full representation of transmission requirements in advance of the RFP process.

[110] PGE's 2019 IRP Addendum – Interim Transmission Solution, p. 6.
[111] PGE's 2019 IRP Addendum – Interim Transmission Solution, p. 6.
[112] PGE specifies this as "appropriate hours" and makes several references to peak system needs throughout the document. See PGE's 2019 IRP Addendum – Interim Transmission Solution, page 6.
[113] PGE's 2019 IRP Addendum – Interim Transmission Solution, p.11.
[114] PGE's 2019 IRP Addendum – Interim Transmission Solution, p.11.
[115] *See* OAR 860-089-0250 (requiring the elements, scoring methodology and associated modeling acknowledged in an IRP to be employed in RFP, unless different methodology to be used in RFP).

Recommendation 25: Staff requests that PGE provide the following additional information about its transmission assumptions and the Interim Transmission Solution in its reply comments:

- Discussion of the appropriateness of requiring firm transmission products for an intermittent resource;
- Discussion of tradeoffs of wind resource quality and available transfer capability (ATC). This discussion could explain tradeoffs of lower quality wind (e.g., lower peak contribution and lower contribution to capacity) with existing ATC vs. higher quality wind with incremental transmission capacity build.
- Discussion of net contribution made by blending diverse regime wind profiles.
- Discussion of the extent to which partnerships or partial share of larger wind projects can lower cost and risk for PGE ratepayers.
- Discussion of the specific transmission paths and resources that would be used to access each wind resource sub-region considered. This discussion would explain how PGE has or would acquire each needed transmission resource or right.

PGE should make its proposal straightforward in what it is trying to achieve and how and why it has confidence in particular sub-regional resources. The discussion should be supported by an appendix explaining what PGE relied on in making its cost and risk projections and how those calculations were specifically made.

4.C. Conclusion
Staff recommends PGE do the following related to its supply-side resource assumptions:

19. Provide the following additional information about its PTC risks and assumptions:
    a. Clarify how the Company captured the risks associated with PTC expiration in its analysis.
    b. Explain the modeling of the unapplied tax credits (i.e., the rate of return penalty) and provide a forecasts of the anticipated PTCs and the year of their application to PGE's federal tax filings.
    c. Explain what market analysis or other research the Company conducted to understand the availability of PTC eligible resources.
    d. Analyze the OASIS interconnection and transmission queues for PGE, BPA and PAC to develop an understanding of the pool of possible resources able to compete and come online by 2023
    e. Provide additional analysis of the difference in performance between renewable size and timing portfolios that add 50 – 100 MWa in 2024 versus the renewable size and timing portfolios that add renewables in 2023, and how that relates the Company's strategy to release a renewable RFP that will capture 2023 wind resources.
20. Provide a sensitivity analysis of the Mixed Full Clean portfolio assuming proportionate changes to the capacity factor of each resource as the assumptions behind the capacity factor sensitivity analysis in Figure 6-15 above.
21. Explain in reply comments how it is considering the coincidence of market prices and the times when the various wind resources modeled are likely to generate.
22. Provide additional clarity on its technology cost trajectories in its reply comments:

a. Staff requests further explanation of PGE's methodology for deriving the low and high fixed cost scenarios wind.
b. Staff requests further explanation of the differences in learning rate methodologies between solar and wind resources.

23. Provide a thorough justification of why its decision to exclude thermal resources from its long term planning is consistent with the best interest of ratepayers, or else update its analysis to consider all resources available to meet its long-term needs.
24. Provide further justification for costs and constraints on the capacity fill resource in its reply comments.
25. Provide the following additional information about its transmission assumptions and the Interim Transmission Solution in its reply comments:
    c. Discussion of the appropriateness of requiring firm transmission products for an intermittent resource;
    d. Discussion of tradeoffs of wind resource quality and available transfer capability (ATC). This discussion could explain tradeoffs of lower quality wind (e.g., lower peak contribution and lower contribution to capacity) with existing ATC vs. higher quality wind with incremental transmission capacity build.
    e. Discussion of net contribution made by blending diverse regime wind profiles.
    f. Discussion of the extent to which partnerships or partial share of larger wind projects can lower cost and risk for PGE ratepayers.
    g. Discussion of the specific transmission paths and resources that would be used to access each wind resource sub-region considered. This discussion would explain how PGE has or would acquire each needed transmission resource or right.

5. Portfolio analysis and construction of the preferred portfolio

Staff begins this section by noting its appreciation for the Company's efforts to enhance the sophistication of its portfolio modeling tools. Staff is supportive of the Company's use of an optimization tool and development of optimized portfolios which are complemented by its hand designed approach. Staff expressed its most pressing concerns at the beginning of these comments. However, Staff has additional feedback and questions about PGE's portfolio analysis.

<u>5.A. Wholesale Market Price Forecast in Aurora</u>
PGE's portfolio modeling relies on a variety of market price futures, each of which is generated in Aurora using different assumptions about gas prices, carbon prices, "WECC renewable buildout" levels, and hydro conditions. Each combination of these potential futures is considered in the analysis, resulting in 54 possible market price futures.

If market price forecasts in Aurora use incorrect assumptions, the portfolio modeling process will compare new resources to a market resource that is not reflective of likely future prices. This will result in the selection of sub-optimal portfolios. Staff finds it critical to vet the market price assumptions and is currently investigating the carbon price scenarios and demand futures.

Carbon Pricing
Staff is concerned that the Company appears to assume a probability of 100 percent that Oregon ratepayers will have to pay for emissions on a range of California Energy Commission

(CEC) prices beginning in 2021.[116] Because the year of a potential future carbon price is not known with certainty, this likely overestimates the expected costs of future carbon pricing.

Recommendation 26: In future IRP analysis, if a carbon pricing policy is not already in place, then carbon prices should be modeled beginning in a range of potential years, rather than assuming a certain start date for the expected greenhouse gas policy.

Demand Futures
PGE has not considered a range of regional energy demand futures in its market price forecast analysis. Staff is concerned that this leaves a set of substantial risks unaccounted for in the market price forecast. Because demand is an important factor in determining the price of market commodities, a future with higher or lower regional demand will have a significant effect on regional market prices.

Recommendation 27: In future IRPs PGE should include a high, low, and reference regional demand future in its wholesale market price forecast.

5.B. Additional Portfolio Analysis Requested
On several topics, Staff found that the IRP either lacked sufficient analysis of an important topic, or else was not up-to-date on important changes that impact the action-plan timeframe.

1. **Emissions Forecast:** Because of the possibility of future cap and trade regulation, Staff requests PGE file, with its reply comments in the IRP docket, yearly emissions estimates for each of its top five portfolios. Stakeholders should have an opportunity to share thoughts and concerns about PGE's emissions forecast since it may be used as the basis for PGE's allowance allocation in future cap and trade policy. The emissions forecasts should be included as graphs, and as data, in both pdf and Excel format.

2. **Energy Imbalance Market:** While PGE's IRP has considered capacity need and flexibility adequacy, Staff would like to see an additional step demonstrating that the Company has included consideration of EIM benefits to PGE's system.

3. **Natural Gas Lifecycle Emissions:** Staff also recommended in the 2013 that PGE perform a lifecycle emissions analysis associated with natural gas generation. Natural gas emissions are significantly higher when lifecycle emissions are taken into account than when only end-use emissions are counted.[117] Further, GHG emissions from gas systems with a high rate of methane leakage can emit similar levels of GHG to coal. Staff encourages PGE to consider whether the risk of potential future GHG regulation that considers lifecycle natural gas emissions has been included in modeling of GHG regulation risk.

4. **Market Price Volatility Study:** After the Enbridge pipeline failure in 2017 and other recent price-spike events in Western energy markets, price volatility is a significant risk factor for energy providers. In its next IRP, PGE should perform a sensitivity analysis for

[116] 2019 PGE IRP, p. 353.
[117] Kaplan, O. AND Andy Miller. Lifecycle greenhouse gas emissions of coal, conventional and unconventional natural gas for electricity generation. 2012 American Institute of Chemical Engineers Annual Meeting, Pittsburgh, PA, October 28 - November 02, 2012. Available at: https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=NRMRL&dirEntryId=305256. Accessed September 08, 2019.

a price spike scenario that shows the impact on portfolios of an event or multiple events such as the Enbridge event in 2017 and 2018.

Recommendation 28: In its reply comments**,** PGE should provide further analysis within the 2019 IRP docket on its GHG emissions forecast, EIM, natural gas lifecycle emissions, and Market Price Volatility.

5.C. Conclusion
Staff recommends PGE do the following related to its portfolio modeling assumptions:

26. In future IRP's, use a range of potential carbon policy start years if a carbon policy is not currently in place.
27. In future IRP's, include a high, low, and reference regional demand future in its wholesale market price forecast.
28. Provide further analysis within the 2019 IRP docket on its GHG emissions forecast, EIM, natural gas lifecycle emissions, and Market Price Volatility.

6. Distributed Flexibility Action Items

Staff continues to be encouraged by PGE's consideration of demand response and customer sited storage in its long-term planning. As noted in the IRP, these actions are critical components of long-term planning and Staff believes they could play an important role in assessing a decarbonization strategy. In this section, Staff notes areas where additional clarity is required to understand how PGE arrived at its distributed flexibility action items.

6.A. Demand Response
SB 1547, passed in the 2016 legislative session, is clear about a utility's responsibility to plan for and pursue the acquisition of cost-effective demand response resources as directed by the Public Utility Commission.

> For the purpose of ensuring prudent investments by an electric company in energy efficiency and demand response before the electric company acquires new generating resources, and in order to produce cost-effective energy savings, reduce customer demand for energy, reduce overall electrical system costs, increase the public health and safety and improve environmental benefits, each electric company serving customers in this state shall:
>
> […](b) As directed by the Public Utility Commission by rule or order, plan for and pursue the acquisition of cost-effective demand response resources.

Staff applauds PGE's inclusion of demand response and distributed flexibility in its long term planning. Staff is supportive of PGE's Action Item 1B to "Seek to acquire all cost-effective and reasonable distributed flexibility, which is currently forecasted to include, on a cumulative basis:

- 141 MW of winter demand response (Low: 73 MW, High: 297 MW).
- 211 MW of summer demand response (Low: 108 MW, High: 383 MW).
- 137 MW of dispatchable standby generation.
- 4.0 MW of utility-controlled customer storage (Low: 2.2 MW, High: 11.2 MW)."

Staff is concerned that PGE has not been able to model all types of demand response in its IRP portfolio analysis. PGE reports that RECAP is not capable of modeling some types demand response. Staff will continue to evaluate whether the IRP modeling of Demand Response (DR) is adequate.

In opening comments of the 2016 IRP, Staff noted that summer demand response direct load control (DLC) programs show a potential of over 261 – 278 MW of cost-effective summer DR by 2021.[118] Since the 2016 IRP, PGE has implemented a residential peak time rebate demand response test bed, and acquired 21 MW of winter DR and 32 MW of summer DR. Staff congratulates PGE on its successful test bed launch and hopes to see new demand response programs from PGE in the near future. Staff is particularly interested in a Dynamic Peak Pricing/Critical Peak Pricing rate schedule that reflects the value created when customers shift energy use away from the most expensive peak times toward off-peak times, and returns this value to customers who shift their energy use.[119]

6.B Dispatchable Customer Battery Storage

Dispatchable, customer-owned storage seems to be a promising flexibility option because it has the potential to provide PGE with reliable, flexible capacity without interrupting customer energy use or requiring customer action. It may have potential to improve the economics of customer-sited solar + storage installations, helping to increase the amount of renewable energy on PGE's system. Navigant's demand response study for PGE assumed the existence of a mechanism for the utility to return the value of dispatchable customer storage to customers. That dispatchable customer battery storage was assumed to be available as early as 2020. [120] Staff requests more information on PGE's plans to facilitate the types of demand response and distributed flexibility forecasted in the Navigant Distributed Resource and Flexible Load Study. The Navigant Study shows substantial increases in Residential Direct Load Control, Residential Pricing, and Electric Vehicle (EV) Direct Load Control by 2023.121 The study also assumes a mechanism for compensating customers for the value of their dispatchable storage. The resulting distributed flexibility forecasts were incorporated into PGE's portfolio analysis. PGE should commit to cost-effectively allowing and facilitating growth of each of these programs in the near-term.

Recommendation 29: Staff requests that PGE provide the following in its reply comments and future IRP analysis:

1. For the next IRP, PGE should consider ways to include all types of demand response in its portfolio analysis.
2. PGE should submit a written summary of its plans to allow and facilitate all cost-effective distributed flexibility, including an explanation of how the Company will allow and facilitate the growth of dispatchable storage, residential direct load control, residential pricing, and EV direct load control in the action plan timeframe.
3. PGE should work with Staff to consider the value of an opt-in Dynamic Peak Pricing/Critical Peak Pricing rate that compensates customers for the value of shifting load away from times when providing energy is most expensive.

[118] *See* Docket No. LC 56, Initial Staff Comments, p. 10.
[119] For example, DTE Energy has a revenue-neutral Dynamic Peak Pricing program designed to incentivize residential customers to use less energy at peak times, with one day advanced notice for critical peak events. The tariff includes off-peak, mid-peak, on-peak, and critical-peak rates. Details are available at: https://newlook.dteenergy.com/wps/wcm/connect/dte-web/home/service-request/residential/pricing/rate-options
[120] 2019 PGE IRP, p. 131.
[121] 2019 PGE IRP, External Study C: Distributed Energy Resource Study, p. A-5.

4. Within the action plan timeframe, PGE should work with Staff to consider a pilot mechanism for utilizing and returning the value of customer-owned dispatchable battery storage to customers.

7. Summary

PGE's 2019 IRP presents a complex and innovative approach to long-term planning. A few critical concerns with the Company's IRP analysis makes it difficult for Staff to determine whether the Action Plan is the appropriate path forward at this time. In its Opening Comments, Staff has requested more information and analysis that it believes will allow it to adequately weigh the costs and risks and determine whether a to recommend that the near-term actions are the right choice for customers.

In summary, Staff will continue to work with PGE to evaluate its substantive questions related to the 2019 IRP:

- Action plan strategies
- Portfolio scoring and selection
- Energy and capacity needs
- Colstrip retirement and the future of other existing resources
- Decarbonization
- Load forecast
- GEAR, Direct Access, and QF forecasts
- Modeling of wind resources and associated PTCs
- Market price assumptions
- Consideration of transmission in the IRP and RFP process
- Distributed flexibility action items

<u>7.A. Listing of Actions and Questions for PGE from Staff's Comments</u>

1. Explain how its Action Plan conforms to the IRP Guidelines, including Guideline 4 and competitive bidding rules.
2. Discuss the potential to run a second RFP for non-emitting capacity, while continuing to pursue bilateral contracts in its reply comments.
3. Provide additional portfolio analysis:
    a. Conduct an additional portfolio analysis without the use of its non-traditional screens so that the impacts of screening for non-traditional impacts before traditional costs and risks can be better understood.
    b. PGE should also review its IRP for compliance with IRP Guideline 8 and provide a summary of its findings.
4. As PGE adjusts its IRP analysis in accordance with Staff's comments, including the removal on non-traditional screens, PGE should provide additional information:
    a. Provide a quantitative comparison of its preferred portfolio to other well-performing portfolios in terms of NPVRR cost and risk.
    b. Explain why the Company believes its preferred portfolio has the best balance of cost and risk for customers.
5. Hold a workshop on the intergenerational equity analysis.
6. Provide an updated portfolio analysis and Action Plan based on an estimate of the comparative likelihood of each potential future and combination of futures.
7. Provide the following analysis related to its RPS compliance strategy.
    a. Model 20% unbundled RECs in RPS compliance in all portfolios.

   b. Model the preferred portfolio and several top performing and optimized portfolios in ROSE-E while allowing the model to choose a reasonable number of banked RECs.
   c. In future IRPs, PGE must consider the use of 20% unbundled RECs and a reasonable amount of banked RECs in years when they are available and less expensive than 100 percent physical compliance.
8. Provide additional analysis and information related to the developments within the GEAR program in reply comments:
   a. Update the portfolio analysis and, as necessary, the Action Plan to reflect the impact of the recent successful launch and subscription of the GEAR. Alternatively, PGE could reduce its renewable energy resource acquisition in its Action Plan proportionate amount to the GEAR subscription.
   b. Report on the transmission arrangements for its first phase of GEAR resources and the impacts of these resources on the availability of transmission for resources modeled in the IRP.
9. Provide additional analysis and updated information related to the closure of Colstrip in reply comments:
   a. Perform a rate impact analysis of advancing the depreciation dates of these units to 2027. PGE should report on the potential rate impacts of accelerated depreciation at Colstrip in the 2019 IRP docket.
   b. Provide information in its reply comments explaining the drivers behind the increase in the variability risk metric in the Colstrip sensitivity.
   c. Report any steps it has taken or could take to work toward negotiating an early exit date from Colstrip. And, if these actions are affected by early closure of Units 1 and 2.
   d. Provide an updated Colstrip Analysis in the 2019 IRP docket demonstrating the effects of any updated information on the variable costs of generation at Colstrip.
10. Provide additional analysis and information related to PGE's approach to climate change:
    a. As PGE adjusts its IRP analysis in accordance with Staff's comments to identify a least cost, least risk portfolio that considers all resources equally, PGE can present an alternative portfolio that is targeted at least cost, least risk decarbonization for the Commission to compare costs and risks.
    b. Staff proposes that PGE develop and submit a climate adaptation plan as part of the 2019 IRP Update.
11. Work with Staff and ETO to see if there are opportunities to apply more appropriate input selection for energy efficiency, and potentially for other demand-side and load forecast inputs to scenarios.
12. Explain in its reply comments how the Company accounted for consumer vehicle preferences and availability of heavier electric vehicles in its load forecast.
13. In future IRPs, PGE should be careful not to imply that the Market Energy Position analysis represents an energy shortage or a need to acquire new resources.
14. In its replay comments, discuss how the resource needs assessment and Action Plan should be altered, if at all, in response to the potential outcomes of current Commission activities related to Direct Access.
15. Provide additional analysis and information related to the impact of LTDA on its resource needs:
    g. Provide further justification for its assumption that it could not use historical direct access participation data, knowledge of changes in the Direct Access landscape, or another method to update its load forecast

   h. Alternatively, PGE could update the portfolio analysis and, as necessary, the Action Plan to reflect the impact of including a forecast of additional LTDA participation in its load forecast.

16. Provide additional analysis and information related to the expectation that there will be no new QFs beyond those currently in the contracting process:
   i. Update the load-resource balance and, as necessary, the portfolio analysis and Action Plan to reflect a reasonable QF forecast.
   j. Alternatively, PGE could reduce its 150 MWa energy resource acquisition in its Action Plan by an amount of QF capacity forecast to come online before 2025.
17. Provide additional analysis and updated information related to the future of Boardman:
   k. Hold a stakeholder workshop within the IRP docket to discuss the potential for sustainably harvested biomass capacity at the Boardman plant.
   l. Report in the replay comments whether SCR technology would be required on a plant that only ran a few months out of the year to meet peak capacity.
18. As part of distribution system planning efforts, consider the value of CVR and study its value on additional substations. If additional CVR is implemented, it should be included in IRP portfolio modeling.
19. Provide the following additional information about its PTC risks and assumptions:
   a. Clarify how the Company captured the risks associated with PTC expiration in its analysis.
   b. Explain the modeling of the unapplied tax credits (i.e., the rate of return penalty) and provide a forecasts of the anticipated PTCs and the year of their application to PGE's federal tax filings.
   c. Explain what market analysis or other research the Company conducted to understand the availability of PTC eligible resources.
   d. Analyze the OASIS interconnection and transmission queues for PGE, BPA and PAC to develop an understanding of the pool of possible resources able to compete and come online by 2023
   e. Provide additional analysis of the difference in performance between renewable size and timing portfolios that add 50 – 100 MWa in 2024 versus the renewable size and timing portfolios that add renewables in 2023, and how that relates the Company's strategy to release a renewable RFP that will capture 2023 wind resources.
20. Provide a sensitivity analysis of the Mixed Full Clean portfolio assuming proportionate changes to the capacity factor of each resource as the assumptions behind the capacity factor sensitivity analysis in Figure 6-15 above.
21. Explain in reply comments how it is considering the coincidence of market prices and the times when the various wind resources modeled are likely to generate.
22. Provide additional clarity on its technology cost trajectories in its reply comments:
   h. Staff requests further explanation of PGE's methodology for deriving the low and high fixed cost scenarios wind.
   i. Staff requests further explanation of the differences in learning rate methodologies between solar and wind resources.
23. Provide a thorough justification of why its decision to exclude thermal resources from its long term planning is consistent with the best interest of ratepayers, or else update its analysis to consider all resources available to meet its long-term needs.
24. Provide further justification for costs and constraints on the capacity fill resource in its reply comments.
25. Provide the following additional information about its transmission assumptions and the Interim Transmission Solution in its reply comments:
   j. Discussion of the appropriateness of requiring firm transmission products for an intermittent resource;

k. Discussion of tradeoffs of wind resource quality and available transfer capability (ATC). This discussion could explain tradeoffs of lower quality wind (e.g., lower peak contribution and lower contribution to capacity) with existing ATC vs. higher quality wind with incremental transmission capacity build.
l. Discussion of net contribution made by blending diverse regime wind profiles.
m. Discussion of the extent to which partnerships or partial share of larger wind projects can lower cost and risk for PGE ratepayers.
n. Discussion of the specific transmission paths and resources that would be used to access each wind resource sub-region considered. This discussion would explain how PGE has or would acquire each needed transmission resource or right.

26. In future IRP's, use a range of potential carbon policy start years if a carbon policy is not currently in place.
27. In future IRP's, include a high, low, and reference regional demand future in its wholesale market price forecast.
28. Provide further analysis within the 2019 IRP docket on its GHG emissions forecast, EIM, natural gas lifecycle emissions, and Market Price Volatility.
29. Staff requests that PGE provide the following in its reply comments and future IRP analysis:
    a. For the next IRP, PGE should consider ways to include all types of demand response in its portfolio analysis.
    b. PGE should submit a written summary of its plans to allow and facilitate all cost-effective distributed flexibility, including an explanation of how the Company will allow and facilitate the growth of dispatchable storage, residential direct load control, residential pricing, and EV direct load control in the action plan timeframe.
    c. PGE should work with Staff to consider the value of an opt-in Dynamic Peak Pricing/Critical Peak Pricing rate that compensates customers for the value of shifting load away from times when providing energy is most expensive.
    d. Within the action plan timeframe, PGE should work with Staff to consider a pilot mechanism for utilizing and returning the value of customer-owned dispatchable battery storage to customers.

This concludes Staff's Opening comments.

Dated at Salem, Oregon, this 11th day of October, 2019.

Caroline Moore
Senior Utility Analyst
Energy Resources & Planning Division

CASE: UE 359
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

June 25, 2019

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a senior economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I provide a summary of Portland General Electric Company (PGE)'s 2020 Automatic Update Tariff (AUT) filing and Staff's proposed adjustments. I also discuss Staff's analysis of PGE's load forecast, Production Tax Credit (PTC) forecast and wind capacity factors, PGE's Wheatridge Renewable Energy Facility, and Colstrip modeling.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/102, which includes the Company's response to Staff DR Nos. 39 and 42.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF STAFF'S REVIEW OF PGE'S 2020 NVPC FILING

Q. Please explain PGE's 2018 NVPC filing.

A. Commission Order No. 08-505 authorized PGE's AUT, which allows for an annual adjustment to PGE's rates that accounts for the forecasted changes in the coming test year's NVPC. When filed as a stand-alone case, the AUT is filed by April 1 of the preceding year and includes updates to a pre-specified set of data parameters. When filed as concurrently with a general rate case the Company is also able to propose changes to the methodology.

Q. Apart from the standard parameter updates, is the Company proposing any changes from the 2019 NVPC filing?

A. Yes, the Company has proposed the following changes:

1. Adjust the manner in which it forecasts EIM benefits;[1]
2. Apply a transmission deration on volumes at COB;[2] and
3. Adjust dispatch at Boardman in light of closure at the end of the year.[3]

Q. Please summarize PGE's 2020 AUT filing.

A. The Company's initial filing requests a 2020 Net Variable Power Cost (NVPC) of $422 million, which represents an increase of approximately $60.5 million compared to the final 2019 NVPC.[4] This equates to an increase of $2.93/MWh or 15 percent from $19.60/MWh to $22.53/MWh.[5] Figure 1 below shows the increase percentage by category.

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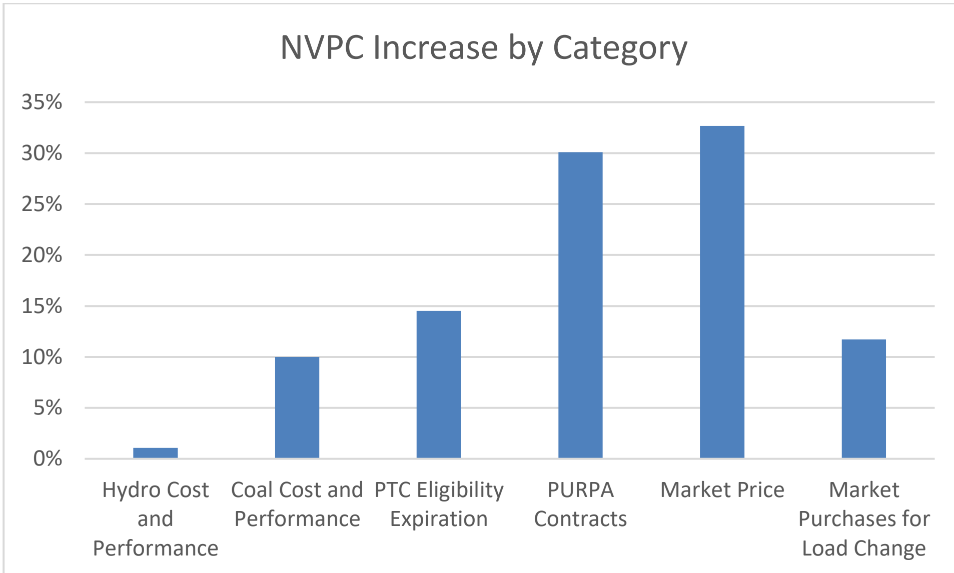
[1] PGE/100, Niman et al./8.
[2] *Ibid.* at 14.
[3] *Ibid.* at 17.
[4] *Ibid*. at 1.
[5] *Ibid.* at 32.

Figure 1



Q. What topics will Staff testimony address?

A. Staff discusses the following issues in our opening round of testimony:

(Staff/100 Gibbens)
1. Load Forecast
2. PTC Forecast and Wind Capacity Factors
3. Wheatridge
4. Colstrip

(Staff/200 Soldavini)
5. California-Oregon Border Margins
6. Boardman Operations 2020

(Staff/300 Enright)
7. Western Energy Imbalance Market
8. Wholesale Transactions

(Staff/400 Zarate)
9. Qualifying Facilities Cost
10. Standard Inputs

ISSUE 1. LOAD FORECAST

Q. What is PGE's load forecast for 2020 retail load?

A. PGE's initial 2020 retail load forecast is 19,657 GWh.[6] This is roughly a one percent increase from forecasted 2019 deliveries.

Q. What are the primary drivers of the increase in load in the 2020 AUT?

A. The forecasted increase in total load is due to increases in the Residential and Industrial customer class loads."[7]

Q. How did Staff analyze this issue?

A. Staff reviewed the Company's workpapers related to load forecast to ensure proper calculation of the impact. Staff focused on the load forecasts that exhibited the largest changes. Staff traditionally does not produce a full model replication of the Company's load forecast in every power cost filing, but reviews the Company's forecast to determine whether it is reasonable on a short-term basis (for the AUT test year). Staff notes that the Company has opposite incentives in load forecast biases between a general rate case (GRC) and the AUT. In a GRC, there is an incentive to under forecast load to put upward pressure on the amount of revenue the Company must collect to cover its Revenue Requirement. In the AUT, there is an incentive to over forecast load to put upward pressure on the amount of power that must be acquired to serve load. As such, one of Staff's main concerns is in verifying that the same methodology is used in power cost filings as in a GRC where a more extensive

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[6] PGE/100, Niman et al./29,
[7] *Ibid*.

review of the Company's forecast is performed. Additionally, Staff notes that the Company is preparing to file its 2020 IRP, and as part of both the AUT and the IRP Staff will continue to monitor and evaluate the load forecast.

Q. Does Staff propose an adjustment to Load Forecasting?

A. No, at this time Staff has no proposed adjustments for this issue.

ISSUE 2. PTC FORECAST AND WIND CAPACITY FACTORS

Q. Please provide a background of this issue.

A. In UE 319 Staff proposed a change to the wind capacity factor calculation methodology.[8] Staff's goal was to share generation risk between shareholders and rate payers. Instead of using only actual generation to calculate the capacity factors, Staff proposed to use a split of the "P50 forecasts"[9] created at the time of project development and actual generation from the projects to determine the capacity factor for PGE's owned resources (50/50 methodology). This methodology:

- Splits wind generation risk between customers and shareholders;
- Incents utilities to accurately forecast wind capacity factor of new projects; and
- Makes the RFP process more competitive and improves outcomes for customers.

The issue was ultimately settled as part of a larger settlement of all issues for PGE's 2018 AUT, which included a dollar adjustment to settle a number of issues.[10] This resulted in no clear resolution for the wind capacity factor issue however. In UE 335, Staff again proposed a similar change for PGE's 2019 AUT. Like UE 319 the previous year, a dollar adjustment was made in

[8] UE 319 Staff/200, Kaufman/11.
[9] When probabilistic Monte Carlo type evaluations are adopted, this is a statistical confidence level for an estimate. P50 is defined as 50 percent of estimates exceed the P50 estimate (and by definition, 50 percent of estimates are less than the P50 estimate).
[10] Order No. 17-384.

conjunction with several outstanding issues, but no change to methodology was made.[11]

Q. How does PacifiCorp forecast wind capacity factors in the TAM?

A. UE 339, PacifiCorp's 2019 TAM, had a similar issue, where parties worked to develop a methodology that would properly align customer and shareholder incentives. In the stipulation associated with that docket, the Company agreed to use the 50/50 methodology on a one-year basis.[12] In this year's filing, PacifiCorp has proposed the continued use of the 50/50 methodology moving forward.[13] Staff noted in its opening testimony that, "the 50/50 approach is a proper way to share performance risk between ratepayers and shareholders, generally, because it provides a good balance between aligning Company and ratepayer incentives in a RFP and forecast accuracy."[14]

Q. What is Staff's proposal for wind capacity factor methodology in this filing?

A. Staff continues to believe that the 50/50 methodology is a proper way to share generation risk. When only actuals are used in power cost filings, utility owned projects receive an unfair advantage in an RFP. Third-party projects must account for generation risk in their bids, as they assume the risk of unrealized generation and PTCs. Under the current construct, PGE owned projects do not need to account for generation risk as the ratepayer assumes all of it in

[11] Order No. 18-405.
[12] Order No. 18-421.
[13] UE 356 PAC/100, Wilding/35.
[14] UE 356 Staff/100, Gibbens/14. Staff ultimately recommended a different treatment for EV 2020 projects.

subsequent AUTs. As the State continues to push to raise carbon reduction goals, this methodology becomes more and more important. Staff also notes that this approach would standardize the methodology between the State's two biggest regulated electric utilities; providing similar customer protections for both PGE and PacifiCorp customers.

Staff realizes that this issue has been a point of contention for the past three power cost filings, and so has come up with an alternative recommendation as well. PTC benefits generally equate to roughly 66 percent of the overall project benefit for the first ten years of a wind project. As such, ensuring the proper incentives between Company and ratepayer is more important during this time than in subsequent years. Staff's secondary proposal is to utilize the same methodology as PGE currently uses, but to use ten years of actuals as opposed to five. In the first year of a project, only the P50 forecast would be used. In the second, year one actuals would account for 10 percent of the calculation while the P50 would account for 90 percent. In the third year it would become 80/20 and so on. Although this is not Staff's primary recommendation, it does achieve a balance between sharing generation risk and forecast accuracy, particularly in the most important years of a project's life cycle. Staff notes that this would result in little change to PGE's current plants, but would properly incentivize PGE in future RFPs.

Q. How is generation risk split between customers and shareholders?

A. When the actual capacity factor of wind facilities is lower than forecasted, there are two financial impacts: lost energy value and lost production tax credit (PTC) value. Wind generation has little to no marginal cost. When wind production is lower than expended, PGE has to replace that energy with higher cost sources. Staff previously estimated that the dollar value of lost energy associated with over forecasting wind capacity factors was about **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]** In addition to the lost energy, PGE does not receive the expected PTCs. Staff estimates that the value of the lost PTCs is about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Under Staff's proposal, PGE shareholders will bear a portion of the risk associated with the lost energy value, and customers will bear the risk associated with the lost PTC value. This approach appropriately shares the risk associated with ownership of wind resources between the utility shareholders and customers.

Q. How does Staff's proposal incentivize utilities to accurately forecast wind generation?

A. Under PGE's method, the Company updates the wind capacity factor every year. In addition, actual wind generation is incorporated in the Power Cost Variance Mechanism (PCVM). The PCVM includes mechanisms that prevent 100 percent of costs passing through to customers. Thus the only exposure the Company has to wind generation forecast risk is through the difference between the year-ahead wind forecast and the actual wind generation. Staff's approach makes the Company accountable for its resource decision. Because of this the Company will be more likely to evaluate and vet the wind forecasts.

Staff's first alternative does benefit the Company in the case of forecasts that are too low. However under both alternatives, customers are guarded against the risk of a low forecast through the competitive bidding process. If the Company under-forecasts wind generation, competing bids will be more likely to be selected.

Q. How does allowing utility shareholders to share in generation risk make the RFP process more competitive?

A. PGE's recent generation RFPs have primarily resulted in PGE ownership of new resources. If shareholders are exposed to some of the generation risk associated with ownership, the utilities will incorporate generation risk into their bids. This is a risk that other bidders already bear. Staff's proposal will bring the Company ownership in line with non-company ownership bids. As a result, the competitive bidding process will be more effective.

A more competitive bidding process will benefit customers. PGE's recent self-owned resource acquisitions have faced substantial problems, either with lower than expected benefits or higher than expected costs.

Q. Why is it fair for PGE shareholders to share in the risk of wind generation?

A. PGE has invested $1.7 billion in wind facilities. At PGE's current capital structure and cost of equity that represents $82 million dollars per year in profit for PGE shareholders. Staff's proposal reduces power costs by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff's alternative approach would have limited impact on current rates, but would improve the structure of wind forecasts for future Company-owned wind plants.

ISSUE 3. WHEATRIDGE RENEWABLE ENERGY FACILITY

Q. Please provide a background on this issue.

A. Following the conclusion of the Company's 2016 IRP and 2018 Renewable RFP, construction is underway to build a 300 MW wind facility called Wheatridge Renewable Energy Facility. PGE will own 100 MW of the total capacity and purchase the power of the other 200 MW through a long-term PPA. Construction of the plant is expected to conclude in December of 2020 in time to qualify for 100 percent of the PTCs. The project will also include 50 MW of solar and 30 MW of battery storage expected to be online in 2021. PGE did not include any benefits associated with the generation from the project in its 2020 AUT.

Q. Does Staff have any concerns regarding the Company's decision to exclude Wheatridge from the 2020 AUT?

A. Yes. In addition to legal concerns, which Staff will address in briefing, Staff has another concern about the Company's decision to not include the NPC and PTC benefits in the 2020 AUT. The concerns mirror concerns Staff had in the 2019 TAM and 2020 TAM when PacifiCorp proposed to exclude the NPC and PTC benefits from its EV 2020 projects. Staff is concerned that the Company's proposed ratemaking treatment is one-sided and inconsistent with Commission policy and precedent regarding the ratemaking treatment for variable costs and benefits for RPS-compliant resources, including PTCs.

Commission policy and precedent regarding ratemaking treatment for costs and benefits of RPS compliant resources.

In 2007, SB 838 was passed, creating Oregon Renewable Portfolio Standard (RPS). SB 838, Section 13, provides for the recovery of "all prudently incurred costs associated with compliance with a renewable portfolio are recoverable in the rates of an electric utility."[15] SB 838 further directed the Commission to establish an automatic adjustment clause or another method for timely recovery of RPS compliance costs.[16] The Commission subsequently opened docket UM 1330, which investigated the adoption of an automatic adjustment clause or other method for timely recovery of costs as required by SB 838. The Commission adopted the non-contested stipulation filed by PGE, PacifiCorp, Oregon Staff, CUB and ICNU.[17] The stipulation authorized PGE and PacifiCorp to implement RAC tariffs by which they could recover the costs associated with RPS compliant resources. The stipulation approved by the Commission states that the revenue requirement recovered pursuant to the RAC includes:

- *The return of and on capital costs of the renewable energy source and associated transmission;*
- *Forecasted operation and maintenance costs;*
- *Forecasted property taxes;*
- *Forecasted energy tax credits; and*

[15] Now codified at ORS 469A.120(1).
[16] ORS 469A.120(2).
[17] Order No. 07-572 at 10.

- *Other forecasted costs and cost offsets authorized by SB 838* ***and not captured in the Utility's annual power cost update****.*[18]

Therefore, the Commission adopted a stipulation that required costs and benefits of RPS compliant resources not otherwise recovered in the utility's annual power cost proceedings to be recovered in the RAC. In short, the RAC is intended to cover items not otherwise included in the AUT.

Subsequent to Order No. 07-572, the Commission opened a second investigation—Docket UM 1662—which considered the recovery of variable costs associated with RPS compliance (i.e., RPS compliance costs subject to forecast in the TAM or AUT, and the PCVM).[19] In that case, PGE and PacifiCorp argued that variations in PTCs and other variable costs and benefits should be recovered on a dollar-for-dollar basis, rather than on a forecast basis and subject to the PCVM.[20] Staff, CUB, and ICNU argued that ORS 469A.120(1) did not require dollar-for-dollar recovery of all RPS related costs and benefits.[21] The Commission adopted Staff's, CUB's, and ICNU's position, concluding that certain RPS costs would not be subject to dollar-for-dollar recovery and would need to be recovered through general ratemaking.[22] This includes variable costs and benefits of RPS compliance.

[18] Order No. 07-572 at 3 (emphasis added).
[19] Order No. 15-408.
[20] Order No. 15-408 at 2-3.
[21] *Ibid*.
[22] Order No. 15-408 at 6-7.

In 2016, the Oregon Legislature passed SB 1547, directing each public utility to forecast, on an annual basis, projected state and federal production tax credits received by the public utility due to variable renewable electricity production, and directing the Commission to allow those forecasts to be included in any variable power cost forecasting process established by the Commission.[23]

In response to this directive, in its 2017 AUT, PGE proposed to include the full effect of PTC generation in its NVPC forecast. This removed the credit from base rates and made it subject to the PCVM true up. The Commission adopted this ratemaking treatment.[24]

The Company's failure to include NPC and PTC benefits for Wheatridge is inconsistent with the ratemaking treatment for PTCs agreed to by the Company, and adopted by the Commission, in the Company's 2017 AUT. The Company's proposed approach is also inconsistent with the Commission's direction in Order Nos. 07-572, 15-408 and 16-419. Furthermore, Staff will reserve this issue for briefing, but notes that it questions whether the Company's proposal is consistent with ORS 757.264 and ORS 757.269.

Q. What is Staff's recommendation for the treatment of Wheatridge?

A. Staff recommends that Wheatridge variable costs and benefits (for both the PGE-owned and PPA portions) be generally reflected in AUT proceedings and therefore included in the forecast for the 2020 AUT. This treatment is

[23] This provision is codified as ORS 757.264.
[24] Order No.16-419.

consistent with PacifiCorp's treatment of EV 2020 benefits for the 2019 TAM and past Commission policy and precedent. Staff believes the AUT is capable of handling the NPC and PTC impacts of the Wheatridge project. PGE is able to encompass all non-Schedule 122 costs and all of the direct and indirect benefits, on a forecast basis, consistent with the ratemaking treatment for all other wind projects included in Oregon rates.

ISSUE 4. COLSTRIP

Q. Please provide a background for this issue.

A. The Company's current contract with Westmoreland Coal Company, the owner of the Rosebud mine that supplies coal for the Colstrip plant, expires at the end of 2019.[25] A new coal supply agreement is still in the negotiation phase and the prices for coal at Colstrip are subject to change in future AUT updates, based upon these ongoing negotiations.[26] Until a new contract is in place, the Company is maintaining the current contract price in the 2020 AUT.

Q. Does Staff have an adjustment or recommendation regarding third-party coal supply costs?

A. No, Staff has no adjustment at this time, and is actively monitoring the Company's ongoing negotiations and awaiting updates on the issue before making a recommendation. The negotiations are highly confidential, but Staff and the Company have been working closely together to so that Staff stays apprised of any new developments. Staff notes that it retains the ability to review the final contract for prudence, whether in this proceeding or in next year's AUT proceeding if the contract is finalized after the close of the record in this case.

Q. Does this conclude your testimony?

A. Yes.

[25] PGE/100, Niman et al./34.
[26] Staff/102, Gibbens/1 (PGE's response to Staff DR No. 39).

CUB Exhibit 504 is Confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 21-206.

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CUB Exhibit 506 is Confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 21-206.

CUB Exhibit 507 is Confidential and has been served upon the Commission and each party designated to receive confidential information pursuant to Order 21-206.