BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 66

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2016 Integrated Resource Plan	Staff Final Comments

Table of Contents

1. PREFACE

The following are Staff's Final Comments concerning Portland General Electric Company's (PGE or Company) 2016 Integrated Resource Plan (IRP or the Plan). Staff remains appreciative of the work done by PGE and the other stakeholders involved in this IRP. Stakeholder input and PGE's Reply Comments have all been substantive and helpful in clarifying several outstanding issues.

Although some of Staff's specific questions have been addressed in PGE's Reply Comments, Staff remains unconvinced of the need to pursue an early acquisition of 175 Average Megawatt (MWa or aMW) of renewable resource and an immediate RFP for up to 550 MW of dispatchable capacity resources within the two to four year Action Plan horizon. While it is clear that PGE put significant resources into this IRP, we cannot conclude anything other than that key parts of the plan do not fully consider or adequately plan for the significant changes that are expected in the electricity industry over the next five to ten years. Those changes, many of which the parties are currently struggling through in a myriad of open dockets before the Commission, deserve to be identified and addressed sooner rather than later if PGE's customers are to incur costs associated with the addition of substantial amounts of new resources.

In these Comments, Staff lays out the traditional analysis of the IRP and the Action Plan. In preface to describing this analysis, Staff believes it is important to provide parties and the Commission with the context behind our analysis and resulting position.

The IRP is more than a series of mechanistic requirements; it is an exploration of the best way a utility can serve its customers in the future. In Staff's view, the IRP process is an opportunity to provide time for a full exploration of risks and uncertainties in long term planning prior to considering major utility investments. Swiftly emerging technologies, changing customer expectations, regulatory mandates, and increasing concern about carbon emissions all point to an evolution of the traditional utility investment pattern. While PGE considered new technologies, Staff believes that a broader exploration of these more systemic risks and uncertainties was not given sufficient consideration in the IRP in light of the investments PGE proposes in its Action Plan.

Staff believes that the timing of the commitment of hundreds of millions of dollars to investment in new Renewable Portfolio Standard (RPS) resources should be informed by potentially profound changes to the utility in the next several years. The inclusion of 515 MW of wind generation in the Action Plan asks today's customers to invest substantial amounts of money a dozen years before there is either a physical or a regulatory need for that resource. The justification is based on a comparative portfolio analysis built on speculative future costs and market assumptions showing customer benefits that amount to less than one percent of the associated Net Present Value of Revenue Requirement (NPVRR) over the 34 year time horizon. Given anticipated changes in technology and market dynamics in the intervening period, the justification of this early investment could very easily disappear, with negative results for ratepayers.

Likewise, Staff recognizes that PGE's need for some amount of capacity is real, though the amount remains uncertain, but the lack of exploration by PGE of short-term resource options prior to concluding that a long-term capacity RFP belongs in the Action Plan leads Staff to conclude that this IRP does not adequately capture the broad future uncertainty in planning.

With significant changes coming to utilities and their customers in the near future, it is important that investments made now are expected to be valuable across a variety of futures and support the inexorable changes that are coming. If utilities are going to commit to, and the Commission to approve, the investment of a significant amount of ratepayers' money in the next few years, those investments must be made in the context of more distributed generation, customers' demands for more options and services, and a smarter distribution system that collects and uses data more efficiently and creatively. Staff questions whether an Action Plan that calls for nearly $1.5 billion in very near-term investments in large, long-term duration resources will lead to a utility system than can adapt to changing markets.

PGE's proposed investment in wind generation raises significant concerns about intergenerational equity because it would require that current ratepayers pay for investments that are not expected to meet a specific need for over a decade. ***More importantly, it commits us to a large capital investment path which effectively deprives both the current and the next generation of ratepayers the benefit of our best thinking and strategic investments over the next several years to make the electric utility in 2030 the most responsive and efficient utility it can be.***

Recent policy directives demand specific new programs, many of which are supported by the utilities and their stakeholders, that aim to develop new technologies (e.g., storage), create new options for customers (e.g., community solar), and decarbonize the utility portfolio (increases in the RPS and utility investment in electric vehicles). Those and other system changes and their implications deserve to be addressed as part of PGE's investment plan. Yet when the opportunity to fully contemplate and plan for a future with these advances simply reverts to build more now, ratepayers may not be well served.

During this process, Staff considered whether the regulatory principles of least cost/least-risk planning or of just-in-time development were outmoded concepts in a changing electricity environment. We concluded that it was precisely because the markets, technologies and customers were on the cusp of such significant change that these principles, as set forth in relevant Commission Orders, are just as, if not more, important than ever.

Concluding that the Commission's current core risk planning tools are still relevant does not mean that all our planning and cost recovery policies are well-suited for the changing utility landscape. Staff recommends that the Commission, the utilities, and the stakeholders invest time and resources to design a regulatory approach that defines better the investment expectations in the evolving utility and that creates confidence that the utility will recover those prudently incurred costs. This will enable all of the parties to work together to design and build the utility of the future that best meets the changing needs of the utilities and their customers.

2. PGE ACTION PLAN OVERVIEW

Per PGE's reply comments, the Company plans to continue to pursue the Action Plan items identified in its IRP to implement its preferred portfolio.[1] The table below summarizes the original Action Plan and any additions or revisions found in PGE's reply comments:

Area	Nov. 2016 *Original Action Plan*	April 2017 *Revisions to Action Plan*
Demand Actions	EE: 135 MWa	*Same*
	DR: 77 MW (Winter) and 69 MW (Summer)	*Same*
	CVR: 1 MWa	*Same*
	CVR: Expand AMI	*Same*
	CVR: R&D around analytics	*Same*
	CVR: Develop expansion plan	*Same*
Supply Side	New Renewables: 175 MWa ≈ 515 MW of new wind	****Revision**-** Added 52 MW of renewable capacity from Qualified Facility (QF) contracts
	New Capacity: ~850 MW ≈ 375 - 550 MW of dispatchable capacity ≈ 400 MW of seasonal capacity	****Revision**** New Capacity: ~561 MW ≈ 240 - 415 MW of dispatchable capacity due to renewed hydro[2] ≈ 400 MW of Seasonal Capacity Potentially engaged in bilateral negotiations for some seasonal thermal capacity; unknown MW
	DSG: 16 MW	*Same*
	Hydro Contracts: ≈ 0 MW unless contracts renewed	****Revision**** ≈ 135 MW from renewed hydro contracts at Wells ≈ ?? MW additional, new hydro through bilateral negotiations
Integration	Submit Storage Proposal, per HB 2193, by 1/1/2018	*Same*
Enabling Studies	Market Capacity	*Same*
	Flexible Capacity & Curtailment	*Same*
	Customer Insights	*Same*
		****Revision**-** Added several new studies and explorations based on stakeholder comments for the next IRP

[1] *See* LC 66, PGE IRP Reply Comments, P. 11.
[2] *See* LC 66, PGE IRP Reply Comments, P. 52 and PGE's April 13, 2017, Letter Updating Figure 5, p. 2.

Area	**Nov. 2016** ***Original Action Plan***	**April 2017** ***Revisions to Action Plan***
Resource Acquisition	One or more than one RFPs for new resources	****Revision**** **-** Will still issue RFP but will notify OPUC of bilateral negotiation status prior to issuing[3]
Benchmark Resources	Carty Unit 2 – Not considering; but open to benchmark proposals	*Same*
	Carty Unit 3 – Not considering; but open to benchmark proposals	*Same*
	Renewables – Exploring benchmark opportunities in RFP.	****Revision**** **-** ~500 MW wind resource identified as benchmark facility[4]
	Storage – Exploring benchmark opportunities in RFP.	****Revision**** **-** No longer considering. Developing site for RFP later[5]

Regarding PGE's supply-side actions for new renewables and new capacity, PGE maintains throughout its IRP and Reply Comments that it is agnostic to the actual technology or solution.[6] For both renewable and capacity resources, PGE points to the RFP process as determining the best solution for ratepayers. For the renewable resource specifically, PGE focused on modeling and analyzing the acquisition of wind based on the compelling economics of Federal Production Tax Credits (PTCs). However, if a preferable solution emerges through the RFP process – including the acquisition of Renewable Energy Credits (RECs) – PGE states they are open to selecting it.

For the new capacity product(s), PGE will consider three gas fired technologies, storage technology and/or hydro facilities that may contribute to 240 to 415 MW of dispatchable capacity. For seasonal products, PGE is open a mix of new and/or existing generation technologies that can meet seasonal capacity and ramping requirements. For both the dispatchable and the seasonal capacity products, PGE maintains that, much like with its procurement of renewable resources, a robust RFP process represents the best method for identifying and selecting least cost, least-risk products for ratepayers.

[3] *See* LC 66, PGE IRP Reply Comments, P. 12.
[4] *See* PGE Reply Comments p.13 and 176.
[5] *Id.*
[6] *See*, for example, PGE IRP p. 226, or PGE Reply Comments p.7-8.

3. Staff Comments on Action Plan Items

This section is specifically focused on the Action Plan items that Staff intends to recommend that the Commission either not acknowledge or acknowledge with requirements. Each subsection contains the logic and evidence for Staff's positions. Our Final Comments may include commentary and recommendations on other Action Plan items not necessarily discussed in this document, but we will attempt to avoid such omissions wherever possible.

3. A. Early Renewable Action

Staff does not recommend acknowledgement of PGE's supply-side action:

> *…to issue one or more RFPs for approximately 175MWa of bundled RPS compliant renewable resources, and/or unbundled RECs, with a preference for maximizing available incentives…*

PGE asks the Commission to acknowledge this Action Plan item within a two to four year period based on what PGE argues are compelling economics and a regulatory need that is twelve to 34 years into the future. As Staff will show, such a request:

1. Relies on assumptions with future uncertainty that is too great to justify such an extensive near-term investment;
2. Unfairly shifts RPS compliance costs to current ratepayers; and
3. Sets a far-reaching RPS policy precedent.

PGE's early-action renewable resource is characterized as a resource to primarily meet a regulatory need, not a capacity need. As a resource it is not necessarily meant to contribute toward PGE's capacity or energy needs, although it has the additional benefit. A least-cost, least-risk analysis of this Early Renewables Action to meet capacity or energy needs is largely absent and certainly not the primary motivation for the Company's pursuit of the resource. PGE provided data and analysis that indicates a capacity deficit within the four-year Action Plan, for which a renewable resource could be justified. However, PGE's justifies the 175 MWa early-action renewable resource is based upon a "need" that arises essentially from regulatory requirements

In the 2016 IRP, PGE established 2025 as the last year it could comply with the RPS using existing resources and the REC bank; in 2026 it would have an insufficient amount of RECs.[7] In PGE's Reply Comments, PGE's RPS compliance need for physical resources moves out to 2029.[8] This is due to updated forecasts and the recent execution of QF contracts contributing 52 MW of capacity. We appreciate PGE updating its forecast with data from June 2016 through December 2016.[9]

Nevertheless, the fact that PGE's RPS insufficiency period shifted out *four years* underscores the tenuous nature of PGE's 2029 regulatory need and raises questions about other uncertainties found in the quantified costs and overall benefits portrayed in PGE's Early RPS Action analysis.

---

[7] *See* p. 293 of 2016 IRP.
[8] *See* p. 16 of reply comments.
[9] *See* PGE Reply Comments, p. 51.

Future uncertainty is too great to justify such an extensive near-term investment as the IRP's two- to four- year time frame has been the historic focus of Action Plan needs and activities

Over the past decade the Commission has acknowledged utility actions that meet a near-term need (i.e., within two- to four- year period of the Action Plan). Generally, the Commission has denied acknowledgement of actions that fell outside of that period.

Generally speaking these Commission decisions have rested upon some combination of the following IRP Guidelines:

- Guideline 4 n. states that required IRP elements include: "*An Action Plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing*."

- Guideline 1 c. requires a review of long-term uncertainties associated with shorter term actions: "*The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource*."

Taken together, IRP Guidelines 4 (n) and 1 (c) require that utilities include in their IRP Action Plans resource activities undertaken to meet system needs in the two to four year Action Plan period, with analysis of the impacts of those decisions over a long-term horizon. The Commission has consistently applied these Guidelines so that Action Plans, which address near-term identified needs, are informed by the IRP's analysis of long-term uncertainties. Most notably in the examples that follow, Staff has found that the Commission generally does not acknowledge near-term Action Items justified primarily by long-term needs.

In Order No. 08-232, the Commission acknowledged Pacific Power IRP Action Items related to the acquisition of thermal resources to meet short-term needs. The acknowledged need was described as follows: "The Company's load and resource balances under a twelve percent planning margin demonstrate the Company is capacity deficient system-wide beginning in 2010. The Company expects the deficit to grow to 2,446 MW in 2012."[10] The IRP in question in this case was filed in 2007; accordingly the acknowledged action supported a need that was anticipated three years after the filing of the IRP. This example represents how electric utilities and staff have traditionally applied these Guidelines to authorize system actions to meet near term needs.

In the past, PGE seems to have refrained from proposing supply side Action Items where there has been no near-term need established. In its 2013 IRP, PGE demonstrated that it had no need for additional resources for six years (until 2019). "In its evaluation, PGE found that its loads and resources are balanced through 2019. Accordingly, the company concludes that it requires no new major resource acquisitions in the current 2013-2017 Action Plan time horizon."[11] Implied in this decision not to pursue resources was the understanding that Action Plan items should address needs that will occur within or very near to the Action Plan time horizon of two- to four- years and that planning for a need six years out was not an appropriate Action Plan item.

[10] *See* Order No. 08-232 Pacific Power 2007 Integrated Resource Plan, LC 42, p. 30.
[11] *See* Order No. 14-415 PGE Integrated Resource Plan LC 56, p.3.

RPS regulatory needs have been no exception to the Commission's past history of denying acknowledgement of actions that fell outside of the two to four year action plan period. In part, these acquisitions were needed to meet RPS requirements that started in 2011. In Order No. 08-246, the Commission did not acknowledge PGE's IRP, but did find that the proposed renewable resource actions in the plan were reasonable.[12] These actions began to be needed under the RPS four years after the filing of the 2007 plan. PGE's regulatory need for physical resources in the 2016 IRP was originally projected at seven to eight years out. Again, it shifted to twelve years out after the recent addition of renewable QF contracts contributing 52 MW of peak capacity.

In addition, when the Commission has acknowledged a resource acquisition based on an RPS need, it has asked utilities to exhaust non-resource RPS compliance strategies before acquiring new resources to meet longer-term regulatory needs. In its 2009 IRP, PGE proposed acquiring 175 MWa of wind resources to meet a regulatory requirement in 2015. The Commission adopted a recommendation to delay any action on this item until an unbundled REC compliance strategy was examined.[13] Here, the Commission was reluctant to invest in major resources more than five years prior to the regulatory need and preferred a path of smaller and shorter-term resources to bridge the temporal gap. The recent QF addition of 52 MW and subsequent shift of RPS need for new resources out to 2029 raises the question as to why similar, less capital intensive approaches than the proposed RFP for 175 MWa of renewable resource acquisition were not considered like in the manner Commission directed PGE in 2009.

In its order in LC 56, the Commission reiterated its guidance to PGE to look to alternatives to physical compliance with RPS requirements: "In Order No. 10-457, we directed PGE to evaluate alternatives to physical compliance with RPS requirements in a given year. 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."[14]

The Commission and IRP Guidelines place an even higher degree of scrutiny on proposed actions for needs outside the near term. For its 2013 IRP, PacifiCorp sought to secure acknowledgement of an SCR upgrade for the Wyodak facility which was justified by a 2019 need (six years after the filing of the IRP).[15] The Commission adopted a Staff recommendation requiring analysis by PacifiCorp for its next IRP (in 2015) as an alternative to acknowledgement of the investment.[16]

In general, Staff believes that a regulatory "need" for renewables nearly a decade outside the Action Plan time horizon inherently rests on a necessarily questionable set of assumptions, regardless of the economic argument. An economic argument that is presented ten years ahead of need is itself suspect given that uncertainties grow with time.

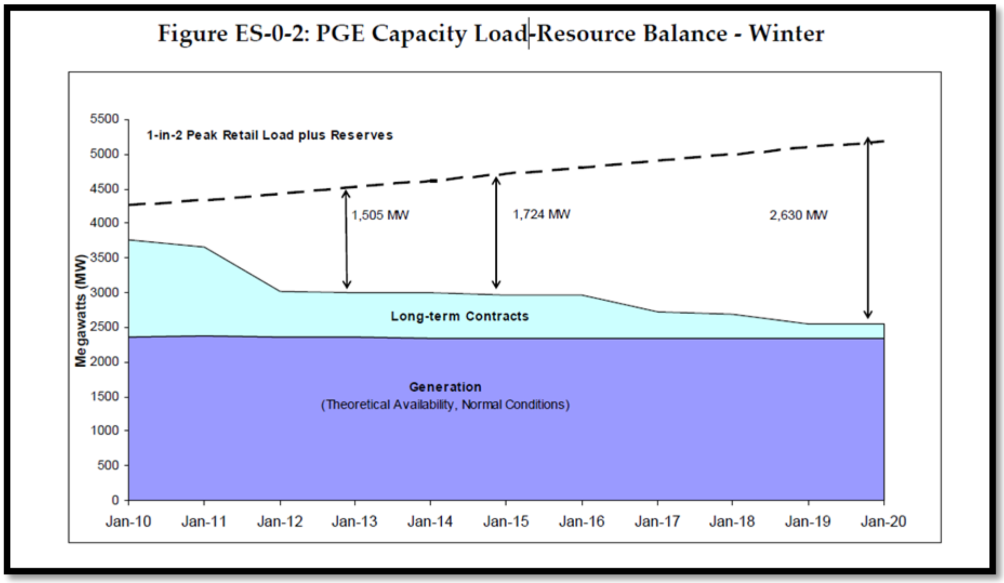
In part, this is because of the inherent inaccuracy and the high levels of risk associated with long-term projections that near term investments for future benefits require a high standard of review. Illustrating this point, PGE's own long-term forecasting during previous IRP processes has been challenged.

---

[12] Order No. 08-246 PGE 2007 IRP LC 43, p.6 and 25.
[13] Order No. 10-457 PGE 2009 IRP LC 48, p.29.
[14] Order No. 14-415 PGE 2013 IRP LC 56, p.13.
[15] Order No. 14-252 Pacific Power 2013 IRP LC 57, p.11.
[16] Id. Appendix A, p.1.

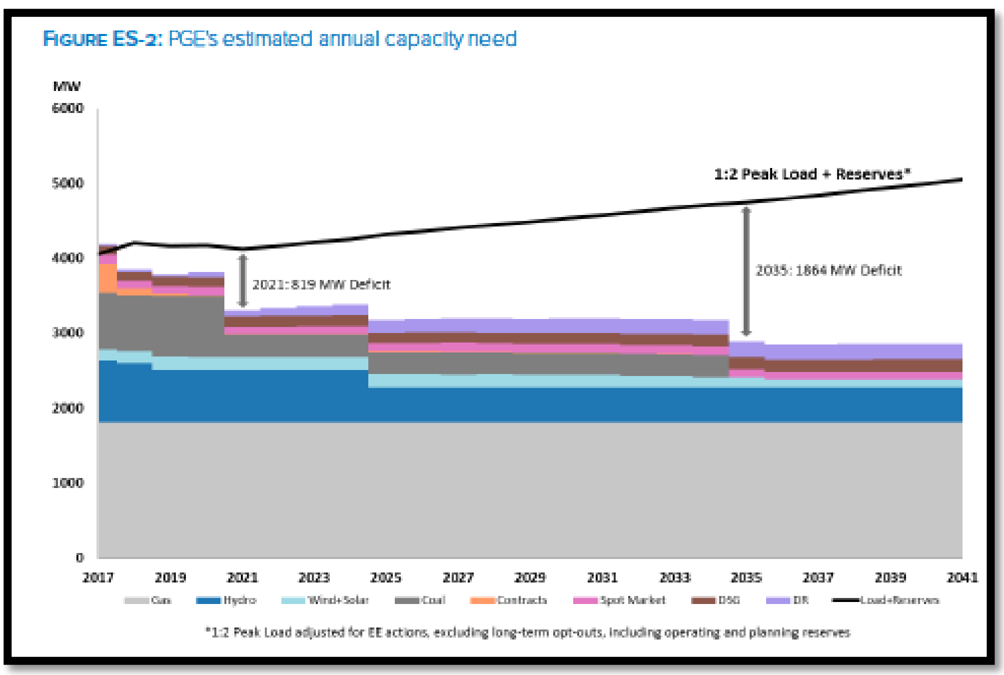
Below is a chart for the 2009 PGE IRP. In that chart, PGE demonstrates an average annual retail load deficit of 2,630 MW by the year 2020.[17]

Figure 1 – 2011 IRP Screen Shot: Load Forecast



Just seven years later in its 2016 IRP, PGE predicted an 819 MW load deficit in 2021. And while the addition of Carty helped address the 2011 deficit, the fact remains that the ten-year projection of capacity need in the 2011 IRP was still off by a net 2,200 MW.

Figure 2 – 2016 IRP Screen Shot: Load Forecast



[17] PGE 2009 IRP, p. 5.

PGE's graphs illustrate the inherent uncertainties in using forecasts to justify near-term actions, even for a need just ten years out, let alone 34 years. The Commission's historical emphasis on near-term needs in the context of IRP Action Plan item approval reflects the Commission's recognition of the uncertainties associated with accurate long-term forecasting. By focusing the Action Plan on near term needs, the IRP Guidelines and Commission precedent help prevent actions based exclusively on long-term forecasts that are inherently more uncertain than shorter-term projections and assumptions.

Failure to Test Assumptions and/or Account for Alternatives to Early RPS Action Raises Questions about Consideration of Uncertainties in PGE's Analysis

In short, key assumptions at the heart of PGE's IRP have not held for four months. Staff subsequently questions the reasonableness of believing these assumptions will hold for an additional twelve years, at which time PGE's need is projected to occur. Staff finds that the following factors could impact RPS compliance needs and investment decisions.

- QF contract growth: As described above, growth in QF contracts will likely continue to delay PGE's need for additional physical renewable resources.
- Solar pricing: PGE solar analysis relied on a 2015 report from the consulting firm DNV-GL. Solar price declines have been precipitous, and pricing in the DNV-GL report was not accurate. The report uses $1.98 per Power Watts (Wp) for single axis tracking utility scale solar capital cost, while the national average in Q4 2015 (the time of the report) was $1.45 per Wp. Although PGE analyzed wind technology curves with sufficient thoroughness in reply comments, PGE's review of solar technology was insufficient and not consistent with the wind analysis. Solar is the fastest growing generation asset in Oregon, and costs are falling on a quarterly basis. Cost for utility scale solar have dropped by 23 percent between Q4 2015 and Q4 2016, placing pricing in Q4 2016 at $1.18 per Wp.[18]
- Utility scale solar: PGE utility-scale solar analysis relied on the DNV-GL report from 2015, prior to the Business Energy Investment Tax Credit (ITC) extension. The report found that with a ten percent ITC, solar becomes cost effective in 2026 after a 17 to 20 percent cost reduction. Yet with the ITC extension that occurred after the 2015 report, solar projects now built before 2020 will receive a 30 percent ITC. Additionally, the costs for utility scale solar have already begun to decline at a steeper rate than the DNV-GL report projected. These combined trends could make solar the lowest cost RPS compliance and perhaps even the capacity option well before the proposed early action resources will be needed or used in 2029.
- Storage cost curves: Capital cost for many energy storage technologies could decrease at a faster rate than anticipated by PGE. One study suggests they may fall 24 to 38 percent by 2020.[19] This has the near term potential to fundamentally alter utility scale renewable energy cost competitiveness, and more importantly to dramatically improve the capabilities and economics associated with customer sited generation.
- Community Solar: Oregon's Community Solar program rules are currently being finalized. As proposed, they have the potential to result in the construction of an amount of utility and distributed solar equal to 2.5 percent of PGE's peak load.

---

[18] Greentech Media U.S. Solar Market Insight 2016 Year in Review" http://www.seia.org/research-resources/solar-market-insight-report-2016-year-review

[19] Lazard's Levelized Cost of Storage – Version 2.0.

- Energy resource diversity: Planning for additional wind capacity in the Columbia River Gorge area presents a lack of diversity in PGE's renewable energy resources and does not fully consider interregional electricity markets. This plan would result in nearly all renewable energy capacity to be located in the same area, giving all resources the same energy production profile. Wind capacity in Montana or Wyoming or utility scale solar capacity would provide a more diverse energy resource with production occurring at different periods and magnitude. There is a real possibility for the near-term availability for substantial transmission capacity from highly productive wind sites in Montana and Wyoming to Oregon.
- Production Risks: The production variability of wind from weather or other issues can greatly impact overall economics. Staff has noted that sustained lower production from wind assets could have an outsized impact on economic performance. We did not find such a risk assessment built into PGE's economic analysis associated with Early RPS Action and the PTC's.
- Distribution System Planning: Distributed Energy Resources, or "DERs," are increasingly becoming part of the utility planning landscape in several states. Distribution System Planning represents an expansion of customer participation in the delivery system of the grid, as dynamic support for shaping load and producing power to provide lower cost alternatives to central generation or more expensive transmission and distribution investments.

PGE's analysis justifying Early RPS Action due to the economic benefits of the PTC has flaws introducing more uncertainty than represented in the IRP

PGE argues that the expiring PTCs present a quickly passing opportunity to cost-effectively benefit of ratepayers in the future by investing as soon as possible. Specifically:

> *…PGE demonstrates that the value of early RPS action [with substantial PTC usage] is robust in a wide range of additional sensitivities and that pursuit of early RPS action continues to present a valuable opportunity for meeting the Company's RPS obligations at the lowest cost to customers.*[20]

Staff finds there are two main problems with PGE's assertion:

1.) PGE failed in its IRP analysis to examine other actions that also maximize PTC benefits. Specifically, PGE did not perform a wind repowering analysis, and did not examine the early RPS wind acquisition size scenarios that PGE's models determined were lowest cost.

2.) The NPVRR benefits of Early RPS Action that captures the PTC are less compelling than presented.

PGE's lack of sufficient review of alternatives

Essentially, for an early action to be justified by speculative savings to customers in the future, a comprehensive set of possible strategies or alternative options should be fully explored and offer support to the early action on the basis of significant benefits. PGE's IRP omitted consideration of at least two such possible alternatives.

[20] LC 66 PGE's Reply Comments at 13.

For example, PGE only presented analysis of a range of sizes of wind when questioned by Staff.[21] PGE's analysis in its Reply Comments demonstrates that other quantities of renewable energy could in fact provide higher levels of savings to customers than its preferred portfolio. PGE did not review the feasibility of any of these options in its IRP.

As another example, PGE did not evaluate repowering existing wind facilities.[22] PTCs are expiring at PGE wind sites. PGE has stated in response to data requests that "Accelerated tax depreciation associated with Tucannon River Wind Farm will be fully recognized by 2020 while the PTC generation will end at PGE's Biglow Canyon Wind Farm in 2018, 2019, and 2020 (i.e. Phase 1, 2, and 3.)"[23] Accordingly, PGE has known for years that these wind sites will soon lose a significant portion of their economic value. Despite this fact, PGE never evaluated wind repowering as a strategy for Tucannon River or Biglow Canyon. Other utilities that have proposed repowering projects assert that repowering is economically justified, despite any stranded capital costs. Benefits from repowering include: increased energy and capacity factors; longer measure life; lower operating costs; minimal environmental impact as compared to new construction; and an additional 10-years of PTC generation.[24] A repowering benefit may also include the generation of "golden" RECs if the Oregon Department of Energy makes such a determination.[25]

PGE's failure to even examine this alternative strategy calls into question whether all scenarios were explored in the IRP with regards to the Early RPS Action involving wind. Staff cannot be sure PGE made every effort to mitigate the uncertainties around least-cost, least-risk planning in its analysis to capture the unique and compelling short-term economic opportunity provided by the PTCs.

Non-Compelling NPVRR Benefits
As presented in PGE's Reply Comments, the estimated benefits of capturing 100 percent of the PTC with the 175 aMW Early Build resource range from \$59M to \$173M over 34 years. If it were to be a utility-owned resource, these benefits would be adjusted downward by approximately \$33M to account for the impact of PTC carryforwards on the NPVRR.[26] Although the overall analyses result in a positive difference for Early Build portfolios across a variety of scenarios, the benefit is less than one percent of the preferred portfolio NPVRR of \$31,319 billion. Staff sees this benefit as small and highly uncertain, even with the variety of scenarios analyzed. If a critical project characteristic such as the capacity factor were to be less than expected, Staff estimates that the benefit could easily be negated.

For additional perspective, Staff found the range of NPVRRs across the original top four portfolios to be \$556M.[27] This is more than three times the high end of the benefit of Early Build, yet PGE described its Action Plan as encompassing any of those top four portfolios. Given this perspective, Staff sees the Early Wind analysis as not showing significant enough benefit that would warrant such investment risk to ratepayers. PGE is justifying the near term investment of nearly \$1B for 515 MW of new wind based on the potential for a 34 year cost reduction of less than one percent.

[21] LC 66 PGE's Reply Comments at 18.
[22] LC 66 PGE Responses to OPUC DR No. 119 and 122.
[23] LC 66 PGE Response to OPUC DR No. 103.
[24] PacifiCorp 2017 Integrated Resource Plan Wind Repower, Energy Gateway & 2017R RFP, Public Utility Commission of Oregon Staff April 27, 2017.
[25] PacifiCorp 2017 Integrated Resource Plan Wind Repower, Energy Gateway & 2017R RFP, Public Utility Commission of Oregon Staff April 27, 2017.
[26] LC 66 PGE's Reply Comments at 27.
[27] LC 66 PGE's Reply Comments at 98

Intergenerational Equity – The RPS unfairly shifts future compliance costs to current ratepayers
PGE asks the Commission to make an inter-generational judgement to have ratepayers today pay more to benefit ratepayers twelve or more years into the future. This request can only be satisfied by an extraordinary showing that the opportunities of early action are certain and definite. Staff strongly believes that there are much higher levels of uncertainty with respect to load forecasts, technology costs, and market and regulatory developments than are reflected in PGE's twelve to 34 year projection of future conditions, which are used to justify an early RPS acquisition based on essentially economic grounds.

Through the general principle of intergenerational equity and the understanding that the reliance on long-term assumptions has inherent risks, the Commission has established high standards of scrutiny for actions that impose near-term costs on current customers for the benefit of future customers. For example, in UE 189 the Commission approved PGE's installation of Advanced Metering Infrastructure (AMI) equipment.[28] The proposal underwent "intense scrutiny" and was conditioned by ongoing review to ensure that the promised customer benefits were accrued.[29] The Commission has also approved long-term hedges that included provisions shifting risks to shareholders, such as those authorized in UM 1717.[30] PGE's proposed early RPS action can be appropriately characterized as a regulatory hedge.

The IRP Guidelines and Commission precedent limiting the action horizon to near term needs wisely reduce the need to analyze decades of projections to justify a resource because they limit the need analysis to a period that can be reasonably forecasted, with a tolerable level of associated uncertainty. PGE asks the Commission to stretch the applicability and understanding of the IRP Guidelines to place substantial costs on today's customers for the potential benefit of customers a decade from now.

This IRP sets a far reaching RPS policy precedent and would have lasting policy implications
PGE's RPS strategy is characterized by components that, given their role in allowing PGE to claim a need for early acquisition of a renewable resource, require a level of scrutiny and analysis that may need to occur outside the confines of the IRP process. These components are:

<u>2040 planning horizon</u>

Properly quantifying future uncertainty is difficult and becomes more difficult as the time horizon increases. Planning and making near-term investment decision for a legislative mandate 23 years into the future stretches the bounds of least-cost, least-risk planning. PGE's 2040 planning horizon for RPS compliance purposes has not been endorsed by Staff nor accepted by the Commission. When contemplated with PGE's REC strategy and bank management, the reasonableness of a resource that optimizes for a far distant and uncertain goal becomes tenuous at best.

<u>The "minimum REC bank"</u>

While Staff appreciates PGE's willingness to conduct REC bank modeling, Staff questions the prudency of an RPS Strategy designed to optimize its REC bank levels through 2040. By designing its REC bank to meet a 2040 goal, PGE creates an enormous amount of RECs in the interim –

[28] Order No. 08-245 In the Matter of Portland General Electric Company Request to Add Schedule 111, Advanced Metering Infrastructure (AMI) p.1.
[29] Id at 1.
[30] Order No. 15-297 In the Matter of Northwest Natural Gas Company, dba NW Natural, Application for Prudence Review of Costs of Post-Cary Wells, p. 6-7.

between 17 to 20 *million* banked RECs depending on the model sensitivity – by 2030. This is approximately 2.5 times more than the RECs that are needed for compliance in 2030 and does not include the RECs that PGE would generate in that year from existing resources.

"Golden" RECs

The "golden" RECs generated by Early RPS Action would not be used until the mid-2030's, and Staff does not have any assurance they may be used at all.[31] By building a resource before 2022, that resource can generate "golden" RECs for five years after its commercial operation date (COD). Based on PGE's sensitivity models, the "golden" RECs generated in the five years following a 2018 COD will likely not be retired until the middle of the 2030s, nearly 20 years later. The prudency of such a decision remains questionable if regulatory intention behind the proposed resource is not actually fulfilled for approximately two decades.

Statutory Limits to RPS Costs

The forecasts in PGE's revised 2016 RPIP show that under a scenario with reference case gas prices, no carbon price and a 175 MWa resource addition in 2018, PGE exceeds the Statutory cost cap at 5.1 percent in 2030. Staff has little reason to believe the parameters in that scenario are likely to change in the coming years, resulting in serious concerns about an early action resource that may not fulfill its intended purpose halfway through the resource's useful life.

Recommendation

At this time, Staff recommends that the Commission not acknowledge PGE's supply-side action "to issue one or more RFPs for approximately 175MWa of bundled RPS compliant renewable resources." Commission Guidelines and precedent limit actions to near term needs, in the context of long-term resource planning. In effect, this Action Item asks the Commission to allow for a near-term and costly action to most cost-effectively meet a need approximately a decade into the future – 2029. Such a request asks the Commission to accept what the Staff views as high levels of uncertainty and a precedent setting intergenerational shifting of costs.

As demonstrated in these reply comments, PGE has not justified acceptance of this uncertainty. PGE asks the Commission to accept this uncertainty because of asserted economic benefits, despite not having examined two potentially lower-cost alternatives. PGE's claimed benefits are small, less than one percent of NPVRR over the term of the analysis. They are also ephemeral. In a historically changing energy landscape any number of highly plausible near-term technology cost, transmission, or third-party energy development scenarios could erase such a small amount of customer benefit, and easily turn it into a net cost. Guidelines and precedent focus on Action Items near-term needs precisely because long term benefits, unless justified by convincing analysis, are so difficult to forecast. Neither the small benefit asserted by PGE or PGE's understanding of the scenarios that could easily eliminate the value of the proposed early action justifies its acknowledgment. Furthermore, the underlying RPS strategy behind PGE's proposed renewable resource has not been endorsed by the Commission, carries exceptional risk and yet is essential for supporting the early action renewable resource. PGE's request for early acquisition of a renewable resource based on a need so far in the future is actually unprecedented in recent history. *There are at least five more IRP planning cycles between now and PGE's 2029 need*.

[31] *See* p. 3 of Attachment B of reply comments.

Staff notes that PGE has established some capacity need. It may be possible that a renewable resource RFP could be justified by the capacity need if renewable resources were demonstrated as the least-cost, least-risk long-term option for capacity for ratepayers. As part of that analysis, it would be appropriate for PGE to examine the relevant attributes of various capacity options for RPS regulatory compliance and environmental performance as part of its overall resource analysis.

3. B. Dispatchable Resources to Meet Capacity Needs

PGE's IRP Action Plan seeks to issue an RFP to acquire 240 to 415 MW of dispatchable capacity. This is part of PGE's supply side actions to acquire capacity resources. PGE states this need for capacity may be met through procurement of a gas plant similar to what was modeled in the IRP. Staff notes that long-lived gas resources generally appear competitive when compared to other resources, given their low (expected) costs. However, Staff has grown increasingly concerned that current changes in electricity sector dynamics as well as future changes completely unknown mean that locking-in a 35-year resource poses significant and unaddressed risk to customers.

Specifically the IRP states:

> *PGE's capacity need…is approximately 819 MW [revised to 561 MW].*
>
> *PGE will issue one or more RFPs to acquire up to 850 MW of capacity. PGE will consider a mix of annual and seasonal resources. PGE may also enter into short and/or mid-term contracts (e.g., 2-5 years) to maintain resource adequacy between the time the capacity is needed and the time in which the resources can be acquired through an RFP. Of the up to 850 MW, and in alignment with the Preferred Portfolio, PGE proposes pursuing acquisition of 375 to 550 MW [revised down to 240 to 415 MW] of long-term annual dispatchable resources and up to 400 MW of annual (or seasonal equivalent) capacity resources.*[32]

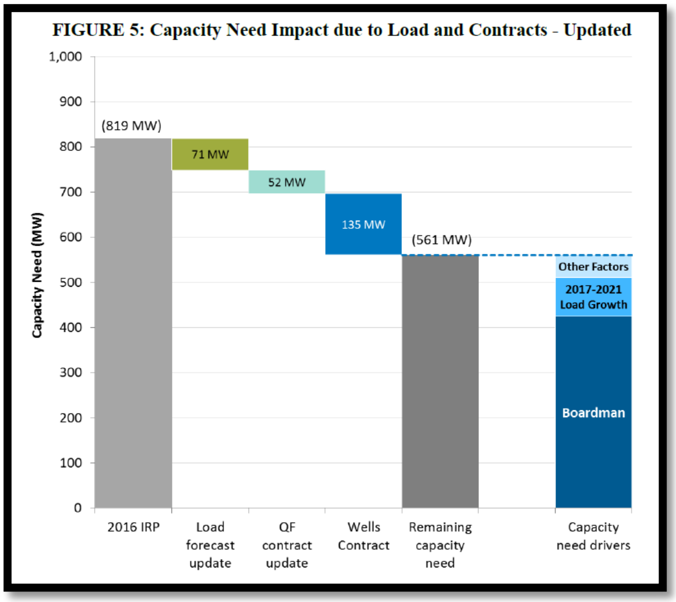
PGE defines a dispatchable resource in this IRP PGE as:

> *…a qualifying dispatchable resource may have operational capabilities similar to a combined cycle, frame combustion turbine, or reciprocating engine to meet this [dispatchability] requirement. [And] Though not explicitly tested, other dispatchable low variable cost resources, like hydro or energy storage, would likely contribute to meeting this dispatchability requirement if they are available to be called in anticipation of flexibility challenges in the day-ahead and re-dispatched within the day.*[33]

PGE's annual capacity need for the 2016 IRP was revised down (by PGE) in April 2017 from 819 MW to 561 MW due in part to bilateral negotiations to renew an existing, hydro resource.[34]

[32] PGE 2016 IRP, p. 343.
[33] PGE 2016 IRP, p. 146.
[34] PGE's letter dated April 13, 2017, "LC 66 –Portland General Electric Company's 2016 Integrated Resource Plan (IRP) Update to Figure 5 of PGE Reply Comments." Available at http://edocs.puc.state.or.us/efdocs/HAC/lc66hac163938.pdf

Figure 3 – 2016 IRP Screen Shot: Updated Capacity Need, 4/13/17



And as stated previously, Staff recognizes PGE's need to acquire some amount of dispatchable capacity by 2021 to meet annual peak capacity needs. Staff believes that, for this IRP, PGE's projections for growth in its capacity need beyond 2021 should be understood to be highly uncertain, and perhaps flat, until PGE resolves the questions and concerns surrounding its load forecasting methodology.[35] Since PGE's IRP was initially filed, PGE has slightly revised its Action Plan to meet its capacity needs. While PGE still plans to issue an RFP to identify and secure necessary capacity, PGE will also continue to conduct it's recently launched bilateral negotiations with a select set of generators and update the Commission as these negotiations develop.[36]

PGE's recent actions to engage in bilateral negotiations with existing dispatchable generators for new capacity in 2021 are a welcome development. Staff appreciates PGE's responsiveness to feedback from Commissioners and stakeholders on this issue. PGE's outreach and subsequent bilateral negotiations have uncovered potential sellers of existing dispatchable capacity that could be in excess of PGE's outstanding, annual capacity needs.

Improved understanding of opportunities should occur prior to issuing an RFP that could result in large, new power plants

PGE's efforts to examine the potential of existing regional generation to serve part of its capacity shortfall may defer the need for a new resource. This work also raises the question of what other efforts may pay off in a similar fashion. Staff believes it would be premature to conduct an RFP for 240 to 415 MW of dispatchable capacity until the following four conditions are met:

<u>Completion of bilateral contract negotiations</u>

[35] *See* Section 4.A. for more discussion on PGE's load forecast methodology.
[36] PGE Reply Comments, p. 12.

PGE's stated pathway for acquiring dispatchable resources in both the Action Plan and in its Reply Comments is "a robustly designed RFP will take full advantage of the numerous resource alternatives available in a competitive market, allowing the Company to seek out and deploy all resources that will bring the best value for customers."[37]
Staff raised concerns about this approach in its Initial Comments, and Staff still questions whether an RFP is the optimal method to acquire unique, dispatchable resources, like hydro.[38] PGE's March 2017 reply comments confirmed these concerns are valid. PGE reported that:

> *…potential sellers of hydro capacity expressed structural concerns about bidding into a utility RFP primarily due to the unique nature of the resources and the seller entities...*[39]

This feedback also echoes a similar statement from PGE in 2013 IRP when the Company sought to directly renew legacy hydro contracts. PGE stated they did:

> *…not believe an RFP would be fruitful and, in fact, we believe the time required to conduct an RFP would in all likelihood jeopardize our ability to renew, these low cost, flexible, and carbon-free resources – a result that is not in the best interest of PGE, our customers, or the environment.*[40]

Staff encourages the continuation of these bilateral negotiations. We appreciate PGE's offer to give the Commission a report on the status of the bilateral contract negotiations prior to issuing an RFP. However, Staff fails to see the advantage to ratepayers of issuing an RFP for dispatchable capacity while simultaneously conducting bilateral negotiations for hydro resources. Staff is concerned there is a risk of locking into unnecessary resources due to these processes operating in parallel.

<u>Better understanding of Market Depth</u>

OPUC Staff and five other stakeholders have each expressed reservations about the IRP's assumptions regarding market depth.[41] Staff stated that it would have preferred that PGE better understood the market prior to planning to acquire new resources and requested that PGE consider some level of market depth analysis in this IRP.[42] PGE's Reply Comments explored regional resource adequacy in response. PGE reviewed several studies and noted that the region could be facing a potential capacity shortfall as high as 1,400 MW in 2021.[43] Yet, PGE's own findings from its Q1 2017 outreach work do contrast to regional projections of a capacity shortfall beginning in 2020. Specifically, PGE was able to find sellers of dispatchable capacity today willing to contract to sell power for terms of five to 15 years *beginning in 2021.* While Staff does not know prices and terms, Staff is firmly convinced that PGE's Action Plan item to conduct a market capacity study as part of its *next* IRP and *after* it

[37] PGE IRP, p. 226.
[38] *See* LC 66.
[39] PGE Reply Comments, p. 12.
[40] PGE 2013 IRP, p. 33.
[41] Broadly speaking these five supporting parties were the Citizen's Utility Board (CUB), the Sierra Club, Northwest Energy Coalition (NWEC), the Industrial Customers of Northwest Utilities (ICNU) and the Northwest & Intermountain Power Producers Coalition (NIPPC).
[42] *See* Staff Initial Comments to LC 66, January 24, 2017, p.23 & 24.
[43] This is per a study by the Northwest Power and Planning Council. *Please see* PGE's 2016 reply comments, p. 57, for more details.

has completed an RFP for new dispatchable capacity is a backwards approach. Staff agrees with PGE that "it makes sense to explore any compelling and time-limited opportunity to acquire existing capacity, particularly while market prices are historically low."[44] Staff believes that it is best to explore the depth of the market now – along with continuing its bilateral contract negotiations–prior to issuing an RFP, especially as PGE's direct outreach this year revealed specific market opportunities not necessarily seen or captured in regional forecasts of capacity.

Consideration of short- to medium- term resources

PGE has stated that it is difficult to model resources of limited duration in IRP portfolios.[45] PGE also claims that including limited duration resources of less than five years as part of its RFP process is not worth the effort, given that such a resource lasts for less time than the "typical planning and procurement cycle."[46] PGE concludes by stating that efforts to design and conduct an RFP specifically for resources of limited duration would most likely reduce the bidding pool and thus increase costs to customers.[47]

Staff understands there can be difficulties in modeling limited duration resources, yet we do not believe that excluding these options from the analysis satisfies IRP Guideline 1 or appropriately reflects least-cost, least-risk planning. In fact, modeling difficulties appears to not have been an issue for PGE in the past. PGE's 2009 Action Plan modeled and called for approximately 9 percent of its future energy resource mix to come from short- to mid- term market purchases.[48]

Staff does not necessarily doubt the claim in PGE's Reply Comments that resources of less than five years could be problematic from a planning perspective, *if the start of the term were near the current IRP cycle*. Staff does not believe that it would, for example, have been problematic to add short-duration resources starting in 2021 where there is the first claimed need for them. Staff would also note that PGE's Reply Comments are noticeably silent on the merits of resources with durations between five and 15 years.

PGE also contends that, since there is no way of predicting how much of its plant's fixed costs a bidder might try to recover in a short-duration contract, any representation of these contracts is inappropriate.[49] Staff does not believe this argument is entirely without merit. Given that it is impossible to know what the market may make available without putting out an RFP, Staff supports doing so. During the evaluation process, however, Staff would expect to see the level of robust analysis typically seen in the IRP around the value of resource deferral that short-term bids would provide.

And while feedback from PGE's bilateral negotiations has indicated that limited duration, hydro resources may not be inclined to participate in a term-limited RFP, PGE has presented no evidence that other types of resources of a limited duration would not participate in a

[44] *See* PGE's March 31, 2017 LC 66 Reply Comments, p. 12.
[45] Staff adopts CUB's description of the term "limited duration" to between two and fifteen years in length.
[46] PGE Reply Comments, p. 10.
[47] Ibid.
[48] PGE 2009 IRP, p. 317. While the 2009 IRP does not state the exact duration of these resources it notes that the resources would be added to cover the time period between 2011 and 2020.
[49] PGE Reply Comments, p.78-79.

term-limited RFP. Given the optionality such resources provide to cost-effectively delay large capital investments—and based on the positive feedback from PGE's recent outreach—Staff believes that exploring the market via an RFP is a low cost, low risk way to better understand the market and the options before the company to cost-effectively meet its 2021 capacity needs.

Recommendation

PGE rightfully asserts that it "should not have to restart the [IRP] acknowledgement process every time a forecast is updated or a new contract is signed."[50] This is a fair point and Staff agrees. However, Staff recommends that the Commission not acknowledge PGE's Action Plan item to issue an RFP for dispatchable capacity. This position is not rooted in new analysis or the possibility of a new contract. Instead it comes from what appears to be easily collected evidence.

PGE does not appear to have fully explored in its research, nor to have been prepared to determine via actions proposed in its Action Plan, the availability, costs and benefits of resources to meet its dispatchable capacity needs outside of generation that generally fits the profile of new thermal plants. This seems especially true for existing resources of limited duration. The evidence would suggest that PGE did not conduct fundamental market research on, "… all known resources for meeting the utility's load…"***prior to*** filing its IRP in November 2016.[51] Further, if Staff were to recommend acknowledging the issuance of an RFP as the preferred pathway to implementing this Action Plan item, this would effectively sanction the preemption of an entire class of cost-effective, low-carbon generators from participating in PGE's procurement process.

Staff recommends that other actions be taken first, prior to considering an RFP for dispatchable capacity products of any duration as part of this IRP or the next one.

- Complete bilateral negotiations;
- Complete market depth/capacity study;
- Reevaluate capacity need by re-running RECAP and REFLEX to determine annual peak capacity need and flexibility needs; and
- Conduct an RFP for limited duration resources of less than 15 years to meet PGE's 2021 capacity needs.

After these actions are completed and if a capacity need still exists, Staff believes it would then be appropriate for PGE to pursue market solutions with an RFP for dispatchable resources of any duration.

3. C. Demand Response

In PGE's recommended Action Plan, the Company states that they will pursue 77 MW of winter demand response and 69 MW of summer demand response through 2020. Staff does not recommend acknowledging PGE's Recommended Action Plan for Demand Response. Given the record produced and PGE's stated need for capacity in the short term Staff recommends PGE pursue its own Demand

[50] PGE Reply Comments, p. 11.
[51] As required by IRP Guideline 1.a, Order No. 07-002, Appendix A, p. 1.

Response High case used in it 2016 IRP modeling of 162 MW of Summer Demand Response and 191 MW of Winter Demand Response.

Staff thanks PGE and parties for their comments on PGE's planning and treatment of demand response. It is evident from the Company's comments and modeling efforts and parties' comments that the discussion and treatment of demand response has matured to an extent that demand response is considered a viable and real resource capable of meeting planning and operational needs. The maturity of the discourse also leads Staff to believe that ultimately all parties want to develop demand response resources, the issues outstanding are the size and pace of the buildout. Staff therefore offers the following recommendations to help with the demand response planning, to accelerate the pilot to resource program cycle and drive market maturity.

Through the passage of Senate Bill 1547 the legislature signaled a new emphasis on demand response. Section 19 of the new law created a loading order requiring investments in cost effective demand response, "before the electric company acquires new generating resources."[52] The notion that demand response can offset the need for new resources was mirrored in the Northwest Power and Conservation Council's Seventh Power Plan whereby the second priority of Seventh Power Plan's Action Plan resource strategy, second only to energy efficiency, was the acquisition of a minimum of 600 MW of demand response by 2021.[53, 54] The Council found that in over 70 percent of all futures tested demand response is cost effective even for utilities with lower costs to serve than PGE.[55] Staff recognizes that the Council's power plan is not necessarily a plan for an individual utility but it does provide guidance on the types of resources that should be considered and their priority of development, guidance that is repeated in legislation.

<u>Staff's Current Position</u>

In comments on PGE's 2016 IRP Staff, CUB, and NWEC characterized PGE's demand response acquisition targets as conservative.[56] In our Initial Comments, Staff offered an illustrative example from PGE's own updated demand response potential study commissioned from a national expert in demand response, Brattle Group.[57] Staff noted that achievable potential of just a few select direct load control programs were more than double PGE's 2016 IRP reference case acquisition targets.[58] In response, PGE states that the Brattle Group commissioned demand response potential study is an assessment of maximum achievable potential target which "cannot be qualified as feasible implementation targets because they do not account for the following constraints: Necessity of pilot periods; Interaction between programs; Participation and maturation rates; Timing aligned with other initiatives; and Evaluation requirements." PGE further called into question the efficacy and applicability of the Brattle Group study in comments through PGE Staff member Josh Keeling's oral comments before the Commission during the Special Public Meeting on February 16, 2017.[59]

---

[52] Senate Bill 1547, Section 19.

[53] Northwest Power and Conservation Council Seventh Power Plan Chapter 4: Action Plan, P. 4-2.

[54] The Commission has a long history of taking into account and finding guidance from the Power Council's Power Plan. See for example Order 89-507, p. 7, where the Commission stated, "The Northwest Power Planning Council's Plan may be a useful model for the utilities."

[55] Supra Note 2.

[56] Initial Comments of Staff (p.1-13), CUB (p.8-9), and NWEC (p. 5).

[57] PGE 2016 IRP, p. 169.

[58] Staff Initial Comments, p. 10.

[59] Comments of PGE Staff Josh Keeling before the Commission during February 16, 2017 Special Public Meeting.

In its Reply Comments, PGE highlights additional "unique circumstances" that make acquisition of the demand response target difficult.[60] These include the fact that PGE is a dual-peaking system, does not use back up generation as a demand response resource, and that demand response is relatively new in the Northwest market.[61] PGE continues in its Reply Comments to highlight additional barriers to demand response acquisition such as the lack of a currently operational and fully deployed Customer Information System (CIS). PGE also notes difficulty with its automated demand response program.[62] To support its conservative approach to demand response acquisition, PGE states that, "cost-savings of DR may be overstated in PGE's results."[63] Staff finds it informative that PGE has presented so many barriers to identification, planning, and acquisition of demand response. The presentation of these barrier merits a modification to the demand response planning and acquisition process and activity currently being undertaken by PGE. Below Staff recommends a series of actions that will assist with the demand response planning and that can accelerate the pilot to resource program cycle and drive market maturity.

Staff is also concerned that PGE seems stuck in a pilot cycle. Few if any demand response pilots that PGE has undertaken have developed into full system wide programs. Staff finds PGE's work on Critical Peak Pricing (CPP) as an illustrative example. In 2008, PGE raised the idea that dynamic pricing and critical peak pricing during rate case UE 189 and the surrounding discussions and approval of Advanced Metering Infrastructure. In making the case for Advanced Metering Infrastructure, two categories of benefits were described. The first category, "operational benefits," included the ability to conduct remote meter reading and service termination/re-institution.

Included in the second category was the opportunity for the utility to engage in dynamic pricing, including critical peak pricing. As part of the AMI approved Settlement in Order No. 08-245, the Commission required action on critical peak pricing. The Company subsequently submitted a CPP tariff in Advice No. 09-05. Only a year later, citing difficulty with enrollment and an inability to process billing for the new tariff PGE filed Advice No. 10-12 on June 17, 2010, requesting the CPP Pilot be withdrawn. A year later PGE filed Advice Number 11-10 asking to reinstate CPP as a pilot. In a subsequent 2012 report to the Commission on the CPP pilot PGE noted familiar barriers to implementation including participation and attrition rates, cost effectiveness, and timing aligned with other initiatives here the development of PGE's Customer Information System.[64]

Thus although dynamic rates were part of the benefits promised through AMI implementation, shortly thereafter PGE presented yet another barrier, lack of additional infrastructure. The pilot was subsequently shut down. However in UE 319, PGE's 2016 rate case, PGE Testimony of Stathis – Dillon states that one of the benefits of the new Customer Information System is its ability to, "support more varied pricing options compared to what is available with our current system."[65] Yet despite this enormous IT buildout detailed in UE 319, in Docket UM 1827 and related Advice No. 17-19, PGE is requesting nearly $2.5M for the development of demand response communication network to support a single two-year demand response pilot. PGE has not provided any detail about the need or utilization of this new network at the date of these comments.

[60] PGE Reply Comments, p. 67.
[61] PGE Reply Comments, p.67-68.
[62] Ibid.
[63] PGE Reply Comments, p. 69.
[64] PGE Critical Peak Pricing Pilot Report dated March 29, 2013, filed April 1 2013.
[65] UE 319 Direct Testimony Stathis – Dillin 900 at p. 13.

In UM 1514, PGE Energy Partners Demand Response program, PGE presented a familiar set of reasons for poor performance and the programs inability to reach the anticipated 25 MW participation goal. Citing poor enrollment and challenge in communicating with it contractor EnerNoc, PGEs' program evaluations seem to again raise many of the same programmatic issues.

Recommendation

Staff has recounted some past trends only to demonstrate the difficulty PGE has had in moving from pilot to a successful program implementation stage. With this in mind Staff recommends a series of actions that will assist with the demand response planning, accelerate the pilot to resource program cycle, and drive market maturity.

Demand Response Potential Study:

- To address the issues raised during the 2016 PGE IRP regarding demand response potential, Staff recommends mirroring the practices of assessing energy efficiency potential and that PGE hire a third party to conduct a study for demand response specific to PGE's service territory in time to inform PGE's subsequent IRPs. Staff recommends PGE conduct such studies for each IRP cycle. These potential studies should be conducted before the development and submittal of PGE's IRPs.
- Additionally, Staff recommends basing the practice and methodology of assessment of technical and achievable cost effective demand response on the work done by the Energy Trust of Oregon for energy efficiency. Staff recommends the Demand Response Review Committee (as described in the last bullet below) review the practice and methodology annually and report on the status and any concerns in a letter to Commission Staff.
- Additionally, Staff recommends PGE submit a draft of its Demand Response Potential study to the Demand Response Review Committee for additional guidance.
- Additionally, Staff recommends that when PGE submits a copy of its final demand response potential study to the IRP Stakeholder Workgroup they include a letter outlining all input received from the Energy Trust of Oregon and the Demand Response Review Committee. The letter should note how PGE responded and addressed any comments received.
- Lastly, to address the barriers and constraints raised by PGE in its Reply Comments, the slow pace of moving from pilot to program, and other challenges raised by PGE, Staff recommends PGE develop a Demand Response Testbed (see Appendix A).
- Staff further recommends the creation of a Demand Response Review Committee whereby all demand response programs are first reviewed ahead of filing. Staff intends to raise the notion during a Staff-led demand response proceeding later this year, unless PGE submits a proposal prior to this.

4. GENERAL IRP COMMENTS

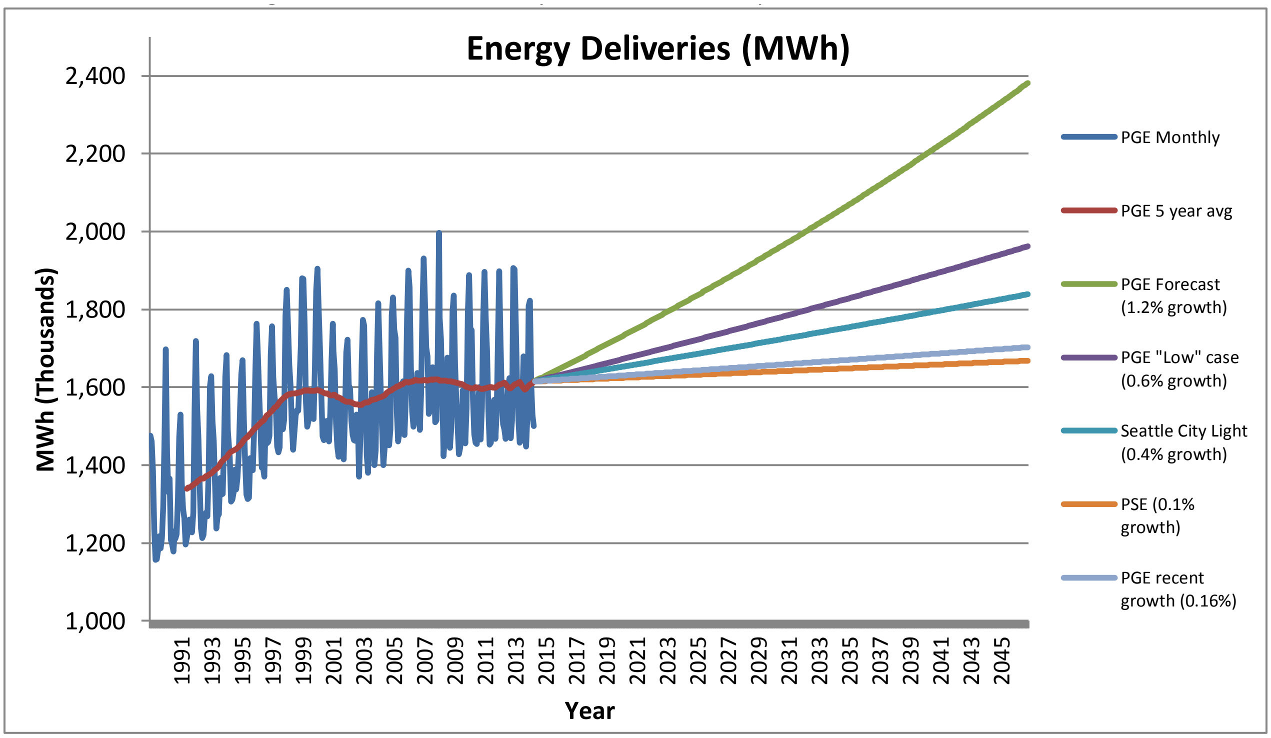
4. A. Load Forecast

PGE's projected load growth contrasts with recent history and other regional utilities
Staff is highly concerned that PGE's load forecasting methods result in projections that greatly exceed both PGE's recent historical load growth and the projections made by several other regional utilities. PGE estimates that its future energy deliveries will grow over the long-term at an annual rate of 1.2 percent. This stands in stark contrast to the load growth expected by other regional utilities. For example, Seattle City Light expects to experience 0.4 percent annual growth[66] while Puget Sound Energy anticipates 0.1 percent annual growth.[67] Even PGE's "low" scenario of 0.6 percent annual growth exceeds these base-case growth rates anticipated by both Seattle City Light and Puget Sound Energy.

Staff also believes that PGE's recent historical load growth should be considered a credible scenario for its future load growth. PGE's average monthly load for residential, commercial, and industrial customers combined was about 1.65 percent greater in the 2010-2014 period than it was in the corresponding period 10 years earlier (i.e., 2000 to 2004).[68] This corresponds to an average annual growth rate of 0.016 percent, which is considerably smaller than even the "low" growth scenario PGE considers in its IRP. The following figure depicts how these potential scenarios could develop by projecting the various growth rates used by other utilities from PGE's historical load data.

Figure 4 – Staff Analysis, PGE's Forecasted Load Growth

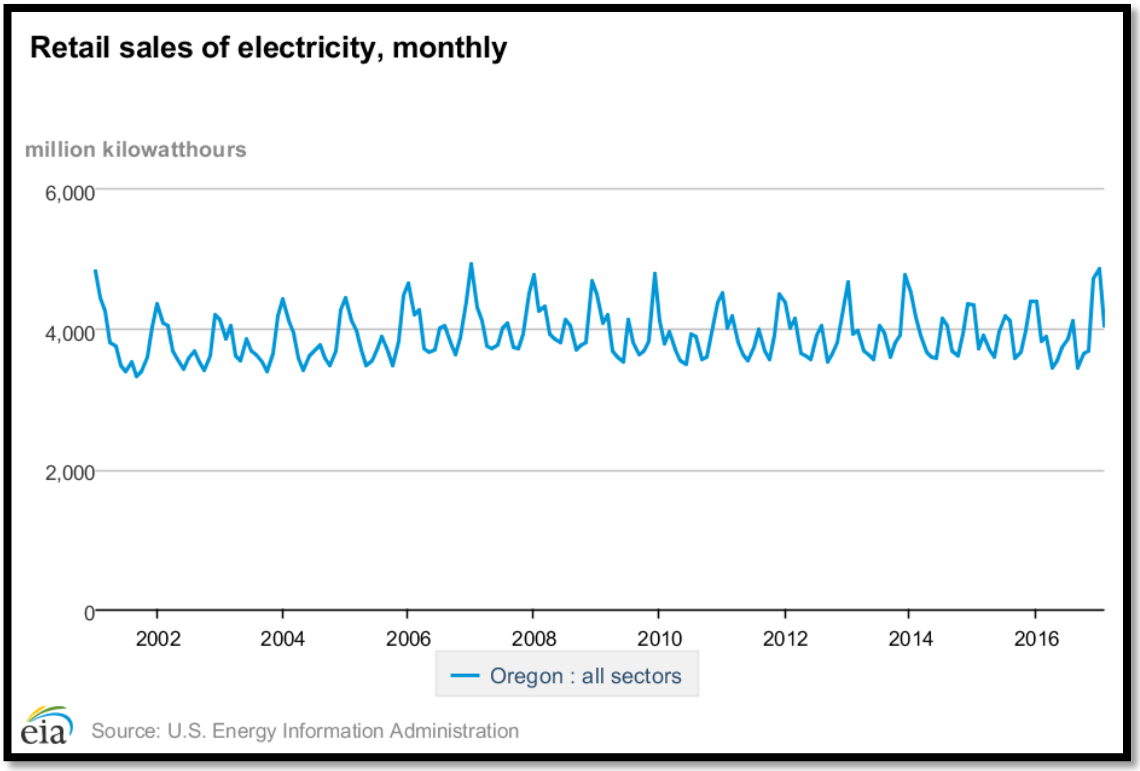
rical trend of retail sales in



[66] Seattle City Light's 2016 IRP (p. 7) states that over the next 20 years, "City Light expects to experience modest average annual load growth of about 0.4% under conditions of normal weather and before the impact of City Light sponsored energy efficiency programs available to its customers."
[67] See slide 15 at https://pse.com/aboutpse/EnergySupply/Documents/Post_IRPAG_Nov14_IRPAG_Distribution.pdf
[68] Staff's calculation is based on the data provided by PGE in its reply to OPUC DR 009.

Oregon as measured by the EIA and depicted in the figure below.[69]

Figure 5 – Historic Monthly Electricity Sales, Oregon



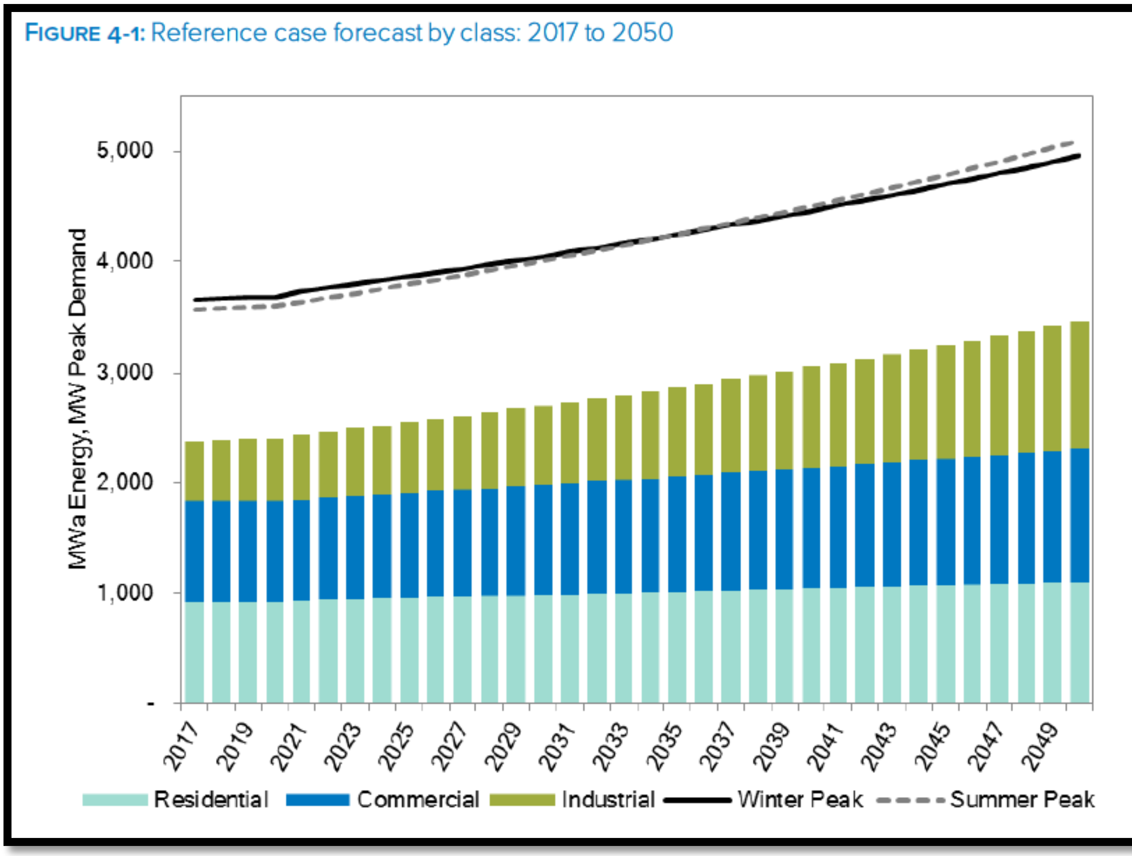
It is also concerning that PGE projects accelerating growth in energy deliveries despite the fact that the forecasts of GDP and employment that PGE uses *decelerate* (from 2.6 percent growth for GDP through 2020, down to 2.3 percent thereafter,[70] and from "as high as 3 percent in the very near term" for employment, down to 1 percent in the long-term[71]). This can be seen in the "kink" at 2001 in the trends depicted in Figure 4.1 from PGE's IRP:

[69] Figure available at: https://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=000000000002&endsec=vg&linechart=ELEC.SALES.OR-ALL.M&columnchart=ELEC.SALES.OR-ALL.M&map=ELEC.SALES.OR-ALL.M&freq=M&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0

[70] PGE IRP, p. 103, states "IHS Global Insight economic forecasts project real GDP increasing at 2.6 percent through 2020 before reverting to a longer-term average of 2.3 percent."

[71] PGE IRP, p. 103, states "The OEA forecast projects a 1.5 percent average annual growth rate over the next ten years, with growth as high as 3 percent in the very near-term, slowing to 1 percent to reflect long-term demographic trends."

Figure 6 – 2016 IRP Screen Shot: Forecasted Energy & Capacity Need



Staff continues to be concerned with PGE's forecasting methods and depiction of forecast uncertainty
Staff has considerable concerns about how PGE has characterized the uncertainty in its forecasts and these concerns have not been adequately addressed in PGE's Reply Comments. Staff believes that the uncertainty in load forecasts deserves considerably greater attention in future IRPs. Staff especially appreciates the detail that PGE has recently provided in its reply to OPUC DR 123, and the analyses included in this reply represent an important step in the right direction. Staff also appreciates PGE's commitment to give these issues more attention in the future. However, none of this allays Staff's concerns that these issues should have been considered and settled well before PGE endeavored to identify a least-cost portfolio and Action Plan for meeting its customers' future needs.

With regard to methods, Staff believes that PGE's claim that its models "contain economic variables with a sound theoretical, historical relationship" misses the mark in two important ways. First, there is considerable evidence that the historical relationships are changing. For example, Mark Quan, Principal Forecast Consultant at Itron, notes that "today, we understand the weakening relationship between electric sales and the economy (employment and GDP)."[72] Staff has repeatedly raised this concern to PGE, including in multiple meetings and emails, in Staff's Initial Comments, and at the Public Meeting on February 16, 2016. More importantly, the evidence that these relationships are changing is not new and PGE has had more than ample time to improve its methods. PGE characterizes the issue as an "emerging conversation within the industry."[73] Staff disagrees with this characterization; this issue emerged years ago. In March of 2013, over four years ago, the EIA published an article demonstrating that the

[72] "The Economy and Electric Sales," December 20, 2016, by Mark Quan. Available at http://blogs.itron.com/?p=55176
[73] PGE Reply Comments, p. 31.

relationship between economic activity and electricity demand has been changing.[74] PGE's own forecasting consultant presented evidence *to PGE* in December of 2014[75] and again in April of 2015[76] showing that the relationship between economic activity and electricity demand has been changing *since as early as 2001*. Staff does not understand why PGE has failed, in light of this evidence, to consider this information before proposing new resource acquisitions. (In its Reply Comments, PGE discusses Staff's concerns about spurious (i.e., incorrect) relationships in the context of PGE's manufacturing models but the Company does not address these concerns with respect to the long-term models or anywhere else outside of its manufacturing models.)

Second, a model may fail not only by omitting relevant variables but also by "containing" appropriate variables but in an incorrect manner (for example, by using the variable in a linear form when the relationship is not in fact linear). This has been one of Staff's main concerns with regard to PGE's modeling of economic "drivers" (e.g., GDP and employment). As Staff explained in its Initial Comments, the way that PGE's models contain economic variables fails to adjust for the non-stationarity in these variables and assumes the relationships between these variables and PGE's load is constant. As noted above, the evidence does not support a constant relationship. Nonetheless, PGE then assumes this constant relationship will hold throughout the IRP's 34 year planning horizon and, despite Staff's repeated requests, PGE has declined to explain why it believes this assumption is reasonable.

Staff appreciates that PGE has begun to re-evaluate its economic "drivers" and to explore ways to examine the changing relationship between economic variables and load. Staff also appreciates the new analyses presented in PGE's Reply to OPUC DR 123. However, Staff believes these analyses are made in a flawed framework which fails to address the concerns with stationarity identified in Staff's Initial Comments. This framework is likely not only to result in incorrect correlations, but also to overstate the precision of the estimates, which further compounds Staff's concerns about PGE's methods for constructing high/low growth scenarios. Staff explained its concerns with PGE's methods in its Initial Comments and PGE's Reply Comments simply state that its high/low scenarios are "realistic" without offering any support based on evidence or statistical theory.[77] Staff has since requested that PGE "identify each of the alternative approaches [for constructing bounds on the load forecast] that PGE has considered or analyzed and explain why PGE declined to use them."[78] PGE objected that this request was "overly broad and unduly burdensome." Staff does not know whether PGE has considered other methods.

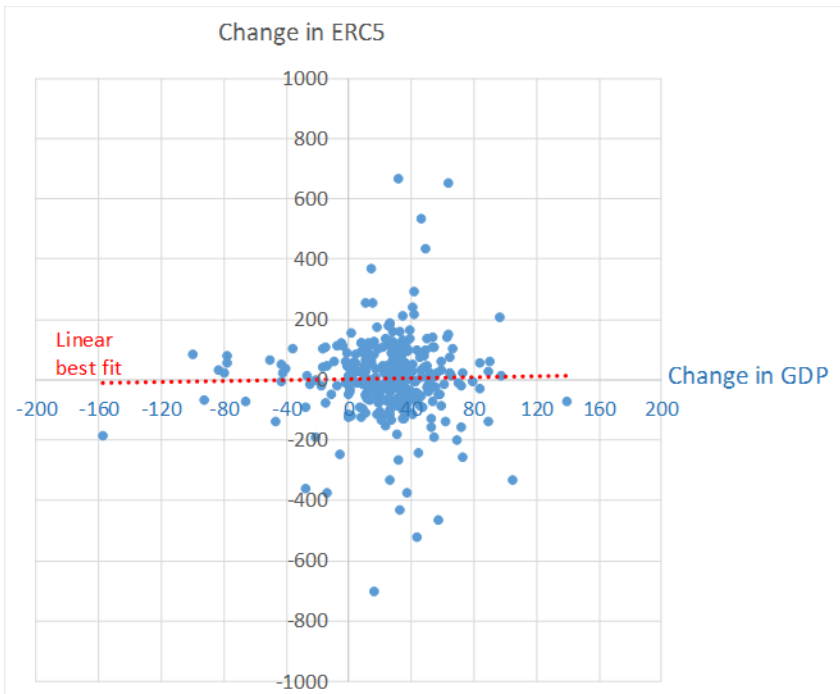
PGE's forecasts are only as accurate is its estimated coefficients, and Staff believes PGE's estimate coefficients are likely inaccurate. Staff's belief is based on several considerations. First, PGE uses ordinary least squares (OLS) regression models to compute the impact of changes in various economic drivers on electric load. These impacts are computed as coefficients that represent how much PGE's load should be expected to change given a 1-unit change in each forecast driver. For example, PGE estimates that "for every 1 Billion dollar increase in the seasonally adjusted annual average level of Real US GDP, PGE's industrial energy deliveries increase by 20.31 MWh."[79] PGE then multiplies IHS's prediction of 2022 Real US GDP by its estimated coefficient (20.31) in order to obtain PGE's forecasted

[74] https://www.eia.gov/todayinenergy/detail.php?id=10491
[75] Attachments B and C of PGE response to OPUC DR 090.
[76] See slide 18 of Itron's April 2, 2015 presentation, available at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2015-4-2-irp-forecast-review-presentation.pdf?la=en
[77] PGE Reply Comments, p. 35.
[78] OPUC DR 123 part J.
[79] PGE reply to OPUC DR 123, p. 4.

2022 industrial energy deliveries. This method relies on the assumption that there is a constant and linear relationship between GDP and PGE's load.

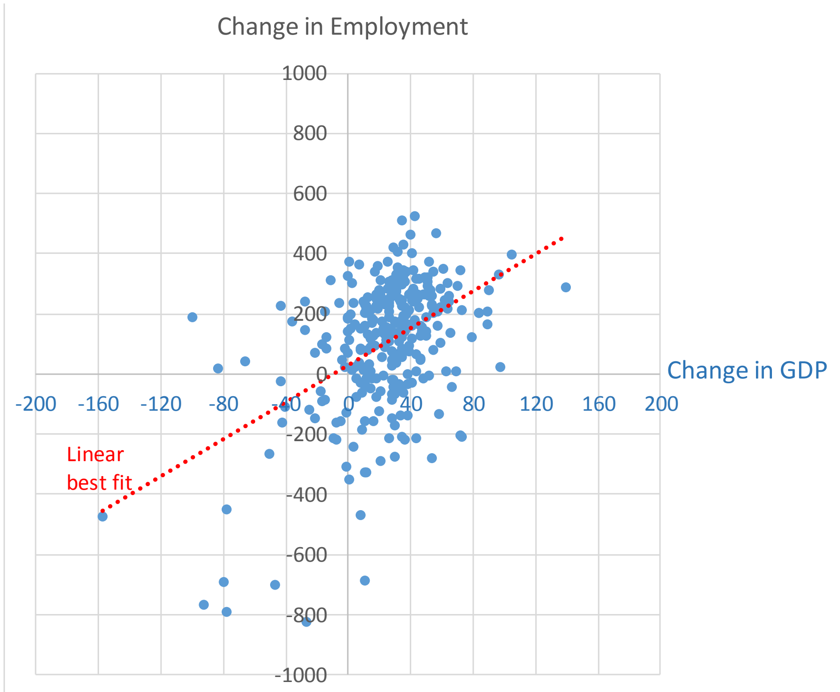
Second, Staff believes there is evidence of a very different relationship between GDP and PGE's load than the one suggested by PGE's estimates. If GDP drives load, then one would expect an increase in GDP from one month to the next to correspond to an increase in load, holding all else constant. The figure below shows that this is unlikely to be the case. It plots *changes* in GDP from one month to the next versus *changes* in PGE's industrial load. There is no clear pattern in between these changes, as demonstrated by the essentially flat best-fit line through these data. Moving along the x-axis, for any given change in GDP, load changes essentially randomly along the y-axis. The figure shows that for each month in which GDP increased, load was essentially equally likely to increase or decrease. This is in direct opposition to PGE's estimated coefficient of GDP on load.

Figure 7 – Staff Analysis: Scatterplot of Changes, GDP & Industrial Load



As a counter example, the figure below shows that there is a clear pattern between changes in GDP and changes in employment. This figure suggests that a strong economy and high levels of employment go hand-in-hand. This is contrast to the previous figure and the relationship between changes in GDP and changes in load. The correlation between changes in GDP and changes in employment is 47 percent. Comparatively, the correlation between changes in GDP and changes in load is 2 percent. As further evidence that the relationship between PGE's load and GDP is much weaker than PGE estimates, Staff re-estimated the Company's industrial load (ERC5) forecast after removing the trends from the independent variables and the regression explanatory power drops substantially (the R^2 value falls to 0.00). This is evidence that the Company's high R^2 value is an error and a symptom of an inaccurate and regression that does not appropriately account for the time-series nature of the data.

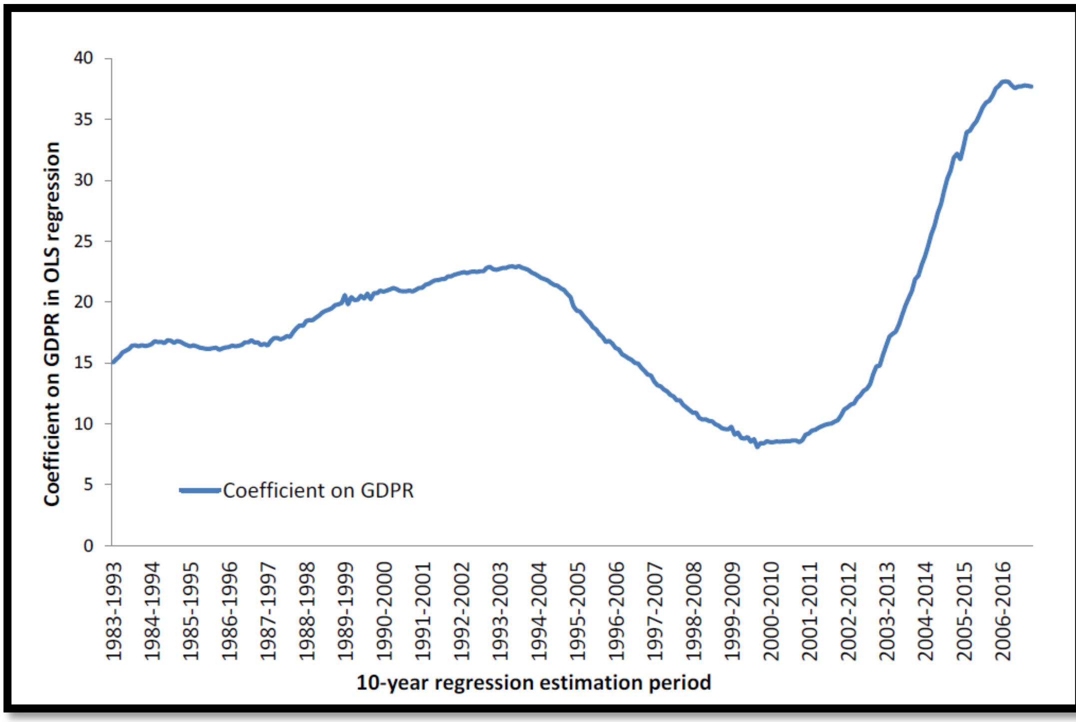
Figure 8 – Staff Analysis: Scatterplot of Changes, GDP & Employment



The overconfidence that PGE places in its estimates is clearly revealed by the relationship PGE estimates between GDP and industrial load. The 99 percent confidence interval for this relationship implied by PGE's methods is from 19.3 to 21.3 (MWh per $1 billion US GDP).[80] This is surprisingly narrow, as revealed by Figure 2 from PGE's reply to OPUC DR 123. This figure demonstrates that this relationship ranges from below 10 to above 35, depending on the time-period of data used.

[80] Unrealistically precise standard errors and confidence intervals are a well-known symptom of regressions that do not account for non-stationary variables or spurious correlations due to trends. This range is calculated using PGE's estimated coefficient and standard error for GDPR as reported in PGE's reply to OPUC DR 12 (Attachment B).

Figure 9 – Industrial Energy Deliveries and GDP



It is important to note that Staff has not reviewed the methods by which PGE constructed this figure, which, if consistent with PGE's other methods, would also be subject to Staff's concerns about incorrect correlations (as explained in Staff's Initial Comments). Nonetheless, it reveals that even disregarding these concerns, there is internal evidence within PGE's methods that the precision of its estimates is overstated.

Recommendation

PGE's forecasts rule out the possibility of zero-growth—which would further reduce PGE's 2021 capacity need by approximately 90 MW[81]—and PGE has not considered in its portfolio analyses any scenarios in which its load grows as slowly as it has in recent years, or as slowly as the growth anticipated by other regionally utilities. Therefore, Staff believes that, for this IRP, PGE's projections for growth in its capacity and compliance needs beyond 2021 should be understood to be highly uncertain, and perhaps flat, until PGE resolves the questions and concerns surrounding its load forecasting methodology.

Staff greatly appreciates that PGE considered a zero growth scenario in its re-analysis of the value of early acquisition of an RPS resource in its Reply Comments (PGE concludes in this analysis that zero load growth would reduce the value (NPVRR) of early acquisition of 175 MWa wind by approximately $23 million, but that early acquisition remains lower cost (by about $150 million) than delaying acquisition to 2029.[82] Staff believes that such a low-growth scenario should have been considered throughout PGE's IRP and should have informed PGE's construction of portfolios, portfolio scoring, and the subsequent determination of PGE's Action Plan.

[81] PGE Reply Comments, p. 52, Figure 5.

[82] PGE Reply Comments, p. 22, Table 6.

4. B. 2021 Capacity Need

Since initially filing its IRP in November 2016, PGE's estimates of annual capacity need in 2021 have fallen by 31 percent. Staff recognizes the time-consuming analyses that goes into an IRP and does not suggest a complete re-analysis given the revisions to PGE's estimates. But in light of the substantial size of the investments being proposed by PGE, and numerous sources of uncertainty in PGE's load and the rapidly changing markets in the West, Staff does believe it is best to exercise an abundance of caution before acknowledging Action Items that could lead to an increase in rate-base of potentially more than $1 billion.

Staff continues to question whether PGE's annual capacity need is as high as 561 MW in 2021. Staff remains unconvinced that short- and mid-term procurement activities (three months to 15 years) are not viable in 2021 and that PGE must build new capacity via an RFP process. Our analyses suggest that the peak need is highly sensitive to assumptions about market access during the summer peak, and exacerbated by PGE's assumed penalty pricing during the peak demand periods. Without access to PGE's flexibility model, Staff could only make broad assumptions regarding market purchases during peak under these conditions and is not able to offer a more concrete figure than what PGE has supplied Staff.

Staff also notes that PGE's assumptions of limited market access during winter peaks, and no access during summer peaks, and no benefits of reduce reserves from joining in the Western EIM stands in contrast to Pacific Power's assessments and experience. Staff understands that these are two different utilities, but notes the importance of the study of market depth that PGE has recommended taking place before an RFP, if PGE is to cost-effectively meet its 2021 capacity need.

Recommendation
As in 4. B., Staff recommends an RFP for shorter-duration resources or contracts starting in 2021. This would allow time for a more robust understanding of market depth, as well as the increasing need for flexibility and its associated impact on system reliability. Additionally any long-term resource delay is valuable as broader energy market uncertainty continues to resolve. To reiterate, PGE's 2009 Action Plan modeled and called for approximately nine percent of its future energy resource mix to come from short- to mid- term market purchases.[83]

During the next IRP, it would helpful to Staff if PGE would hold a workshop or workshops detailing all aspects of its access to the wholesale market, as well as any unique issues or constraints it faces.

4. C. Flexibility

Despite assurances that PGE's need for flexible capacity is independent of incremental RPS action, Staff is as unsure as at any point in the IRP process regarding what PGE's actual flexible capacity needs will be in 2021.[84] First, PGE's proposed resource stack has changed. PGE added the Wells hydro facility back into the mix. Additionally all modeling for flexible capacity assumed PGE would be installing 515 MW of new wind capacity. This may not be the case. Finally, over 52 MW of renewable peak capacity has been added through QF contracts. Based on the extension of the federal Investment Tax Credit, there is likely

[83] PGE 2009 IRP, p. 317. While the 2009 IRP does not state the exact duration of these resources it notes that the resources would be added to cover the time period between 2011 and 2020.
[84] PGE Reply Comments, p. 61.

to be more QF contracts in the near future. Additionally, the near-term load forecast for 2021 has been adjusted down.

In lieu of re-running the REFLEX model, Staff suggests subtracting any changes to the resource stack from PGE's 400 MW requirement. Given the computational complexities associated with a REFLEX run, Staff looks to the Company to inform Staff on the best course of action to determine its 2021 flexible capacity needs in its Final Comments, given the changes in its resource stack.

Staff believes the use of the REFLEX model appears appropriate, though Staff was not able to examine the model itself. Staff looks forward to working with PGE Staff to find a way to share its flexibility model in the next IRP.

When studying flexible capacity needs, Staff noted that PGE used only portfolios that reach 25 percent RPS compliance with variable energy resources, and did not consider employing renewable energy credit purchases. The variability from the variable energy resources almost certainly causes the extent for flexible capacity to be somewhat overstated. We would like to see future runs of REFLEX model the impact of RPS compliance from REC's and no new, renewable resource additions until PGE reaches its RPS deficiency period.

Also, the REFLEX model did not allow the use of market purchases to alleviate ramping issues, except at very high prices. While PGE argues that assuming no access to the market is reasonable when studying capacity needed for reliability during peak-load conditions, Staff argues that this assumption is even more questionable when examining the need for flexibility. Day-in-and-day-out, the hourly markets are available for system balancing. Staff believes that the models should recognize this, as it would substantially reduce the need for flexible capacity.

In sum, the need for flexible capacity cannot be determined before the level of renewables that will be on the system is known. This does not appear to be a settled question. Additionally, Staff believes that the assumption that flexibility needs cannot be met with market access of any kind (other than at penalty prices) continues to seem unduly severe. Staff is certainly willing to work with PGE, as the Company suggests in its Reply Comments, but notes that this will be irrelevant if the flexible capacity is pursued as a result of this IRP.

Recommendation
At a minimum PGE should determine a way to be able to share the REFLEX model with Staff in the next IRP. Additionally, PGE should provide more robust analysis and discussion around the appropriateness of effectively barring market access to the model.

4. D. Assessment of Changing Regional Dynamics

Within the past five years, evidence of shifts in regional energy market dynamics have become more apparent to Staff and these are not addressed in depth or holistically in the PGE's IRP. PGE has a short assessment in the IRP on the region.[85] PGE concludes by stating:

> *The composition of power supply resources is changing rapidly across the WECC. In recent years, the region has experienced the retirement of San Onofre Units 2 and 3, and the rapid increase in wind and solar resources. In the next few years, the retirement of coal plants,*

[85] *See* PGE IRP, p.129, Section 5.2 - Regional Reliability Outlook

Diablo Canyon Units 1 and 2, and an even larger expansion of renewables will further alter the composition of the region, increasing the importance of regional planning and coordination.

Staff continues to find PGE's limited discussion of regional and overall market dynamics worrisome because the underlying analysis and PGE's resulting Action Plan rely on assumptions that reflect a belief of regional market fundamentals continuing forward over the next 34 years essentially unchanged from present today. Fundamental changes Staff sees which were not explored in greater detail, despite their significance, include:

- Negative mid-day spot market pricing at Mid-C due to high solar production in California;
- Availability of existing transmission due to coal plant retirement providing opportunity to access Montana wind; and
- Potential for expansion of the CAISO and growth of the EIM.

Each of these changes could be worthy of deeper exploration within the context of an IRP. When combined with other profound dynamics – i.e., LED transforming the lighting sector, continued trend of declining costs in solar and storage, IT improvements to communication technology, large corporations pushing for renewable PPAs, carbon laws in Washington, CCA's in California, etc. – Staff sees a need for caution and maintaining optionality.

Staff recommends that PGE take on an additional action within this Action Plan to commit to better understanding these changing regional relationships and opportunities. This exploration should be in concert with stakeholders and potentially expanded beyond Oregon to include California, the NW Power Council, and other regional system entities.

4. E. IRP-RFP Relationship

In its Reply Comments, PGE dismisses parties' concerns with "issues that pertain to the design and conduct of PGE's proposed RFPs" by asserting that "consistent with the Commission's RFP Guidelines, these issues will be considered in a new docket when PGE files a draft RFP."[86] It is of course important that these issues will be considered in the RFP docket, but this by no means forbids PGE from addressing these issues in the IRP docket. In fact, there are many important linkages between an IRP's methods and results and any subsequent RFPs.

Staff's concerns with issues regarding any future RFP(s) were not exclusively about RFP design or conduct. Rather, these concerns stem heavily from the wide latitude that acknowledgment of an Action Plan that is relatively open-ended would afford PGE in a subsequent RFP process. The Commission gives considerable weight to utility actions that are consistent with an acknowledged IRP Action Plan.[87] Staff and stakeholders remain justifiably concerned about what exactly the Commission might be approving in this IRP if it were to be acknowledged in its current form. Additionally, the IRP guidelines encourage a reasonable level of specificity in the analysis of needs and determination of resource acquisition strategies and the Commission does not generally acknowledge indefinite future resource acquisitions, which could be influenced by any number of factors.[88] In 2011, the Commission found Pacific Power's request for "up to 800 MW of wind" to be too indefinite to recognize, explaining that "the purpose of an

[86] PGE Reply Comments, p. 12.
[87] *See* Order No. 12-082 In the Matter of PacifiCorp 2011 Integrated Resource Plan LC 52, p. 3.
[88] Id. p. 3.

action plan is to identify specific near-term actions that the company plans to take to meet its resource needs. We will not acknowledge actions that are open-ended and too far in the future to be meaningful."[89] As stated in our initial comments, Staff remains concerned that PGE's current analyses and Action Plan essentially push all evaluation of resource alternatives into the RFP process.[90] Staff believes that should the Commission conclude that this open-ended strategy is appropriate, it will necessarily require a correspondingly open RFP design process that provides substantial opportunities for input from stakeholders and the Commission.

4. F. Portfolio Analysis

In its Initial Comments, Staff expressed the concern that PGE's portfolios failed to consider a sufficiently broad range of strategies, such as one that evaluated the use of short- or medium-term commitments to delay the need for larger resource procurements (for either capacity needs or RPS compliance). Staff maintains that the IRP's lack of a transparent and rigorous analysis of such a strategy remains one of the major short-comings of PGE's IRP. Staff appreciates that PGE is exploring bilateral opportunities to acquire existing capacity and looks forward to receiving updates on this process. Staff also appreciates that PGE was "not able to confirm or refute whether owners of existing hydro capacity would bid into a future PGE RFP."[91] Given that, and that only one hydro capacity bid was received in PGE's 2011 capacity RFP, Staff disagrees with PGE's claim that "issues pertaining to the design and conduct of the RFP should be considered in the RFP docket."[92] Given the implications for an RFP that result from the IRP docket, Staff does not understand PGE's reluctance to discuss RFP issues within the context of the IRP docket.

PGE states that despite parties' suggestions of considering a strategy to delay the acquisition of a large new thermal capacity resource, "PGE cannot wait 30 years to meet its capacity needs."[93] Staff agrees, but does not believe any parties have suggested waiting so long. PGE then presents an analysis that demonstrates that an efficient capacity resource is expected to be cheaper than a generic capacity resource even if the efficient capacity resource can only operate economically for 15 years. Staff wishes this comparison were made not with a generic capacity resource but with a strategy of relying on market purchases and PPAs.

PGE also objects to CUB's suggestion that PGE conduct an RFP for resources two to ten years in duration and no minimum size, on the grounds that it is outside the scope of the Commission's Competitive Bidding Guidelines and "problematic from a process standpoint."[94] PGE states that its capacity needs, "identified as up to 850 MW" would not easily be met with small bids. PGE's Reply Comments then demonstrate that its current capacity need has fallen from the 819 MW identified in the IRP down to 561 MW.[95] Given this, and PGE's ongoing bilateral negotiations, Staff questions PGE's objections and supports CUB's suggestion for a term-limited RFP.

Staff also suggested that PGE consider portfolios designed to meet different load forecast scenarios, especially given Staff's concerns with PGE's load forecast (discussed elsewhere in these comments).

[89] Order No. 12-082 In the Matter of PacifiCorp 2011 Integrated Resource Plan LC 52, p. 7.
[90] Staff comments, p. 32.
[91] PGE Reply Comments, p. 12.
[92] PGE Reply Comments, p. 12.
[93] PGE Reply Comments, p. 94.
[94] PGE Reply Comments, p. 10.
[95] PGE's letter dated April 13, 2017, "LC 66 –Portland General Electric Company's 2016 Integrated Resource Plan (IRP) Update to Figure 5 of PGE Reply Comments." Available at http://edocs.puc.state.or.us/efdocs/HAC/lc66hac163938.pdf

PGE says that evaluating portfolios designed for different load forecasts “would draw false conclusions by comparing portfolios on the basis of cost that meet fundamentally different levels of need.”[96] Staff understands PGE’s concerns, but believes that PGE may in fact have a fundamentally different level of need than the range it considered when evaluating its portfolios. Staff believes PGE’s IRP should have contemplated the possibility of credible low load growth scenarios (such as that expected by Seattle City Light or Puget Sound Energy) by transparently and rigorously evaluating a strategy designed for the possibility of a low-growth future. In its Reply Comments, PGE provides an example of this type of analysis applied to its proposed early RPS action and finds that the value of early acquisition of 175 MWa wind is around $23 million less in a zero-growth future than in PGE’s base-case forecast.[97] Staff believes PGE should have given its proposed capacity resource acquisitions similar scrutiny. Similarly, Staff appreciates PGE’s consideration of a “delay” portfolio for RPS resources (i.e., a portfolio without procurement of a new RPS resource until 2029). Again, Staff believes that a strategy to delay the acquisition of capacity resources should also have been presented.

4. G. Portfolio Scoring

Staff has expressed concerns with PGE’s portfolio scoring metrics throughout the IRP process and appreciates PGE’s efforts to investigate these concerns. PGE’s Reply Comments include detailed sensitivity analyses to test whether its portfolio rankings are influenced by small changes in how certain metrics are constructed and weighted. These analyses demonstrate that the rankings in this instance are largely unaffected by these sensitivities. This has greatly reduced Staff’s concerns that the problems present in PGE’s metrics and ranking procedures are in this case affecting the selection of the preferred portfolio from among the particular portfolios that PGE has considered in this IRP.

However, PGE’s sensitivity analyses confirm that its ranking system is subject to concerns Staff has identified. Because Staff’s concerns are ultimately with the scoring system, not the outcome, Staff is reluctant to recommend acknowledging a flawed scoring system given the precedents such an acknowledgement would set and the existence of requirements that link RFP analyses to methods used in the IRP. In particular, Staff believes an important feature of a ranking system is that the relative rankings of the included portfolios should be invariant to the inclusion (or exclusion) of other portfolios. These concerns are discussed in greater detail in Staff’s Initial Comments. PGE’s sensitivity analyses confirm that its ranking system suffers from this problem.

Staff and other parties raised concerns with PGE’s “Durability” metric in particular. PGE states that the durability metric “relies on some extent on arbitrary definitions” but that it nonetheless provides “insight” that is “not captured by other risk metrics.”[98] Staff believes that the durability metric’s arbitrariness and reliance on ordinal (rather than cardinal) information is opaque and clumsy. More importantly, the important information underlying this metric could more easily be captured simply by using the average cost of a portfolio, rather than arbitrary thresholds and rankings. For example, PGE “contends that a portfolio that outperforms all other portfolios, regardless of which future is realized, should be preferred to other portfolios.” Staff does not disagree. However, a portfolio that performs in this manner will necessarily have the lowest average cost, and the durability metric does not improve in any way on average cost as a metric. PGE points out that the case of one portfolio always performing better than all others is overly simplified but offers no justification that its durability metric somehow

[96] PGE Reply Comments, p. 86.
[97] PGE Reply Comments, p. 22, Table 6.
[98] PGE Reply Comments, p. 102.

performs well in more complicated situations. Staff maintains that the durability metric is not sufficiently useful to justify its arbitrariness or opacity and recommend discontinuing its use.

4. H. Distribution System Planning (DSP)

In its Initial Comments on the PGE 2016 IRP, Staff reflected on the implications of the transforming expectations and opportunities for the distribution system on utility planning and operational practices and arrived at two general observations.

1. Current utility and regulatory distribution planning processes may not be sufficiently linked, nor transparent enough to provide comprehensive review and engagement by the Commission and stakeholders.
2. The current representation of DERs in the IRP may be underrepresenting the potential contribution of DERs to the system, which could lead to a greater risk of identifying an inflated resource need in the IRP.

Combined, these observations are symptoms of not having the right tools in place to evaluate and plan for optimizing the distribution system as a resource.

Benefits of DSP

Staff identified several potential benefits to undertaking some form of a DSP process at this time to address these areas of concerns. These benefits include:

- Creating a comprehensive, transparent plan for distribution level investments. This plan and the process in developing it would provide a framework for meaningful regulatory review, connecting and streamlining disparate processes, leading to greater regulatory guidance to utility investment strategies on the distribution system. Creation of this framework would allow parties to get ahead of data, consumer protection, DER penetration, and other complex issues that may grow in harmful directions if not addressed early on.
- Establishing clear links between distribution system and IRP planning would establish the distribution system itself as a resource option to meet bulk system needs.
- Enabling intentional locational planning for DERs by capturing locational value of resources and optimizing use of existing resources, leading to lower system cost.
- Minimizing costs and risks of uncoordinated growth and investment. Comprehensive planning could help minimize risks of investing in grid improvements that may not be compatible with other investments, supporting a least-regrets investment strategy.

PGE responded to Staff's Initial Comments in a positive manner stating "PGE supports efforts to align the various regulatory processes related to distribution planning and is willing to work with Staff and others on this effort. PGE is also open to suggestions for improved assessment of DERs in its IRP."[99] Staff is encouraged by PGE's response and would like to begin to work with PGE and stakeholders to investigate, define, and implement DSP over the next several years.

<u>Potential Process</u>

As generally envisioned by Staff, a process to define DSP could include the following steps.

[99] PGE Reply Comments, p. 116.

- Preliminary scoping and setup
  This step begins with Staff requesting that the Commission open an investigation into DSP with a list of proposed goals for the process. To inform the request, Staff and interested parties would partake in preliminary discussions. Upon Commission Order, the process would begin by Staff and parties scoping the activities needed to achieve the adopted direction of the Commission. Essentially this is the road map creation phase of the process with a deliverable of this phase being a plan or roadmap for approaching DSP.

- Baseline assessment
  The first major activity could be a baseline assessment of three distinct categories:
  a. The current distribution system infrastructure, including communications and controls equipment capabilities and DER penetration.
  b. The links between four existing planning categories: DER locational value dockets, distribution capital planning, Smart Grid Reports, IRPs and ultimately the translation of these activities to customer rates through rate cases and power costs.
  c. Current access to enabling data and analytics needed to turn data into useful information.

- Definition of Planning and Operational Investigation Areas
  With a thorough understanding of the current state, the next step would be to define what is needed related to planning and operational activities to achieve the goals of DSP. Examples of these activities could include the following:

  a. ***Creation of the Distribution System Plan*** as a guide for how to most efficiently prepare the system to handle and enable additional cost effective DERs. This plan would be similar to the IRP, filed on a regular basis, include an assessment of uncertainty and risks but focused on the distribution system over a shorter time horizon than the IRP.

     As a new planning effort, Staff sees the Plan evolving over time with better information and tools created in parallel to the Plan. The Plan would connect and possibly consolidate other planning categories noted above, ultimately streamlining multiple activities into one coordinated effort. This plan would evolve over the years and be informed by other parallel tasks listed next.

  b. ***DER forecasting and modeling improvements*** would include identifying and implementing improvements to current studies used to asses individual types of DERs on the system. This could include identifying specific scenarios for DER growth and incorporating interactions between DERs in forecasts.

  c. ***Identification and implementation of pilots*** to help answer specific research and implementation questions. Utilities are running multiple pilot projects today as a way to test new ideas before investing significant funds. Pilots could be designed to learn how to assess locational situations and better understand data needs, technology barriers, and customer behavior as well as provide utilities with operational experience before investing in large scale projects.

d. ***Tool development*** ensures that newly created and collected data points from a modern grid turn into useful information for utilities, customers, and the market to enable valuation of DERs leading to efficient investment. An example includes tools to determine and share feeder level hosting capacity information. Tools to evaluate the system benefits of specific DERs so that those resources can be evaluated on par with traditional options. Utilities are in the midst of working on tools to evaluate costs and benefits of DERs and prioritization of grid investments. This effort would ensure consistency across utilities in approach as well as transparency and collaboration.

These ideas are not all inclusive at this point but are provided as examples of activities that may be considered within the context of DSP.

<u>Conclusion</u>

Costs of new technologies such as energy storage, electric vehicles, communications and controls, and distributed generation are on declining cost curves and interest is growing in them. To plan for cost-effective integration of these new technologies and to encourage the most beneficial placement of new DERs and most efficient use of the system Staff recommends that it's time to create a comprehensive, transparent plan for grid modernization through Distribution System Planning.

5. Recommendations

At this point, Staff recommends the following actions and additional requirements:

- **<u>Actions: Recommend for Non-Acknowledgment</u>**
    a. Early RPS Action
    Staff recommends the Commission not acknowledge PGE's plan to issue an RFP in 2018 for up to 500 MW of renewable capacity. Instead Staff recommends that renewables be considered as one of the allowable products in a near-term RFP to cost-effectively meet PGE's 2021 capacity need.

    b. Dispatchable Capacity
    Staff recommends the Commission not acknowledge PGE's Action Plan item to issue an RFP for dispatchable capacity between 375 – 550 MW. Instead, Staff recommends an RFP for dispatchable capacity be considered following the next IRP update and only after PGE satisfies the following four requirements: conclude bilateral negotiations, complete a market study, present a re-analysis of adjusted dispatchable capacity need, and conduct RFP(s) for resources of limited duration and renewables of any duration.

    c. Demand Response
    Staff recommends that the Commission not acknowledge PGE's Action Plan item to acquire only 77 MW of DR by 2021. Instead, Staff recommends that PGE seek to obtain more than 77 MW in 2021 by working with Staff to create a DR Review Committee and by launching a DR Testbed no later than July 2019.

- **<u>Actions: Recommend for Acknowledgment with Requirements</u>**
    a. 135 MW of EE
    Staff recommends acknowledgement of PGE's proposed EE actions but recommends the Commission require that Energy Trust provide more information to PGE on energy efficiency measures and its forecast methodology.

- **<u>Actions: Acknowledgment</u>**
    a. CVR Activities

    b. DSG Activities

    c. Submission of storage proposals in 2018

    d. All enabling studies and studies mentioned in PGE's Reply Comments

- **<u>Additional requirements or recommendations for PGE's next IRP</u>**

    a. Load Forecast Methodology & Scenario Analysis
    PGE should conduct an in-depth analysis of forecast drivers and the likely-changing nature of their assumed relationship with load, compare alternative forecast methods based on out-of-sample performance, and re-evaluate its methods for constructing high and low scenarios based on advanced forecasting practices.

    b. RPS Strategy to be opened as a Docket or taken up as part of the RPIP

c. Conclude bilateral negotiations

d. Complete a market study

e. Present re-analysis of adjusted dispatchable capacity need

f. Conduct an RFP for two products: resources of limited duration and renewables of any duration.

g. Launch Distribution System Planning Docket

This concludes Staff's final comments.

Dated at Salem, Oregon, this 12th of May, 2017.

JP Batmale

JP Batmale
Sr. Utility Analyst
503.378.5942
jp.batmale@state.or.us

APPENDIX A: DEMAND RESPONSE TESTBED OVERVIEW

Introduction

Portland General Electric's (PGE) latest Integrated Resource Plan (IRP) filing with the Oregon Public Utility Commission (OPUC) indicates PGE and their customers are facing a deficit of over 562 MW of generation capacity by 2021 driven in large part by the pending retirement of the Boardman coal generation plant. Commission Staff are interested in PGE acquiring the best combination of resources, from both a cost and risk perspective, to fill this need.

In their IRP, PGE has proposed to acquire roughly 78 MW of Demand Response (DR) by 2021. The amount of DR PGE is proposing is based in part on assumptions of achieving about half the Brattle-defined resource over twice the time period. Staff is sensitive to concerns expressed by PGE that:

- The DR resource PGE needs to offset generation requires both summer and winter peaking resources;
- PGE and regional customers have little experience with DR on which to base long-term planning assumptions about costs, penetration rates, and achievable penetration; and
- PGE's new customer service information (CIS) system is not yet ready to support more aggressive programs based on dynamic pricing schemes such as time of use (TOU), critical peak pricing (CPP), and peak time rebates (PTRs).

However, Staff is not satisfied with PGE's rationale for aiming for a target well below what Brattle suggests is possible.

Representing the interests of Oregon electric utility customers requires balancing the potential of achieving a much larger cost-effective demand response resource against the uncertainties associated with key assumptions.

Therefore, as PGE begins immediate deployment of its proposed DR programs, Staff proposes that the Company establish a testbed where the proposition of DR <u>at scale</u> can be tested on a limited population to anticipate penetration rates, test program designs and customer recruitment strategies, establish the required mix of customer types, test the acceptability of dispatching DR with the frequency and duration needed to achieve such large offsets, and project costs at scale with a high level of confidence, etc., while limiting financial exposure on the part of ratepayers. This would involve choosing specific populations of customers in confined service areas, preferably in areas exhibiting rapid growth where transmission and distribution (T&D) benefits can also be derived to offset costs, and targeting them with an aggressive set of current *and forward looking* programs designed to test DR potential at scale.

This discussion paper describes the rationale and key characteristics of such a testbed.

Why a Testbed is needed

The fundamental purpose of the DR testbed is to test a number of hypotheses and critical assumptions about the potential of DR in the Northwest that are difficult or impossible to obtain during the initial rollout of PGE's proposed DR programs. Without such a concerted effort, and in light of the Brattle study results (imperfect as they are) and the recent information from the Council about the value of DR to the region, the prudence of PGE selecting lower acquisition targets without answering fundamental questions about actual DR resource potential in its service territory would be in question.

Time is also of the essence in order to address the potential gap identified in 2021. PGE cannot wait to begin deployment of its proposed DR programs, so Staff is interested in near term actions that are consistent with the larger long term strategy and goals.

Program design is critical – poor program design leads to poor results -- so engagement and accountability in program design is critical. Both the initial DR programs and those developed and tested in the testbed should be considered to be "Phase 1" of program rollouts, rather than "pilots". While this distinction is to a degree semantic, Staff feels that it embeds a necessary intent on the part of PGE to design programs with the seriousness and completeness to persist though changes may be indicated by early deployment experiences.

Key information that should be gathered from the test bed programs include:

- Data on achievable potential informed in part by participation rates and savings for both winter and summer peak.
- Program and customer costs under different scenarios such as new construction, end-of-life replacement, retrofit, and when DR programs are combined with energy efficiency programs.
- Develop experience and program management best practices to achieve desired outcomes, including cultivating PGE expertise.
- Moving from initial program offering such as direct load control to long term strategies that consider subsequent stages which include TOU/CPP pricing programs and PTR (Stage 2), truly dynamic pricing programs such as variable time rebates (VTR) or real-time prices (RTP) that provide greatly increased flexibility to manage renewables (Stage 3), and ultimately mechanisms akin to transactive coordination schemes that provide closed loop control and the "throttle" necessary to manage DR networks at scale to achieve multiple, complex operational objectives.
- Develop specific information on PGE's needs for human capacity and infrastructure associated with achieving different scales of DR deployment.

What would the Testbed look like?
The essential notion of the testbed is to pick a community and focus a concentrated effort to recruit virtually everyone to participate in DR programs to see how many can be engaged and maintained and what mechanisms are best suited to achieving penetration at scale. This is analogous to the Hood River Project experiment in the Northwest in the early 1980s that sought to quantify the achievable potential of conservation.

Key characteristics of the testbed could include:

- Focus on a geographically defined community where recruiting and deployment efforts are both concentrated, to both save overall testbed costs and to test them at scale. For example, marketing, outreach, customer service, and installation efforts should be reduced as a result and much better represent those at scale.

- Automated metering infrastructure (AMI) should be nearly universal as a foundation for evaluation and dynamic pricing or rebates.
- Ideally, the community should be experiencing high growth. This provides ample new construction to test the degree to which deployment costs are lower in new buildings. It also affords the possibility to offset testbed costs.
- Multiple communities may be necessary to target multiple customer segments –downtown Portland may be the only locale with large high-rise commercial buildings, for example. Nonetheless, the resulting DR resource should be operated as if it was in a single locale.

Hypotheses and Critical Planning Assumptions to be measured
Among the hypotheses and critical assumptions that should be tested in the testbed are:

- **Can customers be recruited in sufficient numbers to achieve more significant peak demand offsets and renewable integration cost benefits?**
- **To what degree does customer awareness and acceptance of the Northwest's historically aggressive energy efficiency programs offset customer's unfamiliarity with DR programs?**
- **Forecast ultimate penetration and time periods to achieve them?**
- **Will customers who sign up for DLC programs, accept being dispatched with the frequency and duration needed to achieve substantial reductions in peak loads for PGE as a whole or local T&D systems?**
- **Do pricing-based programs mitigate mandatory dispatch issues for consumers?**
- **Can Portfolios of DR offerings increase recruiting?**
- **How much more cost effective is DR, and what level of increased penetration rate can be achieved, by programs targeting new buildings?**
- **Replacement programs, working with supply chain partners.**
  Similar to new construction, the equipment replacement market for air conditioners, water heaters, and other equipment represents a major marketing and cost-saving opportunity for DR. The Northwest has a long history of applying "market transformation" approaches, working with supply chain partners, to advance energy efficiency. These approaches should be applied and tested as a key program element for DR. PGE should work with the Oregon Energy Trust to do marketing and leverage the Energy Trust's trade ally network. It should also consider how to synergize with Northwest Energy Efficiency Alliance (NEEA) and the Energy Trust in other ways – make time to explore this up front in a transparent way.

- **Regional branding program.**
  To address the issue of low customer awareness of DR, PGE should partner with the NEEA and the Oregon Energy Trust to lead development and testing of a regional collaborative branding campaign centered around the dual message of "green + incentives" that will enhance DR program potential.

- **Joint EE/DR programs.**
  Because there are likely synergies with energy efficiency objectives, messaging, recruiting, and in some cases equipment costs, PGE should undertake to develop and test this proposition.

- **Determine the level of customer service staff and program operating staff needed.**
  Staff acknowledges that PGE will need additional staff to manage programs and customer relations in conjunction with DR programs. The testbed programs should also be used by PGE to estimate the numbers of staff that will be needed when deploying at scale. At the same time, it should leverage this as an opportunity to train a core complement of customer engagement staff in preparation for full scale implementation.