BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 66

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2016 Integrated Resource Plan.	Staff's Initial Comments

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1. EXECUTIVE SUMMARY

These first round Comments by Staff represent the culmination of work and research by many people, most notably Portland General Electric (PGE). Staff appreciates the work done by PGE on this Integrated Resource Plan (IRP). They have managed the IRP process in a collaborative and constructive manner. The technical innovations introduced by PGE in this IRP are an encouraging evolution to the IRP process. As the Oregon Public Utility Commission (OPUC or Commission) enters its 28th year of least-cost planning this IRP represents both how far the process has come and the immediate challenges ahead.

The goals of Staff's Comments are to raise questions, share observations and provide feedback for areas of additional review. Staff continues to undertake careful review of the IRP as it recommends significant resource investments by 2021 against the backdrop of many uncertainties.

The list below highlights Staff's main points of concern or uncertainties with PGE's IRP at this stage. It is not meant to capture all concerns.

- **Capacity need**
  Staff is uncertain as to the extent of PGE's actual capacity needs beginning in 2021. Our analysis using the same data and software, but using existing operating conditions, led to a capacity need of 40 percent less than PGE's.

- **Projected load growth**
  Staff has concerns about the methods underlying PGE's projected load growth of 1.2 percent in this IRP and therefore has low confidence in PGE's projections. Our concerns stem from the need to better understand – and address – four things: PGE's assumptions and statistical approach for projecting load growth; their explanation of these assumptions; the methodology for characterizing and assessing the uncertainty in the projections; and, the basis for the high industrial load growth forecasts that drive the overall load growth projection.

- **Portfolio construction & selection**
  All portfolios were constructed around a defined set of risks and assumptions that did not vary. Selection of the top portfolios was then based on the economic costs to meet this limited range of risks and assumptions. Staff has concerns about this approach.

- **Timing of renewables**
  Given what PGE has presented, Staff is unconvinced of the need to acquire renewables in 2018. The economic arguments PGE presents need more support. Specifically, staff is unclear as to the actual usability of the Federal Production Tax Credits. Also, Staff questions the RPS compliance value of the "golden REC's" generated by wind – or any new renewables – in 2018. Finally, Staff needs to better understand PGE's REC bank policies as they seem to artificially propel economic decisions by overstating RPS compliance risks.

- **Market Depth**
  In the recent past PGE relied much more on the market than the IRP suggests it will in the future. This IRP marks a definitive shift away from the market reliance for energy and capacity needs. PGE says it will study the market in greater depth, but this will

effectively occur after the RFP is complete and PGE has decided upon new resources to build.

- **Resource duration consideration**
  PGE's portfolio construction and overall analysis seems to be weighted toward long-term assets. Staff needs to better understand how the immediate acquisition of long-term assets best serves ratepayers given near-term market uncertainties. These uncertainties include disruptive distributed technologies, regional market dynamics and public policies that will make fundamental changes to how utilities operate over the next five to ten years.

- **Bilateral contracts**
  Staff noted the drop off in hydro capacity between the last IRP and hydro going forward with little to no explanation as to the results or activities around renewing existing hydro contract or the availability of new hydro contracts, especially given the role hydro played in meeting PGE's retail load just four years ago.

- **IRP and RFP Relationship**
  Staff believes that one of the key outcomes of an acknowledged IRP is the specific guidance it provides for subsequent resource procurement. And while Staff agrees with PGE that there are many uncertainties in the market currently, the relative vagueness of the IRP's Action Plan is problematic. The RFP is not meant to be the forum to assess and build the optimal portfolio of new resources. Staff needs greater clarity from PGE within this IRP about how its RFP will proceed and be constructed.

- **Lack of demand response**
  PGE's level of demand response (77 MW) acquisition over the course of the IRP Action Plan time horizon is considerably *less than* the cost-effective DR potential identified by its own study. An aggressive set of demand response programs could have a significant impact on PGE's peak capacity needs. Staff needs to better understand PGE's barriers to quicker adoption given that successful examples of demand response programs already exist across the country.

2. DEMAND SIDE [1]

Overall, Staff is concerned about the analysis behind PGE's projected need for energy and capacity. We are unconvinced of the reasons behind the low adoption rate of demand response (DR) programs in the near-term and PGE's forecasted load growth in the medium- to long- term. Staff believes that adjustments to these two elements of PGE's IRP could reduce PGE's resource capacity needs by 100 to 200 MW in 2021 and have even large ramifications in 2025 and beyond.

2. A. Load Forecast

Staff's review of PGE's load forecasting methodology has raised a number of concerns. In short, Staff is concerned that, because of methodological issues, PGE's load forecast may not be an accurate representation of the expected future demand. Furthermore, Staff believes PGE's current approach may not fully capture the uncertainty present in its projections of future load growth.

Staff bases this position on several issues: 1) the implicit assumptions in the load forecast methodology and the IRP's lack of an explanation of these assumptions, 2) the construction of the high and low load growth scenarios (PGE refers to these as "jaws") used to represent the uncertainty in the load forecast and the findings from an independent study produced at Lawrence Berkeley National Laboratories (LBNL) assessing various utilities load forecast historical performance,[2] and 3) concerns with assumptions used to construct industrial load growth projections.

As described later in these comments, Staff believes the high and low load growth scenarios currently considered in PGE's IRP understate the uncertainty in PGE's reference case forecast of its long-term future load growth. The underrepresentation of uncertainty in load growth projections raises the concern that PGE's portfolios have not been designed with sufficient diversity to determine the best near-term actions to pursue, given the large and uncertain range of possible future conditions. Staff notes that the rankings of PGE's portfolios remain constant across load growth scenarios. Staff sees this "load-invariant" characteristic of PGE's portfolio rankings as potentially indicative of methodological flaws.

<u>Load Forecast Methodology</u>

The IRP's discussion of PGE's long-term load growth forecast does not clearly describe PGE's forecasting methodology. Staff seeks more clarity regarding the major assumptions contained in PGE's forecast, as required by the Commission's IRP Guideline 4b.[3] This includes both (1) assumptions about the relationship between variables implied by a model's specification, and (2) assumptions about the structure of the data that must be met in order to make valid inferences from estimates of the models parameters.

For example, Staff is concerned that PGE's long-term forecasting method carries the implicit assumption that there will be a constant relationship (through the planning horizon) between

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[1] Staff's Comments reference and rely upon materials from other Commission dockets as well as documents that originate outside of the Commission's processes. To the extent necessary, Staff asks the Commission to take official notice of such materials pursuant to OAR 860-001-0460.

[2] *See* "Load Forecasting in Electric Utility Integrated Resource Planning" by Lawrence Berkeley National Laboratory, October 2016, available at https://emp.lbl.gov/sites/all/files/lbnl-1006395_0.pdf. It should be noted that PGE had the highest forecast error among all utilities studied (table 3) and PGE's projections of its load growth rates increased over time despite the fact that PGE's actual load growth rates were declining (table 13).

[3] *See* Commission Order No. 07-002.

electricity demand and the fundamental economic drivers that PGE considers in its models (e.g., GDP).[4] This is an example of a major assumption that arises implicitly from PGE's forecasting methods and it deserves explicit explanation in the IRP, as required by Guideline 4b.[5] This assumption arises because, when forecasting load, PGE models the relationship between load and various economic variables (e.g., GDP) without allowing for the relationship between these variables to change over time. When PGE subsequently applies the parameter estimates from its models to the forecasts of the economic drivers, this implies the assumption that the relationship between economic activity and electricity demand will remain constant throughout the planning horizon. Staff believes it is important to examine whether these relationships have historically been constant, or changed over time.

Staff is also concerned that PGE's models may violate a basic assumption required in time-series econometrics, which is that the data used to estimate the model have a stationary distribution.[6] Staff appreciates the time that the Company's forecasting team has provided to discuss its methodology, and recognizes that this concern about stationarity is a technical issue that perhaps the Company has addressed elsewhere. Staff believes it is an important issue, however, and elaborates on its concern here in the spirit of reaching a greater understanding of PGE's forecasting methods.

One of the most serious potential results of using regression models on data with a nonstationary distribution is as follows: "an extreme example of the risks posed by stochastic trends is that two series that are independent will, with high probability, misleadingly appear to be related if they both have stochastic trends, a situation known as spurious regression."[7] The use of nonstationary data in forecasting is also problematic because projections derived from such data are often highly sensitive to how the lagged (historical) variables are included in the model.

Staff's concerns that PGE's models may be subject to the problem of non-stationarity are as follows. A classic example of data that do not have a stationary distribution are data that have a trend over time, such as GDP (and many other economic variables), which some of PGE's models employ. Staff obtained the data that the Company uses to estimate some of its models (in PGE's confidential response to Staff DR 9) and Staff performed an Augmented Dickey Fuller test on the confidential data. Using this test, Staff found that, for some of the data series, the test failed to reject the null hypothesis of a unit root. This is often an indication that the data are not stationary. This finding is problematic because nonstationary data violate the stationary data assumption of time series regression, and therefore some of the Company's model results might be invalid.

<u>Load Forecast Error Analysis</u>

Staff has concerns with the Company's characterization of the uncertainty surrounding estimated load growth. Staff understands that PGE's intention was to form high and low forecasts of load growth based on a difference from the reference case of "one standard deviation." Staff is concerned that the Company's method of constructing its high and low cases

[4] The "planning horizon" for this IRP is 34 years, roughly 2017 to 2040. In past IRP's the planning horizon has been 20 years. The "action plan time period" is from 2017 to 2021.

[5] This assumption arises because PGE's methods rely on an estimate of the relationship between load and economic variables that is derived from models which do not allow for the relationship (between GDP and load) to vary over time. When PGE subsequently uses this estimate to create its load forecast, it embeds within its forecast the assumption that these relationships will be the same over the planning horizon as they have been historically, as estimated under the assumption that they have historically been constant.

[6] *See*, for example, Stock, J.H. and Watson, M.W. (2011) "Introduction to Econometrics" page 537.

[7] Stock and Watson (2011), page 549.

may be incorrect because PGE has used the standard *error* in growth rates, not the standard *deviation*. If PGE were to base its high and low cases instead by using the standard deviation, as Staff believes was PGE's intent, this would move the current "jaws" away from the reference case by a factor of roughly five.[8] However, Staff is further concerned that prediction intervals are typically formed using the distribution of residuals (errors) from a model, rather than the distribution of the outcome (dependent variable) modeled, as PGE has done.

Staff also has concerns about PGE's practice of including various "shift" (dummy) variables in its econometric models, which Staff has raised previously in rate cases. Staff appreciates the Company's work in examining this issue. However, Staff continues to be concerned about this, especially with regard to understanding the uncertainty in the Company's load forecast because the practice of including in the historic model variables that cannot be included in the forecast has the effect of "over-fitting" the model and therefore further understates the uncertainty present in forecasts generated with the estimates of the models parameters.

As evidence of Staff's uncertainty in PGE's load forecast, Staff believes PGE's response to IR 017 is illustrative. It reveals that PGE's actual monthly load has fallen outside of the range defined by the high and low forecasts presented in its 2013 IRP in 20 out of the 22 months for which PGE provided data. In other words, PGE's high and low demand forecasts contained the actual monthly load less than ten percent of the time.[9] PGE's 2016 IRP states that its high and low cases "appropriately bookend load forecast scenarios" and are "sufficiently large" to encompass differences from the reference case caused by broad economic changes in the region, technology developments, or other long term trends.[10] Staff does not understand how PGE came to view its "jaws" as "sufficiently large" given the recent experience.

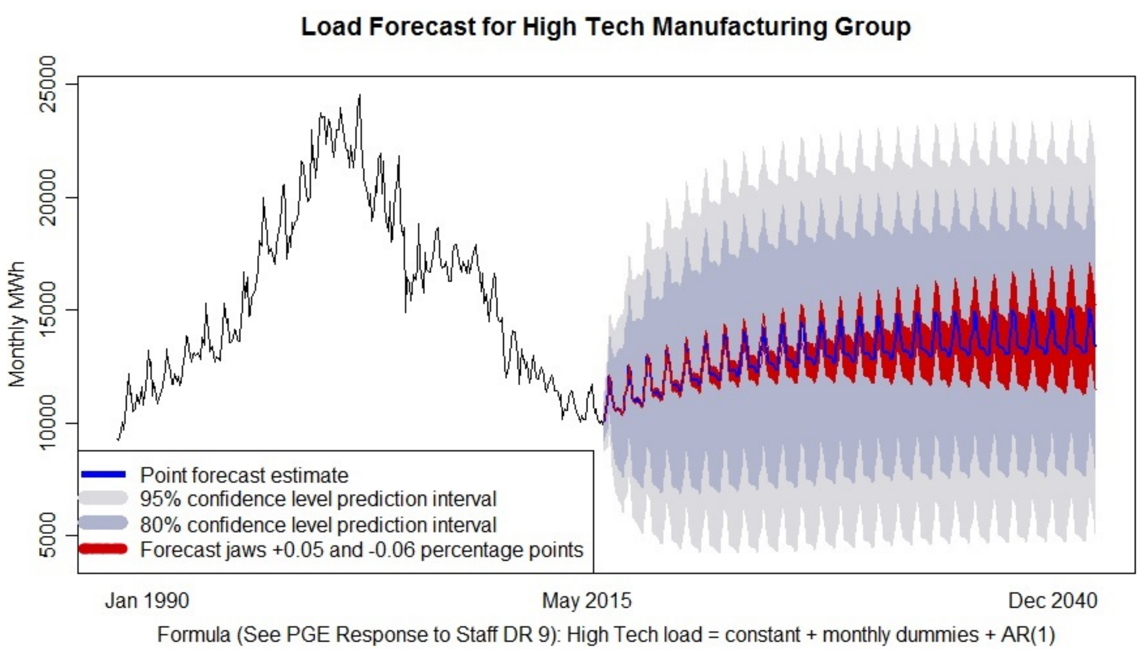
The Lawrence Berkeley National Laboratories (LBNL) published a report in 2016 that compares the load forecasts of several utilities to their actual demands.[11] This report further increases Staff's concerns with PGE's load growth forecasts because it identifies two facts about PGE's recent forecasts that are particularly concerning. First, like the 12 other western utilities studied by LBNL, PGE's load forecasts have been consistently higher than its actual load. PGE has pointed to the broader economic recession in the late 2000s as a reason for this, but it must still be noted that PGE has had the highest forecast error (at 19 percent) among all the utilities studied.[12] The poor historical performance of PGE's load forecast, relative to the other electric load-serving entities studied by LBNL, further increases Staff's concerns with PGE's characterization of the uncertainty in its current load forecast (described above). Second, during 2007 to 2014, PGE's projections of its load growth rates increased over time despite the fact that PGE's actual load growth rates were declining.[13]

[8] Based on a comparison of the standard errors provided in, and standard deviations calculated with, the data contained in DR Attachment 012-E.
[9] Prediction intervals for forecasts are typically designed to reflect the expectation that they will contain the actual outcome either 80 percent or 95 percent of the time. *See*, for example, Hyndman, R. and Athanasopolous, G. (2013) "Forecasting: Principles and Practice" OTexts, or Casella, G. and Berger, R.L. (2001) "Statistical Inference" Duxbury Press.
[10] PGE IRP page 107.
[11] LBNL (2016) "Load Forecasting in Electric Utility Integrated Resource Planning" available at https://emp.lbl.gov/sites/all/files/lbnl-1006395_0.pdf.
[12] *See* Table 3, LBNL 2016.
[13] *See* Table 13, LBNL 2016.

Period	Projected Avg Annual Growth Rate	Actual
2007-2014	1.78 percent	0.23 percent
2009-2014	2.10 percent	0.09 percent
2012-2014	2.30 percent	-0.18 percent

Source: Table 13, LBNL 2016.

Staff provides an example in the graph below to illustrate two different approaches to convey forecast uncertainty. The graph uses the Company's short-term forecasting equation for the high tech manufactures' load and depicts an approximation of the Company's jaws approach (in red) and the confidence interval approach (the shaded grey bands). The jaws approach applies +0.05 and -0.06 percentage points to Staff's point estimate of load growth, consistent with the high and low cases presented in Table 4-1 in PGE's IRP (page 106). The confidence level prediction interval approach is a much more commonly-used statistical approach and Staff believes that the use of an 80 or 95 percent prediction interval would more transparently characterize the uncertainty in the Company's long-term load growth forecast.[14]



Industrial Load Growth Assumptions

PGE's overall long-term load growth forecast is driven by its projection that the industrial sector will grow at a faster pace than the other sectors PGE serves.[15] Staff has issued data requests to gather more information about the assumed growth rates that PGE uses when constructing its industrial load growth forecasts, and Staff continues to examine PGE's forecast of its industrial load growth. Based on Staff's analysis so far, Staff is concerned that PGE's projected

[14] *See*, for example, Hyndman, R. and Athanasopolous, G. (2013) "Forecasting: Principles and Practice" OTexts.
[15] PGE IRP page 105.

growth rates for its industrial customers unreasonably exceed recent trends. Staff has additional methodological concerns, outlined below.

Methodology Concerns
PGE's 2016 IRP assumes no additional long term opt-outs of cost of service rates.[16] Staff assumes that a substantial portion of direct access load would be industrial customers, thus any assumptions about opt-out levels will directly influence the industrial load forecast. PGE estimates that approximately 80.4 average megawatt (aMW) of load would be allowed to long-term opt-out of cost of service rates under the first 300 aMW limitation.[17] PGE's confidential response to Staff DR 19 indicates that a wide variety of business types, spanning 61 unique NAICS codes, have opted for direct access. Staff requests that the Company provide further justification and evidence for its assumption of no new direct access customers.

Load Forecast Actions for PGE

1. Identify and explain the assumptions that are contained in the load forecasting methodology. Explain and provide support, such as the historical basis, for any relationships assumed in the models. Provide support for the assumption that PGE's econometric models appropriately handle the likely stationary nature of its time-series data.
2. Update PGE's load forecast methodology to better represent the uncertainty around load growth scenarios.
3. Provide further justification and evidence for its assumption of no new direct access customers.
4. If PGE has not already done so, adjust post-2021 growth forecasts for industrial load (by sectors) to the levels recommended by Itron and share the results with Staff.
5. Adjust large, individual industrial customers' load growth forecast to approximately equal their individual average load growth over the past 15 years and share the results with Staff.
6. Using the data from the bullets above adjust PGE's overall load growth forecast beginning in 2021 and share the results with Staff.

2. B. Energy Efficiency

Staff notes that Energy Trust of Oregon (Energy Trust) forecast of cost-effective energy efficiency used in PGE's IRP is from June 2015. This older forecast has been superseded by the most recent forecast from Energy Trust's budget process. In general, this reflects a broader pattern of Energy Trust usually securing more energy efficiency than they originally forecast. Staff believes the most up-to-date forecasts for energy efficiency should be included in this IRP.

PGE and Energy Trust have recently demonstrated how energy efficiency investments in PGE territory can be leveraged by other programs potentially making these investments, like demand response and other demand energy resources, more cost-effective in turn.[18] Staff encourages

[16] *See* PGE's response to ICNU's DR 6.
[17] One average megawatt (aMW) is defined by OAR 860-038-0005 (43) as 8,760,000 kilowatt-hours (8,784,000 in a leap year) of electricity per twelve consecutive month period.
[18] Energy Trust's smart thermostat program was leveraged to support PGE's residential peak demand program.

the Company to explore other similar technology leveraging opportunities that could be missed without more intentional analysis outside the IRP process.

Energy Efficiency Actions for PGE

7. Adopt Energy Trust's most recent savings forecasts into IRP Action Plan.

2. C. Demand Response

PGE is forecasting 78MW of Demand Response (DR) by 2021 and as pilot programs.[19] However, potential studies commissioned by PGE show more cost effective DR capacity within the PGE system.[20] Given PGE's need for flexible capacity and peak resources Staff is concerned they may not have sufficiently explored how to acquire demand response as a potential resource within the time frame of this Action Plan.

Staff notes that as a summer peak resource, demand response direct load control (DLC) programs show a potential of over **261 - 278 MW** of cost-effective DR by 2021 without any customer program crossover. [21] Summer DLC Program capacity Identified by Brattle Group [22] (2021 potential) and used by Staff in their assessment of **261 – 278 MW** potential includes:

- Residential AC DLC = 106.5MW
- Residential Water Heating DLC = 31.1MW
- Electric Vehicle DLC = 1.3MW
- Small C&I AC DLC = 12.8MW
- Small C&I Water Heating DLC = 0.7MW
- Medium C&I Third Party DLC = 46.1MW
- Large C&I Third Part DLC = 62.8MW or Large C&I Curtailable Tariff = 80.4MWMW

In addition, the Brattle Group report also identified a potential Winter DLC Program capacity of **181.7 – 196.9MW** by 2021. Specifically:

- Residential Space heating DLC = 20.1 MW
- Residential Water Heating DLC = 61.9 MW
- Small C&I Space Heating DLC = 6.0 MW
- Small C&I Water Heating DLC = 1.3 MW
- Medium C&I Third Party DLC = 38.1 MW
- Large C&I Third Party DLC = 54.3 or Large C&I Curtailable Tariff 69.5 MW

These programs do not require PGE's Customer Relations System (CRS) system to be operational or be fully developed.

Staff also notes PGE attempted a new portfolio run which included a "high case" DR portfolio as described in Table 6-11 of PGE's IRP.[23] Their high case included an additional 88 MW of

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[19] PGE IRP Table 6-11.

[20] Demand Response Market Research: Portland General Electric, 2016 to 2035, Ryan Hledik, Ahmad Faruqui. January 2016, *See also* Demand Response Study Result, December 17, 2015, Public Meeting #5.

[21] DR offered and utilized as DLC has been operational in other jurisdictions since the 1970's. Staff assessment of DR available to PGE in 2021 uses only Summer DR and only direct load control DR, which are generally preferred by utilities nationwide.

[22] PGE commissioned Brattle Group and Ahmad Faruqui to conduct a demand response study. Mr. Faruqui and Brattle Group are nationally recognized experts in the demand response field.

[23] OPUC Staff IR 59

summer demand response and 113 MW of winter demand response by 2021. In their response to IR 59 PGE creates a scenario whereby 81 MW of summer and 109 of winter incremental demand response becomes available in 2020 with some additional megawatts becoming available in 2021. Staff has several concerns with PGE's response to IR 59 and its treatment and modeling of demand response resources.

There is no explanation in PGE's response to IR 59 as to what type of demand response is being modeled. At a high level demand response resources can be categorized in five discrete sub-resources, each with their own operational characteristics which affect the resources costs and benefits. Below are descriptions:

- **Emergency demand response** – this resource is of limited availability but generally contributes more capacity then other demand response resources that are dispatched seasonally.
- **Direct load control demand response and AutoDR** – this resource may not provide the amount of capacity an emergency DR program may but this capacity is more readily available, is dispatchable by the utility and can be dispatched several times during the demand response program season; summer or winter. Direct load control DR is generally reliable and preferable over other demand response programs that re non-dispatchable.
- **Price responsive demand response** – these programs are generally rate driven through a time-of-use rate. These programs can be paired with DLC for more firm demand response or are considered non-firm and rely on customers to respond to pricing signals to change usage patterns.
- **Back-up generation demand response** – Staff places back-up generator (BUG) in a separate category because these units have discrete operational characteristics that include increased emissions and the behind the meter or self-generation. These characteristics differentiate BUGs from other forms of DR that require energy usage reduction with supplementation.
- **Non-firm demand response** – these programs are more passive and are non-dispatchable. They can include behavior change demand response, rate driven demand response or event alert driven demand response such as California's Flex- Alert program whereby the state issues an alter for demand reductions and customer independently respond to their degree capable.

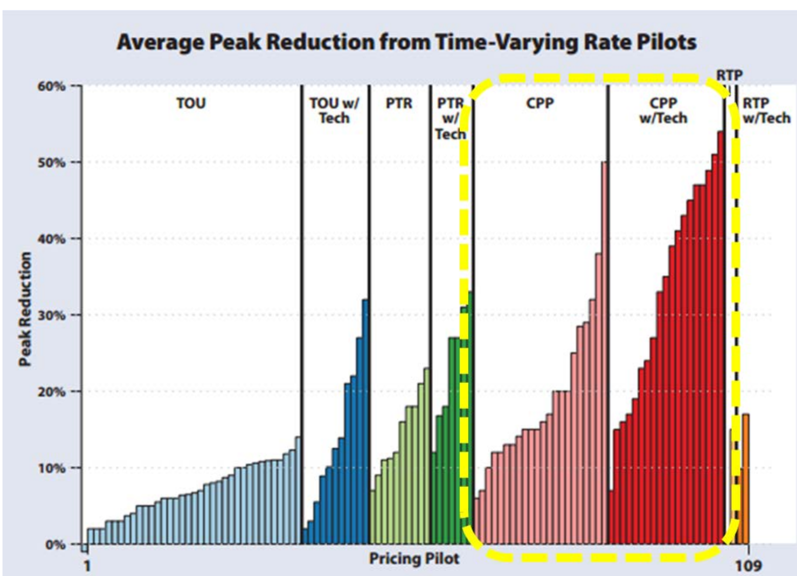
As a result of simply lumping these various demand response resources into a simple "incremental DR" bucket which becomes available in 2020, Staff, PGE, and Stakeholders do not gain insight into the shape, costs, benefits, operational characteristic and therefore the viability of the DR resources PGE seems to be modeling.

From a resource supply perspective Staff does not understand the assumption in PGE's response IR 59 that first shows a rapid demand response growth in 2020, some additional build in 2021 and then a decline in the resource through 2031. Under PGE's IRP load growth assumption, which shows increasing load growth year over year, the expectation would be that DR opportunity also grows over time proportionately. However, in PGE's analysis DR opportunity does not increase over time but instead lessens over time. It is not clear to Staff why increases in load do not correspond to increases in demand response opportunities.

Further evidence that PGE may not be optimizing the modeling of DR in their portfolio runs is in PGE Response IR 59 Attach D. PGE's model of DR dispatch shows utilization of DR only once during each DR season; summer or winter through 2050. The table on Sheet 2 of IR Attach D shows that PGE is dispatching an undefined DR resource at full capacity in September and again in December. Staff does not understand the decision to dispatch Summer DR in September, considering PGE's summer peak generally occurs in the mid-summer months, and rarely more the twice in a year through 2050. Staff needs to learn more about PGE's rare use of DR in the modeling output as it affects how PGE assesses the resource's cost effectiveness and therefore competitiveness against supply side resources which ultimately affects PGE utilization of DR.

Finally, Staff's DR assessment does not include rate-driven DR approaches, such as "critical peak pricing" (CPP), time-of-use (TOU) and peak-time rates (PTR) that are available in conjunction with DLC DR. Such an assessment is likely to add additional DR capacity and the Company should be actively exploring these programs.

In its Comments regarding PGE's 2013 IRP Staff stated as follows, "Staff reviewed the results of the Critical Peak Pricing (CPP) pilot and noted that a CPP program is not determined to be cost effective with the existing computer systems. PGE notes that the new computer systems will be in place in 2017, which should greatly improve the cost effectiveness of a CPP program. Staff recommends that PGE continue to move toward exploring a full scale CPP program once upgraded computer systems are in place."[24] Staff notes that several CPP pilots have found CPP to reduce peak load. For example, Faruqui, Hledik and Palmer (2012) present a summary of results from utilities in North America, Europe, and Australia[25]:



In addition to PGE's Schedule 6 Peak Time Rebates, Staff recommends the Company explore using CPP rates in 2017 or shortly thereafter, due to the peak reductions experienced in other service territories.

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[24] *See* Staff's Final Comments in LC 56 at 3. http://edocs.puc.state.or.us/efdocs/HAC/lc56hac103522.pdf

[25] *See* "Time-Varying and Dynamic Rate Design" at 28. http://www.raponline.org/wp-content/uploads/2016/05/rap-faruquihledikpalmer-timevaryingdynamicratedesign-2012-jul-23.pdf

Staff is concerned that in PGE's response to Staff's discovery the Company has disregarded its own demand response study commissioned from Brattle Group and Ahmad Faruqui. PGE has not incorporated the resource findings Brattle Group supplied to PGE into its resource planning. As noted above, based on the findings of the Brattle Group study, Staff believes PGE has the opportunity between now and 2021 to develop hundreds of megawatts of direct load control demand response.[26] Staff also believes, based on the Brattle Study, that PGE still has available price-based demand response resources, back-up generator demand response, and emergency demand response.

Demand Response Actions for PGE

8. PGE needs to further develop a DR deployment strategy that maximizes DR acquisition in all programmatic forms over the planning horizon.

9. Additionally, PGE should be modeling emergency DR and back-up generation DR opportunities for advanced DR capable of offering ancillary services and third party DR.

10. PGE should explain the assumptions behind it's declining growth of DR in PGE's response to Staff IR #59, especially in relation to 1.2 percent projected load growth.

11. PGE should describe which of the five types of DR were added as "incremental DR" and their estimated MW contribution to the revised total of DR in response to IR 59.

12. PGE should provide any internal analysis PGE did to assess the potential quantity of rate driven DR available, such as CPP, TOU and PTR when PGE constructed the IRP. Materials submitted and work conducted to generate such an assessment should predate the IRP filing.

13. PGE should explain the deployment of DR in PGE's response to OPUC's IR #59. Specifically include explanations as to why DR is rarely deployed more than twice per year and why the summer dispatch of DR does not coincide with the times of greatest LOLE during the summer, per Figure 5-3 on page 120 of the IRP.

14. PGE should explore using CPP rates in 2017 or shortly thereafter, due to the peak reductions experienced in other service territories.

2. D. Conservation Voltage Regulation (CVR)

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

[26] Supra Note 2

16 AMW[27] or 142,934 MWh[28]. Currently, PGE uses manual intervention in the form of data spreadsheets to maintain customer voltage information.

In order for PGE to progress its system-wide CVR program, several smart grid investments need to be in place before implementing CVR in 2018:[29]

- Advance Metering Infrastructure (AMI) Voltage Data Bandwidth Expansion. With its current AMI structure, PGE will develop its ability to retrieve customer voltage data in 60-minute intervals. The 60-minute voltage data includes the following three data points: the average voltage for the hour, the minimum voltage during the hour, and the maximum voltage during the hour.

- Data analytics research and development. PGE is currently piloting a data analytics tool to pair with Eaton's CYMDIST distribution system analysis software. This will allow PGE to provide an interactive user interface where engineers can monitor and evaluate voltage data and set an alarm for those meter voltages that travel outside the lower portion of the voltage bandwidth.

- Dynamic CVR Expansion. After the two elements described above are completed, PGE will be able to expand its CVR program. PGE will be able to manage the CVR settings and controls locally, inside the substation control house. With the ability to capture customer voltage data every 60 minutes, PGE will utilize the data analytics software to assist in continuously delivering customer acceptable voltage.

While Staff appreciates PGE's ongoing efforts to build and maintain a flexible CVR program as explained by the Company in response to Staff's IR No. 6, Staff would still like to see PGE describe the flexibility in its CVR program in far more detail moving forward. Specifically, PGE should provide an analysis on those distribution feeders which CVR has been deployed.[30]

CVR Actions for PGE

15. Provide more detail around the timing and progress of CVR associated smart grid investments in place by 2018 for CVR implementation.

16. Describe the flexibility plan in its CVR program in far more detail and provide an analysis on those distribution feeders which CVR has been deployed

3. SUPPLY SIDE

Overall Staff is uncertain about PGE's proposed actions to invest in resources by 2021. Staff currently finds that PGE's proposed acquisition of wind in 2018 lacks sufficient justification to pursue in the near future. Staff is also unsure as to the extent of PGE's capacity needs after

[27] An average megawatt (MWa) is a unit for measuring power that is equal to one megawatt of capacity produced continuously over a period of one year. One MWa is equivalent to 1,000 kilowatts or 1 million watts of electricity.

[28] A megawatt-hour is equal to 1,000 kilowatt hours of electricity used continuously for one hour.

[29] *See* PGE's 2016 Integrated Resource Plan, pp. 165-166.

[30] The analysis should include: CVR accomplishments and setbacks, total monthly customer dollar savings, implementation costs by CVR distribution feeder, monthly voltage levels for each CVR distribution feeder, monthly kW consumed, monthly load in kWh, and estimated costs for the remaining distribution feeders initially identified as part of the 94 optimal candidates.

2021. Based on Staff's work to replicate and verify capacity needs, using the same software and data, Staff finds that PGE's capacity needs could be as much as 40 percent less than the IRP projects.

Staff recognizes that it has fewer insights into PGE's flexibility needs as only the model results were available. If PGE does not acquire wind in 2018 or 2021, Staff is uncertain as to how PGE's total flexible capacity needs over the five years covered by this Action Plan would be impacted. Finally, Staff is uncertain about PGE's assumptions behind the market depth and the future uncertainty of availability of bilateral contracts for hydro power. These assumptions seem to exacerbate reliability concerns and drive the need for new capacity that may not be fully necessary.

3. A. Renewable Energy Strategy

Staff's Comments regarding PGE's renewable energy strategy as presented in the Company's 2016 IRP are composed of two sections: first, Staff's analysis of PGE's 515 MW "PNW Wind" resource proposed in its preferred portfolio. Second, Staff's analysis of PGE's overall renewable energy strategy that spans the time horizon studied in the 2016 IRP. Overall, at this point, Staff finds the analysis and claims used to support the 515 MW wind resource to be questionable and in some ways to not fully comport with either Commission precedent or IRP guidelines. Furthermore, Staff believes the underlying claims that justify PGE's long-term RPS compliance strategy are not fully supported.

515 MW PNW Wind Resource

PGE proposes in the 2016 IRP Action Plan that the Company acquire:

> *[A]pproximately 175 AMW (equivalent to 515 MW nameplate of wind generation) of bundled RPS-compliant renewable resources (energy and RECs), and/or Renewable Energy Certificates (RECS), with a preference for maximizing available federal incentives (such as sec 45 Production Tax Credit) for the benefit of customers.*[31]

The Company is flexible as to technology and plant type, but for the sake of analysis has modeled this resource as a 515 MW (nameplate) wind resource located somewhere in the Pacific-Northwest region (the Company refers to this resource as PNW Wind).[32] To economically justify acquisition of the PNW Wind resource, the Company claims that the existence of the production tax credits (PTC) coupled with recent changes to the renewable energy credit (REC) banking provisions provides economic incentive for the near-term acquisition. This is despite the fact that the Company may not have a capacity deficit until 2021 nor a near-term period of Renewable Portfolio Standard (RPS) non-compliance.[33]

A cornerstone of the Company's argument in support of the PNW Wind acquisition is the availability of federal wind production tax credits. The Company claims that the ability to qualify for PTCs will provide an economic justification for obtaining the wind resource in the near term. However, based on historical performance, it is not clear that the Company can fully utilize the PTCs that would be generated by the PNW Wind resource.[34] In PGE's 2016 general rate case (GRC), the Company provided data that indicated it could only claim PTCs valued at

[31] PGE's 2016 IRP, at page 33, Docket No. LC 66, November 2016.
[32] PGE's 2016 IRP, at page 341, Docket No. LC 66, November 2016. Note that the Company claims that the PNW Wind resource will not necessarily be limited to Oregon and will encourage resource proposals from Washington, Idaho, or Montana states.
[33] PGE's 2016 IRP, at pages 293 and 308, Docket No. LC 66, November 2016.
[34] PGE's 2016 IRP, at page 266, Docket No. LC 66, November 2016.

$31,516,720 of the Company's total beginning 2016 PTCs balance of $42,427,293, or approximately 74 percent of the available balance, for the year 2016.[35] From that perspective, the value of the PTC's to customers may be reduced by up to 74 percent of its full value.

Further detracting from the PTCs value to customers, PGE currently earns a return on any unused PTCs. This results in an additional revenue requirement for the Company and therefore reduces the savings PTCs may provide to PGE's net-present revenue requirement. In other words, the benefits from earned PTCs may simply never materialize in customer rates because PGE is unable to use them. In fact, for any existing PTC held in account, ratepayers may be obligated to pay higher rates as a result of the Company holding them, rather than realize the savings they are expected to represent.

PGE's inability to fully utilize the wind PTCs leads Staff to question the validity of the Company's argument that the PNW Wind resource must be acquired by 2018. In the end, Staff finds that the argument to maximize the collection of PTCs before they decline or are unavailable to be speculative in nature. It presumes PGE will have a taxable income that permits full use of PTC. But, this is in complete disagreement with recent Company history. Staff continues to investigate issues surrounding PGE's use of PTCs and tax mechanisms through discovery.

Renewable Portfolio Standard Compliance and RECs

SB 1547 modified the parameters governing utility REC usage. Before the enactment of SB 1547, all RECs had an unlimited life but had to be used in a "first in, first out" fashion. However, SB 1547 has created a myriad set of requirements for RECs that ultimately result in acquired RECs either having a bankable lifetime of five years or an unlimited lifetime. Unlimited life RECs, also known as "golden RECs", are a major contributor to PGE's desired 2018 PNW Wind resource procurement.[36] A qualifying renewable resource that begins operation in 2018 would generate golden RECs for five years, adding to PGE's existing bank of RECs that were produced prior to the signing of the SB 1547.[37] PGE would then reserve those banked golden, unlimited life RECs as a risk-abatement strategy; the Company identifies six scenarios that banked RECs may facilitate.[38]

PGE states that there is an economic benefit to acquiring renewable resources prior to a physical need in order to build the REC bank; however Staff questions the value in acquiring RECs well before they are needed for compliance. Staff believes the generation and subsequent banking of RECs for an indeterminate amount of time under the auspices of mitigating what are essentially speculative risks lies contrary to Commission precedent regarding utility resource planning.

Simply put, PGE has existing RECs that can completely satisfy its known, near-term RPS compliance requirements without any additional resource acquisition. This REC accounting is corroborated by PGE's data presented in the 2016 IRP that demonstrates the Company, without any new resource acquisition of any kind, can successfully satisfy the RPS compliance through 2025.[39] To further highlight the fundamental issues regarding the PNW Wind resource, the accompanying golden RECs that would be generated must be considered as well.

[35] PGE's 2016 General Rate Case, "2016 Schedule Ms" spreadsheet, "Tax Credits – Federal BLF" tab, Docket No. UE 294, February 12, 2015.
[36] PGE's 2016 IRP, at page 284
[37] SB 1547 was signed into law March 8, 2016.
[38] PGE's 2016 IRP, at pages 290 to 292, Docket No. LC 66, November 2016.
[39] PGE's 2016 IRP, at page 293, Docket No. LC 66, November 2016.

IRP Guideline 1c states "the primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[40] PGE's current REC bank position, with its far horizon in which the utilization of golden RECs generated by the PNW Wind resource begins, along with the possibility that PTCs will not be optimally utilized, introduce premature costs and significant risks to ratepayers. In reviewing the Company's analysis, Staff is unconvinced that a portfolio which contemplates acquiring a qualifying RPS resource prior to having a RPS compliance need will exhibit less risk than those portfolios which defer such an acquisition.

Finally, IRP Guideline 1d states "the [action] plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies."[41] PNW Wind neither would serve an immediate system or regulatory need and rests on speculation that its near-term acquisition would serve as an economic hedge comes at the expense of ratepayers who may not receive the benefit for a number of years, potentially over a decade. Economic hedging, in the form of full utilization of PTCs, decreasing resource capital costs that do not outweigh early action benefits and optimal resource site availability seem somewhat speculative and may actually result in costs to customers not outweighed by the benefits. Furthermore, PGE compared renewable resource action in 2020, 2021, and 2025. Given that the present value revenue requirement of the preferred portfolio and each of the comparison portfolios are very close, Staff is skeptical of the desired 2018 acquisition date when considering the potential for future lower costs, commensurate flexible capacity needs, interaction with other major resource investments within portfolios and the overall risk associated with economic hedging arguments.

In addition, Staff is still exploring the future costs of wind and the economic trade-offs involved. PGE's IRP projects a capital cost decline for wind close to 10 percent by 2030.[42] A recent Lawrence Berkeley National Labs (LBNL) survey of 163 experts in wind technology forecasted that the median costs of onshore wind could decrease by 24 percent by 2030.[43] While the LBNL report noted some uncertainty around these projections, LBNL found their median results to be consistent with the recent declining cost trend for wind technology between 20 percent to 40 percent since 2008.[44] Staff is still exploring the extent to which lower, future wind costs (*i.e.*, 2021 or 2025) potentially outweigh any gains from building wind in 2018 with tax credits.

For the reasons described above, Staff continues to consider whether PGE's 2016 IRP's Action Plan's proposed 175 AMW 2018 renewable resource is the best path forward in terms of cost and risk. Staff will continue to evaluate the Company's proposal to acquire a resource in 2018.

PGE's Long-Term RPS Compliance Strategy

Staff agrees that PGE will need to acquire a physical renewable resource in the form of either a utility-owned resource or a power-purchase agreement (PPA) over the next 20 years. These resources, along with potential bundled products like qualifying facilities and unbundled REC purchases, will contribute to an overall REC utilization or management strategy, which PGE discusses in its 2016 IRP.[45] However, Staff believes that the supporting analysis and claims found in PGE's 2016 IRP that govern mid-and long-term projected RPS requirements overstate RPS compliance risk. Staff reviews and Comments on its current understanding of PGE's REC

[40] Ibid., at pages 1 – 2.
[41] Ibid., at page
[42] PGE's 2016 IRP at Page 751, Docket No. LC 66. Staff would also note that PGE used a single source of information – again Black & Veatch – for projecting the future cost of wind despite urging the Company to use a more diverse set of inputs in our 2013 IRP Comments.
[43] LBNL, "Forecasting Wind Energy Costs and Cost Drivers," June 2016, https://emp.lbl.gov/publications/forecasting-wind-energy-costs-and-cos
[44] US DOE "2014 Wind Technologies Market report" August 2015, https://emp.lbl.gov/sites/all/files/lbnl-188167.pdf
[45] PGE's 2016 IRP, at page 290, Docket No. LC 66,

bank policy in the sections below. Staff notes that these positions are preliminary and ongoing analysis and discovery will continue.

Projected Minimum REC Bank Need

Driving PGE's long-term projected RPS resource needs is the concept of a "minimum REC bank," which PGE claims is "sufficient to cover one-to two years' worth of event risks over the 2020-2024 planning horizon, or approximately 130-260 AMW."[46] This minimum REC bank increases to approximately 730 AMW in 2035 and continues through 2040. PGE is claiming that in order to hedge against risks such as "annual RPS deferral," "annual forecast generation," and "annual load forecast," the Company needs to maintain a renewable resource portfolio that can generate an amount of <u>banked</u> RECs that is more than half of what the Company will need in a given compliance year.[47] This is despite the fact that the Company will be able to meet a more significant portion of load in a given year with RECs generated <u>within</u> that same year, if the Company pursues the 2018 175 AMW project.[48] In other words, a given year's RPS requirement could be met at the 90 percent level with RECs generated in that same year, yet PGE would maintain a REC bank that maintains an additional, unneeded amount of RECs that equal more than 50 percent of that year's RPS requirement. In essence, PGE has presented risks that result in the likely acquisition of RPS qualifying resources that significantly exceed the Company's actual need.

PGE identified six scenarios that a REC bank could facilitate should they occur.[49] Of those six, the Company quantifies five of those scenarios in order to determine the projected minimum REC bank. Below Staff analyzes the viability of these scenarios:

- **Mitigating timing differences in acquiring and constructing new renewable generation**
  Staff notes that any state, regional or national policy that may have an adverse impact on PGE's RPS compliance strategy would likely provide ample time for proper adjustment. The notion that "flexibility" is needed seems curious when the telegraphing of policy usually grants affected entities sufficient time to react. For example, the recent SB 1547 adjustments did not fundamentally change RPS compliance requirements until 2025, nearly a decade from the legislation's enactment. The Clean Power Plan's requirements are not binding until 2022, which is seven years from the enactment of the rule. Despite the constant impending implementation of a state or regional carbon tax policy, none have been enacted to date besides California's cap and trade program, which has been in place since 2012.[50] In each case, the Company has been granted ample time to comply with regulatory changes. PGE's claim that flexibility is needed for what appears to be an unlikely outcome is unwarranted.

- **Acting as a temporary alternative to physical supply in the event of adverse market conditions**
  PGE's claim that increased demand of RPS qualifying resources could result in difficulty is troublesome in that it fails to acknowledge the likelihood of the antithetical outcome occurring. That is a depressed demand for RPS qualifying resources produces circumstances that are highly favorable to the Company. While such a situation may

[46] Ibid., at page 292.
[47] *See* table 10-7 and Figure 10-11 in PGE's 2016 IRP, pages 292 – 293
[48] UM 1788, RPIP_REC_Accoutning_06_23_2016_stagedbuild_CONF
[49] PGE's 2016 IRP, at pages 290 to 292, Docket No. LC 66, November 2016.
[50] California AB 32.

even be more likely than a situation that involves adverse conditions, PGE to date has not provided historical and quantitative evidence that demonstrates the likelihood of various favorable or adverse outcomes.

- **Replacing RECs from physical resources generating at levels less than forecast**
  Using this scenario to justify building a renewable resource earlier than actually needed either for a system or regulatory need in order to create a buffer of RECs for potential under generation of PGE's renewable resources is problematic for the reason that the Company acknowledges in its description: it's just as likely that RECs in excess of what is needed could be produced.[51] Staff continues to explore this scenario through discovery and ongoing analysis.

- **Aligning timing differences in acquiring and constructing new renewable generation with tax policy**
  As discussed earlier in this section, the disconnect between PTCs generated and the ability to utilize them for actual federal income tax reductions remains uncertain. PGE's 2016 General Rate Case, UE 294, demonstrated that the Company anticipated being unable to use the PTCs are generated.[52] Regardless of whether the Company is actually able to employ the PTCs it acquires, the notion that the Company should use the REC bank as a means to secure speculative economic benefits in the form of tax credit mechanisms may not comport with longstanding regulatory principles.

- **Filling the incremental RPS compliance obligation resulting from retail load growing more quickly than forecast**
  Staff presents in these Comments arguments to suggest that the likelihood of load growth is highly uncertain. Staff cannot accept this scenario without an acCompanying acknowledgment of load stagnation or even decline. For PGE to only weigh scenarios that necessitate a REC bank that is responsive to additional REC need is analytically incomplete.

PGE states that, "Banked RECs represent a finite resource, and, as such, are best suited to providing flexibility and acting as a balancing mechanism to hedge against a number of factors that post future cost or compliance risks for PGE."[53] The implication of PGE's statement that banked RECs are a "finite" resource, and therefore the Company must pursue additional resource acquisition and preserve those RECs as a "mechanism to hedge," is concerning considering the amount of banked RECs PGE currently possesses. IRP Guidelines direct PGE to pursue the "best combination of expected costs and associated risks" – if those RPS related risks are potentially mitigated through existing resources in the form of RECs, Staff questions whether PGE is pursuing a resource plan that is least-cost/least-risk.

PGE also asserts that "these banked RECs may act as a balancing a mechanism to hedge against a number of factors that pose future cost or compliance risks for PGE."[54] Considering the preliminary analysis that Staff has been provided on these potential costs and risks, Staff finds it unlikely that the REC bank can act as an economically efficient hedge.

[51] PGE's 2016 IRP, at page 290, Docket No. LC 66, November 2016.
[52] UE 294
[53] PGE's 2016 IRP, at page 286, Docket No. LC 66, November 2016.
[54] Ibid., at page 290.

Unbundled RECs

PGE states that "the use of unbundled RECs to a maximum of 20 percent of the compliance obligation in each year… is not a primary strategy for achieving compliance, but instead used to complement a physical or bundled REC compliance strategy."[55] Following this, PGE claims that if it "pursues an unbundled REC strategy and their expected energy needs exceed the expected RPS compliance obligation, they must account for the energy deficit component associated with the unbundled RECs" and that "beyond 2021, PGE projects that incremental annual average energy needs will exceed the incremental annual RPS requirements."[56] In the Company's analysis, two "economic tests" must be passed in order for the strategy of maximum use of unbundled RECs to be deemed cost effective.[57]

These two tests are:

- The expected life-cycle levelized cost for qualifying resources is greater than the capacity equivalent cost of non-qualifying alternatives at the time of the decision;
- The cost of unbundled RECs is less than the cost difference between the qualifying resource and the non-qualifying alternative identified in [test] 1 above.

PGE provides an example, entitled "illustrative unbundled REC price scenario," in which the Company calculates the incremental savings based on unbundled REC prices that are either equal to or 50 percent less than the levelized cost of non-qualifying resource. Staff has concerns with the logic and example described above. First, PGE's point regarding energy needs that exceed expected RPS obligation as a result of unbundled REC use is a highly deterministic scenario that precludes options PGE can readily access to alleviate this. For example, the Company could purchase power from the wholesale market, a fact that is noticeably absent from PGE's entire discussion on this topic. Wholesale market prices are far lower than the non-qualifying levelized cost presented in the example in Table 10-6; around $30 - $40 per MWh compared to the $74 per MWh. In fact, PGE's own projected nominal wholesale market prices do not exceed the non-qualifying levelized cost until approximately 2033.[58] PGE's proposed "flexible capacity" in its Action Plan is another option the Company could rely on if energy needs unexpectedly exceed the Company's planned RPS compliance strategy. Staff believes that this particular concern greatly inflates the risk associated with unbundled RECs, making their use and potential savings to customers unnecessarily unattractive.

Finally, Staff believes PGE's statements regarding the status and characteristics of an unbundled REC market tend to diminish the potential value of unbundled REC use. PGE claims use of unbundled RECs is challenging because the "absence of an organized market enabling efficient pricing of RECs" and "constantly changing market dynamics make it unlikely that recent imbalances will persist in the long-run."[59] Staff and other Stakeholders in previous dockets regarding PGE's RPS strategies have expressed strong concerns regarding PGE's opaque experience with unbundled REC transactions. Without greater transparency into PGE's historical unbundled REC transactions, which it has used to maximize unbundled REC compliance every year since 2011, Staff does not find PGE's concerns as presented in the 2016 IRP to be supported.

[55] PGE's 2016 IRP, at page 286, Docket No. LC 66, November 2016.
[56] Ibid., at page 287.
[57] Ibid., at page 288.
[58] PGE's 2016 IRP, Figure 10-5 "PNW Reference case electricity prices 2017-2050 (nominal $/MWh), at page 271, Docket No. LC 66, November 2016.
[59] PGE's 2016 IRP, at page 287, Docket No. LC 66, November 2016.

Because of the reasons described above, Staff believes the Company's analysis related to projected RPS compliance obligations and subsequent resource needs over the planning horizon in the 2016 IRP is flawed. PGE should revise the inputs that create the forecasted obligation and the assumptions regarding the RPS compliance options available to the Company. In this way, PGE could enhance transparency and methodology in order to produce an acceptable long-term RPS compliance strategy.

REC Bank Policies Impact on Portfolio Development
The Company's assumptions regarding REC's and the size of its REC bank seem to give preference to physical resource acquisition for RPS compliance. This in turn drives a need for flexible capacity. Every portfolio reflects the need for some level of physical renewables and thus some level of flexible capacity. Staff believes it is possible that portfolios with greater levels of unbundled RECs could reduce the need for flexible capacity, and may prove to be lower cost than current portfolios. Staff would like PGE to conduct analysis into utilizing a combination of unbundled REC's from the region and from within Oregon to meet RPS compliance needs up to 2025 and potentially through 2030. Portfolios 20 and 21 approached this question, but did not move forward due to PGE's preference for acquiring PTC's in 2018. Staff plans to work with PGE in the coming months to develop insights around this approach and understand what its impacts could be on portfolio development.

Renewable Energy Strategy Actions for PGE

17. Consider as "actionable" portfolios designed to delay the acquisition of a renewable resource. See comments along these lines in Section 4.C.
18. Develop a more transparent and realistic unbundled REC analysis for future resource evaluations.
19. Revise the Minimum REC Bank strategy.

3. B. Capacity Adequacy, Contribution and Reliability

Methodology and Model
Staff believes the Company's methodology for assessing capacity adequacy and contribution is sound and reasonable, and that the RECAP model used by the Company was an excellent choice. RECAP is open-source and available without cost from Energy and Environmental Economics, LLC (E3). Staff obtained this model from the Company and was able to examine how reliability varies as the resource portfolio changes.

Assumptions
Staff generally viewed the system assumptions used as reasonable. Several assumptions made may have been overly-conservative, however, and inflated the resulting 2021 capacity deficit of 819 MW:

- **Available market purchases:** The Company assumes the maximum reliable spot market purchase in constrained hours is 200 MW during all non on-peak summer hours, zero MW otherwise.[60] In response to an IR, the Company indicates this value comes from the 2013 IRP and was based on "the experience and professional judgement of our power operations staff."[61] In the 2017 PacifiCorp IRP General Public Meeting held

[60] PGE 2016 IRP, page 118.
[61] PGE 2013 IRP, page 191.

September 22-23, 2016, available market purchases in the west were revised down to 875 MW. PacifiCorp also relied on its power traders in arriving at these numbers. While the Company need not agree with PacifiCorp on western market liquidity, the disparate figures cause Staff to desire additional support for its 819 MW capacity need.

- **Non-renewal of supply contracts:** The Company has a number of hydro and non-hydro contracts expiring prior to 2021, and takes the conservative position that none of them will be renewed. Staff believes that the expected level of renewed contracts should be included. These could be aggregated into a single line-item for purposes of the IRP so as to not affect ongoing negotiations.

- **Zero transfer capability/no Energy Imbalance Market (EIM) impact:** One benefit included in the CAISO quarterly "Benefits for Participating in EIM" report is the reduction of required flexibility reserves across the footprint.[62] The Company plans to be an EIM participant by 2021, but does not include any incremental, related benefit. The Company indicated that this failure to account for a benefit from its joining EIM is because it will not change the Company's Northwest Power Pool (NWPP) Contingency Reserve Obligation (CRO). If it were the case that more than the minimum level of reserves is being held (which seems likely for all utilities, as exactly matching the CRO each hour would be challenging, for example), then there could be some potential EIM reserve-reducing benefit. Staff is interested in understanding more fully if this potential exists.

- **Target loss-of-load-expectation:** The Company uses a target loss-of-load-expectation of 2.4 hours per year,[63] meaning the model should determine the additional capacity required to be added to the system so that there is at most 2.4 hours per year that firm load must be shed. In fact the Company operates to achieve zero hours of firm load-shedding. Setting a target loss of load greater than zero is an acknowledgement that simple models do not reflect the range of options open to the Company in its day-to-day operation that help to maintain reliability. In response to OPUC IR 30,[64] the Company indicated that in 2019 the model shows a loss-of-load-expectation of 23.3 hours (almost 10 times the 2.4 hour target), but that the Company will "meet its resource needs through the 2020 time frame through its regular mid- and short-term planning and procurement activities." In 2021, the model adds over 340 MW of capacity to reduce the loss-of-load-expectation from 23.3 hours to 2.4 hours. Therefore there is 340 MW of capacity which isn't strictly "necessary."

Capacity Adequacy, Contribution and Reliability Actions for PGE

20. Adjust RECAP to include 200 MW of market purchases at summer peak

21. Staff believes that the expected level of renewed contracts should be included. These could be aggregated into a single line-item for purposes of the IRP so as to not affect ongoing negotiations.

22. Estimate transfer benefit from joining the EIM and include it in the IRP

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[62] *See*, for example https://www.caiso.com/Documents/ISO-EIMBenefitsReportQ2_2016.pdf: "Reduced flexibility reserves needed in all balancing authority areas, which saves cost by aggregating the load, wind, and solar variability and forecast errors of the combined EIM footprint. This report quantifies the diversity benefits of flexibility reserves for the entire EIM footprint." (page 4)

[63] Page 116.

[64] OPUC IR 30: "*See* section 5.1.3. What number of hours does the RECAP model predict for loss of load expectation (LOLE) each year 2017 – 2020? If any year shows a LOLE greater than the 2.4 hour per year target, how does PGE plan to manage the reserve shortfall?"

23. Set LOLE to 23.3 hours to reflect anticipated 2018 operating conditions and include the Company's ability to address this level of LOLE going forward.

3. C. Flexibility

Methodology and Model

Unlike the RECAP model, Staff was not provided a functioning copy of the REFLEX model. As such, Staff cannot draw any conclusions about the model other than those that are based off the IRP description of the model. Despite this, Staff believes conceptually that the way the REFLEX model attempts to identify flexible resource needs is reasonable but Staff does have the following concerns regarding its assumptions.

Assumptions

- **Limited market purchases/unrealistic market purchase penalties (Table 5-2):** The model limits available day-ahead super-peak market purchases by assuming high-cost penalty pricing. The cost of day-ahead, hour-ahead, and real-time purchases range from $6,000/MWh to $10,000/MWh. Because this model is not intended to determine required capacity—that is the purpose of RECAP—Staff believes the prices of these products should be much more like typical market prices ($25 - $50/MWh). This will cause the model to reflect how actual operations occur hour-to-hour. If the model can meet its flexibility requirements through a combination of resource deployment and market purchases or sales, it will do that. If it cannot, then it will curtail variable energy resources (if long energy) or firm load (if short energy). In the present setup, however, the penalty pricing will cause the model to avoid purchasing in the market at all costs, even though day-ahead and hour-ahead market purchase in reality occur with high frequency.

  Allowing market purchases and sales at reasonable prices and having more renewable curtailment might lead to a viable portfolio that costs less than a portfolio with an incremental dispatchable 400 MW resource. Staff would like to test this sensitivity but due to access issues mentioned above will instead plan to gain better understand of these modeling dynamics through additional information requests.

Flexibility Actions for PGE

24. Use market prices for market purchases and sales instead of penalty prices. Determine cost of that portfolio and compare cost to portfolio that adds flexible capacity.

3. D. Market Depth

Staff has difficulty in understanding what PGE believesis the market depth of the WECC's energy and capacity market for this IRP. PGE limits future spot market purchases in the IRP to 200 MW out of reliability concerns.[65] However, this seems to stand in contrast to just four years ago when PGE was securing over 33 percent of its retail load needs through purchased power.[66] We appreciate that PGE will conduct research on market depth before the next IRP. [67] Staff would have preferred that PGE had a better understanding of market capacity prior to planning to acquire new generation resources.

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[65] PGE 2016 IRP, page 118

[66] PGE August 2016 Investor Presentation, http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=903377&filekey=50BADF10-0FB1-45EA-824B-42A52BC17F9C&filename=08-2016_PGE_Investor_Presentation_August_2016.pdf

[67] PGE 2016 IRP, page 344

Market Capacity Actions for PGE

25. Request that PGE consider some level of market depth analysis in this IRP to better support their conclusions.
26. Demonstrate in this IRP how the subsequent RFP will allow for and evaluate broad participation of resources of various ownership, duration, and technology type.

3. E. Transmission

Staff would like a better understanding—at a high level—of what a Montana wind option would look like. It would be helpful to understand items like siting, permitting, general route, BPA or other interconnection, system upgrade requirements, etc. Staff intends to follow up with the Company to gain insight on these topics as well as the potential benefits of inclusion of Montana wind in the Company's portfolio as wind resource in Montana could complement Gorge wind output.

Transmission Actions for PGE

27. Provide Staff more information at a high level of the Montana wind option and its associated transmission constraints/options.

3. F. Natural Gas Storage

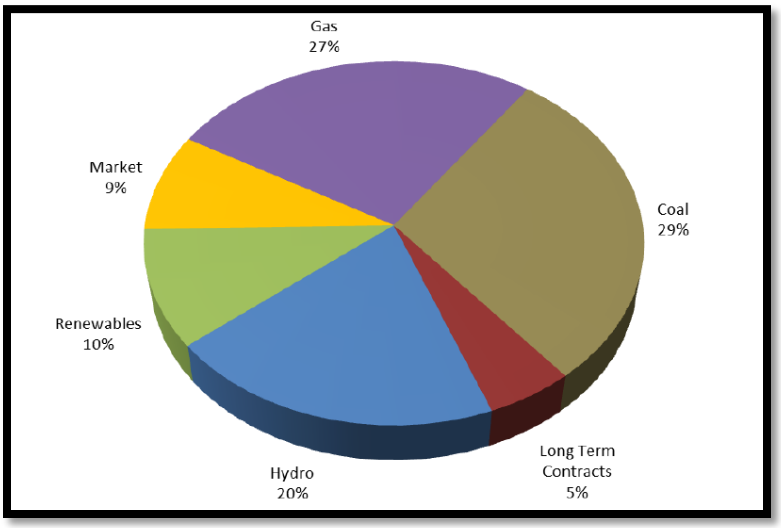
Northwest Natural Gas Company (NWN) has a contract with PGE to store and deliver natural gas for three PGE power plants, on a no-notice service basis. The agreement calls for 2.54 million MMDTh of gas storage capacity. NWN has designed and is building an underground natural gas storage facility, and installing new compressor stations, as well as storage and injection wells, and transmission and delivery pipelines as part of this agreement. Collectively, this infrastructure shall be referred to as the "North Mist Expansion Project" or NMEP. As of now, PGE is NWN's only customer. PGE and NWN previously had an agreement wherein NWN stored natural gas and delivered it through existing infrastructure via the original North Mist facility. The original North Mist facility has a 16 Bcf storage capacity. The NMEP facility will add 2.5 Bcf of storage capacity. It is Staff's opinion that the prudence of the substantial investment of the NMEP facility must be considered relative to the overall resource needs of PGE as described in other sections of the IRP, and, whether or not PGE plans to recover contract costs from ratepayersIt should be noted that NWN is responsible for infrastructure costs; however, the NMEP project would not be executed but for the contract with PGE.

A preliminary review of the engineering data and injection/withdrawal modelling provided in Staff IRs 46-48 reveals that for the scenarios described by PGE, the infrastructure specifications are reasonable to meet storage, service, and delivery needs. For instance, the 16'' pipeline balances the relatively high compression horsepower and operational times needed to transmit and deliver natural gas, with the lower installation costs relative to a 20'' pipeline. However, to assess whether the compressor station and pipeline specifications are more efficient than the original Mist infrastructure, Staff will send PGE an IR to request the specifications of the original Mist infrastructure. A thorough review of the documents provided by NWN and PGE will be undertaken by Staff before firm conclusions are drawn.

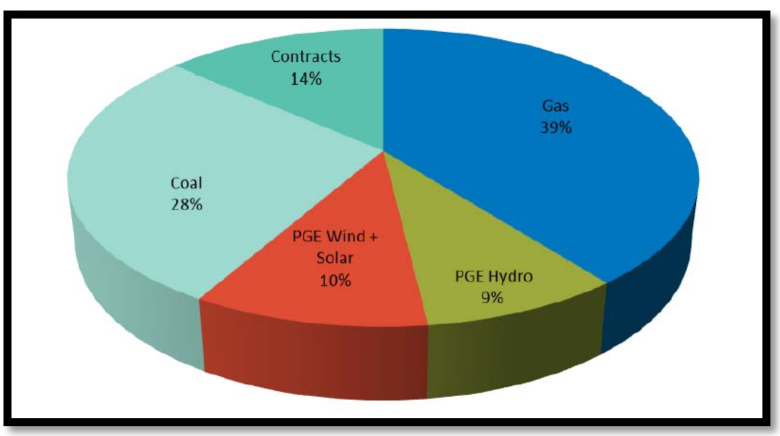
3. G. Bilateral contracts

Hydro Power

In PGE's 2013 IRP acknowledgement the Commission supported PGE's action item to renew all cost-effective hydro contracts under an alternative acquisition method outside of the RFP process. In the 2016 IRP PGE states it will, "seek the renewal, or partial renewal of expiring legacy hydro contracts," but Staff noted the drop off in hydro capacity between the last IRP and hydro going forward with little to no explanation of the results or activities around renewing existing hydro contracts or the availability of new hydro contracts.[68] In 2014, hydro represented 20 percent of PGE's energy resource mix. In 2017 it drops to 9 percent. In 2021, hydro will drop even further as a percent of energy resource mix. See the three graphs below:

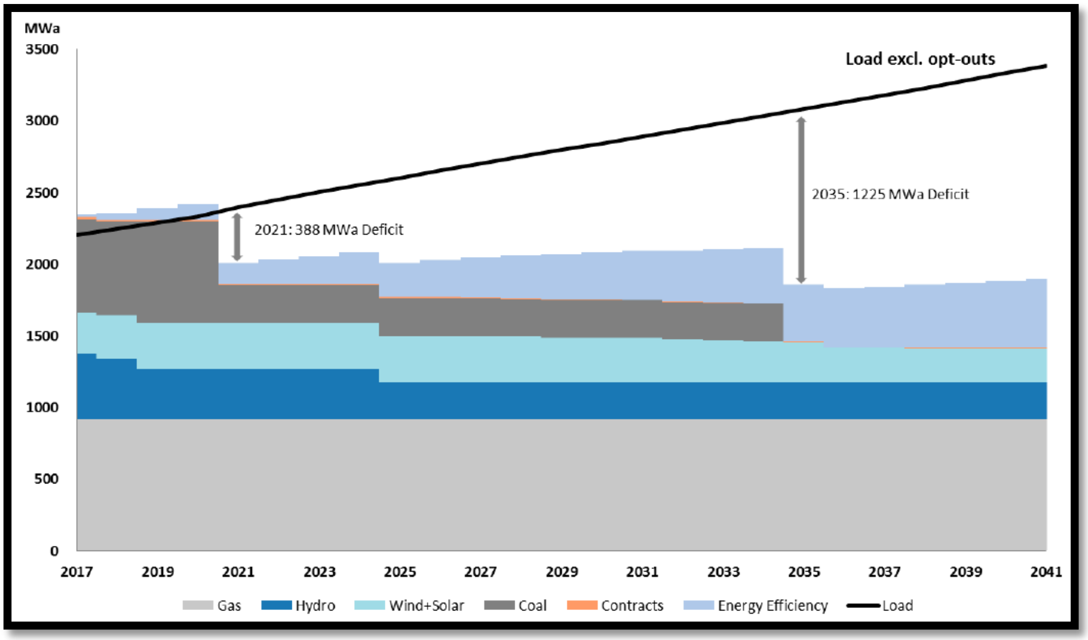


2014 Average Energy Resource Mix (availability)[69]



2017 Average Energy Resource Mix (availability)[70]

[68] PGE 2016 IRP, page 344
[69] PGE 2013 IRP, page 32
[70] PGE 2016 IRP, page 42



PGE's Projected Annual Average Energy Load-Resource Balance[71]

Despite Commission Order No. 14-415 from LC 56 encouraging PGE to renew existing hydro contracts outside of an RFP process, it appears that several of these renewals have not taken place *or* are projected to not take place in the near future. If correct, the declining presence of hydro in PGE's resource mix comes in the absence of any discussion in the 2016 IRP around the ongoing difficulties in renewing existing hydro contracts. This echoes questions from the Commission at its December 20, 2016 public meeting about the status of any contract negotiations, especially hydro at Mid-C.

Also, PGE has stated that new hydro resources would be eligible to compete in their upcoming Multi-Source RFP.[72] However, in LC 56 PGE stated that direct negotiation for hydro resources, "… is warranted because of the unique nature of these resources." Staff would like to better understand PGE's strategic shift in the preferred approach to acquiring hydro resources.

Given that hydro resources seem to represent an economic, dispatchable and carbon-free resource that was formerly 20 percent of PGE's energy mix just a few years ago, Staff expected more discussion from PGE on changes in the regional hydro market and why hydro resources apparently represent a declining share of the Company's energy resource mix going into the future.

Bilateral Contracts Actions for PGE

28. PGE should describe the change in the region's hydro market that has led to the decline of hydro in PGE's resource capacity mix since 2013.

29. Can PGE share any information that would help staff better understand PGE's strategic shift in the preferred approach to acquiring hydro resources?

[71] PGE 2016 IRP, page 151
[72] OPUC Public Meeting, 12/20/16

3. H. Distributed Generation (DG)

PGE conducted three DG studies for this IRP.[73] They resulted in a series of costs and capacity projections that vary by technology. The studies' applicability to the IRP are impacted by the rapidly changing DG market, which is very sensitive to price and policy changes. Staff appreciates the difficulties for PGE in forecasting DG adoption rates.

However, the Commission expects utilities to develop supply curves for different DG technologies and include them in portfolio modeling.[74] Staff cannot easily locate individual or aggregate supply curves for DG technology; for the most part they appear to be captured in load forecasts. Without more explicit modeling Staff is left with the impression that the growth of DG – except for Distributed Standby Generation – in PGE territory is mostly endogenous to overall demand. How does growth of DG embedded within the load forecast compare to the Black & Veatch study? Per IRP Guideline 12, DG should be broken out as a supply resource in the IRP, this includes Solar DG.

Staff also finds the interrelated and mutually reinforcing nature of DG technology to policy and demand-side management approaches (*i.e.,* demand response, TOU rates, Smart Grid, etc.) challenging to the Commission's previous direction of evaluating all resources on a consistent basis.[75] Additionally, Staff understands that the potential supply of DG can be impacted by technical considerations relative to the distribution system. The extent to which the distribution system's technical considerations impact the overall adoption of DG in PGE's territory as a supply-side resource is difficult to discern.[76]

Distributed Generation Actions for PGE

30. Staff notes that Table 7-1 lacks any BESS in the column "2020 – 2025." We believe this should be updated to reflect the5MW from the Salem Smart Power Project.

31. Develop standard, annual supply-curves for DG technology over the time frame of the IRP and include them as discreet forecasts in IRP analysis independent of the load forecast.

[73] PGE's DG studies provided them with (1) a market assessments and (2) cost projections for all DG technology, along with (3) a methodology for valuing solar on PGE's grid. *See* PGE 2016 IRP chapter 7.

[74] OPUC Order No. 07-002, page 22.

[75] Examples: the Black & Veatch study notes how assumptions regarding TOU rates impacts the penetration rate of energy storage systems (PGE IRP page 574) and how net-metering policy impacts the decision to adopt storage with solar (PGE IRP, page 577).

[76] Black & Veatch's novel approach to determining technical potential of solar (PGE IRP, beginning on page 498) is excellent. However, it does not analyze the distribution system's technical capacity to absorb higher penetration rates of solar and where higher rates of penetration would be costly or beneficial. The IRP's only comment on higher DG PV penetration rates is that, "Since the capacity-to-energy ratio of distributed PV was 6-to-1, a large increase in DG PV would necessitate back-up generation to provide ancillary services." (PGE IRP, page 185).

4. IRP PROCESS AND METHODOLOGY

Staff has reservations about how PGE selected, scored and – at a fundamental level – constructed the portfolios utilized in this IRP.

4. A. Portfolio Selection for Scoring

Following is a summary of Staff's main concerns with PGE's approach to portfolio selection for the IRP:

- The Company's assumptions regarding PTC utilization prioritized portfolios with wind in 2018. This resulted in Portfolios 17 through 21 being removed despite these portfolios having an NPVRR better than eight of the ten selected portfolios.[77]
- The selection of Wind 2018 has near-term flexibility impacts requiring more flexible capacity to be acquired sooner.
- Portfolios are never assessed against alternate scenarios (e.g., reduced capacity needs) so that portfolio selection is optimized to meet only a single capacity need scenario. Portfolios that may perform better if PGE's resource needs are different are excluded from the rankings.

Portfolio Selection Actions for PGE

32. Add portfolios 17 through 21 into the current top ten portfolios and then re-rank all 15.

4. B. Portfolio Scoring

Staff and other parties have expressed a variety of concerns with PGE's portfolio scoring methods throughout the IRP process and Staff appreciates PGE's presentation of additional scoring analyses in Appendix L.[78] However, Staff does have the following remaining concerns: the ultimate portfolio rankings may be sensitive to (1) the set of portfolios included in the rankings, and (2) a variety of smaller factors, such as small changes in the weighting of the scoring metrics or in the weights assigned to each future. PGE has not presented an examination of the sensitivity of its ranking system to changes in these factors. Staff would like PGE to consider this.

<u>Explanation of Concern 1: The Rankings May Be Sensitive to the Set of Portfolios Scored</u>

PGE includes only a subset of portfolios in its final rankings and Staff is especially concerned that the portfolio rankings are sensitive to the ***<u>set</u>*** of portfolios included in the scoring process. This would mean that the choice of which portfolios to include may have an undue influence on the ultimate rankings. In other words, it is possible that the relative rank of two portfolios could switch with the introduction (or removal) of a different portfolio. This is because the influence that each metric has on the final rankings is affected not just by the weight assigned to it by PGE,[79] but also, because of PGE's scoring system, by the distribution of the scores within each metric.[80]

[77] PGE 2016 IRP, Appendix L, Page 755

[78] These concerns were expressed at PGE's public workshops, during meetings with Stakeholders, and in a meeting between OPUC and PGE Staff on September 14, 2016.

[79] The ultimate rankings of the portfolios that PGE considers "actionable" are determined from a weighted combination of four metrics: Cost (given 50 percent weight), "Variability" (16.67 percent), "Severity" (16.67 percent), and "Durability" (16.67 percent).

[80] The scores for each metric are scaled to assign 0 to the worst performing portfolio (and 100 to the best) *among the set of portfolios included in the process*. *See* Table 12-16, on page 337.

Staff has not yet determined whether this concern is actually present in PGE's portfolio rankings, or is only possible in such a system but not of consequence in this particular instance. However, even if the rankings of PGE's "actionable" portfolios are not affected in this case, Staff is reluctant to endorse a scoring system with these issues because it may set a precedent for subsequent IRP or RFP analyses. Staff would like PGE to use a scoring system that results in a relative ranking between any two portfolios that is invariant to the set of other portfolios included in the scoring process. Or, at the least, Staff would like PGE to examine how sensitive its portfolio rankings are to its choice of the set of portfolios included in the scoring process, and present rankings using a larger set of portfolios (for example, include Portfolios 17-21 with the currently ranked 10 portfolios) for comparison with the rankings calculated using only the 10 portfolios that PGE deems "actionable."

<u>Explanation of Concern 2: The Rankings May Be Sensitive to Small Changes in Assumptions and Weights</u>

Staff has the more general concern that when PGE's scoring metrics are altered slightly they may affect the portfolio rankings. Staff believes that, in order to support the outcome of the portfolio rankings and subsequent identification of a preferred portfolio, the Company should examine whether its portfolio rankings are robust to a variety of factors. For example, the Severity and Durability measures (discussed further below) are both constructed using arbitrary thresholds. Staff would like PGE to consider how the scores in these metrics are sensitive to the choice of thresholds.

As a second example, the Company assigns equal weight (probability) to each future when calculating the scoring metrics, which implies that the probability that each future comes to pass is assumed to be equally likely. PGE should examine how the rankings change with small changes in the assumed probabilities of each future. Staff notes that assuming equal probabilities for each future is not an unreasonable assumption or method. However, the Company's construction of the scoring methods amounts, in Staff's view, to a complicated re-weighting scheme where certain futures are given extra weight, yet the scoring system does not reveal this in a transparent way. For example, the future comprised of low gas prices, mid-level carbon prices, and 1.2 percent long term load growth, is given significantly greater weight than the others because it alone is used to calculate the Cost metric, which contributes 50 percent of the portfolios' final score.

<u>Comments on Specific Metrics</u>

- ***Cost*****:** The Company constructs the Cost metric by using the estimated cost of the reference case future (low gas, mid-level carbon price, expected (mid-level) load) for each portfolio. This implies that the reference case is assumed to be a better representation of expected costs than the average of all the cost estimates. In turn this means that in the ultimate portfolio rankings, the Company gives the reference case more weight than the other futures. Staff appreciates the Company's comparison of this method to the use of average cost (in Appendix L) and does not see reasons for concern among the portfolios considered in this comparison. However, Staff maintains that using the average cost is a more common and transparent method for characterizing the expected outcome of a distribution of data.

- ***Severity*****:** The Company calculates this metric as the average of the three most expensive futures for each portfolio. While this is a reasonable way to measure the "worst case outcomes," Staff believes that the choice of using the top three is arbitrary. Has PGE considered how sensitive the rankings are to the use of some other threshold? Alternatively, Staff would request the Company consider analyzing the severity of bad outcomes without including it as a metric in its scoring system.

- ***Variability*:** This metric is calculated by taking the "semi-variance," which is similar to a standard deviation of a subset of a portfolio's cost estimates. In this case, the subset is those cost estimates that exceed the cost of the reference case for that portfolio. Staff understands that this metric is meant to reflect only the "bad" risk (*i.e.,* the risk of high costs) for a portfolio. However, Staff is concerned that the use of this measure under weighs the possibility that a particular portfolio may result in lower than expected costs. The focus on risk as only a measure of "bad" outcomes may be similar to the psychology with which some people might actually make some decisions, but it is not rational. Staff appreciates PGE's further explanation of this issue in Appendix L and does not have specific concerns at this time that this metric's construction has an undue influence on the portfolio rankings. However, Staff cautions against discarding the information contained in the "better than expected" outcomes when constructing risk metrics. Staff maintains that using the variance or standard deviation is a more common and transparent method for characterizing the uncertainty contained within a distribution of data.

- ***Durability*:** Staff is concerned that the Durability metric, which is calculated based on a relative ranking of portfolios, also suffers from the same problem as the overall scoring system (described above) in which the set of portfolios included when constructing the durability score may actually affect the rankings. In other words, the addition of a new portfolio to those that are scored may flip the ranking of two other portfolios. Furthermore, Staff finds the durability metric to be opaque and without adding any new information. More specifically, PGE's durability metric is calculated by subtracting the percentage of futures in which a portfolio is in the most expensive third (of portfolios) from the percentage of futures in which a portfolio is in the least expensive third. Staff finds this construction to be confusing and does not understand the basis for constructing such a measure or how such a measure should be interpreted. Clearly, a portfolio with a higher Durability score is expected to be cheaper than one with a lower score, but only in a selective way because the metric discards all of the information contained in the non-extreme outcomes (*i.e.,* those not in the top or bottom third) as well as the cardinal information contained in the cost estimates (because it is based on rankings (1^{st}, 2^{nd}, 3^{rd}, etc.), rather than on actual dollar cost estimates). Staff believes Company's scoring system could improve by discarding the durability measure. If the Company insists on using ordinal rankings (rather than the underlying cardinal data) to construct a metric, Staff would request using a portfolio's average rank rather than the difference in the fractions of times in which a portfolio ranks in the extremes, which is confusing in numerous ways. The durability metric as currently constructed would also be heavily influenced by the weights given to each future and the set of portfolios included in the scoring process. Overall Staff believes the Durability metric could be removed as it is currently constructed.

Portfolio Scoring Actions for PGE

33. Present an examination of the sensitivity of its ranking system to suggested changes.

34. Use a scoring system that results in a relative ranking between any two portfolios that is invariant to the set of other portfolios included in the scoring process.

35. Examine whether its portfolio rankings are robust to a variety of factors.

36. Consider how the scores in Severity and Durability are sensitive to the choice of thresholds.

37. PGE should examine how the rankings change with small changes in the assumed probabilities of each future.

38. Consider analyzing the severity of bad outcomes without including it as a metric in its scoring system.

39. Consider discarding the durability measure.

4. C. Portfolio Construction

Staff agrees with PGE that it is important to "assess resource and portfolio performance across a diverse range of credible potential future environments."[81] Staff also believes that it is important to assess a diverse range of *strategies within its portfolios.* Staff is concerned that PGE's ten "actionable" portfolios do not encompass a sufficiently diverse range of strategies. This concern is amplified by the fact that PGE's relative portfolio rankings are sensitive to which other portfolios are included in its scoring calculations (as described in Staff's comments on PGE's portfolio scoring system, below). For example, none of PGE's actionable portfolios consider renewable resource acquisitions in 2018 of less than 432 MW. As expressed elsewhere in Staff's comments, Staff is concerned that PGE has not sufficiently considered alternatives to such a large renewable resource acquisition in 2018. Staff is curious about how a strategy that contains significantly less than 432 MW of new renewable resources in 2018 would compare to PGE's actionable portfolios.

Staff believes that the portfolios are not designed with sufficient diversity to appropriately reflect the range of strategies that might be optimal across a reasonable range of long-term load growth scenarios. This concern is amplified by Staff's observation that PGE significantly understates the uncertainty present in its projected load growth (as described in Staff's comments on PGE's load forecast) and therefore its capacity need. The fact that PGE's portfolio rankings are the same across its load growth scenarios (see Figure 12-11, page 329) raises the concern that PGE's portfolios are not designed to reflect the different load growth futures that PGE considers, not to mention the greater range of load growth scenarios that Staff recommends PGE consider in its comments on PGE's load forecast. Staff questions the reasonableness of the Company's conclusion that the best portfolio for a high growth future will also be the best portfolio in a future with low growth. Staff is concerned that PGE has considered too small of a range of possible strategies and then subsequently concluded that there is not much difference among the strategies they have selected. This, in combination with what Staff views as an excessively broad and open-ended action plan, causes Staff significant concern because the analyses contained in this IRP offers very little guidance for (1) the subsequent development of one or more RFPs to fill the claimed capacity needs, and (2) the assessment of the wide range of bids, which may differ significantly in their technologies, durations, and other terms, that may potentially be submitted to the RFP(s).

In conjunction with Staff's suggestion that PGE consider a wider range of potential future load growth scenarios, Staff would like PGE to consider a portfolio specifically designed for a low load growth future (and likewise consider a portfolio that would be optimal for a high growth

[81] PGE IRP page 262.

future). These concerns, especially those about the insufficient consideration given to the possibility of long-term growth rates below PGE's projected reference case, are compounded by Staff's concerns (expressed elsewhere throughout this document) that PGE's capacity needs may be less than PGE projects.

Portfolio Construction Actions for PGE

40. Consider portfolios specifically designed for low and high load growth scenarios that are well beyond the current load growth sensitivities (see comments on load forecast) and give greater consideration to a strategy that delays acquisition of new renewable resources beyond 2018.

5. OTHER ISSUES

5. A. IRP and RFP relationship

PGE's IRP team stated that its Action Plan has been designed to avoid ruling out any potential actions that may benefit its customers, and that they do not know what potential actions will turn out to be most beneficial before gathering information through a competitive solicitation. Yet, an open-ended Action Plan offers little guidance to Company's upcoming solicitation, given that the solicitation will encompass a diverse pool of bids to be evaluated.

PGE's illustrative comparison in Chapter 13 of two portfolios that are consistent with the Action Plan is a good example of this issue.[82] PGE compares two possible portfolios with very different resource compositions. For example, one meets capacity and 2021 RPS needs with annual and seasonal contracts, unbundled RECs, a CT frame unit, and hydro contracts while the other one also has annual and seasonal contracts but includes a wind resource and a CCCT. While these portfolios do represent only illustrative examples of resource diversity that may respond to an RFP, the fact that both are consistent with the Action Plan leads Staff to believe that PGE's IRP process may not have resulted in robust guidance for PGE's resource strategy. IRP analysis and portfolio construction that leads to a multiplicity of acceptable outcomes ultimately pushes all evaluation of resource alternatives on to the RFP process. Staff believes the IRP is an opportunity to examine future uncertainties and compare a combination of resource options with the outcome of specific guidance for subsequent resource procurement solicitations that best balance cost and risk for ratepayers.

Another example of Staff's concern is in how the Company has proposed to conduct a study of "wholesale market risk"[83] and "market capacity"[84] only *after acquiring new generating resources*. In essence, the upcoming RFP will reflect the IRP's limited understanding of market options. Staff believes this approach could commitment PGE to a large capital investment of new resources without having sufficient knowledge of the market landscape.

[82] PGE IRP page 344
[83] PGE 2016 IRP, page 339.
[84] PGE 2016 IRP, page 344.

5. B. Distribution System Planning (DSP)

It is widely recognized that increased adoption of Distributed Energy Resources (DERs)[85] has the potential to greatly change the power sector. This pending paradigm shift is a transition from power flowing in one direction on the grid (from centrally located resources to instantaneously serve load), to two way managed power flow, with distributed generation, storage, and advanced controls. As the adoption of DERs grows, there will be less reliance on centrally located generation. Planning for this transition has led other states to adopt some form of Distribution System Planning (DSP).

Although the details of DSP and the naming convention looks different in every state, DSP can generally be described as a utility system planning process that results in a long term (5-10 yr) plan for distribution system investments and actions. These investments and actions will provide the most efficient use of existing and new system resources while enabling further growth of cost effective DERs. In many states, the DSP process is directly tied to grid modernization efforts ("smart grid") and is a transparent regulatory stakeholder process. Similar to the Commission's IRP guidelines, DSP incorporates the uncertainty of load growth and DER adoption when determining the best balance of cost and risk for ratepayers from long term investments.

The main difference between IRP and DSP is the granularity of the analysis. While IRP includes transmission level constraints between load and resources, DSP accounts for constraints at the local level. These local level constraints inform the best opportunities for new investment where adding new system equipment or distributed resources would be beneficial for grid operations. In preparation for the distribution system itself becoming a larger piece of the resource to meet load, consistency between the scenarios and assumptions used in DSP and IRP are important such that the outcome of DSP informs the IRP and vice versa.

There are two main reasons driving Staff's mention of distribution planning generally at this time.

- Current resource specific planning dockets, distribution capital planning, smart grid report initiatives (grid modernization) and IRP processes may not be optimally aligned. The continued efficient, safe and reliable operation of the grid with higher levels of DERs will require new infrastructure investments with long term implications for ratepayers. Planning for prudent investments on the distribution system will require transparency and alignment with transmission level IRP system investments. To ensure that we are planning for and investing in a distribution system that is capable of managing and encouraging cost effective DERs, adoption of some form of Distribution Planning could provide a comprehensive efficient approach

- The Commission's current planning processes may be underrepresenting the potential impact of DERs due to lack of sufficient modeling tools and analytical priority or attention, which could lead to a greater risk of identifying an inflated resource need. Distribution System Planning could provide a transparent regulatory framework to support improved tool development to account for locational constraints and uncertainty in loads and address and plan for DER growth to better inform the IRP process.

[85] "Distributed energy resources (DERs) are defined by FERC as a source or sink of power that is located on the distribution system or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment." Staff expands this definition to include energy efficiency (EE), conservation voltage reduction (CVR), and demand response (DR). https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf , page 6

Below, Staff expands on these two concepts and concludes with questions to help further explore what a new approach to Distribution Planning could look like for Oregon and what the benefits of doing so may be.

Aligning Planning Processes with DSP

There are four general areas of planning across which consistent assumptions for local load and resource growth should be used to ensure optimal resource decisions are being made. Currently, the link between each is not clear or transparent.

A. Resource specific planning dockets

Two established dockets are working through distribution system related issues; Resource Value of Solar (Docket No. UM 1716) and Energy Storage (UM 1751). In addition PGE filed a proposal for Transportation Electrification Programs under Docket No. UM 1811. There are also established methodologies for avoided costs for energy efficiency and the PUC plans to explore cost effectiveness of Demand Response in 2017, both of which include location specific benefits.

B. Internal distribution system planning

Distribution level investments to provide safe and reliable service are reviewed in aggregate by the PUC in rate cases for trends and justified deviations from past investment levels. In addition, PGE files a New Construction Report (RE 18) each year, listing capital investments in excess of $1M. Major distribution system investments are included in this report.

C. Smart Grid Reports

Through Order No. 12-158, the Commission adopted policy goals and objectives, reporting requirements, elements of annual reports, and general Commission guidelines for considering and investing in smart-grid technologies. The Commission concluded that adopting a reporting requirement, rather than a planning requirement, was appropriate since the many technologies were in different stages of development and affordability making a comprehensive smart grid plan unwarranted at the time. However, the Commission recognized the potential for significant benefits of smart grid investments and therefore the goal of the policy is to benefit ratepayers by fostering utility investments in cost effective smart grid measures that:

- Enhance the reliability, safety, security, quality, and efficiency of the transmission and distribution network
- Enhance the ability to save energy and reduce peak demand
- Enhance customer service and lower cost of utility operation
- Enhance the ability to develop renewable resources and distributed generation

Since 2013, PGE has filed annual smart grid reports. Reports are required to include utility strategy, goals, and objectives for smart grid investments, as well as the status of and plans for investments over the next five years within the Commission guidelines that support the four policy objectives listed above. PGE's 2016 Smart Grid report, lists 50 individual initiatives.

D. Integrated Resource Plans (IRPs)

Through Order No. 89-507, the Commission adopted least cost planning for all energy utilities in Oregon. The Commission guidelines require utilities to compare all possible resource options on a consistent basis. As DERs grow, the importance of ensuring this consistent comparison of resources becomes apparent.

Integrating the Commission's Planning Processes
Interactive effects between the four processes could impact today's investment decisions. For example, new capital investment decisions made for equipment with a life of 10 years should be assessed with local load and resource forecasts that consider the potential for increased DER penetration. Specific initiatives in Smart Grid Reports should be reflected in local system investments and linked to the IRPs.

Staff sees the following potential benefits to ratepayers in undertaking some form of DSP at this time including;

- Lower overall costs, improved system reliability, and more efficient use of investment capital.
- Creation of a framework under which similar efforts related to grid modernization and DER valuation would be housed would lead to greater connectedness, transparency and a holistic consideration of multiple, currently disparate planning efforts.
- Alignment of current disconnects between distribution and transmission level planning efforts that would reduce the risk of overstating PGE's assessment of resource needs for system adequacy.
- Greater attention to and rigor in assessing growth rates of DERs would improve planning assumptions and reduce resource investment risk for ratepayers.
- Greater transparency may lead to advancement in understanding of locational values of DERs, leading to further adoption of cost effective DERs.
- Provision of signals to customers regarding where to add DERs.
- There may be a cost of not adopting a comprehensive process for distribution system planning that sufficiently considers market advancements and opportunities for improving the efficiency of grid operations.

Improvements to DER modeling in the IRP

In the 2016 IRP, PGE provides a broad quantitative and qualitative review of individual types of DERs on PGE's system over the IRP planning horizon and offers ***significantly*** more information on DERs than the 2013 IRP. This more robust focus comes with good reason. Collectively, these resources account for a significant amount of new capacity on PGE's system over the next 20 years, much more so than was anticipated in IRP planning just 5 years ago.

When considered alone, some types of DERs may seem too small to have significant system impacts over the planning horizon and therefore may not appear to warrant the level of study rigor beyond qualitative consideration. However, when grouped together and when a range of scenarios of adoption rates that link multiple DERs together are considered, it is possible that the collective impact could significantly impact the near term resource planning actions of the Company.

There are seven major areas of DER analysis in the IRP, four of which (energy efficiency, demand response, conservation voltage reduction, and distributed standby generation) are explicitly modeled either on the demand side as a reduction to load or as a supply side resource. The remaining three DERs (distributed generation, electric vehicles, and energy storage) are not modeled explicitly. Distributed generation and electric vehicles are assumed to be within the load forecast reflective of prior growth rates.[86] PGE recognizes that the cost of energy storage remains high and modeling tools are still evolving. Therefore, storage is not included in portfolios in this IRP but is anticipated to be an emerging resource in the future. As modeled, these three DERs do not yet explicitly impact PGE's long term resource planning decisions.

Those DERs that are explicitly included appear in each of the 21 portfolios with the same timing and magnitude as listed in Table 1 below. By 2021, they are expected to provide 281 MW of new capacity and by 2040, 839 MW.

Table 1

Cumulative New DER Capacity (MW)					
Resource	**2017**	**2021**	**2025**	**2030**	**2040**
Explicit DERs					
EE	16	180	297	404	571
DSG	4	22	30	39	57
DR	26	77	162	187	198
CVR	0	2	4	6	13
Total Explicit	**46**	**281**	**493**	**636**	**839**
Implicit DERs					
DG (MW dc)				125-233 by 2035	
EV (aMW)		2-14	5-30 by 2025		
ES	5	44	44	44	44

What is apparent from this collective look at DERs in Table 1 is that, as described in the IRP, the annual numbers cannot be added or summarized in a consistent way making it unclear if the full potential impact of these resources on overall system needs is represented adequately. For example, the distributed solar PV forecast range of 125-233 MW dc by 2035 from the Brattle Group study commissioned by PGE for the 2016 IRP, is already partially included in the load forecast but the amount and location of that assumed increase in distributed generation is not transparent. In other words, the Brattle study result was not explicitly used to adjust the load forecast and the load forecast only considered distributed solar PV growth based on past adoption rates of the resource by customer type.

Other Staff concerns and questions in relating these DERs to system level adequacy planning of the IRP include, by resource:

- Energy efficiency (EE) and Demand response (DR)
    - Is the locational value of these resources important to capture within IRP planning? Is it being captured and shared with distribution system investment plans?

- Conservation Voltage Reduction (CVR)
    - The inclusion of conservation voltage reduction as a resource in 2016 IRP, even at a relatively small amount (3aMW, 4MW), is an important advancement for PGE's IRP. CVR can contribute significant distribution level impacts that link to transmission level and resource adequacy system level planning. Are the

[86] PGE 2016 IRP p. 104

locational values of CVR captured in this analysis and are they effectively translating to system wide impacts?

  - There is some mention of two Smart Grid initiatives within the CVR section of the IRP. This connection of grid modernization work by the Company to the overall IRP and major system investments is noticeable but brief. Should there be greater connection between Smart Grid, IRP and Distribution System investment planning?

- Dispatchable Standby Generation (DSG)
  - On page 196 of the 2016 IRP, PGE estimates 'that the DSG program could grow to meet the majority of the Company's standby capacity needs (non spin)". This is a potentially compelling prospect and one that Staff would like to better understand. Do the current growth assumptions for 57 MW by 2040 meet this standby capacity need? If not, what level of capacity and by what time period could this occur and could it offset resource needs identified in the IRP?

- Distributed Generation (DG)
  - In addition to the concern raised above that there is no explicit adjustment to loads based on the study from the Brattle Group, growth of DG implied in the load forecast may also not account for the time and shape of the resource, the hourly "net load" effect. As DG levels rise, this "duck curve" impact to load may not be represented in the current modeling approach, impacting the timing and magnitude of system resource need.

  - SB 1547 requires the Commission to complete rules for a Community Solar program by mid-2017. Although there is some uncertainty about the impact Community Solar may have on new solar development, based on other states' experiences the potential for high impact on the system is possible. For example, Minnesota has had over 800 MW of community solar applications queued for interconnection since December 2015.[87] Given the potential impact of Community Solar on loads or as a supply side resource capturing this uncertainty in planning at both the distribution and system adequacy level seems important.

- Electric Vehicle Charging (EV)
  - PGE shares a forecast of possible EV charging load which they constructed for their 2013 IRP, ranging from 5-30 aMW by 2025. However, PGE's planning horizon extends to 2040 and the EV load assessment does not extend past 2025. Does it consider how the SB 1547 requirement for utilities to file EV program ideas and more recent projections of adoption[88] may impact the 2013 forecast.

- Energy Storage (ES)
  - PGE provided a comprehensive review of their current understanding of energy storage technologies and how the benefits of these systems may soon be an integral part of their system once cost declines and improved modeling of benefits can be realized.

[87] https://www.greentechmedia.com/articles/read/Xcels-Community-Solar-Program-Turns-Two

[88] A December 2015 report from Goldman Sachs projects that the global penetration rate of EV's will increase from under 3 percent in 2015 to over 22 percent by 2025. Oregon currently ranks 5th in charging infrastructure, 5th in EV concentration relative to population and the City of Portland ranks 1st nationally for EV readiness. https://en.wikipedia.org/wiki/Plug-in_electric_vehicles_in_the_United_States

- As with DG and EV, potential significant growth of energy storage was not considered over the 34 year planning horizon.

Incorporating DERs into existing IRP tools is not necessarily easy to do as the temporal and location specific nature of DERs is hard to capture in high level production dispatch models that were not intended for that purpose. Each DER has a different, location specific influence on the grid, yet IRP modeling tools generally represent the system average value. IRP modeling tools have evolved to meet planning needs for bulk power supply and demand but are possibly inadequate to meet future planning needs as DERs grow on the system. The need to ensure that we have the right framework in place to take these potentially location specific issues into account when planning for the next 20 years of investments at the bulk/transmission system level is now apparent.

Staff is supportive of many of PGE's efforts to incorporate DERs in the IRP to date. However, it is apparent Staff needs to plan to address identified deficiencies and determine how best to prepare its planning processes and tools for DER growth with ratepayer's interest in mind. Staff recommends that PGE continue to refine their assessments of individual DER growth and make explicit use of any study results within their IRP modeling. Aligning all major assumptions that are used to drive DER growth with those used in the IRP is fundamental to any resource planning analysis.

Staff plans to continue to explore these issues and provide process recommendations in Final Comments on this IRP for next steps for investigating, defining and potentially implementing DSP over the next several years

Distribution System Planning Questions

1. How does PGE envision improving the connection between planning for and investing in a distribution system that is needed to efficiently and safely manage higher levels of DERs while determining resource adequacy needs in the IRP?
2. Does PGE see benefit in reassessing and possibly reworking the current regulatory structure connecting locational value dockets, distribution infrastructure planning, the Smart Grid Reports and the IRP?
3. Would greater, more comprehensive, regulatory guidance related to Distribution System Planning enable more efficient prioritization of Company actions and resources?
4. Could greater transparency of location specific aspects of distribution system resources and loads lead to greater adoption of cost effective DERs than currently reflected in IRP planning assumptions and potentially lessen the need for system resources?

6. SUMMARY

Staff has concerns with and questions about PGE's proposal to acquire substantial generating capacity and renewable resource additions within the Action Plan timeframe. Staff's primary concern is that PGE has not persuasively justified or defined the proposed acquisitions. The Company's proposed acquisitions appear vague and open-ended in nature, may not be fully supported by the analysis of a sufficiently diverse set of strategies, and do not seem to sufficiently consider and appropriately value the substantial degree of uncertainty introduced by new and rapidly developing markets and technologies. PGE responds to this uncertainty with an open-ended Action Plan which defers collection of resource information and decisions to a competitive solicitation and a proposal to conduct a study of "wholesale market risk" and "market capacity."

In summary, Staff still has substantive questions with the following elements of PGE's 2016 IRP:

- Renewable timing, especially as it relates to PTC utilization
- Load growth forecast
- Capacity needs
- Availability of hydro contracts
- REC strategy
- REC bank policies
- DR program roll-out

6. A. Listing of Actions and Questions for PGE from Staff's Comments

1. Identify and explain the assumptions that are contained in the load forecasting methodology. Explain and provide support, such as the historical basis, for any relationships assumed in the models. Provide support for the assumption that PGE's econometric models appropriately handle the likely stationary nature of its time-series data.
2. Update PGE's load forecast methodology to better represent the uncertainty around load growth scenarios.
3. Provide further justification and evidence for its assumption of no new direct access customers.
4. If PGE has not already done so, adjust post-2021 industrial load growth forecasts by sectors to those levels recommended by Itron and share the results with Staff.
5. Adjust large, individual industrial customers' load growth forecast to approximately equal their individual average load growth over the past 15 years. Share the results with Staff.
6. Using the data from the bullets above adjust PGE's overall load growth forecast beginning in 2021.
7. Adopt Energy Trust's most recent savings forecasts into IRP Action Plan.
8. PGE needs to further develop a DR deployment strategy that maximizes DR acquisition in all programmatic forms over the planning horizon.
9. Additionally, PGE should be modeling emergency DR and back-up generation DR opportunities for advanced DR capable of offering ancillary services and third party DR.
10. PGE should explain the assumptions behind the PGE's declining growth of DR in PGE's response to Staff IR #59, especially in relation to 1.2 percent projected load growth.
11. PGE should describe which of the five types of DR were added as "incremental DR" and their estimated MW contribution to the revised total of DR in response to IR 59.
12. PGE should provide any internal analysis PGE did to assess the potential quantity of rate driven DR available, such as CPP, TOU and PTR when PGE constructed the IRP.

Materials submitted and work conducted to generate such an assessment should predate the IRP filing.

13. PGE should explain the deployment of DR in PGE's response to OPUC's IR #59. Specifically include explanations as to why DR is rarely deployed more than twice per year and why the summer dispatch of DR does not coincide with the times of greatest LOLE during the summer, per Figure 5-3 on page 120 of the IRP.

14. PGE should explore using CPP rates in 2017 or shortly thereafter, due to the peak reductions experienced in other service territories.

15. Provide more detail as to how PGE will have all of its smart grid investments in place by 2018 for CVR implementation.

16. Describe the flexibility plan in its CVR program in far more detail and provide an analysis on those distribution feeders which CVR has been deployed

17. Consider as "actionable" portfolios designed to delay the acquisition of a renewable resource. See comments along these lines in Section 4.C.

18. Develop a more transparent and realistic unbundled REC analysis for future resource evaluations.

19. Revise the Minimum REC Bank strategy.

20. Adjust RECAP to include 200 MW of market purchases at summer peak

21. Staff believes that the expected level of renewed contracts should be included. These could be aggregated into a single line-item for purposes of the IRP so as to not affect ongoing negotiations.

22. Estimate transfer benefit from joining the EIM and include it in the IRP

23. Set LOLE to 23.3 hours to reflect anticipated 2018 operating conditions and include the Company's ability to address this level of LOLE going forward.

24. Use market prices for market purchases and sales instead of penalty prices. Determine cost of that portfolio and compare cost to portfolio that adds flexible capacity.

25. Request that PGE consider some level of market depth analysis in this IRP to better support their conclusions.

26. Demonstrate in this IRP how the subsequent RFP will allow for and evaluate broad participation of resources of various ownership, duration, and technology type.

27. Provide Staff more information at a high level of the Montana wind option and its associated transmission constraints/options.

28. PGE should describe the change in the region's hydro market that has led to the decline of hydro in PGE's resource capacity mix since 2013.

29. Can PGE share any information that would help Staff better understand PGE's strategic shift in the preferred approach to acquiring hydro resources?

30. Staff notes that Table 7-1 lacks any BESS in the column "2020 – 2025." We believe this should be updated to reflect the5MW from the Salem Smart Power Project.

31. Develop standard, annual supply-curves for DG technology over the time frame of the IRP and include them as discreet forecasts in IRP analysis independent of the load forecast.

32. Add portfolios 17 through 21 into the current top ten portfolios and then re-rank all 15.

33. Present an examination of the sensitivity of its ranking system to suggested changes.

34. Use a scoring system that results in a relative ranking between any two portfolios that is invariant to the set of other portfolios included in the scoring process.

35. Examine whether its portfolio rankings are robust to a variety of factors.

36. Consider how the scores in Severity and Durability are sensitive to the choice of thresholds.

37. PGE should examine how the rankings change with small changes in the assumed probabilities of each future.

38. Consider analyzing the severity of bad outcomes without including it as a metric in its scoring system.

39. Consider discarding the durability measure.

40. Consider portfolios specifically designed for low and high load growth scenarios that are well beyond the current load growth sensitivities (see comments on load forecast) and give greater consideration to a strategy that delays acquisition of new renewable resources beyond 2018.

41. How does PGE envision improving the connection between planning for and investing in a distribution system that is needed to efficiently and safely manage higher levels of DERs while determining resource adequacy needs in the IRP?

42. Does PGE see benefit in reassessing and possibly reworking the current regulatory structure connecting locational value dockets, distribution infrastructure planning, the Smart Grid Reports and the IRP?

43. Would greater, more comprehensive, regulatory guidance related to Distribution System Planning enable more efficient prioritization of Company actions and resources?

44. Could greater transparency of location specific aspects of distribution system resources and loads lead to greater adoption of cost effective DERs than currently reflected in IRP planning assumptions and potentially lessen the need for system resources?

This concludes Staff's initial Comments.

Dated at Salem, Oregon, this 24th of January, 2017.

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