CASE: UM 1662
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Reply Testimony

May 11, 2015

Q. Please state your name, present position with the Oregon Public Utility Commission, and business address.

A. My name is John Crider. I am employed as a Senior Utility Analyst in the Energy Resources and Planning (ERP) Division of the Utility Program. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address concerns and issues associated with aspects of the Joint Utilities' proposal for recovering certain costs related to compliance with Oregon's Renewable Portfolio Standard (RPS).

Q. How is your testimony organized?

A. The testimony is organized as follows:

1. <u>Description of Joint Utilities Request</u>
2. <u>Summary of Staff's Recommendation</u>
3. <u>Primary Issue – Forecasting Errors</u>
4. <u>Explanation of the Joint Utilities Proposed Cost Calculation</u>
5. <u>Other Issues</u>
    a. <u>Risk Shift to Customers</u>
    b. <u>Possibility of Over-Earning</u>
    c. <u>Use of PowerDex Index</u>
6. <u>Alternative to the Calculation</u>
7. <u>Summary & Recommendation</u>

1. Description of Joint Utilities Request

Q. What are the Joint Utilities requesting in this docket?

A. The Joint Utilities (Pacific Power and Portland General Electric) are requesting a revision to their individual annual power cost adjustment mechanisms (PCAM) that would allow them to recover net variable power costs (NVPC) associated with compliance with Oregon's Renewable Portfolio Standard (RPS) on a dollar-for-dollar basis.

Q. How do the Joint Utilities currently recover costs associated with the RPS?

A. The Joint Utilities each recover capital costs associated with the RPS through a recovery mechanism, the Renewable Adjustment Clause (RAC), established solely for that purpose by the Commission as directed by ORS 469A.120(2).

Q. What portion of RPS-related costs is recovered through the RAC?

A. Each company recovers its "costs to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission."[1]

Q. Are NVPC recovered through the RAC?

A. No. These costs are treated like any other power cost, and are recovered through the companies' PCAMs.

[1] ORS 469A.120.

Q. Please describe what RPS-related costs are considered variable costs for the purpose of the Joint Utilities' request.

A. According to the Joint Utilities' initial filing there is a cost associated with the difference between the wind forecasted energy and the actual energy realized from the wind generation.[2] The Joint Utilities believe a similar cost exists for all renewable resources, not just wind.[3] The Joint Utilities claim that the cost is realized when energy that was forecasted is not actualized and the company must supply replacement energy.[4] The converse is also possible when renewable resources produce more than forecast and the utility is able to displace other operating cost thereby saving margins.[5]

Q. Why do the utilities believe it is appropriate to remove the RPS-related costs from the PCAM?

A. The Joint Utilities argue that the PCAM is not well-suited for recovery of costs and benefits of intermittent renewable resources. The Joint Utilities note that costs and benefits of renewable resources are difficult to project and that the renewable resources' actual costs and benefits for a 12-month period will usually vary significantly from the projected costs and benefits included in the utilities' base rates under the PCAM.[6] Under the PCAM, NVPC is subject to deadbands such that if the NVPC falls within the deadband, no further recovery

[2] UM1662/PGE-PAC/100, Tinker-Dickman/5, 10-11.
[3] Id. at 8-9.
[4] PGE-PAC100, Tinker-Dickman/11.
[5] PGE-PAC, Tinker-Dickman/11.
[6] PGE-PAC/100, Tinker-Dickman/5.

or refund of NVPC is allowed. That is, the NVPC is absorbed by the company.[7] The design of the PCAM anticipates that years of over-collection within the deadband will balance with years of under-collection, and on the average these deviations will effectively cancel each other. The Joint Utilities claim that in the case of renewable NVPC, the PCAM is not operating as planned and as a result the companies are consistently under-collecting.[8]

2. Summary of Staff's Recommendation

Q. What is Staff's recommendation regarding the Joint Utilities' proposal?

A. Staff recommends that the Commission reject the Joint Utilities' proposal to recover RPS-related net variable power costs (NVPC) through the proposed recovery method. Staff bases this recommendation on the discovery of what Staff believes are substantial flaws in the Joint Utilities proposal, and the belief that these flaws would lead to unjust and unreasonable rates if the proposal was adopted by the Commission.

3. Primary Issue – Forecasting Errors

Q. Does Staff agree with the Joint Utilities that RPS-related NVPC should be removed from the PCAM to ensure the utilities collect any variance in this subset of NVPC?

A. No. As the Joint Utilities note, a portion of the NVPC incurred is due to the fact forecasts are rarely accurate.[9] Forecast errors exist with all generation resources and are a normal part of a company's operation. The PCAM design

[7] PGE/-AC/100, Tinker-Dickman/6.
[8] PGE-PAC/100, Tinker-Dickman/6-7.
[9] PGE-PAC/100, Tinker-Dickman/5.

anticipates that there will be errors in forecasting from year to year and that in any given year the PCAM will result in an over-collection or an under-collection. The design of the PCAM is such that these over- and under-collections will essentially negate each other over the long run.[10]

Q. In the event that a persistent under-collection does exist, what is Staff's preferred solution?

A. A persistent under-collection, if it exists, could be caused by a persistent difference between forecasted energy generation and actual energy generation. Instead of correcting for this difference by utilizing an external recovery process as proposed by the Joint Utilities, Staff recommends further refinement of the forecast such that the forecast error – and the associated costs of the error – is reduced.

Q. How do the Joint Utilities characterize the nature of wind forecasting?

A. In the filing the Joint Utilities claim that wind forecasting, in particular, presents "challenges"[11] and can "vary significantly from actuals due to uncontrollable circumstances such as weather conditions."[12]

Q. Does Staff agree with this characterization of wind forecasting?

A. Staff agrees that in a given year both of these statements may prove true. However, Staff maintains that a properly designed forecasting methodology will create normalized forecasts that anticipate variance both positive and negative.

[10] Order No. 07-015 at 17-19 (PCAM imposed for PGE intended to be revenue neutral); Order No. 12-493 at 15 (PCAM imposed for PacifiCorp intended to be revenue neutral).
[11] PGE-PAC/100, Tinker-Dickman/1.
[12] PGE/PAC/100, Tinker-Dicman/5.

The important factor is that over time, the positive variances will balance the negative variances such that any associated net cost will also be reduced.

Q. Do other types of forecast used in the PCAM have characteristics that are similar to the wind forecast?

A. Yes. The PCAM includes forecasts of hydro generation that also may deviate from actual generation.

Q. How is this deviation of actual hydro energy from forecast hydro energy handled in the PCAM?

A. In the PCAM several decades of historical water flows and levels are analyzed and averaged to create a normalized projection of hydro generation. The intent of the normalized projection is not to attempt a precise and accurate forecast of the test year's hydro generation but instead to discover an average expected projection. The use of the normalized projection anticipates that some years will have greater than normal generation and some years will have less than normal generation. The important aspect is that over time, the over- and under-generation will balance out, and any deviations in costs associated with the forecast error will similarly balance each other.

Q. Could this approach be adopted for wind generation forecasts?

A. Using historical annual averages of wind production certainly seems like a reasonable approach to forecasting future wind production. Staff recognizes that there are far fewer years of actual wind generation to draw upon than there are for hydro normalization, so it may take time for the "true" average to be reached, consistent with the law of large numbers.

Q. Has the issue of wind forecast modeling been discussed in other dockets?

A. Yes. In PacifiCorp's 2014 Transition Adjustment Mechanism (TAM) the Commission adopted the Company's proposed change to the wind modeling that was intended to capture the variability in the wind energy production and thus provide a more accurate representation of daily wind shape.[13] Staff suggests that coupling this modeling change of wind shape to a baseline normalized wind profile would address both intraday variability (through the shaping) and long-term variability (through normalization).

4. Explanation of the Joint Utilities Proposed Cost Calculation

Q. How do the Joint Utilities propose to address managing the costs caused by a difference between forecasted energy and actual energy from wind?

A. Instead of addressing a correction to the forecasting error directly, the Joint Utilities propose to estimate the cost incurred by the forecasting error and to collect it exogenously from the PCAM. The Joint Utilities have proposed a simple mathematical calculation to estimate the cost they wish to recover. In summary form, the proposed calculation is:

Cost = (Energy forecast * Market price forecast) –
(Energy actual * Market price actual)[14]

[13] See PUC Order No. 13-387 at 4.
[14] UM 1662/PGE-PAC/100, Tinker-Dickman/9-10.

with this calculation applied to each individual renewable resource, repeated for every hour of the year, and the sum of all hours for all resources totaled to obtain the total cost, or the total additional revenue requested.

Q. Please describe each of the terms in the calculation.

A. The "Energy forecast" is the amount of expected energy from a specific renewable resource in a specific hour. This forecasted energy amount (in MWh) is an input to company's annual power cost projection. The "Market price forecast" is the company-forecasted hourly cost of electricity at the mid-Columbia hub. The "Energy actual" is the recorded amount of energy the resource produced at that specific hour, looking back after the fact. The "Market price actual" is the PowerDex© "Mid-C" published index that provides an average actual hourly market price for the mid-Columbia trading hub.

Q. Does Staff agree that the proposed calculation accurately reflects RPS-related variable costs?

A. No. The approach would lead to an adjustment even if actual renewable resource production exactly matched forecast. This is because the formula uses both forecast market prices and actual market prices. The proposal shifts market price risk from the company to customers and this has nothing to do with renewable resource cost recovery. This aspect is discussed in more detail later on in this testimony.

Q. Does Staff have an alternative to suggest in the event the Commission does not adopt Staff's principal recommendation to not adopt a mechanism?

A. Yes. An alternative would be to replace forecast renewable generation with actual renewable production as the only change in the power production cost model. All other assumptions would remain in place. This is also discussed later in this testimony.

5. Other Issues

Q. Other than issues with the calculation itself, does Staff have any other concerns about the Joint Utilities proposal?

A. Yes. Staff believes the proposed method unduly shifts risk from the company to customers. Also, by carving out the renewable costs from the PCAM mechanism, there is a possibility a company could exceed its authorized return on equity. In addition, in the event that the Joint Utilities' calculation method is adopted, Staff is concerned that the PowerDex© index used for valuation is not a reflection of actual costs incurred by the companies. I discuss each of these by section. Further, Staff believes it is possible that the utilities and stakeholders will disagree on which NVPC is "associated with compliance" with the RPS and recoverable under ORS 469A.120. Staff does not think the current circumstances warrant introducing this point of contention into the utilities' recovery of NVPC.

Risk Shift to Customers

Q. Please explain what you mean by risk in this context.

A. In this context, "risk" refers to the possibility of incurring cost or benefit based on how closely an actual value comes to matching the projected value in a specific hour. The projected value is typically estimated several months to a year or more in advance and then compared to the actual value after the fact. There is real cost (or benefit) incurred as a result of how well the forecast matches the actuals. Whichever party assumes the risk then also assumes the responsibility for absorbing the cost or benefit.

Q. Explain the risk inherent in the Joint Utilities proposal.

A. Staff has identified three areas of risk in the Joint Utilities proposed methodology. The calculation may be summarized as:

Cost = (Energy forecast * Market price forecast) –
(Energy actual * Market price actual)

Two risk areas are in the two forecasts. Any difference between the actual energy and forecasted energy represents a risk. Similarly, any difference between the actual market price and the forecasted market price represents a risk. There is a third risk element implied but not explicit in the equation. The calculation assumes that the load forecast is correct and that Unrealized Energy = (Energy Forecast – Energy Actual) is always needed and must be purchased at market price. In reality, there may be many instances where the load forecast is in error and the unrealized energy is not needed. In these instances, no real cost is incurred.

Q. How are these risks currently managed?

A. Each company has a carefully crafted PCAM which has three sharing mechanisms created with a purpose of sharing these types of risks. Currently these costs are included in the PCAM and the sharing mechanisms are applied to these costs, and to all variable power costs.

Q. In terms of risk, what is the effect of the Joint Utilities proposal?

A. Currently the risks are shared by customers and the company through the PCAM. By removing these costs from the PCAM as proposed by the Joint Utilities, 100 percent of the risk is shifted to customers as is 100 percent of the resulting cost.

Q. Does Staff believe it is appropriate to shift 100 percent of the risk and cost to customers?

A. No. The Commission has clearly indicated its wish that the company share risk with customers through the development of the PCAM. Risk associated with price forecast error was clearly anticipated in the PCAM and the sharing mechanisms were put into place specifically to address this kind of risk. Similarly, load forecast error has consistently been considered as normal business risk and thus absorbed at least in part by the company.

Q. Does Staff believe it is appropriate to shift any risk to ratepayers?

A. No. However, in the event that the Commission approves the Joint Utilities request for 100 percent recovery of RPS-related variable costs, Staff believes it will be appropriate to match risk and cost and thus shift only the risk associated with renewable plant generation forecast error to ratepayers.

Q. Assuming this is the case, will the calculation proposed by the Joint Utilities accurately estimate the cost?

A. No. The proposed calculation does not isolate this single source of risk (i.e., renewable plant generation forecast error) and thus does not calculate the cost appropriately.

Q. Can Staff offer an alternative calculation that addresses this issue?

A. Yes. The market price risk can be removed from the calculation by valuing both the forecasted energy and the actual energy at the same market price. Staff proposes repricing the actual energy values using the forecasted market price, and then computing the difference between the forecasted cost and the actual cost using the same price variable. This removes the market risk from the calculation, and removes the shift of market risk to customers. The modified calculation is:

Cost = (Energy forecast * Market price forecasted) –

(Energy actual * Market price forecasted)

= (Energy forecast – Energy actual) * Market price forecasted.

This calculation is applied on an hourly basis to each qualifying resource and summed over the course of a year.

Q. Is this the same proposal Staff offered in Docket No. UE 283?

A. Yes. This calculation is essentially the same as Staff's preferred method as presented in Docket UE 283.[15]

Q. Does Staff have a proposal for eliminating load forecast error from the calculation?

A. Yes. Staff proposes that each hourly cost estimate resulting from the application of Staff's proposed calculation be subject to a comparison with that hour's load. There can be two outcomes from this comparison – either the

[15] See Docket UE 283, Staff/1100, Bracken/28-32.

generation is less than the load, meaning that the company must supply replacement energy, or the generation is greater than the load, meaning the company may sell the excess energy on market for a benefit.

Q. Please explain this concept in more detail.

A. The process consists of 3 steps. First, the energy forecast error is computed for each hour. Specifically:

$$\textit{Energy forecast error}_{hour} = E\Delta = (\textit{Energy forecast} - \textit{Energy actual})_{hour.}$$

Next, the load forecast error is calculated in a similar fashion,

$$\textit{Load forecast error}_{hour} = L\Delta = (\textit{Load forecast} - \textit{Load actual})_{hour.}$$

The next step involves comparing the two errors by taking the difference between them. There are two cases of outcome – either the difference (LΔ – EΔ) is positive, meaning that the load forecast error was greater than the energy forecast error, or the difference is negative, meaning that the energy forecast error was greater than the load forecast error. When the difference is positive, there is no need for the company to purchase replacement energy since the load is served. When the difference is negative, it means that there is still load unserved, and the company needs to generate or purchase that amount of energy.

Q. Please demonstrate this concept with an example.

A. Consider the four scenarios in the table below. Assume all entries are in MWh.

	A	B	C	D	E	F
CASE	**Load Forecast**	**Load Actual**	**Load Delta (A-B)**	**Wind Forecast**	**Wind Actual**	**Wind Delta (D-E)**
1	1000	800	200	150	100	50
2	1000	1200	-200	150	50	100
3	1000	900	100	150	0	150
4	1000	800	200	150	200	-50

The cost we are seeking is the cost of renewable (in this case, wind) energy that was forecasted and planned for, but was unrealized AND was needed to be replaced. So, what needs to be discovered is the amount of unrealized energy that is needed to serve load. To discover this, apply the different equation (LΔ – EΔ):

In case 1, (LΔ – EΔ) = (Column C – Column F) = 200-50 = 150.

In words, this means that the actual wind energy was 50 MW less than expected; however, the load was also 200 MW less than expected. Since the Load Delta is greater than the Energy Delta, there was no need for replacement energy. This is indicated by the (LΔ – EΔ) value being positive and represents a benefit by having excess energy sold at market.

In Case 2, (LΔ – EΔ) yields (-200 – 100) = -300. In this case, more load was present than was forecasted, coupled with less wind than forecasted. This result is negative, indicating a need for replacement energy of 300 MW in this hour. However, only part of this replacement energy is due to the wind shortfall, namely 100 MW. This example indicates that the maximum hourly cost for replacement energy due to the renewable energy forecast error is limited by the Energy Delta.

In Case 3, (LΔ – EΔ) yields (100 – 150) = -50. Again, since this number is negative it indicates a need for replacement energy of 50 MW. Since 50 MW is less than the maximum amount of Energy Delta (=150), all of the replacement cost associated with the replacement energy of 50 MW is assigned to the renewable resource.

Finally, in case 4 (LΔ – EΔ) yields (200 – (-50)) = 250. In this case, not only was the load less than forecasted, but wind energy was 50 MW over the forecast. The positive number of 250 indicates a benefit. However, the benefit associated with renewable energy cannot be greater than Energy Delta, so the benefit would be based on maximum (absolute) value of Energy Delta, or 50MW.

The formula can be represented as: Replacement MWh = $\{(L\Delta - E\Delta)\}_{|max|E\Delta|}$.

Possibility of Over-Earning

Q. What is an earnings test?

A. In this context, an earnings test is a comparison of a company's computed return on equity (ROE) with its Commission-authorized ROE. The company computes the ROE based on projected revenue and expenses.

Q. How does the proposed recovery of RPS variable costs impact revenue?

A. The Joint Utilities are proposing to isolate RPS-related variable costs and recover these costs through a new or existing tariff. This implies an increase in company annual revenue.

Q. How is revenue increase related to power costs currently administered?

A. Revenue increases indicated through the company's PCAM are first subject to sharing mechanisms and then subject to an earnings test. The earnings test prevents the company from recovering amounts that would cause their computed ROE to exceed the Commission authorized ROE by more than 100 basis points.

Q. How does the Joint Utilities' proposal alter this?

A. The proposal removes RPS-related costs from the PCAM, thus removing these amounts from all sharing mechanisms and the earnings test. This may create a scenario where the company realizes an ROE greater than their Commission-authorized ROE.

Q. Does Staff have a proposal to mitigate this risk?

A. Yes. Staff proposes that the RPS-related cost recovery discussed in this proceeding remain subject to an earnings test identical to that in the PCAM. Any revenue amounts that would cause the computed ROE to exceed the Commission-authorized ROE plus 100 basis points would not be subject to recovery from customers. This treatment would be in alignment with the

Commission's development of PCAM to exercise their discretion in keeping rates just and reasonable.[16]

Q. How does this treatment differ from recovering the costs through the PCAM?

A. Although the earnings test is the same, the costs in this case are not subject to the risk-sharing or the cost variance deadbands, in essence allowing dollar-for-dollar recovery up to the limit of the earnings test.

Use of PowerDex index

Q. What is the POWERDEX© index?

A. According to the PowerDex© website, the index is an hourly weighted average of physical power trades in the Mid-Columbia market.[17] As such, the index provides an average of all trades in the hour for a given hour. This may or may not represent the actual prices paid or received by the Joint Utilities in a given hour.

Q. Does Staff have an alternative suggestion to using the POWERDEX© index to determine costs in the Joint Utilities proposed mechanism?

A. Yes. If accurate assessment of actual costs incurred by the company is the goal of the proposed mechanism, Staff suggests using actual transaction costs for each respective company to value the replacement energy in place of the index.

[16] Oregon Revised Statue (ORS) 756.040.
[17] http://www.powerdexindexes.com/about.htm

6. Alternative to the Calculation

Q. In light of Staff's forgoing concerns regarding the Joint Utilities calculation method, can Staff offer an alternative method for estimating RPS-related NVPC?

A. Yes. The existing power cost models used by the Joint Utilities represent an excellent tool for estimating these costs. Since these models have been vetted over the course of many years and many power cost cases, Staff believes the models are an accurate representation of each utility's dispatch operation, and hence an excellent method to estimate operational costs. As discussed previously, by comparing a base model run using the wind forecast to a second run that replaces the wind forecast with actual wind generation, Staff believes a reasonable representation of RPS-related NVPC variance can be obtained.

7. Summary & Recommendation

Q. Please summarize Staff's recommendation.

A. Staff recommends that the Commission:

1) reject the proposal by the Joint Utilities to isolate the RPS-related NVPC for recovery in a separate mechanism; and

2) instruct the Joint Utilities to further refine their respective wind forecasting methodologies to develop a normalized wind projection in order to resolve any potential issues with persistent under-collection.

Q. Can Staff offer possible alternatives to the Staff recommendation?

A. Yes. In the event that the Commission adopts a recovery method for RPS-related NVPC, Staff recommends using the existing NVPC models (Monet for

Portland General Electric and GRID for Pacific Power) to calculate these costs for ultimate recovery. Alternatively, if the Commission instead adopts the Joint Utilities proposed calculation for estimating the RPS-related NVPC, Staff recommends adoption of these modifications to the Joint Utilities proposal:

1) Market risk should be removed from the computation proposed by the Joint Utilities. The result is the calculation proposed by Staff in this testimony.

Cost = (Energy forecast * Market price forecasted) –
(Energy actual * Market price forecasted)
= (Energy forecast – Energy actual) * Market price forecasted;

2) Forecast risk should be removed from the computation as described in this testimony;

3) Actual company trading costs should be used in place of the proposed PowerDex© index pricing;

4) An earnings test identical to the PCAM earnings test should be applied to the proposed recovery amount; and

5) Any amount for recovery under this proposal should be recovered through a new tariff and not through the existing RAC.

Q. Does this conclude your testimony?

A. Yes

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PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 101

Witness Qualification Statement

May 11, 2015

WITNESS QUALIFICATION STATEMENT

NAME: JOHN CRIDER

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EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2012. My current responsibilities include analysis and technical support for electric power cost recovery proceedings, with an emphasis on variable power costs and purchases from qualifying facilities. Prior to working for the OPUC I was an engineer in the Strategic Planning division for Gainesville Regional Utilities (GRU) in Gainesville, Florida. My responsibilities at GRU included analysis, design and support for generation economic dispatch modeling, wholesale power transactions, net metering, integrated resource planning, distributed solar generation and fuel (coal and natural gas) planning. Previous to working for GRU, I was a staff design engineer for Eugene Water & Electric Board (EWEB) where my responsibilities included design of control and communications system in support of water and hydro operations.

I am a registered professional engineer in both Oregon and Florida.