PUGET SOUND ENERGY

Puget Sound Energy
P.O. Box 97034
Bellevue, WA 98009-9734
PSE.com

Received
Records Management
08/02/19 15:42
State Of WASH.
UTIL. AND TRANSP.
COMMISSION

August 2, 2019

Filed Via Web Portal

Mark L. Johnson, Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

Re: **Docket UE-170002: Comments of Puget Sound Energy on Rulemaking to Address Electric Cost of Service.**

Dear Mr. Johnson:

Puget Sound Energy ("PSE" or the "Company") appreciates the opportunity to respond to the questions posed in this docket and submits the following comments in response to the request in the Washington Utilities and Transportation Commission's ("Commission") Notice of Opportunity to File Written Comments dated May 6, 2019.

General comments

In addition to responding to questions posed in this docket, PSE is providing comments to the Draft Cost of Service Rules. PSE's comments are embedded in the Draft Cost of Service Rules, circulated by the Commission. PSE's comments on the draft rules are being filed concurrent with this letter.

Questions for all interested Stakeholders:

1. How should a cost of service study reflect special contracts?

PSE reflects special contracts as a separate class in its cost of service models for both electric and gas customers. This is the preferred approach for PSE but other approaches may be appropriate for other utilities.

a. Is it appropriate to treat them as a separate customer class?

Yes. By treating special contracts as a separate class it provides data regarding the performance of the special contracts. However, as noted in earlier comments by PSE in this docket, this data should not be used to challenge special contract rates during the term of the special contract.

b. How should revenue from special contracts be included or shown as an offset to other customer classes?

PSE includes revenue from special contract customers under their own separate class in the cost of service model. If special contracts are not treated as a separate class in the cost of service model then the revenues from these customers should be included as an offset to other customer classes.

i. Would this require a specific adjustment in the revenue requirement model?

No.

2. Are the proposed input data types (advanced metering infrastructure, special contracts, load studies) sufficient, or should there be other types of data?

PSE believes other types of input data should be allowed as necessary and appropriate for the cost of service studies. PSE doesn't have any specific input data types to include in the rule at this time but would prefer the rule to be flexible enough to include other data types as appropriate.

3. How often should load studies be performed?

Load studies should be performed for each general rate case or a minimum of every five years.

<u>Electric Scenarios:</u>

For all the electric scenarios, PSE used the cost of service model approved in Docket UE-180282, the filing that reflected the decrease in the federal corporate tax rate from 35 percent to 21 percent (which was based on PSE's most recent General Rate Case filing, Docket UE-170033). The results for each scenario can be found in the attachment to this letter.

Generation and Transmission Classification

1. Average and Excess

For this scenario, PSE used the methodology outlined in pages 49-52 of the NARUC Electric Utility Cost Allocation Manual, resulting in a classification of 51% demand and 49% energy factor. For both generation and transmission cost classification, an average of each class's contribution to the highest coincident peaks in January 2015, February 2015, November 2016 and December 2016 ("4CP") was used as the demand class allocation factor, and class energy usage, adjusted for losses, was used as the energy class allocation factor.

2. Fixed Ratio Methodology

For this scenario, PSE assumed 75% of production costs are energy related and 25% are demand related. For both generation and transmission cost classification, the 4CP allocation factor was used for demand costs. Class energy usage, adjusted for losses, was used for the energy costs. This is the same methodology used by PSE in its 2017 General Rate Case filing (Docket UE-170033) and the Tax Reform filing (Docket UE-180282). The results match what was approved in Docket UE-180282.

3. Renewable Future Peak Credit

For this scenario, PSE attempted to match the renewable technology with the same level of service in output and capacity that would be provided by the Thermal Peak Credit Scenario. The cost of wind at a 30% capacity factor is adjusted to match the output from a combined cycle plant which has an 80% capacity factor. The capacity provided by the battery is adjusted to provide peak capacity over the duration of a peak period, thereby matching the capacity contribution provided by a simple cycle combustion turbine (SCCT). It should be noted that assumptions used for renewable output and capacity have large impacts on the renewable future peak credit results. Small changes to the battery capacity contribution and wind output adjustment significantly alter the peak credit result. This scenario results in a classification of 49% demand and 51% energy factor.

For both generation and transmission cost classification, the 4CP allocation factor was used for demand costs. Class energy usage, adjusted for losses, was used for the energy costs.

4. Thermal Peak Credit

For this scenario, PSE compared the costs for a SCCT to a combined cycle combustion turbine (CCCT). Capacity was defined as one-half SCCT fixed costs plus fuel costs to operate for 200 hours. Energy was defined as the fixed and fuel costs for a CCCT. PSE utilized the Wood Mackenzie long term price for natural gas fuel prices. This scenario results in a classification of 12% demand and 88% energy factor.

For both generation and transmission cost classification, the 4CP allocation factor was used for demand costs. Class energy usage, adjusted for losses, was used for the energy costs.

5. Renewable Future Peak Credit with NPC allocated on Energy

For this scenario, the Renewable Peak Credit is identical to Scenario 3, except that the specified NPC accounts were allocated 100% on energy. This scenario results in a classification of 49% demand and 51% energy factor.

6. Top 100 Winter/Top 100 Summer

For both generation and transmission cost classification, an average of the top 100 winter CP hours (October through March) and top 100 summer CP hours were used to allocate demand related costs. Class energy usage, adjusted for losses, was used for the energy cost allocation to customer class. The average and excess factor split of 51% demand and 49% energy was used.

7. Load Net of Renewable Generation (1CP)

For both generation and transmission cost classification, the system peak (or 1 CP), with non-dispatchable renewable generated energy (solar and wind) contribution removed, was used to allocate demand related costs. Class energy usage, adjusted for losses, was used for the energy cost allocation to customer class. The average and excess factor split of 51% demand and 49% energy was used.

8. Load Net of Renewable Generation (12CP)

For both generation and transmission cost classification, the average of the 12 monthly system peaks (or 12 CP), with non-dispatchable renewable generated energy (solar and wind) contribution removed, was used to allocate demand related costs. Class energy usage, adjusted for losses, was used for the energy cost allocation to customer class. The average and excess factor split of 51% demand and 49% energy was used.

9. Load Net of Renewable Generation (Top 1 Winter/Summer)

For both generation and transmission cost classification, the average of the top 1 winter CP hours (October through March) and top 1 summer CP hours, with non-dispatchable renewable generated energy (solar and wind) contribution removed, was used to allocate demand related costs. Class energy usage, adjusted for losses, was used for the energy cost allocation to customer class. The average and excess factor split of 51% demand and 49% energy was used.

10. 12 CP Method

For both generation and transmission cost classification, the average of the 12 monthly system peaks (or 12 CP) was used to allocate demand related costs. Class energy usage, adjusted for losses, was used for the energy cost allocation to customer class. The average and excess factor split of 51% demand and 49% energy was used.

11. Generation (Top 100 Winter/Top 100 Summer) & Transmission (12CP and 100% Demand)

For this scenario, generation costs were allocated identically to Scenario 6 above. Transmission costs were allocated based on the average of the 12 monthly system peaks (or 12 CP) and are 100% demand related.

12. Load Net of Renewable Generation (1CP)

For this scenario, generation costs were allocated identically to Scenario 7 above. Transmission costs were allocated based on the average of the 12 monthly system peaks (or 12 CP) and are 100% demand related.

13. Load Net of Renewable Generation (12CP)

For this scenario, generation costs were allocated identically to Scenario 8 above. Transmission costs were allocated based on the average of the 12 monthly system peaks (or 12 CP) and are 100% demand related.

14. Load Net of Renewable Generation (Top 1 Winter / Summer)

For this scenario, generation costs were allocated identically to Scenario 9 above. Transmission costs were allocated based on the average of the 12 monthly system peaks (or 12 CP) and are 100% demand related.

15. 12 CP Method

For this scenario, generation costs were allocated identically to Scenario 10 above. Transmission costs were allocated based on the average of the 12 monthly system peaks (or 12 CP) as well, but are 100% demand-related.

Please refer to the attachment labeled "PSE Electric Scenarios" for the requested electric scenarios. For each scenario, in addition to the relative parity ratios, PSE has also provided the costs to serve each class.

Please contact Birud Jhaveri (425) 462-3949 for additional information about these comments. If you have any other questions, please contact me at (425) 456-2142.

Sincerely,

/s/ Jon Piliaris

Jon Piliaris
Director, Regulatory Affairs
Puget Sound Energy
PO Box 97034, EST07W
Bellevue, WA 98009-9734
425-456-2142
Jon.Piliaris@pse.com

cc: Lisa Gafken, Public Counsel
Sheree Strom Carson, Perkins Coie