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Chairman Danner, Commissioner Rendahl, and Commissioner Jones
Washington Utilities & Transportation Commission
1300 S. Evergreen Pk. Dr. S.W.
P. O. Box 47250
Olympia, WA 98504-7250

Re: The 2015 Integrated Resource Plan (“IRP”) of Puget Sound Energy (the “Company”)

Dear Commissioners:

I appreciate the opportunity to provide these comments on behalf of the Industrial Customers of Northwest Utilities (“ICNU”) regarding the Company’s 2015 IRP. ICNU is a trade organization representing large electric consumers throughout the Northwest, including customers of Puget Sound Energy. Consistent with ICNU’s interests in this proceeding, these comments specifically address the portions of the IRP dedicated to the Company’s electric service.

COMMENTS

These comments identify three primary concerns ICNU has with the assumptions in the Company’s 2015 IRP. First, the Company appears to be considering issuing an all-source request for proposals (“RFP”) despite the fact that its own projections do not indicate the need for a new capacity resource until at least 2021. Second, ICNU has serious concerns with the assumptions the Company made that lead to it forecasting a need for a new capacity resource in 2021. These assumptions underlie a planning standard that is new to this IRP, and the Company has not adequately justified its decision to move to this new standard. Finally, it appears that the Company has understated the capacity it obtains from Colstrip, leading it to further over-forecast its capacity needs.

A. The 2015 IRP Demonstrates That the Company Does Not Need a Supply-Side Resource in the Next Three Years.

As a component of its third Electric Action Plan item, the Company states that it “intends to issue an all-source RFP in 2016,” subject to its planning assumptions being updated based on

the Final Seventh Power Plan (“7th Power Plan”) of the Northwest Power and Conservation Council (the “Council”).^{1/}

The Commission’s regulations generally require an electric utility to conduct an RFP within 135 days of the due date of its IRP,^{2/} unless the IRP “demonstrates that the utility does not need additional capacity within three years.”^{3/} Figure 6-5 of the Company’s current IRP clearly demonstrates that the Company does not need additional supply-side capacity within the next three years, and accordingly, it would not be required under this Commission’s rules to conduct a supply-side RFP in 2016.

Updating to the Final 7th Power Plan assumptions is also not expected to accelerate the need for a supply-side resource to within the next three years. For its IRP, the Company relied on a May 2015 regional resource adequacy outlook from the Council, which was based on the energy efficiency assumptions from the Council’s 6th Power Plan.^{4/} Compared to the data relied on by the Company in its IRP, the Draft 7th Power Plan, which was released in October 2015, is showing substantially greater resource adequacy in the Northwest, primarily due to increased energy efficiency potentials.^{5/} As the Council discusses, “[i]n more than 90 percent of future conditions, cost-effective efficiency met *all* electricity load growth through 2035.”^{6/}

From ICNU’s perspective, a key conclusion of the IRP is that the acquisition of cost-effective conservation will be sufficient to mitigate any near-term need for the Company to acquire a new supply-side resource.^{7/} Such a conclusion can be reached by simply reviewing Figure 5-22 and Figure 5-23 in the Company’s demand forecast.^{8/} ICNU is generally supportive of using conservation to meet the near-term resource adequacy obligations of the Company, and believes that the Company would be unjustified in deviating from such a strategy at this time.

Furthermore, it is worth noting that the Company is statutorily required to acquire all cost-effective conservation pursuant to the Energy Independence Act,^{9/} and is also required to pursue an additional 5% of conservation pursuant to the Commission’s order approving the Company’s decoupling mechanism.^{10/} Thus, to the extent the Company determines that cost-effective conservation will eliminate any near-term, supply-side capacity needs, acquiring supply-side capacity in favor of energy efficiency would seem to be inconsistent with statutory

^{1/} 2015 IRP, Chapter 1 at 1–10.

^{2/} WAC 480-107-015(3)(b).

^{3/} WAC 480-107-015(3)(a).

^{4/} Northwest Power and Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2020-21 at 1-2 (May 6, 2015). Available at: http://www.nwcouncil.org/media/7149624/2020_21-adequacy-assessment-final-050615.pdf

^{5/} Draft 7th Power Plan, Chapter 1 at 1-1.

^{6/} Id. at 1-1 (emphasis in original).

^{7/} 2015 IRP, Chapter 5 at 5-27.

^{8/} Id.

^{9/} See RCW 19.285.040.

^{10/} Docket Nos. UE-121697/UG-121705 and UE-130137/UG-130138, Order 07 ¶¶ 108-112 (June 25, 2013).

requirements. At most, the Company should conduct a single RFP tailored to acquiring conservation, including demand response opportunities, as was done following the 2011 IRP.^{11/}

Finally, the need for a supply-side resource in 2021 may be further unrealistic because the Company never updated its conservation assumptions in the demand forecast presented in the IRP.^{12/} As the Company states, “[t]he [Resource Adequacy Model (“RAM”)] analysis used to calculate the 234 MW capacity addition [in 2021] included conservation assumptions from the 2013 IRP.”^{13/} The demand-side resource potential assessment analysis performed in the 2015 IRP, however, showed a dramatic increase in the achievable technical potential for conservation relative to the 2013 IRP, particularly for the winter peak. The winter peak achievable technical potential increased from 1,017 MW in 2033^{14/} in the 2013 IRP to 1,394 MW in 2035 in the 2015 IRP.^{15/} That is an approximate 40% increase in energy efficiency potential, which has not been reflected in the Company’s resource expansion analysis. Accordingly, the Company expects that the updated conservation assumptions will reduce demand,^{16/} further delaying the need for a new supply-side resource.

In summary, ICNU does not believe that the Company is justified at this time in taking any near-term action to acquire a supply-side resource. The 2015 IRP clearly shows that the Company’s conservation efforts required under the Energy Independence Act result in no near-term need for a supply-side resource, a determination that is likely to be reinforced when the Company updates its assumptions to incorporate the findings of the Final 7th Power Plan.

B. The 2015 IRP Uses an Overstated Planning Reserve Margin.

The Company’s 2015 IRP adopts the equivalent of a 20% planning reserve margin, which is significantly higher than the reserve margin it assumed in the 2013 IRP.^{17/} This increased margin is alone sufficient for the 2015 IRP to identify a capacity need of 275 MW in 2021.^{18/} Using the planning reserve margin from the 2013 IRP, however, the Company would not see an equivalent capacity deficit until sometime between 2025 and 2026.^{19/}

The increase in the Company’s planning reserve margin is the consequence of several modeling changes the Company has made in the 2015 IRP relative to the 2013 IRP. ICNU is

^{11/} See e.g., Puget Sound Energy, Request for Proposals for Program Design and Implementation Services for Demand-Side Capacity Reductions from Targeted Commercial-Industrial Customers (Jan. 3, 2012). Available at: <http://pse.com/aboutpse/EnergySupply/Documents/DemandRFP.pdf>

^{12/} 2015 IRP, Chapter 6 at 6-11.

^{13/} Id.

^{14/} 2013 IRP, Appendix N at 1.

^{15/} 2015 IRP, Appendix J at 2.

^{16/} 2015 IRP, Chapter 5 at 5-26.

^{17/} Compare 2015 IRP at 6-15 (identifying equivalent of 20% reserve margin) with 2013 IRP at 5-4 (identifying winter planning margin for 2014-2015 of 13.5%).

^{18/} 2015 IRP, Chapter 6 at 6-11.

^{19/} Id.

concerned with three aspects of these modeling changes. First, ICNU is concerned that the Company has abandoned the use of the “Loss of Load Probability” (“LOLP”) resource adequacy metric in favor of a new metric based on “Expected Unserved Energy” (“EUE”). Second, ICNU disagrees with the Company’s decision to value EUE using the Interruption Cost Estimator (“ICE”) tool. Third, ICNU is concerned with how the Company has assigned reliability risk to its wholesale market purchases, decreasing those purchases’ contribution to the Company’s peak capacity.

1. LOLP or LOLE are better metrics for forecasting capacity needs.^{20/}

Until the 2015 IRP, the Company had used a 5% LOLP in developing its planning reserve margin. As the Company stated in its 2013 IRP, “[t]he 5 percent LOLP is an industry standard resource adequacy metric used to evaluate the ability of a utility to serve its load, and one that is used by the Pacific Northwest Resource Adequacy Forum.”^{21/} LOLP “is a measure of the likelihood of a load curtailment occurring.”^{22/} Conversely, the Company now proposes to use EUE, “a measure of the magnitude of potential load curtailments”^{23/}

The Company’s use of EUE to develop its planning reserve margin is problematic because EUE does not provide a good indication of when to build a capacity resource. The purpose of capacity planning is to determine what resources to build and when to build them. Accordingly, the focus should not be on reducing the length of reliability events, nor should it be on reducing the magnitude of reliability events. If a resource was to be built for the sole purpose of making a reliability event shorter, or making the magnitude of a reliability event less severe, it would not be as effective a capacity resource as one that is capable of eliminating the occurrence of a reliability event altogether. Thus, when making capacity planning decisions, the key consideration should be to maintain an acceptable probability of reliability events occurring, rather than planning based on the severity of an event. This favors the use of LOLP or LOLE as the reliability metric to calculate planning reserve margins.

It is also noteworthy that the Company’s use of EUE in its 2015 IRP is the equivalent of a 1% LOLP.^{24/} Thus, even if EUE were the appropriate metric for the Company to use to develop its planning reserve margin, it is questionable whether the Company has assumed the appropriate amount of EUE in its IRP.

2. The Company’s estimate of the value of lost load is problematic.

The Company’s decision to adopt the equivalent of a 1% LOLP is based on the value it assigned to EUE based on an estimated economic value (i.e., a cost) associated with reliability

^{20/} LOLE stands for “Loss of Load Expectation” and is similar to LOLP.

^{21/} 2013 IRP, Chapter 5 at 5-3.

^{22/} 2015 IRP, Chapter 2 at 2-3.

^{23/} Id.

^{24/} Id.

events. The Company's proposed cost of lost load was estimated using the Interruption Cost Estimator ("ICE") tool, as developed by the Lawrence Berkeley Laboratory.^{25/} ICNU disagrees with the use of this tool, which has not been thoroughly vetted or reviewed by the Commission and is not reflective of the economic preferences of the Company's actual customers.

As discussed by Ms. Alexander on behalf of Public Counsel in Avista Corporation's 2015 General Rate Case, there are a number of problems associated with the ICE tool.^{26/} Most notably, the ICE tool is a form of contingent valuation, based on the economic preference of customers of whether to be subject to an outage or to pay more in rates.^{27/} These sorts of contingent valuations have the potential to be very subjective. For example, a recent article by professor Jerry A. Hausman of the Massachusetts Institute of Technology even went so far as to characterize contingent valuation as "hopeless."^{28/} Mr. Hausman also discussed how contingent valuation tends to overstate value.^{29/}

In addition, the ICE tool is a generic tool and is not specifically tailored to the economic preferences of the Company's actual customers. Certainly, no survey was performed in an attempt to determine the economic preference of the Company's large energy customers when estimating the value of lost load.

Due to the speculative nature of outage valuation using the ICE tool, ICNU is very concerned that the Company has relied upon it to make aggressive changes to its reliability standard—reducing it from a 5%, to the equivalent of a 1%, LOLP. From the perspective of ICNU members, the economic preference is to rely on a traditional planning standard, such as that used by the Council, rather than the equivalent of a 1% LOLP proposed by the Company.

3. The Company's assignment of reliability risk to market purchases undervalues the Northwest market's contribution to capacity.

The use of an equivalent 20% planning reserve margin is also driven by a newly proposed market reliability risk methodology.^{30/} The Company's proposed market reliability risk methodology relied on a stochastic modeling tool used by the Council, called Genesis, populated with data from May 2015. The Company used the output from that model in an attempt to ascertain the likelihood of regional capacity shortfalls in the Northwest. Based on those

^{25/} 2015 IRP, Appendix N at N-41 – N-48.

^{26/} WUTC v. Avista Corporation, Docket Nos. UE-150204/UG-150205, Direct Testimony of Barbara Alexander at 33:16-41:10.

^{27/} Id.

^{28/} The Journal of Economic Perspectives, Volume 26, Number 4, Fall 2012, pp. 43-56. Abstract available at: <http://www.ingentaconnect.com/content/aea/jep/2012/00000026/00000004/art00003>

^{29/} Id.

^{30/} 2015 IRP, Chapter 6 at 6-15.

shortfalls, the Company proposes to model market capacity using an 84% availability factor, reducing the available market capacity by approximately 269 MW.^{31/}

An 84% capacity contribution factor for market purchases, however, represents a resource that is extraordinarily unreliable, and much less reliable than a typical thermal facility. This is particularly concerning to ICNU because forward bilateral power markets in the Northwest have proven to be a reliable source of capacity. While there has been price volatility in these markets—price volatility that is already reflected in the IRP analysis—ICNU is not aware of any physical market shortages in the Northwest since the 2001 California energy crisis. Notwithstanding, the Company’s analysis would suggest that there is an approximate one-in-six probability of regional shortage, which does not appear to be consistent with historical market availability.

In addition, because market risk is already reflected as a stochastic variable in the Company’s RAM,^{32/} accounting for market reliability risk as a second parameter in the Company’s modeling framework serves to double-count the impact of market risk in the Company’s planning framework. The Company’s stochastic modeling is designed to account for a distribution of price outcomes, including pricing for those periods when the region is short on market capacity. As discussed by the Company, “The goal of the stochastic portfolio analysis is to examine the resource plans over a wide range of potential futures, [...] including variations in gas and electric prices[.]”^{33/} The use of this stochastic modeling is specifically designed to account for the probability of high market price scenarios, scenarios in which the region is presumably short on capacity. By applying a second reliability constraint on market purchases, through its market reliability risk methodology, the Company overstates the risk associated with regional shortages, effectively double-counting the risk implications associated with market purchases.

Furthermore, as discussed above, the Company’s market reliability risk analysis was based on the Council’s May 2015 Resource Adequacy Study, which contained outdated energy efficiency assumptions from 2009. The Draft 7th Power Plan has subsequently updated those assumptions and has demonstrated that energy efficiency and demand response will be largely sufficient to maintain resource adequacy for the next 20 years in the Northwest.^{34/} This suggests that the market reliability risk analysis in the 2015 IRP is not a very accurate representation of regional resource adequacy in the Northwest.

Finally, ICNU is concerned about the Company’s assumption in its market reliability risk methodology regarding the Grays Harbor facility, a 650 MW facility located in the Puget Sound area. The Company has excluded Grays Harbor from its Genesis regional resource adequacy analysis on the basis that it does not have firm gas supply. ICNU understands that the Company

^{31/} Id. at 6-13.

^{32/} 2015 IRP, Appendix N at N-2.

^{33/} Id. at N-15.

^{34/} Draft 7th Power Plan, Chapter 1 at 1-1.

is in control of some of the pipeline rights that are used by Grays Harbor to generate electricity. Yet, this alone is insufficient to demonstrate that Grays Harbor will be unable to contribute at all to regional reliability. By excluding its entire capacity from the regional adequacy study, the Company assumes that Grays Harbor will never contribute to regional resource adequacy, meaning that facility will never have access to gas during a period with loss of load probability, even though this loss of load probability can occur in varying hours throughout the year, including periods when there is abundant pipeline capacity. Irrespective of its gas supply rights, Grays Harbor does contribute to regional reliability and ICNU disagrees with the Company's proposal to exclude it altogether.

C. Colstrip's Capacity is Understated

When applied against a planning reserve margin in the Company's capacity expansion model, Colstrip should be counted at 100% of its nameplate capacity. The planning reserve margin accounts for the availability of all resources across the Company's system and it is, accordingly, unnecessary to derate the capacity of any particular thermal resource to account for availability when developing a capacity expansion plan.

The Company, however, only includes 90% of Colstrip capacity in its capacity expansion plan, based on availability at the time of system peak relative to a peaker unit.^{35/} Because the Company's planning reserve margins, however, already account for the availability of Colstrip at the time of system peak, applying an additional derate to Colstrip capacity in the Company's IRP double counts the impact of Colstrip's availability.

The Company calculated the Colstrip capacity by comparing Colstrip availability to a peaker unit.^{36/} In determining the appropriate planning reserve margin, the Company considered the possibility of forced outages at Colstrip, based on its unique availability characteristics and how its availability interrelates with its existing portfolio. Comparing Colstrip to a peaker unit is not an appropriate methodology because Colstrip was not operated as a peaker unit in the reliability studies used to calculate planning reserve margins.

It should be noted that, in preparing the incremental capacity equivalent of market purchases, the Company recognized this double-counting issue. The Company discussed that the market risk could be applied to either the planning margin, or as a capacity reduction, but not to both.^{37/} The case for Colstrip is similar, in that the Company has included Colstrip availability in the planning reserve margin and has also modeled it with reduced capacity, double-counting the impact.

As a result of this double-counting issue, ICNU believes that the Company should be required to count Colstrip towards the planning reserve margin based on its full nameplate

^{35/} 2015 IRP, Appendix N at N-49 – N-50.

^{36/} Id.

^{37/} See 2015 IRP, Chapter 6 at 6-15.

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capacity. This will have the effect of further reducing the need for supply-side capacity, providing greater evidence that a supply-side resource in 2021 is not justified.

CONCLUSION

I appreciate the opportunity to provide these comments on Puget Sound Energy's 2015 IRP on behalf of ICNU. While ICNU agrees that the IRP meets applicable regulatory requirements, ICNU does not agree with many of the assumptions in the IRP. I look forward to continued discussion with the Commission and parties on this matter.

Sincerely

/s/ Bradley Mullins

Bradley Mullins

Consultant, Energy & Utilities

o/b/o Industrial Customers of Northwest Utilities