



## PUGET SOUND ENERGY

*The Energy To Do Great Things*

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### ***Via Electronic Mail***

Steven V. King, Executive Director and Secretary  
Washington Utilities and Transportation Commission  
P.O. Box 47250  
1300 S. Evergreen Park Drive S.W.  
Olympia, Washington 98504-7250

Re: **Docket UE-161024: Comments of Puget Sound Energy on Rulemaking for Integrated Resource Planning WAC 480-100-238, WAC 480-90-238, and WAC 480-107**

Dear Mr. King:

Puget Sound Energy (“PSE”) appreciate the opportunity to respond to the questions proposed in this docket and submits the following comments in response to the request in the Washington Utilities and Transportation Commission’s Notice of Opportunity to Submit Written Comments issued in Docket UE-161024.

#### **A. General:**

*1. The Commission has identified a broad scope of issues to evaluate in its inquiry. Are there other issues or topics that should be addressed? What type of schedule would best lend itself to a proceeding of this scope?*

#### PSE Response:

Given the broad scope and timing of this rulemaking, PSE proposes that the Commission also consider providing more clarity and/or definition around which “environmental effects” are to be modeled in an Integrated Resource Plan (“IRP”). WAC 480-100-238(2)(b) and 480-90-238(2)(b) require modeling of “costs of risks associated with ‘environmental effects’ including emissions of carbon dioxide.” Does the Commission interpret the term ‘environmental effects’ to apply to emissions beyond carbon? If so, emissions of which gases or other environmental issues fall under the definition?

## **B. Energy storage**

*1. The Commission has already engaged in an investigation regarding energy storage technologies and their treatment in IRP documents (Docket UE-151069). The Commission is considering merging that investigation with this proceeding, then issuing a straw proposal and soliciting one more round of comments before issuing a policy statement on the topic. Do the parties have any concerns with this approach? Is there any information relative to modeling energy storage that has not been presented in the existing docket?*

### PSE Response:

In Docket UE-151069, the Commission has been on the path to develop/issue a policy statement on energy storage. PSE recommends the Commission keep the policy statement on energy storage separate from the IRP rule. Some of the energy storage values may be derived from the IRP process. Others are more appropriately determined within the context of the transmission and distribution system planning process.

In its investigation in Docket UE-151069, the Commission has identified the following value streams that energy storage could provide: arbitrage, frequency response, voltage regulation, energy imbalance, and integration of renewable resources. PSE is supportive of having a policy statement that clarifies the value streams that should be reflected. The statement should not specify any specific model, as some models may be more useful for making operational decisions versus acquisition decisions. Energy storage alternatives may be least-cost when combined with some transmission and distribution system constraints. The Commission should provide direction but not specific mandates to utilities as they incorporate these new commercially-available resources so that so utilities can have the flexibility to develop frameworks as such resources evolve.

The IRP may not be the first place where energy storage will appear as a least-cost resource to utilities. Energy storage may appear as least-cost resources used to defer or avoid transmission and distribution investments. Alternatively, it is possible that energy storage systems may appear as least-cost resources in a general supply-side resource acquisition process. Therefore, a prudence case, not an IRP, is the most appropriate place for the Commission to review those specific decision frameworks.

## **C. Requests for proposals**

*1. WAC 480-107-015 requires any utility that files an IRP identifying a generation capacity shortfall within the next three years to issue a request for proposals (RFP) within 135 days of filing its IRP. In recent IRP cycles, utilities have frequently requested waivers of this rule, generally citing the cost and complexity of the RFP process and stating that the IRP selected market purchases as the low cost, preferred approach to meeting short-term capacity needs. Given the frequent requests for waivers of this rule, should the Commission change it? What type of changes would parties recommend to make the rule more broadly applicable and reduce the need for waiver requests?*

PSE Response:

PSE would support a change to WAC 480-107-015 that reduces or eliminates the requirement to file for supply-side RFP waivers when the IRP does not identify a resource need. The Commission could consider restructuring the rule so that utilities are only required to file a supply-side RFP if the IRP identifies a resource need after conservation and/or demand response program(s) are taken into account. If the utility's conservation and/or demand response program(s) will meet the utility's capacity need, the rule should not require a supply-side resource RFP. The rule should seek to avoid requiring the unnecessary paperwork and administrative burden of filing for waivers when a supply-side RFP is not identified in the IRP.

*2. Utilities state that the RFP process is time-consuming and complex, and does not lend itself to a biennial cycle. Are there alternative means of meeting the rule's requirement? Would narrowly crafted solicitations that are tailored to the specific resource needs identified in the IRP be an effective way of reducing administrative burden and costs, while still encouraging bidders to provide the utility with a range of resource options?*

PSE Response:

Alternative means of meeting the rule's requirements or narrowly crafted solicitations are not necessary at this time. The main issue that needs to be addressed is the timing of RFP issuances, i.e. only required after a resource need is identified in the IRP. The RFP process is time-consuming and complex, but not overly so, when it is needed to support prudent resource acquisition decisions. The RFP process is designed to eliminate high cost and/or risk resources that do not meet a utility's need early in the evaluation process. Changing the all-source nature of the process might reduce the options available for a utility to select on behalf of customers. It is more important that the timing of the RFP justify the expense -- both to the utility expense preparing and issuing the RFP and to potential vendors' time and resources in preparing and providing responses.

*3. In considering the waiver requests to this rule, Commission staff and utilities have been at odds whether the IRP actually identified a resource shortfall in the following three years. Staff has generally held that if the IRP model relies on market purchases for capacity needs, then the utility is short on capacity; utilities have generally held that if the model selected market purchases, then the resource need has been cost-effectively met. Is there a potential compromise on this issue? Could improved modeling of market risk in the IRP increase confidence in the model's determination? How might market risk be modeled?*

PSE Response:

This question raises a broader point about state policies and incentives for potential examination and discussion. The region is projected to be short and utilities are relying on a short-term market, yet no additional generation is being built in the state or region by utilities under the Commission's jurisdiction. An additional question the Commission could consider is "what

specific policies should be changed or developed in order to facilitate electric utilities to add resources under such conditions?”

Regarding the Commission’s questions above, PSE remains open to discussing market risk modeling methodologies and techniques. However, it is important that resource shortfall determinations and market reliance should be addressed in the IRP rules, not the RFP rules regarding waivers.

The use of short-term market purchases to meet capacity needs may be quite reasonable when the region has adequate resources. When the region fails the resource adequacy test, however, PSE believes the Commission has a responsibility to question whether it is appropriate for utilities to continue to rely on short-term markets in the IRP process.

In any discussion around modeling methodologies, the primary source of the resource adequacy determination should remain with the Northwest Power Planning and Conservation Council’s annual regional resource adequacy assessments. Several utilities and other stakeholders participate in this process. It is the most comprehensive resource adequacy assessment of the region, which combines the analytical capabilities of BPA and the Power Planning Council, together with technical and steering committees.

There are different ways an IRP analysis could address diminishing reliability in the region. For example, PSE’s 2015 IRP translated the physical supply risk into costs to customers. It incorporated the regional resource adequacy assessment work performed by the Northwest Power Planning and Conservation Council’s Resource Adequacy Advisory Committee. This analysis demonstrated PSE could reduce expected portfolio costs to customers and dramatically reduce cost risk to customers by adding resources to reduce market reliance. The IRP used this analysis to justify deviating from the 5% Loss of Load Probability (LOLP) planning standard.

While the Commission did not support changing from the regional 5% LOLP planning standard, that analysis demonstrated additional resources are justified to reduce cost and risk. That is, PSE could retain the 5% LOLP planning standard, then use this analytical framework to demonstrate that going beyond the 5% LOLP standard would be in the best interest of our customers. There may be other ways to incorporate such market risks. For example, PSE’s 2017 IRP will propose a different, simpler approach that will start with the Northwest Power Planning and Conservation Council’s recent adequacy assessment (shows the region is short 1100 MW in 2022) and apply a market-based allocation method to identify the PSE’s share of that shortfall. PSE will use that outcome as the basis for reducing reliance on short-term market.

Generally, PSE would encourage the Commission to allow utilities the flexibility to explore market risk methodologies and techniques that create more accurate analysis. However, if there are specific approaches the Commission would not find reasonable, it would be helpful to explore those boundaries.

*4. Conservation is currently included in WAC 480-107-015. Should the Commission require utilities to issue RFPs for conservation measures and programs on a regular basis? If so, should RFPs be issued in conjunction with the IRP cycle or the biennial conservation planning cycle described in WAC 480-109-120?*

PSE Response:

PSE issues two conservation RFPs in conjunction with its biennial conservation planning cycle. PSE does not advocate any changes to its existing process with its Conservation Resource Advisory Group (CRAG). The CRAG has been an efficient and effective means to acquire the cost-effective conservation identified in the IRP in a workable timeframe. Utilities should be allowed to use an RFP process as part of their ongoing conservation program design and planning process, but it should not be required. The timing is already compressed between completion of the IRP, setting conservation targets and implementing programs. For example, in the first conservation RFP, PSE requests bidders to propose new offerings. This RFP is issued shortly after PSE's Energy Efficiency department receives guidance on the ten-year potential and two-year target from the draft IRP, which typically occurs in the May timeframe of odd years. Two months later, PSE issues the second conservation RFP requesting bidders to submit proposals for existing conservation programs. Both RFPs indicate that it is necessary for selected programs to go into effect at the beginning of the following year. Attempting to maintain the existing biennial process and implementing a separate conservation RFP process in that same timeframe would be challenging, if not unworkable.

**D. Avoided costs**

*1. Avoided costs are used by utilities in multiple applications. They are used for determining rates for qualifying facilities in compliance with the Public Utility Regulatory Policy Act (PURPA), they are used for identifying cost-effective conservation measures, and they are used in determining the incremental cost of resources used for complying with the state's renewable portfolio standard. Despite their ubiquitous use, however, avoided costs can be difficult, if not impossible, to identify in current utility planning. Would it be feasible and beneficial for the utilities to transparently report their avoided costs in the IRP document? What obstacles exist that would complicate such a report? Would it be possible to create a generic avoided cost calculator that could be used to generate avoided costs for various applications? Should the included elements of avoided costs be different for different applications? Is the avoided cost methodology different for natural gas distribution utilities?*

PSE Response:

PSE would support including additional reporting of avoided costs in the IRP. More detailed avoided costs would be beneficial to PSE customers and potential suppliers. Although PSE outlines a few obstacles to better reporting below, this rulemaking is an opportunity to find agreement around the elements and details of avoided costs that would make reporting more transparent and useful.

PSE files a Schedule of Estimated Avoided Costs each year with the Commission. For example, PSE filed its four most recent Schedules of Estimated Avoided Costs in dockets UE-152314, UE-144174, UE-132353, and UE-122005. These filings are consistent with and meet the requirements of WAC 480-107-055. The Schedule of Estimated Avoided Cost does not provide a guaranteed contract price for electricity. As indicated in WAC 480-107-055(4), this Schedule of Estimated Avoided Costs provides only general information to potential bidders about the costs of new power supplies. It should be noted that this requirement is different and separate from the requirement to offer a standard tariff for purchase from qualifying facilities, pursuant to WAC 480-107-095. PSE's standard tariff for purchases from qualifying facilities is its Schedule 91. PSE has annually filed for updates to Schedule 91 – Cogeneration and Small Power Production in the following dockets: UE-152230, UE-143944, UE-132184, and UE-121873.

At a high-level, the concept of avoided cost is simple. However, when trying to apply avoided costs in practice, things quickly get complicated. An important concept with “avoided cost” is represented in this set of questions posed by the Commission. That is, the cost of avoiding what? Different resources or actions will have different impacts on energy supply costs. For example, consider a 100 MW firm, baseload cogeneration project and a 100 MW utility scale solar project. The amount of energy from those two resources will be different, the timing (thus market value) of the energy will be different, and the contribution to meeting reliability/peak capacity needs. That is, those resources will have different avoided costs. This is because the resources have different peak capacity and energy profiles. A 50 MW utility scale solar in southern Idaho would have a different avoided cost than 50 MW of distributed solar on PSE's system because the quantity and timing of energy will impact the relative cost impact of those two resources. Contribution to peak, energy profiles, and dispatchability/flexibility values are all individual resource attribute comparisons that would affect true avoided costs.

In addition to these individual resource attributes, avoided costs must be viewed in the context of a utility's portfolio, especially with respect to the timing of resource needs. Again consider the example of a 50 MW firm, baseload cogeneration project. The cost impact of such a resource is quite different if the utility has a 50 MW resource need in two years versus 10 years. It is even more than just the time value of money. There would be difficult to quantify risk associated with acquiring a resource that is not needed for 10 years, as this is generally further out in the future than utilities would make generation decisions.

Conservation resources have another dimension: avoided renewable energy costs under RCW 19.235. Renewable resource needs are a function of sales volumes. Since renewable resources are not least cost (as defined in RCW 19.280) conservation avoids the need to add renewable resources. A renewable resource that includes all environmental attributes would provide similar value, but other resources would not.

Therefore, PSE suggests that the elements and inputs for avoided costs need to be better defined to be useful in practice. One needs to clarify the cost of avoiding what, in order to have a reasonable idea of an avoided cost. This way, utilities can properly reflect the operational and portfolio issues, to ensure resource additions are least cost for customers.

As discussed above, there is no simple, generic “avoided cost.” In order for reporting in the IRP to be feasible and beneficial, there would have to be more definition around which elements of avoided costs are appropriate. Currently, PSE’s IRP incorporates an average monthly forecast of wholesale market prices for the next 20 years. This level of detail provides a forecast of the energy value of resources based on the market value of energy based on seasonal shapes. Market energy prices are a base element of avoided cost would be the same across all resource types. Going much beyond that for sizable resource decisions really requires a resource specific portfolio analysis.

A simple calculator that anybody could use is challenging because avoided cost is not simple in application. It requires running the portfolio analysis, extracting information, and analyzing it to ensure results are reasonable. Further, since sizable resources will generally be fully examined in the context of an RFP, trying to create a simple calculator is not necessary in order to ensure least cost resource decisions are made on behalf of customers.

Finally, avoided costs concepts also apply to gas utilities. The primary avoided cost issue people seem to consider is conservation, but the high-level concept applies to every resource decision. Since IRP modelling reflects all the relevant factors, it does not seem to be necessary in order to ensure lowest reasonable cost service to customers.

## **E. Transmission and distribution modeling**

### PSE Introduction

Generally, it has been the experience of PSE that the references to transmission and distribution planning in WAC 100.238 are too loose and have created confusion. It appears these words are being used to question whether a utility’s entire transmission and distribution systems are properly included in the IRP process. PSE has received comments from numerous individuals that the IRP is a good place to address transmission and distribution system planning issues because the IRP incorporates public participation requirements. The purpose of the IRP is to focus on the “least cost mix of energy supply and conservation.” PSE supports a reasonable approach to incorporate transmission and distribution level savings for conservation programs and distributed resources (as appropriate), but the IRP should not be expanded to create an entirely new planning process, simply because some people want to discuss transmission and distribution system planning in an IRP. The core modeling for an IRP is already complex, and getting more complex as the need for sub-hourly flexibility increases. Adding requirements to fully explain transmission and distribution planning would make the process too cumbersome.

Including more distribution planning in the IRP will further increase the time required to develop, communicate with stakeholders, and write-up an analysis for a process that is much more like resource decisions than the kind of planning with an IRP. Furthermore, references to transmission and distribution do not even appear RCW 19.280. Therefore, the Commission does not need to expand the scope of the IRP process in incorporate transmission and distribution system planning. There is no need to make an already complex process more complex.

*1. The IRP rule requires utilities to conduct “an assessment of transmission system capability and reliability” and “a comparative evaluation of energy supply resources (including transmission and distribution) ....” How are utilities currently meeting these requirements in their IRPs? Has modeling software advanced in a way that might allow for a more detailed analysis of transmission and distribution systems?*

PSE Response:

PSE’s IRP processes address transmission system capability and reliability in three different ways.

- **Regional Transmission Overview:** PSE relies on the regional transmission grid. An overview of that system, from PSE’s perspective, is included in the IRP. Please refer to Appendix I in PSE’s 2017 IRP.
- **Transmission Availability and Costs for Specific Resource Types:** Fixed and variable transmission costs are included for resources that need to be delivered to PSE’s balancing authority. Figure D-21, in Appendix D, at page D-41, in PSE’s 2017 IRP is an example. In the 2017 IRP, PSE also examined several transmission scenarios for wind from Montana—please refer to Appendix D, pages D-44 through D-49.
- **Reliability of Transmission to Market:** PSE relies on up to 1600 MW of transmission capacity to the Mid-C market hub to meet peak needs. PSE’s resource adequacy modeling framework is designed to reflect the reliability of that transmission, by aligning PSE’s regional adequacy model to the regional adequacy model (GENESYS) supported by BPA and the Northwest Power Planning and Conservation Council (GENESYS). Please refer to PSE’s 2017 IRP, Appendix G: Wholesale Market Risk.

The specific element of WAC 480-100-238 (3) (e) must be viewed in its entirety and considered in the context of the entire rule, as this statement does not stand on its own:

“A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using the criteria specified in WAC 480-100-238 (2)(b), Lowest reasonable cost.”

The purpose of this language is to ensure that potential transmission and distribution system savings are reflected in determining the “...least cost mix of energy supply resources and conservation,” as defined in the purpose of the IRP in subsection (1) of the rule. PSE’s methodology is consistent with the Northwest Power Planning and Conservation Council’s approach. That is, an estimated transmission and distribution system benefit to conservation (and distributed resources when appropriate) are imputed as an offset to the cost of the conservation or relevant distributed resource. This is a reasonable approach to ensure the higher



relative value of conservation/relevant distributed resource is reflected with respect to supply-side resources.

Regarding software, it is important to acknowledge the IRP is a pure planning process—it is not an acquisition process. “Planning” is a loose term that can be used to mean a process that provides a general direction or a process that determines a specific decision. Many stakeholders assume the IRP process is about making specific resource decisions. The transmission and distribution system planning process is much more action-oriented than the IRP. Thus, it is not an issue of tools, but one of processes. The transmission and distribution system planning function can consider non-wires solutions—but that does not make it is much more like acquisition analysis on the supply-side than long-term resource planning.

Information from the IRP process is used to support other planning/acquisition processes. For example, the IRP process provides “avoided cost” type information to conservation program planning, to ensure the energy supply value of what’s being avoided is properly considered. Similarly, such information can be used by transmission and distribution system planners to ensure they are placing reasonable values on non-wires solutions.

The focus of the IRP is provided in RCW 19.280.020 (9)

Integrated resource plan" means an analysis describing the mix of generating resources, conservation, methods, technologies, and resources to integrate renewable resources and, where applicable, address over-generation events, and efficiency resources that will meet current and projected needs at the lowest reasonable cost to the utility and its ratepayers and that complies with the requirements specified in RCW 19.280.030(1).

The IRP rule need not try to force utility planning functions into one document or all planning analysis into one model. PSE is not aware of planning models that integrate all these functions and would be sufficiently robust to meet the prudence needs for decision-making.

*2. To what degree are utilities currently planning for distribution system impacts such as electric vehicles, changes in end uses, and distributed generation? Are there opportunities for utilities to improve their modeling related to these issues without overly burdening the planning process?*

PSE Response:

PSE’s transmission and distribution system planning group is considering distribution system impacts such as electric vehicles, changes in end uses, and distributed generation. PSE believes consideration of those issues is appropriate for transmission and distribution system planning but does not believe that those issues are directly related to the IRP. Rather, the IRP can be used to provide avoided-cost related input to System Planning processes. However, distribution impacts of electric vehicle charging is not directly related to purpose of an IRP, which is describe in RCW 19.280.010 (Intent-Finding) as:

...explain the mix of generation and demand-side resources they plan to use to meet their customers' electricity needs in both the short term and the long term.

PSE would be happy to participate in a Commission investigation into how utilities are considering the issues mentioned in transmission and distribution system planning processes. In the context of IRP process, PSE suggests the Commission consider reframing the question to ask: "How are utilities considering impacts of electric vehicles, changes in end uses, and distributed generation on resource plans?" To the extent distributed generation or smaller scale energy storage systems are cost effective-applications for transmission and distribution system planning solutions (including avoided cost information from the IRP), those resources would be reflected in future IRPs.

*3. The Commission's rule requiring smart grid reports, 480-100-505, is scheduled to sunset this year absent an order from the Commission requiring utilities to consider filing the reports. What has the experience of utilities been in filing these reports? Would there be value in extending this requirement? Is there a way to address the Commission's desire for information on this topic through the IRP?*

PSE Response:

PSE believes the smart grid reports are helpful and should continue. Utilities should have the option to decide whether or not to include the Smart Grid Technology Report as an Appendix in the IRP. It is not necessary to mandate the Smart Grid Technology Report be including in the IRP and burden staff with a review of the Smart Grid Technology Report. Again, avoided costs from the IRP can inform the Smart Grid Technology Report. Action plans from System Planning can in turn inform the IRP. Merging the reports would not enhance efficiency for utilities or the Commission.

PSE suggests the Commission avoid expanding the scope of the IRP rules to include the Smart Grid Technology Report just because an IRP is already being filed. Rather, PSE would support separate filing requirements that include a sunset date in six years. A sunset date would be helpful if Smart Grid Technology Reports are no longer useful in a few years. However, PSE recommends Smart Grid Technology Reports be addressed in a separate proceeding.

*4. The natural gas IRP rule requires plans to include "an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources," but is silent on distribution system modeling. To what degree are gas utilities currently engaged in modeling their distribution system? Would it be beneficial for utilities to further engage in distribution system modeling? If so, is there commercially available software that is capable of meeting these modeling needs?*

PSE Response:

Similar to the electric IRP, the natural gas utility IRP should be focused on the least cost mix of energy supply and conservation, not a focus on distribution system planning. WAC 480-90-010 (1) states:

“(1) Purpose. Each natural gas utility regulated by the Commission has the responsibility to meet system demand with the least cost mix of natural gas supply and conservation. In furtherance of that responsibility, each natural gas utility must develop an "integrated resource plan."

There may be times when resource planning and distribution system planning intersect (*e.g.*, peaking capacity associated with PSE's Tacoma LNG Facility requires incremental distribution system investments). However, such costs have been included in the cost of the Tacoma LNG Facility. Again, the focus of the IRP should not shift to include more distribution planning than is necessary to ensure the least-cost mix of natural gas supply and conservation.

Regarding the current extent of natural gas utility modeling, PSE has nearly all of its 12,000 mile distribution system modeled for distribution system planning purposes utilizing the Synergi Gas network modeling software. These are hourly models that are used to identify where constraints might happen in the system and how different alternatives affect areas that might experience pressure problems. The models are assessed and updated on an annual basis, and take into account numerous factors, including new load growth, system constraints from current changes or construction and data from our Gas Control systems. The models are also run under different scenarios, including extreme weather conditions and emergency line breaks. Customer loads that are input to the system are imported from actual billing data, thus, the model is continuously being trued to actual conditions. This is a much different kind of analysis than the core IRP analysis, as natural gas supply is analyzed on a daily demand level, because the natural gas supply market works on a daily basis.

Regarding whether further natural gas utility modeling would be beneficial, PSE assumes this question is asking whether distribution system models should be integrated with upstream supply models. Such modeling, if even feasible, would not improve either IRP analysis or System Planning analysis. To the extent there are impacts between the two planning functions, they can be coordinated, when necessary. One model would not help.

Regarding software modeling tools, PSE is not aware of any models that can do both hourly hydraulic modeling and upstream supply modeling, on an integrated basis.

*5. In recent years, other states have required or considered requiring utilities to engage in full-scale distribution system planning. What are the costs and obstacles associated with such a requirement? What are the benefits? Is detailed distribution planning feasible now, and if not, what is needed for it to become so?*

PSE Response:

PSE does not believe attempting to integrate distribution planning and resource planning makes sense at this point. It is more efficient for resource planning and system planning processes to communicate with the IRP process, but there is little to gain by integrating such planning efforts. The potential impacts of high penetrations of electric vehicles, distributed generation, etc., should be examined; impacts on both the transmission and distribution systems and the impact on resource plans. However, these kinds of analysis are entirely different. Transmission and distribution system planning focuses on load flow studies and solutions to any problems. To the extent there are energy supply values (or avoided costs) associated with utility deployment of distributed resources, those values come from the IRP process. Similarly, if distribution system solutions affect energy supply—such as distributed batteries—those resources can be reflected in the IRP. Combining these two analytical processes would create challenges in staging the analyses. Transmission and distribution system planning needs inputs from the IRP (e.g., avoided cost). That is not available until after the portfolio analysis is completed. Thus, the transmission and distribution system planning element would need to start after the IRP is done.

Practical models and a mismatch between the processes are barriers to full-scale distribution system planning. PSE is not aware of a model that can integrate everything needed to perform the core IRP analysis (i.e., to identify the least cost mix of energy supply and conservation) that would be sufficient to support prudent decision making. The IRP is an analytical framework, not a model. Transmission and distribution system planning is similar. It is not just a “model” but an analytical framework. Both processes focus on solving different problems—the engineering analysis to support distribution planning is entirely different than portfolio analysis for an IRP. PSE cannot identify specific efficiencies that would be achieved even if a model existed that could integrate resource and system planning. An IRP is more of a pure planning exercise than System Planning. Resource decisions are not made in an IRP. Specific decisions are made in the System Planning process. Therefore, the mismatch in processes would also be a barrier.

Regarding potential benefits of such a requirement, PSE does not understand what could be gained by integrated these processes that would not be realized by having the existing processes communicate.

Regarding feasibility of distribution planning, PSE performs detailed distribution planning analysis today, and has for many years. That planning, however, is only tangentially related to the purpose of the IRP.

**F. Flexible resource modeling**

*1. Current IRP models balance load and resources on an hourly basis over a 20-year period, generating more than 175,000 data points for the model to solve. Many of the new resource alternatives that utilities consider, however, operate on a sub-hourly basis and therefore generate benefits that cannot be captured in the IRP’s hourly modeling. These benefits promise to increase over time as the penetration of variable generation increases and the need for*

*flexibility from fast-moving resources grows. Prime examples of this type of resource are energy storage, reciprocating engines and the Energy Imbalance Market. How are utilities accounting for sub hourly resources in current IRP models?*

PSE Response:

PSE interprets this question to mean that the Commission sees increasing importance in sub-hourly operational capabilities of different resources. As flexibility of the regional hydro system continues to diminish and the quantity of intermittent resources continues to increase, PSE agrees with the Commission's concern. It will become increasingly important to ensure that sub-hourly operational flexibility values are accurately reflected when evaluating the relative value of different resources.

It is important to note that PSE does not have "a model." PSE has a robust analytical framework that incorporates several different models. These models are used together to help us identify the least-cost set of resources. While PSE often refers to "the model," it is actually an analytical framework.

PSE is modeling sub-hourly flexibility in the 2017 IRP. To perform this analysis, PSE acquired the PLEXOS model from Energy Exemplar. PSE is planning to use Plexos to examine how resources with different sub-hourly operational characteristics would affect total portfolio costs. Information from the flexibility analysis will then be incorporated into PSE's portfolio optimization model. This process will use a test year and run through a sequential 10 minute dispatch analysis with several different resource portfolios. As this will be PSE's first IRP to utilize an effective production cost model at the 10-minute time interval, additional enhancements and innovations will be developed as the process becomes integrated into the Company's analytical framework. For example, as PSE gains experience in the Energy Imbalance Market, additional information will be incorporated in future IRP processes.

PSE's 2015 IRP applied this approach. Adjustments were made to the relative cost of different resources based on a sub-hourly dispatch model. PSE did not, however, use this analysis to draw any conclusions. The self-built, sub-hourly model was designed to support very short-term analyses. The Company found it was not able to process enough samples in a timely manner to be useful for informing long-term resource decisions. Plexos will replace that self-built model from the 2015 IRP. The sub-hourly flexibility values will be incorporated into the analytical framework the same way as shown in the 2015 IRP.

*2. Are there readily available means of using sub-hourly IRP models? For example, if the model ran in 15-minute increments over 20 years, it would generate more than 700,000 data points – four times as many as current models. But if it ran in 15-minute increments for just 10 years, it would only double the number of data points, to about 350,000. Would it be possible to adapt current IRP models to operate in that way? Are there commercially available alternatives for sub-hourly modeling? Do utilities or other parties have experience in operating those models?*

PSE Response:

Please refer to PSE's response to F1, above. There are models that are capable of doing that kind of analysis for 20 years. PSE reviewed a few software alternatives before deciding to acquire Plexos this summer. However, running a sub-hourly dispatch model out 20-years is not necessary. The additional information created will not be materially different than what would be learned in a test year analysis. Even changes like removing resources from a portfolio can be done with a test year. The additional time to develop sub-hourly assumptions and run times is not worth the expense.

**G. Procedural improvements**

*1. Should the commission clarify its treatment of confidential information in IRP and RFP dockets? If so, how?*

PSE Response:

IRP and RFP processes and documentation are quite different, so PSE's comments will address each separately.

Regarding the IRP process, there is a difference between the process to develop an IRP versus the IRP filing itself. PSE's IRP has not needed to include any confidential information in an IRP filing with the Commission. Some assumptions and details that go into the modeling process are confidential. However, results of the analysis have been presented in a way that demonstrates PSE's IRP filings have complied with the requirements of the rule. In PSE's experience, the Commission's current process has been reasonable and sufficient. Unless the IRP document itself includes confidential information, which may happen with other utilities, the Commission's process appears adequate for the purposes of determining if a utility has complied with the IRP rule. PSE has no recommendation at this time regarding treatment of confidential information in the IRP.

Regarding the RFP process, there are three areas of this rule that may include information that could include confidential information:

- **RFP Filing:** The information in WAC 480-107-025 Content of Solicitation provides the requirements for what must be included in the filing. These requirements raise no confidentiality concerns and PSE has no recommended changes at this time.
- **Ranking:** WAC 480-107-035 (3) states utilities must make a summary of each project proposal and the final ranking available at the utility's "designated place of business." Some details will need to be kept confidential, but that is workable. The requirement for making the ranking available at the utility's designated place of business is not efficient during the current internet age and could be improved. PSE recommends that utilities be required to post the ranking on its website and inform the Commission including a link to

the document. This will allow the Commission to notify the Commission's interested parties list that the information is available.

- **Schedule of Estimated Avoided Costs:** PSE has not experienced any concerns with respect to the annual filing of the Schedule of Estimated Avoided Cost and has no recommended changes at this time.

*2. Should the commission outline more specific requirements for public involvement, like identification of meeting time and location on the workplan, and the identification of the date a draft will be available for public review?*

PSE Response:

PSE supports including the suggestions outlined in the question above. The following are three specific recommendations PSE believes may be helpful:

- *Recommendation #1—Meeting and Milestone Timeline:* Public meeting dates, locations, and filing milestones. PSE is supportive of including such a timeline in the IRP work plan filing. Additionally, the schedule should be posted on the utility's website and updated as meeting dates and locations change throughout the process. Please see Attachment 1 for an example of a timeline from PSE's IRP process.
- *Recommendation #2—Process Timeline:* In addition to the meeting and milestone timeline, it may be helpful for utilities to communicate the timing of different elements of developing an IRP. This could be consolidated with Meeting and Milestone timeline or in addition to it. In past IRP processes, PSE consolidated those timelines, but for the 2017 IRP, there are significantly more meetings, so one timeline did not work. Please see Attachment 2 for an example of a high-level process timeline.
- *Recommendation #3—Processes to Facilitate Feedback in Work Plan:* Stakeholder interest in IRP processes have increased over time. There are numerous areas that received very little attention and informal dialogue was sufficient. Now, with more stakeholders more interested in more details, utilities should plan to have more structure around certain processes. PSE recommends the IRP Work Plan identify specific areas where input will be sought along with the process that will be used to manage that feedback. The specific details need not be identified in the rule, because topics may change over time. The rule should provide flexibility for utilities to evolve with changes in the market and stakeholder interest. Overall, including this kind of requirement in the Work Plan provisions would improve the process for stakeholders and utilities.

*3. How can the commission increase the transparency of IRP models? Is there a way to allow commission staff and other stakeholders to independently access company modeling software and test assumptions, without violating proprietary agreements or confidentiality, as is done with power cost models?*

PSE Response:

As the IRP is a compliance filing, the focus should be on what is needed for the Commission to determine whether an IRP complies with the rule. It is more accurate to describe the IRP process as a framework that consists of numerous models—some are purchased off the shelf while others are developed in-house. More importantly, the models are used by highly technical and skilled analytical experts. An appropriate metaphor could be that an orchestra is more than the instruments. Skilled musicians practice constantly and rehearse together with those instruments to produce a professional symphony. Making tools available to stakeholders that have no experience in using the tools together will not assist the Commission to meet its requirement of ensuring an IRP complies with the rules and would increase confusion.

Even in power cost cases, referenced in the question, PSE does not make its models available to the public. PSE provides Commission Staff with Aurora modeling inputs during a power cost case because Commission Staff has a license for Aurora and the ability to use the information. PSE has also facilitated temporary access to the Aurora model for parties to a contested power cost case when they have hired consultants that can use the model. Additionally, the Aurora database includes confidential information, which requires a protective order, before PSE can share the information with consultants.

PSE recommends the Commission clarify the definition of “transparency.” PSE is eager to assist in helping to make the IRP more transparent. However, specifics are needed. For example, based on PSE’s experience, many stakeholders that submit comments and even some that participate in the IRP process do not understand the role the IRP plays in informing other planning/acquisition processes. Transparency in general is not specific enough for the Commission or utilities to act upon; i.e., we need to be sure about the question before we go about answering it. Through this rulemaking process, PSE recommends the Commission facilitate a dialogue to put more structure around the problem statement, so utilities can address it productively.

*4. Are there any improvements that could be made in the IRP reporting or review process? Staff will ensure rule language is simplified and written in terminology that promotes clarity and understanding for all stakeholders. Rules that are written in Plain Talk are easier to understand and implement consistently.*

PSE Response:

PSE recommends that the Commission Staff issue a memo prior to the open meeting reviewing an IRP. PSE suggests the Commission Staff present its memo including draft recommendations for the next IRP. This was common practice through at least 2003. The Commission’s letter to utilities on an IRP is not an order, so the Commission does not have to rely on a record to make suggestions included in an IRP acceptance letter. However, this step would be very helpful. It would allow utilities to clarify issues that might have been missed in the IRP document. For example, in the 2015 IRP, the Commission’s letter stated PSE changed from ELCC (Effective



Load Carrying Capability) to ICE (Incremental Capacity Equivalence). That is not accurate— PSE never used ELCC in the past, and the way it used ICE is consistent with what some others call ELCC. Had the Commission Staff presented that draft suggestion in the Open Meeting, PSE could have clarified. While not necessary under the Administrative Procedures Act nor necessary for the Commission to determine whether an IRP filing is consistent with the rule, such a process might allow for greater clarity (that is, transparency) in such complex areas.

PSE appreciates the opportunity to provide responses to the questions identified in the Commission's Notice of Opportunity to File Written Comments. Please contact Nate Hill at (425) 457-5524 or Phillip Popoff at (425) 462-3229 for additional information about this filing. If you have any other questions please contact me at (425) 456-2110.

Sincerely,

*Nathan Hill*  
for

Regulatory Initiatives  
Manager

Ken Johnson  
Director, State Regulatory Affairs

