COMMENTS to HDR and PSE related to July 26, 2018 IRPAG TAG Meeting
All submittals provided by deadline on August 2, 2018
All submittals acknowledged by PSE on August 2 or 3, 2018

<u>PSE responses</u> in black bold italics, dated August 16, 2018

Submittal #1: <u>Invenergy (provided on August 2 by email at 12:50 pm)</u>

Invenergy considers HDR's supply-side technology characterizations to be generally reasonable, and an overall improvement from the assumptions PSE used for its 2017 IRP. In particular, the overnight capital cost estimates for new simple cycle and combined cycle combustion turbine projects appear to be based on a more rigorous analysis. These assumptions are also more consistent with other recent estimates, and with Invenergy's experience in developing similar projects.

PSE has indicated that it intends to finalize its cost assumptions for new generating resources by August 10, 2018. Invenergy recommends that PSE retain some flexibility to make subsequent updates to the cost assumptions if new information becomes available that clearly indicates material changes in capital costs or other characteristics of generating resources. Invenergy also recommends that if PSE identifies such changes have become apparent, whether as a result of PSE's ongoing Request for Proposals process or otherwise, PSE address these changes at an upcoming Technical Advisory meeting.

<u>PSE response</u>: PSE acknowledges the comments and request, thank you. RFP results cannot be used in the IRP due to non-disclosure agreements. Although the final IRP is not due until July 2019, our modeling process requires us to lock down resource costs early in the process and not continually update the costs. In addition, PSE will utilize the same model for the RFP and the IRP for future generic resources; the costs for the IRP need to be locked down to support the RFP evaluations in August 2018. To address uncertainty in future resource costs, PSE will develop an alternative resource cost sensitivity. The purpose of this analysis will be to examine whether a reasonable, alternative set of resource assumptions would affect the least-cost mix of resources.

During the July 26, 2018 meeting, several clarifications and corrections to the presentation slides were identified. Invenergy recommends that these and other potential errors identified below be reflected in an update to the presentation materials. Examples include the following:

1. On the Thermal Resources table, page 12 of the HDR presentation, the Capacity Factor for Combined Cycle CT is shown as 85%. This assumption should not be used as a constraint in PSE's resource analyses; instead, the annual capacity factor should be allowed to vary based on fluctuating need and market economics. In addition, it would be helpful to show First Year Variable O&M at several annual average capacity factors, e.g., 30%, 50% and 75%.

   <u>PSE Response:</u> Plants will be dispatched to market. As HDR presented in the meeting: there will be no appreciable change with VOM within a reasonable range of capacity factors. If for example plant such as combined cycle is running at very low capacity factor it will be priced out the market regardless of VOM.

2. On the Renewable Resources table, page 13 of the HDR presentation, the Capacity Factor for Solar Photovoltaic is shown as 19%; HDR indicated that this should be 24%.

   <u>PSE response</u>: HDR will update this in the final report. Thank you.

3. On the Renewable Resources table, page 13 of the HDR presentation, the Winter Peak Net Output for Solar Photovoltaic is shown as 25 MW; HDR indicated that the assumed nameplate capacity is 25 MW, and winter net peak output would be 15 MW. The table should be clarified to reflect this.

   ***PSE response**: PSE has provided this suggested correction to HDR; thank you.*

4. On the second slide of the Appendix to the HDR presentation, the NOx emissions rate for a 1x0 F-Class Dual Fuel CT (NG) is shown as .004 lbs/MMBtu; this should be corrected to .008 lbs/MMBtu.

   ***PSE response**: PSE has provided this suggested correction to HDR; thank you.*

5. On the one-page handout titled "2019 Electric Supply-Side Resources – Thermal", the First Year Available for Frame Peakers is shown as 2022; for CCCT's, it is shown as 2023. Is this due to the difference in assumed Greenfield Development and Construction Lead-Times shown at the bottom of the table? PSE should clarify the basis for the difference in assumptions for the different technologies.

   ***PSE response**: Yes, the 2022 verses 2023 dates are due to timing between development, construction duration, and commercial operation start date.*

Thank you for the opportunity to comment and Invenergy looks forward to continued participation in PSE's 2019 IRP process.

Orijit Ghoshal | Senior Manager, Regulatory Affairs
Invenergy | 1401 17th Street, Suite 1100 Denver, CO 80202

***PSE response**: And thank you for your review.*

Submittal #2: <u>Larry Becker, P.E. Northwest Power Consulting (provided on August 2 by email at 2:23 pm)</u>

<u>PSE responses</u> in black bold italics, dated August 16, 2018

Hello Michele,

Thanks for the heads up on this. I did review the latest 2019 TAG IRP presentation Electric Resource Costs as presented by HDR at our meeting last week and have the following comments.

1.) The Renewable Resources – Biomass project as presented for an EPC price for a 15MW plant at $7000/kw is incorrect. Taking all factors into account few if any biomass projects are developed for a 15MW plant to begin with and I don't believe this is a representative plant cost in today's EPC market. This smaller plant size won't be as economical as a larger plant but should be in the range of tops at $5000/kw for an EPC price.

For a Biomass project in the more realistic market these days the EPC price should be for a 20 – 35MW in the smaller size. This is more market based in any biomass project size are more representative at $4500 - $5000/kw.

I would suggest that the gas and electrical interconnect costs at $628/kw are very high also as most if not all biomass plants have no gas interconnect costs . The only interconnect costs electrical interconnect should be in the range of $200/kw.

In summary for this category I believe that for the all in Resource Costs for the Biomass Plant should be in the range of $7,000/kw - $7500/kw – Total with Interconnects in the market place today . Not $9,695/kw as presently shown on the table.

<u>PSE response</u>: PSE has forwarded your comments to HDR; thank you for this thoughtful contribution.

2.) The Thermal Resources for Simple and Combined Cycle Gas Turbine EPC costs are conservative and approx.. 8% - 10% higher than an EPC contractor would base pricing on in today's market. That said I compared these costs against costs for my Thermo Flow computer estimating program that is recognized as the standard in the Power Industry in arriving at these estimated costs. The EPC costs are of course subject to actual pricing and negotiations on a specific project location with all factors involved , but for this category as very conservatively estimated at high end numbers .

In summary for this category I believe that the all in costs for the Thermal Resources are approximately 8% - 10% higher overall than normally expected in the marketplace today.

<u>PSE response</u>: PSE has forwarded your comments to HDR; thank you.

3.) I understood from our discussions at last week's meeting that the Aero derivative Gas Turbines are not under consideration due to their expected higher installed costs . I truly doubt that is the case for a typical multi-unit plant utilizing the LM – 6000 in a combined cycle plant to produce 230+ MW . I would concede that the LMS –

100 would be a more costly plant on an installed cost basis. At the generation levels of 230+ MW the Frame gas turbines will be more completive on a simple cycle basis but will not provide the lower heat rates and turndown capability of the smaller and more flexible LM – 6000 plant

I have been involved in the EPC business in competively bidding and building biomass and gas fired gas and reciprocating engine generator plants for major contractors for the past 35 years and offering my opinion at this time on this technology only.

***PSE response*: Duly noted by PSE; thank you!**

Please let me know if any questions arise, I can be reached at (206) 818 – 4305

Best Regards,

Larry Becker, P.E.
Northwest Power Consulting

Submittal #3: Bill Pascoe comments on PSE 2019 IRP Resource Costs and Characteristics (provided on August 2 by email at 3:37 pm)

***PSE responses* in black bold italics, dated August 16, 2018**

Process. I am concerned about the tight schedule for finalizing the resource costs and other characteristics. The HDR report was only provided to TAG members a few days before the TAG meeting and comments are due a few days after. These dates are tight, but my biggest concern is lack of time between PSE receiving the comments and finalizing the inputs. It does not appear that there is adequate time for PSE and HDR to consider comments, interact with commenters, and make any appropriate changes. So, it feels like the HDR report will be difficult to modify at this point.

***PSE response*: PSE and HDR carefully considered all comments and HDR incorporated them into the final report as appropriate. PSE distributed draft HDR's report nine days before the TAG meeting and collected comments until a week after the TAG meeting. PSE appreciates stakeholder's partnership in the 2019 IRP.**

During the TAG meeting, PSE staff explained that there are limited staff resources to simultaneously support the RFP and IRP processes. If that's the case, I would support a delay in filing the 2019 IRP rather than not taking adequate time on the front end to vet critical inputs.

- **Montana Wind.** HDR has developed parameters for two Montana wind sites. The Great Falls site is characterized as having a 42.4% CF and a 75-mile gen tie line with an interconnection cost of \$830/kw. The Colstrip site is characterized as having a 35.5% CF and a short gen tie with an interconnection cost of about \$100/kw. If PSE intends to evaluate all Montana wind as being delivered into the Colstrip Transmission System, I can support the notion of modeling two sites – one near the CTS and one further away. Note that in addition to the two existing CTS substations at Colstrip and Broadview, construction of the Gordon Butte PSH project would provide an additional CTS interconnection point in the Martinsdale area for accessing the high-quality wind resources in that area.

  ***PSE response*: HDR will review wind sites in the general areas discussed with Bill Pascoe, and use a profile that is better than average, and update our assumptions. Also, as a result of the meeting HDR will update the wind and solar capital costs (\$/kW) to reflect larger plant size to take advantage of the plant size.**

- I think Great Falls is a poor choice for the more distant site. Great Falls is much further than 75 miles from existing CTS substations and does not have an especially robust wind resource by Montana standards. There are better sites in closer proximity to the CTS. This was reflected in the 2017 IRP where a site near Judith Gap was included with a 46% capacity factor (using modern turbine technology) and gen tie / interconnection costs of less than \$200/kw. This estimate included 75 miles of 230 kV line at a cost of about \$600,000/mile, while HDR's new estimate includes 75 miles of 115 kV line at more than \$1 million/mile. It is crucial for the more distant Montana wind site to be sized so that a reasonably priced gen tie can be included. And the gen tie costs should be based on rural conditions and wood structures.

<u>PSE response</u>: HDR will develop an interconnection cost for MT wind that avoids the 75-mile generation tie line and instead interconnects with Northwestern's transmission. HDR will consider updating the $/mile of transmission intertie in MT to reflect lower costs, because cross country transmission in MT is much less expensive.

Within a few weeks, PSE will be receiving RFP bids. I believe PSE will be receiving Montana wind bids with materially higher capacity factors and significantly lower gen tie / interconnection costs than the values proposed by HDR. These proposals should be reviewed and considered by PSE before the Montana wind inputs are finalized for the IRP.

<u>PSE response</u>: The RFP bids are completely separate from the IRP. The IRP is based on a generic site whereas the RFP is based on specific site capacity factors and costs. If developer can demonstrate that the generation tie/interconnection costs in are lower than PSE will take that into consideration of the project.

<u>Pumped Storage Hydro.</u> Table 8.3-1 of the HDR report includes operating parameters that severely limit the ability of PSH to provide flexible capacity and ancillary services. The Min Gen and Min Pump values in the table eliminate approximately one-half (for the 500 MW option) to two-thirds (for the 300 MW option) of the PSH operating range. This will significantly impair the value that PSH can provide in an environment where flexible capacity needs can be expected to grow over time.

My understanding is that the values in Table 8.3-1 are based on variable-speed turbine technology. More advanced configurations of PSH technology, such as ternary units (hydraulically short-circuited pump/turbine units able to operate independently), should also be modeled in the IRP. The Gordon Butte PSH project in Montana, which is fully licensed and permitted, will employ this type of hydraulically short-circuited unit technology (modeled on equipment designs that have been successfully deployed in Europe). This configuration will effectively make the entire PSH operating range (from full generation to full pumping) available for providing flexible capacity and ancillary services. It is critical that the IRP include a PSH option with full flexibility especially when system flexibility needs and possible flexible capacity alternatives are studied.

<u>PSE response</u>: PSE will perform a portfolio sensitivity on pumped hydro storage operating parameters, as part of the alternative resource cost sensitivity.

<u>Montana Transmission.</u> Proposed Montana transmission costs are shown on slide #35 of the TAG meeting presentation. These proposed transmission costs overstate the cost of procuring resources from Montana for two important reasons. <u>First</u>, PSE's costs for the CTS and BPA Montana Intertie are treated as incremental costs rather than sunk costs. The retirement of Colstrip 1&2 will free up CTS and MI capacity controlled by PSE's merchant group. The cost of this capacity will continue to be borne by PSE's retail customers following the closure of Colstrip 1&2 whether or not that capacity is used to deliver other resources from Montana. These costs are effectively sunk and should be treated that way in the IRP.

<u>Second</u>, the slide shows additive losses of 2.7% for the CTS and 5% for the MI. Under the CTS Agreement and the Montana Intertie Agreement a single loss rate is applied to the combined transmission facilities from Colstrip to Garrison. For the CTS owners, the CTS/MI loss rate is calculated each hour and averages approximately 2.7% as specified in PSE's OATT. (It is not possible to separately calculate losses for the CTS and the MI because there is no metering at Townsend.) For third party users (not CTS owners) the

loss rate is contractually specified to be 5%. (This is an alternative to the calculated losses of approximately 2.7% and not an additional loss charge.) For the IRP, the 2.7% loss rate should be applied since all generic resources are assumed to be PSE-owned. Even if a PPA was assumed, PSE would almost certainly take ownership of the power before it entered the CTS and would therefore be eligible for the 2.7% calculated loss rate.

***<u>PSE response</u>*: PSE consulted with Bill Pascoe and HDR by phone to update these assumptions.**

Given the limited time to review materials and prepare comments, my comments must be limited to the topics discussed above. Additional time may have resulted in additional comments.

***<u>PSE response</u>*: PSE acknowledges your comment. Thank you for your review and participation.**

Submittal #4: National Grid USA ("National Grid") and Rye Development, LLC ("Rye") (letter provided via email on August 2 at 4:34 pm)

***PSE responses* in black bold italics, dated August 16, 2018**

National Grid USA ("National Grid") and Rye Development, LLC ("Rye") are proud to be involved with the development of the two most promising pumped storage projects in the Pacific Northwest: the Swan Lake North Project in southern Oregon ("Swan Lake") and the Goldendale Energy Storage Project in southern Washington ("Goldendale"). Not only can these projects provide significant reductions in greenhouse gas (GHG) emissions and help states in the Pacific Northwest meet their GHG reduction goals, they also utilize environmentally-friendly "closed-loop" technology, are located near high voltage transmission corridors, and will be able to provide unmatched flexibility as a resource by serving multiple roles and providing stacked energy, capacity, and other reliability and economic benefits on a utility and/or regional basis. National Grid and Rye are jointly developing these projects and appreciate the opportunity to provide these comments on the July 18, 2018 draft "Generic Resource Costs of Integrated Resource Planning" report prepared by HDR Engineering, Inc. (HDR) for Puget Sound Energy's (PSE's) 2019 Integrated Resource Plan (IRP).

GENERAL COMMENTS:

National Grid and Rye appreciate PSE's continued investment in long-term resource planning and the development of analytical methods and reliable data to inform its planning and procurement processes. The draft report prepared by HDR provides a solid foundation for the assessment of available resources and analysis of potential resource portfolios. It is clear from this report that HDR has a breadth of experience that makes it uniquely situated to provide technical and cost parameters for PSE's resource assessment. We understand that HDR was tasked with developing these parameters for generic technologies located in the Pacific Northwest. We agree with the selection of representative technologies and appreciate that the energy storage section of the report addresses pumped storage separately from battery storage.

Given that pumped storage is a much more mature technology than most other forms of energy storage, and that it is deployable at significantly larger scales and has a useful life of three to four times longer than battery storage, National Grid and Rye request that pumped storage be considered as a separately-studied resource throughout PSE's modeling and analyses for the 2019 IRP, including sensitivities that specifically address new pumped storage. Furthermore, because the costs of pumped hydro facilities can vary significantly by site, and because potential sites for pumped storage on the high-voltage transmission system are limited by geography and other strategic considerations, we encourage PSE to consider site-specific information from existing, under-development resources in its analyses whenever possible to reduce uncertainty and produce more accurate results.

***PSE Response*: The IRP is high level analysis and does not analyze specific projects. PSE encourages National Grid to submit proposal for specific sites in the RFP where they can be fully vetted. The IRP provides information on the performance of various resources but it is not the decision point.**

Using generic assumptions to represent these specific opportunities will likely overestimate costs and underestimate performance of these high-quality projects. This is because HDR has necessarily had to consider the wide range of expected costs and performance characteristics of potential pumped storage projects, while only the best projects have been developed to the point where they should be considered in the current IRP. PSE should model the specific projects likely to be available to it for procurement rather than use generic costs that do not accurately represent these opportunities. For example, while HDR estimates that capital costs for a generic pumped storage project would be $2,612/kW, we expect the capital costs for Swan Lake to be less than $2,000/kW at the high end of the expected range. Similarly, HDR suggests an economic life of 30+ years for generic pumped storage, while we expect Swan Lake's operating life to be double that amount.

<u>PSE Response</u>: As stated above the specifics of your project can be evaluated in the RFP. The pumped storage assumptions in the IRP are completely separate from the RFP process.

There is also a risk in using generic costs and performance characteristics for technologies like Li-Ion batteries that, while not site specific, must necessarily be based on forecasts of rapidly changing market data. There is a risk that such forecasts incorporate a bias toward assuming continued improvements that may not necessarily be realized. We urge caution in relying on forecasts that assume significant changes over what is currently available.

<u>PSE Response</u>: PSE has noted your concern. HDR used the industry standard base on EIA reports. There are other stakeholders who believe that we should use more aggressive price curves.

Based on our extensive development efforts to date, National Grid and Rye have prepared detailed estimates of costs and performance characteristics for the Swan Lake and Goldendale projects. We would be happy to review these assumptions with you and HDR to ensure that pumped storage projects are accurately represented in your IRP modeling.

<u>PSE Response</u>: The details of your project would be better reviewed in the RFP. PSE would be more than happy to discuss your project in the context of the RFP.

We urge PSE to give energy storage issues comprehensive consideration in the current planning process. It is important that these issues are considered now, given the long lead timelines for permitting both natural gas and pumped storage facilities and the potential reliability issues associated with 1) the impending medium-term "capacity cliff" in the PNW region[1], and 2) potential retirement of a large portion of PSE's remaining dispatchable coal-fired resources (e.g., Colstrip 3&4) combined with the planned addition of new intermittent wind and solar resources.[2] The importance of considering these issues now is elevated by concerns expressed by PNW regulatory commissions about over-reliance on the market/front-office transactions (FOTs) to provide capacity.[3]

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[1] See, for example, predictions of regional inadequacy by 2021 in the Pacific Northwest Power Supply Adequacy Assessment for 2023 at https://www.nwcouncil.org/reports/pacific-northwest-power-supply-adequacy-assessment-2023

[2] PSE 2017 IRP, p. 1-5 – 1-8, https://pse.com/aboutpse/EnergySupply/Documents/01_IRP17_CH1_110117b.pdf

[3] For example, Washington Utilities and Transportation Commission's Letter Acknowledging Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan, Docket UE-160918.

We request that PSE:

- Give detailed consideration to the value of grid-scale storage in its 2019 IRP, including analyzing a portfolio that specifically models Swan Lake[4] across a range of scenarios, given the lack of other attractive and mature pumped storage projects in the region and the portfolio effects and other benefits that may only be captured through scenario modeling;
- Incorporate the value of pumped storage into considerations of intra-hour/EIM interactions and taking advantage of the solar oversupply from California; and
- Use caution with assumed aggressive battery cost declines and optimistic degradation curves.

<u>PSE response</u>: PSE assumes National Grid will be submitting a bid into the RFP.   The bids are due August 17. PSE is more than happy to give Swan Lake consideration in the RFP and should this project be bid-in, looks forward to examining the specific details of the individual proposal.

We look forward to the opportunity to comment further on modeling approaches, scenarios and sensitivities later this year, but raise these issues generally here to the extent that the ability to perform such modeling may be limited by data availability. Given the important role that pumped storage will likely play in PSE's modeling for the 2019 IRP, we encourage you and HDR to reach out to National Grid, Rye and other developers to ensure that the final set of input assumptions accurately reflect the costs and performance characteristics of the projects currently being developed in the Pacific Northwest.

Thank you for the opportunity to provide these comments.

Sincerely,

Nathan Sandvig
Director, US Strategic Growth
National Grid Ventures
Nathan.Sandvig@nationalgrid.com

Erik Steimle
V.P. Project Development
Rye Development, LLC
Erik@ryedevelopment.com

[4] Although both Swan Lake and Goldendale are under active development, Swan Lake's development is more advanced and is more likely to be available during procurement stemming from the 2019 IRP.

Submittal #5: <u>WUTC Staff Comments on PSE's July 26 IRP Technical Advisory Group meeting (provided by on August 2 by email at 5:06 pm)</u>

<u>PSE responses</u> in black bold italics, dated August 16, 2018

The following paragraphs provides UTC staff feedback pursuant to the PSE Technical Advisory Group meeting held at Bellevue College on July 26, 2018.

Prematurely Locking in IRP Resource Costs

At the July 26 IRP TAG meeting PSE staff indicated that they needed fixed resource costs soon in order to perform analyses of the proposals received from the current RFP evaluation process. PSE further indicated that the RFP process will extend beyond the point when the PSE staff will need to start running the same model for the IRP.

<u>PSE response</u>: IRP process will remain on schedule and this does not support on-going updates to the electronic resource costs.

The IRP modeling will not actually begin until a large part of the RFP results have been evaluated and a short list of resources created. That point in time is early next year, five or more months from now. PSE indicated that at the point where the IRP modeling needed to start that they could see if they have some more current estimates from the RFP process and leverage any usable results to update the HDR resource costs and other performance assumptions.

<u>PSE response</u>: RFP results cannot be used in the IRP due to non-disclosure agreements.

Because many resource prices continue to rapidly change, it seems premature to lock in pricing now for the purposes of RFP evaluation when the IRP modeling is still many months ahead. Locking in current prices now makes sense for the RFP evaluation but not for the IRP modeling. Locking in prices for the IRP now seems premature.

<u>PSE response:</u> Although the final IRP is not due until July 2019, our modeling process requires us to lock down resource costs early in the process and not continually update the costs. It is likely that bids in the RFP will not be consistent with generic resource assumptions, because prices bid in August of 2018 reflect market conditions at this time, not a longer-term resource outlook. This is similar to natural gas prices. It would not be reasonable for PSE to take actual natural gas spot prices during August of 2018 as a forecast of market prices for the next 20 years. Markets for electric generation, and component parts, are dynamic, so a longer-term view for resource planning is more reasonable. In addition, PSE utilizes the same model for the RFP and the IRP; the costs for the IRP need to be locked down to support the IRP evaluations in August 2018.

Going forward, there should be at least another TAG session to discuss stakeholder feedback of cost assumptions instead of relying on a quick turn around with written comments on presentation slides without any further questions or dialogue. The HDR presentation was well done, however, without a deeper dive into the methods and sources used, based on TAG enquiries, it seems like locking in those specific values is un-necessarily rushed.

PSE response: ***Request has been noted, thank you. PSE has taken input from TAG members and has provided the feedback to HDR. Based on the feedback, HDR may make revisions to the report. PSE will develop an alternative set of resource costs that we hope will represent a consensus opinion of serval TAG members. This will allow us to examine whether these specific assumptions are in a range that would significantly affect the least-cost mix of resources.***

Because resource cost and performance assumptions are fundamental to the most informed set of IRP modeling outcomes, more time needs to be made for further discussion. On the other hand, for RFP modeling purposes, the modeling assumptions may need to be nailed down earlier than for the IRP.

PSE response: ***Request for more time for discussion has been noted, thank you. And thank you for acknowledging the timing of the RFP (bids due August 17, 2018).***

Realistic Renewables Future Costs

HDR slides showed projected cost reductions in various resources and relatively flat forward cost estimates for others. There was no indication of where those forward prices were derived or how calculated. Some of the renewable resource cost projections seemed conservatively high priced, which seems to be a common trend in IRPs. Before accepting these forward cost estimates, the sources or information and basis for these estimates using unbiased publically available data should be revealed and explained by HDR.

PSE response: ***Request for more time for discussion has been noted, thank you. And thank you for acknowledging the timing of the RFP (bids due August 17, 2018).***

To provide an example, offshore wind price are rapidly declining. Articles published today on Utility Dive[1] and yesterday by GreentechMedia[2] cited record low US offshore wind prices for MA, $65/MWh energy plus $10/MWh capacity. These are lower than the cost declines predicted by analysts and lower levelized costs than estimates for market purchases plus REC purchases in MA. This offshore wind project has an 800 MW capacity and will serve for multiple utilities in MA. This is approximately the scale at which offshore wind appears to currently become cost competitive in MA and includes taking advantage of the soon to disappear federal ITC tax credits. In western Europe recent offshore wind bids have come in at very competitive levelized costs without subsidies and this may be the case in the US before long, likely within the timeframe of the 2019 IRP. As such it would be appropriate for PSE to model this kind of price decline in the near future in the IRP for a low cost range of offshore wind generic resources.

PSE response: ***Thank you for this information and it is acknowledged by PSE and has been shared with HDR.***

UTC staff previously provided PSE with results of a large survey of international wind experts who projected future onshore and offshore wind costs. Was this or similarly robust pricing data used in developing the HDR future cost estimates for wind resources? This is a relevant question as there was no transparency regarding sources or methods for the values provided in the HDR presentation or the forward price decline estimates.

PSE response: ***This information was provided to HDR for consideration in the draft report. Thank you.***

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[1] Gavin Bade, Massachusetts utilities file US-record offshore wind contracts at $65/MWh, Aug. 2, 2018, Utility Dive;

[2] Julia Pyper, First Large US Offshore Wind Project Sets Record-Low Price Starting at $74 per MWh - Pricing for the 800-megawatt Vineyard Wind project off the coast of Massachusetts came in well below analyst expectations, Aug. 1, 2018, Greentechmedia.com.

Generally, for renewable resources IRP modeling purposes, HDR should be able to make reasonable reverse engineering estimates to break down typical generic levelized costs into their component parts. In the case of offshore wind this could be based on the recent bids for the MA project mentioned above. It should be possible for HDR to use their experience, professional judgement, and their sub-consultants, to allocate typical generic renewable resource costs estimates to capital, operations, financing and other parameters for PSE to use as IRP modeling inputs.

<u>PSE response</u>: In PSE's view, HDR did provide generic renewable resource costs in the draft Generic Resource Cost for Integrated Resource Planning report prepared for PSE.

In the recent past many cost projections for renewables have underestimated their future costs. To alleviate the problem of relying on a single, often unreliable cost estimate, for generic renewables, it would be useful to project high, low, and medium future pricing of most renewables to account for this uncertainty.

<u>PSE response</u>: As mentioned above, PSE will develop an alternative resource cost sensitivity.

Accurately Modeling Wind Resources

When performing wind resource modeling it is almost always preferable to use actual wind data whenever it is available. Therefore UTC staff recommends using actual available wind data instead of relying on the generalized NREL model for Montana and WA offshore wind resource estimates.

There is actual wind data available from Renewable NW for Montana and from NOAA buoy wind observations for the WA coast (going back decades) that should be used instead of the NREL macro-modeling tool used in the HDR report. HDR, or their wind sub-consultant, were apparently unaware of the availability of these publically-available data sets. The RNW data was used in the 2017 IRP but not the buoy data. Both of these real data sets should be compiled and used in the 2019 IRP for generic Montana and WA offshore wind resources.

This issue was brought up during the 2017 IRP modeling and links to the buoy data were sent to PSE, but was not used by their consultant. As the price of offshore and onshore wind continues to decline, as shown above in the recent MA announcements and other sources, it becomes critically important to accurately model the potential wind resource options using real-world wind data.

<u>PSE response</u>: PSE acknowledges the comment and request, thank you.

[Signed UTC Staff, August 2, 2018]

Submittal #5a: WUTC Staff, supplement

Additional email from David Nightingale on August 2 at 5:49 pm:

PSE IRP Team -

One other suggestion missing from the attached set of comments it that the assumed offshore wind turbine in the HDR report is only 6 MW size. Because size is a very significant factor in the performance and economics of offshore wind and what separates onshore from offshore wind farm potential, the 6 MW turbine size should be used as a lower bound for offshore wind farm development. The upper bound is the GE 12 MW turbine, appropriately cited in the HDR report. As a forward-looking study, the 2019 IRP should model upper and lower bounds for offshore wind developments based on turbine sizes.

Dave N

<u>PSE response</u>: PSE acknowledges the additional comment, thank you.

<u>Submittal #5</u>: David Perk, 350 Tacoma (provided by email on August 2 at 5:44 pm):

<u>PSE responses</u> in black bold italics, dated August 16, 2018

Dear Ms. Kvam,

I would like to provide the following on-the-record comments regarding Puget Sound Energy's first Technical Advisory Group meeting, held Thursday, July 26, 2018 at Bellevue Community College. I was present in the room as citizen observer. I did not join this meeting using the virtual WebEx meeting provided by PSE.

I apologize for the brevity of these comments, I only just learned that there was a deadline for submitting them today by 6:00pm.

I believe it was Mr. Nightingale of the UTC who raised the question of whether the bids submitted for the current Request For Proposal process would inform the Integrated Resource Planning process for the 2019 plan. The answer that I heard was 'no' and the reason given was that the timelines overlapped too closely. This concerns me. From it I would infer, first, that the inputs to the 2019 IRP will be overly generic, and second, that the IRP planning process has already reached inflexible conclusions regarding its resource inputs.

<u>PSE Response</u>: It is likely that bids in the RFP will not be consistent with generic resource assumptions, because prices bid in August of 2018 reflect market conditions at this time, not a longer-term resource outlook. This is similar to natural gas prices. It would not be reasonable for PSE to take actual natural gas spot prices during August of 2018 as a forecast of market prices for the next 20 years. Markets for electric generation, and component parts, are dynamic, so a longer-term view for resource planning is more reasonable.

I was also struck by the overt bias towards fracked gas, both in the economies of scale cited by HDR, and when their calculations for renewable resources are limited to the those required by law. Given the recent climate science showing that upstream emissions are up to 60% greater than EPA estimates, reducing fracked gas from your resources portfolio should be the primary goal of the 2019 IRP. I am concerned that the EPA's Social Cost of Carbon calculation is not strong enough to adequately represent the costs of upstream methane emissions, given their greater warming potential over the short term.

<u>PSE response</u>: The HDR report made no assessment on bias toward thermal or renewable projects, it is strictly a review of the resource costs for different technologies. Your concern goes beyond the scope of what was presented but your comments have been noted, thank you. The Integrated Resource Plan is a regulatory filing, not a long-term strategic plan. Your stated goal is inconsistent with the requirements of the IRP rules.

It was also concerning that the HDR representative seemed unfamiliar with calculating the climate impacts of energy resources like fracked gas, and that PSE was not including climate impacts in HDR's set of requirements. I am concerned that climate impacts will not be modeled appropriately, and that PSE ratepayers, and indeed all citizens of Washington State, will bear costs that could have been avoided.

<u>PSE response</u>: HDR was commissioned to provide PSE generic resource cost. The impact of climate change goes beyond the scope of the meeting. Note, resource costs are not the portion of the process where we address potential costs of greenhouse gas emissions. Those will be addressed through portfolio scenarios and sensitivities.

Echoing the comment made by Jim Adcock, PSE Customer, the 2019 IRP should include at least one 100% renewables scenario, preferably more, in order to better calculate the costs of a resource portfolio that takes the well-being of future generations into account. (In past years I might have said, "ensures a stable climate for future generations," but I believe it's clear to all of us that we have crossed that threshold already.)

<u>PSE response</u>: PSE will be running multiple scenarios. In addition to different societal cost of carbon scenarios, PSE will also incorporate hard carbon constraints and a scenario where all fossil fuel generation is retired and replaced by non-emitting resources.

Finally, I would like to reiterate the comments made by Sierra Club representative Doug Howell. The best 2019 plan that PSE could provide to its ratepayers, and all citizens of Washington State, is one in which all energy resources are carbon-free by 2038. To do anything less would be irresponsible.

<u>PSE response</u>: Thank you for your submittal, David.

Sincerely yours,

David Perk

350 Seattle

Cc: David Nightingale, Senior Regulatory Engineering Specialist, Washington Utilities and Transportation Commission

Submittal #7: <u>Northwest Energy Coalition (provided by email on August 2 at 5:04 pm, with two attachments)</u>

<u>PSE responses</u> in black bold italics, dated August 16, 2018

Michele,

The following comments are in response to your reminder that we need to submit input concerning HDR's draft generic resource costs for the 2019 IRP.

First, we appreciate the efforts made to standardize cost categories, enabling comparisons between various resources on an "apples to apples" basis. This is definitely an improvement over the 2017 IRP.

1. Overall, we do not think it is necessary to finalize resource cost numbers by August 10th. With an all-resource RFP currently underway and constant cost declines occurring for a number of technologies, there will be more up-to-date numbers to use in the IRP in just a few months. We think it more reasonable, if modeling must begin immediately, to use the current numbers as placeholders, but to replace those numbers when the more up-to-date information is available.

   This is also true for the transmission costs, which were only distributed at the meeting, leaving almost no time for stakeholders to analyze the data and respond with thoughtful comments.

<u>PSE response</u>: PSE acknowledges the comments and request, thank you. RFP results cannot be used in the IRP due to non-disclosure agreements. Although the final IRP is not due until July 2019, our modeling process requires us to lock down resource costs early in the process and not continually update the costs. In addition, PSE will utilize the same model for the RFP and the IRP for future generic resources; the costs for the IRP need to be locked down to support the RFP evaluations in August 2018. To address uncertainty in future resource costs, PSE will develop an alternative resource cost sensitivity. The purpose of this analysis will be to examine whether a reasonable, alternative set of resource assumptions would affect the least-cost mix of resources.

2. Regarding various resource costs, we would encourage further investigation into costs for all the renewable and storage resources and their projected reductions in cost over time. For example, it seems odd that wind costs do not show any reductions from the last IRP, given owners' costs have been reduced. In addition, the simple trend reduction for renewables that HDR shows in Figure 2.4-2 is very conservative based on recent experience.
   a. Attached are the interactive experience curve worksheet on solar costs with the accompanying report, which we have submitted before.
   b. Lazard's report on levelized costs of various resources is here: https://www.lazard.com/perspective/levelized-cost-of-energy-2017.

<u>PSE response</u>: These comments were provided to HDR. Also, HDR reviewed the Lazard report in preparation for the draft report and addressed this topic during the July 26 TAG meeting. As mentioned above, PSE will develop an alternative resource cost sensitivity. We would be happy to consider using alternative cost curves in this sensitivity, as we did in the 2017 IRP.

Solar economic life should be at least 25 years; the 20 years HDR used is too conservative. For example, Sunpower, LG, and Panasonic all warranty their systems to 25 years. PacificPower recently executed six contracts for solar, four of which were for 25-year terms.

PSE response: ***PSE is considering using 25 years for the economic life in the 2019 IRP. Thank you.***

3. Chosen renewable systems for pricing are too small compared to chosen thermal systems. For example, HDR only modeled 25 MW for solar, but of the six contracts mentioned above for PacificPower, the smallest was 45 MW and the largest were 100 MW.

   PSE response: ***PSE models solar in 25 MW increments and does not restrict the upper limit. By adding interments of 25 MW, this allows choice of a small or larger need by scaling up (100MW or above, in increments of 25 MW).***

4. Given the recent lengthy discussions on which generator models to include in the analysis to update the Washington emissions performance standard (EPS), we urge PSE to assess newer models, such as J or H, which would operate more cleanly than F class gas turbines, which are the only ones considered in HDR's report.
   a. PSE staff noted during the TAG meeting that the F models were the "right size" (~340 MW), and that H/G/J models would be too big.
   b. However, a look at manufacturer websites shows this not to be true. For example, GE manufactures two H-class machines in the 300 MW range and Mitsubishi has a number of different higher-class products, as small as 40 MW.

PSE response: ***In the past PSE has looked at the newer models but was not economic as compared to the J class. The J class will provides general information in how combined cycle will perform in the portfolio.***

Cordially,

Joni Bosh
Amy Wheeless

PSE response: ***Thank you, Joni and Amy.***

(NWEC's Attachment A: Using the NWEC Simple Solar Model

Version 0.93
26 September 2016
Background
The NWEC Simple Solar Model is an exploratory tool to assess future cost projections for photovoltaic energy (solar PV).
There are many nuances to the experience curve approach that this model does not seek to address directly. Instead, it is a rangefinding tool to generate parameters for use in long-term planning studies and to evaluate the performance of other cost projection methods.
Standard cost estimation approaches including bottom-up and top-down cost component analysis and expert elicitation ("Delphi process") do not have good forecast skill for long-term resource planning. Interest is shifting to exponential cost models including those based on cost changes per increment of time ("Moore's Law") and

cost changes per increment of market saturation (learning/experience curves or “Wright’s Law”), usually expressed as a constant learning rate per doubling of aggregate market saturation.
The latter approach (experience curves) appears to have more face validity for technologies where policy interventions play a substantial role in the product life cycle. This is particularly true for most energy technologies, where policy (primarily through regulation and financial incentives) plays a substantial role.
The NWEC Simple Solar Model is designed to provide a reduced-form approach to experience curve analysis for solar PV. While the term “learning curve” is more prominent, that usually refers to cost declines from increasing production within a single facility or company. The term “experience curve” refers to the relationship of aggregate production to cost for a single product globally.
For the purposes of this model, we assume that aggregate production has a linear relationship with market saturation because total electric power demand is fixed. The purpose here is to provide a general sense of the relative growth of solar PV without getting deeply into the complexities of estimating total demand over time.

Model Parameters
There are three basic parameters to the model: (1) starting cost; (2) learning rate per aggregate market doubling; and (3) the expected duration of doubling periods.

1. **Starting Cost - $2,300 per kW-AC.** For the default here, we choose the large solar PV system cost in 2015 in the 7th Power Plan of the Northwest Power and Conservation Council. While the actual projects used to estimate that cost vary in size, configuration and location, we assume a reference plant of 20 MW-ac output (after conversion from dc to ac) in eastern Oregon and Washington or southern Idaho, with a tracking mount.

   (The tracking equipment added a substantial cost in previous years, but is less of a differential now. It does not affect the capital cost perspective in the current version of the model, but would affect a life cycle cost of energy (LCOE) analysis because tracking PV produces more energy per area of collector surface than fixed PV. However, LCOE is beyond the scope of this version of the model.)

2. **Learning Rate – 20% for modules, 15% for other costs.** The Simple Solar Model is based on the well-established observation that costs decrease by a fixed percentage for each doubling of the aggregate global PV market. The range of estimates for the learning rate in the literature is between 10% and 30%, with a clustering at 20%, which is the default value selected for this tool.

   Until recently, analysis generally focused on just the solar PV module since it formerly was the dominant part of total cost, but has rapidly declined over the last decade. The analysis of other costs has not been as extensive, but the model has a default of 15% decline per aggregate market doubling, a reasonable and conservative value.

3. **Doubling Period in Years (DPY) – DPY 3, DPY 4, DPY 5.** The final basic parameter in the model estimates the number of solar PV market doublings over the next 20 years. This short description cannot review all the detail, but there were 7 such doublings between about 2001 and 2015, during which market saturation rose from hundredths of a percent to somewhat above 0.5% of total electric production in the US.

   As each subsequent doubling occurs in the model, the cost for solar PV declines by 20% for module costs and 15% for other costs. The question is how many doublings will occur in the next 20 years. The model deliberately ignores the real world variance in market expansion, where some doubling periods will take longer than others. In reality, we expect more doublings to occur in the next decade, and fewer thereafter, but setting an average duration simplifies the analysis significantly.

As noted above, market doublings have been occurring about every 2 years for the last decade and a half. Now that market saturation is reaching noticeable levels (somewhat above 0.5%), the rate of expansion is likely to slow down. Based on national and global assessments by IEA, IRENA, US DOE, BNEF and many others, we consider that a reasonable analytical range is doubling periods of 3 to 5 years, and we choose 4 years as a moderate value. As Table 1 below shows, a 3-year doubling period provides 6+ doublings in 20 years and raises market saturation from 0.5% to above 32% in 2035. A 4-year doubling period provides 5 doublings and market saturation of 16%, and the 5-year period provides 4 doublings and a final saturation of 8%.

NWEC considers both the DPY 3 and DPY 5 to be bookends, with a likely outcome between 3.5 and 4 year doubling periods, and US solar PV saturation in 2035 between 16% and 25%.

Table 1. Solar PV Saturation and Market Doubling Periods

	DPY 3	DPY 4	DPY 5
Year	Saturation		
2015	0.50%	0.50%	0.50%
2016			
2017			
2018	1%		
2019		1%	
2020			1%
2021	2%		
2022			
2023		2%	
2024	4%		
2025			2%
2026			
2027	8%	4%	
2028			
2029			
2030	16%		4%
2031		8%	
2032			
2033	32%		
2034			
2035		16%	8%

Operation
The Simple Solar Model is displayed in 5 sections:

1 Current Costs
2 Learning Rates
3 Doubling Period in Years (DPY)
The first three sections contain the model parameters for the three standard cases (DPY 3, DPY 4, DPY 5) and an optional user-defined case.
The analyst can enter values in the appropriate boxes for starting year, learning rates for module and other costs, the base year, and an optional entry for a different DPY. If the values are erased from the boxes, the model will revert to the default values. When an optional DPY is entered, other areas of the spreadsheet will display the related values.

4 Annual Cost Estimator Summary
This section displays final results per year and per case as estimated in the following section.

5 Annual Cost Estimator Workspace
The simple model analysis is performed in this section. For each case (DPY 3, DPY 4, DPY 5 and the optional analyst DPY), the model first establishes the (negative) compound annual growth rate for each case (divided into module and other costs), and displays a CAGR cost factor for each year. This step is not necessary to the model since the CAGR can be applied directly, but it allows a ready assessment of cost decrease percentage from the base year to any given year.
The model then applies the CAGR cost factor year over year to module and other costs.

Questions and comments to:
Fred Heutte
Senior Policy Associate
NW Energy Coalition
503.757-6222
fred@nwenergy.org

(NWEC's Attachment B: Excel spreadsheets spreadsheets – separate)

***PSE response*: PSE acknowledges NWEC's desire that PSE use alternative price curve and has provided back up spreadsheets. Thank you for providing.**

Submittal #8: **<u>Andrea Scott-Murray (provided by email on August 2 at 9:16 pm)</u>**

<u>PSE responses</u> in black bold italics, dated August 16, 2018

Subject: Additional Comments on July 26, 2018 IRP meeting

I observed the July 26th meeting as a ratepayer with some experience with data and it's graphic presentation and the scientific process but no specific experience in energy.

I appreciated the time and effort you took to present HDR's take and your sitting down with people from the community who have technical energy and infrastructure experience.

Several broad observations.

1. Many graphs looked to be comparing apples to oranges. Cost of gas was not included in graphs showing comparative costs of gas to renewables. A plant powered by the wind/solar has no input costs such as gas/coal generation. Even PSE represented at this meeting that the last 10 to 20% of fossil fuel may be quite costly. The common perception is that in 20 years or so we will be at that point. Why is a 20 year plan being contemplated that does not include this crucial cost?
2. At every turn, data was proclaimed to be generic. I can understand that plant specifications etc. are generic, but there is nothing generic about the specific locations and opportunities for generating energy that exist here in the Northwest and there is nothing generic about the energy market as far as I understand. There are known, real numbers that must be input at every point--transmission distances, transmission losses, current bids for renewable energy sent on the grid, etc. All assumptions should be clearly stated, both in the body of the text and in every graph where an assumption has been made.
3. Modeling is used to compare among various courses of action. I find little value in the current work because there are no substantive alternative courses of action contemplated. We need to see Plan A vs Plan B vs. Plan C. etc.

The usefulness of modeling is limited by the quality of data and fit of the assumptions applied. The result of garbage in is garbage out -- worthless forecasts and lost time and opportunities. I support PSE continuing to serve the region's energy needs and to prosper. I respectfully request that you, PSE, present at least two models--the one you currently contemplate as presented at the meeting AND a carbon free grid in 20 years.

Respectfully,

Andrea Scott-Murray

<u>PSE response:</u> Thank you for your submittal, Andrea. The purpose of this meeting was specifically to discuss the cost to build a new power plant, and the operational parameters needed to model how resources can be dispatched. Fuel costs are a separate input that is addressed separately. Both sets of assumptions are used in PSE's modeling efforts. PSE also reached out to Andrea by email on August 9 to request a time to talk concerning some orientation regarding the IRP and acknowledges the observations.

Submittal #9: Western Grid Group Northwest Energy Coalition (letter provided via email on August 2 at 10:14 pm, with one attachment)

***PSE responses* in black bold italics, dated August 16, 2018**

Michele Kvam August 2, 2018
Resource Planning & Analysis Puget Sound Energy, Inc.
10885 NE 4th Street; PSE-11S
Bellevue, Washington 98004-5591

Dear Michele:

On behalf of Western Grid Group, I am pleased to submit these comments in response to the Integrated Resource Plan (IRP) Technical Advisory Group (TAG) meeting held in Bellevue, WA on July 26th, and to the working documents provided to the IRP TAG members and stakeholders prior to the meeting.

Western Grid Group is a Public Interest Organization whose primary mission is to achieve a reliable, modernized, and low carbon Western electricity grid that is capable of accommodating the many technological, policy, and market-based changes that are rapidly occurring in our region. We work on regional policies that advance our goals throughout the Western Interconnection. In Washington, our Directors work closely with the Washington Utilities & Transportation Commission (WUTC), Governor Inslee's Office, our Legislature, and others to act as credible advisors to key energy matters in our state. As former regulators, state energy policy officials, and former electric utility executives, Western Grid Group aims to act as technically competent advisors to energy matters in our region. As such, we are pleased to participate in the TAG.

The thrust of the first TAG meeting, in addition to introducing people, roles, an overview of the IRP process, and stakeholder engagement, was to focus on PSE consultant HDR's assessment of various energy production/conservation resources and their projected costs and performance capabilities within the 20-year IRP timeframe. HDR's analysis includes supply-side-resources as well as storage, demand-side, and other conservation alternatives. My comments focus primarily on the technical and economic aspects of both PSE's and HDR's projections and assumptions for the 20-year timeframe. I have a number of questions and comments related to those aspects, which I provide below. My overarching concern is that HDR's analysis includes many assumptions that disadvantage variable renewable resources. Further, I have concern that moving forward with some of these assumptions at the stage in which they become inputs to Plexos (or other capital expansion models) will artificially yield results that favor more natural gas or other fossil resources in the future.
***PSE response*: Comments noted, thank you.**

Concerns about PSE's assumptions:

- During the July 26th meeting, PSE noted that in their resource cost evaluations, Levelized Costs of Energy (LCOEs) are not considered; rather only capital costs are utilized. PSE's reasoning is that LCOEs do not reflect the portfolio value of a resource that (for example) provides production when marginal market prices are high vs. low. My concern is that neither does a capital cost value provide insight about total portfolio value without consideration of its capacity, flexibility, temporal production value, etc. Today's inverter-based technologies are capable of providing voltage/VAR support, frequency response, ramping capability, and other essential reliability services. Despite much discussion during the meeting about many recent RFP bid responses in Western states that demonstrate dramatically reduced energy tenders, I would contend that further evaluation of the 2017 bid responses from XCel, NV Energy, TEP, PacifiCorp, and others yield incontrovertible insights that should not be ignored. To that end, I enclose a document that itemizes recent bids (with and without storage) from seven different utilities across six states. The numbers expressed in the document itself convey primarily PPA pricing and LCOEs, but in addition, URLs to each RFP response are included. I would request that PSE staff and/or HDR evaluate these bids on the basis of EPC costs, owners' costs, interconnection, and other aspects of the all-in capital costs associated with these dramatically low bid prices and include them in the overall capital cost assumptions to be utilized in the 2019 IRP.

<u>PSE comment concerning levelized costs</u>: PSE does not use levelized costs in the core IRP analysis. Levelized costs are average costs, not marginal costs. The IRP seeks to minimize marginal costs, based on how a resource addition affects total portfolio costs. Total portfolio cost includes fixed and variable cost of new resources and variable costs of existing resources. The difference is that average levelized costs are not what customers will experience in rates. Specifically, levelized costs do not reflect how resource additions would affect how much electricity PSE must purchase from the wholesale market or sell to the wholesale market. Phillip provided a simplified example to illustrate the difference. Assume PSE could purchase one of two renewable resources. The first has a levelized cost of $35/MWh, the second a levelized cost of $40/MWh. Minimizing levelized cost would mean PSE should purchase the first resource. However, what if the first one only generates electricity during April, when market prices are $20/MWh, whereas the second only generates electricity during August when market prices are $50/MWh? By offsetting wholesale purchases in April, the first resource would be a net cost of $15/MWh ($35/MWh-$20/MWh). The second will be a net benefit of $10/MWh ($40/MWh - $50/MWh). This example illustrates that using levelized costs could lead to a higher-cost decision, because levelized costs do not reflect the value of resources to the portfolio of resources used to meet the needs of PSE's customers. Levelized costs are good for high level comparisons of like resources. All the information presented in the tables are needed for PSE's portfolio modeling.

<u>PSE comment concerning differing subhourly flexibility value of different resources</u>: PSE agrees that capital costs and levelized costs do not reflect day-ahead, hour-ahead, and sub-hourly flexibility values that different resources may bring to PSE's portfolio. PSE uses the Plexos model in our analytical process, to ensure that the flexibility value of different kinds of resources are reflected in the analysis.

During the July 26th TAG meeting, there was much discussion about PSE considering bid responses from its current RFP to lend insight about actual resource costs available in the market today. Understandably, PSE cited that there is a significant distinction between "evaluated vs. as-bid" prices. PSE also raised the concern that bid prices are confidential. However, stakeholders made relevant suggestions that bid prices can easily be anonymized by using median values or other means, and questioned why there is insufficient time during this early stage of the 2019 IRP cycle to wait for evaluated bid prices. I kindly request that PSE provide some response to those questions/suggestions.

PSE response*: PSE acknowledges the comments and request, thank you. RFP results cannot be used in the IRP due to non-disclosure agreements. Although the final IRP is not due until July 2019, our modeling process requires us to lock down resource costs early in the process and not continually update the costs. In addition, PSE will utilize the same model for the RFP and the IRP for future generic resources; the costs for the IRP need to be locked down to support the RFP evaluations in August 2018. To address uncertainty in future resource costs, PSE will develop an alternative resource cost sensitivity. The purpose of this analysis will be to examine whether a reasonable, alternative set of resource assumptions would affect the least-cost mix of resources.

Please note, the RFP is a separate regulatory process that has specific disclosure requirements that PSE will follow, to ensure the Company is able to acquire the most cost effective resources for our customers through that process.

Questions/concerns about economic assumptions:

- Discount rates used for planning values: we may not yet be far along enough in the process to have considered stakeholder input on this topic, but for ongoing consideration I would like to suggest that for any planning values that are discounted to present values, a sensitivity analysis be included that includes not only the standard Weighted Average Cost of Capital (WACC), but also zero, half, and double the WACC values. Such a sensitivity exercise will yield great insight as outcomes will vary substantially.

  ***PSE response*: PSE appreciates that such sensitivities would produce interesting information, but such scenarios would be very time consuming, and PSE must prioritize work so the IRP may be filed on time. Note, PSE will examine an alternative discount rate for residential conservation, along the lines of what the Commission suggested in their acceptance letter for the 2017 IRP.**
- Fuel price volatility risks: many states within the Western Interconnection, as part of their IRP practices, require that utilities file statements - as part of their IRP filings, that convey direct measures undertaken by the utility to ensure that fuel price volatility risks are not placed on the backs of electricity customers. WGG requests that PSE's chosen projections for natural gas forward pricing be guaranteed by PSE's shareholders, and without risks placed upon ratepayers.

PSE response*: An integrated resource plan is not the forum to create new regulatory policies. The WUTC's on-going IRP rulemaking process is a more suitable forum for making such policy recommendations. Specifically to the technical point in your comment, PSE does perform a stochastic analysis to ensure a consistent risk analysis that is applied to all resources. This analysis incorporates variability in wholesale electric prices, natural gas prices, uncertainty in hydro generation, uncertainty in wind and solar generation, and uncertainty in loads from temperatures. These impacts are interrelated and need to be analyzed together to have a complete picture of the variability in costs of different combinations of resources.

Concerns about HDR's cost and performance assumptions:

• The "book life" of solar resources are estimated by HDR at 20 years, which is not born out by empirical experience with large scale photovoltaic (PV) plants. The economic life

of PV plants should be no less than 30 years.
PSE response: PSE will consider a 25-year life of solar, which is consistent with assumptions for wind generation.
• Given a typical 30-year book-life of natural gas plants, and the half-life of CO_2 in the earth's atmosphere, future natural gas plants present more than a 30-year stranded asset problem. It is actually more like a 90-year carbon problem.
PSE response: Comment noted, thank you.
• HDR's assumptions regarding the scale of wind and solar resources are assumed at much lower values than those of thermal resources. PSE/HDR respond that wind and solar capacities are based on assumptions about RPS need, but they ignore a goal toward a carbon-free roadmap and the very relevant fact that renewables are lower in cost than the marginal pricing of most existing fossil resources, regardless of an RPS compliance need.
PSE response: HDR will update the cost assumptions to ensure a higher degree of economies of scale are realized.
• Thermal/fossil resource costs and emission values are calculated by HDR at full load operation levels, which artificially represents lower costs, lower heat rates (higher plant efficiency), and lower emissions. In reality, the majority of PSE's natural gas resource fleet operates at varying levels of output, with many combined cycle plants and combustion turbines operating at partial load levels. This results in higher heat rates, lower efficiency, and higher emissions. My understanding from the July 26th meeting is that PSE takes actual operating profiles into production cost modeling for the purposes of project and purchase considerations, but it is not clear that they are used in year 20 planning for the IRP. We respectfully request a clarification on this point.
PSE response: PSE production cost model dispatches the units based on the forward price marks versus the variable cost of running the units and not actual profiles. It takes into account the heat rates as the units ramp up to full load.
• Regarding wind resource capabilities, HDR's wind resource estimates are based on 100-meter hub heights, while today's typical wind turbines have hub heights of 160 meters, with much greater output. WGG kindly requests that HDR revise their assumptions in this regard.
PSE response: Your comments have been provided to HDR.
• If we understand correctly regarding interconnection costs, HDR's assumptions place all network upgrade costs on single wind and solar projects without regard to likely distribution of benefits to other network users. Such is rarely the outcome of the findings from a thorough FERC small or large-scale interconnection process (SGIP or LGIP). We request further evaluation of these assumptions from PSE.
Michele, WGG deeply appreciates the sincere and open public process you and your PSE colleagues have created. I hope you will find our recommendations to be useful, insightful, and actionable. I look forward to continued engagement in this process.

Michele, WGG deeply appreciates the sincere and open public process you and your PSE colleagues have created. I hope you will find our recommendations to be useful, insightful, and actionable. I look forward to continued engagement in this process.

With deep appreciation,

(signed) Kate Maracus

PSE appreciates your comments and participation, thank you! PSE also acknowledges the "West PPA Prices" excel spreadsheet you provided.