The following stakeholder input was gathered through the online Feedback Form, from June 23 through July 7, 2020. PSE's response to the feedback can be found in the far right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on July 21, 2020.

2021 IRP Electric Price Forecast Workshop Feedback Report			
Feedback Form Date	**Stakeholder**	**Comment**	**PSE Response**
6/24/2020	James Adcock (1)	Re Page 50 Please compare battery costs to: Cole, Wesley, and A. Will Frazier. 2019. Cost Projections for Utility-Scale Battery Storage. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-73222. https://www.nrel.gov/docs/fy19osti/73222.pdf. Please make sure that your battery costs are consistent with latest publications, including this recent NREL publication.	Thank you for suggesting an additional data source for inclusion in the 2021 IRP generic resource cost calculation. PSE has reviewed the publication and found that the contents of the report have already been incorporated into our analysis as part of the National Renewable Energy Laboratory's 2019 Annual Technology Baseline (ATB). The Cole and Frazier report was used as the basis for cost projections for the 2019 ATB as discussed on the Battery Storage discussion page of the ATB website (https://atb.nrel.gov/electricity/2019/index.html?t=st).
6/29/20	Kathi Scanlan, WUTC	Question before webinar on transmission constraints: It is important to know the assumptions for the MW capacity of imports on the "interties," B.C. to NW, MT to NW, SW (CA+ AZ effect) to NW. How is company modeling this?	PSE is modeling the following: BC to NW: PSE will not model any capacity on the BC to NW intertie for BC hydro resources. MT to NW: Capacity on the MT to NW intertie is modeled in the Montana resource region. SW (CA + AZ effect) to NW: Capacity on CA/SW to NW intertie is assumed to be unavailable due to constraints on the BPA transmission system.
6/30/20	Virginia Lohr, Vashon Climate Action Group	The Consultation Report from the May 28 IRP meeting has links to find relevant information, but they do not take you to the needed information, only to the overall IRP entire website, leaving the person seeking that information to spend time searching through your website to try to find the information. Here is an example from the Consultation Report: "The capital cost has been updated in the revised summary workbook Excel file for the generic resources assumptions available on PSE's IRP website under materials for Webinar 1 on pse.com/irp." If you follow the link, you will see nothing on that page that says "Webinar 1." I searched a number of pages linked to pse.com/irp, and I could find nothing called "Webinar 1" except in the Consultation Report itself. Please provide meaningful links with accurate titles to the referenced material.	Thank you for your suggestion concerning improving the process with meaningful links with accurate titles to the referenced material. PSE is adopting your suggestions and will continue to improve this aspect of the process to promote meaningful stakeholder participation.
6/30/20	Fred Huette, NW Energy Coalition (1)	Initial questions: (1) what transmission planning models does PSE use (powerflow and production cost) and how will the analysis with those models interact with the AURORA IRP analysis (2) is PSE using the most recent ATC values published by BPA for its transmission paths, especially those with substantial effect on PSE's system, such as West of Cascades North, North of Hanford, Raver-Paul, BC Intertie and the paths from Montana westward	For the purpose of long-term resource planning, PSE does not use transmission planning models to provide the values that are inputted into AURORA. PSE is using the most recent available transfer capacity (ATC) values published by BPA. PSE uses the latest ATC values from BPA for any study or analysis.
6/30/20	James Adcock (2)	While I was generally much happier with the format of today's meeting, I was disappointed that PSE chose to "cut and run" at the end of the meeting rather than allowing the last questions to get asked and answered. In particular, I do not find that your modeling choices of interconnect costs on batteries are AT ALL reasonable! For example you are modeling interconnect costs on 2 hour batteries -- slide 50 -- as being 43% of capital costs!!! This is NOT at all reasonable "modeling" -- in that a utility would never build a project in that manner. In turn, the reason that you are creating such high interconnect costs for batteries is that you are needlessly assuming that battery system sizes are very small compared to other projects such as NG Peakers -- thereby artificially raising the percentage of interconnect costs associated with batteries. In practice, for example, if a utility chose to	Thank you for your feedback. PSE has consistently applied the interconnection cost described in the 2019 HDR Report (linked below) for all generic resources. For all battery types, the assessment assumes a 115 kV, 5-mile tie line to the point of interconnection and a breaker and one half interconnection arrangement at the point of interconnection. These are fixed capital costs, regardless of resource nameplate capacity. The capital cost adder in dollars per kilowatt may appear inflated for

		implement 2 hour batteries, they would choose a much larger battery system size, in order to reduce the percentage of "overhead" associated with transmission connection costs. Can you please review and rework this modeling to more fairly represent interconnect costs on batteries, because frankly right now it looks like you are just trying to "cook the books" to unfairly make batteries appear to be uncompetitive compared to NG Peakers! And frankly batteries have greater siting flexibility that NG Peakers due to lower noise and air pollution profiles, so battery interconnect costs should be much smaller than NG Peakers costs! Recalculate battery storage system interconnect costs to be LOWER than NG Peaker costs on a per megawatt nameplate basis due to the much better siting flexibility that battery storage systems allow.	smaller nameplate resources such as battery resources (25 MW nameplate) and biomass facilities (15 MW nameplate). Given the expectation for significant quantities of battery energy storage systems in the 2021 IRP, PSE will include a 100 MW nameplate battery. The interconnection for a 100 MW nameplate battery would be $91.80/kW in real 2016 US dollars. 2019 HDR Report: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/10111615-0ZR-P0001_PSE_IRP.pdf
7/1/20	James Adcock (3)	In Regards to Transmission Constraints Presentation Page 50 I believe your "Interconnection Costs" for battery storage systems are about 16X too high. For the battery plants the assumption of a 5 mile stub line is unreasonable, since the plant have little siting constraints they can be sited near major transmission lines. Looking for generic costs of interconnect -- since the interconnect requirements for 100 MW of battery storage are essentially "identical" to the interconnect requirements for 100 MW of CT NG Turbine plants, I looked to the following document (from Brattle) page 22. https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx PJM Electrical Interconnection for CT NG Turbine plants $8 Million for a 355 MW plant. Or $22,535 per MW. Or $22 per KW Where for similar interconnection requirements for Battery Storage Systems you are quoting $367 per KW -- or about 16X higher interconnect costs! Can you please give me references for how you derived your assumed much-higher interconnection costs of $367 per KW ? Thank You, Jim Adcock	See response to James Adcock (2).
7/1/20	James Adcock (3)	Lower your assumed interconnection costs (Transmission Constraints Presentation Page 50) for utility-scale battery storage from $367 per KW to $22 per KW.	See response to James Adcock (2).
7/1/20	Don Marsh, CENSE (1)	Dear IRP Team, In yesterday's presentation on Transmission Constraints, you showed a cost table that anticipated interconnection costs of $367/kW for batteries of any type or duration. This is far higher than the interconnection costs for gas plants, and one of the participants asked why. The answer from PSE was because of the small size of batteries. If I recall correctly, PSE said that the costs were for a 10 MW battery, which is a capacity approximately 30 times smaller than a gas plant, so the economies of scale work out badly for batteries, especially if you assume five miles of transmission line to connect the battery to the grid. There are many flaws with this reasoning: 1. Why is the battery assumed to be so small? A 10 MW battery might have been "cutting edge" a few years ago, but that would be quite small by today's standards. For example, Southern California Edison recently signed seven contracts to acquire 770 MW of lithium-ion battery storage projects (https://pv-magazine-usa.com/2020/05/02/southern-california-edison-wants-huge-770-mw-battery-storage-procurement-online-fast/). Here are the sizes: a) 88 MW/352 MWh Garland Project b) 72 MW/288 MWh Tranquility Project c) 115 MW/460 MWh Blythe 2	See response to James Adcock (2).

		d) 115 MW/460 MWh Blythe 3 e) 230 MW/920 MWh McCoy Project (connected to 250 MW solar farm) f) 50 MW/200 MWh Sanborn Project g) 100 MW/400 MWh (stand-alone) The average size of these projects is 110 MW/440 MW. Why is PSE assuming a battery less than one-tenth this size? Also, the McCoy project is almost the capacity of a peaker plant, so there appears to be little justification for claiming that a battery would have different interconnection costs compared to a peaker. 2. Five miles of transmission cost for a battery overstates the typical scenario. The beauty of batteries is that they can be located close to the load (or the generation resource), without concern for the emissions that make it hard to site gas plants close to neighborhoods. PSE states that siting problems prevented the company from siting a peaker plant anywhere on the Eastside as an alternative to the transmission upgrade project, Energize Eastside. We agree. A gas plant would have significantly more transmission cost to keep it away from population centers and residents who might experience breathing difficulties as a result of the emissions. To properly account for this, we expect the interconnection costs to be higher for gas plants than batteries. Please make this correction. 3. Batteries are more easily scaled to higher or lower capacities than peaker plants. Although there are some modular designs for peakers, the increments are pretty coarse compared to batteries. This means that some of the capacity of a peaker plant might not be needed in a particular location, while batteries can be more easily customized to the exact need. PSE appears to be penalizing batteries for their ability to scale down to 10 MW, whereas it would be hard to find a peaker plant with that miniscule capacity. It would be prohibitively expensive if there were one that small. To be fair, we must compare apples to apples. Please be explicit in your cost table about the size of the resource and its location. For example, if you compare the cost of a 300 MW battery to a peaker, but you divide that battery into 30 pieces and charge 150 miles of transmission lines, that is not the same scenario as a single peaker plant with only 5 miles of transmission. It may well be that 30 distributed batteries provide more reliability, resiliency, and system benefit than a single peaker plant. The batteries should get credit for that. When I first saw these numbers, I feared that my interpretation of the numbers must be incorrect. However, there is ample evidence that other utilities around the country are finding batteries to be a economical choice compared to gas plants. As just one data point, there is this quote from today's issue of T&D World: "According to research completed in 2019 by the Rocky Mountain Institute, 90% of proposed gas-fired power plant construction through 2025 is more costly than equivalent clean energy portfolios consisting of distributed solar, storage and energy efficiency. Further, the economics to operate fossil fuel powered generation is expected to decline significantly, resulting in a higher risk of stranded assets." (https://www.tdworld.com/smart-utility/data-analytics/article/21133422/why-arent-utilities-combining-energy-efficiency-solar-and-storage) If my reasoning and intuition has led me astray, I hope you will explain your rationale for the high cost of battery interconnection. I would expect you would have made this clear during the presentation rather than showing us opaque numbers without adequate explanation. This whole process feels more like hide-and-seek than a collaborative exchange with both parties being treated with professional respect. If this isn't quickly rectified, stakeholders may have to seek remediation from appropriate agencies. That would be a tragic outcome of our sincere effort to participate in matters that directly affect us, our planet, and future generations. Sincerely, Don Marsh	
7/1/20	Don Marsh, CENSE (2)	To accurately assess resource costs, you must factor in the following benefits of batteries: 1. Easier siting than peakers. (Shorter transmission lines.) 2. Stacked benefits (voltage regulation, storage of cheap, clean renewable electricity, relatively easy scaling, T&D deferral, peak demand service, outage service, and others) 3. No emissions. 4. Very fast response (no long warm-up times with high levels of emissions)	See response to James Adcock (2).

		5. Distributed resource (more reliable and resilient than a large plant with a single point of failure) PSE's current analysis appears to ignore these advantages, and we are not confident they will be accurately assessed later in the IRP proceeding.	
7/2/20	Don Marsh, CENSE (3)	Dear IRP Team, We formally request that PSE include in its 2021 IRP and CETA modeling the option of using grid-scale batteries to meet Eastside energy needs as an alternative to the proposed “Energize Eastside” transmission line upgrade. Specifically, we would like to understand how costs and operations compare if a reasonable amount of storage were to be located near centers of heaviest peak demand in Eastside cities. To our knowledge, this option has not been studied (a 2018 Strategen study assumed batteries were placed many miles away from load centers, making batteries only 20% effective in reducing loads on critical transformers). As I mentioned in the Transmission Constraint webinar, batteries offer many economic, environmental, and reliability benefits compared to an 18-mile transmission line: 1. Batteries will save money for ratepayers. The transmission line upgrade is only needed a few hours per year (if that), while a battery can provide grid benefits around the clock, 365 days per year. For example, batteries can earn money by stabilizing voltages, time shifting cheap renewable energy for use during peak demand, and reducing the cost of atmospheric emissions. The Tesla battery in Australia is generating astonishing financial returns (https://reneweconomy.com.au/tesla-big-battery-at-hornsdale-gets-big-jump-in-revenues-more-to-come-65622/). Admittedly, Australia is an extreme case, but we think it’s obvious that batteries will save more money each year for ratepayers than a transmission line will. 2. Batteries will help PSE meet CETA goals. By releasing clean renewable energy during peak hours, batteries will reduce the need to run gas peaker plants, which will account for a higher percentage of PSE’s emissions as the energy mix shifts to renewables. Batteries also help the environment by preserving thousands of valuable urban trees that are threatened by the transmission line project. These trees not only sequester carbon, but their shade moderates the intensity of urban heat islands, reducing the need for more air conditioning during hot summer days. 3. Batteries enhance reliability. Batteries can be distributed throughout the Eastside. Many can be located in existing substations. Besides reducing the risk of a single point of failure, distributed batteries can provide power during local outages, and this is a significant advantage because many power outages occur due to failures of neighborhood distribution lines. Since PSE has had a poor reliability record in recent years (as reported to the WUTC), distributed batteries could help reverse disappointing reliability trends. A holistic view of our energy grid will show that batteries deliver multiple benefits and should be valued accordingly. PSE’s current analysis does not properly value all of these benefits, and therefore batteries appear to be more expensive than gas peaker plants. Many utilities that are using more objective measures are choosing batteries over peaker plants, and it is time for PSE to do the same. If PSE ignores these realities, there is significant risk that the UTC will not allow full cost recovery of Energize Eastside, causing financial hardship for the company and its investors. Please protect their investment and our communities by doing an accurate assessment of the advantages I’ve described here. Sincerely, Don Marsh	Thank you for sharing your thoughts and suggestions.
7/2/20	Don Marsh, CENSE (4)	Please protect your investors and our communities by doing an accurate assessment of the advantages batteries provide compared to the proposed "Energize Eastside" transmission upgrade. The 2018 Strategen report on batteries, paid for by PSE, contains invalid assumptions and cannot be cited as a realistic analysis of the potential of this technology.	Thank you for your comment and suggestion.
7/4/20	Willard Westre, Union of	Slide 28 - Dual purposed transmission of Renewable resources and existing Gas plants is a creative approach. This helps address intermittency, peak load, and resource adequacy issues with renewables without addition of new transmission resources. Dual purposed transmission should be used wherever practical.	Thank you for your comment and suggestion.

	Concerned Scientists (1)		
7/4/20	Willard Westre, Union of Concerned Scientists (2)	Slide 29 – This slide is very misleading. The proposed sale of Colstrip Unit 4 actually reduces the Colstrip transmission line capacity (for PSE) from 750MW to 565MW equaling a 185MW reduction. This proposed sale is very troubling for a number of reasons. From the ratepayer perspective, in my opinion, the proposed sale raises the appearance of a blatant disregard of public trust. Ratepayers would in effect be paying for 185MW of transmission twice – once for the original Colstrip construction and now to restore that capacity. The value of this 185MW of capacity would be approximately $380 million using transmission cost data for new transmission lines from similar locations on the east side of the Rocky Mountains as noted on slide 46. This certainly does not appear to be prudent. From the CETA perspective, the proposed sale increases the cost of replacing the coal power with renewables. The analysis preceding the Dec 11 webinar established that Montana wind was the lowest cost renewable energy generation source available. The proposed sale reduces the amount of that lowest cost resource by at least 185MW thus increasing the CETA implementation cost. From a performance perspective, MT wind has the highest winter season capacity factor matching PSE's peak seasonal load and the highest ELCC rating (needed to meet resource adequacy requirements) of all renewables. With the serious transmission constraint this is critical. Other resource options with lower capacity factors require much higher nameplate MW's and hence require even more transmission capacity. From an environment perspective – one of the rationales given for this proposed sale is to satisfy environment organizational pressure to close the coal plants. Nearly all environmental groups oppose this sale. We only have one atmosphere and it doesn't matter where the emissions are released, they affect everyone everywhere. The proposed sale allows Unit #4 to continue for many years into the future in direct contradiction to the intention of the CETA requirement that they close in 2025. 1. Terminate the proposed sale of Colstrip #4. 2. Retain the full 750MW transmission capacity. 3. The Colstrip transmission line is one of the most valuable assets PSE owns. Maximize its use.	PSE will not model 185 MW as a sensitivity in the IRP analysis because there is a pending WUTC filing for the sale of Colstrip Unit 4.
7/4/20	Willard Westre, Union of Concerned Scientists (3)	Slide 33 – I agree with changing the long-term firm (LTF) transmission policy for renewables. Renewable generation resources rarely operate at their nameplate rating because of weather dependence as evidenced by lower capacity factors. If existing interpretation of LTF is used, transmission lines would rarely be efficiently loaded to capacity requiring significantly more transmission capacity. I recommend transmission policy be linked to the peak seasonal capacity factor of each resource.	Thank you for your support concerning PSE changing the policy to match renewable transmission with actuals instead of name plate capacity factors. PSE is still considering a sensitivity where firm transmission is obtained for lower than 100% of nameplate.
7/4/20	Willard Westre, Union of Concerned Scientists (4)	Slides 48-52 – I appreciate the cost data, but you repeatedly leave out the most important cost and sometimes largest cost – Fuel. You do not even mention it or explain where it fits in the analysis. Newer participants who try to add up the costs to come to some conclusion are misled. Is this intentional? Just give us 1 more slide on fuel cost along with the other costs so it isn't forgotten. Better yet - report all cost data in $/MW, $/KW, $/KWh, or $ MWh.	Natural gas (fuel) prices were discussed at the June 10, 2020 IRP meeting. Though natural gas prices are variable costs that depend on dispatch, natural gas prices are added as a separate cost from the rest of the variable costs. Variable costs are stated as $/MWh because they are dependent on how much electricity is produced at the plant, whereas fuel costs are stated as $/mmBtu since they are dependent on how much fuel is burned.
7/4/20	James Adcock (4)	At the June 30 Transmission Meeting PSE was quoting very high transmission connection costs for battery storage units -- much higher than other technologies. My estimates were that these connection costs were estimated to be 16X too high. I also suggested that battery storage units tend to be located very close to existing connection points -- not the 5-mile connection distance that PSE was estimating. I went back and used aerial photographs to estimate the connection distances for recent large battery storage projects as follows: Ventura Energy Storage: 0.1 Miles to adjacent solar generation facility AES Alamitos Energy Battery Storage: 0.1 Miles to adjacent substation	See response to James Adcock (2).

		Tesla Moss Landing: 0.08 Miles to adjacent substation Reduce the assumed connection distance for battery storage units to the closest reasonable transmission line or substation from current estimate of 5 miles to down to 0.1 miles.	
7/6/20	Bill Pascoe	<u>General Comment</u> PSE appears to be taking a progressive approach to modelling transmission opportunities and constraints for the IRP. This type of forward-thinking approach is necessary to optimize transmission rights in a new planning and market environment with increasing reliance on clean energy resources. <u>Comments on June 30, 2020 Presentation</u> Slide 23 – Pumped storage hydro (PSH) should be modelled in the Montana resource region. Gordon Butte PSH has a FERC license and could use PSE's existing Montana transmission rights, perhaps in combination with Montana wind to "dual purpose" these rights. Slides 25, 27 and 28 – PSE is to be commended for considering "dual purposing" of transmission rights in this IRP. Slide 29 – PSE should model cases with 750 MW of existing Montana transmission rights to reflect the possibility that the proposed sale of 185 MW of capacity to NorthWestern Energy does not go through. Slide 33 – PSE is to be commended for considering less than 100% long term firm transmission rights in this IRP. Slides 45, 46 and 48 – Idaho/Wyoming transmission costs should include wheels on BPA (and any other intermediate systems) in addition to the costs of the ID/WY new builds.	Thank you for your positive and supportive general comment concerning PSE's approach to modelling transmission opportunities and constraints for the IRP. Slides 23: Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. Slides 25, 27 and 28: Thank you for your positive and supportive general comment concerning PSE's approach to modelling transmission opportunities and constraints for the IRP. Slide 29: PSE will not model 185 MW as a sensitivity in the IRP analysis because there is a pending WUTC filing for the sale of Colstrip Unit 4. Slide 33: Thank you for your support concerning PSE changing the policy to reduce the amount of long-term firm transmission to less than name plate capacity. Slides 45, 46, and 48: For the Idaho/Wyoming wind, the transmission line will only deliver the power to Boardman, so PSE will need to rely on a BPA wheel to deliver the power to PSE load. The BPA tariff rates will be included on top of the costs for Idaho/Wyoming wind.
7/7/20	Anika Arugunta	With the depletion of natural resources each day, there is great need to protect our environment so I feel that there is a great need to encourage organizations such as PSE . PSE is doing a great job in bringing to light these environmental issues and it's working to not only educate others about these issues but also to solve these issues as well, which is one of the reasons why I love to work with PSE. Even considering it would be a long 900 miles to travel on the transmission lines, is PSE looking into creating wind and or solar in or on Coalstrip? This would not only be close to transmission lines and a good utilization of land but also create jobs for any workers displaced by the coal stacks closing down.	Thank you for your comment and suggestion. Because of the location of the site and ownership arrangement of Colstrip, PSE is not looking at developing the Colstrip land for wind or solar. However, PSE is analyzing other wind opportunities in Montana.
7/7/20	Anne Newcomb	Thank you for your dedication to move PSE into the clean energy future! I'm so happy it's finally happening! Increase solar on the Westside of the cascades through incentivizing home and business owners as well as public places to create new solar reducing transmission load over the pass. Work towards more solar that can be produced, used and stored onsite in addition to being fed back into PSE lines, to help with the reduction of load on transmission lines	Thank you for your comment and suggestion.
7/7/20	Katie Ware, Renewables NW	*See attached PDF for comments (2020-07-07 RNW Feedback re PSE Transmission Constraints.pdf)*	PSE responses by number: 1. PSE will not model 185 MW as a sensitivity in the IRP analysis because there is a pending WUTC filing for the sale of Colstrip Unit 4. 2. Thank you for your comment. PSE will ensure all modeling resources accurately reflect the 4.6% line loss for transmission from the Colstrip substation. 3. Thank you for your comment and suggestion. Given that all renewable resources outside of PSE will require wheeling through BPA, the BPA tariff

			rate is a reasonable assumption given that PSE does not have an available integration cost. 4. Thank you for your comment and suggestion. 5. Thank you for your support concerning PSE changing the policy to reduce the amount of long-term firm transmission to less than name plate capacity. 6. Thank you for your suggestion, PSE is weighing feedback received by all stakeholders and will provide a final determination of our modeling approach in the July 21 Consultation Update. 7. Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. 8. Thank you for your suggestion. PSE is considering the possible modeling approach to satisfy this request and will provide additional feedback in the July 21 Consultation Update.
7/7/20	Fred Heutte, NW Energy Coalition	July 7, 2020 To: Puget Sound Energy From: Fred Heutte, Senior Policy Associate on behalf of NW Energy Coalition Re: 2021 IRP Webinar #3: Transmission Constraints The NW Energy Coalition (NWEC) appreciates the opportunity to provide the following comments on the Puget Sound Energy (PSE) presentation in 2021 IRP Webinar #3: Transmission Constraints on June 30, 2020. 1. NWEC would like to have a review, perhaps in an informal discussion group with technically minded stakeholders, about the interaction between power planning (IRP) and transmission planning at PSE. On the transmission side, our questions include: what transmission models does PSE use (powerflow and production cost), what types of cases or scenarios are used to assess transmission constraints currently and in the future, and how does the transmission modeling assess new resources, resource retirement and transmission expansion over time. On the power planning side, does PSE apply the outputs of previous transmission studies throughout the IRP process, or is there additional transmission modeling to assess scenarios being considered as the IRP progresses? 2. What assumptions does PSE have about interregional transmission constraints, particularly for connections to BC Hydro and also the Pacific Intertie? 3. To what extent will PSE consider non-transmission alternatives to make more effective use of its existing transmission system and transmission rights? This includes both flexible demand (including demand response and storage of various kinds) and in-grid elements including traditional equipment such as static var compensators and phase shifters, and new approaches such as “storage as a transmission asset.” 4. With the ongoing progress of the proposed CAISO enhanced day ahead market (EDAM) proposal, NWEC recommends PSE incorporate a market flexibility scenario for the IRP specifically to address reducing constraints and better utilization of the transmission system. While the elements of EDAM are still in early review, the WIEB Western Flexibility Study and the forthcoming State-Level Market Study (with participation by the UTC and Washington State Energy Office) provide useful elements for modeling the potential capability of enhanced markets. 5. (slide 23) We join with other stakeholders in suggesting that pumped storage in Montana should definitely be included in the IRP Assessment. The Absaroka Gordon Butte project is a very important possibility for integrating Montana wind. 6. (slide 24) In terms of the timing for tiers representing transmission constraints, we suggest 2026 as an important checkpoint in view of the availability of Colstrip transmission facilities and rights, the potential availability of pumped storage, and possibilities for transmission expansion including the BPA Montana-to-Washington project, Boardman to Hemingway and Gateway West.	PSE responses by number: 1. PSE will follow up with NWEC and coordinate an informal meeting. 2. SW to NW: Capacity on CA/SW to NW intertie is assumed to be unavailable due to constraint on BPA system. BC to NW: PSE will not model any capacity on the BC to NW intertie for BC hydro resources. 3. PSE is considering a balanced approach to meeting CETA compliance. PSE will be discussing distributed energy resources (DERs) in the August 11 webinar. PSE will also be discussing transmission and distribution (T&D) planning during the November 4 webinar. 4. Thank you for the suggestion and the accompanying resources. However, given the CAISO enhanced day ahead market (EDAM) is still in the early stages of development PSE will not be including it as a viable market in the IRP process. 5. Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. 6. Thank you for your comment and suggestion. 7. Thank you for the comment, dual purposed transmission will be included in the 2021 IRP modeling process. 8. The IRP team will be evaluating the portfolio benefits of these transmission project investments, which will assist PSE in making a future decision. 9. Thank you for your comment and suggestion. 10. Thank you for your comment and suggestion. PSE is happy to have a follow-up discussion on this topic. 11. Thank you for your comment and suggestion. 12. PSE is considering expanding cross-Cascades transmission capacity as an alternative and will have an update for the consultation update 13. Per the NREL website, the Mid Technology Cost Scenario is the characterized as "likely" while the Low Technology Cost Scenario is characterized as at the "limit of surprise". PSE has included only the most-likely cases (or an average of high and low cases, as applicable) from other data sources. For consistency, PSE will maintain this precedent for the NREL ATB. 14. See response to James Adcock (2).

		7. (slide 27) NWEC strongly supports PSE's interest in dual-purpose use of existing transmission and transmission rights for gas power plants by incorporating new renewable sources that will improve transmission utilization and provide more system value at low incremental transmission cost. 8. (slide 30) NWEC requests that PSE provide more context for the interest being expressed in the proposed Boardman to Hemingway and Gateway West projects. Since PSE would be a new entrant with existing project sponsors and co-developers, it is important to have a better understanding of what PSE's expectations are for the net benefits to be gained and the timing and form (equity ownership or long term transmission rights) of any such commitments. 9. (slide 31) NWEC requests that PSE discuss in more detail how it views the initiatives by BPA to develop new and more flexible transmission products, such as the anticipated revisions to Conditional Firm. 10. (slide 32) Concerning Option 1 and Option 2 for incorporating transmission constraints into the IRP modeling, NWEC thinks both options may add some value and is interested in a more detailed conversation with PSE on this point. 11. (slide 33) NWEC sees the concept of acquiring renewables while having less transmission capacity than their nameplate worth exploring, but we believe that a more in-depth discussion with renewable developers, Renewable Northwest and NIPPC will be important to understand the commercial considerations involved. 12. (slide 34) Is PSE considering expansion of its cross-Cascades transmission capacity? 13. (slide 49) Concerning the use of the NREL Annual Technology Baseline, we now understand that PSE is using the ATB for future resource cost projections, and we appreciate PSE's response to our previous recommendation that regard. However, we continue to view a midrange between the ATB Mid and Low cost projections the most likely, given our analysis particularly of solar PV costs and a separate experience curve analysis we have conducted. Since the ATB became available a few years ago, our view is that the Mid scenario has overestimated short term cost reductions and it is more appropriate to view the ATB Mid and Low projections as "middle-high" and "middle-low." The ATB does not have a "high" projection; the "constant" projection is simply a straight line extension of current cost estimates useful for their scenario modeling. Therefore, we believe a mid-range between the ATB medium and low projections is the most appropriate cost trajectory for use in IRP modeling. 14. (slide 50) As noted by other stakeholders, the battery interconnection costs indicated in the chart appear to be far too high. Thank you for considering NWEC's comments. /s/ Fred Heutte Senior Policy Associate NW Energy Coalition	
7/8/20	Steve Lewis, Sapere Consulting	1. It appears that some of the 450 MW on PSE's cross-Cascades transmission system is reserved for priority use by the Schedule 449 customers (see https://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/Posted_Path_Discussion28.pdf). How much of this transmission has been reserved for Schedule 449 customers historically and how much has been used? 2. If the transmission is not used by the Schedule 449 customers, do the remaining core customers of PSE utilize that transmission path as a cheaper alternative to using the BPA cross-Cascades transmission? 3. As long as PSE keeps the Schedule 449 customers whole with respect to cost and reliability, could PSE connect a new resource on the Kittitas transmission system and move the Schedule 449 customer's service onto PSE's long-term BPA transmission from the MIDC? If not, what specifically prevents this approach of reoptimizing PSE's generation and transmission assets for the benefit of their core customers?	1. Per a settlement with PSE's 449 customers, PSE provides firm transmission service to 449 customers on the cross-Cascades path up to the amount of their load. Most of the time, the 449 customers schedule less than their allotted capacity (due to seasonal loads) and the remaining unscheduled transmission is released to the market as non-firm transmission. 2. The non-firm transmission on this path is available in OASIS for purchase by any PSE transmission customer. PSE Merchant (PSE's energy trading group) will sometimes schedule delivery of Wild Horse energy on this path when there is non-firm transmission available. 3. There is not a regulatory or legal mechanism under the FERC Open Access Transmission regulations to transfer the 449 customer's rights under the settlement agreement with PSE (and WUTC Schedule 449 Retail Wheeling Service) to standard transmission tariff service with BPA.

7/9/20	Kyle Frankiewich, WUTC	This feedback, dated July 8, 2020, states the informal comments, questions, and recommendations of Washington Utilities and Transportation Commission Staff. Timely feedback is offered as technical assistance and is not intended as legal advice. Staff reserves the right to amend these opinions should circumstances change or additional information be brought to our attention. Staff opinions are not binding on the commission. Apologies for this comment being a bit late. I am getting up to speed with this new assignment after a few months out of office, but intend to submit future feedback forms within the requested 7-day window. As a newcomer to the 2021 process, I want to recognize PSE for the massive strides made in the company's transparency and public engagement. The website is useful, easy to navigate and contains all presentation information and materials. All meetings are recorded and freely available. This form is a great idea. The commitment to follow up on participants' questions and comments is a customer-focused investment, one that I would wager will pay dividends at the end of the IRP process. Questions from presentation: • slide 17: Does the AURORA zonal model include more than just two zones? The first bullet is a bit ambiguous; I trust that this means PSE considers new generation transmitted to PSE or Mid-C as effectively meeting load (also considering the limit on Mid-C transmission to PSE). Is this correct? Please provide the transmission modeling topology to clarify. To the extent this topology does not align with • slide 17: PSE's presentation included a mention of the limitations of generation-focused or transmission-focused modeling. PSE could use either a generation model or a transmission model, but not both, and chose the generation model. Does PSE run a Tx-given-Gen optimization? Is there a reason why that paradigm is less useful than the chosen Gen-given-Tx approach? • slides 21 and 22: Staff is trying to track PSE transmission that can deliver from the east side of the Cascades to Westside of the Cascades (to PSE BA or to a Westside transmission facility that can be delivered to the PSE BA). In table form, please provide the POD/POI of the existing transmission resources in each of the tiers discussing in the presentation. This could look something like Figure D-6 in the 2017 IRP (pg D-17), but augmented with endpoints. This could also perhaps pair with the maps on slides 21 and 22. Finally, it would be useful to describe the many varieties of transmission rights held by PSE – what attributes of these rights are and are not flexible. Please include this as part of the table. • slide 22: I'm not disagreeing with the use of these resource group areas, but I don't recall why the resource group areas are needed, and how the company settled on these groups rather than some other arrangement. Is there a reason why this modeling approach is more appropriate than other approaches? • slide 22: I heard during the presentation that the "South WA" resource group may include. some of Oregon. Are southern Oregon or CA resources considered? If so, how are any relevant transmission constraints modeled? • slide 23: Staff understands that some prospective pumped storage resources may be available in Montana. Does PSE intend on modeling those resources as well? • slides 25-30: Again, I don't disagree with this approach, but I want to understand how these tiers were generated. I understood that the potential projects and their assignment into tiers is based on PSE's subject matter expertise, rather than a quantitative analysis. Is this a fair description? If so, it may be worth doing some sensitivities to see how significant these assignments are to the resulting optimized portfolio. • slide 25: To clarify, the 1,500 MW of Mid-C T "reserved for Market Purchases" could be used for either purchases or new resource acquisitions, correct? Was that what was meant in the following bullet discussing "dual purpose" transmission? • slide 29: Does the possible sale of Colstrip to Northwestern include any transmission assets that could otherwise be used by PSE for other resources?	Thank you for your feedback concerning improvements to the 2021 IRP process. PSE's responses concerning the presentation by slide number: Slide 17: PSE portfolio model includes two zones, PSE and Mid-C. There is a transmission link between the PSE zone and the Mid-C equivalent to the available Mid-C transmission for market purchases and sales. Transmission constraints discussed in this meeting is the first step toward incorporating generation and transmission optimization. Currently transmission and generation do no interface in the portfolio model. Slides 21 and 22: PSE will be reaching out to you to clarify the request. Slide 22: PSE acknowledges that there are several possible approaches to model transmission constraints within the Aurora framework. These include 1) creation of additional zonal areas; 2) use of the nodal analysis framework; 3) use of the custom constraint matrix; 4) use of the operating constraints table; and 5) use of the resource group table. Creation of additional zonal areas or use of the nodal model would require extensive revision of PSE's current model topology. As this is the first IRP process which PSE is exploring the use of transmission constraints, extreme revision of the model topology did not seem appropriate at this time. PSE understands the remaining three methods could all be incorporated into the existing model topology. Given the resource group table is a 'standard component' of the Aurora model, PSE expects this method to be the most straightforward to use. However, PSE is also exploring the use of the custom constraint matrix and operating constraints table should there be a need for increased modeling flexibility. Slide 22: PSE is currently not considering resources in Southern Oregon or California due to lack of potential transmission. Slide 23: Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. Slides 25-30: Tier 1, 2 and 3 will be modeled as sensitivities in the portfolio analysis. Slides 25: Yes, the Mid-C transmission could be used for either market purchases or delivery of new renewable resources. Slides 29: The sale of Colstrip Unit 4 to Northwestern includes up to 185 MW of transmission on the Colstrip Transmission System. Slides 33: BPA regularly posts its path ratings including cross Cascades, however it does not include sufficient information to see how those hours correspond to an hourly production profile.

		• slide 33: Has PSE analyzed the utilization of the east-to-west Cascade transmission capacity to determine, at least approximately, how many hours are constrained (i.e. for which short-term or short-term non-firm transmission capacity is available/not available) and how those hours correspond to the hourly production profile of the potential VERs resources? If that is • slide 34: I trust that other distributed resources, such as flexible demand / DR and behind-the-meter storage, will also be considered. Puget-area solar may have limited impact, but other distributed resources might also sidestep transmission constraints. • slide 35: Is there a price component to the assumption that T capacity will be unconstrained in the future? I understand that this modeling choice will help PSE determine where future T investments will bring the most value, but am confused about whether a $0 price along with unconstrained availability will cause the optimization to "wait" on resources to make use of that assumed availability. • slide 44: Are any of the MT transmission costs something that PSE would have to pay even if the asset is unused? Also, are any of PSE's rights along these lines subject to the potential sale of Colstrip? • slides 45 and 46: The ID/WY transmission options are modeled as a capital cost for Tx build. Are there also other Tx rights that would need to be acquired to get from, for example, PacifiCorp's transmission (which I understand would be co-built and co-owned with PSE under this Tx option), to PSE's BA? Are there any pancaked rates to wheel through BPA, or does this option presume that all needed BPA wheeling rights are already owned? • slide 50: The list of interconnection cost assumptions made me think about some extended interconnection delays in other parts of the WECC. Are there any known interconnection queue issues in the resource group regions that should be considered? If so, how are those interconnection constraints represented in PSE's modeling? 1. Testing the importance of tiers: Perform some sensitivity analysis to gauge whether the "tiering" of possible Tx projects has an outsized impact on the optimized portfolio. For example, if dual-purposing Goldendale's 330 MW of transmission is considered Tier 1 instead of Tier 2, how different is the resulting portfolio? Also, if the renewable resource sharing the transmission is not directly co-located, there may be other Tx costs or risks involved in redirecting transmission rights. 2. Transmission modeling options: I'm not fully tracking on the modeling approaches discussed on slide 32, but it seems that Option 2 'bakes in' limitations on Tier 2 and 3 resources such that they are not available at any cost earlier in time. If this is the case, it seems that Option 1 will enable PSE to identify what transmission constraints are best prioritized to access the most appropriate resources. I would appreciate a deeper explanation of how the results of the Option 1 sensitivities would guide PSE. 3. Tx capacity by % of nameplate: I'm very happy to see this being considered, and am excited to see the results. 4. Staff and other stakeholders submitted feedback prior to this presentation. Were those questions and comments recognized during or after the presentation? If not, please help us set expectations and clarify how the public engagement process works with pre-presentation feedback.	Slides 34: Yes, PSE is exploring DR and other distributed resources. These topics will be covered in greater detail in two upcoming webinars on July 14 and August 11. Slides 35: Wheeling and integration costs will be included similar to previous IRPs. Slides 44: We do not anticipate transmission to go unused because transmission can be redirected for short or long-term transmission usage elsewhere on BPA's system. Only the transmission on the Colstrip Transmission System is included in the Unit 4 sale. Slides 45-46: A transmission wheel will be needed on BPA's system from the Boardman site to PSE's system. Slide 50: PSE is only modeling the transmission constraints listed in the slides. PSE's responses concerning additional questions: 1. Thank you for the recommendation. To clarify, the Tier system is intended to provide sensitivity analysis on various possible transmission outcomes. PSE devised the Tier system as a means of exploring transmission uncertainty. During internal discussions, PSE established there were two possible methods of modeling that uncertainty, Option 1 - discreet sensitivity analyses or Option 2 - tying uncertainty to a specific timeframe, given that more transmission may be acquired as more time and effort is expended. PSE thought both these methods seemed a valid exploration of transmission uncertainty and therefore asked stakeholders to provide their perspective. 2. Thank you for your suggestion, PSE is weighing feedback received by all stakeholders and will provide a final determination of our modeling approach in the July 21 Consultation Update. 3. PSE appreciates that the WUTC supports the presentation of transmission capacity by percentage of nameplate and are looking forward to the results. 4. All feedback forms received before the presentation are included in this feedback report. PSE reviews feedback reports prior to the meeting and where possible, PSE revises the presentation of the material based on the feedback received prior to the meeting, where feasible. Pre-presentation feedback opportunities help inform PSE of stakeholder questions and feedback and provide more time for stakeholders to ask questions and have the questions addressed.