NW Energy Coalition
for a clean and affordable energy future

February 5, 2021

Mark Johnson, Executive Director/Secretary
Washington Utilities and Transportation Commission
1300 S. Evergreen Park Dr. S.W., P.O. Box 47250
Olympia, Washington 98504-7250

Re: Puget Sound Energy 2021 Draft Integrated Resource Plans for Electricity and Natural Gas, **Dockets UE-200304** (electricity) and **UG-200305** (natural gas)

Mr. Johnson;

The NW Energy Coalition ("NWEC" or "Coalition") appreciates the opportunity to comment on the draft Integrated Resource Plan ("IRP") submitted by Puget Sound Energy ("PSE") on January 4th, 2021, as provided by the Notice of Opportunity to File Written Comments issued January 5th.

The Coalition is an alliance of more than 100 organizations united around energy efficiency, renewable energy, fish and wildlife preservation and restoration in the Columbia basin, low-income and consumer protections, and informed public involvement in building a clean and affordable energy future.

Overall Comments:

The Coalition notes that the submitted draft is an improvement over both the December 15th version and the previous draft, but still needs substantial improvement. The deterministic analysis available so far in the incomplete IRP provides initial data; but does not grapple with the essential choices that PSE must make in this IRP cycle. If the deficiencies in the draft are not addressed, we would hope the Commission would direct PSE to correct remaining deficiencies before acknowledging the final IRP.

The Coalition is only able to offer preliminary comments at this time, since the submitted draft IRP is an incomplete document. Because this draft lacks significant details, including a comprehensive sensitivity and scenario analysis, market reliance analysis, stochastic analysis, avoided costs and other important analyses, as well as the associated detailed appendices that stakeholders need to fully respond to the IRP, the commission should allow for appropriate time for stakeholder review of and comment on these pieces of the IRP as they become available.

Further, some crucial data, such as the demand forecast, was not made available until late in the process. Adequate descriptions of the assumptions, costs, methodologies and calculations, such as for how the Social Cost of Greenhouse Gas (SCGHG) was actually administered in the modeling, are still lacking. We will extend our comments as needed, as missing details and analysis are provided.

This situation raises serious concerns about the development of the Clean Energy Implementation Plan (CEIP) which is due by October 1st of this year, with final adoption by the end of this year and actual implementation beginning in 2022. The development of detailed, specific and intentional CEIPs is a new requirement added by the Clean Energy Transformation Act (CETA) along with the expanded scope of the integrated resource planning process (RCW 19.280.030) and the addition of a new analysis, the 10-year Clean Energy Action Plan ("CEAP"). The utilities must soon prepare their first CEIPs under CETA. It is extremely important that the IRP/CEAP be technically correct and thorough, since it "informs" the CEIP. The specific actions the utility plans to undertake as described in the CEIP per 19.405.060(1)(b)(i) and (iii) are intended to be informed and consistent with the IRP. A weak IRP/CEAP must not be used as a means to limit the utilities' attainment of CETA standards in their CEIP. A CEIP based on an insufficient IRP/CEPA analysis that fails to create a path towards meeting the 2030 standards will not be acceptable.

> *(b) An investor-owned utility's clean energy implementation plan must:*
> *(i)* ***Be informed by the investor-owned utility's clean energy action plan developed under RCW 19.280.030;***
> *(iii) Identify specific actions to be taken by the investor-owned utility over the next four years,* ***consistent with the utility's long-range integrated resource plan*** *and resource adequacy requirements****, that demonstrate progress toward meeting the standards under sections 4(1) and 5(1) of this act and the interim targets proposed under (a)(i) of this subsection.*** *The specific actions identified must be informed by the investor-owned utility's historic performance under median water conditions and resource capability and by the investor-owned utility's participation in centralized markets. In identifying specific actions in its clean energy implementation plan, the investor-owned utility may also take into consideration any significant and unplanned loss or addition of load it experiences.*
>
> *19.405.060(1)(a) By January 1, 2022, and every four years thereafter, each investor-owned utility must develop and* ***submit to the commission:***
> ***(i) A four-year clean energy implementation plan for the standards established under sections 4(1) and 5(1) of this act*** *that proposes specific targets for energy efficiency, demand response, and renewable energy; and*
> *(ii) Proposed interim targets for meeting the standard under section 4(1) of this act during the years prior to 2030 and between 2030 and 2045.*

It is important that the utilities get it right from the start.

The Coalition is disappointed by the approach all three IOUs appear to have taken this planning cycle. Even though the rules were not adopted until late December 2020, the intent of the statute and the shape of the rules was clear much earlier. The commission even granted waivers for the 2019 IRPs, converting them to progress reports, so the utilities could turn their attention to developing the 2021 IRPs that would comply with CETA. Despite the transformative nature of CETA, it is evident that utilities have not changed their approach to planning.

1. **The standard for integrated resource planning has changed.**

Unlike previous planning cycles, CETA unequivocally established standards for 2030 and 2045. The approach to integrated resource planning and resource acquisition planning should have changed accordingly. IRPs are no longer simply analyzing lowest reasonable cost alternatives, but lowest reasonable cost alternative *pathways that lead to achieving the 2030 and 2045 standards*. That is the analysis needed to provide the data and context for specific targets and actions in the CEIP.

CETA's intent is to transform the electric system - it requires a utility to: (1) eliminate coal fired resources from a utility's allocation of electricity by the end of 2025; (2) achieve cost-effective conservation and efficiency to reduce load; (3) reduce demand as much as possible with demand response actions; and (4) use electricity from renewables and non-emitting generation to serve 80% of the remaining retail load by 2030, and 100% by 2045[1].

Nonetheless, it seems the utilities so far have pursued traditional lowest reasonable cost planning, then added the conservation and resources requirements of CETA i as a supplemental compliance obligation to be addressed after the "real" planning was complete.

2. **PSE has failed to demonstrate how it plans to meet the 2030 standard.**

This first round of IRPs under CETA should be clearly focused on how to reach the goals, not how to approximate the standards or to reach a utility's own vision of "carbon neutrality", while ignoring the statutory requirements.

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[1]*19.405.030 (1)(a) On or before December 31, 2025, each electric utility must* ***eliminate coal-fired resources from its allocation of electricity****. This does not include costs associated with decommissioning and remediation of these facilities.*

19.405.040(1)(a) For the four-year compliance period beginning January 1, 2030, and for each multiyear compliance period thereafter through December 31, 2044, an electric utility must demonstrate its compliance with this standard using a combination of non-emitting electric generation and electricity from renewable resources, or alternative compliance options, as provided in this section. ***To achieve compliance with this standard, an electric utility must: (i) Pursue all cost-effective, reliable, and feasible conservation and efficiency resources to reduce or manage retail electric load, using the methodology established in RCW 19.285.040, if applicable; and (ii) use electricity from renewable resources and non-emitting electric generation in an amount equal to one hundred percent of the utility's retail electric loads over each multiyear compliance period.***

19.405.050 (1) It is the policy of the state that non-emitting electric generation and electricity from renewable resources supply one hundred percent of all sales of electricity to Washington retail electric customers by January 1, 2045. By January 1, 2045, and each year thereafter, each electric utility ***must demonstrate its compliance with this standard using a combination of non-emitting electric generation and electricity from renewable resources.***

For example, the draft IRP states PSE will meet the 2030 standards by reducing carbon by over 70% and relying on energy transformation projects to "achieve carbon neutrality"[1]. This statement does not assure the statutory standards will be met by 2030. While greenhouse gas reduction is an important policy objective, the CETA statutory standard specifically requires the use of clean energy resources within the state, not simply reducing emissions. PSE clearly understands the standard, as stated on page 1-8 at the end of the first paragraph:

> *CETA requires that the 2030 electric supply be carbon neutral, s****uch that at least 80 percent of Washington state electric sales (delivered load) are met by non-emitting or renewable resources by 2030, and 100 percent of sales must be met with renewable or non- emitting electricity by 2045.***

We expect the first planning process under CETA to analyze the various paths to reach the CETA standards, not simply accommodate those standards if they fit within the old planning paradigm.

The Key Outcomes for the 2021 PSE IRP

The PSE 2021 IRP has two high priority tasks:

- First, to set a new direction in electric system planning in accordance with the policy direction and compliance requirements of CETA. Both the policy and compliance aspects are important.

- Second, to address system needs after the conclusion of 750 MW of coal plant service to PSE customers by the end of 2025, as required by CETA.

The draft IRP falls significantly short of the mark for both tasks. We address the major shortcomings below in two sections focusing on the overall IRP and the 2027 preferred resource portfolio.

Parts of the preferred portfolio in the draft IRP are commendable or at least acceptable. The draft portfolio proposes the acquisition of new renewable resources up to the limit of existing transmission constraints. Energy efficiency and other demand side resources are given a significant role, although we believe further refinement will show increased availability. The IRP shows the company's openness to new resources including battery storage and various forms of demand response -- although we will demonstrate below that the positioning of DR in the draft portfolio is far below its true potential.

But even with these positive aspects, the key question emerging from the draft IRP is whether the addition of 948 MW of new natural gas-powered combustion turbines is the only way to keep the lights on after meeting the minimum compliance requirements for CETA. We believe a reanalysis will show that there are substantial available and cost-effective clean energy resources, potentially supplemented by existing thermal resources for long-duration peak needs, that can defer or eliminate this vast expansion of the gas fleet.

The challenge before the company is to change course and file a final IRP on April 1 that lays the groundwork for a fully responsive and effective initial Clean Energy Implementation Plan filing in the fall of 2021.

<u>Cross-Cutting Issues for CETA Policy and Compliance</u>

A. Natural Gas Resource Risk

The continuation in the draft IRP of all existing gas resources and acquisition of four new large natural gas power plant units in the years 2026, 2032, 2039 and 2043 defies the clear policy direction of CETA to decrease, rather than increase, dependence on fossil fuel resources. Even if the gas fleet as a whole operates at a lower annual capacity factor over time, an increase of nearly 1000 MW of peak gas use would pose both reliability and cost concerns. Recent episodes including the Enbridge pipeline explosion in October 2018, ongoing restrictions in pipeline delivery and Jackson Prairie storage through the spring of 2019, and more recently maintenance problems on the Williams pipeline through the Columbia Gorge in the fall of 2020, highlight the tenuous situation for the existing gas supply, creating concerns around any proposals for new peakers.

Using the draft IRP's combined capital cost for a frame peaker, the first 237 MW unit in 2026 would have an initial cost of about $215 million, with large additional ongoing costs for fixed and variable O&M including fuel cost. The question left unanswered by the draft IRP is whether a better and cheaper mix of clean resources could meet actual peak system needs. We will return to this point below.

B. Market Reliance

The draft IRP assumes continued reliance on 1500 MW of market purchases, but defers the market analysis to the final IRP. Without that analysis, it is not possible to assess market risk, but we make the following observations.

PSE is unique among Northwest utilities in its overreliance on the short-term market, and customers paid a significant price for that as a result of the February-March 2019 price break during a very cold period with diminished gas deliverability.

The draft IRP basically brushes this issue off. But a recent PacifiCorp presentation in an IRP workshop shows that the transaction volume for the Mid-C trading hub has basically fallen in half over the last five years. There is some evidence that much of the decline is the result of transactions moving to the Energy Imbalance Market which is more liquid and has a favorable real-time pricing regime compared to the outmoded high load hour/low load hour Mid-C construct.

PSE itself is a full participant in the EIM. But the EIM does not address the need for day ahead and operating hour unit commitment and dispatch, and so increased cost and reliability risk from PSE's already overexposed market position will only become greater as more of the Northwest coal fleet retires and other system changes occur. While it is conceivable that the Enhanced Day Ahead Market expansion of the EIM will soon occur, providing much deeper and more liquid market access, we conclude that PSE's current market exposure is increasingly risky. However, we are also confident that clean energy resources can help reduce market exposure.

C. Social Cost of Greenhouse Gases (SCGHG)

The Coalition is also very concerned by possible modeling assumptions that may have contributed to the low forecasts of conservation and demand response. However, the incomplete material presented so far makes it impossible to determine if that is so.

Among the scenarios the Coalition and others specifically and repeatedly requested was one in which the social cost of greenhouse gases (SCGHG), a variable cost, be applied to each incremental ton of emissions from fossil fueled resources dispatched in the modeling process and applied to fossil fueled electricity brought into the state. The reason we asked for that is to evaluate how other resources, such as DR, conservation and other demand side measures, would be selected against thermal plants. The point of including SCGHG as a requirement in CETA was to level the playing field between resources. That analysis has not been submitted, so we cannot compare to the analysis that was completed. We suspect that adding the SCGHG to the capital costs of thermal units tamped down the values of other resources, since not a single thermal unit is retired in the preferred resource for economic reasons.

D. Upstream Methane Emissions

An issue linked to the application of SCGHG is the life cycle emissions for gas power plants. As we explained in a workshop submission, the upstream methane emissions factor assumed in the draft IRP for the vast majority of PSE's gas supply, which comes from British Columbia and Alberta, is based on desk calculations two decades ago by the Canadian gas industry.

More recent peer reviewed research including both field observations and assessment of compliance filings by gas producers indicates that the likely value is much higher. The authoritative research coordinated by EDF indicates the US emissions factor is at least three times the Canadian value. There is no indication that regulation of Canadian gas production is more stringent than in the US; in fact, emissions data from abandoned wells indicates it may be less.

Because a tripling of the upstream methane emissions factor would substantially increase the effective SCGHG for existing and new gas power plants, this issue must be reassessed for the final IRP.

E. Flexible Capacity = New Natural Gas Plants

PSE claims at numerous points in the draft IRP that only new combustion turbines can meet peak capacity needs beyond available clean resources during high load periods, especially in cold weather conditions when renewable generation is limited. We discuss this in detail in the next section.

But PSE also claims that such capacity can be provided by “alternative fuel enabled combustion turbines.” In reality, at this point no such claim can be sustained. NWEC fully supports responsible efforts to develop renewable natural gas and renewable hydrogen resources, and we applaud PSE for its early and active support.

But the draft IRP notes, “Because of RNG’s significantly higher cost, the very limited availability of sources and the unique nature of each individual project, RNG is not suitable for hypothetical analysis.” (Draft IRP at 4-13.) Similarly, it will take considerable time to bring the price of renewable hydrogen to acceptable levels for power plant use, since “our region is not expected to have a surplus of baseload renewable energy any time soon.” (Draft IRP at 4-15.) Labeling the proposed new resources as “alternative fuel enabled” flexible capacity avoids the fact that the fuel source is likely to continue being natural gas. Yet, the term “natural gas power plant” does not appear in the draft IRP.

The conclusion therefore is that in the 2021 IRP, new combustion turbine flexible capacity must be assumed to rely on natural gas fuel, and the full SCGHG including a more appropriate upstream methane emissions factor must be applied.

<u>2027 Preferred Resource Portfolio</u>

While coal power must no longer be used to serve PSE customers after 2025, the draft IRP poses the analysis with reference to 2027 rather than 2026.

Figure 3-2: Draft Preferred Portfolio Meeting Electric Peak Capacity

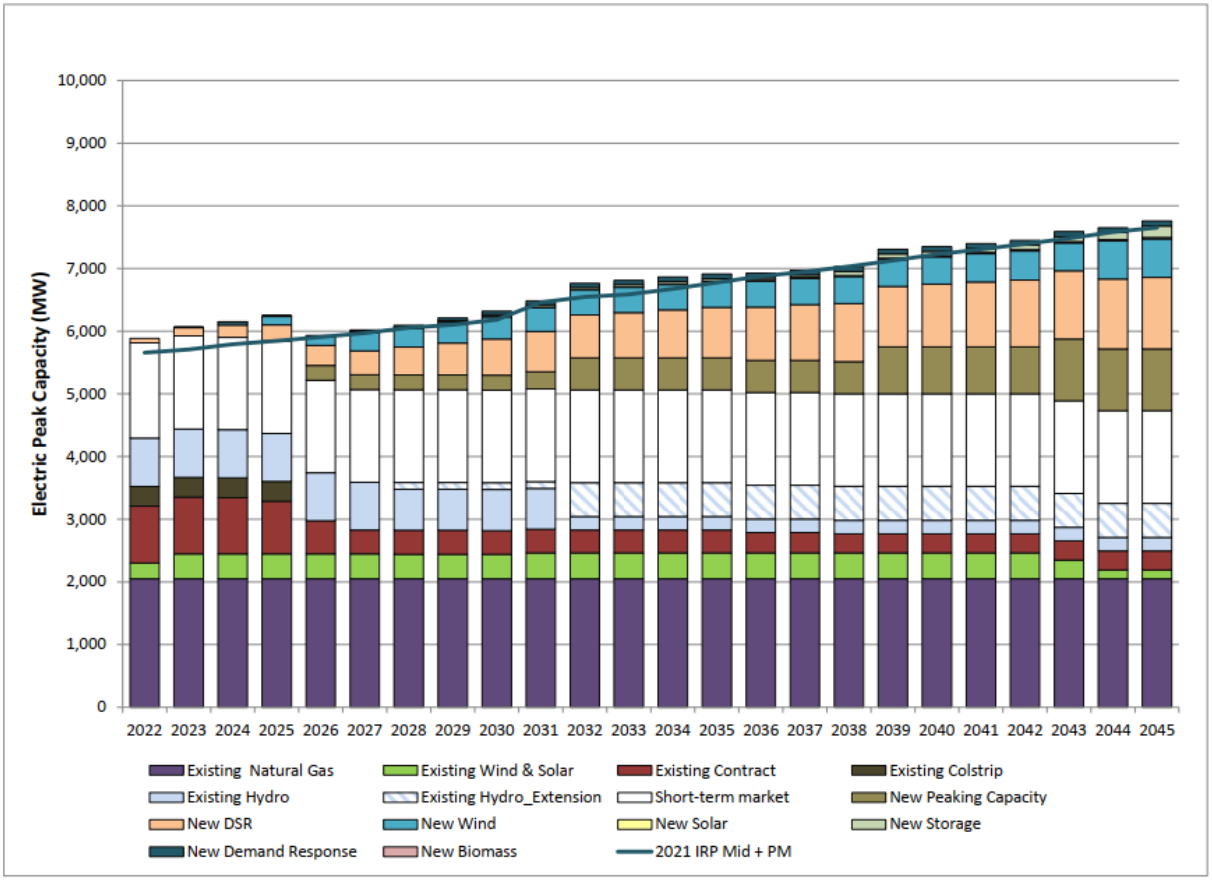


Figure 3-1: Electric Preferred Portfolio, Cumulative Nameplate Capacity of Resource Additions

Resource Additions (MW)	2022-2025	2026-2030	2031-2045	Total
Distributed Energy Resources				
Demand-side Resources	256 MW	360 MW	1,168 MW	1,784 MW
Battery Energy Storage	75 MW	125 MW	550 MW	750 MW
Solar - ground and rooftop	80 MW	150 MW	450 MW	680 MW
Demand Response	10 MW	161 MW	44 MW	215 MW
DSP Non-Wire Alternatives	22 MW	24 MW	72 MW	118 MW
Total DER	443 MW	820 MW	2,284 MW	3,547 MW
Renewable Resources	600 MW	1,100 MW	2,762 MW	4,462 MW
Flexible Capacity	0 MW	237 MW	711 MW	948 MW

In 2027, the draft IRP indicates a need for 527 MW of capacity after inclusion of existing resources and new demand side resources. The draft proposes to fill this gap with 1100 MW of new wind, a small amount (around 20 MW) of demand response, and a 237 MW natural gas peaking plant (combustion turbine). These are estimates based on Figure 3-2, because the IRP only provides specific data for new resource additions in multi-year blocks, not annual values (Figure 3.1).

As we note in the following discussion, the 2027 resource additions do not provide a balanced new resource portfolio. In particular, the need for a new gas peaker is considerably in doubt.

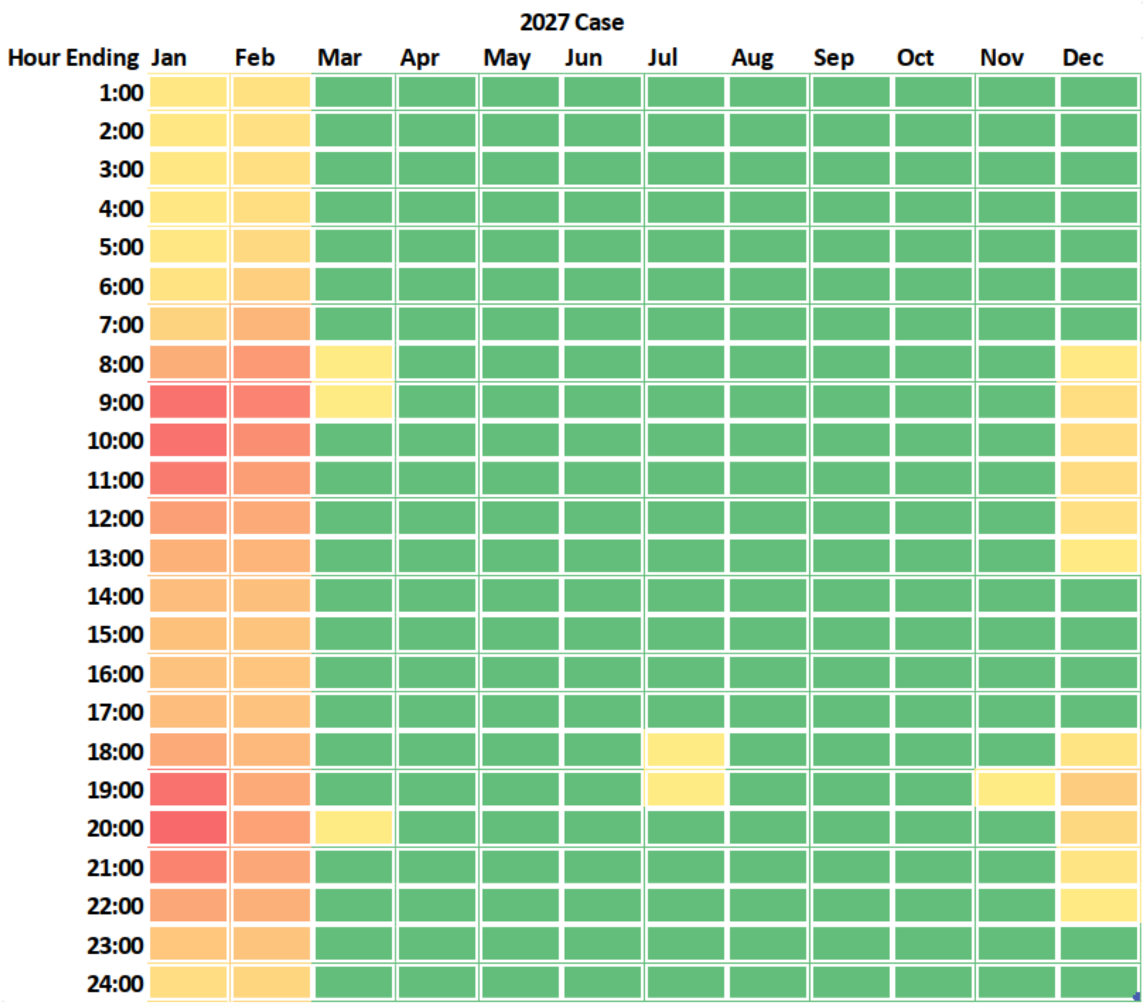
A. Two Types of Capacity Need

The pivotal point to understand about the period after the 2025 coal retirements is that there are basically two types of capacity need. We refer to these as typical and long-duration peak periods. A typical peak period is that observed in most years, where demand peaks within a range described by the median or "1-in-2" demand forecast.

Once or more per decade, a long-duration peak condition may occur, with extended high daily peaks that may recur for two or more consecutive days, as reflected in a "1-in-10" forecast and tested for in a 5% LOLP analysis. These conditions may occur during very cold "Arctic express" periods where demand is very high on a sustained level and renewable energy production is low. In such conditions, the entire Northwest will be energy limited, market supply will be very expensive and perhaps restricted, and gas supply from Canadian sources and storage withdrawals may also be constrained.

Figure 3-14 illustrates the challenge, showing stress conditions based on peak load duration in 2027. These conditions do not occur year-round, but almost entirely in the mid-winter quarter from December to February.

Figure 3-14: Loss of Load Hours for 2027



The draft IRP proposes to fill the 2027 gap with peak-oriented renewable resources -- primarily Montana wind, providing CETA-compliant clean energy up to the limit of available transmission -- a small amount of demand response, and a new 237 MW natural gas peaker plant. The question we pose is whether a staged approach to capacity need could provide a new balanced 2027 resource portfolio that is better aligned with CETA policy guidance while meeting reliability needs cost-effectively:

Stage 1: The first stage involves maximizing the availability of so-called “energy limited” clean flexible resources, including demand response and storage. These are generally considered to provide capacity value of 4 hours duration and should suffice for meeting needs during typical peak periods.

Stage 2: In the second stage, meeting rare long-duration peaks requires supplemental resources. The draft IRP suggests that only new peakers can meet these supplemental needs. But once these very expensive and high-emitting new peakers are put into the resource mix, the IRP models will dispatch them not only for very infrequent long duration high peaks, but much more often across the year because they are now "existing" resources. As a result, these new peakers will displace less expensive, non-emitting resources. This creates a lost opportunity for CETA compliant clean energy resources.

Below, we first examine the additional potential for clean flexible resources including demand response, storage and hybrids to meet typical peaks.

Then, we suggest other alternatives for supplemental long-duration peak capacity, including cleaner imports and in-region existing gas.

B. Demand Response

The Conservation Potential Assessment (CPA) prepared by PSE's consultant Cadmus includes estimates for the technically available potential of demand response. Our review of the CPA and the draft IRP preferred portfolio indicates the likelihood that the potential for cost-effective DR is substantially underestimated.

An overall rule-of-thumb estimate for DR potential, based on detailed assessment and actual program achievement elsewhere, is that 10% of peak demand reduction is achievable in about a decade. As applied to PSE, that would amount to 500 MW of winter peak DR.

The Northwest Power and Conservation Council draft DR inputs for the 2021 Northwest Power Plan were also prepared with assistance from Cadmus. The Council indicates that about 1800 MW of winter peak DR is available by 2027, or about 5.5% of regional peak demand. PSE has about 15% of Northwest peak demand, so a proportional share would be 280 MW of winter DR.

Portland General Electric's 2019 IRP includes 141 MW of winter DR by 2025 (about 3.5% of peak) and 210 MW of summer DR (5.2% of peak). PGE's new Flexible Load Plan lays the groundwork for increasing those targets going forward.

By comparison, the PSE draft IRP preferred portfolio includes 226 MW of DR by 2045, or about 4.5% of winter peak, and only about 20 MW by 2027, or less than 0.5%.

A clear example of the shortfall is the assumptions regarding residential grid-enabled water heaters. The CPA estimates total availability of 58 MW by 2045 at a levelized cost of $81/kW-year, well below the cost of a new natural gas peaker. (IRP Appendix E, Table 43.)

A very simplified analysis shows far higher potential on a much faster timeline. We assume only the current fleet of about 500,000 electric water heaters, not including water heaters for new construction or gas-to-electric conversions. For simplicity, we also assume only electric resistance water heater replacements, setting aside the more efficient and greater peak reducing heat pump water heaters.

> ***Example:*** *Given an average lifetime of about 12.5 years, 40,000 water heaters will be replaced each year. With a 4.5 kW heating element and a duty cycle of about 11%, the average coincident peak reduction per unit is about 0.5 kW. Thus, 40,000 new grid-enabled water heaters per year, with the CTA-2045 communications port required by the Washington appliance code, plus an additional communications device, will provide a technical achievable potential of 20 MW per year, or a total of 100 MW by 2027. This single measure amounts to more than 40% of a new 237 MW gas peaker at a much lower cost.*

C. Storage and Hybrid Resources

The draft IRP examines battery storage in some detail, but results in disappointingly small proportions of new storage resources. We will provide a more detailed review in comments on the final IRP.

While about 150 MW of behind-the-meter battery storage is included in the 2027 portfolio (estimating from Figure 3.1), no grid-connected storage or hybrid resources are included in the draft IRP. This is surprising given the rapid emergence of hybrid resources around the nation and in the Northwest. A leading example is PGE's acquisition of a large portion of the NextEra Wheatridge project, an innovative three-way hybrid of wind, solar and storage.

In addition, with regard to PacifiCorp's current all-source RFP, it is widely expected that solar+battery hybrids will be selected for half or more of the total acquisition, which could be more than 2000 MW of solar capacity and over 1000 MW of battery storage.

A recent study by Astrape Consulting for Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric found a substantial increase in ELCC value for Northwest wind hybrid resources.

Table A2. ELCC Values for 2026 (expressed as a percentage of assumed interconnection capability)

Region	BTM PV	Fixed PV	Tracking PV	Tracking PV Hybrid	Wind	Wind Hybrid
CA-N	1.3%	2.1%	3.4%	100%	17.9%	94%
CA-S	0.6%	1.2%	1.9%	100%	17.8%	95%
AZ APS	N/A	~0.0%	1.9%	97%	30.8%	97%
NM EPE	N/A	~0.0%	1.9%	95%	30.8%	97%
BPA	N/A	N/A	N/A	N/A	32.8%	90%
CAISO	**1.0%**	**1.7%**	**2.7%**	**100%**	**17.9%**	**94%**
Average	**1.0%**	**0.8%**	**2.3%**	**98%**	**26.0%**	**95%**

While these values are based on California ISO summer peak and wind in the BPA Balancing Area, primarily "Gorge wind" with a low summer capacity factor, the effect of battery availability to shift energy to peak periods is clear – from 32.8% to 90%.

Re-examining hybrid potential is especially important for PSE given the heavy reliance of the draft preferred portfolio on Montana and Wyoming wind. With limited available transmission and high winter peak needs, hybrid wind+battery or wind and associated pumped storage could provide significant additional peak capacity.

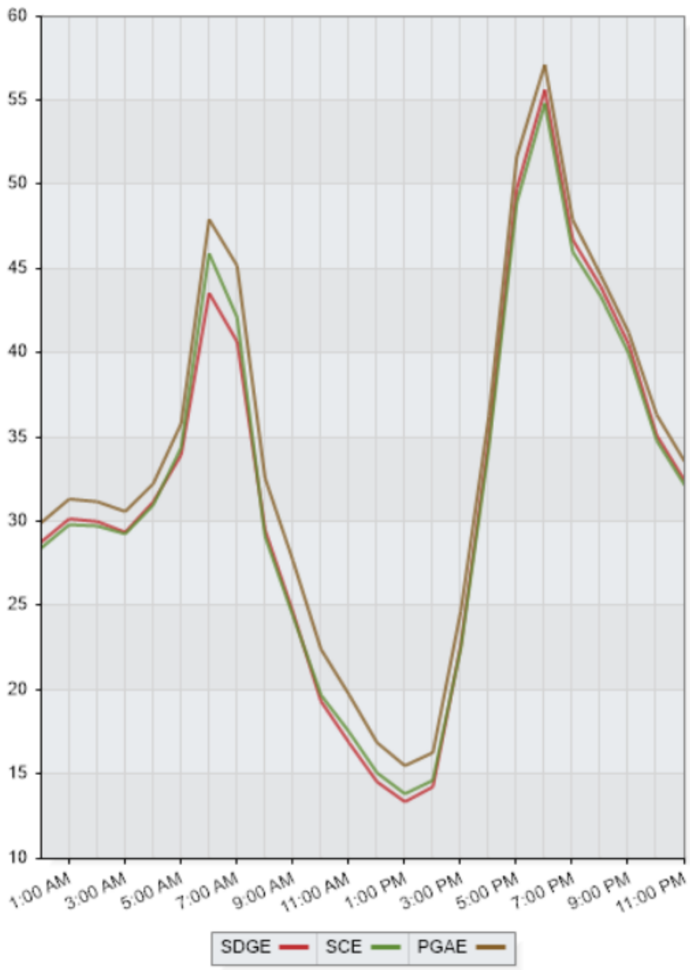
D. Capacity Imports

The PSE draft IRP does not examine the potential for peak capacity or power imports from California. The winter is a period of low demand in California and substantial surplus power is available at very low prices.

For example, on Feb. 3, California ISO day-ahead market prices averaged less than $20/MWh between 10 am and 3 pm. In addition to substantial standby gas capacity, mid-day solar is often curtailed during the winter, providing another source of very cheap and clean energy. In the past week over 2,000 MWh/day of solar was curtailed in CAISO for economic reasons. PSE should study the potential for acquiring California winter surplus to meet winter peak needs. The exact form of such purchases requires considering a range of term offers, but we provide a back-of-the-envelope example.

> ***Example:*** Assume 250 MW of firm energy for 100 midwinter on-peak hours delivered from California for $100/MWh including transmission wheeling charges. That amounts to $2.5 million per year. With the availability of sufficient flexible load and storage resources, instead of buying on peak hours, California surplus could be acquired in the very low-cost mid-day period with a much higher renewable energy content. All this suggests that imports could be far cheaper than a new gas peaker.

CAISO (California ISO)
Day-Ahead Price



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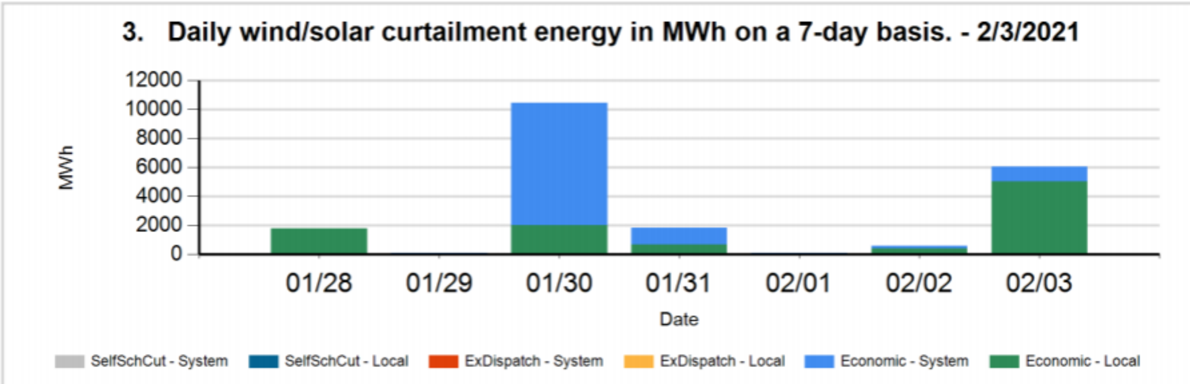

http://www.caiso.com/Documents/Wind_SolarReal-TimeDispatchCurtailmentReportFeb03_2021.pdf

E. Existing Gas Power Plants

A final possibility for supplemental peak capacity is existing merchant gas power plants with proximity to PSE's system. The Grays Harbor Energy Center is a good example, and there are others. Securing a peak capacity contract with right balance between price and contract terms for both parties will take some effort. NWEC does not support overbuying of merchant gas, and prefers that all clean options be considered first. But surely this is a better choice than building a new gas peaker plant.

Conclusion

The Coalition acknowledges that a great deal of time and work has gone into the preparation of the draft IRP. Yet at this point, the draft is incomplete and deficient on a number of key issues that could impact the successful implementation of Washington's clean energy policies. The key question for the final IRP preparation is whether increased conservation and demand response can provide a more affordable and achievable pathway to meeting PSE's compliance obligation under CETA, and whether projected peak capacity shortfalls can be met with cleaner, more flexible measures than building new gas peakers that will only be used a very small percentage of the time.

Without further analysis of these issues, we are concerned that this IRP may not be relied upon to inform the development of PSE's first CEIP.

We look forward to expanding our comments when the rest of the IRP information is made available.

Respectfully,

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