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: Avista 2021 Draft Integrated Resource Plans for Electricity and Natural Gas
Dockets UE-200301 (electricity) and UG-190724 (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 Avista Utilties on January 4th, 2021, per the Notice of Opportunity to File Written Comments issued by the Commission on January 5th, 2021.

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.

The Coalition notes Avista's timely submission of a draft integrated resource plan (IRP) in compliance with the schedule established by the Commission. We hope our comments will be useful in revising the IRP for its final submission. 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. Shortcomings in an 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.

Our comments address both the overall context for planning and specifics issues in the IRP.

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 1 to serve 80% of the remaining retail load by 2030, and 100% by 2045.

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.

Avista's explanation for the Clean Energy Targets table (CEAP p. 15-4, table 15-2) indicates that may be the case in the CEAP. Avista raises the strawman that "use" of electricity from renewable and non-emitting sources means "minute-by-minute tracking" of electrons. That is not the case. While the rules regarding "use" are still being developed, the language of the statute is clear. As Avista states in the introduction to the CEAP "this Action Plan is subject to change prior to the April 1, 2021 IRP filing date to account for potential renewable resource acquisitions from the 2020 Renewable FRP and as final CETA rules by the Washington Utility and Transportation Commission (WUTC) are issued". An IRP should analyze the various pathways to meet the standards as set out in statute.

For example, using the data from that chart for a quick "back of the envelope" calculation, it appears likely that Avista could meet the 2030 compliance standards for using electricity from renewables and non-emitting to meet the 80% standard. Using the data in WA Clean Energy Targets table 15.2, adjusting the net retail load of 641 aMW in 2030 to 80% amounts to 512.8 aMW. Most of that can be met with the 436 aMW from the renewable resources Avista already owns. The shortfall of 76.8 aMW can be met with a little more than half of the planned 144 aMW from Montana wind. The 20% portion of retail sales, or 128.2 aMW, could be met with various other resources listed on that chart.

Key Outcomes for the 2021 Avista IRP

The Avista 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 222 MW of coal plant service to Avista customers by the end of 2025, as required by CETA, and other system changes, especially the termination of the Lancaster 257 MW natural gas contract in 2026.

Recognizing that the draft IRP takes significant steps in the right direction, NWEC believes additional improvements can be made for both tasks. We address these questions below in two sections focusing on the overall IRP and the 2027 preferred resource portfolio.

While the draft IRP is not fully complete, Avista has presented a clear and detailed analysis, provided work products and responded to stakeholder questions. The preferred portfolio continues to develop energy efficiency and begins to lay out a strategy for acquiring demand response resources, although we believe the targets can be increased and the pace can be accelerated. The treatment of new renewable resources is somewhat more mixed, as described below. Finally, significant improvement is needed for both the cost and capacity value battery and pumped storage.

We also give special commendation to Avista's Energy Equity analysis in chapter 13. This is a strong first step in assessing energy burden and service quality across Avista's Washington service territory, especially for vulnerable populations and highly impacted communities. Avista's work is already setting a standard for utilities across the Northwest. We look forward to further enhancements, including assessment of whether services and programs for customer side resources like energy efficiency, demand response, distributed generation and electric vehicle support are equitably available.

All that said, a significant question still should be addressed. While the draft IRP anticipates retirement of Colstrip coal as early as 2021 and Lancaster gas in 2026, we are concerned about the addition of 211 MW of new gas peaking capacity in 2027 to help address the gap. A new peaker unit of that size would have a capital cost above $200 million, with additional fixed and variable O&M including fuel cost, and would continue in operation for many years. We believe further analysis will show that there are substantial available and cost-effective clean energy resources that can defer or eliminate this new emitting resource.

Cross-Cutting Issues for CETA Policy and Compliance

A. Natural Gas Resource Risk

Even if the Avista gas fleet as a whole operates at a lower annual capacity factor over time, continued additions of new gas capacity resources could pose both reliability and cost concerns. Recent episodes including the BC 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 gas deliverability.

B. Market Reliance

We commend Avista for a thorough market analysis (chapter 10) and provide the following observations.

The price and availability risk in the short-term market (primarily the Mid-C trading hub) has been growing in recent years. Underlying recent price disturbance episodes, including very high prices in February-early March 2019 due to exceptionally cold weather and gas delivery constraints, there is an underlying structural change in the Northwest bilateral market with two key drivers.

First, 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. While EIM energy flows to load in an economically beneficial manner, the EIM cannot assist with day-ahead and operational unit commitment and dispatch.

Second, the retirement of Northwest coal resources and other changes is continuing to diminish market supply relative to demand. This poses increasing price and availability risk going forward.

Two other developments may counter the trend somewhat. For short term capacity, the proposed Northwest Power Pool resource adequacy program could alleviate peak risk both through advance commitments and an operational program. On the energy side, the Enhanced Day Ahead Market expansion of the EIM could move forward, providing much deeper and more liquid market access.

All that said, we conclude that the short-term market is increasingly risky, but we are also confident that enhanced development of clean energy resources can help reduce market exposure.

C. Social Cost of Greenhouse Gases (SCGHG)

The IRP analysis states "construction and operational greenhouse gas emissions are considered and priced using the SCC", but that the SCGHG was not applied to market purchases and sales in the PRS as done previously. The reason for the change from previous practice is not clear. The statute at 19.280.030(3)(a) states a utility must incorporate the SCGHG when evaluating and selecting conservation policies, programs and targets; when developing integrated resource plans and clean energy action plans; and when evaluating and selecting intermediate term and long-term resources. The SCGHG is a variable cost used in planning to internalize the costs of emitting CO2e. The SCGHG does not function as a tax that is passed through to customers. In the *modeling* process, for both the IRP and CEAP, the SCGHG should be applied to variable costs, dispatch modeling and unspecified or fossil fueled market purchases.

The impact of adding the SCGHG to market purchases is tested in portfolio #19 – SCC on Purchases/Sales Resource Selection (IRP p. 12-29). This results in relatively little impact relative to the PRS portfolio, except to select less solar. That result might well change if hybrid resources, such as solar+battery were assessed, instead of charging storage with market purchases.

Further, the Optimized SCGHG Carbon Future Portfolio shown in Table 12.24 not only improved costs over the PRS, reduced natural gas by 88MW and increased energy efficiency and wind. This option also reduced solar, but probably for the same storage charging reasons as in portfolio #19.

In the final IRP/CEAP Avista should model a portfolio in which the SCGHG is optimized as a variable cost and applied to unspecified and fossil fueled electricity brought in state for customer use. This portfolio should also include hybrid resources, as discussed later.

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 submission to the Northwest Power and Conservation Council,[1] recent peer-reviewed research has revised upstream methane emissions factors sharply upward. Because of the current and proposed new addition of natural gas generation, we urge Avista to revisit this issue and adjust the upstream methane emissions factor represented in the Social Cost of Greenhouse Gas analysis.

2027 Preferred Resource Portfolio

With the cessation of coal power supply after 2025 and the expiration of the Lancaster gas contract in 2026, the year 2027 is a useful point for evaluating system need and proposed new resources.

In 2027, the draft IRP indicates a need for 301 MW of capacity. The draft proposes to fill the gap with ongoing energy efficiency, the beginning of a demand response program, 200 MW of Montana wind, a 12 MW upgrade at Kettle Falls, and 211 MW of peaker resources (85 MW for Idaho and 126 MW for Washington/Idaho).

NWEC believes further review is needed on several categories of clean energy resources to see if they can provide additional capacity value and defer or eliminate the need for new peaker resources.

[1] NWEC letter to Northwest Power and Conservation Council, June 15, 2020, https://www.nwcouncil.org/sites/default/files/2020_0616_2.pdf

A. Two Types of Capacity Need

The pivotal point to understand about the period after 2026 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. In the winter, 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.

In the late summer, similar heat wave conditions may occur. The reduced availability of hydro peaking compared to winter stress conditions is an additional factor.

The question we pose is whether a staged approach to capacity need could provide a balanced 2027 resource portfolio that is better aligned with CETA policy guidance while meeting reliability needs cost-effectively.

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.

In the second stage, meeting rare long-duration peaks requires supplemental resources. The draft IRP suggests that 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.

Avista should investigate the availability of firm capacity or other term resources to meet infrequent long-duration event needs, for example from regional imports or merchant gas plants. As time goes on, those resources could be replaced with new long-duration storage from sources such as renewable hydrogen, renewable natural gas and pumped storage.

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

B. Demand Response

The Conservation Potential Assessment (CPA) includes estimates for the technically available potential of demand response, and the preferred portfolio includes initial steps toward achieving that potential.

The CPA summarizes the technically achievable potential for DR at 90 MW in 2025 (about 5.1% of peak load) and 170 MW in 2045 (almost 10% of peak). NWEC agrees that this is a reasonable magnitude for total potential, but we believe it can be achieved considerably faster.

The preferred portfolio indicates 53 MW of DR in 2027 (3% of peak) in 2027. We believe further assessment will show this amount can be increased.

For example, we estimate about 7 MW per year of technically achievable potential is available from one specific resource – stock turnover and conversion to grid enabled residential electric water heaters, or about 35 MW between now and 2027. In addition, new construction and gas-to-electric conversions could increase the potential. This resource is facilitated by Washington's incoming requirement for all new electric water heaters to have a CTA-2045 communications interface, providing a common access standard.

It remains to be seen what level of customer participation can be achieved for a grid enabled water heater program, but we anticipate that with effective customer engagement strategies it can be higher than the 50% saturation assumed by Avista and the savings potential of 48.9 MW by 2045 can be increased and significantly accelerated.

For demand response and load management as a whole, it is apparent that program launches can be moved forward considerably. In the Clean Energy Action Plan, Table 15.1 indicates that the first programs will appear in 2024, and the last in 2031. It would make more sense to launch a coordinated set of DR programs earlier so they can scale up rapidly to meet capacity need in 2027 and beyond. Portland General Electric has already succeeded in taking that path, including both coordinated pilot programs and the Smart Grid Testbed. Their new Flexible Load Plan lays out a strategy for moving DR to full maturity in the next 5 years.

Table 15.1: Demand Response and Load Management Programs

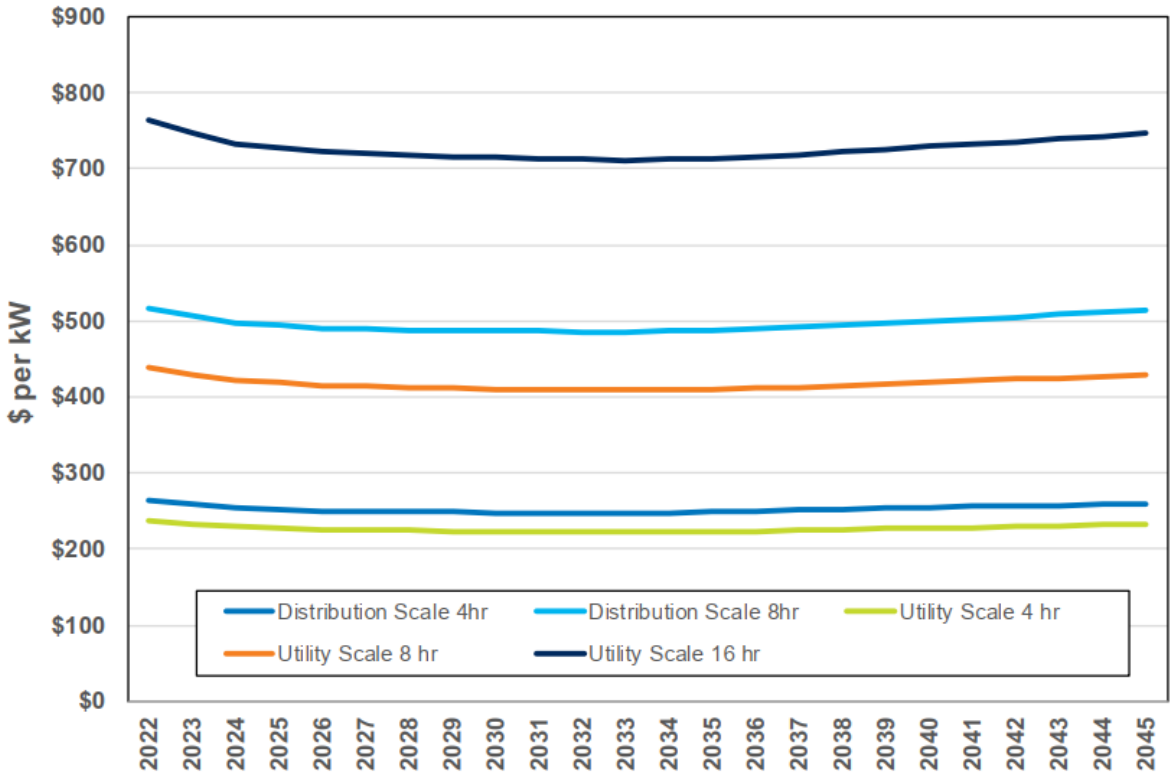
Program	Washington
Time of Use Rates	3.1 MW (2024)
Variable Peak Pricing	8.9 MW (2024)
Large C&I Program	25.0 MW (2027)
DLC Smart Thermostats	0.6 MW (2031)
Total	37.6 MW (2031 Total)

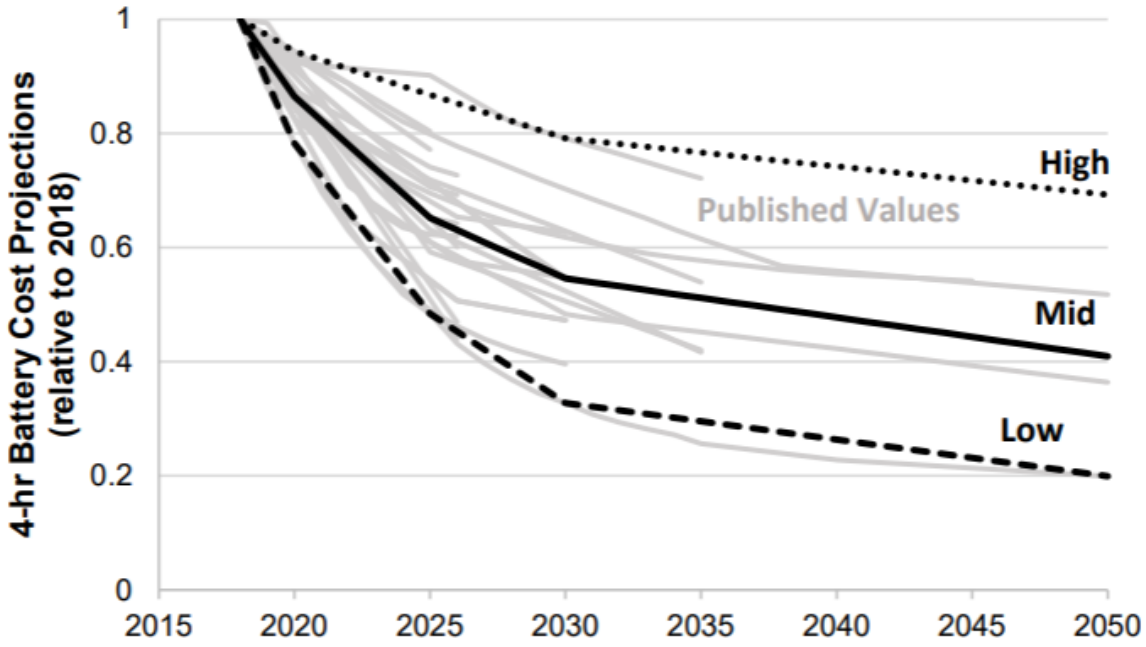
C. Storage Cost

NWEC believes that most of the reference resource costs in the draft RFP are in the reasonable range, though we may have different views on specific resources and future cost trajectories.

However, the future costs for batteries and pumped storage simply don't seem reasonable. The values in Figure 9.1 show slight declines in battery costs, and then flat or rising costs through the remainder of the planning horizon. Most other estimates show consistently declining costs through the coming decades, though at varying rates.

Figure 9.1: Lithium-ion Capital Cost Forecast





Cost Projections for Utility-Scale Battery Storage, National Renewable Energy Laboratory (2019). NREL/TP-6A20-73222, https://www.nrel.gov/docs/fy19osti/73222.pdf

Turning to pumped storage, the draft IRP states:

> With the exit of Colstrip and the expiration of the Lancaster PPA in the fall of 2026, the PRS adds 211 MW of natural gas-fired CTs. The 2020 IRP assumed the capacity lost from Colstrip and Lancaster could be met with long duration pumped hydro, but the updated cost and construction schedule information for pumped hydro caused this resource to not be selected in this IRP. This modeling result is consistent with a scenario analysis performed in the 2020 IRP showing natural gas CTs would be required if low cost long-duration pumped hydro was not available by 2026. Avista will continue to follow pumped hydro developments for future consideration.
> Draft IRP at 11-5.

Table 9.6, Pumped Hydro Company-Owned Options, provides a summary of costs, but NWEC does not fully understand the presentation and has not been able to pinpoint the underlying data for this conclusion. There are at least two pumped hydro projects with a reasonable chance of commercial operation by 2027, and further specific project assessment would be useful.

D. Storage and Hybrid Capacity Value

A notable aspect of the preferred portfolio is the lack of composite (hybrid) resources before 2038, when the first solar+battery resource appears.

The rapid emergence of hybrid resources around the nation and in the Northwest indicates the importance of composite resources to meet both energy and capacity needs. 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.

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, potentially amounting to 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 (BPA Balancing Area) wind hybrid resources. No value for solar hybrids was provided for the Northwest because of insufficient data, but the effect is expected to be similar.

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%**

The values in the Astrape analysis are not directly comparable because they are with reference to California ISO summer peak conditions. That said, the dramatic effect of battery availability to shift energy to peak periods is clear. Yet the draft IRP indicates only a 17% peak credit value for solar plus 4-hour battery resources and 15% for standalone 4-hour storage.

Table 9.12: Peak Credit

Resource	Peak Credit (percent)
Northwest solar	2
Northwest wind	5
Montana wind[10] 100-200 MW	35 to 28
Hydro w/ storage	60-100
Hydro run-of-river	31[11]
Storage 4 hr duration	15
Storage 8 hr duration	30
Storage 12 hr duration	58
Storage 16 hr duration	60
Storage 24 hr duration	65
Storage 40 hr duration	75
Storage 70 hr duration	90
Demand response	60
Solar + 4 hr Storage[12]	17
Solar + 2 hr Storage[13]	12

Whether the renewable resource is Montana wind with batteries or pumped storage shifting energy into the morning and evening peaks, or eastern Washington solar plus batteries shifting mid-day peak solar into late afternoon demand, NWEC views Table 9.12 as likely underestimating peak value. In addition, there is no value listed for wind + storage (either battery or pumped hydro), which is a clearly relevant use case.

As Avista proceeds towards the 2021 capacity RFP, we encourage revisiting this key issue. Hybrid resources could provide a significant capacity benefit and defer the need for new gas peakers, as well as make more effective use of limited available transmission capacity for renewables and provide more operating flexibility.

Conclusion

The Coalition appreciates the work that has gone into the preparation of this draft IRP. We look forward to collaborating on analyzing the changes we have suggested.

Respectfully,

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