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EXHIBIT: RJB-1T
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EXH. RJB-1T
DOCKET UE-230172
WITNESS: RONALD J. BINZ

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP, d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET UE-230172

DIRECT TESTIMONY AND EXHIBITS
OF RONALD J. BINZ

ON BEHALF OF
SIERRA CLUB

September 14, 2023

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I. INTRODUCTION, SUMMARY, AND RECOMMENDATIONS

Q: Please state your name, position, and address.

A: My name is Ronald J. Binz. I am a Principal with Public Policy Consulting, a firm specializing in energy policy and regulatory matters. I primarily provide regulatory consulting services to public-sector and private-sector clients in the energy and telecommunication industries. My business address is 333 Eudora Street, Denver, Colorado 80220-5721.

Q: On whose behalf are you testifying in this case?

A: I am testifying on behalf of Intervenor Sierra Club.

Q: Please discuss your relevant professional expertise and educational background.

A: I have been involved in energy regulation since 1979. From 1995 to 2006, and from 2011 to the present, I have served as a principal of Public Policy Consulting. My focus in recent years has been on performance-based regulation and energy regulatory policy, including integrated resource planning ("IRP"), fuel cost proceedings, clean technology, smart grid, and climate issues.

From 2007 to 2011, I was Chair of the Colorado Public Utilities Commission ("Colorado PUC"). In that capacity, I helped implement Colorado's vision for a "New Energy Economy" and its 30% Renewable Energy Portfolio Standard, participated in the Governor's Climate Action Plan, rewrote the Colorado PUC's IRP rules, and improved the Colorado PUC's operations. As Chair, I presided over implementation of the Colorado Clean Air-Clean Jobs Act, examining proposals of electric utilities to reduce pollutants from their fleets of coal fired power plants. I also presided over the modification and approval of an electric utility resource plan that involved the early closure of two coal power plants and added a substantial amount of new wind capacity and additional energy efficiency savings.

In addition to my experience as a commissioner, I have held a number of positions in the field of energy and utility regulation, with a focus on protecting consumer interests. From 1984 to 1995, I was first director of the Colorado Office of Consumer Counsel, Colorado's (new at the time) state-funded utility consumer advocate office. During my tenure, the office was a party to more than two hundred legal cases before the Colorado PUC, the Federal Energy Regulatory Commission ("FERC"), the Federal Communications Commission ("FCC"), and the courts. I negotiated rate settlement agreements with utilities, regularly testified before the Colorado General Assembly, and presented to professional business and consumer organizations on utility rate matters,

From 1996-2003, I served as President and Policy Director of the Competition Policy Institute, an independent non-profit organization based in Washington, D.C., advocating for state and federal policies to advance competition in the energy and telecommunications markets for consumers' benefit.

From July 2011 to July 2013, I was Senior Policy Advisor at the Center for the New Energy Economy ("CNEE") at Colorado State University. Founded by former Colorado Governor Bill Ritter, CNEE assists policymakers, governors, regulators, and other decision-makers in developing roadmaps to accelerate the nationwide development of a new energy economy.

Since the start of my career in 1979, I have participated in more than 150 regulatory proceedings before FERC, the FCC, the U.S. Supreme Court, the Eighth Circuit, Tenth Circuit, and D.C. Circuit Courts of Appeal, state and federal district courts, and state regulatory commissions in California, Colorado, Georgia, Hawai'i, Idaho, Maine, Massachusetts, Missouri, Montana, New York, North Dakota, Rhode Island, North Carolina, South Carolina, Texas, Utah, Washington, Wyoming, and the District of Columbia. I have filed testimony in more than sixty proceedings before these bodies, addressing technical and policy issues in electricity, natural gas, telecommunications, and water regulation. I have also testified before U.S. House and Senate Committees sixteen times.

I have authored or co-authored numerous publications on energy and regulatory matters, including Risk-Aware Planning and a New Model for the Utility-Regulator Relationship (July 2012).[1]

My educational background includes an M.A. degree in Mathematics from the University of Colorado (1977), course requirements met for Ph.D., graduate coursework toward an M.A. in Economics from the University of Colorado (1981-1984), and a B.A. with Honors in Philosophy from St. Louis University (1971).

A copy of my professional resume, which includes my employment history, education, Congressional testimony, selected regulatory testimony, reports and publications, and professional associations and activities, is attached as Exhibit RJB-2 to this testimony.

[1] Ron Binz & Dan Mullen, *Risk-Aware Plan. and a New Model for the Util.-Regul. Relationship*, *available at* http://www.rbinz.com/Binz%20Marritz%20Paper%20071812.pdf, attached as Exhibit RJB-3.

Q: Have you previously testified before this Commission?

A: Yes. I submitted pre-filed testimony before the Washington Utilities and Transportation Commission ("WUTC" or "Commission") in July 2022 in Docket UE-220066 and Docket UG-220067, concerning incentive-based regulation.

Q: What is the focus of your current work?

A: In recent years, I have focused on how cost-effective renewable energy resources can offset rate pressure from the retirement of aging grid infrastructure. In addition, I've worked with regulators and legislators on the use of securitization to recover undepreciated investment in closing fossil and nuclear plants. Finally, I have testified about the importance of utility planning and how, based on my work on the Colorado PUC, all-source competitive bidding can result in very low prices for added resources.

Q: What is the purpose of your testimony?

A: Sierra Club retained me to examine a proposal from PacifiCorp d/b/a Pacific Power and Light ("PacifiCorp" or "Company") to largely eliminate the fuel cost sharing mechanisms that are now part of the Power Cost Adjustment Mechanism ("PCAM") in Washington. In that context, I examined:

1. The reasons behind the volatility in net power costs discussed in this case;
2. The risk inherent in fossil fuel resources and its relationship to a risk-sharing mechanism;
3. The changing role of renewables in the Extended Day-Ahead Market ("EDAM") regime; and
4. The benefits of all-source competitive bidding for renewable resources.

Q: What documents did you review in preparing this testimony?

A: I reviewed the net power cost section of PacifiCorp's filing; and portions of the discovery adduced in the case.

Q: Please summarize your testimony.

A: Section II of my testimony discusses fuel cost adjustment mechanisms, PacifiCorp's current rate case application, and the Company's testimony regarding the difficulty of accurately predicting Net Power Costs ("NPC"). In Section III, I discuss the merits of cost risk sharing mechanisms in fuel cost adjustment mechanisms and respond to PacifiCorp's proposal to significantly modify the current cost risk sharing mechanisms employed in Washington. In Section IV, I discuss the role of renewable energy in reducing NPC. In Section V, I discuss Public Utility Regulatory Policies Act ("PURPA") compliance and NPC, and finally, in Section VI, I conclude my testimony.

Q: Please summarize your findings and recommendations in this case.

A: My findings and recommendations are as follows:

- Fuel cost sharing is a valuable element of the PCAM in Washington. It serves as a corrective to some of the poor incentives of traditional regulation and partially levels the regulatory playing field between fossil generation and zero-cost renewable generation.

- EDAM does not replace or moot out the importance of fuel cost risk sharing. Sharing will add to the benefits of EDAM; entering EDAM does not lessen the value of cost risk sharing.

- A PCAM without the deadband and asymmetrical sharing bands (collectively "sharing mechanisms") will present PacifiCorp with a classic "moral hazard." The Company will be insulated from the risks with fossil fuel resources because it knows the Company will be made whole by the regulator. The Commission should not eliminate the deadband or asymmetrical sharing bands.

- The Commission should examine and adopt competitive bidding as a superior method for PURPA compliance. Competitive bidding can improve outcomes that benefit the utility, consumers, and independent power producers alike.
- The Commission should use the occasion of the IRP to study supply portfolio variations, especially in view of the changed incentives brought by the Inflation Reduction Act ("IRA") and EDAM; the Commission should test whether deployment of more low-cost renewables will keep Washington's costs and rates in check.

II. FUEL COST ADJUSTMENT MECHANISMS AND PACIFICORP'S RATE CASE APPLICATION

Q: Please discuss the history and theory of regulatory tools like PCAM.

A: Fuel cost adjustments ("FCAs") first originated in the mid-1970s.[2] Before that time, fuel costs were included in base rates and the levels remained fixed until the next rate case when total rates, including the cost of fuel, would be reset. Fuel costs were relatively stable and there usually was not a "true-up" mechanism.

All of that changed with the 1973 Oil Embargo, which caused market prices for generation fuels to become much more volatile.[3] Because of rapidly increasing fuel prices, many utilities filed "pancaked" rate cases, with new cases being filed before pending cases were settled. Indeed, I witnessed this and other developments firsthand in my role as a consulting utility rate analyst. These pancaked rate cases led to proposals to defer fuel costs that were above the levels included in base rates, and then collect those deferred amounts at a later date, oftentimes in the following month. For regulators, this helped lighten the regulatory load by reducing the need for frequent rate cases.

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[2] *RRA Regul. Focus, Adjustment Clauses, A State by State Overview*, S&P Glob. Mkt. Intel. at 2 (Sept. 12, 2017), *available at* https://www.spglobal.com/marketintelligence/en/documents/adjustment-clauses-state-by-state-overview.pdf.
[3] *Id.*

Unsurprisingly, there was a lot of resistance among customer groups and consumer advocates to FCAs. Those opponents argued that FCAs were "single issue ratemaking," that they were overly generous to the utilities, that they relieved much of the pressure on the utilities to be efficient, while shifting all fuel cost risk to customers. Despite this opposition, FCAs became a feature of most state regulatory systems, often enshrined in enabling legislation. In the decades following the adoption of FCAs, numerous other "adjustment clauses" were adopted across the country: for pension benefits, inflation tracking, changes in labor costs, environmental compliance costs, and capital investment, to name a few.

This array of adjustment clauses altered cost-of-service regulation in a way that weakened or removed one of the main incentives for utilities to become and remain efficient as business firms: pressure from cost changes. Recognizing that a cost tracker for fuel and purchased power reduces utilities' incentives toward efficiency, some states began adding features to these fuel clauses, rewarding the utilities for specific actions, such as reducing the heat rate at fossil plants or increasing load factors for their plants. In my view, these ad hoc adjustments to the fuel clauses have been only partially successful.

Q: Please explain what PacifiCorp is seeking in this case.

A: PacifiCorp has filed a general rate case so that there are numerous issues raised by the filing. Focusing on Net Power Costs ("NPC"), the Company is seeking to raise base rates to reflect sharply higher power costs.

PacifiCorp witness Mitchell's testimony summarizes the changes to elements of NPC, which grew by 74% from the Company's 2021 power cost only rate case

("PCORC") to a new total of $2.555 billion[4] on a Company-wide basis. The Washington-allocated NPC increased by $53.8 million or 37%.[5] Table 2 in the testimony of PacifiCorp witness Mitchell, reproduced below as Table 1, shows that the increase in NPC is driven by increased cost of natural gas and purchased power expense. Notably, both of those factors are driven by changes in the price of natural gas.

Table 1: Comparison of Forecasted Net Power Costs in Washington 2020 General Rate Case and Current Rate Case

Net Power Cost Reconciliation ($)		
	($ millions)	$/MWh
WA 2021 PCORC Final Forecast	**145.2**	**32.47**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(19.56)	
Purchased Power Expense	35.10	
Coal Fuel Expense	(6.43)	
Natural Gas Fuel Expense	42.76	
Wheeling and Other Expense	1.93	
Total Increase to NPC	**53.80**	
WA 2024 GRC Initial Forecast	**199.0**	**43.47**

Another useful view shows the components of the $199.0 million NPC allocated to Washington. The following table is derived from data provided in Exhibit RJM-2 accompanying the direct testimony of PacifiCorp witness Mitchell.[6]

[4] Exh. RJM-1CTr, Redacted Direct Test. of Ramon J. Mitchell at 6:20, 7:14-15 (Mar. 2023, Revised Apr. 4, 2023, Refiled Apr. 19, 2023) (hereinafter "Exh. RJM-1CTr").
[5] *Id.* at 7:16-17.
[6] Exh. RJM-2, 230172-PAC-RJM-ExhRJM-2WashingtonAllocatedNetPowerCosts.xlsx (hereinafter "RJM-2").

Table 2: Components of Net Power Costs

Components of Net Power Costs WA 2024 GRC Initial Forecast		
Total Special Sales For Resale	($20,324,156)	-10.2%
Total Purchased Power & Net Interchange	$99,594,396	50.1%
Total Wheeling & U. of F. Expense	$13,353,516	6.7%
Total Coal Fuel Burn Expense	$39,288,430	19.7%
Total Gas Fuel Burn Expense	$66,745,943	33.5%
Total Other Generation	$329,287	0.2%
Total	$198,987,417	100.0%

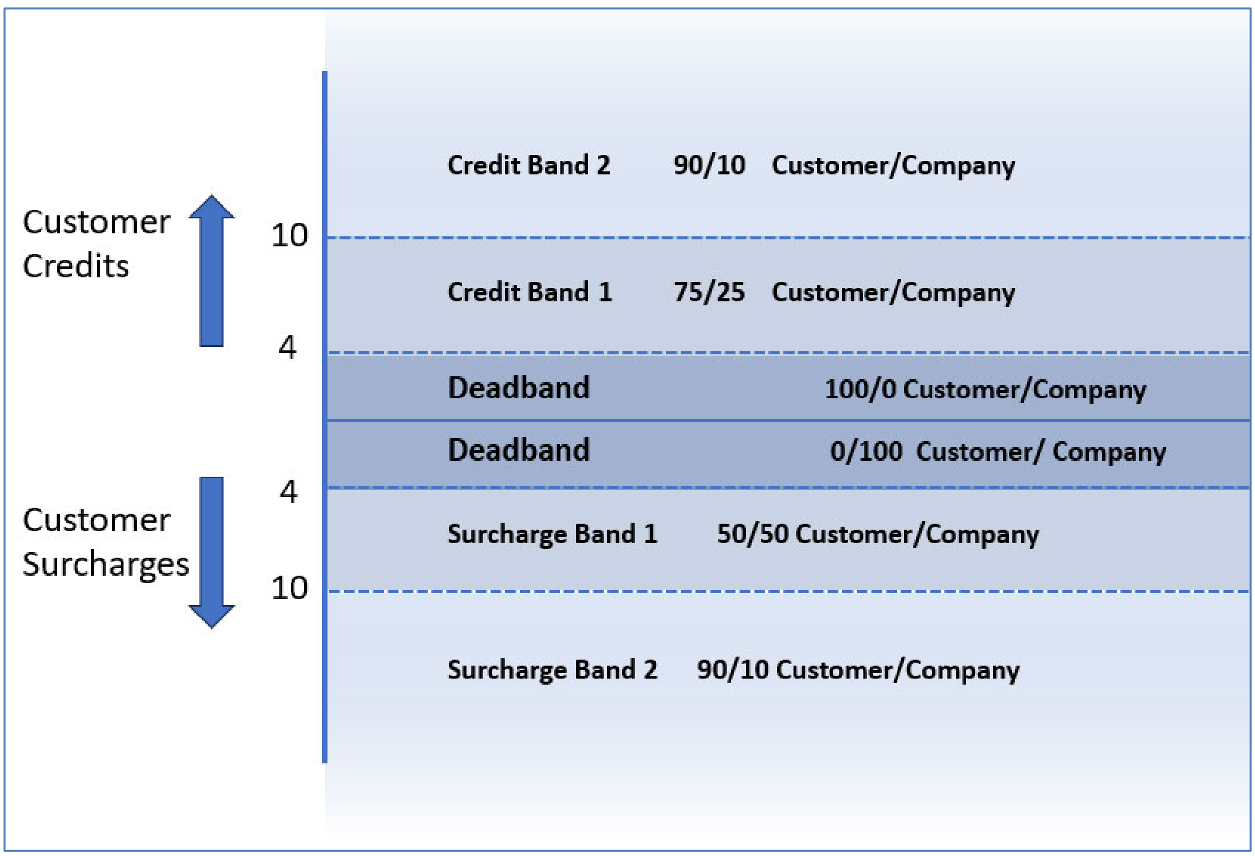
This table reveals that the largest component of net power costs is fossil fuels expense for Company generation, eclipsing the role of purchased power and interchange power.

PacifiCorp also asks the Commission to modify the adjustment mechanism that applies to Net Power Costs, the Power Cost Adjustment Mechanism, through which the utility is permitted to charge customers the large majority (but not all) of the difference between forecast NPC and the actual NPC. The existing PCAM operates as follows:

The difference between Forecast NPC and Actual NPC is calculated. That difference is then reduced by $4 million (the deadband). If there is a remaining balance, it is apportioned between the Company and consumers by the use of two sharing bands and the final balance is booked into the deferral account. For credits owing to customers (Actual NPC is less than Forecast NPC), the amount above the deadband, up to $10 million is split 75/25 between customers and the Company. The amount of the credit to customers above $10 million is split 90/10 between customers and the Company. The treatment of surcharges (Actual is more than Forecast) is similar, but with different sharing percentages. Amounts outside the deadband, up to $10 million, are split 50/50 and the surcharges above $10 million are split 90/10 between the customers and the Company, then booked into the deferral account. If the amount in that account exceeds $17 million, it is surcharged or refunded. This $17 million trigger can be met in a single annual PCAM filing or cumulatively over multiple PCAM filings.

Figure 1 below is a visual representation of the deadband and sharing bands described above.

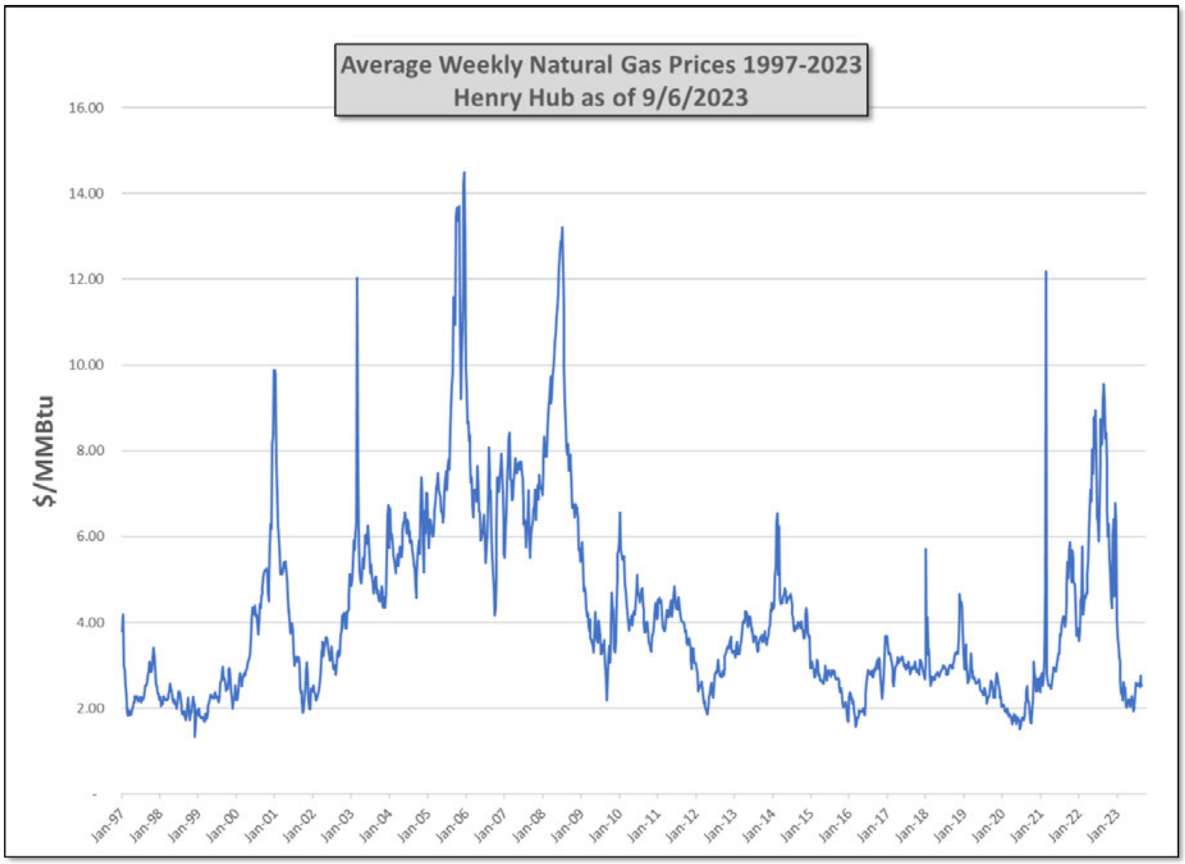
Figure 1: PCAM Deadband and Sharing Bands



Q: What has happened to generation fuel prices over the past two years?

A: After a period of relatively stable prices in the period 2016 to 2020, natural gas prices became much more volatile and increased sharply, especially during 2022. The following chart shows the cost of natural gas at the Henry Hub price point for the years 1997 to date.

Figure 2: Average Weekly Natural Gas Prices 1997-2023, Henry Hub



Q: What does it mean for prices to be volatile?

A: In everyday usage, "volatile" means the tendency to change quickly and perhaps unpredictably. We might speak of someone's personality being "volatile" or the Dow Jones Industrial Average exhibiting "volatility." For commodities like natural gas or coal, "volatility" describes how quickly the price of the commodity changes over time. The term has loose, informal meanings. But it also has technical, economic meanings. In finance the term is well-defined and can be measured. Officially, “volatility” is the standard deviation of changes in value of a variable over time.

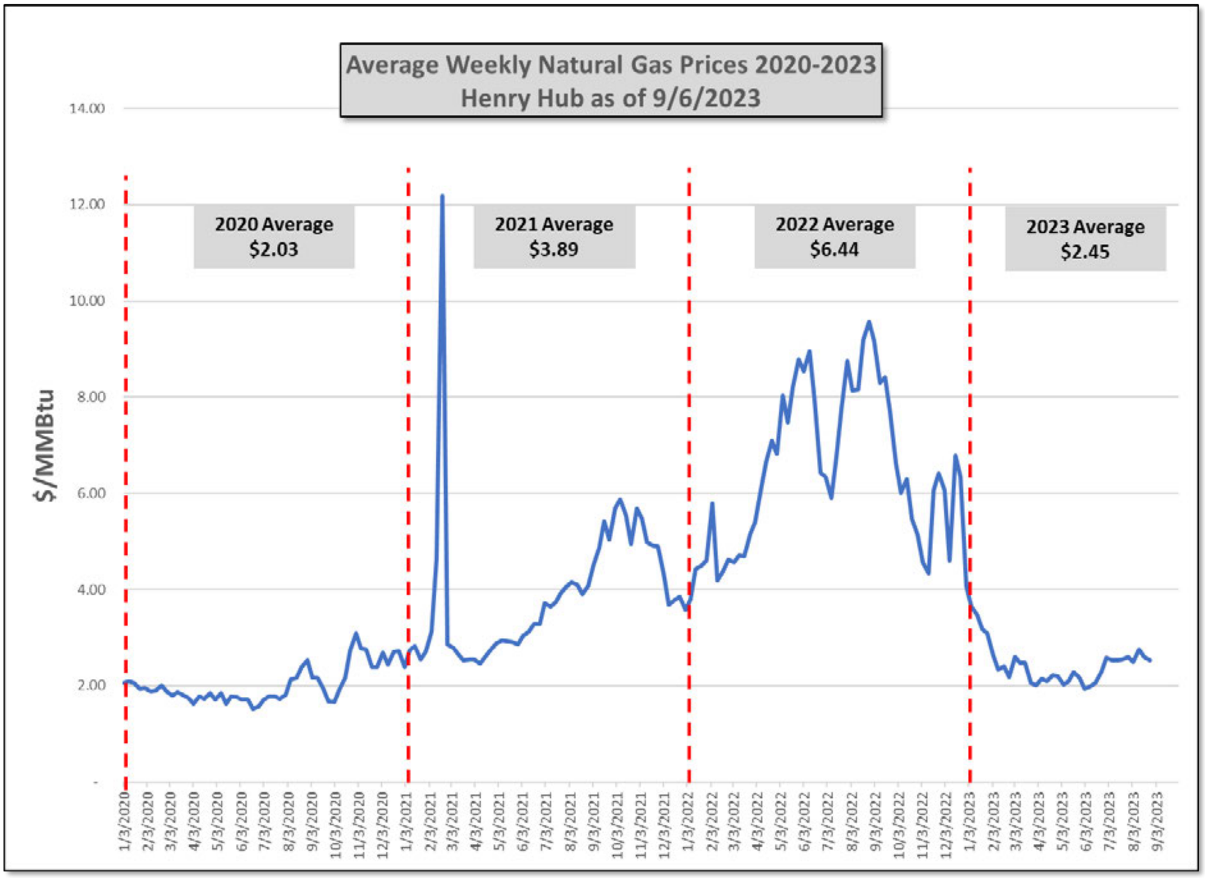
Rising prices do not necessarily signal high volatility. Volatility measures the rate of price changes, both up and down. A slowly rising price might have low volatility; a downward trending price may or may not be volatile. Further, prices that are very volatile in one period might not be volatile in another period. However, in the past two years, the prices of both natural gas and coal have been volatile *and* increasing.

Q: What does Figure 2 show?

A: Over the past 44 years, the price of natural gas has shown itself to be quite volatile, swinging both up and down. I clearly recall the day when the price of natural gas reached a price of over $13.00/MMBtu in early July 2008, one of the highest price levels ever seen. I was Chair of the Colorado Public Utilities Commission, and we were very worried about residential heating costs in the upcoming winter season. We issued a Consumer Alert warning about the coming price increases. As it turned out, the price of gas fell consistently for the next six months, arriving at a price of $3.88 by the end of winter. Happily, the heating season was relatively normal, notwithstanding that natural gas prices had reached record levels only months before. In this case, volatility worked to the customers’ advantage when the price of natural gas fell so rapidly.

Most relevant to this case, it is helpful to examine the natural gas price history on a shorter time scale. Figure 3 is a chart with the same data as Figure 2, limited to the range of 2020-2023. Figure 3 also shows the calculated average of average weekly prices at Henry Hub for each of the calendar years 2020 to 2023.

Figure 3: Average Weekly Natural Gas Prices 2020-2023, Henry Hub



Looking at the average annual price of natural gas in 2021 and 2022, it is not surprising that PacifiCorp's estimate of NPC in 2021 was off base for 2022, as the average weekly price of natural gas increased over 217% between 2020 and 2022. Higher natural gas prices affect almost every element of the NPC calculation. Clearly, an estimate of future NPC made in 2021 may not have anticipated the subsequent large increase in natural gas prices, especially not the "black swan" events in 2022, such as the war in Ukraine. Finally, I note that the price of natural gas so far in 2023 has returned to nearly the price in 2020.

Q: Do you agree with Mr. Painter's explanation for differences between Forecast NPC and Actual NPC?

A: Only partially. Mr. Painter cites several reasons why he thinks the estimate for NPC is often wrong. Among others, he lists the ongoing drought's effect on hydro generation, the asymmetric relationship of cost changes for increases and decreases along the supply curve, the cost of natural gas, and the proliferation of "weather dependent generation." These and other factors undoubtedly affect the level and volatility of market prices. But these factors have various levels of influence.

I do not think that Mr. Painter stresses enough the role of natural gas prices as a factor. As I will show, most of the fluctuation in NPC stems from changes in the price of natural gas, which directly affect PacifiCorp's generation costs. But higher gas prices also affect the market price of electricity and the costs of most power purchase contracts.

The takeaway is this: natural gas prices are inherently volatile and difficult to predict. This translates directly to less predictable market prices and less predictable generation costs.

Q: What is your response to Mr. Painter's observation about the difficulty to accurately predict NPC?

A: Mr. Painter goes into great detail about why predicting future NPC is challenging. He invokes a long list of examples, among which are:

- Heat waves in the summer with neighboring utilities having the same challenges, combined with the possibility that renewable resources will under-perform;
- The war in Ukraine, driving up natural gas prices;
- Additional environmental requirements;

- Favorable weather conditions leading to renewable over-production and additional wholesale sales, resulting in an "unforecastable net power costs variances."[7]

I agree with Mr. Painter that the western grid is getting more complicated. He is also correct that it is difficult to predict wind and solar generation in the short run. But there are three things working in the utility's and the consumer's favor.

First, it has been shown in theory and in practice that there is a great benefit for wind and solar generation if there is geographic diversity. While the wind may die down at one site, it might pick up at a geographically distant site. This smoothing of wind generation is very helpful to control room operators who can use the geographic diversity to their advantage.

Second, much like geographic averaging, wind generation tends to become regular over longer time periods. For that reason, wind generators are able to sign contracts committing to specified levels of generation over periods of years, but not with a month-to-month specificity. Those performance commitments are backed up with penalties if the generator fails to perform as committed.

In fact, Mr. Painter acknowledges that wind production is reasonably predictable over longer periods:

> Across an annual period, average wind speed forecasts are borderline reasonably accurate. At more detailed levels of granularity, example monthly or hourly, these forecasts do not exhibit reasonable levels of accuracy.[8]

and

> Figure 8 shows that in 2021 actual hourly wind generation from PacifiCorp's owned wind resources deviated from forecast on average by

[7] Exh. JP-1T at 15-18.
[8] Exh. JP-1T at 13:10, n.12.

> 80 percent, using the absolute hourly deviations, even though on an annual basis, the actual wind generation deviated from forecast by only 7 percent.[9]

Third, it is incorrect to blame wind and solar generation initially for unpredictable moves in market prices. To be sure, there is some effect, but it is small and swamped by the biggest factor: variability in the price of natural gas. I have prepared the attached 3-page Exhibit RJB-4 that illustrates this effect. The first page shows a hypothetical supply stack. As can be seen, the generation resources are ordered according to their marginal cost of generation. Renewable resources have almost zero marginal cost; next is nuclear; next is coal generation; following coal are combined cycle gas turbines ("CCGT"); and last are the costliest on a marginal cost basis – gas combustion turbine generators. Although this is illustrative, it is quite representative of the situation for each U.S electric utility or independent system operator/regional transmission organization.

Q: What does the second page of Exhibit RJB-4 illustrate?

A: The second page illustrates what happens to the system clearing price if **all** wind and solar resources stopped producing when the system is at average load. This is an extreme assumption with near-zero probability, especially considering the likely geographic diversity of the renewable resources. Nevertheless, we see that removing all of the renewable generation in this illustration shifts the supply curve left, putting a more expensive CCGT plant on the margin. But the new marginal plant is another combined cycle plant, whose cost difference with the previous marginal plant is relatively small. We see that the effect of **all** solar and wind disappearing is a minor change in the marginal cost of the last plant, which sets the clearing price in the market.

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[9] *Id.* at 22:7-10.

Q: Please explain the third page of Exhibit RJB-4.

A: The third page shows what happens when the price of natural gas increases from \$2.45/MMBtu (the average price at Henry Hub so far in 2023) to \$6.44 (the average Henry Hub price in 2022). In this case, the supply curve moves up, by about \$28/MWh for the combined cycle plants and by about \$40/MWh for the gas turbines. CCGTs have a heat rate of about 7000Btu/kWh. This means that a \$2.00 change in the price of a MMBtu of gas will change the cost of electricity by about \$14.00/MWh for a CCGT plant. Recall Figure 2 above that shows the volatility of natural gas prices as they move from a weekly average low of \$1.34 to a high of \$14.49, a swing of almost 11-fold.

Q: What can be understood from this exhibit?

A: The takeaways from this illustrative exhibit are these:

- The variable output of wind and solar generation can affect the market clearing price to a degree. The cost of wind and solar does not change, but variable output can affect which gas plant sets the clearing price of the market. In most circumstances the effect is likely to be relatively small.
- The price of natural gas drives the clearing price in this illustrative market. A change in that price can have a very large effect on the clearing price, and actual experience in the years 2020 to 2023 demonstrates the dominant effect of natural gas price volatility.

Q: What is the essential challenge that Mr. Painter identifies?

A: It seems that Mr. Painter's central problem is that he cannot predict wind and solar performance on an hourly, daily, or monthly basis, even though he has a good idea of what annual performance might look like. This inability interferes with the Aurora model used by the Company to predict NPC, presumably by summing up power costs on an hourly or sub-hourly basis. The irony here is that solar and wind generation almost always lowers NPC given the current economics of the utility industry. The more wind and solar generation there is, the better for customers and the Company. It's simply that PacifiCorp cannot model this using their chosen production cost model.

Q: Do we know how valuable wind generation is on the PacifiCorp system?

A: Yes. In the rate case now being heard in Wyoming, PacifiCorp witness Ramon Mitchell testifies as follows:

> Q. Although regional proliferation of weather dependent generation results in less accurate price forecasts and correspondingly less accurate NPC forecasts; does this weather dependent generation lower the Company's NPC?
>
> A. Yes. Since calendar year 2020 the Company has repowered existing wind facilities, gained ownership of new wind facilities and built new transmission lines, all of which are operational in the test period. Without these new wind resources and the associated transmission lines to move the generation to load, the 2024 NPC forecast would be $343 million higher on a total-Company basis, approximately $47 million on a Wyoming-allocated basis.[10]

Although Mr. Mitchell did not repeat this statistic in his testimony in this case, PacifiCorp in Washington reaps some portion of those savings in NPC.

Q: What are your conclusions about Mr. Painter's complaints about the contribution of renewable energy to the inaccuracy of NPC forecasts?

A: Mr. Painter mixes apples and oranges. The apples are the short-term variability in renewable production; the oranges are the much larger fluctuations in market prices driven by big moves in natural gas prices and extreme weather events. Short term variability in wind and solar production are inherent variations that system operators have

[10] *In the Matter of the Appl. of Rocky Mountain Power for Auth. to Increase its Retail Elec. Serv. Rates by Approximately $140.2 Million Per Year or 21.6 Percent and to Revise the Energy Cost Adjustment Mechanism*, Wyo. Pub. Serv. Comm'n, Dkt. No. 20000-633-ER-23, Record No. 17252, Exh. 10.0, Redacted Direct Test. of Ramon J. Mitchell at 52:11-19 (March 2023) (citations omitted). An excerpt of Mr. Mitchell's testimony in this proceeding is provided as Exhibit RJB-5.

learned to handle in the control room. Longer term, much of that variation evens out.[11] Price spikes in the gas market prices and demand crunches in winter are features of a system with fossil fuel dependence. His difficulty in accommodating variability in renewable production can be cured by looking longer-term with renewables or using more sophisticated modeling techniques.[12]

Mr. Painter's claimed connection between the difficulties in NPC forecasting and the merits of the PCAM sharing mechanisms is extremely strained, basically a non-sequitur. Consider this testimony:

> Yes. Although several factors can contribute to the modeling of the underlying Forecast NPC being inaccurate as compared to Actual NPC, I believe that: (1) regional forward power market price forecasts in the western interconnection becoming less accurate; and (2) renewable resources being added to the Company's system will primarily contribute to the continued inaccuracy of Forecast NPC. **Accordingly**, I recommend that the deadband and asymmetrical sharing bands be removed from the PCAM to allow the Company to fully refund to customers or only recover its prudently incurred power costs, and not allow for any possible unbalanced outcomes in power costs.[13]

Of course, he is correct on his first point: that untrustworthy forward market prices will contribute to an inaccurate NPC forecast. But that should not be the end of his investigation. Market price forecasts are inaccurate precisely because the biggest players, gas generators, cannot predict or control natural gas prices. Wind and solar producers don't have that problem: their marginal cost is near zero and they can be assured that their production will be taken at market clearing prices. Wind and solar are not price makers; they are price takers. The hourly or daily variation in wind or solar output may

[11] *See* Exh. JP-1T at 22:7-10.
[12] For example, the "Monte Carlo" analytical method can be used to model the probability of different outcomes in a process that cannot easily be predicted due to the intervention of random variables.
[13] Exh. JP-1T at 8:3-9:3 (emphasis added).

confound efforts to model those resources in a short time frame, but that won't have much effect on the net power cost over a year. As I showed above, even very large hypothetical swings in renewable production (e.g., removing all wind and solar) will not affect market prices nearly as much as actual historical changes in gas prices.

In his second point, Mr. Painter asserts that the continued addition of renewables will create more uncertainty in NPC forecasts. That is wrong. More renewable production might make his short-term forecasting more difficult. But the fixed-cost nature of much renewable production will dampen, not exaggerate swings in market prices over the longer term.

Consider this thought experiment: if 100% of energy needs were met with solar, wind, geothermal, and storage resources, how much cost fluctuation would there be? None of those resources have costs that fluctuate in the short term. There might be predictable long-term cost changes, but none in the short term. For example, solar production at a site might degrade at 0.5% per year, but even that smooth trend is captured in power purchase agreement ("PPA") prices or incorporated in Levelized Cost of Energy ("LCOE") estimates. It does not create volatility or reduce the ability to forecast. Wind resources have a known and fixed rate of Operation and Maintenance ("O&M") costs and no fuel costs. Similar for geothermal production.

In sum, contracts for renewable production assure both production and price. Contacts for natural gas or coal production typically provide for changes in price due to changes in fuel costs and may not guarantee production as the fossil fuel industry experiences significant changes.[14]

III. MERITS OF SHARING MECHANISMS IN FUEL ADJUSTORS

Q: In your view, what are the merits of Washington's PCAM deadband and asymmetrical sharing bands?

A: I have testified in several states about the benefits of a risk-sharing fuel cost mechanism. First, this approach is fairer to utility customers who, without a sharing mechanism, shoulder all the risk of fluctuations in fuel costs and bear all the cost risk of a resource decision that they were not party to. While future gas prices are difficult to predict; that gas prices are unpredictable is not. Armed with this information, the utility—not its customers—determine how exposed it should be to gas price fluctuations. Unfortunately, in most states, regulation has moved from a point where utilities once bore this risk of fuel cost changes—they had to file a rate case to increase fuel prices—to the point where utilities are now often fully shielded from that risk. When I was the Consumer Counsel in Colorado in the 1990s, consumer advocates across the country objected to fuel cost pass-throughs and other "adjustment clauses." Their argument was that, by automating the recovery of those costs, regulators and legislators were removing the primary incentive the utilities have to become and stay efficient: cost pressures. That argument regarding utility incentives is now updated to apply to the utility's incentives in resource choices. Washington is one of a handful of states that allocates the over/under risk between

[14] For example, in PacifiCorp's fuel cost adjustor proceeding in Oregon (called the Transition Adjustment Mechanism ("TAM")), PacifiCorp witness James Owen noted that "[t]wo of PacifiCorp's largest coal suppliers in Utah made force majeure claims in 2022 that resulted in significant delivery shortfalls of PacifiCorp's contracted coal supply." *In the Matter of PacifiCorp's 2024 Transition Adjustment Mechanism*, Or. Pub. Util. Comm'n, Dkt. No. UE-420, Exh. PAC/200, Direct Test. of James Owen at 5:3-5 (Apr. 2023). An excerpt of Mr. Owen's testimony in this proceeding is provided as Exhibit RJB-6.

customers and the utilities. Basic fairness suggests that the utility should share the risk of higher prices due to resource choices, as is currently the practice in Washington.

Second, a risk-sharing mechanism is a signal or a reminder to the utility of the risks of including natural gas generation in their portfolio. It is not a prohibition on using natural gas; instead, it simply requires the utility to factor in a known risk of reliance on gas fuel when determining an appropriate mix of generation resources. In other words, it is an equalizing factor when comparing natural gas generation to other energy resources such as energy efficiency or renewable generation, neither of which have fluctuating costs. Without a risk-sharing mechanism, the utility is incentivized to ignore gas price volatility because it knows that, regardless of price fluctuations, it will be made whole. This is a classic example of "moral hazard."

Q. Please expand on this last idea.

A: In economics, finance, and insurance theory, a situation might arise where one party engages in risky behavior or fails to act in good faith because it knows the other party bears the economic consequences of their behavior. This situation is called a "moral hazard." As one well-known example, economists largely agree that the 2008 Great Recession was ushered in when banks took risks they thought the federal government would cover. From Investopedia:

> The financial crisis of 2008 was, in part, due to unrealistic expectations of financial institutions. By accident or design - or a combination of the [two] - large institutions engaged in behavior where they assumed the outcome had no downside for them. By assuming the government would opt as a backstop, the banks' actions were a good example of moral hazard and

behavior of people and institutions who think they are given a free option.[15]

In this case, Mr. Painter recommends dropping risk-sharing, meaning that its customers will “opt as a backstop.” PacifiCorp would be entirely shielded from fuel cost risk by passing through all changes in Net Power Costs to consumers, leaving PacifiCorp whole.

The concept of moral hazard comes home to roost with utility resource selection. If dollar-for-dollar cost recovery for gas or coal is a foregone conclusion, utilities do not appropriately account for the risk of fossil fuel resource acquisition, especially not when compared to the much lower risk of low-cost solar and wind generation, which do not suffer from fluctuating costs.

Q: Are ratepayers protected against this moral hazard because a utility’s regulators could find that its failure to account for price volatility in its resource selection was imprudent?

A: No, they are not. Utilities assume that they will be compensated for their expenses and capital outlays as long as those expenditures are not egregiously imprudent. In theory, imprudent expenditures are disallowed, and ratepayers are protected from unreasonable decision making by the utility. However, while the idea is discussed in textbooks, the actual number and value of “disallowances” for imprudent expenditures in utility regulation is vanishingly small. Utilities such as PacifiCorp are well aware of this.

Q: Why does PacifiCorp oppose retaining Washington’s risk sharing mechanisms?

A: PacifiCorp offers three arguments for eliminating the sharing mechanisms:

[15] Investopedia, *How Did Moral Hazard Contribute to the 2008 Fin. Crisis* (Oct. 29, 2021), *available at* https://www.investopedia.com/ask/answers/050515/how-did-moral-hazard-contribute-financial-crisis-2008.asp.

1. Joining EDAM beginning in 2025 means a loss of control for PacifiCorp's economic dispatch; this makes PCAM sharing unnecessary.
2. Company argues that NPC "will be driven as low as the EDAM can achieve" and "out of the Company's control" so that risk sharing can be set aside.
3. PCAM objectives will be met automatically by EDAM even if PCAM sharing is removed.

Q: What is your response to PacifiCorp's first argument?

A: The first argument—that EDAM will control PacifiCorp's economic dispatch—overstates the effect of EDAM on Net Power Costs. It is true that EDAM will be dispatching the participating units in the short run, but much of that dispatch would have happened anyway. In fact, the predicted impact of EDAM on the eastern PacifiCorp region indicates higher generation levels, with increased sales. But lower costs for power in Washington should allow more Washington sales as EDAM presents new sales opportunities, as I will discuss later.

PacifiCorp's NPC is dominated by coal and gas (56%) and purchased power (23%), although Washington consumers do not share in the costs of most coal generation. The mix of resources in PacifiCorp's generation fleet available to meet load largely determines NPC, not the daily dispatch of those resources, which is determined by the marginal costs of each power source. This is because, while PacifiCorp has some ability to ramp its resources up or down, depending on load, it cannot change out those resources—it must "go to war with the army it has." In that sense, at the point of cost reimbursement, it is too late to affect the resource mix; that comes at the time of the IRP. The sharing mechanism conveys the risk that resource choices can make. Utilities can compare lower-risk portfolios with a fossil portfolio that is known to have fluctuating costs to which the utility is exposed.

PacifiCorp, and not EDAM, will determine how that mix of resources (and their associated costs) evolves over time. While PacifiCorp cannot control market prices for gas, coal, or power produced by others, it can shape its NPC by judicious resource expansion. As I will discuss later, adding more wind and solar will be key to lowering NPC. In short, EDAM will not be running the Company: PacifiCorp will still be in control of resource selection and subject to the incentives of cost-of-service regulation.

Q: What about Mr. Painter's next two arguments—that EDAM will drive costs lower with or without the sharing mechanism in PCAM?

A: My response is that the Company can push its costs even lower than those produced by the market. EDAM will function to optimize dispatch of multiple generation resources across the market footprint and optimize the use of the transmission grid. The result will be lower total costs of power production. Neither PacifiCorp nor any single market participant can accomplish this optimization: it requires an operative, the EDAM, with the authority to dispatch plants in reliability-constrained merit order. The savings achieved by this optimization will flow through to each participating entity through a lowering of the market price, compared to what would have been. Mr. Painter is correct that these results will occur whether or not the Washington Commission requires differences between Forecast NPC and Actual NPC to be shared between PacifiCorp and its customers.

But that is not the end of the story: EDAM does not prevent PacifiCorp, through its short- and long-run management choices, from lowering power costs even further. Most of these savings beyond EDAM will not occur in a timeframe of hours or days. They will occur as a result of whether PacifiCorp makes least cost resource decisions, whether PacifiCorp operates its units optimally, and how PacifiCorp interacts financially with the EDAM market. There is simply no reason to stop with the cost improvements resulting from EDAM: others are available to PacifiCorp, and they should be incentivized.

Q: What do you recommend the Commission do with the sharing mechanisms?

A: I think that the Washington Commission should retain the sharing mechanisms. They still serve a valuable and equitable role by putting part of the fuel cost risk on the utility. A fuel cost sharing mechanism gives the Company some “skin in the game.” Further, customers see a sharing mechanism as fundamentally fairer than customers shouldering all the risk.

Q: PacifiCorp proposes eliminating the deadband and asymmetrical sharing bands but retaining the $17 million credit or surcharge threshold in the PCAM. Why is the $17 million threshold not sufficient?

A: First, I think the $17 million threshold should be retained. It reduces regulatory costs, eliminates relatively small adjustments to customer bills and avoids all the overhead costs that entails. However, the $17 million threshold alone does not convey the same incentives that the deadband and sharing bands do. PacifiCorp will be made exactly whole if only the threshold is retained, even if PacifiCorp must wait multiple PCAM cycles before reaching the $17 million threshold. Eliminating the deadband and sharing bands shifts all of the risk back onto customers, whether or not the $17 million threshold is retained.

IV. THE ROLE OF RENEWABLE ENERGY IN REDUCING NPC

Q: Why should Washington regulation encourage more zero-cost resources and storage?

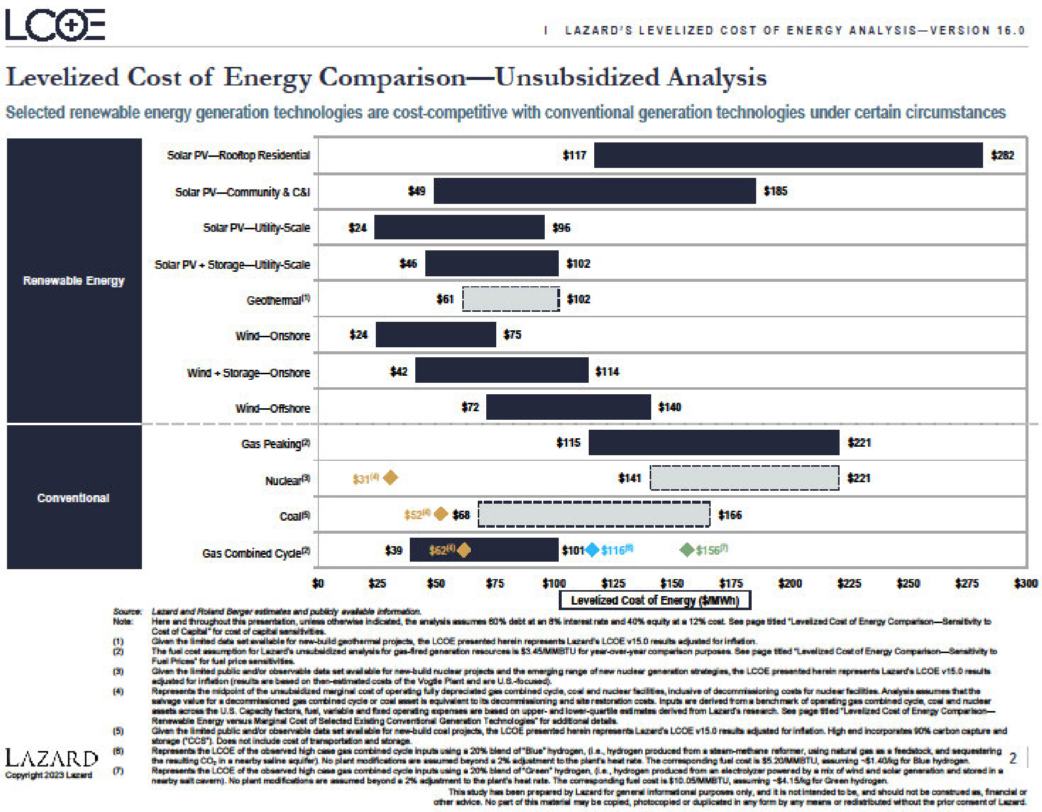
A: In addition to the climate benefits of moving to zero-emission resources, there are multiple reasons why the Commission should promote adoption of additional low-cost renewable resources in Washington.

- Wind and solar costs are now often lower than any fossil resource.
- Washington has good wind and solar resources.
- Low-cost wind and solar generation in Washington can be very profitable in EDAM.
- New tax policies in the Inflation Reduction Act will boost renewable production.

Q: Please explain your first point

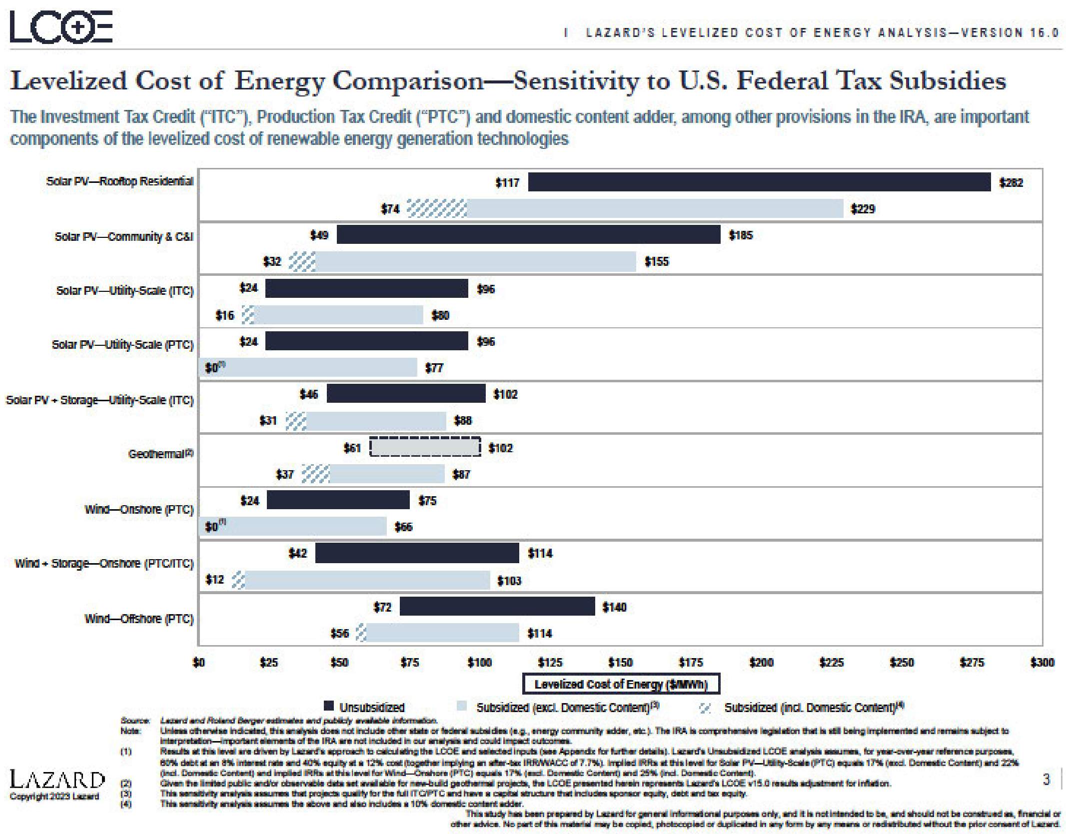
A: First, renewable resources are now often lower cost than gas generation and sometimes coal generation. In many places geothermal energy is also now a competitive baseload option. I am attaching as Exhibit RJB-7 a copy of the Lazard's 2023 Levelized Cost Of Energy Analysis, the 16th edition of this comprehensive report. The report shows the range of costs—overnight and levelized—that characterize every significant electric energy source. As the Commission can see on page 2 of the report, renewable energy—chiefly wind and utility scale solar—is competitive with fossil and nuclear generation on an unsubsidized basis. That page is reproduced below as Figure 4.

Figure 4: Levelized Cost of Energy Comparison – Unsubsidized Analysis



But the current federal administration has championed the Inflation Reduction Act ("IRA") that extends and increases the federal tax credits for renewables and storage. Page 3 of the Lazard report shows how federal tax credits affect each major resource type. This page is also reproduced below as Figure 5.

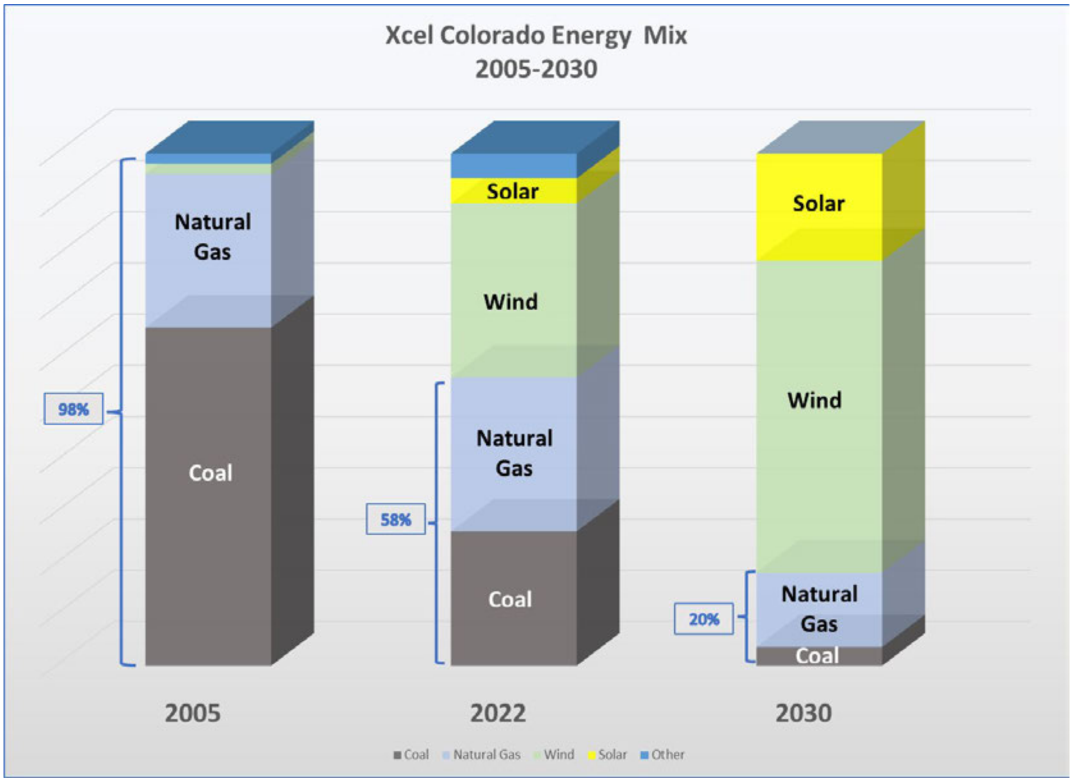
Figure 5: Levelized Cost of Energy Comparison – Sensitivity to U.S. Federal Tax Subsidies



Q: How are these low prices and new tax policies affecting investor-owned utilities?

A: The low cost of renewables has changed how many utilities are doing business. Xcel Energy Colorado provides a good example. The following figure shows the change in generation fuel mix since 2005 and what is planned for 2030, only 7 years from now. To be clear, the chart below measures the fuel sources behind energy (MWh) production. Xcel separately arranges capacity to cover its peak demand.

Figure 6: Xcel Colorado Energy Mix 2005-2030



Utilities like Xcel can use renewables, both wind and solar, in a "fuel-saving" mode. This means that the resources provide energy that allows Xcel to throttle back their gas and coal plants. The fossil plants remain in service for capacity, but are used much less often for energy. With competitive bidding, Xcel has been able to obtain wind and solar (including with storage) at rock-bottom prices. Below, Table 3 shows the bid prices for wind and solar Xcel Colorado received in its 2016 IRP. Following this summary, the bids were evaluated, ranked, and contract negotiations continue followed.

There are several key features of this matrix. First note that the prices quoted for wind and solar are **median** prices. In other words, half the bids were cheaper than the quoted number. This means that half of the 42 wind bids were cheaper than $18.10/MWh.

Similarly, half of the 59 bids for solar with storage were cheaper than $36.00/MWh. As it turns out, Xcel contracted with NextEra for 300 MW of wind energy at the near-unbelievable price of $10.07 per MWh[16].

Table 3: Xcel Energy Request for Proposal ("RFP") Responses by Technology, 2016

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11	[redacted]	$/MWh
Biomass	1	9	1	9	[redacted]	$/MWh
Total	430	111,963	238	58,283		

Further, the solicitation by Xcel led to a vast number of bids. While the target solicitation was about 1200 MW, Xcel got bids for 58,283 MW—forty-three times the amount sought. The "incredibly low" prices caught the attention of Utility Dive.[17]

Part of the value of Xcel renewable play is that wind and solar are immune to fuel cost risk. The marginal cost of operating wind and solar is only the variable operation and maintenance costs ("VO&M"), which are near zero. These resources can be owned by the

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[16] Mich. Pub. Serv. Comm'n, *MI Power Grid Phase II, Advanced Plan. Evaluator and All-Source Mtg.* (Feb. 2021), *available at* https://www.michigan.gov/-/media/Project/Websites/mpsc/workgroups/comp-proc/Feb_18_Competative_Procurement_Presentation_.pdf?rev=c0dfd06533714ee9991658e2f8c145f2.

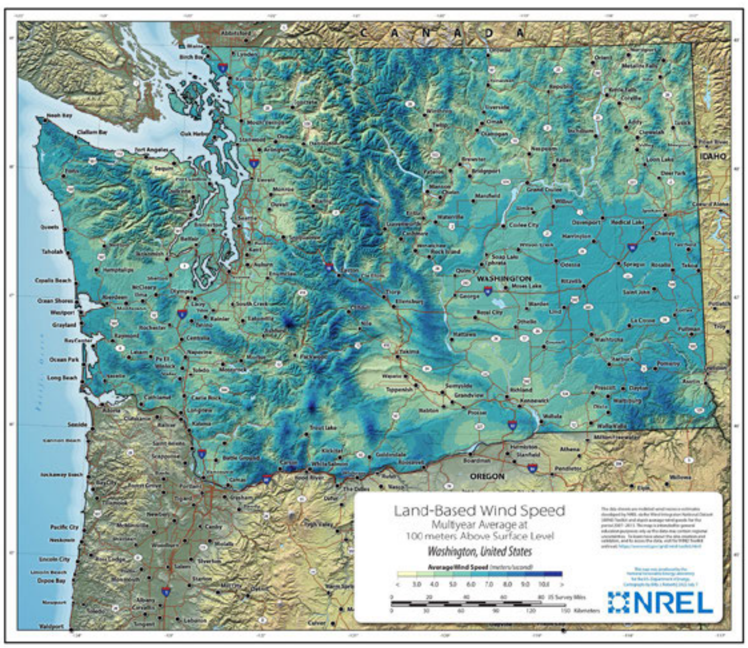
[17] *See* Herman K. Trabish, *Xcel's Record-Low-Price Procurement Highlights Benefits of All-Source Competitive Solicitations*, Util. Dive (June 1, 2021), *available at* https://tinyurl.com/y4d4re5c.

utilities or purchased under contract from independent power producers. Those contracts may or may not have an annual price escalator, but there are no provisions, as with fossil power contracts, that permit passing through increased operating costs similar to fuel costs with fossil resources. There will be no "price surprises" with these resources.

Q: What about your second point—Washington's renewable resources?

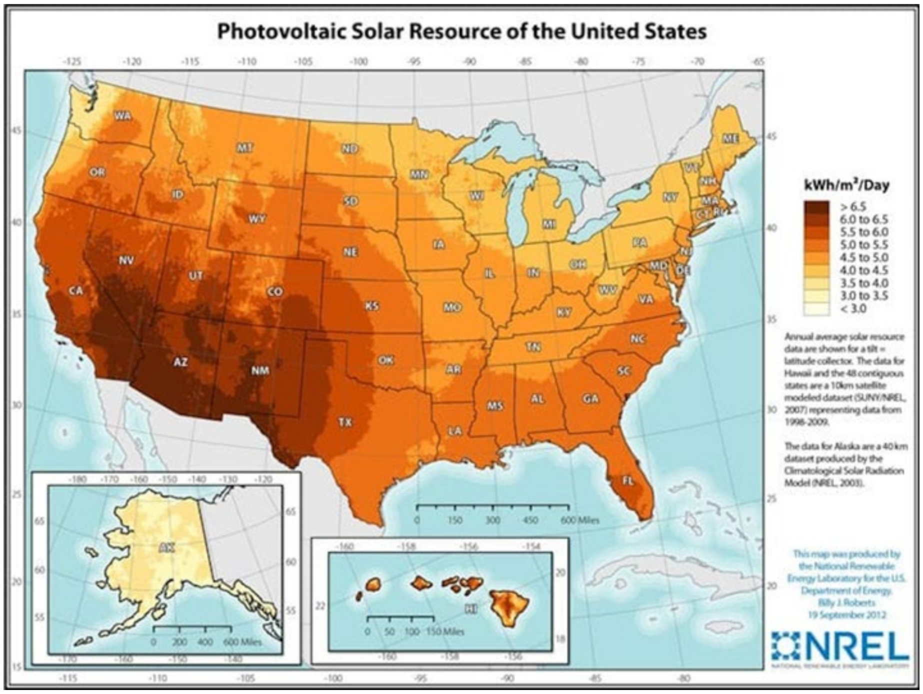
A: Washington has good solar and wind resources, and is, in fact, already experiencing low-cost renewable energy development. A look at the wind resource map prepared by the National Renewable Energy Lab ("NREL") shows how rich the wind resource is, especially in the southeast quadrant of the state.

Figure 7: Washington Wind Resource Map



Washington also has good solar resources. Its average insolation is on par with much of the eastern half of the United States, as can be seen in the following NREL insolation map. Four of the top ten solar states—Florida, North Carolina, Georgia, Virginia—have insolation levels that are similar to Washington's levels, especially in areas in the south-central and southeast portions of Washington. The Commission is undoubtedly aware that Yakima County is the site of several large solar projects under development, with others being proposed.

Figure 8: Photovoltaic Solar Resource of the United States



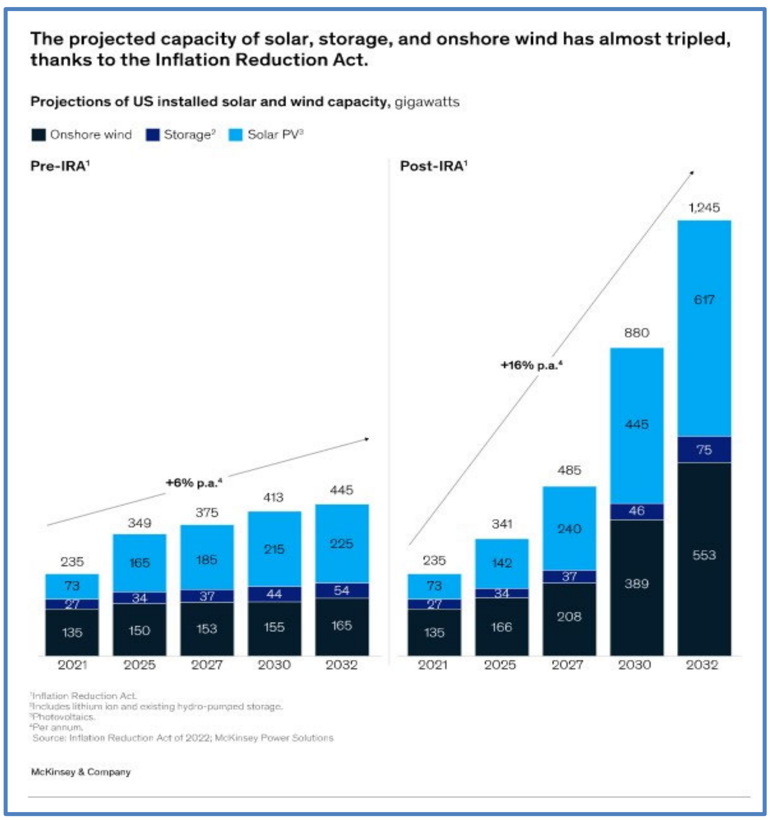
Q: Please explain your third point concerning renewables in EDAM.

A: Low-cost renewable resources could be very profitable in the EDAM market to utilities in Washington. The all-in costs of stand-alone photovoltaic solar generation are often in the range of $20 per MWh. Recall that Lazard (Figure 5 above) prices solar with federal tax credits at $0 to $16/MWh. Wind costs are even lower. While Washington may need some of this renewable energy for its own residents, companies and customers in other states need it as well. EDAM will be a marketplace that will match Washington's sales to out-of-state purchases. If the mid-day market price of energy is, for example, $40/MWh, then energy produced at half that cost (as is the case for many new renewable energy projects) will be very profitable when sold through EDAM.

Q: Are there any other factors that the Commission should consider relating to renewable energy development in Washington?

A: Yes. My fourth point is that the Commission should consider the impact that the IRA will have on solar and wind development. The IRA contains many provisions designed to increase renewable deployment. Federal subsidies for solar have been modified in ways that will make solar investment more directly beneficial to utilities, among other changes. McKinsey & Company issued a recent report that estimates the Inflation Reduction Act will nearly triple the development of wind and solar generation in the next ten years. See Figure 9 below.

Figure 9: Impact of IRA on Projected Solar, Storage, and Onshore Wind Capacity



This means that there will be plenty of market for Washington solar generation to grow into. PacifiCorp will be able to reach much of that market through the EDAM structure. Bottom line, Washington's solar potential is large and could be very profitable to the state's utilities that participate in the EDAM.

V. PURPA AND NET POWER COSTS

Q: Are PURPA-related costs an important factor in the NPC calculation?

A: According to Exhibit RJM-2, long-term firm contracts for renewable energy total $13,464,649 and "QF Washington" contributes another $595,442. Together, these purchases comprise about 14.1% of Purchased Power Expense and about 7.1% of total Net Power Costs.

Q: How are PURPA requirements met in Washington?

A: PacifiCorp appears to meet its PURPA requirements in Washington by offering a combination of "avoided cost" tariffs for qualified facilities with less than 5 megawatts capacity and a negotiated pricing regime under which the Company will purchase renewable energy from larger qualified facilities ("QFs"). This is not unlike many other states. However, based on my experience as Chair of the Colorado Public Utilities Commission, I think there is a better approach to QF purchases that will benefit the utility, its customers, and independent power producers alike: all-source competitive bidding.

Q: Please explain.

A: Colorado initially managed its PURPA obligations by buying QF power at a set tariff rate based on "avoided cost." There was a predictable amount of regulatory jockeying, conflicting studies about avoided cost, and eventually lawsuits. There seemed never to be a consensus on what constituted "avoided cost" and whether the utility was obliged to buy the power when evidence showed it wasn't needed.

In the early 1990s, the Colorado PUC scrapped the avoided-cost-tariff system and replaced it with a different approach. Only the smallest projects (less than 100 kW) are handled by a standard tariff offering. QFs larger than 100 kW are required to offer their projects into a competitive bidding process that is tied to a utility's periodic IRP proceeding. The first phase of the IRP process established the need for additional power and a schedule of acquisition of resources over a five-year implementation period. The theory of this practice is that competitive bids would reveal the cost of the next resources required by the utility in a manner that was superior to estimating avoided cost.

The Colorado PUC carefully designed the competitive bidding process, overseeing the language of the solicitation, the model contract language and importantly, employing an Independent Evaluator to check the selection and negotiation processes.[18] It was important to the PUC that the process be transparent and give assurance to all players that the results would be fair.

As the years passed, competitive bidding was applied to renewable energy projects (PURPA-affected or not) that utilities began to purchase to meet renewable energy targets. By 2016, the system and the market had matured into a remarkable combination where the utilities were swamped with very low-cost wind, solar, and storage projects. Anyone will tell you that the process has been a resounding success.

[18] 4 Colo. Code Regs. § 723-3-3611-3613.

Q: What are the advantages of using competitive bidding to acquire PURPA resources?

A: I would cite four major advantages;

1. All-source competitive bidding eliminates the nettlesome problem of determining a utility's "avoided cost" with all its variations for resource size, quality, geography, etc. Competitive bidding sorts out those variables.

2. With a well-designed regime, industry participants will be treated equitably and will trust the process. There will be winners and losers, but probably not litigious losers.

3. In contrast to case-by-case negotiating, competitive bidding brings out many bidders at once on equal terms; the acquisition can stretch over three or four years.

4. And most importantly, the utility is able to buy the economically <u>correct</u> amount of energy resources, at economically <u>correct</u> prices; fixed tariffs and negotiations are liable to buy too much or too little energy.

Earlier I discussed the results of Xcel Colorado's competitive bidding for resources. It's fair to say that everyone, including Xcel and the electricity trade press, were quite surprised at the outcome of that solicitation. The resource RFP drew interest from hundreds of bidders, who collectively offered 410 proposals. But most surprising were the rock-bottom prices that the solicitation produced. At the time of that solicitation, prices for wind and solar with storage were the lowest seen in the country.

PacifiCorp Washington is a smaller playing field than Xcel's Colorado territory, but I predict comparable results if the Commission instructs the state's utilities to fulfill their PURPA needs by using all-source competitive bidding following the acceptance of the utility's integrated resource plan. And, as discussed earlier, adding more low-cost wind and solar resources can replace gas burn in units and position PacifiCorp to profit from EDAM.

Q: What sort of portfolios do you recommend the Washington Commission require PacifiCorp to evaluate in its IRP?

A: As the economics of electric power in the Western Interconnection continue to change, the Commission should ensure that PacifiCorp is looking at supply portfolios that take advantage of the changes. My recommendation is that, at a minimum, the Commission require a portfolio that maximizes the use of federal tax credits available to PacifiCorp from the Inflation Reduction Act. The Commission should also direct the Company to run a sensitivity analysis increasing the level of renewable generation on PacifiCorp's system in order to test whether deployment of more low-cost renewables will keep Washington's costs and rates in check due to their low cost and also the ability to sell these resources on the market through EDAM.

VI. CONCLUSION

Q: Please summarize your findings and recommendations.

- Fuel cost sharing is a valuable element of the PCAM in Washington. It serves as a corrective to some of the poor incentives of traditional regulation and partially levels the regulatory playing field between fossil generation and zero-cost renewable generation.
- EDAM does not replace or moot out the importance of fuel cost risk sharing. Sharing will add to the benefits of EDAM; entering EDAM does not lessen the value of sharing.
- An PCAM without the sharing mechanism will present PacifiCorp with a classic "moral hazard." It will take risks with fossil fuel resources because the Company knows it will be made whole by the regulator. The Commission should not eliminate sharing mechanisms.
- The Commission should use the occasion of the IRP to study supply portfolio variations, especially in view of the changed incentives brought by the IRA and EDAM; the Commission should test whether deployment of more low-cost renewables will keep Washington's costs and rates in check.

- The Commission should examine and adopt competitive bidding as a superior method for PURPA compliance. Competitive bidding can improve outcomes that benefit the utility, consumers, and independent power producers alike.

Q: Does this complete your testimony at this time?

A: Yes.