Exh. SJK-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET UE-240006

DOCKET UG-240007

DIRECT TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, employer, and business address.

A. My name is Scott J. Kinney. I am employed as the Vice President of Energy Resources at Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational and professional background?

A. Yes. I graduated from Gonzaga University in 1991 with a Bachelor of Science in Electrical Engineering and I am a licensed Professional Engineer in the State of Washington. I joined the Company in 1999 after spending the first eight years of my career with the Bonneville Power Administration. I have held several different positions at Avista beginning as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations Department as a Supervisor and Operations Support Engineer. In 2004, I was appointed as the Chief Engineer, System Operations and as the Director of Transmission Operations in June 2008. I became the Director of Power Supply in January 2013 and Vice President of Energy Resources in September 2022.

The Energy Resources group is primarily responsible for producing or procuring the electricity and natural gas to serve our customers' needs, including the construction, operation, and maintenance of our generation facilities and the optimization of those electric and natural gas facilities for the benefit of our customers.

Q. What is the scope of your testimony in this proceeding?

A. My testimony provides an overview of Avista's electric and natural gas resource planning and energy supply operations. This overview includes summaries of the

Company's current resource plan, an update on the Company's participation in the Western Resource Adequacy Program and Western Energy Imbalance Market, resource needs to support compliance with the Climate Commitment Act (CCA), an overview of the Company's Energy Resources Risk Policy, the Company's new Energy Trade and Risk Management (ETRM) system, and an update on the use of the Company's demand response contract with Inland Empire Paper (IEP). I also provide an overview of the Company's natural gas supply and resource plan. Next, I address new resource acquisitions from Chelan Public Utilities District (Chelan PUD) and from the 2022 All-Source Request for Proposals (RFP). Finally, my testimony concludes with a request to move to a 95/5 split in the Energy Recovery Mechanism and removal of the current deadbands.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- Exh. SJK-2 Avista's 2023 Electric Integrated Resource Plan and Appendices.
- Confidential Exh. SJK-3C Avista's Energy Resources Risk Policy.

- Exh. SJK-4 Nucleus Assessment Final Report.
- Exh. SJK-5 ETRM Implementation Business Case.
- Confidential Exh. No. SJK-6C IEP Special Contract Tracking of Curtailment Events.
- Exh. SJK-7 2023 Natural Gas IRP and Appendices.
- Confidential Exh. SJK-8C 2020 Renewable RFP Report and Documentation.
- Confidential Exh. SJK-9C First Chelan PUD Power Purchase Agreement.
- Confidential Exh. SJK-10C Second Chelan PUD Power Purchase Agreement.
- Confidential Exh. SJK-11C 2022 All-Source RFP Report and Documentation.
- Confidential Exh. SJK-12C Lancaster Power Purchase Agreement.
- Confidential Exh. SJK-13C Columbia Basin Hydro Power Purchase Agreement.
- Confidential Exh. SJK-14C Clearwater Wind Power Purchase Agreement.
- Confidential Exh. SJK-15C Lancaster CCCT Emissions Performance Standard Documentation.
- Exh. SJK-16 Review of PCAM Implementation in Other States

II. RESOURCE PLANNING AND POWER OPERATIONS

Q. Please provide a summary of Avista's power supply operations and acquisition of new resources.

A. Avista uses a combination of owned and contracted-for resources to serve its load requirements. The Energy Resources Department (Energy Resources) is responsible for dispatch decisions related to those resources for which the Company has dispatch rights. Energy Resources monitors and routinely studies capacity and energy resource needs. Short- and medium-term wholesale transactions are used to economically balance resources with load requirements. The Integrated Resource Plan (IRP) generally guides longer-term resource decisions such as the acquisition of new generation resources, upgrades to existing resources, demand-side management (DSM), demand response, energy storage, and long-term contract purchases. Resource acquisitions typically include a RFP and/or other market due diligence processes.

A. 2023 Electric Integrated Resource Plan

Q. Please summarize Avista's load and resource position.

A. Avista's 2023 IRP shows forecasted annual energy and capacity deficits beginning in 2026. The deficits are a result of load growth and the elimination of Colstrip from the Company's resource portfolio. The winter and summer capacity resource positions are shown on page 4-5 of Avista's 2023 Electric IRP, included as Exh. SJK-2, which was filed with the Commission on June 12, 2023.

Q. How does Avista plan to meet future energy and capacity needs?

A. The Preferred Resource Strategy (PRS) in the 2023 Electric IRP guides the Company's resource acquisitions, subject to additional legislative requirements, such as the clean energy goals under Washington's Clean Energy Transformation Act (CETA) and the CCA. The IRP provides details about future resource needs, specific resource costs, resource-operating characteristics, and scenarios used for evaluating the mix of resources for the PRS under different future assumptions. The IRP represents the preferred plan at a point in time; however, Avista continuously evaluates alternative resource options to meet current and future load obligations considering new legislation and market opportunities.

Avista's 2023 PRS includes 2,003 MW of net supply-side resources which includes 1,045 MW of new wind, 587 MW of natural gas-fired generation, 696 MW of power to gas (hydrogen to ammonia CT), 11 MW of biomass, battery storage, 10 MW of solar, 197 MW of energy storage, 216 MW of net hydro power additions, and the loss of 766 MWs of coal and natural gas-fired resources from Avista's resource portfolio. The PRS also includes 7 MW of demand response and 85 aMW of new energy efficiency through 2045. The timing and type of resources included in the PRS for the 2023 IRP are provided in Table No. 1 below.

Table No. 1: 2023 Electric IRP Preferred Resource Strategy

Resource	2024-2029	2030-2034	2035-2039	2040-2045	Total
Natural Gas	283	90	0	213	587
Natural Gas Retirements	0	0	(62)	(482)	(544)
Coal Retirements	(222)	0	0	0	(222)
Thermal Total	**61**	**90**	**(62)**	**(269)**	**(179)**
Hydrogen to Ammonia CT	0	0	88	608	696
Power to Gas Total	**0**	**0**	**88**	**608**	**696**
Biomass	11	0	0	0	11
Biomass Total	**11**	**0**	**0**	**0**	**11**
Northwest Wind	0	200	0	545	745
Montana Wind	100	200	0	0	300
Wind Total	**100**	**400**	**0**	**545**	**1,045**
Distributed Solar	4	4	1	1	10
Utility-Scale Solar	0	0	0	0	0
Solar Total	**4**	**4**	**1**	**1**	**10**
Demand Response	7	0	0	0	7
Demand Response Total	**7**	**0**	**0**	**0**	**7**
Short-Duration Storage (<8 hr)	0	0	0	25	25
Medium-Duration Storage (8-24 hr)	0	0	0	0	0
Long-Duration Storage (>24 hr)	0	0	52	118	170
Distributed Storage (<4hr)	0	0	1	2	2
Energy Storage Total	**0**	**0**	**53**	**144**	**197**
Hydropower	322	6	0	0	328
Hydropower Contract Expirations	(24)	(88)	0	0	(111)
Hydropower Total	**298**	**(81)**	**0**	**0**	**216**
All Resource Total	**481**	**413**	**80**	**1,030**	**2,003**
Additions	727	500	142	1,511	2,880
Subtractions	(246)	(88)	(62)	(482)	(877)

B. Western Resource Adequacy Program (WRAP)

Q. Would you please provide a high-level summary of Avista's participation in the WRAP?

A. Yes. Avista has been involved in the design and development of the WRAP program since its inception in the Fall of 2019. Avista has participated in the three non-binding, forward-showing seasonal trials consisting of the Winter of 2022/23, Summer 2023, and Winter 2023/24. The Company is also participating in the first non-binding operations program trial in the Winter of 2023/24. Avista anticipates the WRAP will provide significant benefit to its customers by ensuring that Avista and the participant footprint across the West has committed adequate forward capacity under ownership or contract to meet peak seasonal Summer and Winter demand. The WRAP ensures deliverability of capacity with a requirement to procure at least 75% of firm or conditional firm transmission prior to the critical season. It also includes a backstop operational program through a sharing mechanism that allows Avista to call on excess energy held by other program participants if operating conditions are significantly different than what was planned. An additional WRAP benefit is the requirement to use consistent resource planning methodologies including a reliability planning metric (Loss of Load Expectancy) and resource capacity contribution calculations (Effective Load Carrying Capability). Using consistent planning methods allows the region for the first time to truly understand and monitor committed and available regional capacity and energy to serve customer load.

Avista has committed to participate in the WRAP for the foreseeable future to reduce resource operating risk and improve overall system reliability. The Company anticipates spending $282,000 in 2025 and $268,000 in 2026 to participate in the WRAP based on forecasts provided by the Western Power Pool who is the program administrator. Avista is committed to join the first binding forward-showing season that has sufficient committed participants to ensure adequate capacity and energy is available through the program. The Company is hopeful the first binding season will occur in the Summer of 2026.

C. <u>Western Energy Imbalance Market</u>

Q. Please provide an update on Avista's involvement with the Western Energy Imbalance Market.

A. As detailed in the Company's last general rate case, Avista started participating in the California Independent System Operator (CAISO) Western Energy Imbalance Market (EIM) beginning in March 2022. The Company and its customers have observed value from its participation in the EIM through additional revenue from dispatching resources that were either previously held for operating reserves or not able to be dispatched on a five-minute basis, or through lower resource dispatch costs because resources dispatched through the EIM allowed Avista to reduce generation at its higher cost resources. Company witness Mr. Kalich explains how EIM participation benefits customers by $5.5 million annually in this case, based on model results from Aurora using intra-hour five-minute markets.

Q. Please discuss the changes in operations and dispatch of Avista's generation resources based on its participation in the EIM.

A. Avista has significantly changed the operation and dispatch of its generation fleet based on participation in the EIM. During the Company's 20-months of EIM operations, Avista's resources have been ramped up or down more frequently to capture value depending upon the market dispatch price. The increase in ramping leads to additional maintenance intervals and associated costs. The Company believes that a new approach to recovering associated EIM operating costs should be incorporated into future rate recovery so that any additional revenues collected and associated with added maintenance costs from resource cycling will be applied directly towards those costs. The Company is evaluating different methodologies and will provide additional information during the pendency of this case. One method being evaluated includes capturing some of the revenue received from a portion of EIM bids and using it to fund additional maintenance costs resulting from unit ramping. As part of Avista's resource bid, the Company includes a maintenance adder as allowed in the EIM market design. The maintenance bid adder is included in our energy bid submission to the CAISO market and recovered through our settlement payments. The Company is currently evaluating if revenue associated with this EIM bid maintenance adder can be separated as a generation maintenance expense offset, rather than recovered through the Energy Recovery Mechanism (ERM). By separately accounting for this portion of the resource bid, EIM revenues and expenses will be appropriately matched. Another approach being evaluated is to include the generation maintenance costs associated with EIM participation in the ERM. This would require a special accounting petition. The intent of this evaluation is to ensure that revenues received from EIM participation are appropriately matched to associated generation maintenance on an annual basis.

D. Climate Commitment Act Resource Needs

Q. Would you please provide a summary of Avista's resource needs to comply with the CCA?

A. Yes. As discussed by Company witness Mr. Thackston, the Climate Commitment Act was effective on January 1, 2023. Meeting the requirements of the rule resulted in increased workload for several departments, including Government Relations, Environmental, Energy Supply, Accounting, Regulatory, and Risk Management. We anticipate labor requirements will continue to increase to comply with the rule, including forecasting, tracking, operational implementation, reporting, evaluating, and funding new investments for low-income customers. Further, as the Company's compliance obligations associated with CETA increase, so will the complexity of the analyses, monitoring and reporting.

Avista has added significant processes to both its power and natural gas supply departments to account for activity associated with CCA compliance. Currently, this additional CCA work has been performed by existing employees. However, this resource approach cannot be sustained as other critical work has been either delayed or not adequately supported. The Company plans to hire four additional positions in 2024 to support compliance with CCA. These positions include a Climate Compliance Manager, a CCA Portfolio Manager, an Energy Supply Analyst, and an Investment Program Manager.

The need for these positions has materialized beginning in 2023 as the complexity and broad scope of CCA compliance has developed. The Climate Compliance Manager will oversee all the various components of CCA within Energy Supply and serve as the lead policy expert and Energy Supply liaison to other key impacted business units at Avista (Environmental, Finance, Accounting, Energy Efficiency, Community Affairs, etc.). The CCA Portfolio Manager will be tasked with recognizing and following the impacts of the CCA and other climate-based initiatives from an economic perspective to properly manage and value Avista's portfolio of climate negotiable items (CCA Allowances, RECs, RINs, etc.). The Energy Supply Analyst will focus on the changing requirements of the Avista energy supply portfolio (natural gas and electric) to account and plan for meeting load obligations while also meeting climate-based regulations. The Investment Program Manager will facilitate the development of a process and programs to support new low-income offerings. Company witness Ms. Schultz discusses in Exh. KJS-1T her adjustment (PF Adjustment 3.10) to reflect these incremental positions, increasing Washington electric and natural gas labor expense approximately $500,000. Please note these positions are incremental to what is included in the Company's Non-Executive Labor Adjustment 3.07. The exact salaries will be updated as position profiles and salary ranges are finalized.

Q. Does the Company anticipate it will need any additional new positions to comply with the requirements of CCA beyond those four identified above?

A. Yes, it does. The Company is still learning of the broad reaching effects of what it means to equitably transition to clean energy for all its customers as required by the CCA. The CCA not only changes how the Company views the work it performs, but it changes how the Company will do its work. New clean energy legislation is actively being evaluated as considerations are being made regarding possible linkage with California and Quebec, concerns by Washington State Legislators about changes that would need to be proposed for that linkage, significant changes needed upon approval of the Company's first Clean Energy Implementation Plan (CEIP), and ongoing work as it relates to CCA. It is likely that new positions will be necessary to support the growing workload required to successfully comply with the CCA.

Q. Has the Company included any other incremental costs within this case as it pertains to CCA beyond the four positions described above?

A. No, it has not. The CCA labor adjustment is the only pro forma adjustment in this case where the Company is seeking approval of incremental costs incurred to comply with CCA.

E. Avista's Risk Management Program for Energy Resources

Q. Please provide a high-level summary of Avista's risk management program for energy resources.

A. Avista uses several techniques to manage the risks associated with serving customers and managing Company-owned and controlled resources. The Energy Resources Risk Policy attached as Confidential Exh. SJK-3C, provides general guidance to manage the Company's energy risk exposure relating to electric power and natural gas resources over the long-term (more than 41 months), the short-term (monthly and quarterly periods up to approximately 41 months), and the immediate term (present month).

The Energy Resources Risk Policy is not a specific procurement plan for buying or selling power or natural gas at any point in time but is a guide for management to make procurement decisions for electric power and natural gas as fuel for electric generation. The policy considers several factors, including the variability associated with loads, hydroelectric generation, planned and forced outages, and electric power and natural gas prices in the decision-making process.

Avista aims to develop or acquire long-term energy resources based on the current IRP's Preferred Resource Strategy, while taking advantage of competitive opportunities to satisfy electric resource supply needs in the long-term period. Electric power and natural gas fuel transactions in the immediate term are driven by a combination of factors that incorporate both economics and operations, including near-term market conditions (price and liquidity), generation economics, project license requirements, load and generation variability and availability, reliability considerations, and other near-term operational factors.

For the short-term timeframe, the Company's Energy Resources Risk Policy guides its approach to hedging financially-open forward positions. A financially-open forward position may be the result of either a short position situation, for which the Company has not yet purchased the fixed-price fuel to generate, or alternatively has not purchased fixed-price electric power from the market, to meet projected average load for the forward period. Or it may be a long position, for which Avista has generation above its expected average load needs and has not yet made a fixed-price sale of that surplus to the market to balance resources and loads.

The Company employs an Electric Hedging Plan to guide power supply position management in the short-term period. The Risk Policy Electric Hedging Plan is essentially a price diversification approach employing a layering strategy for forward purchases and sales of either natural gas fuel for generation or electric power to approach a generally balanced financial position against expected load as forward periods draw nearer considering time to delivery and market conditions.

F. New Energy Trade and Risk Management System

Q. What has led Avista to implement a new Energy Trade and Risk Management system?

A. Over the last 20 years, the energy market has significantly changed with a shrinking bi-lateral market, the expansion of organized markets, reliance on renewable generation and ever-growing environmental compliance obligations and costs. As the market evolves, the utility must adjust to emerging market requirements, demonstrate compliance, effectively manage the whole power and natural gas business, balance inflationary pressures and risks, and understand it's physical and financial positions.

Prior to the late 1990s, the Company did not have a system to capture wholesale energy trades or systematically manage financial risk and endeavored to meet this need with a commercial software product called Nucleus. Through a merger in the late 1990s, the Nucleus software application was acquired, and the Company chose to develop the product for the wholesale electric and natural gas businesses. This has led to more than 20 years of custom in-house development, on what now is an aging and obsolescing platform. As the system used for conducting wholesale electric and natural gas sales, transmission billing, wholesale risk/credit obligations, managing energy schedules, energy accounting and energy billing, it is a critical business tool for Energy Supply, System Operations, Transmission Billing, Credit and Risk Management, and Resource Accounting.

As the market evolved, so have the efficiencies and capabilities of commercial Energy Trade and Risk Management (ETRM) technologies. Avista is not a software development company and is progressively replacing custom software with industry-standard applications to reduce the risk and costs of owning and maintaining such applications. Implementing a vendor-support ETRM allows Avista to transfer the risk and responsibility of system enhancements, upgrades, and maintenance to the vendor, while leveraging industry-wide market features and functionality common in a commercial ETRM, including those Avista traditionally conducted on spreadsheets. The Company plans to implement a modern ETRM with the necessary associated software to gain efficiencies, reduce spreadsheet reliance, increase frequency and visibility of position reporting, while leveraging an industry wide vendor who will maintain compliance and support with organized market changes and state policies.

Q. What pre-planning did Avista conduct for this project?

A. Although the Company has considered Nucleus replacement options in the past, the identified risks, which were primarily driven by future end-of-life software support dates, did not outweigh the replacement costs or need for change. In 2017 and 2018, Avista explored replacement options, but the timing of the review also coincided with evaluating

Avista's participation in the EIM operated by the CAISO. On April 25, 2019, Avista signed the EIM Implementation Agreement with CAISO and began a multi-million-dollar, three-year software and system integration implementation with significant business change. Conducting an ETRM replacement while simultaneously implementing a multi-year organized market project was an additional risk the Company did not want to assume, and the project was delayed. The Company joined the EIM on March 2, 2022. In the fall of 2022, Avista contracted Utilicast[1] to conduct a Nucleus/ETRM assessment to identify risks, key business processes, ETRM vendor options, and to provide an estimate of implementation costs with the intent to start an ETRM implementation before Avista expanded its organized market participation. This schedule will avoid multiple simultaneous software changes to critical business functions.

Q. What risks were identified by the assessment?

A. The Nucleus/ETRM Assessment (Exh. SJK-4) determined risk severity in terms of impact (low, medium, high, and critical) and likelihood of impact (improbable, plausible, probable, and existing) across personnel, process, and technology. Figure No. 1 below outlines 17 risks associated with continued use and development of the Nucleus application.

[1] Utilicast is a provider of consulting services to the energy and utilities industry, providing expertise and experience in the areas of regional electricity market solutions, power systems operations, project implementation, analytics, energy services, customer care and related IT infrastructure.

<u>Figure No. 1 – Nucleus Assessment Risks</u>

Category	Risks
People	• Personnel Retirement • Personnel Replacement & Retainment (Business & Technology) • Domain / Tech Expertise to Support Processes / Spreadsheets • Documentation Limitations • Uncertainty of Change
Process	• Data Entry – Multiple Manual Entries of Data • Manual Verification Processes (comparing multiple datasets) • Ability to Maximize Dataset Value • New Market Opportunities
Tech	• Spreadsheet Reliance • Vendor Support / Legacy Application End-of-Life • Python Open-Source Package Security • User Interface Quirks • Globalscape and MuleSoft Incongruities • Nucleus Outage Recovery • General Nucleus Cyber Security Awareness • Development Tool Acceptance Impacts to Hiring

Critical High Medium Low

Two risks are categorized as critical – personnel retirement and spreadsheet reliance. Nucleus has been with the Company for more than 20 years as have many of the Nucleus developers. As retirements approach, finding developers with the specific skill set needed for supporting Nucleus will and has been difficult as the required development code is outdated and not used on modern application platforms. In addition, retaining such developers is also a challenge, as developing on current industry-standard code is preferred. It is common practice for the Company to link its Nucleus database to complex, business critical, spreadsheets, including the electric and natural gas financial position report and the electric and natural gas hedging report. These spreadsheets efficiently support critical business functions and decision management, but they also introduce business risks as they are commonly maintained by a single employee with decades of industry experience. As individuals maintaining these spreadsheets approach retirement, mitigation plans can be developed, but decades of industry and Nucleus-specific experience cannot be replaced easily. Instead of primarily relying on spreadsheets to conduct business, a ETRMs systematically handle these functions, strengthening the resiliency and scalability of our processes and lessen reliance on single individuals.

Of the four Nucleus risks categorized as high, end of life software support by the vendor Oracle and potential Nucleus limitations that may arise as the Company considers additional opportunities to participate in expanded organized markets, such as Southwest Power Pool's Markets+, CAISO's Extended Day Ahead for EIM members or a Regional Transmission Organization. As of November 2023, Oracle's published end-of-life date is planned for December 2026 (in May 2023, the end-of-life was December 2025), with an option to purchase extended support through December 2027 for an additional fee. Although Oracle has extended their end-of-life support date in the past, there is no guarantee they will continue to do so in the future. When the end-of-life support date is met, vendors no longer develop enhancements, provide security patches, or performance upgrades. The Company, by continuing with its reliance on Nucleus, is at risk of losing its ability to conduct wholesale electric and natural gas operations safely and reliably and may even be limiting its ability to join organized markets.

To operate in complex organized markets, evaluate participation in future markets, balance multi-jurisdictional energy laws and grid decarbonization – all while providing cost-effective reliable energy – a modern and integrated ETRM system, with a lower risk of terminated vendor support, is required.

Q. Did the Nucleus assessment identify other business system requirements?

A. Although at its core Nucleus is an ETRM, years of custom development have added functionality that would not be native to a modern ETRM system. It is anticipated that additional software beyond the ETRM would be needed to replace all Nucleus functionalities. Utilicast conducted an inventory of business processes and identified core ETRM functionality, and functionality better suited for other systems, such as intertie bidding settlements, meter data management, and balancing authority functions. In a modern software environment, it is common for other systems to handle these business processes and send only the required data to the ETRM to complete business processes. Until Avista issues a software RFP to replace Nucleus functionalities, the total number of replacement systems is unknown.

Q. What is the proposed ETRM Implementation cost and schedule?

A. With Avista input, the Utilicast assessment provided an ETRM implementation estimate range of $21.5 million to $26.3 million, including integration capital and incremental expense costs, system integrator and vendor(s) costs. Annual software license/maintenance costs estimates were between $0.6 million and $1.2 million in a presumed software as a service environment (cloud hosted). This estimate also included implementation and maintenance costs for the to-be-determined ancillary software applications. The Utilicast estimates did not include costs associated with maintaining and supporting Nucleus during implementation, which is estimated at an additional $0.9 million over the four-year period. Using the high range estimate, the Company plans for $25 million in capital and $2.7 million in incremental expense for a combined implementation total of $27.7 million over a four-year period from 2025 to 2028.

As shown in Table No. 2, $1.2 million (system) in expense is needed in 2025 to conduct a software RFP process, hire a system integrator, and support incremental labor associated with RFP requirements and vendor evaluation. In 2026, $0.76 million (system) in expense is needed to support vendor and system integrator costs, and incremental labor associated with the implementation and the support of the Nucleus application. Please see Ms. Schultz's testimony, Exh. KJS-1T, for additional information regarding the Washington electric and natural gas share of incremental ETRM expense included in this case. Exh. SJK-5 contains the ETRM Implementation Business Case.

Table No. 2 – Incremental ETRM System Expense Estimates

Incremental ETRM Implementation Expense Estimates by Year				
2025	**2026**	**2027**	**2028**	**Total**
$1.20	$0.76	$0.45	$0.32	$2.73

Q. Please update the Commission on the curtailment events of the Inland Empire Paper (IEP) Special Contract.

A. Order No 08/05 in Dockets UE-200900 et. al., discusses Avista's agreement to retain certain records of each curtailment event concerning the IEP Special Contract and provided in the following summary form:

i. Every request, including the date, time, and duration of the requested curtailment, and the level of requested curtailment;
ii. Amount of power that IEP actually curtails;
iii. Amount of any penalty paid by IEP to Avista, pursuant to the contract or of any buy-through by IEP;
iv. Interruption Cost Estimator ("ICE") day-ahead price at the Mid-Columbia trading hub;

v. Amount of EIM imbalance payment, if incurred; and
vi. IEP's total load during the event.

The IEP special contract was called on 11 times from January 1, 2023, through June 30, 2023 test period. Please refer to Confidential Exh. SJK-6C for the details of the IEP Special Contract Tracking of Curtailment Events required in Order No. 08/05.

III. NATURAL GAS SUPPLY

Q. Please describe Avista's natural gas portfolio as it relates to the procurement of the natural gas commodity for its local distribution company (LDC) customers.

A. Avista manages natural gas procurement and related activities on a system-wide basis with several regional supply options available to serve LDC customers. The Company purchases natural gas for its LDC customers in wholesale markets at multiple supply basins in the western United States and western Canada. Purchased natural gas is transported from these various US or Canadian-sourced supply basins through six inter-connected pipelines within the region and delivered to city gates or put into the Jackson Prairie Natural Gas Storage Facility (JP) for future use. Avista holds firm contractual transportation rights on five of these pipelines, as well as firm withdrawal capability from JP, helping diversify where supply can be received to meet customers' needs among the three jurisdictions.

JP is an underground aquifer natural gas storage facility located south of Chehalis, Washington. Through a joint ownership agreement, Avista, Puget Sound Energy, and Williams Northwest Pipeline each hold one-third equal, undivided interest of JP. Presently, Avista <u>owns</u> a total of 8,528,013 dekatherms (Dth) of working gas capacity at JP. This capacity comes with a withdrawal capability (deliverability) of 398,667 Dth per day. Jurisdictionally, this amount is broken out as follows:

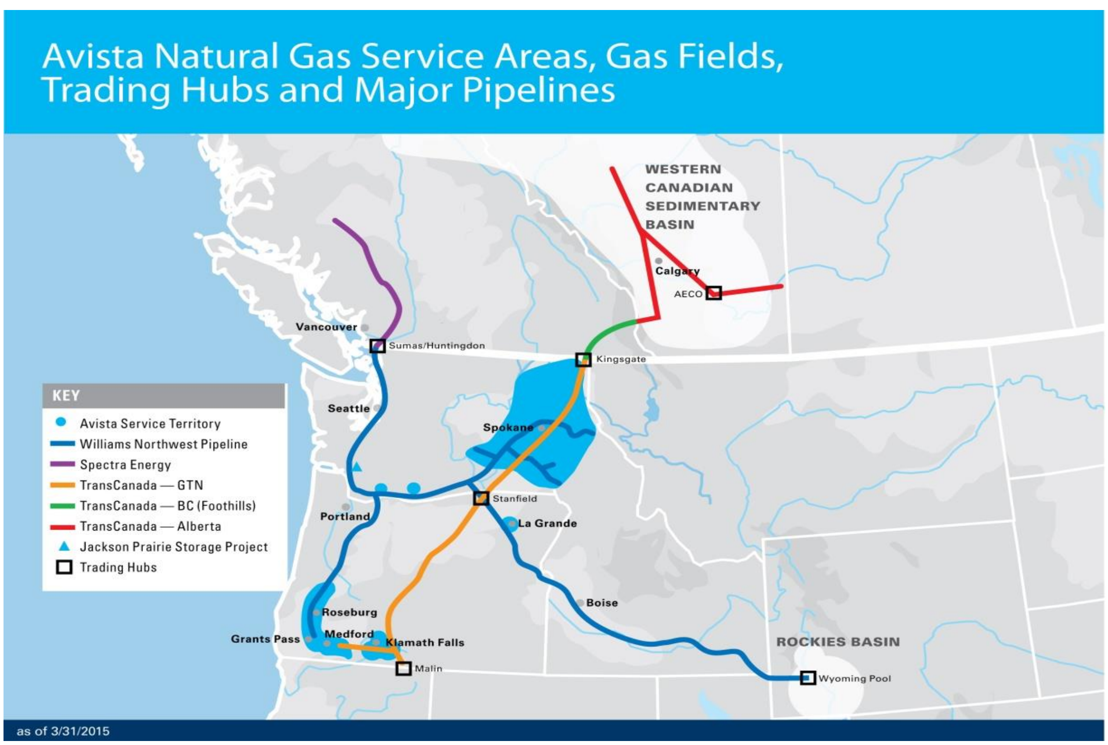
<u>Table No. 3: Jackson Prairie Working and Withdrawal Capacity by Jurisdiction</u>

Jurisdiction	Working Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)
Washington/Idaho	7,704,676	346,667
Oregon	823,337	52,000
Total Owned	8,528,013	398,667

Access to regionally located storage provides several benefits to Avista customers, including improving reliability and flexibility of supply, mitigating daily price volatility and peak demand price spikes, and capturing price spreads between time periods.

Illustration No. 1 below is a map showing our service territory, natural gas trading hubs, interstate pipelines, and the Jackson Prairie Natural Gas Storage Facility.

<u>Illustration No. 1: Avista Natural Gas System Map</u>



Wholesale natural gas prices are a fundamental component of both natural gas procurement and integrated resource planning. Pacific Northwest natural gas prices can be affected not only by regional factors, but by global energy markets, and supply and demand factors from other regions within the United States and Canada. Price volatility and delivery constraints can have an impact on where our natural gas is sourced. Avista's diverse portfolio of natural gas supply resources allow the Company to make natural gas procurement decisions based on the reliability and economics that provide the most benefit to our customers.

Because future natural gas prices cannot be accurately predicted, the Company has developed a Natural Gas Procurement Plan (Plan) to ensure reliable supply and a level of price certainty in volatile markets. The Company recently made modifications to the Plan from past practices to hedge a higher percent of load prior to the delivery month, considering the recent natural gas price volatility the region has experienced, to ensure reliable supply and a level of price certainty in these more volatile markets since future natural gas prices cannot be accurately predicted. Market conditions, analysis, and experience shape the updated Plan's overall strategy, which still includes a comprehensive program of hedging, storage utilization, and index purchases. This approach is diversified by transaction time, term, counterparty, and supply basin. The Plan provides general guidelines regarding the use, procurement, and execution of transactions as authorized in Avista's Energy Resources Risk Policy (Confidential Exh. SJK-3C). Although the specific provisions of the Plan will change based on ongoing analyses and experience, this Plan utilizes a combination of strategies to reduce the impacts of fluctuating commodity prices.

The Natural Gas Supply Department continuously monitors the results of the Plan, evolving market conditions, variation in demand profiles, new supply opportunities, and regulatory conditions. Although the initial windows and targets are established in the initial design phase, the Plan allows discretion for ultimate decision making as market conditions warrant. The Plan is reviewed with senior management and state regulators in the Fall of each year.

Q. What delivery period does the natural gas Procurement Plan include?

A. The target delivery periods for the Procurement Plan cover 36 months. The first five to eleven months are addressed in monthly blocks depending on the current month. After these monthly blocks, a minimum of four seasonal blocks are addressed in consecutive November – March and April – October blocks. Additional November – March or April – October blocks are added so that in any given delivery period, there are between 30 and 36 months to be monitored and eligible for a hedge. By the time the delivery period is reached, each individual month will have been available for hedging for a full 36 months prior to delivery.

Q. Please describe the components of the Natural Gas Procurement Plan.

A. Each year a comprehensive review of the previous year's Plan is performed. The review includes analysis of historical and forecasted market trends, fundamental market analysis, demand forecasting, and transportation, storage and other resource considerations, with the load forecast being the basis of the Plan. Avista secures/purchases natural gas supply through the transactions and procedures described below to serve load and optimize resources for the benefit of customers:

1. **Fixed-Price Purchases**: To provide a level of price certainty in volatile natural gas commodity markets, Energy Supply will hedge some of its load with fixed-price transactions, either with fixed-price physical purchases or with financial swaps or financial futures, which will be matched to purchases of index-priced physical products prior to the products settlement. These hedges will be structured to diversify

procurement in terms of timing of the transaction and duration of committed supplies.

2. **Storage Injections and Withdrawals**: Avista owns and contracts for storage services at Jackson Prairie. Avista has a contractual operational requirement to have its share of Jackson Prairie full by September 30 of each year. Energy Supply retains flexibility in terms of the timing and volume of the injection and withdrawal schedules. Actual storage injections and withdrawals will be executed to optimize the economic value of storage within the reliability constraints of the project and the ability to serve retail customers' peak day needs.

3. **Index-Based Physical Purchases**: Energy Supply generally purchases physical index-based natural gas for up to the difference between the average daily load forecast for each month and the sum of the fixed-price purchases and projected storage withdrawals. Energy Supply retains flexibility to modify the components of its purchases in a month due to operational or other reasons. The selected indices may be first-of-month indices or an average of daily index prices for the month.

4. **Daily Adjustments Due to Load Variability**: To the extent actual loads differ from the average daily load forecast for the month, the difference will be managed through a combination of: a) daily purchases or sales of natural gas, or b) withdrawals from, or injections into, natural gas storage facilities.

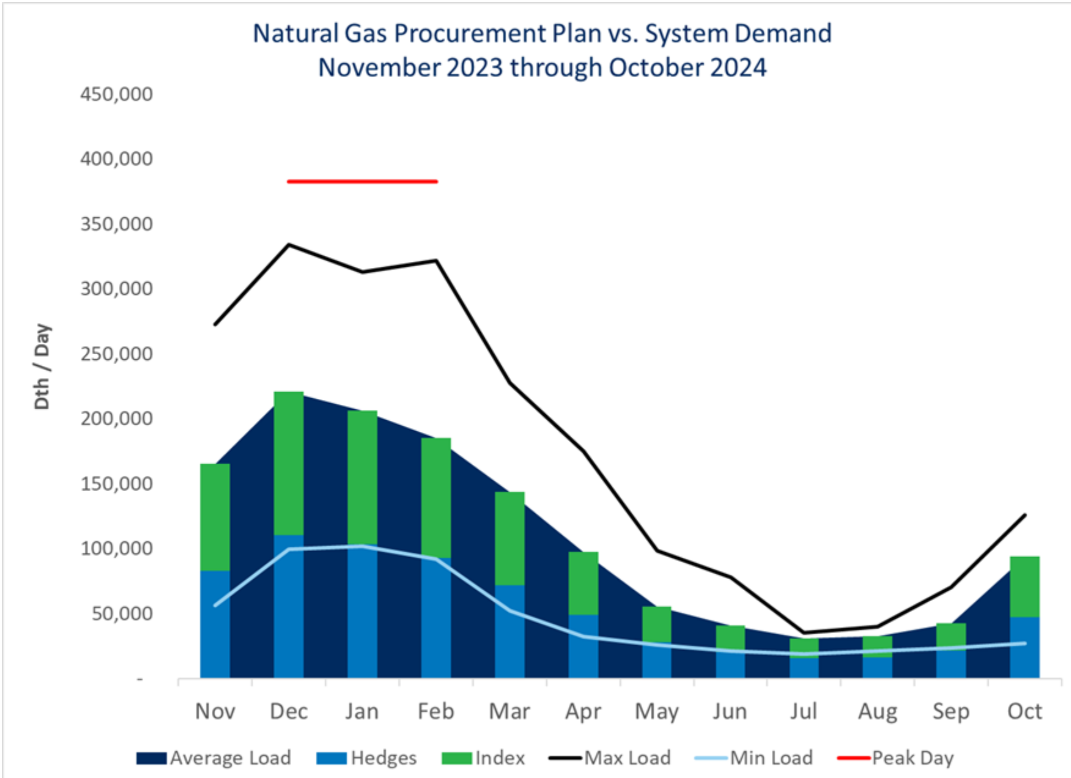
5. **Use of Derivative Contracts**: Subject to limitations in the Energy Resources Risk Policy, Energy Supply may enter derivative-based contracts intended to reduce or manage exposure to rising prices or fluctuating loads.

6. **Resource Optimization**: Energy Supply may enter transactions that create value for customers using unutilized supply, transportation, or storage assets. Utilization of these resources reduces fixed costs and lowers overall costs to customers.

Q. Please describe how the Procurement Plan manages volatility.

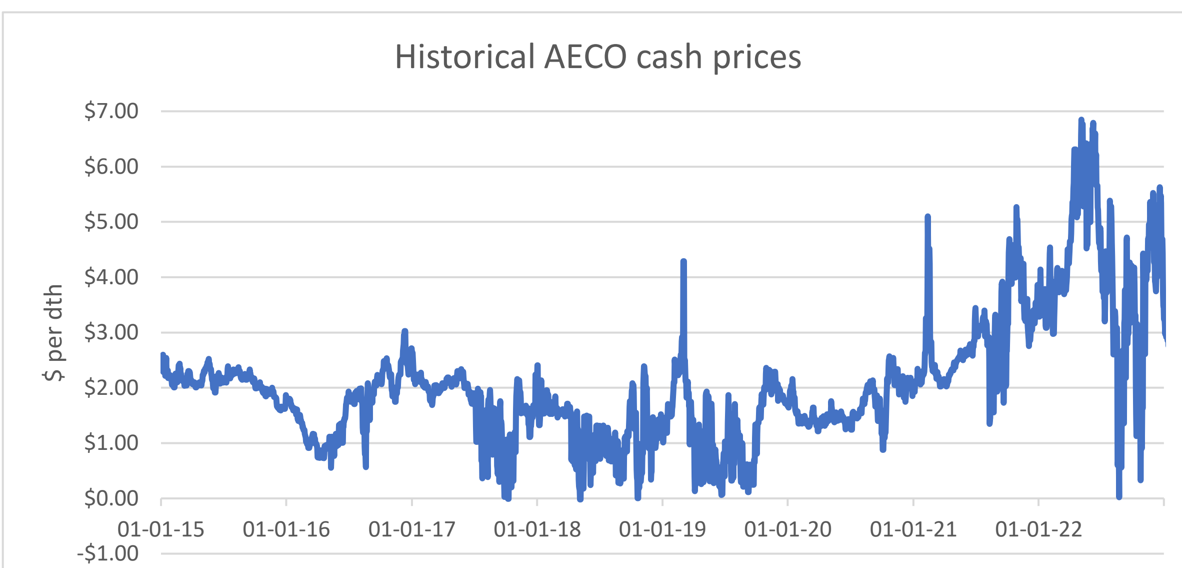
A. The Plan focuses on managing the costs associated with serving varying retail load with supply from a wholesale market with price volatility. To manage these seasonal, monthly, and daily volume swings, Avista shapes the components of the Plan by month (i.e., more natural gas is hedged for the winter months than for the summer). Daily index purchases and withdrawals from JP are used to meet demand not covered by hedges. Illustration No. 2 below includes a chart that shows the demand volatility.

Illustration No. 2: Natural Gas Procurement Plan vs. System Demand



Price volatility can also vary widely by season, month, and day. Illustration No. 3 below includes a chart depicting the natural gas price volatility over time.

Illustration No. 3 – Historic Natural Gas AECO Prices



Avista cannot predict with accuracy what natural gas prices may be. Our experience and intelligence related to market fundamentals guide our procurement decisions. By layering in fixed price purchases over time, setting upper and lower pricing levels on the Hedge Windows, managing the VaR of our LDC natural gas portfolio's open position daily, and actively managing storage resources, Avista is able to meet our goal of providing a meaningful measure of price stability and certainty, and competitive prices for our customers.

IV. 2023 NATURAL GAS IRP

Q. Please provide an overview of the Company's development of its 2023 Natural Gas Integrated Resource Plan.

A. The 2023 Natural Gas IRP was filed with the Commission on March 31, 2023. The IRP includes forecasts of natural gas demand and any supply-side transportation resources and demand-side measures needed for the coming 20-years, which will help Avista continue to reliably provide natural gas to our customers. A copy of the Avista's 2023 Natural Gas IRP is included as Exh. No. SJK-7.

Q. What are the summary highlights from the 2023 IRP?

A. Highlights from the 2023 IRP are as follows:

- Idaho has higher growth when compared to Oregon and Washington with growth rates of 1.5% in the study horizon. This is primarily the result of building code changes for Residential and Commercial customers in Washington with expected impacts reducing future customer demand to strictly space heat backup during cold weather events. Oregon maintained its expected growth trajectory at 0.9%, though new statewide policy or code may reduce customer expectations like those displayed in Washington.

- Weather futures were utilized in the IRP as a forecast to possible temperatures Avista could see in its service territories. The peak day design weather considers a 99% probability of a weather event centered on a rolling 30 years of weather data.

- Alternative fuels like renewable natural gas, synthetic methane and hydrogen were incorporated into the IRP to help customers in Oregon and Washington comply with climate policy emissions targets while meeting energy demand.

- Oregon and Washington both have Climate policies in place to meet climate reduction targets by 2050. These policies will be further considered along with impacts to Avista's system in the 2025 IRP.

Q. Has the Company's 2023 Natural Gas IRP been acknowledged by this Commission?

A. Not yet.

Q. When will the Company file its next natural gas IRP?

A. Avista plans to file the 2025 natural gas IRP on or before April 1, 2025.

V. <u>NEW GENERATION RESOURCES – CHELAN PUD</u>

Q. Can you please explain what is different about this filing for contracts with Chelan PUD hydro compared to the Company's 2022 rate filing?

A. Yes, the Company filed for a determination of prudence for a PPA with Chelan PUD in Case No. UE-220053 based on the 2020 RFP. As discussed in that case by Company witness Mr. Thackston, the first PPA with Chelan PUD was selected along with a biomass project. After the biomass project removed their bid from further consideration due to pending environmental legislation at that time, the Company re-engaged with Chelan PUD on their <u>second bid</u> which also ranked in the top three bids of the evaluation matrix for the 2020 RFP. The Company closed out its 2020 RFP with a second contract with Chelan for an <u>additional</u> 5% (88 MW/51 aMW) with delivery starting on <u>January 1, 2026</u>. The second contract added an additional 5% share of Chelan PUD hydro from January 1, 2026, through December 31, 2030 and increases to a 10% share on January 1, 2031 and expires on December 31, 2045. That second contract was discussed in the 2022 case (Dockets UE-220053 et. al.) but was not included as part of that general rate case since the contract started in 2026 and was outside of the test year for that case. Table No. 4 illustrates the sizing and timing of each of the PPAs.

Table No. 4: Summary of Chelan PPAs

Description	MW / aMW	Timeline
5% Fixed-Cost	88 MW / 51 aMW	January 1, 2024 – December 31, 2033
5% Cost-Plus	88 MW / 51 aMW	January 1, 2026 – December 31, 2030
10% Cost-Plus	176 MW / 102 aMW	January 1, 2031 – December 31, 2045

Q. Please explain the Chelan PUD Hydro Slice Power Purchase Agreements and what was the need for these resources.

A. Avista's 2020 request for proposals (RFP) for renewable energy resulted in the acquisition of an additional 5% slice of Chelan PUD's Rocky Reach and Rock Island hydro projects. The new contract provides energy and capacity to Avista beginning on January 1, 2024 and continuing through December 31, 2033. As explained later in my testimony, an additional contract was signed for 5% or 88 MW hydro slice of the Rocky Reach and Rock Island hydro projects starting January 1, 2026, that increases to 10% (176 MW) starting in 2031 and ending in 2045. The acquisition began with the needs identified in the 2020 IRP with a goal to acquire resources meeting Avista's renewable energy need at less-than avoided cost inclusive of the social cost of carbon. Long-term resource acquisitions below this avoided cost deliver net value to customers in Washington State.

A full summary of the RFP process and justifications for signing the 2020 RFP Chelan

PPA is in Confidential Exh. SJK-8C – 2020 Renewable RFP Report, containing the following supplemental documentation in addition to the main summary report:

- Exhibit A – Evaluation Methodology
- Exhibit B – Avista 2020 Renewables RFP Instructions and Preliminary Proposal Information
- Exhibit C – Avista 2020 Renewable RFP Document
- Exhibit D.1 – Evaluation Matrix 9/8/20
- Exhibit D.2 – Financial Analysis 9/14/20
- Exhibit E.1 – Short List Bid Scoring Summary 9/4/20
- Exhibit E.2 – Financial Analysis 9/30/20
- Exhibit F – Commission Staffs Update 9/22/20
- Exhibit G.1 – Evaluation Matrix Short List Bids 10/14/20
- Exhibit G.2 – Financial Analysis Summary 10/14/20
- Exhibit H – Management Approvals
- Exhibit I – Updated Presentation 3/12/21

Q. Would you provide a simplified timeline of events leading up to the execution of the PPAs from the 2020 Renewables RFP?

A. Yes. The following list is a timeline of the major events leading up to the execution of the Chelan PUD Hydro PPAs:

- **February 28, 2020:** Company files 2020 IRP showing need for new clean resources.
- **June 3, 2020:** Renewable RFP update to WUTC.
- **June 17, 2020:** Renewable RFP update (agenda item) to IPUC on Avista IRP discussion agenda.
- **June 18, 2020:** RFP and eval methodology docs to WUTC.
- **June 18, 2020:** RFP update and eval methodology to ATG PC.
- **June 26, 2020:** Phase I – RFP released.
- **July 22, 2020:** Preliminary information due.
- **July 31, 2020:** Short list identified.
- **August 21, 2020:** Detailed proposals due from shortlisted bidders.
- **August 21, 2020 –** September 9, 2020: Negotiations with shortlisted bidders.
- **October 16, 2020:** Final bidder(s) selected.
- **November 17, 2020:** RFP update Technical Advisory Committee for the Electric

IRP.

- **March 24, 2021:** Final contracting complete on first RFP selection (See Confidential Exh. SJK-9C for the first Chelan PUD PPA).
- **December 30, 2021:** Final contracting complete on second RFP selection (See Confidential Exh. SJK-10C for the second Chelan PUD PPA).

Q. Please explain why the Company initiated an All-Source RFP for resources in 2020.

A. Based on market conditions and identified resource needs, in the spring of 2020, Avista believed it was a good time to solicit pricing for new renewable resources through a RFP. Indicators that it was an opportune time to acquire resources to meet identified deficiencies included sunsetting of the Production Tax Credit (PTC), pricing and developer activity, competition for preferred projects and locations, technology advancements and the risk of rising competition among utility buyers for least-cost clean resources. The 2020 Renewable RFP resulted in attractively priced offerings of clean energy and dispatchable capacity from existing projects, limiting Company exposure to delays and execution risk.

Q. Please summarize the resource acquisition prudency standards of this Commission considered by Avista in its RFP processes.

A. The Commission articulated in PacifiCorp's rate proceeding (Docket No. UE-090205) four main questions that must be answered to support acquisition of a generation resource as "prudent and used and useful in providing service to customers in Washington" (see Order No. 09, p. 23):

> When examining the acquisition of new facilities, we consider whether: (1) the new resources are necessary; (2) the Company evaluated and considered alternatives; (3) the acquisition decision involved the Board of Directors; and (4) whether the Company's analysis and decision-making process is adequately documented. In addition, new power resources must comply with all state laws including the RCW 80.80 Greenhouse Gas Emissions

Performance Standard.

Each is discussed in order below.

1. Resource Necessity

Q. At the time of the 2020 Renewables RFP, please explain how the Company determined that a new resource was necessary.

A. The 2020 RFP for renewables began with the goal of acquiring renewable energy to meet needs identified in Avista's 2020 IRP at less than avoided costs, including the social cost of carbon. The 2020 IRP identified 100 MW (37 aMW) of on-system wind and 100 MW (48 aMW) of Montana wind needed in 2022, as well as an additional 100 MW (37 aMW) of on-system wind in 2023.

Avista's identified needs in the 2020 IRP along, with industry indicators, revealed the spring of 2020 as an opportune time to request and evaluate competitively priced options. The indicators included the continued sunsetting of the PTC, indicative pricing and activity by developers, growing competition among utilities and other industry players for the ever-shrinking pool of preferred projects and locations, and technology advancements.

2. Evaluation and Consideration of Alternatives

Q. Did Avista evaluate and consider alternatives to the Chelan PUD Hydro PPA?

A. Yes. Though WAC 480-107 does not obligate Avista to perform an RFP, the Company felt it would offer the best outcome for customers and itself. To ensure the broadest possible response, the RFP was open to all parties owning, proposing, or holding rights to renewable resource generation facilities. It was not open to proposals offering only renewable energy certificates.

As specified in the RFP, Avista sought proposals from eligible renewable resources defined by RCW 19.285, including wind, solar, geothermal, biomass, and hydroelectric sources. We also considered proposals including storage. Bidders were required to outline development of up to approximately 120 aMW, with a minimum net annual output of 5 aMW satisfying the requirements of the RFP. Bidders could submit more than one proposal, or proposals with multiple developments, and projects could be new or existing. Our objective was to secure new eligible renewable resource(s) under terms and conditions were economical and favorable to Avista customers. Bidders were required to assume the risks associated with federal tax incentives.

The Company used evaluation criteria and a similar methodology to that used in scoring bids developed in consultation with Black & Veatch, our 2018 RFP third-party independent evaluator. The 2020 RFP differed in in that it included additional emphasis on emerging issues including identified community and vulnerable population impacts. Absent an Avista self-build option, the expense of a third-party reviewer in the 2020 RFP was not necessary. The 2020 RFP methodology is provided in Exhibit A of Confidential Exh. SJK-8C and was shared and discussed with both WUTC and IPUC staffs prior to its issuance.

The general qualifications for each proposal were evaluated and weighted on the six characteristics listed in Table No. 5 below. Weightings for each characteristic were based on their importance helping the Company meet the resource development goals stated in the 2020 IRP. Within each characteristic, <u>points were subtracted or added to an initial 100 points</u> based on responses to the RFP and Avista's interpretation of submitted data. Avista reserved the right to modify the scoring criteria in consultation with Commission Staffs if received proposals contained circumstances not envisioned in the methodology. However, no modifications were necessary for the 2020 RFP.

Table No. 5: 2020 Renewables RFP Evaluation Criteria and Weightings

Characteristic	Weighting (%)
Risk Management	20
Net Price	40
Price Risk	5
Electric Factors	20
Environmental	10
Community Impact	5
Total	100

Avista used a two-step bidding process. In the first step projects were evaluated and ranked projects based on a condensed initial bid translated to the template shown in Exhibit B of Confidential Exh. SJK-8C. This evaluation and ranking focused on conforming each bidder's submittal with the requirements of the RFP, proposed pricing, and other factors. The first step produced a project short list. Shortlisted bidders we asked to submit detailed proposals in accordance with Exhibit C of Confidential Exh. SJK-8C and evaluated against one another.

The two-step approach was well-received. Twenty-five developers submitted over 40 project responses exceeding of 4,800 MW of nameplate capacity on July 22, 2020. All were evaluated quantitatively and qualitatively using predetermined criteria shared with the Staffs of the Idaho and Washington commissions. Preliminary information was reviewed for all projects.

The seven shortlisted projects included three wind, two hydro and one each of solar and biomass. Most shortlisted projects had either executed a binding option to lease the project site or executed lease agreement(s) with landowner(s) and a few projects were from existing generation resources. Over the period August 21, 2020, through September 9, 2020, each shortlisted bidder was asked to provide detailed proposals upon which additional due diligence was performed. The evaluation matrix for shortlisted proposals is included in Exhibit E.1; financial analysis is included in Exhibit E.2 of Confidential Exh. SJK-8C.

A presentation of the RFP process and shortlisted bidders was made to Washington Commission Staff on September 22, 2020 and is available in Exhibit F of Confidential Exh. SJK-8C. The complete evaluation matrix is found in Exhibit D.1 and the financial analysis is provided in Exhibit D.2 of Confidential Exh. SJK-8C

Avista allowed shortlisted bidders to refresh their prices in early September 2020 to help differentiate their projects from the competition. Based on the new pricing information, a new assessment and project ranking was performed. The complete evaluation matrix of the seven shortlisted projects is provided in Exhibit G.1 and the financial analysis including re-pricing is provided in Exhibit G.2 of Confidential Exh. SJK-8C.

Based on the financial and full evaluation matrix analysis, Chelan PUD’s 5% fixed cost hydro slice and a biomass project were selected for further negotiations (Chelan initially bid their 5% and 10% proposals as separate, either/or, proposals). The biomass project pulled its bid from further consideration in early January 2021 citing concerns with pending carbon emission legislation.

Q. How was transmission considered in this decision?

A. The cost of transmission was considered for the each of the projects. Avista is already connected to the Mid-C and has been actively buying power from Chelan PUD for decades. No new transmission facilities or contracts were needed for this PPA.

<u>3. Board of Directors Involvement</u>

Q. Was Avista’s Board of Directors involved with the acquisition of the

Chelan PUD Hydro PPA by Avista Utilities?

A. Yes. The Company's Board of Directors was apprised of the 2020 Renewables RFP and its evaluation process. Documentation of Board involvement is provided in Confidential Exh. SJK-8C including presentations made to them.

4. Documentation of Analysis and the Decision-Making Process

Q. What documentation for the analysis and decision-making process has the Company provided to explain why it entered into contracts for the Chelan PUD Hydro?

A. Confidential Exh. SJK-8C includes complete documentation of the RFP solicitation, and the evaluation process resulting in the selection of the Chelan PUD Hydro PPAs.

Q. Does the Company believe that it has met the criteria and provided the requisite information demonstrating the Chelan PUD Hydro PPAs acquisition were prudent?

A. Yes. My testimony and exhibits provide the documentation necessary to demonstrate the long-term economic benefit of the Chelan PUD Hydro PPA to customers and offers supporting details of Company analysis and decisions. The executed PPA also helps meet Avista and Washington State renewable and clean energy goals under the Energy Independence Act and CETA. The Chelan PUD PPA also fits within the analysis performed under the Company's IRPs. Our Board of Directors agreed with the recommendation to issue the 2020 RFP and was apprised of management's recommendation to negotiate PPAs with Chelan PUD under terms and conditions consistent with their bid proposal. The Company has provided and explained all analytical work completed for this acquisition, to include a competitive RFP inclusive of participation by both Commission Staffs.

Q. Does the PPA with Chelan PUD for hydro power comply with RCW 80.80, the emissions performance standard?

A. Yes, it does. This PPA automatically complies with RCW 80.80 under WAC 173-407-120 (c) because it is powered exclusively by renewable water resources.

VI. NEW GENERATION RESOURCES – 2022 ALL-SOURCE RFP RESOURCES

Q. Please explain the new Lancaster, Columbia Basin Hydro and Clearwater Wind Power Purchase Agreements, and the need for these resources.

A. Avista's 2022 All-Source RFP resulted in the acquisition of a new PPA for 97.5 MW of wind from the Clearwater project in Eastern Montana and the extension of the existing Lancaster PPA. The Columbia Basin Hydro projects were not bid into the 2022 RFP. Avista had participated in a Request for Offer initiated by the project owners in the fall of 2021 and was selected as the preferred bidder. Contract discussions had already begun prior to the Company initiating its 2022 RFP; however, the Columbia Basin Hydro projects contract was evaluated as if it had been bid into the RFP.

Q. Please briefly describe the Lancaster contract.

A. The Lancaster contract is a tolling agreement for continued sole dispatch of its output of the Lancaster gas plant, located in Rathdrum, Idaho. The original contract expires in October 2026. The plant interconnects directly with Avista at the BPA Lancaster substation. Under the new contract, Avista will continue to pay a monthly capacity payment for the sole right to dispatch the plant through December 31, 2041. As before, Avista pays a variable charge and arranges for all fuel for the plant. Please see Confidential Exh. SJK-12C.

Q. Please briefly describe the Columbia Basin Hydro Contract.

A. The Columbia Basin Hydro (CBH) contract was signed in December 2022, purchasing the entire output of CBH's irrigation generation fleet through 2045. Along with the generation, the agreement includes all environmental attributes from its seven hydroelectric projects totaling 146.3 MW of capacity. Avista will take delivery of projects over time as existing contracts with other utilities expire. Table No. 6 outlines the project delivery timeline, capacity, and energy deliveries.

Table No. 6: Columbia Basin Hydro Projects

Project Name	Start Date	Capacity (MW)	Energy (aMW)
Russell D. Smith	1/1/2023	6.1	1.5
EBC 4.6	5/1/2023	2.2	0.9
Summer Falls	1/1/2025	94	41.4
PEC 66	3/1/2025	2.4	0.5
Quincy Chute	10/1/2025	9.4	3.6
Main Canal	1/1/2027	26	11.6
PEC Headworks	9/1/2030	6.2	2.3
Total		**146.3**	**61.8**

These projects are unique, being based on the amount of irrigation used by central Washington farmers from March through October; most generation occurs in May through August. The projects offer consistent firm energy deliveries of valuable renewable summer capacity. Please see Confidential Exh. SJK-13C for a copy of the PPA.

Q. Please briefly describe the Clearwater Wind Contract.

A. The Clearwater Wind Contract is a 30-year PPA signed in January 2023 to acquire 97.5 MW from Nextera Energy's 750 MW Clearwater Wind Farm located approximately 80 miles north of Colstrip, Montana in Rosebud, Custer and Garfield counties in Montana. This contract runs from January 1, 2026, through December 31, 2055. As part of the negotiations, Avista agreed to an Early Commercial Operation Date (COD) where it will accept delivery of test energy as early as September 1, 2024, with an estimated COD of

December 1, 2024. Please see Confidential Exh. SJK-14C for a copy of PPA.

Q. Please explain the timeline of events leading to execution of the PPAs from the 2022 All-Source RFP.

A. The following timeline lists the major events leading up to the execution of the Lancaster, Columbia Basin Hydro and Clearwater Wind PPAs:

- **April 1, 2021:** Company files 2021 IRP showing need for new resources.
- **February 18, 2022:** Avista publishes the final 2022 All-Source RFP on its website www.myavista.com/ALLSourceRFP.
- **Feb/Mar 2022:** Avista hosts Bidders' conference.
- **March 25, 2022:** RFP proposals due to Avista.
- **April 25, 2022:** Avista posts a compliance report consistent with the requirements of WAC 480-107-035(5) to the 2022 All-Source RFP web site.
- **June 10, 2022:** Avista selects and notifies Short Listed Bidders.
- **July 18, 2022:** Detailed Proposals due from Short Listed Bidders.
- **September 2, 2022:** Final price refresh request.
- **September 29, 2022:** Avista selects proposals for Negotiations List.
- **January 20, 2023:** Executed contract with NextEra (Clearwater Wind).
- **March 31, 2023:** Executed contract with Rathdrum Power LLC (Lancaster).
- **February 17, 2023:** Within 30 days after executing an agreement for acquisition of a resource, Avista must file the executed agreement and supporting documents with the Commission - NextEra.
- **April 21, 2023:** Within 30 days after executing an agreement for acquisition of a resource, Avista must file the executed agreement and supporting documents with the Commission - Lancaster.
- **By June 29, 2023:** This report meets the requirements of WAC 480-107-145(2) with the Commission.

Q. Please provide background for why the Company initiated its 2022 All-Source RFP.

A. Avista's 2021 Electric IRP identified needs for additional energy, renewable resources, and capacity to meet customer needs and clean energy goals and requirements between 2026 and 2030. As those needs were within a four-year window, in accordance with

WAC 480-107-009(2), the Company filed a draft all-source request for proposal on November 1, 2021 (Docket UE-210832) soliciting bids meeting all or part of the characteristics or attributes of its resource need. The 2021 IRP identified 196 MW of winter capacity and 190 MW of summer capacity by 2030 for reliability purposes. The objective of the RFP was to secure energy and capacity resource(s) under terms and conditions that are economical and favorable to Avista's customers, while also meeting state energy requirements including CETA and Purchase of Resource Rules. Section II – Resource Need of Confidential Exh. SJK-11C provides specific details of the needs by year and by season.

Q. Can you discuss how the four prudence standards described above apply to the acquisition of the resources identified in the 2022 All-Source RFP?

A. Yes, the four main prudency considerations for resources acquired in the 2022 RFP are discussed below.

1. Resource Necessity

Q. At the time of the 2022 Renewables RFP, please explain how the Company determined that a new resource was necessary.

A. The 2022 All-Source RFP began with the goal of acquiring capacity and energy to meet needs identified in Avista's 2021 IRP. The goal was acquiring resources meeting energy and capacity goals at lowest reasonable cost. The 2021 IRP identified the need for 196 MW of winter capacity and 190 MW of summer capacity by 2030 for reliability purposes,

2. Evaluation and Consideration of Alternatives

Q. What were the overarching issues Avista used to evaluate and consider alternatives to the contracts chosen in the 2022 All-Source RFP?

A. The RFP was open to parties who owned, proposed to develop, or held rights to resource generating facilities. We did not accept proposals for stand-alone renewable energy certificates. In addition, Avista in its 2022 RFP prioritized a procurement process accessible and fair for all bidders. We made specific outreach efforts to encourage bids from minority, women, disabled, and veteran-owned businesses. We also encouraged bidders interested in partnering to support supplier diversity through inclusive, competitive procurement processes.

For its RFP, Avista's intent was to secure resources satisfying identified needs through one or a combination of PPAs, ownership (or future option to purchase) opportunities, self-build options, or demand response projects. The project(s) should fulfill the identified amount and meet delivery period needs with flexible pricing and ownership options to allow for optimal combination to meet established separate or combined goals.

Beyond timing and price, the RFP required bidders to provide information on non-energy (NEIs), environmental, resiliency and security impacts, and other information required to fully evaluate proposals. At the time of release, the Company's CEIP was not approved by the UTC; however, the RFP included preliminary CBIs where applicable.

Q. Did Avista utilize an independent evaluator for the 2022 All-Source RFP?

A. Yes, in parallel with initial RFP development Avista conducted an informal Request for Information (RFI) process to evaluate potential Independent Evaluators (IE). In compliance with WAC 480-107-023(1), Avista filed with the UTC a request for approval of an IE,[2] Sapere Consulting (Sapere), for the purpose of assisting in the design and evaluation of Avista's RFP. On August 12, 2021, by way of Order 01, the UTC approved of Sapere as

[2] Docket UE-210545.

Avista's IE. Sapere's role for the RFP was to:

- Provide professional assistance to Avista's Wholesale Marketing Power Supply Department to assist in the design and fair evaluation of both third party and Avista Proposals in response to Avista's 2022 All-Source RFP;

- Ensure that the RFP process is conducted according to both Idaho and Washington resource acquisition rules, specifically Washington's Purchase of Resource (POR) rules outlined in WAC 480-107-025;

- Review all third party and Avista Proposals responding to the RFP and evaluate the unique risks, burdens, and benefits of each bid;

- Provide to Avista the IE's minutes of meetings and the full text of written communications between the IE and Avista and any third-party related to the IE's execution of its duties;

- Ensure the RFP process is conducted fairly, transparently, and properly assess whether Avista's process of scoring the bids and selection of the initial and final shortlists is reasonable; and,

- Prepare a final report summarizing the duties performed in the design and evaluation and why Avista's selected Proposal is in the best interest of its customers. The report was to be filed with the commission after reconciling rankings with Avista in accordance with WAC 480-107-035(3).

Q. Please explain how Avista evaluated and considered alternatives to the contracts chosen in the 2022 All-Source RFP.

A. The evaluation methodology utilized in the RFP, including categories and weightings, was built upon the template developed and refined as part of the Company's prior RFPs for energy resources. In 2018, the RFP evaluation methodology was developed with the help of a third-party consultant, Black & Veatch, to gain an outside perspective and to ensure a fair and transparent process. In the Company's 2020 Renewable RFP, the evaluation methodology was further refined to include additional NEIs. The evaluation methodology for the 2022 All-Source RFP continued to benefit from modifications to incorporate factors such as the addition of Highly Impacted Communities and Vulnerable Populations, and draft customer benefit indicators from Avista's 2021 CEIP, and it included guidance from our third-party evaluator.

Sapere provided independent review of the preparation of Avista's RFP materials, monitored the process of issuing and communicating with the interested parties, reviewed the proposal materials submitted to Avista, and independently scored the proposals according to the scoring criteria established by Avista.[3] The IE process proved to be effective for the resource selection process as Avista and Sapere did not agree on all scoring quantities, but both resulted in similar rankings of projects. Where needed, Avista and Sapere worked together to resolve any variations in scoring. The result of this negotiation was a short list of bids and, while both parties did not arrive at identical scores, the same resources were ultimately selected. Sapere's IE report is included in Exhibit E of SJK-11C.

The general qualifications for each proposal were evaluated and weighted on six characteristics listed in Table No. 7. The weightings for each characteristic were determined based on their importance in helping the Company meet its resource development goals stated in the 2021 IRP. Within each characteristic, points were subtracted or added to an initial 100 points based on responses to the RFP and Avista's interpretation of submitted data.

Table No. 7: 2022 All-Source RFP Evaluation Criteria and Weightings

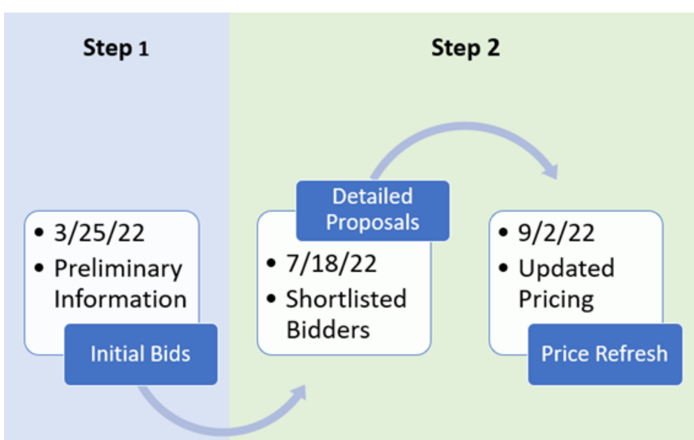
Characteristic	Weighting (%)
Risk Management	20
Net Price	40
Price Risk	5
Electric Factors	20
Environmental	10
Community Impact	5
Total	100

[3] See WAC 480-107-023 for a full list of the IE's responsibilities.

As with our 2020 RFP process, Avista utilized a two-step bid process for reviewing and ranking bids received in the 2022 RFP as illustrated in Figure No. 2 below. The two-step approach considered each bid independently and gauged its strength against other bids received. This approach was well-received with 21 developers submitting 56 responses to the RFP with projects over 13,000 MW proposed. The bids are further summarized in Confidential Exhibit No. SJK-11C.

The first step included evaluating and ranking projects based on preliminary information by allowing developers to submit a condensed initial bid as shown in Exhibit B of Confidential Exh. SJK-11C. The evaluation and ranking of the preliminary information focused on conformance of each bidder's submittal with the requirements of the RFP and the proposed net price, among other factors. The initial evaluation and ranking, performed in a fair and consistent manner, produced a short list of bids. Once the short list was compiled, shortlisted bidders submitted detailed proposals in accordance with Exhibit C of Confidential Exh. SJK-11C. The second step in the bid process was to evaluate each shortlisted bidder's detailed proposal was evaluated against the other shortlisted bidders' detailed proposals to determine the overall strength of the bid and the ability to meet the Company's resource needs.

<u>Figure No. 2: Two-Step 2022 RFP Review Process</u>



Initial bid responses were due by March 25, 2022. The fifty-six projects included 23 wind, 9 storage, 13 solar, and 11 projects of other technology. In total, over 8,200 MW were bid into the RFP. In accordance with WAC 480-107-035(5), Avista made the bid summary shown below in Table No. 8 available to the public on our website.[4]

Table No. 8: Summary of Bids Received by Technology Type

Resource	Type	# of Proposals	Total Capacity (MW)
Wind	Wind	12	1804.7
	Wind + Storage	6	856.2
	Wind + Solar	1	404
	Wind + Solar + Storage	4	2159.8
Solar	Solar	6	749.9
	Solar + Storage	7	660
Storage	Battery	6	643
	Pumped Storage Hydro	3	393.3
Other	Biomass	2	226
	Waste Heat	1	9.9
	Geothermal	1	8
	Hydro	1	38.7
	Demand Response	3	25.8
	Natural Gas	3	282

Of the 56 bids received,[5] two included options for utility ownership of the proposed facilities. All other proposals were PPAs except for three of demand response. The Avista self-build option at its Kettle Falls biomass project was part of the list above.

As noted above, Sapere was selected as the IE for this RFP to perform a separate, independent evaluation to ensure no preferential treatment was given to self-build projects. Avista and Sapere worked separately to evaluate all bids, ultimately reaching consensus on

[4] https://www.myavista.com/about-us/integrated-resource-planning/2022-all-source-rfp
[5] Some Bidders provided multiple bids or capacity options within each type; Table No. 8 only includes initial option's capacity.

the top three bids, two of which proceeded to negotiation. Avista's self-build proposal did not require a PPA but similarly proceeded to negotiations for supporting agreements with the carbon reduction facility that would provide additional steam to Kettle Falls. Sapere's final evaluation report is included as Exhibit E of Confidential Exh. SJK-11C.

Avista evaluated a parallel proposal (i.e., not offered through the RFP) for the Columbia Basin Hydro Project (CBHP) in conjunction with RFP bids. In late 2021 CBHP filed a non-binding Request for Offer for some or all of its existing hydropower facilities located on the Columbia Basin Irrigation Project. Avista was the winning bidder for these projects. To validate the price offered for CBHP was competitive for customers, Avista utilized the same scoring system and financial evaluation used for the 2022 RFP bids to ensure all areas within the evaluation matrix were given a competitive evaluation. The evaluation methodology is included with this report in Confidential Exh. SJK-11C Exhibit A.

The initial screening evaluated which bids met all minimum RFP requirements to eliminate proposals from further consideration which failed to meet the minimum RFP requirements. Projects were evaluated both quantitatively and qualitatively based on the predetermined criteria and weightings. Preliminary information was reviewed for all projects and an initial break point was established based on project site control and other issues. Most projects had either executed a binding option to lease the project site or executed lease agreement(s) with landowner(s) and a few projects were from existing generation resources. The full evaluation matrix for all proposals, and associating ranking is found in Exhibit C.1 of Confidential Exh. SJK-11C. A summary of all bidders, components of their bid and initial financial analysis is provided in Exhibit C of Confidential Exh. SJK-11C.

The second step of the RFP process involved the evaluation of detailed proposals.

The top ten ranked projects included three wind, three solar, and four classified as "other" which includes demand response, biomass, storage, and natural gas. Following the Initial Screening shortlist, Avista notified the RFP respondents of the decisions and the status of their proposals. Avista asked that all shortlisted proposals be updated with a more detailed proposal consistent with the process that had been laid out in the RFP. Detailed proposals were delivered to Avista on July 18, 2022. The short-listed bidders were further evaluated, and additional due diligence was performed on each offering. On August 9, 2022, Avista requested a price refresh from the shortlisted respondents by September 2, 2022. The complete evaluation matrix of the short-listed projects after the price refresh is provided in Exhibit D.1 and the financial analysis including re-pricing is provided in Exhibit D.2 of Confidential Exh. SJK-11C. Based on the financial and full evaluation matrix analysis, three projects were selected to fulfill Avista's resource needs, in additional to CBHP that was selected outside of the RFP. Table No. 9 illustrates the final resource selections, including CBHP, which totaled over 500 MWs.

Table No. 9: 2022 All-Source RFP Resource Selections[6]

Counterparty	Description	MW / aMW	Timeline
Columbia Basin Hydro, LLC.	Hydroelectric	146	March 2023 – December 2045
Tyr Energy	Lancaster Natural Gas CCCT	282	November 2026 – December 2041
NextEra	Clearwater Wind	97.5	January 1, 2026 – December 2056
Avista Corp.	Kettle Falls Upgrade	11.2	July 2026 – June 2046

Of the 56 bids received, 18 individual proposals were within an area designated as a

[6] NextEra has an early delivery option beginning September 1, 2024 at a reduced delivery price.

Highly Impacted Community. Most of these communities were located within Avista's service territory; however, some projects exist in Highly Impacted Communities outside of Avista's territory. A total of 13 individual bids received were from promotors or developers that are considered women, minority, disabled, or veteran-owned businesses. Additional details about bids from Highly Impacted Communities and ownership are available in Confidential Exh. SJK-11C. As part of its RFP, Avista presented the opportunity for bidders to indicate their community involvement, how the project might utilize women, minority, disabled, and/or veteran-owned businesses along with a supplier diversity plan and/or DEI policy. These elements were considered within the selection criteria for initial and final resource selections. Of the Washington submitters that participated in the RFP, 6 of the 29 bids indicated diversity elements as identified in RCW 82.12.962 by including diversity attributes in their bid.

Q. How was transmission considered in this decision?

A. The cost of transmission was considered for the each of the bidders. Lancaster is already connected directly to the Avista transmission system. The Clearwater Wind Project is located approximately 80 miles north of Colstrip, Montana, connecting via a gen-tie line constructed by NextEra to the Colstrip Transmission System (CTS), which is also the interconnection point for Northwestern Energy (Northwestern). No additional transmission needs to be constructed for the already operating Columbia Basin Hydro Projects.

<u>3. Board of Directors Involvement</u>

Q. Was Avista's Board of Directors involved with the acquisition of the Lancaster, Columbia Basin Hydro, and Clearwater Wind PPAs?

A. Yes. The Company's Board of Directors was apprised of the 2022 All-Source

RFP and the evaluation process used to compare project bids from which the Lancaster, CBHP and Clearwater Wind PPAs were selected. Documentation of Board involvement in the Chelan PPAs is provided in Confidential Exh. SJK-11C, including presentations made to the Board.

4. Documentation of Analysis and the Decision-Making Process

Q. What documentation for the analysis and decision-making process has the Company provided for its decision to contract from the 2022 All-Source RFP?

A. Confidential Exh. SJK-11C includes documentation of the RFP solicitation and evaluation process resulting in the selection and signing of the contracts resulting from the 2022 All-Source RFP, including PPAs with the Lancaster CCCT, Columbia Basin Hydro and the Clearwater Wind Project.

Q. Does the Company believe that it has met the criteria and provided the requisite information to show that the Lancaster PPA, Columbia Basin Hydro PPA and the Clearwater Wind Project PPAs were prudent acquisitions?

A. Yes. My testimony and exhibits provide the documentation necessary to demonstrate the long-term economic benefit to customers for the extension of the Lancaster CCCT contract with a new PPA, as well as the additions of the Columbia Basin Hydro and Clearwater Wind PPAs and has provided specific supporting details regarding the Company's analysis and decision on these contracts. The executed PPAs for Columbia Basin Hydro and Clearwater Wind will also help meet the renewable and clean energy goals under Washington's Energy Independence Act, CETA, CCA as well as support the Company's own clean energy goals. All three of these PPAs also fit within the analysis performed under the Company's IRPs. The Board of Directors agreed with the recommendation to issue the 2022

All-Source RFP for 196 aMW of RPS-qualified renewable energy in 2022 and was apprised of management's recommendation to negotiate PPAs with Tyr Energy for the Lancaster PPA, Columbia Basin Hydro and Clearwater Wind under terms and conditions consistent with their bid proposals. The Company has provided and explained all the analytical work that was completed related to these acquisitions through a competitive RFP with the aid of an independent evaluator, as well as participation by both the Washington and Idaho Commission Staffs in the entire RPF process.

Q. Does the PPA with the Lancaster CCCT comply with RCW 80.80, the emissions performance standard?

A. Yes, this plant still complies with the current 925 pounds per MWh standard. Please refer to Exh. No. SJK-15 for more details about the greenhouse gas emissions of the Lancaster plant.

Q. Do the Columbia Basin Hydro and Clearwater Wind PPAs comply with RCW 80.80, the emissions performance standard?

A. Yes, they do. The PPAs automatically comply with RCW 80.80 under WAC 173-407-120 (c) because they are powered exclusively by renewable water and wind energy.

Q. Were any other projects selected under the 2022 RFP process?

A. Yes, under Avista's self-build option at Kettle Falls, a steam agreement was being negotiated with Myno to construct and operate a gasifier at the plant. However, an agreement to contract terms could not be reached and Myno officially ended contract negotiations on October 23, 2023. There are no additional plans to construct a gasifier at Kettle Falls.

Q. Are there any additional generation projects that you would like to

discuss?

A. Yes, the 30-year Palouse Wind PPA, signed on June 28, 2011, includes an opportunity to convert the PPA to Avista ownership after the first 10 years. Avista is conducting due diligence on the ownership option, including a comprehensive engineering review of the property and turbines, negotiating new leases, and determination of next steps should the Company decide to pursue ownership of the Palouse Wind Project under the terms of the PPA. We contracted in October 2023 with Sargent & Lundy for an initial facility assessment which is expected to be completed by the end of the first quarter of 2024. A decision on the option is not expected until 2024, and a determination of prudence would occur in a future rate process.

Q. Has the Company included interest associated with qualifying PPAs according to RCW 80.28.410?

A. Yes, it has. Per RCW 80.28.410(2)(b), the Company has included interest on qualifying PPAs (Chelan, Clearwater III and Columbia Basin Hydro) at the Company's proposed rate of return in this general rate case of 7.61%. The result of the Company's pro forma adjustment as discussed by Ms. Schultz, includes interest totaling $2.16 million included for Rate Year 1 (2025), reflecting interest to be deferred in 2024 of $0.66 million and recovered in 2025, and incremental interest in 2025 of $1.50 million. For Rate Year 2 (2026), the Company has included $2.34 million of total PPA interest, resulting in an incremental interest amount of $176,000 above Rate Year 1 (2025) levels.

VI. MOVE TO SINGLE 95/5 ENERGY RECOVERY MECHANISM BAND

Q. What is the Company's proposal to modify the ERM?

A. The Company proposes moving to a single 95% customer / 5% Company (95/5) sharing level applied to the entire difference between actual and authorized power supply costs presently included in the ERM and subject to deadbands. My testimony details the current ERM and its deadbands, as well as the Company's rationale for its modification.

Q. Briefly summarize the reasons for moving to a 95/5 sharing.

A. There are multiple reasons to change the current structure of the ERM including the elimination of the deadbands. They include the following which are further discussed later in my testimony:

- Forecast error – Authorized power supply expenses are determined using forward market prices as much as 35 months prior to the actual operating day with a multi-year rate filing. Power supply costs cannot be forecasted accurately this far in advance especially during volatile market conditions and therefore managing the forecast error is outside of the Company's control.

- Regional resource adequacy – The current regional resource mix is shifting with the retirement of thermal resources and the integration of more variable resources. The region is shifting from a resource sufficient position to a resource neutral or deficit position creating market uncertainty and forward price premiums.

- Lack of market liquidity – With less resources available in the region it is difficult to procure future energy through market transactions as utilities are holding back capacity to meet peak load needs.

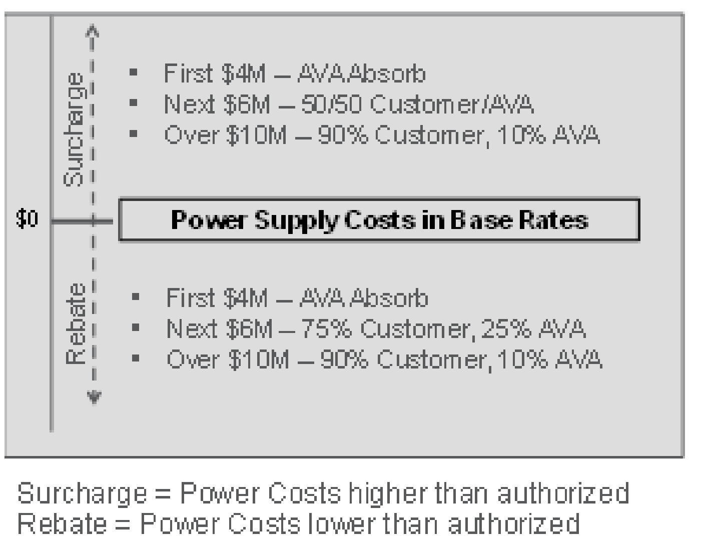
- Carbon emission policy – New carbon emission policy has created market uncertainty resulting in forward price premiums.

- Changing market dynamics – With the uncertainty in market liquidity, emission policy implementation, and resource adequacy market dynamics have changed with significant volatility occurring for any unplanned event such as colder or warmer weather. These conditions can't be predicted when setting net power supply expense (NPE).

Q. What is the structure of Avista's current ERM?

A. Each calendar year, the Company absorbs the first $4 million of the difference between certain actual and authorized power supply related costs, either in the surcharge or rebate direction. This is referred to as the "deadband," as costs are absorbed by the Company until this band is exceeded. When actual costs exceed authorized costs by more than $4 million (surcharge direction), 50% of the next $6 million difference is absorbed by the Company, and 50% is deferred for future recovery from customers. When actual costs are less than authorized costs (rebate direction), 25% of the next $6 million difference above the $4 million deadband is absorbed by the Company, and 75% is deferred as a rebate to customers. If the difference in the actual and authorized costs exceeds $10 million, either in the surcharge or rebate direction, 10% of the amount above $10 million is absorbed by the Company, and 90% is deferred. Illustration No. 4 shows the ERM and deadbands.

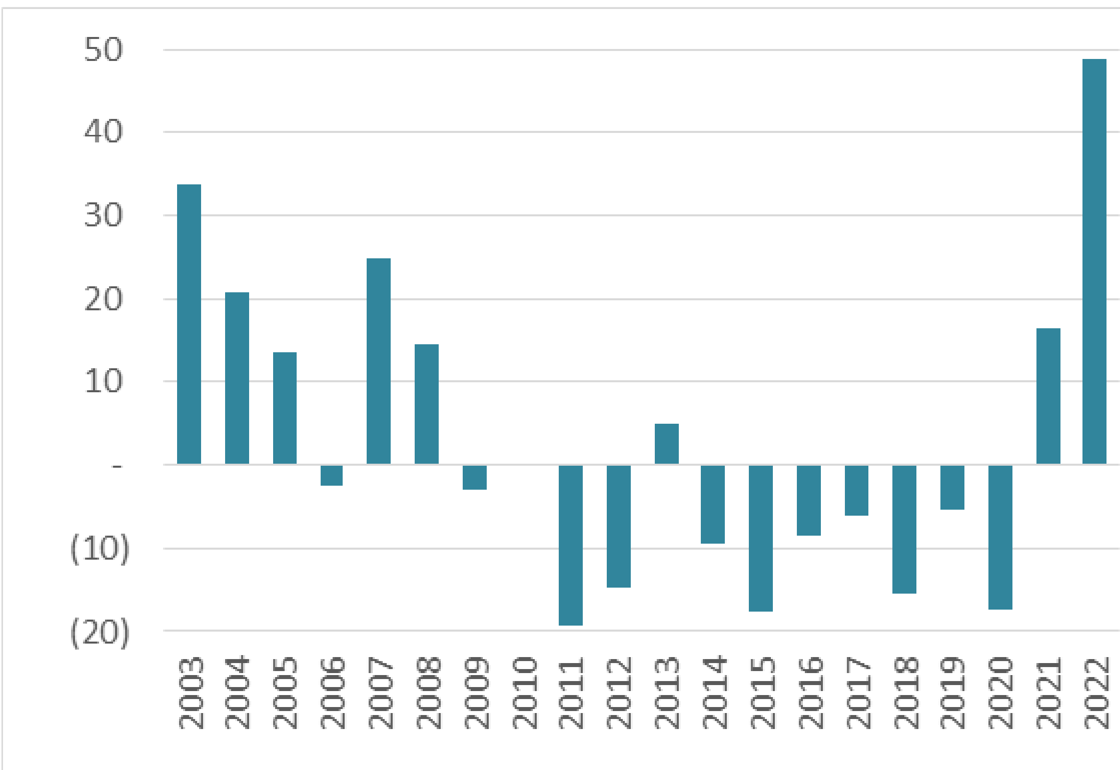
<u>Illustration No. 4: Washington ERM and Deadbands</u>



Q. How has the ERM balance changed over time?

A. The ERM has varied significantly over its more than 20-year history. In its early years, the Company absorbed over $100 million in cumulative costs. Market prices generally were rising over this period. This was followed by a period of relative stability and falling natural gas prices from 2011 until 2020 where the cumulative balance over this time was approximately $100 million in the Company's favor. Since 2020 the ERM has witnessed some of the highest surcharges on record, as market prices have risen significantly above those projected in rate filings. In 2023, high prices continue, and we are witnessing the poorest hydro conditions since the 2000-01 energy crisis. Illustration No. 5 shows the changes in the annual Washington ERM balance from 2003 through 2022.

Illustration No. 5: Washington ERM Deltas, 2003-2022 ($ millions)



Q. What is the intent of the ERM, and is it still relevant today?

A. The intent of the ERM is to share risk between the Company and customers and provide a financial incentive for Avista to reduce or to better manage power supply costs.

The ERM structure is relevant for revisiting today for three main reasons: volatile market price and liquidity conditions, which are now even greater than when the ERM was first enacted, policy changes leading to greater unknowns in power supply costs, and an expectation for a cost sharing arrangement from investors after two decades of having one.

Q. You are proposing the elimination of deadbands in the ERM. Do customers or the Company benefit from an ERM inclusive of deadbands?

A. No. Deadbands skew risks in favor of one party or the other, are not an industry standard, and focus utility rate proceedings on power supply expense deadband management instead of overall costs estimation. For deadbands to provide benefits, at least two criteria must be met: 1) the Company needs an opportunity for actions resulting in significant cost reductions and commensurate benefits through the deadband, and 2) the net power cost forecast upon which the ERM is calculated must be accurate and without significant forecast error. Neither of the criteria are currently met, meaning deadbands skew results in favor of one party or the other based on the Net Power Supply Expense (NPE) forecast relative to conditions experienced during the rate period. Risk is not shared, and one-party benefits at the expense of the other. The outcome essentially is a gamble.

Further, limiting risk exposure and limiting cost are conflicting concepts. The Company cannot manage risk when actions affecting costs ultimately fall outside the deadband due to forecast error. With deadbands as a component of the ERM, the Company must be more careful, and in fact conservative, in its forecasting assumptions. Being conservative as it relates to forecast assumptions isn't always the best means for achieving the best forecast. Intervenors also are not insulated from this conflict when advocating for assumptions used in forecasting. Almost certainly intervenors have incentives to argue for assumptions biased toward customers ending up on the "winning" side of the deadbands.

Q. Hasn't NPE forecast error always been present when forecasting power costs?

A. Yes, and the Company has been concerned about its level and potential to increase for a long time. Yet actual experience and the potential for rising forecast errors now and in the future is much higher. New Company analysis prepared for this filing demonstrates that power supply costs cannot be forecasted accurately, and for reasons outside of utility control. Our forecasts continue to get worse with new and nearly impossible to predict variables I describe later in testimony.

Q. Setting aside your concerns discussed above, have customers benefitted financially from having the deadbands relative to your simpler 95/5 approach?

A. I don't believe so. In the most recently completed year, 2022, customers did benefit from the current ERM structure relative to the simpler 95/5 sharing I propose. One or two years is not a trend. Looking back five years, customers were nearly indifferent financially to the two approaches, but only because of two back-to-back years with conditions not included in pro forma NPE, and which were very unfavorable to the Company. Where one looks back 10 years, customers would have received nearly $14 million more, and the Company $14 million less, with the proposed 95/5 approach. Looking back to 2011, when the deadbands were modified so customers receiving 75% of any cost savings from authorized in the second sharing band rather than the previous 50% share, customers would have received $25 million more, and the Company $25 million less. As shown in Table No. 10 below, looking at individual years of history, customers would have benefitted with the 95/5 approach in nine of 12 years, or 75% of the time.

Table No. 10: WA ERM Actual vs. Authorized Power Supply Expense ($ millions)

		Tracked Power Supply Costs			Current ERM		95/5 ERM		Customer 95/5 Value	
	Year(s)	Actual	Authorized	Delta	Customers	Company	Customers	Company	Delta	Benefit
	2011	101.7	120.9	(19.2)	(12.8)	(6.4)	(18.2)	(1.0)	5.5	Yes
	2012	114.2	128.9	(14.7)	(8.7)	(6.0)	(14.0)	(0.7)	5.2	Yes
	2013	123.3	118.2	5.0	0.5	4.5	4.8	0.3	(4.3)	No
	2014	108.7	118.2	(9.5)	(4.1)	(5.4)	(9.1)	(0.5)	4.9	Yes
	2015	96.2	113.8	(17.6)	(11.3)	(6.3)	(16.7)	(0.9)	5.4	Yes
	2016	81.3	89.8	(8.4)	(3.3)	(5.1)	(8.0)	(0.4)	4.7	Yes
	2017	82.3	88.5	(6.2)	(1.7)	(4.6)	(5.9)	(0.3)	4.2	Yes
	2018	82.0	97.6	(15.5)	(9.5)	(6.1)	(14.8)	(0.8)	5.3	Yes
	2019	97.0	102.5	(5.5)	(1.1)	(4.4)	(5.2)	(0.3)	4.1	Yes
	2020	85.0	102.5	(17.5)	(11.2)	(6.2)	(16.6)	(0.9)	5.4	Yes
	2021	112.3	96.0	16.4	8.7	7.6	15.5	0.8	(6.8)	No
	2022	121.1	72.3	48.8	38.0	10.9	46.4	2.4	(8.4)	No
All Years	2011-22	1,205	1,249	(43.9)	(17)	(27)	(42)	(2)	25.1	Yes
Last 10 Years	2013-22	989.3	999.3	(10.0)	4.9	(14.9)	(9.5)	(0.5)	14.4	Yes
Last 5 Years	2018-22	497.4	470.7	26.7	24.9	1.9	25.4	1.3	(0.5)	No

Q. Has Avista proposed removing deadbands in a previous case?

A. Yes, in the Company's 2012 general rate case, Company witness Mr. Johnson discussed how the deadband was intended to motivate the Company to manage power supply costs and "have skin in the game," but the reality was the primary drivers were factors outside of the Company's control such as stream flows, natural gas prices, power prices, forced outages, and retail loads. The amount absorbed by the Company was, and essentially still is, a collection of events and drivers outside Avista's control. This lack of control already is recognized on the natural gas distribution side of our business, and cost variation is passed through 100% to customers.

Q. The Commission was not persuaded to remove the deadbands in 2012. Why should it agree with the Company today?

A. Deadbands magnify the sensitivity of forecast error. When a large cost driver is mis-forecast, much or most of that error transfers to the Company. Where costs can be reasonably estimated, sharing bands have the potential to, but are not guaranteed to incentivize utility behavior to benefit customers. But sharing bands do not provide productive or equitable incentives for cost management when pro forma estimates are subject to large forecast error. An incentive program works only when both parties have a reasonable expectation of outcomes. When a reasonable expectation isn't possible, parties instead work to limit exposure to risks of a bad forecast based on their own interests.

Q. Are there other reasons the Commission should reconsider the removal of the deadbands?

A. Yes. The comments above apply mostly to changing market dynamics that cannot be hedged, and how they contribute to growing forecast error. But unique to this filing specifically, another large uncertainty adds to forecast error: new regulations from the CCA. The Company considered directing our staff to include a CCA cost estimate in our pro forma but decided against it because of uncertainty. Not including a CCA cost in our pro forma does not mean we avoid a large cost. With a projected portfolio carbon-equivalent of nearly 2 million metric tons annually, and a carbon cost of around $60 per metric ton, CCA compliance costs could be very large. Depending on forthcoming Commission guidance, Avista may be required to include carbon costs in its plant dispatching decisions, adding tens of millions of dollars to NPE because of reduced thermal fleet dispatch benefits to customers. The choice to not include an estimate of CCA costs therefore could be harmful to the Company if deadbands remain in the ERM. On the flip side, had the Company directed our staff to include an estimate in our NPE that ultimately overstated its cost, customers would be harmed by the first $4 million flowing directly to the Company in the first deadband, and another $1.5 million through the second deadband.

Q. Are better forecasting methods of NPE possible?

A. Correctly forecasting NPE is of high importance to the Company. The value is used throughout our organization to project revenues and earnings. Our financial modeling and projections are based on it. Even as important as it is, Avista does not believe there are methods to significantly reduce NPE forecast error or prevent its rise in today's changing markets. This assessment is not new. It is based on the outcomes of efforts made over many rate filings. A multi-year Commission-ordered power supply cost modeling workshop also was unable to find means to reduce forecast error. This workshop series was comprised of the Company, Commission Staff, and other intervenors. The effort was aided by E3 Consulting.[7] We did reach important agreement on a standardized modeling method but were unable to solve the forecasting error concern shared by all parties. Too many things outside Company control affect our forecasting accuracy.

Q. Besides what you describe above, would elimination of the deadband offer other potential customer benefits?

A. Yes. Removing ERM deadbands allows Company staff to focus on issues they can affect, including risk management policy (discussed in Section II of my testimony), asset reliability and availability, and bidding and trading in the marketplace. Focusing on issues that the Company can affect will benefit customers.

Q. Please discuss how rising market volatility impacts your business and NPE.

A. Potentially the largest driver of NPE cost and forecast errors are variations from market price assumptions included in pro forma modeling. The agreed-to methodology

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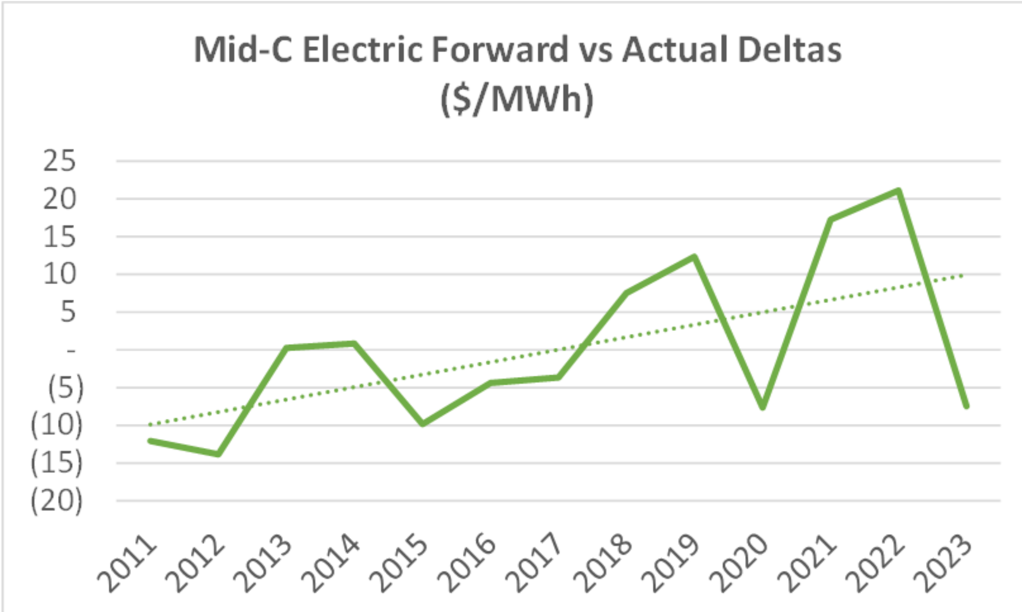
[7] https://www.ethree.com/

for projecting NPE uses pricing in the forward markets for the pro forma period. While forward prices likely offer the best available information for ratemaking, their use does not result in an accurate forecast. There is simply too much volatility in the marketplace today. Rising volatility is borne by the Company through costs diverging from forecast and is ultimately paid for by customers through the ERM.

Q. How does volatility translate to higher forecast error?

A. Random and modest volatility has the potential for prices and their impact on our portfolio to average out over time, or to nearly do so. Yet what is being experienced today is not modest in magnitude or random in nature. Volatility is being driven by factors the market clearly struggles to understand and price correctly. A trend of rising deltas between forward prices and what is experienced in the real-time markets is rising, as shown below in Illustration No. 6, where deltas between annual average electricity and natural gas prices projected in September prior to the delivery year are compared to what occurred in the delivery year.

Illustration No. 6: Electricity and Natural Gas Forward vs. Actual Deltas, 2011-2023[8]

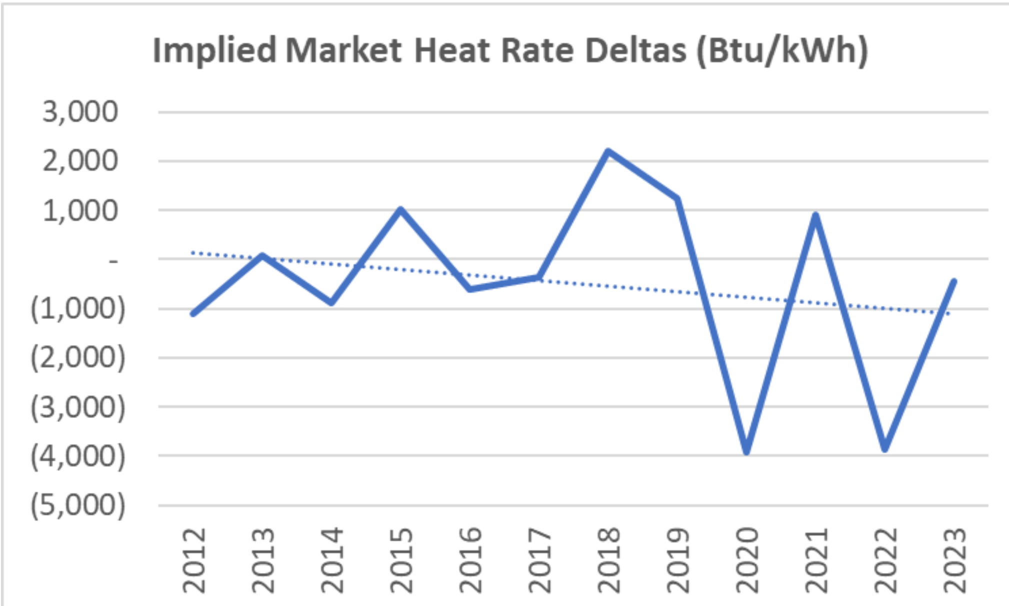


The most impactful aspect of forward price forecasting error affecting our NPE projection is the relationship between natural gas and electric prices. This is expressed in the form of an "implied market heat rate," the division of electricity price by the cost of natural gas. A falling implied market heat rate (IMHR) means the value of our thermal fleet becomes smaller in actual operations relative to its forecasted value. Illustration No. 7 explains three important things. First, we are experiencing large volatility in the IMHR, helping to explain why NPE is difficult to correctly project. Second, a general downward trend over time shows why our forecasts are less representative of actual experience, with deltas being multiples of two to eight times that experienced in the past. Lastly, falling IMHRs illustrate how the NPE forecast is over-valuing our thermal fleet relative to what we experience in our day-to-day business. Where IMHRs drop from the time we forecast our costs to when we experience

[8] 2023 compares data through October.

them, it explains that expected operating margins are falling from what we estimate, meaning costs are much higher than we project them to be. Also of note is the rising volatility of IMHR in Illustration No. 7.

Illustration No. 7: Implied Market Heat Rate[9]



Q. Are changing market dynamics a reason for removing the deadbands from the ERM?

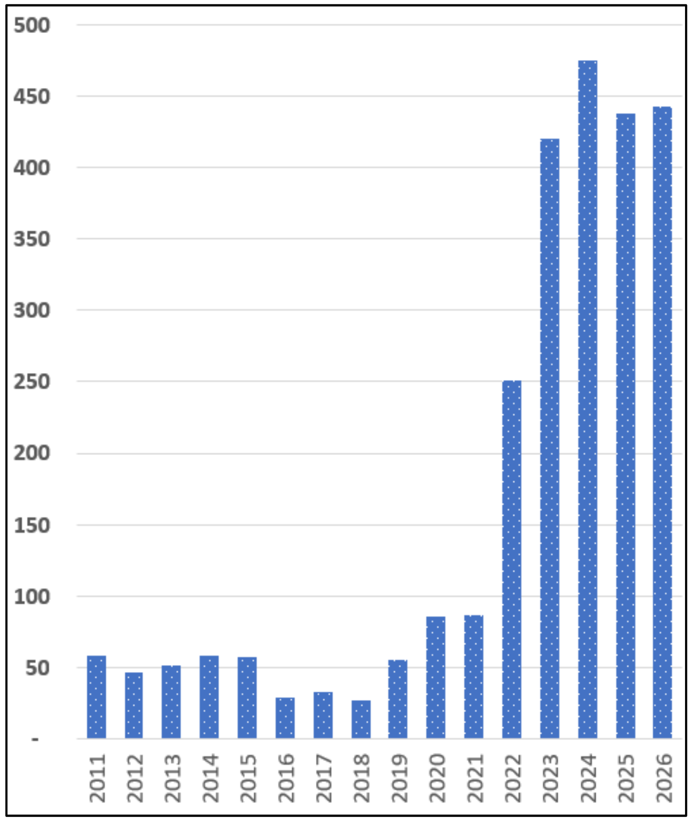
A. Yes. In recent years several market fundamental conditions appear to have changed, warranting a rethinking of the equity of risk sharing in the ERM. In most ERM history, sharing bands were a means to distribute the impacts of varying electric and natural gas prices, along with hydro variability risk. When our thermal fleet had an expected annual value of **$30 to $50 million**, as it did for many years, even 10 to 20% error resulted in costs falling within the deadbands. With today's estimate of annual thermal fleet value approaching **$500 million**, that same 10 to 20% error becomes multiples of the deadbands, and overwhelms

[9] 2023 compares data through October

any efforts made by the Company to reduce costs. Illustration No. 8 displays the expected value of our thermal fleet from 2011 through 2026 based on forward market projections in September of each year prior to the forthcoming year.

<u>Illustration No. 8: Avista Forward Year Thermal Fleet Value Projected Each September 2011-2026 ($ millions)[10]</u>

Year	Forecast Trade Day	Forecast MTM
2011	9/24/2010	58
2012	9/26/2011	46
2013	9/26/2012	51
2014	9/26/2013	59
2015	9/26/2014	57
2016	9/25/2015	29
2017	9/26/2016	33
2018	9/26/2017	27
2019	9/26/2018	56
2020	9/26/2019	86
2021	9/25/2020	86
2022	9/24/2021	251
2023	9/26/2022	420
2024	9/26/2023	474
2025	9/26/2023	437
2026	9/26/2023	443



The thermal mark-to-market illustration above clearly shows the situation we face, and how less-accurate NPE forecasts are of a <u>magnitude much greater than in the past</u>.

The reasons for this shift cannot be explained with certainty. Falling industry surplus generation, resource adequacy initiatives including WRAP to address the falling surplus,

[10] 2025 and 2026 projections are based on Sept-23 forward prices.

rising liquidity risks, and new carbon emission policies surely play large roles in the rising value of our thermal fleet, but also a large role in the rising delta between projected and actual operating values. It is fortunate that customers receive the benefits in their rates of values much higher than projected at the times when our thermal plants were acquired. This prudent resource acquisition and management, supported by this Commission, has greatly insulated customers from what otherwise might have caused very large increase from higher NPE. Yet the fortune of having cost-effective resources should not expose the Company to greater risks outside of its control while customers benefit so significantly.

Q. Does falling market liquidity present a risk for the Company that affects NPE forecast error?

A. Yes. There is a level of illiquidity in the marketplace today that has not been witnessed before. In the past we could cost-effectively hedge shares of our portfolio in the market by buying and selling forward electricity and natural gas. By transacting in the forward markets, we could reduce NPE by locking in value on portions of our thermal fleet. With the uncertainty before us today, forward markets simply cannot be used as in the past because the liquidity doesn't exist. Equally concerning are the unaffordable and large margin calls necessary to hedge portfolio risk, even when a forward trading opportunity presents itself. Avista recently was unable to enter a forward transaction on a modest share of its position because of the $1 billion credit exposure associated with it. Because of a lack of liquidity and the much higher expense of doing so, hedging in the forward markets to lock in projected value no longer is an option for most of our business. Instead, we must wait for the near-term and accept what markets offer to meet our load obligations and price our surplus. Being unable to capture forward resource value, due to its cost of financing and market illiquidity, results in the Company taking more of the financial risk with the current ERM deadbands and recovery structure.

Q. Do you expect the conditions you describe here to change during the next two rate years?

A. There is no expectation that the challenges of volatility, market liquidity and resultant NPE forecast errors we face will get better in the short- to medium-term. Fundamental drivers of this volatility, and forecast error, will remain in our business. Regional markets continue responding to increasing amounts of renewable generation, to new and expanding clean and renewable policies, to tax and social policy incentives moving the industry away from natural gas-fired and coal generation sources, and the resultant capacity shortages expressing themselves in the marketplace.

Almost all portfolio optimization choices having the potential to positively affect costs in the next few rate years already are made. Markets outside our control will react, likely over-react, to weather, geopolitical concerns, and policy choices, each by themselves being large risk factors in forecasting our NPE. It is equitable that cost recovery reflects conditions before us, not some future or past state. <u>A 95/5 sharing best fits this situation</u>.

Q. Is Washington among the small minority of jurisdictions that have a power cost recovery mechanism with a cost-sharing or deadband feature?

A. Yes, decidedly so. I have included a survey of jurisdictions in that regard, as Exhibit SJK-16, based on descriptions of electric fuel and purchased power adjustment clauses by SNL Energy Regulatory Research Associates (RRA) as of 2020 (now S&P Global). It demonstrates that among the 35 States with vertically regulated utilities that have regulated power supply, only six states have a risk sharing mechanism (AZ, HI, ID, MO, MT and WY), only three have risk sharing and a deadband (OR, VT and WA), only one has a deadband only (WI).[11]

Q. Do changing laws and regulations also support removing deadbands from the ERM?

A. Yes. New laws and regulations, beginning with the Energy Independence Act and culminating in the CETA and CCA, are fundamentally changing the market supplying customers with clean electricity as Washington decarbonizes its overall economy. It is not known how the CCA, and its implementation, will affect our business going forward. Costs will rise but we do not know by how much. They will come from regulation and market impacts from decarbonization, including the treatment of EIM transactions, how the CCA true-up mechanism is implemented, potential linkage to other state carbon programs, and forthcoming day ahead market design and treatment of transactions. Many unknowns exist on the path to decarbonization that likely are not reflected in our normalized NPE modeling and forecast. Had the Company included an estimate for CCA costs in the case there would be risks of greatly over- or under-estimating that cost.

Q. How does the Company propose recovering CCA costs going forward?

A. We will propose a means to recover CCA costs in the long run after more experience with CCA. In the short term, the best approach is flowing the CCA costs we incur through a 95/5 ERM without deadbands. Allowing those CCA costs driving NPE to flow through the ERM at 95/5 obligates the Company to pay 5% of anticipated CCA costs, but in

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[11] Summary compiled by Mr. Frank Graves, Principal at The Battle Group, based on descriptions of power cost recovery mechanisms provided by RRA. See, PacifiCorp Public Utility Commission of Oregon Docket UE-374, Exh. PAC/602, and more recently, PacifiCorp has before this Commission, in Docket UE-230172, a proposal to eliminate the Company's deadband and sharing mechanism in its PCAM.

exchange we avoid disagreements between the parties over a cost magnitude that cannot be known at this point, except that it will be much greater than zero.

Q. Is paying 5% of CCA costs fair to the Company?

A. No. The Company's first instinct was to exempt CCA costs from the 95/5 proposal and request 100% recovery. This would be the fairest outcome and reflect the intent of the legislation. However, for this two-year period, as part of an overall package to simplify the ERM and address rising forecast error, we offer this compromise of passing the CCA costs through the proposed ERM's 95/5 sharing arrangement instead rather than asking for 100% recovery.

Q. Do organized markets impact the need for deadbands?

A. Transformation to new markets, including EIM, EDAM, Markets+, and WRAP create efficiencies by integrating markets within a large geographical area, offering NPE lower relative to what otherwise would occur. The structure and inherent nature of these markets ensures resources are operated in an efficient manner best for customers. However, they reduce our ability to affect costs because they reflect resource dispatch decisions made by the market operators, not the Company. EIM/EDAM/Markets+ operators assume control of day-ahead, hourly, and intra-hour operations of our generation portfolio. When the benefits of new markets are reflected in power supply modeling, as they are now, it is fair to remove deadbands historically intended to reflect value not modeled in pro forma NPE and incentivize actions and trading behavior no longer possible in today's marketplace.

Q. Please summarize why deadbands should be removed from the ERM in favor of 95/5 cost sharing.

A. Shifts to new market structures taking most operational control from the utility, new laws and regulations expressing themselves through the CCA, rising prices and portfolio sensitivity to market conditions from the elimination of coal and natural gas-fired baseload generation in favor of non-emitting solar and wind resources are not substantially the result of Company action or inaction. Eliminating the deadbands in favor of a 95/5 cost share removes what has become the punitive nature of volatility and variability almost entirely outside utility control. One main purpose of deadbands is to provide a financial incentive for cost control, but variability outside of the purview of a utility instead makes the deadbands punitive rather than incentivizing.

Q. Company witness Mr. Kalich has included an NPE adjustment of $65.8 million to address anticipated forecast error. Why should the Commission authorize this new adder to Avista's authorized expenses in 2025 and 2026?

A. There are various drivers for why the adder is necessary. We are witnessing the magnification over time of forecast error in our portfolio. Forecast error has always been a concern of the Company and was the primary driver of a Commission-ordered set of workshops recommended by Staff in 2017. While there was much success in standardizing the power supply modeling methodology used in our rate filings, which has greatly reduced conflict between the Company, Staff and intervenors, the workshop process never satisfactorily identified a means to eliminate or greatly reduce forecast error. Several years after the workshops, it can be concluded that forecast error was not reduced even with the best efforts of the parties involved. Given the forecast error persists, it became important to evaluate its causes. After an analysis of the forecast error, the Company concluded that a $65.8 million portfolio adjustment to NPE is justified.

Q. Please explain the analysis performed.

A. We do not have a new rate filing annually. NPE is not reset every year, and the NPE forecast in rate proceedings has not always occurred at the same time or even been updated due to various choices by the parties. So, it is not possible to look at the historical record and determine the impacts of forecast error. It is therefore necessary to create a consistent and longer-term dataset valuing NPE over time to help illustrate its magnitude.

As laid out in the Power Supply Methodology, a 60-day update of NPE is performed and its results set the NPE contained in rates. The Company emulated the process valuing our portfolio at the end of September for each following calendar years. This entailed taking forward market prices and valuing the three major components of Avista's portfolio: 1) portfolio load serving retail customers, 2) dispatchable thermal plants, and 3) the rest of Avista's portfolio of non-thermal generation, including hydro. Call this the "Forward (Forecast) Value" of our portfolio. Once the Forward Value was determined for each year, a similar analysis of portfolio value was calculated by replacing forward prices and resultant plant dispatch with actual index prices and operations. Term this "Actual Value" because it uses actual generation valued against prices we experienced in the marketplace. The delta between the Forward (Forecast) Value and Actual Value provides an estimate of forecast error in each calendar year.

Q. What were the findings of the work?

A. The results confirmed our expectations about increasing levels of forecast error. Portfolio forecast error has increased greatly over time, as shown in Table No. 11, below.

<u>Table No. 11: Portfolio Forecast Error 2018 – 2023 ($ millions)</u>

Year	Forward	Actual	Delta
2018	69.9	69.2	(0.7)
2019	48.3	80.3	32.0
2020	24.5	63.3	38.8
2023	38.6	94.6	56.0
2022	(11.3)	191.3	202.7
2023 *	(73.2)	140.6	213.8
2018-22 Average			65.8
2019-23 Average			108.7

The 5-year delta between Forward (Forecast) Value and Actual Value was $108.7 million through 2023. However, because 2023 was not complete at the time of testimony drafting, for our recommended NPE adjustment we shifted backwards the 5-year average calculation to include 2018 where actual operational results ended up reasonably like the forecast. The 5-year average through 2022 equals the $65.8 million adjustment being recommended in this case.

Q. Why does 2018 show actual power supply expense lower than forecast when the remaining years show costs greater than forecast?

A. There are many driving forces of forecast error each year, but markets tend to be the greatest driver of forecast error. In 2018, Actual Value natural gas prices ended up modestly higher than the Forward (Forecast) Value. But offsetting that was a larger increase in electricity prices that pushed our surplus sales revenues to exceed the incremental cost of higher-priced natural gas. This isn't something we have witnessed since 2018. In fact, a general trend exists illustrating how forecast error is increasing drastically over time. What used to be annual variation of $10 to $30 million per year has become multiples of that in current markets. This is a value discrepancy the Company simply must reflect in its pro forma.

Q. Table No. 11 presents a marked increase in forecast error in 2022 and

2023. What has driven this rise in forecast error?

A. As shared above, there are many factors that drive variation in NPE. Generally, one or two drivers are responsible for pushing forecast versus actual NPE in a direction up or down from authorized each year. The "big ticket" items in 2022 and 2023 are different. 2022 witnessed an approximate 35% run-up in power prices that could have helped us with higher revenues. However, because natural gas prices were about 95% above the forecast, the relationship between electricity and natural gas fell, grossly dropping the value of our thermal fleet. The result of nearly doubling our natural gas fuel expense was a significant increase in error relative to the forecast; almost four times the error seen in 2021.

In 2023, the main driver is poor hydro conditions. Natural gas prices through October 2023 fell 6% from forecast, but electricity prices fell almost double that amount, meaning our thermal fleet underperformed the forecast. But our lowest hydro year since the energy crisis of 2000-01 magnified the difference between the forecast and actual and resulted in our largest ever delta between portfolio forecast and actual costs.

Q. Is there an underlying change driving NPE forecasts that increases the risk of large divergences between forecasts and actuals?

A. Yes. Historically the "mark-to-market" or "MTM" value of Avista's natural gas-fired plants ranged around $15 to $30 million per year. Until 2018, neither the forecast nor actual value exceeded $30 million. Forecast error was commensurately small, with the absolute error averaging under $6 million. Beginning in 2018, the value of the natural gas fleet began rising aggressively, exceeding $150 million in 2022 on a forecast basis and rising to $279 million in 2023. The variation between the forecast and actual value also began to increase significantly. Post 2023, the forward projections for the operating margins of these plants continues to rise. See Table No. 12.

Table No. 12: Portfolio Forecast Error 2010 – 2023 ($ millions)

Year	Forecast MTM	Actual MTM	Delta
2010	26	18	(8)
2011	20	6	(14)
2012	14	8	(6)
2013	21	27	6
2014	24	23	(1)
2015	21	17	(4)
2016	14	11	(3)
2017	15	21	6
2018	14	53	39
2019	39	81	43
2020	61	28	(33)
2021	53	88	35
2022	151	135	(17)
2023 *	279	199	(80)
2024	338	Forecast period, so no actuals data available	
2025	308		
2026	313		

* YTD thru October scaled up to annual value by 2022 delta for Nov-Dec

Q. Is this rise in thermal fleet value and impact to forecast error expected to persist?

A. Yes. Several drivers indicate continued support for higher forecast natural gas-fired fleet value and associated forecasting errors. Many baseload coal and the more inefficient natural gas-fired plants in the West have or soon will be retired, starving the marketplace of capacity. Most new regional generation is wind and solar, each providing smaller contributions to system peaking needs and consuming the capacity of other resources de-optimizing their output to absorb inherent wind and solar variability.

With baseload generation losses, the industry is moving to ensure it can reliably serve its growing load obligations. In the West, this expresses itself through the WRAP, obligating participants to "forward-show" they can meet average and on-peak generation daily. Somewhat counter-intuitively, at least in the short- to medium-term, the WRAP program appears to be pulling capacity from the marketplace as utilities shift to consistent operating parameters limiting their forward capacity offerings. As Table No. 12 shows, the forward MTM value of our thermal fleet is projected to continue rising. With the rise in MTM value, the opportunity for widening forecast error increases.

Q. Could the Company address this discrepancy in Aurora?

A. Yes. We could adjust the relative margins between Forward (Forecast) Value and expected Actual Value price deltas. Aurora would then reduce our NPE to account for the difference. This approach was not part of our methodology agreed to in the power supply cost modeling workshops. The Company decided it was better to show the value in testimony as a single adjustment rather than translate the results of the analysis into a price dataset that would bury the impacts within Aurora.

Q. Does this conclude your pre filed direct testimony?

A. Yes, it does.