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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-19-04 DIRECT TESTIMONY OF SCOTT J. KINNEY

FOR AVISTA CORPORATION

(ELECTRIC)

I. INTRODUCTION

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

A. My name is Scott J. Kinney. I am employed as the Director of Power Supply for 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 B.S. in Electrical Engineering and I am a licensed Professional Engineer in the State of Washington. I joined the Company in 1999 after spending eight years with the Bonneville Power Administration. I have held several different positions at Avista in the Transmission Department, beginning as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations Department as a Supervisor and 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, where my primary responsibilities involve management and oversight of short- and long-term planning and acquisition of power resources.

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

A. My testimony provides an overview of Avista's resource planning and power supply operations. This includes the current and future load and resource position and future resource plans, planned participation in the Western Energy Imbalance Market, and the recent signing of a 20 year Power Purchase Agreement (PPA) for the Rattlesnake Flat wind project output. As part of an overview of the Company's risk management policy, I will provide an update on the Company's hedging practices.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. 5, Schedules 1 – 4. Schedule 1 includes Avista's 2017 Electric Integrated Resource Plan and Appendices. Confidential Schedule 2C includes Avista's Energy Resources Risk Policy. Confidential Schedule 3C includes the Rattlesnake Flat Wind Power Purchase Agreement justification and Request for Proposal Contract documentation. Confidential Schedule 4C includes the Rattlesnake Wind Power Purchase Agreement.

II. RESOURCE PLANNING AND POWER OPERATIONS

Q. Would you please provide a summary of Avista's power supply operations and acquisition of new resources?

A. Yes. Avista uses a combination of owned and contracted-for resources to serve its load requirements. The Power Supply Department (Power Supply) is responsible for dispatch decisions related to those resources for which the Company has dispatch rights. Power Supply 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 Request for Proposals (RFP) and/or other market due diligence processes.

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

A. Avista's 2017 IRP shows forecasted annual energy and capacity deficits beginning in 2027. The capacity and energy load/resource positions are shown on page 6-7 and page 6-9 of Exhibit No. 5, Schedule 1.

The next Electric IRP is currently being developed and is scheduled to be filed with the Commission on February 28, 2020. The Commission issued Order No. 34312 in Docket AVU-E-19-01 where it approved Avista's request to delay the IRP filing from the original August 31, 2019 filing date. The extension to file the IRP in 2020 allows extra time to model legislation in the State of Washington which will fundamentally change the Company's resource planning targets. In particular, Washington "Clean Energy" legislation (Senate Bill 5116) requires the elimination of all coal-fired resources from serving Washington load by the end of 2025, requires all Washington load to be served with 100 percent carbon neutral resources by 2030, and prohibits the use of fossil-fuel generation for Washington load by 2045. The Company will work with the Idaho and Washington Commissions to ensure these new requirements concerning coal-fired and other carbon emitting resources will be modeled appropriately and met in the Preferred Resource Strategy to the satisfaction of cost and environmental requirements for customers in both states.

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

A. Until supported by the next Electric IRP (to be filed February 2020), the Preferred Resource Strategy (PRS) in the current Electric IRP guides the Company's resource acquisitions, subject to any legislative requirements. The IRP provides details about future resource needs, specific resource costs, resource-operating characteristics, and the scenarios used for evaluating the mix of resources for the PRS. The Commission acknowledged the 2017 Electric IRP in Docket No. AVU-E-17-08 in Order No. 339714 on February 1, 2018. The IRP represents the preferred plan at a point in time; however, Avista continuously evaluates different resource options to meet current and future load obligations, especially in light of new legislation.

Avista's 2017 PRS includes 203 MWs of cumulative energy efficiency, 44 MWs of demand response, 5 MWs of energy storage, 34 MWs of upgrades to existing thermal plants, and 335 MWs of natural gas-fired peaking plants. The timing and type of these determined resources in the 2017 IRP is provided in Table No. 1.

Table No. 1: 2017 Electric IRP Preferred Resource Strategy

Resource	By the End of Year	Nameplate (MW)	Winter Peak (MW)	Energy (aMW)
Solar	2018	15	0	3
Natural Gas Peaker	2026	192	204	178
Thermal Upgrades	2026-2029	34	34	31
Storage	2029	5	5	0
Natural Gas Peaker	2030	96	102	89
Natural Gas Peaker	2034	47	47	43
Total		**389**	**392**	**344**
Efficiency Improvements	**Acquisition Range**		**Winter Peak Reduction**	**Energy (aMW)**
Energy Efficiency	2018-2037		203	108
Demand Response	2025-2037		44	0
Distribution Efficiencies			<1	<1
Total[1]			**247**	**108**

Q. Would you please provide a high-level summary of Avista's risk management program for energy resources?

A. Yes. Avista Utilities uses several techniques to manage the risks associated with serving customers and managing Company-owned and controlled resources. The Energy Resources Risk Policy, which is attached as Exhibit No. 5, Confidential Schedule 2C, 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).

[1] Does not include recent Solar and Wind acquisitions discussed below.

The Energy Resources Risk Policy is not a specific procurement plan for buying or selling power or natural gas at any particular time, but is a guideline used by management when making 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 Integrated Resource Plan'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 period 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 in order 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 in order to approach a generally balanced financial position against expected load as forward periods draw nearer.

III. WESTERN ENERGY IMBALANCE MARKET

Q. Would you please provide an update concerning Avista's involvement with the Western Energy Imbalance Market?

A. Avista has been actively monitoring the operation and development of the CAISO Western Energy Imbalance Market (EIM). The Company regularly participates in regional meetings and dialogue associated with the EIM including the potential expansion of the EIM to incorporate day ahead transactions. Avista has been continuously evaluating the operational benefits associated with EIM participation, and the associated risks of not participating in the market. One of the largest operational benefits for current EIM participants is the ability to balance and regulate renewable resources by leveraging available market resources instead of relying on only internal Avista resources to provide regulation and flexible ramping for variable resources.

Avista's renewable resource mix is changing as the price of renewable resources continue to decline and our customer's interest in purchasing cleaner energy increases. Recently, Avista signed two Power Purchase Agreements (PPA) for 20 MW of solar starting in December of 2018 (Adams-Neilson) and 145 MW of wind starting in late 2020 (Rattlesnake Flat), based on customer demand and competitive pricing. Avista expects to integrate

additional renewable resources into its Balancing Authority Area (BAA) in the future associated with the development and adoption of national, state and local clean energy or carbon emission policies, and the increased interest of qualifying resources that meet the requirements under the Public Utility Regulatory Policies Act (PURPA). As additional variable resources are integrated into the Avista BAA, it becomes more efficient and cost-effective for Avista to rely on the EIM to help meet the in-hour variability of renewable resources, instead of holding back and dispatching Avista owned resources to meet the flexible ramping requirements.

Avista has also been closely monitoring the impacts to the bi-lateral trading market as more entities join the EIM. The recent integration of Idaho Power and Powerex into the EIM had an impact on short term hourly market liquidity in the summer of 2018. In addition, the commitment of Seattle City Light and NorthWestern Energy and the notice of intent of the Bonneville Power Administration to join the market in the next few years, will continue to put a stress on near term hourly market liquidity. EIM participants are less likely to conduct bi-lateral transactions close to the operating hour, due to the need to pass EIM sufficiency and flexible ramping tests and meet other market transaction closing times that occur well before the operating hour. This leads to significant risk and inefficiencies for non-market participants to reliably and responsibly meet load service obligations.

Based on Avista's changing resource portfolio, that will include additional variable resources in the near future, and the risks of being one of the few non-EIM participants, Avista has decided to join the Western EIM. Avista signed an EIM implementation agreement with the CAISO on April 25, 2019 with a planned go-live date of April 1, 2022. Avista is currently

working with the CAISO to develop a project plan to meet the different implementation milestones to ensure Avista is prepared to enter the market on schedule.

Q. What is the estimated cost and benefit associated with Avista joining the EIM?

A. Avista recently updated and re-evaluated our previous cost and benefit assessments associated with participating in the EIM. Utilicast was hired in the second half of 2018 to help Avista develop a technology road map and perform a metering assessment associated with EIM participation. Utilicast also updated the market costs assessment that it had previously conducted for the Company in 2015. Avista estimates it will cost between $21 million and $26 million to fully prepare for market entry. These costs include metering upgrades, generation control modifications, communication infrastructure additions and improvements, the purchase and integration of at least six market based software applications, the hiring of a System Integrator consultant, and internal Avista labor. The on-going annual costs to operate in the market are anticipated to be between $3.5 million and $4.0 million. Anticipated on-going costs include maintenance costs for software licenses and communication networks, the addition of approximately 12 new employees to facilitate market operations and settlements, and CAISO EIM membership fees. The initial cost and on-going cost estimates will be further refined as Avista conducts extensive planning assessments in 2019, including initiating a request for proposals for the software applications, selecting a System Integrator, and finalizing the internal program structure and associated employee resource plan.

Avista also recently reviewed the EIM benefit assessment conducted by Energy and Environmental Economics (E3) in the fall of 2017. E3 has conducted similar benefit

assessments for several other utilities to help understand the potential value of EIM participation. The E3 assessment estimated that Avista could see a range of annual benefits from $2 million to $12 million from EIM participation. There are four main study assumptions that drive the wide range of potential EIM benefits: the amount of flexible hydro Avista bids into the market, the amount of transmission that is made available for market transactions, the amount of renewable generation that is integrated into the Avista BAA, and the assumed EIM price volatility. Using Avista's best estimates for these critical study assumptions, Avista anticipates EIM annual benefits to be close to $6 million, with potential for benefits to move closer to the upper end of the study range depending upon observed market price volatility. Recent market price volatility experienced in 2018 significantly increased the benefits of current EIM participants. Both the Idaho Power Company (IPC) and Portland General Electric (PGE) achieved EIM benefits in 2018 as calculated by the CAISO that were over five times their anticipated benefits calculated by E3. Avista's resource mix and transmission connection to other EIM participants most closely matches IPC and PGE. Therefore Avista may achieve similar elevated EIM benefits during times of high market price volatility.

Q. Has the Company built any costs related to EIM in its base revenue requirement requested in this Case?

A. No, the Company has not included the any EIM costs expected during 2019 or 2020 associated with the implementation of EIM in this Case. The current total estimate for EIM implementation O&M expense over the entire project from 2019 to April 2022 is between $3.2 million to $4.0 million. The estimated annual project costs will be reassessed after the completion of project planning efforts in 2019. Estimated planning costs for 2019

related to the initial Project Manager labor, system integrator selection, software requirements development and request for proposal issuance, and potential accuracy testing analysis for generation and metering measurement devices is expected to be between $700,000 and $850,000, on a system basis.

Q. Is the Company proposing to flow incremental EIM costs through its PCA?

A. Yes. Beginning with the effective date of this case and the revised Power Cost Adjustment (PCA) base, in 2020 the Company proposes to allow incremental costs associated with the implementation of EIM to flow through the PCA until such time as they are included in base rates via a general rate case proceeding.[2] These costs will primarily be related to the network model expansion including EMS/SCADA integration, development of generation resource bid strategy and population of the generation resource master file, completion of modeling into the CAISO test environment, change management and employee training. These costs would flow through the PCA at the current allocation ratios 90% Customers / 10% Company.

Q. Is the proposed treatment of flowing incremental EIM costs through the PCA a method approved by the IPUC for other Idaho utilities?

A. Yes. First, in January 2017, the IPUC issued an order allowing Idaho Power to defer their incremental costs associated with joining the Western EIM, with recovery from customers to be determined in a future rate proceeding (Case No. IPC-E-16-19, Order No. 33706). Then, in July 2018, in Case No. IPC-E-17-16, the IPUC issued Order No. 34100

[2]An Expenditure Requisition (ER 7141) has been established to track costs associated with EIM. Various projects will be utilized to track components by department, FERC account, and expenditure type.

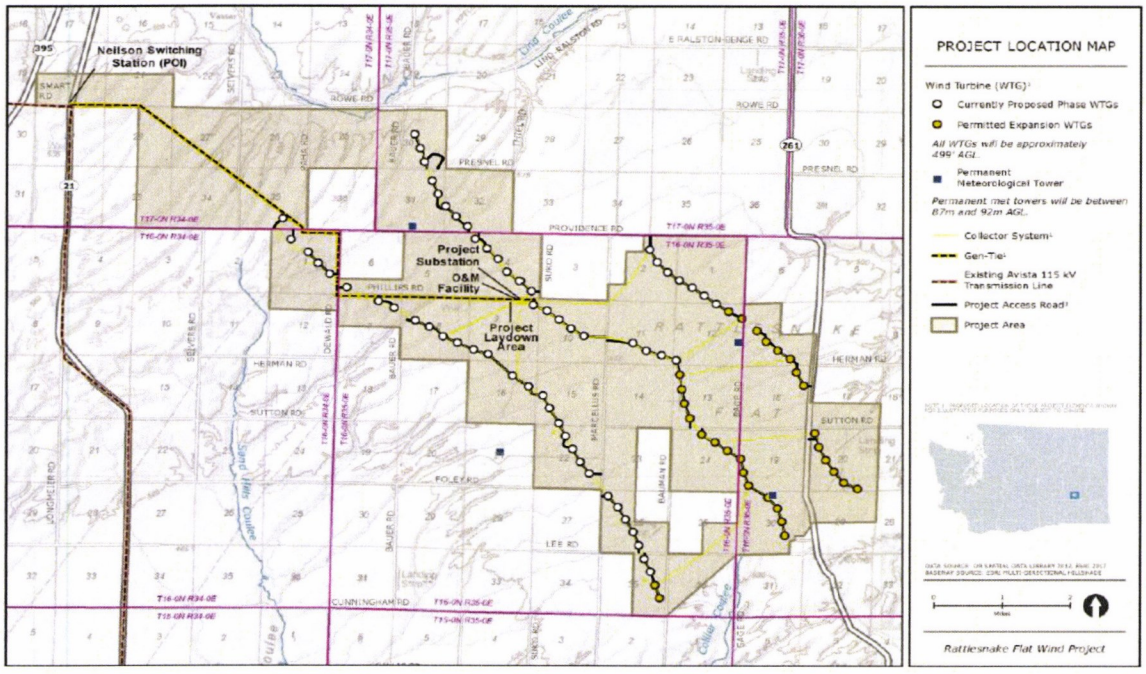
approving the Settlement Agreement between IPUC Staff and Idaho Power, allowing Idaho Power to add an EIM-related monthly revenue requirement (including rate base return of and return on) to its monthly PCA deferral calculation based on actual EIM participation costs after it has incurred those costs, until that amount is fully imbedded in base rates.

IV. RATTLESNAKE FLAT WIND POWER PURCHASE AGREEMENT

Q. Please briefly describe the Rattlesnake Flat Wind Project.

A. The Rattlesnake Flat Wind Project consists of 50 Siemen's S-129 2.9 MW wind turbines that are located on 20,000 acres about 12 miles southeast of Lind, Washington with a total capacity of approximately 145 MWs. The project will be directly connected to the Avista electric system and is expected to begin commercial operation in December 2020. The following map shows the location of the project.

Map No. 1: Rattlesnake Flat Wind Project



Q. Can you provide some background regarding why the Company initiated an RFP for renewable resources in 2018.

A. Yes. The Company's 2017 Electric IRP, described in Section II of my testimony, identified a need for additional generation resources beginning in 2026 with the expiration of the Lancaster PPA. The Company also uses short term market transactions when economical to replace the dispatch of owned or contracted for resources. Several changes in the market and price for renewable generation prompted Avista to issue an RFP for additional renewable resources without a self-build option.

The Company issued a Request for Proposals (RFP) on June 6, 2018 for 50 aMW of Washington State-qualified renewable energy online no later than December 31, 2022. The RFP indicated that the Company would consider the acquisition of additional renewable resources if the resources had lower long-term costs than electric energy market alternatives. The indicators that supported the release of the RFP at that time included the following:

- The expiring Production Tax Credit (PTC) was lowering prices as compared to price quotes after 2020;
- Other market indicators, such as pricing and developer activity;
- Competing renewable RFPs; and
- Further advancing renewable technology and competition for least cost resources.

Q. At the time of the 2018 RFP, please explain how the Company determined that a new resource was necessary.

A. As explained in the previous question and documented in Exhibit No. 5, Schedule 3C, the Company had four main drivers for issuing the 2018 RFP. First, the expiring

PTC was lowering prices as compared to price quotes after 2020 because the PTC is scheduled to be reduced or expire in 2020. The Investment Tax Credit (ITC) is scheduled to do the same in 2022. There is a strong likelihood that the pricing of additional renewable generation will increase given the decrease and/or expiration of the PTC and ITC. At the time of the 2018 RFP, many developers had projects ready to be completed by the end of 2020 that they were offering competitive pricing to potentially interested parties.

Other market indicators, such as pricing and developer activity, also indicated this was an opportune time for issuing an RFP for additional renewable energy. Developer activity along with industry market insights provided Avista personnel opportunities to observe and analyze changes in renewable energy technology and pricing. Indicative and actual pricing for renewables in the Western United States suggested that renewable resources were competitive in the wholesale market at the time the 2018 RPF was issued. Indicative pricing provided to Avista at the time showed falling prices for renewables.

Competing RFPs indicated that the timing was good for obtaining additional renewable generation. At the time, other utilities in the Northwest were actively pursuing renewable resources. Portland General Electric had issued an RFP, and Puget Sound Energy issued an RFP in June 2018 to replace the 272 MW expected deficiency from the closure of Colstrip Units 1 and 2 by 2022, as well as 671,000 renewable energy credits beginning in 2023 and increasing after that. This demand for additional resources could create increased competition for preferred products based on location and ability to site utility-scale projects.

With the advances of machine technologies and the sun-setting of tax credits, pricing for renewables had never been lower. Pricing may have been expected to increase if available tax opportunities were not fully captured before reduction or expiration.

Q. How did the Company determine the amount and type of resource needed?

A. The Company's energy, capacity and REC needs were used as inputs to the development of the Preferred Resource Strategy (PRS). The PRS is developed using a proprietary linear programming model called PRiSM. The PRiSM model helps select the PRS and uses:

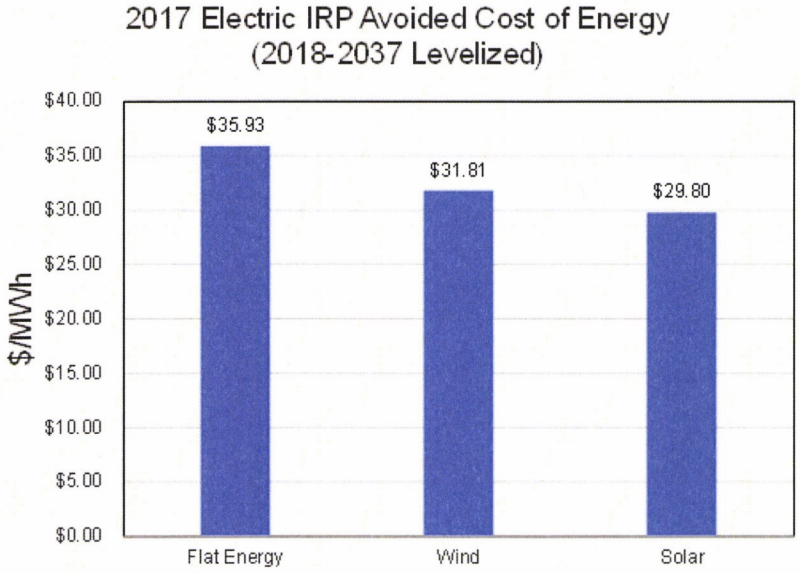
1. load deficits (energy and capacity);
2. RPS requirements;
3. Avista's existing portfolio's costs (loads and resources) and operating margins (resources);
4. Fixed operating costs, return on capital, interest and taxes for each resource option;
5. Generation levels for existing resources and new resource options; and
6. Carbon emissions levels for existing resources and new resource options.

Additional details about the development of the PRS and the PRiSM model can be found in Chapter 11 of the 2017 IRP (Exhibit No. 5, Schedule 1).

Q. Is this resource consistent with the 2017 Preferred Resource Strategy in the Company's 2017 IRP?

A. Yes, the 2018 RFP for renewables was consistent with the 2017 Preferred Resource Strategy by considering acquiring additional resources if the resource has a lower long-term cost than electric energy market alternatives. Chart No. 1 below shows that the 2018-2037 levelized cost of energy in the 2017 IRP was projected to be less costly for wind and solar resources than for a flat energy project.

Chart No. 1: Levelized Electric IRP Avoided Cost of Energy*



*Source: Data from 2017 IRP, Table 11.6 on pages 11-19.

Q. How did Avista evaluate and consider alternatives to the Rattlesnake Flat Wind PPA?

A. The Company issued an RFP on June 6, 2018, for 50 aMW of renewable energy to be online by the end of 2020. (See Confidential Exhibit 5, Schedule 3C). The Company indicated in the RFP that a self-build option would not be included in the RFP process.

On June 20, 2018, the Company received proposals totaling over 2,000 MW of wind and solar projects in response to the RFP. The Company with the assistance of a third party independent evaluator (Black & Veatch) evaluated potential projects both quantitatively and qualitatively against one another based on predetermined criteria that had been vetted with the Idaho and Washington Commission Staffs. The weighted, evaluated characteristics, included risk management (25%), net price (40%), price risk (5%), electric factors (20%), and environmental factors (10%).

The RFP evaluation process included two screening levels which resulted in a short list of eight bidders. The short listed projects were given an opportunity to provide additional information and update their bid price. After completion of due diligence of the short-listed projects, the Rattlesnake Flat Wind Project was the highest overall ranked resource as determined by both the Company and Black & Veatch. The Rattlesnake Flat Wind proposal was for an approximately 145 MW project located near Avista's Transmission System (12 miles southeast of Lind, Washington) and with an expected 34.2 percent capacity factor. The project committed to reach commercial operation by the end of 2020 to qualify for federal tax benefits.

Q. How was transmission considered in this decision?

A. The evaluation process included the transmission interconnection cost in the case of projects with proposed direct interconnection with the Avista transmission system or transmission and losses for projects proposed to interconnect to third party transmission systems and wheeling power to the Avista system. The Rattlesnake Flat Wind Project will be directly interconnected to Avista's system, so no long-term third-party transmission is required for this project to serve our customers. Short-term transmission rights may need to be purchased from Grant PUD if the scheduled transmission upgrades to the Avista system are not completed in the required timeframe. These potential additional short-term transmission costs were included in the RFP evaluation for the project.

Q. What documentation for the analysis and decision-making process has the Company provided regarding the decision to enter into a contract for the Rattlesnake Flat Wind Project?

A. The documentation provided concerning the analysis and decision-making process regarding the decision to execute a contract for the Rattlesnake Flat Wind Project are included in Exhibit No. 5, Schedule 3C 2018 Renewable RFP Report and Schedule 3C Request for Proposal documentation.

Q. Does the Company believe that the Rattlesnake Flat Wind PPA was a prudent contract to enter into?

A. Yes. My testimony and exhibits demonstrate the long-term need for the Rattlesnake Flat Wind PPA and provide specific supportive details regarding the Company's analysis. The Rattlesnake Flat Wind PPA is consistent with the economic analysis in the Preferred Resource Strategy in the Company's 2017 Electric IRP, which is discussed earlier in my testimony. Avista's Executive Officers agreed with the recommendation to issue the RFP for 50 aMW of renewable energy in 2018, and subsequently approved the recommendation to negotiate a PPA with Clearway Energy (developer of Rattlesnake Flat Wind Project) under terms and conditions consistent with their bid proposal. The Company has provided and explained all of the analytical work completed for this acquisition. The 20-year Rattlesnake Flat PPA is included in Exhibit No. 5, Schedule 4C.

Q. Does this conclude your pre-filed direct testimony?

A. Yes it does.