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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 AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-21-01 DIRECT TESTIMONY OF CLINT G. KALICH

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Clint G. Kalich. I am employed by Avista Corporation at 1411 East Mission Avenue, Spokane, Washington.

Q. In what capacity are you employed?

A. I am the Manager of Resource Planning & Power Supply Analyses in the Energy Resources Department of Avista Utilities.

Q. Please state your educational background and professional experience.

A. I graduated from Central Washington University in 1991 with a Bachelor of Science Degree in Business Economics. Shortly after graduation, I accepted an analyst position with Economic and Engineering Services, Inc. (now EES Consulting, Inc.), a Northwest management-consulting firm located in Bellevue, Washington. While employed by EES, I worked primarily for municipalities, public utility districts, and cooperatives in the area of electric utility management. My specific areas of focus were economic analyses of new resource development, rate case proceedings involving the Bonneville Power Administration, integrated (least-cost) resource planning, and demand-side management program development.

In late 1995, I left Economic and Engineering Services, Inc. to join Tacoma Power in Tacoma, Washington. I provided key analytical and policy support in the areas of resource development, procurement, and optimization, hydroelectric operations and re-licensing, unbundled power supply ratemaking, contract negotiations, and system operations. I helped develop, and ultimately managed, Tacoma Power's industrial market access program serving one-quarter of the Company's retail load.

In mid-2000 I joined Avista Utilities and accepted my current position assisting the Company in resource analyses, dispatch modeling, resource procurement, integrated resource planning and rate case proceedings. Much of my career has involved resource dispatch modeling of the nature described in this testimony.

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

A. I will explain efforts the Company has made to simplify our power supply adjustment, providing for better transparency and ease discovery for the Parties and a reasonable level of expense in this case. My testimony will include documentation of the rationale for key inputs and assumptions driving power supply cost values including loads, natural gas and electricity prices, and a comparison to the current level of authorized power supply expense. Finally, I will identify and explain the proposed pro forma adjustments to the 2019 test period power supply revenues and expenses, including the Retail Revenue Credit used in Power Cost Adjustment (PCA) deferral calculations.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. 9, Schedules 1 through 5 as shown in Table

No. 1 below. Confidential Schedule 1C and Schedules 2 through 5 are contained within one workbook in my workpapers, with all formulas and links intact for ease of reference. In addition to these Schedules, additional sheets in the workbook provide more detail and supporting calculations on the methodologies used in this case. Information contained in these exhibits were prepared by me or at my direction.

Table No. 1 – Exhibit No. 9 List of Schedules

Schedule Name	**Description**
Confidential Schedule 1C	Dispatch Model Results
Schedule 2	Pro Forma and Adjustment Summary
Schedule 3	Pro Forma Line Descriptions
Schedule 4	Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Schedule 5	Proposed Power Supply Base for PCA

II. PORTFOLIO MODELING METHODOLOGY

Q. Has the Company made any changes to the overall Portfolio Modeling Methodology used in this case?

A. Yes. I will briefly explain each major part of the methodology below, and I have highlighted the areas of change by indicating with "(New)" in the list below. More details are provided in Section III.

1. Source of Market Prices
2. Modeling Tool
3. Pricing Methodology (New)
4. Water Record (New)
5. AECO to Malin Transportation Contract Hedging Methodology (New)

Q. Please provide a brief description of each area where the Company has made changes to its modeling methodology.

A. The following summarizes the description of each area included in the draft methodology:

1. Source of Market Prices. We continue to use forward prices for natural gas and electricity. While forward price projections are far from perfect, they appear from data to be the best available source of information. In this case, following past Commission order, the Company uses a one-month historical average of actual electricity and natural gas prices for the forward rate period, referred to here as the "forward market." Electricity prices are represented by heavy (HLH) and light load (LLH) hours, priced at the Mid-C trading hub. Natural gas prices are represented as a single average price for each month, priced at the AECO and Malin trading hubs.

2. Modeling Tool. Consistent with previous General Rate Cases (GRCs), we use Energy Exemplar's Aurora software (the "Model") to calculate the authorized power supply expense. Several northwest regulated utilities, including Avista, use the Model for a variety of modeling applications.

3. Pricing Methodology. Instead of iterating with modifications to many of the "out-of-the-box" Model assumptions, thereby driving calculated prices until they match forwards, we instead input forward prices directly. In this way, we obtain reasonable results but simplify how forward prices are input into the Model and avoid potential conflict over the out-of-the-box assumptions. The software is used only for dispatching Avista resources and contracts against these prices.

Electricity prices are input hourly while natural gas prices are input daily, as they can be transacted in the marketplace today. Monthly forward HLH/LLH electricity prices are "translated" to hourly prices, just as monthly forward natural gas prices are similarly translated to daily prices to create a smoothed, normalized test year shape. The methodology for this effort generates prices by breaking out periods and algebraically shaping based on prices witnessed in the test year. Weekdays are shifted as necessary to align the test year to the rate year. Aligning in this exercise means that, for example, where the rate year begins on Tuesday and the test year began on

Monday, test year data is shifted by one day so that the weekdays line up. Although not applied for this case, where an historical test year contains volatility from extraordinary events not expected to occur in the normalized test year, adjustments are made to remove such events, and the filing would document the approach used.

The calculation described results in hourly electricity prices for the proforma period, such as 744 hours for the Mid-C in January, split between HLH and LLH. AECO and Malin natural gas prices are calculated similarly using the Malin daily price shapes, as natural gas spot market trades are reported as a single price for each day.

4. Water Record. In the past, Avista ran the entire hydro record through the Model, averaging the results.[1] This required the model to run 80 times, creating a more time-consuming and complex filing. This exercise was important when the Model was used to determine market prices, though as described above they were driven to approximate forward prices, and it was important to capture the reality that the hydro record is not normally distributed. By inputting prices, however, this effort is no longer necessary. We now dispatch resources using median monthly water levels derived from the 80-year water record.

5. AECO to Malin Transportation Contract Hedging Methodology. Avista's thermal operations rely on long-term firm transportation contracts from the AECO basin in Alberta, Canada, to Kingsgate at the U.S. Border, and from Kingsgate to multiple points south, terminating at the Malin basin located in Oregon.[2] Avista represents its system in the Model such that Avista electricity generating plants use a "landed" natural gas price. The landed price is derived in most cases by discounting the Malin forward price with fuel loss, delivery, and tax charges associated with transportation to each plant. A spreadsheet then further reduces natural gas fuel costs from Model plant dispatch to lower AECO prices up to the contractual rights Avista

[1] In this filing, consistent with our previous case, an 80-year record exists, beginning in 1929.

[2] Avista has approximately 61,000 dekatherms per day of natural gas transportation rights from AECO. Lancaster and Coyote Springs 2, our efficient combined cycle gas turbines when operating together exceed this amount. Total natural gas consumption across the fleet during peak days approaches a demand level of twice our contractual rights from AECO.

holds from AECO and Kingsgate. Our gas-fired plants thereby "consume" most of their fuel from the lower-cost AECO basin. Surplus transportation capacity not used for dispatch is valued using the spread between AECO and Malin, consistent with overall market prices. In this way, we value transportation rights in the model based on actual relationships between AECO and Malin instead of its value from a historical period.

In past cases, fuel costs for each gas plant were valued based on their geographic location and our transportation contracts were valued separately, not on what we expected the costs for our gas plants to be. Then the value of gas transportation, essentially the basis differential between AECO and Malin, was estimated using an historical look at data. While this calculation might seem straight forward, in practice it is a complex topic and subject to disagreement. A historical average based on recent years' results was used in the past, but the result was a higher value in actual operations than was modeled in the rate filing. Though there remains uncertainty with this valuation method, linking transportation to the plants is believed to greatly improve the valuation as it relates to power supply costs.

III. DISPATCH MODEL

Q. What model is the Company using to dispatch its portfolio of resources and obligations?

A. As with previous cases, the Company uses the Aurora Model to dispatch its portfolio of resources and obligation.[3] The Model optimizes Company-owned resource and contract dispatch during each hour of pro forma year.

Q. What experience does the Company have using Aurora?

A. The Company purchased a license to use the Model in April 2002. It has been used for numerous studies, including each of its integrated resource plans and rate filings after

[3] The Company uses Aurora version 13.5.1001 with a Windows 10 operating system.

2001. The tool is also used for various resource evaluations, market forecasting and requests-for-proposal evaluations.

Q. Please briefly describe how the Model is used in this case.

A. As briefly described above, departing from the past general rate cases, the Company is using the Model with "input prices". Input prices provide hourly prices for electricity and daily prices for natural gas that reflect market conditions forecast for the rate period. Once input, Avista resources and contracts are dispatched in the Model against the wholesale electric market price and netted against test year loads to determine overall portfolio costs. When market electricity prices are lower cost than operating one or more Company resources in each hour or hours, wholesale market power replaces that generation. Where Avista resources are available in excess of hourly loads, and one or more of those resources cost less to operate than the market price of electricity, the resources are sold into the Model-emulated market and the operating margin is retained to lower overall portfolio operating costs in the pro forma period. Once resources are dispatched and market transactions are determined, all costs are summed into my Exhibit No. 9, Schedule 2.

Q. More specifically, how is the Model used differently with input prices in this case relative to past cases where the software was used to emulate market prices?

A. The Model was not originally designed by its vendor to operate as a "closed" single-utility system with input prices; however, the software can now use input prices with the appropriate system setup resulting in simplified modeling, significantly less processing time, and with reasonable results. Specifically, the setup contains a single zone with Avista loads, contracts and resources. In addition, a single large load (Mid-C Market Load) is added to the zone, as is a single large resource (Mid-C Market Resource). The price of the Mid-C

Market Resource equals the input electricity price in each hour. The single Mid-C Market Resource is big enough to meet the Mid-C Market Load plus Avista's load, essentially creating a "market" for Avista to dispatch its resources against.

Q. When you say "large," what do you mean?

A. The Mid-C Market Load must be big enough to absorb all potential surplus sales from Avista resources when they are lower cost to operate than the market price of power and are surplus to Avista's loads. In addition, the Mid-C Market Resource must meet all of the Mid-C Market Load plus potential Avista deficits created by dispatching down resources having operating costs above market prices in any period. For simplicity, Avista elected to create a Mid-C Market Resource with a capacity equal to twice our maximum hourly annual balancing area load in the pro forma period, or 4,274 MW. For the Mid-C Market Load, Avista elected to create a load in each hour equal to twice Avista's area load in the same hour.

Q. Does creating the Market Resources affect power supply costs?

A. No. Irrespective of the size of the Mid-C Market Resource, so long as it is at least large enough to absorb all surplus power from Avista's generation portfolio, it has no impact on power supply costs.

Q. Does creating the Mid-C Market Load change how resources are dispatched in the Model?

A. No, because of the approach used where the Model dispatches hydro against the shape of all loads in the load area. A Mid-C Market Load with the same shape in all hours (e.g., 5,000 MW in each hour of the rate period) would change the area load shape and therefore affect the hydro generation profile. By shaping the Mid-C Market Load the same as Avista's load, hydro continues to dispatch to the shape of our loads and equals the same five-year average on- and off-peak shapes by month. Non-hydro resources are not affected in any way by the size of the Mid-C Market Load.

Q. How are Avista's resources dispatched in the Model?

A. In each hour where the Mid-C Market Resource price is higher than operating one or more Avista resources, the Avista resource, or resources, is dispatched. Load not served by Avista resources in the hour, if any, is served by the Mid-C Market Resource with a cost equal to the input market price. If dispatched Avista resources exceed Avista's load in the hour, the extra power displaces a portion of the Mid-C Market Resource serving the Mid-C Market Load, and this revenue is credited to reduce pro forma power supply costs. In this way, Avista's resources and loads are valued at the electricity prices input into the Model.

Q. What are the prices input into the Model?

A. Forward electricity and natural gas prices use the one-month average (approximately 20 market settlement days) of Intercontinental Exchange (ICE) prices from October 1, 2020 through October 30, 2020, the date range up to the point where Avista began modeling its costs for this case. Table No. 2 below details the prices input into the Model affecting our resources.

<u>Table No. 2 – Monthly Forward Prices at Key Hubs</u>

	Price $/dth or $/MWh			
Basin	**AECO**	**Malin**	**Mid-C Off**	**Mid-C On**
Sep-21	2.08	2.87	27.78	45.33
Oct-21	2.15	2.84	25.85	32.67
Nov-21	2.31	3.12	30.25	36.98
Dec-21	2.41	3.46	39.82	49.49
Jan-22	2.48	3.59	34.78	44.96
Feb-22	2.48	3.45	30.88	38.45
Mar-22	2.33	2.91	26.76	32.31
Apr-22	1.85	2.28	13.92	20.37
May-22	1.74	2.21	10.36	19.66
Jun-22	1.72	2.24	8.74	20.14
Jul-22	1.77	2.37	24.54	44.44
Aug-22	1.77	2.39	28.39	49.19
Avg	2.09	2.81	25.17	36.17

Prices are shaped hourly for electricity and daily for natural gas, reflecting how these spot markets traded in the test year and are anticipated to trade in the pro forma year. The hourly (electricity) and daily (natural gas) shaping is based on 2019 test year prices. For example, if the 2019 Mid-Columbia electricity price in the first hour of September is 90 percent of the average September price in the test year, then the Mid-Columbia input price to the Model for that hour in the test year is equal to 90 percent of the September forward price. Similar math is performed for natural gas, but because the spot market for natural gas is based on daily pricing, the shape is done on a daily basis using the Malin daily test year shape. Backup for the price calculations are in my workpapers.[4]

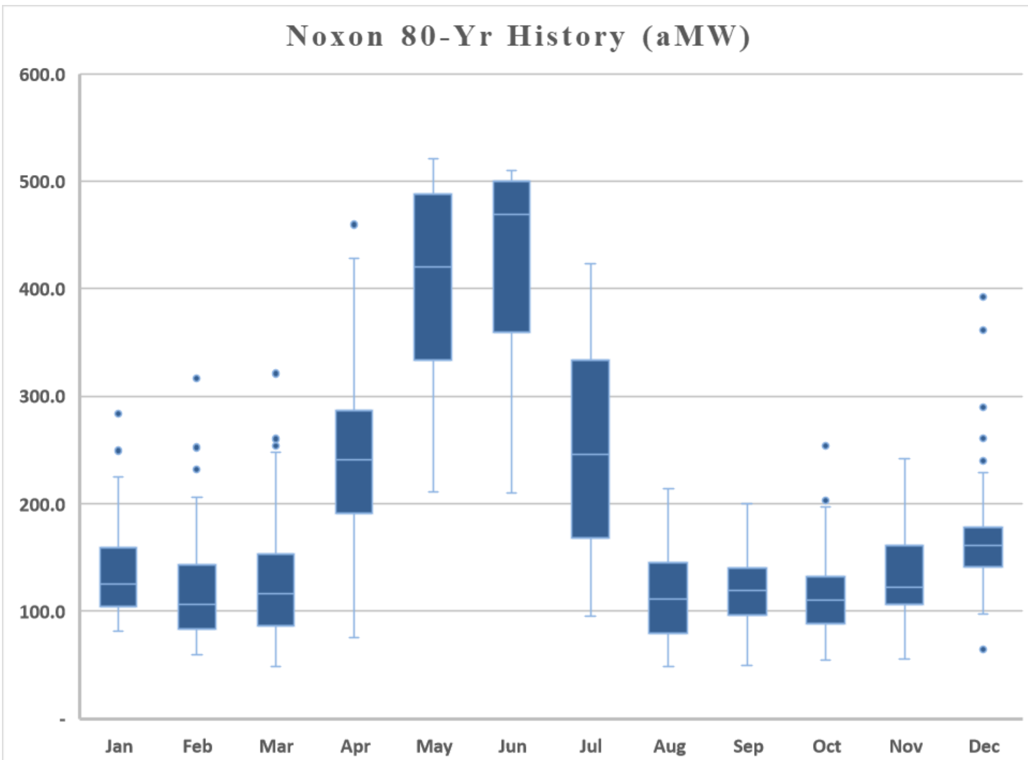
Q. Has the Company made any changes to the way it models hydro for this case?

A. Yes. In past cases all 80 years of hydro data were run through the Model,

[4] See Kalich workpaper: NaturalGas_Elec_Prices_2020_081020.xlsx.

requiring significant computing time and added complexity. In order to minimize the complexity associated with hydro, a single year of median monthly values extracted from the 80-year water record is used. The graph below depicts the 80-year record and median values for our largest hydroelectric resource, Noxon Rapids, on the Clark Fork River. Supporting data for the chart, as well as similar data and charts for our other hydro plants and Mid-C contracts are presented in my workpapers.

<u>Chart No. 1 – Monthly Median Water at Noxon Rapids</u>



Q. How does the Model operate Company-controlled hydroelectricity generation resources?

A. To account for actual flexibility of Company hydroelectricity resources, Avista develops individual operations logic for each river system. This separation ensures the flexibility inherent in these resources is credited to customers in the pro forma exercise using generation profiles for each river system closely matching the latest five-year average (through 2019 in this case).

Q. Please compare the operating statistics from the Model to recent historical hydroelectricity plant operations.

A. Over the pro forma period, the Model generates 72% of Clark Fork generation during on-peak hours. Since on-peak hours represent only 57% of the year, this demonstrates a substantial shift to the more expensive on-peak hours. This dispatch approximates the five-year average of on-peak generation at the Clark Fork. Avista ensures this historical shaping by river system for each month. Data supporting these calculations are in my workpapers.[5]

Q. How are reserves modeled?

A. At this time Avista does not implicitly represent reserves in the Model, though the Company employs two methods to reflect reserves. The first is the use of five-year hydro shaping. This shape reflects the operations of our hydro plants over time and how they are impacted (de-optimized) to provide reserves. The second method is limiting the dispatch of our Northeast and Rathdrum gas plants, just as we do in actual operations. I discuss the impacts reserves place on our thermal fleet later in testimony.

Q. Previously you noted changes to how the Company dispatches and prices its natural gas portfolio. What is the combined impact of the changes to the usage of transportation contracts versus what was included in the current authorized level?

A. Natural gas costs are modeled to increase by $23.8 million system from the last

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[5] See Kalich workpapers: Hydro History_ClarkFork.xlsx, Hydro History_Spokane.xlsx, Hydro History_MidC.xlsx.

case, offset by a decrease in firm natural gas transportation costs of $0.9 million,[6] and $5.0 million surplus AECO to Malin transportation sales. The total difference from authorized is $17.9 million.

Q. What's driving this increase?

A. Several things are driving this increase; most notably the price of natural gas. For example, the average AECO price for the pro forma period in this case is $2.09 per dekatherm, up more than 71 percent from $1.22 per dekatherm in the last case. In addition, and likely reflecting an overall tightening of the market from the many retirements of thermal plants, the Company's gas fleet experiences slightly higher utilization in this case relative to the last. It should be noted that for this case the pro forma shows a reclassification between "fuel for generation" and "natural gas off-system sales revenue". These changes were made in order to sync up with accounting records, align transportation cost and sales to individual plants and provide additional transparency.

Q. How are Company natural gas-fired plants <u>dispatched</u>?

A. As with previous cases, our natural gas-fired plants continue to be dispatched using fuel priced at their respective locations.

Q. How has <u>pricing</u> for natural gas-fired plants changed from the last rate case?

A. In the last case the Company reflected the cost of each natural gas-fired plant using fuel priced at its delivery point. Consistent with the methodology described above, the Company manages its AECO to Malin Transportation rights on a portfolio basis and this case

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[6] Lower pipeline transportation costs reflect the impacts of recent rate cases by both of our Canadian and US pipelines before their respective regulatory bodies.

reflects that behavior. The benefit of lower-priced AECO gas, as discussed previously, is now embedded within the natural gas fuel cost for each plant recorded to FERC Account 547 in Exhibit No. 9, Schedule 2, line 41. Our plants have lower fuel expenses relative to if they were dispatched as before using gas prices at their specific geographical location.

Q. How is the Company valuing the firm transportation contracts when they are not needed for fuel?

A. In previous cases the Company calculated the value of its firm transportation from AECO to Malin based on historical values obtained from contracts. The benefit was included as a FERC Account 456 Revenue. In this case, the benefit is reflected in lower fuel costs for our plants, reflected as a one-for-one reduction in FERC Account 456 Revenue and FERC Account 547 Other Fuel Expense. As explained earlier in my testimony, where our plants consume gas in quantities below our transportation rights, we reduce pro forma power supply costs by the surplus transportation valued at the difference in natural gas prices between the AECO and Malin hubs.

IV. OTHER KEY MODELING ASSUMPTIONS

Q. What are other key modeling assumptions being made by the Company?

A. Other modeling assumptions driving our Aurora-modeled pro forma costs are (1) loads, (2) forced outages, and (3) planned maintenance outages.

Q. What is the Company's assumption for rate period loads?

A. Consistent with prior GRC proceedings, historical loads are weather adjusted. In addition, there was an adjustment to load to account for a large customer being offline for a portion of the test year due to a fire. For this filing weather normalized calendar year 2019 load is 1,033.7 average megawatts compared to actual loads of 1,040.6 average megawatts. Table No. 3 below details data included in this proceeding. Please see Company witness Ms. Knox's direct testimony for additional information on the weather normalization.

<u>Table No. 3 – 2019 Weather Normalized Loads versus Actual Loads</u>

Month	Actual Load (MW)	Weather Adjustment (MW)	Modeled Load (MW)
Sep-21	926.1	1.6	927.7
Oct-21	999.3	-36.9	962.4
Nov-21	1,082.0	-2.8	1,079.1
Dec-21	1,136.9	52.9	1,189.8
Jan-22	1,163.8	16.7	1,180.5
Feb-22	1,261.7	-107.9	1,153.8
Mar-22	1,093.3	-53.8	1,039.5
Apr-22	929.5	10.9	940.4
May-22	896.5	29.5	926.0
Jun-22	949.9	-14.1	935.8
Jul-22	1,007.0	42.1	1,049.2
Aug-22	1,054.1	-30.1	1,024.0
Total	1,040.6	-6.9	1,033.7

Q. What are the assumed forced outage and planned maintenance rates for your fleet?

A. As with previous cases, we use the most recent five years' data (through 2019) to calculate average forced and planned outage rates at each of our plants except Colstrip maintenance. Table No. 4 below details these rates and compares them to our 2019 filing.

<u>Table No. 4 – 5-Year Forced and Maintenance Outage Rates, 2020 and 2019 filings</u>

	Forced Outage Rates			Maintenance Rates		
Facility	2020	2019	Difference	2020	2019	Difference
Boulder Park	5.8%	3.6%	2.2%	n/a	n/a	n/a
Colstrip	10.4%	11.4%	-1.1%	4.2%	4.8%	-0.6%
Coyote Springs 2	2.8%	5.6%	-2.8%	7.4%	6.8%	0.6%
Kettle Falls	2.2%	7.1%	-4.9%	3.5%	3.5%	0.0%
Kettle Falls CT	2.2%	3.9%	-1.7%	13.0%	11.2%	1.8%
Lancaster	2.2%	2.0%	0.2%	5.9%	5.7%	0.2%

Q. Please discuss your outage assumptions for the Colstrip units.

A. Historically the planned maintenance cycle for Colstrip was three years, so the most recent six-year average (through 2019) was used. However, as the Company nears the exit of Colstrip[7], the planned maintenance cycle is shifting to every four years. Forced outages are consistent with other plants, using five-year averages.

Q. Are the Rathdrum and Northeast natural gas-fired plants modeled differently in this case than in the past?

A. Yes. These plants provide most of our contingency and standby-reserve capabilities. Both are high heat rate facilities, meaning they rarely run over a year and their operating margins are low. In past cases Avista did not reflected these plants being held for reserves. Northeast, even if cost-effective to run relative to market prices, is limited to 100 hours per year due to regulation by the Spokane Air Pollution Control Board, and so the Company holds the units back for emergency and near-emergency operations. To cover unanticipated outages, our trading floor generally sets aside one Rathdrum unit even in the rare hours when market conditions show it to be lower in cost than buying market power. To reflect Northeast and Rathdrum operations, the Model does not dispatch the Northeast units, and can dispatch only one of the two Rathdrum units when market conditions support their operations. Table No. 5 below details energy and lost margins resulting from these modeling choices.

Table No. 5 – Northeast and Rathdrum Reserves Set-Aside Lost Margins

	Rathdrum	Northeast	Other Units	Total
Total Energy Revenue	$(10,261)	$(181)	$78	$(10,364)
Less Fuel	$6,821	$118	$473	$7,412
Lost Margins	$(3,440)	$(62)	$551	$(2,951)
MWh (reserve)	226,320	3,087	-	229,407

[7] The exact exit date of Colstrip has yet to be determined as the Company continues to negotiate with multiple owners.

Q. Please describe any changes to power contracts since the 2019 filing and their impacts on power costs.

A. Avista updates all contracts over the pro forma term to account for expiring and new contracts. Any contract without a known and/or fixed schedule is represented with a five-year historical average (e.g., PURPA contracts).[8] Table No. 6 below lists all contract changes in this case since our 2019 GRC.

<u>Table No. 6 – Wholesale Contract Changes (MWa)</u>

Contracts	Ann	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Chelan PUD	(1.4)	0.5	(2.6)	(3.0)	(0.0)	0.4	(0.8)	(1.4)	(2.9)	(1.6)	(1.0)	(1.8)	(2.6)
Douglas PUD	(0.4)	1.2	0.6	(1.8)	(0.4)	(0.1)	(0.3)	(0.7)	(1.2)	(1.2)	(1.0)	(1.3)	0.7
Grant PUD	0.6	3.5	(0.2)	(1.0)	2.3	2.6	2.6	3.0	(1.4)	(1.1)	(0.5)	(1.1)	(1.0)
Douglas Exchange Purchase	0.5	(3.4)	(5.7)	(5.7)	0.5	22.1	21.5	0.3	(6.2)	(4.3)	(3.6)	(4.5)	(5.6)
Canadian Entitlement	1.3	1.6	1.4	1.1	1.3	1.2	1.3	1.5	1.0	1.3	1.6	1.0	1.3
Nichols Pumping	2.5	2.5	2.6	2.5	2.6	2.5	2.6	2.5	2.5	2.6	2.5	2.6	2.5
Small Power	0.1	0.0	0.1	(0.2)	0.3	0.9	0.6	(0.3)	(0.2)	(0.1)	0.0	(0.1)	(0.3)
Spokane Waste-to-Energy	(0.3)	(0.0)	0.2	(0.2)	(0.4)	(1.7)	(0.2)	0.5	(0.8)	(0.7)	(0.2)	(1.0)	1.0
Stimson Lumber	0.5	0.3	0.1	0.5	0.3	0.7	0.9	0.8	0.5	0.6	0.4	0.4	0.5
Upriver	-	0.4	0.4	(1.7)	(1.5)	(1.2)	(2.2)	(2.4)	(0.4)	(0.7)	(0.0)	0.4	(0.5)
Douglas Exchange	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total Contracts	**4.4**	**7.8**	**(2.2)**	**(8.4)**	**6.0**	**28.4**	**26.9**	**4.8**	**(8.0)**	**(4.2)**	**(0.8)**	**(4.4)**	**(2.9)**

[8] When five years of history are not available a lesser number of years might be used. For new resources, such as Rattlesnake Wind, the vendor's forecast is used until such time an adequate history exists.

Q. Were there any large components worth highlighting in Table No. 6?

A. Yes. The Company has included the 2021 annual price change from Grant County PUD. We have used the 2021 monthly contract amounts through the entire pro forma period September 2021 – August 2022 as it is our best estimate for 2022 at this time. Finally, we have entered into or renewed a number of small PURPA contracts reflected in the Small Power line shown in Table No. 6 above. Each new contract is included in my work papers.

Q. Are there contracts not included in the Model?

A. Yes. We do not model index contracts since they do not impact power supply costs. There is only one such contract in this year's filing, the 2021 Morgan Stanley Renewable Energy Credit (REC) sale. This contract prices all delivered energy at the Mid-C index. Besides having no impact on power supply expense because it is index-based, the Morgan Stanley contract has flexible REC deliveries with the potential for all deliveries to occur prior to the start of the 2021-2022 pro forma year. REC values associated with this contract are also not accounted for in the pro forma power supply costs, but rather are reviewed annually as part of the PCA filing.

In addition, the mark-to-market value of all forward natural gas and power positions with contract durations falling within the pro forma period have been included, but outside of Aurora.

Q. Do Idaho customers receive benefits other than an energy resource from Palouse Wind and other Avista renewable energy resources?

A. Yes. Avista is actively involved in the REC market and has received significant REC sales revenue due to our mix of renewable resources. While the state of Idaho may not have a renewable portfolio standard (RPS), the presence of RPSs in other western states and the national Green-e REC market has provided significant benefits to Idaho customers. Avista's Idaho customers have received $23.8 million dollars of revenue from REC sales for the period 2007 through 2020. This rate case includes $423,407 of REC sales revenue for Idaho customers.

Q. How has the Company included Palouse and Rattlesnake Wind in this case?

A. The costs and benefits of our Palouse Wind and Rattlesnake Flat Wind power purchase agreements (PPAs) are included in modeling. The 105 MW Palouse Wind resource has been in our portfolio since 2012. The 160 MW Rattlesnake Flat Wind PPA began commercial operation in December 2020. Company witness Mr. Thackston's direct testimony and exhibits provide support for inclusion of the new Rattlesnake Flat resource.

Q. In prior Avista GRCs did the Commission preclude the Company from requesting that the full cost of the Palouse Wind PPA be included in base retail rates in the future?

A. No. In prior GRCs where Avista sought recovery of the Palouse Wind PPA, the parties agreed for settlement purposes to track the Palouse Wind project through the PCA. The Commission has not otherwise ruled on incorporating Palouse Wind or the Rattlesnake Flat PPAs into base rates.

Q. How is the Adams-Neilson Solar project treated in this filing?

A. This facility is used in its entirety to serve our Solar Select program in the State of Washington. Self-electing customers consume its entire output to serve their retail loads. In the Model we show the Adams-Neilson resource and an offsetting sale at its contract price, thereby netting to zero the resource entirely from our power supply expense.

Q. How was the new Clearwater contract modeled in this case?

A. The Company entered into a new contract on November 20, 2018, which was approved by the IPUC in Order No. 34252, whereby we purchase all of Clearwater's generation and sell it back to them at the same price. As a result, no purchase power expense associated with Clearwater has been included in this pro forma. However, there is a component of transmission expense and REC revenue which flows through the current PCA and is assigned 100% to Idaho customers (outside of the sharing band). See Exhibit No. 9, Schedule 2, lines 73 and 74.

Q. How are thermal fuel expenses for non-gas resources determined in the pro forma?

A. Non-gas fuel is procured for Colstrip and the Kettle Falls Generating Station. Our coal supply costs are dependent on the amount of coal purchased each year. For the proforma, the Model estimates the amount of coal dispatch in the pro forma period and this level is used to estimate a price based on the contract. This calculation is provided in workpapers. After the Model dispatches the plant, our coal supply contract prices are applied to that dispatch.

Unit wood fuel costs at the Kettle Falls Generating Station are based on multiple shorter-term contracts we have with fuel suppliers and our existing inventory. The total fuel cost is determined similarly to Colstrip. Expected Model dispatch is priced using budgeted prices from our fuel supply contracts. Fuel cost calculations can be found in my workpapers.

Q. Are there any other miscellaneous changes you would like to note?

A. Yes. To recover actual-incurred costs of transacting in the marketplace, the Company has pro-formed broker fees into this case. Prior to this filing, broker fees were recorded in actuals but not requested in our filings for collection in authorized power supply base costs. Similarly, new costs incurred from merchandise processing and CAISO transaction fees are included in this case. The 5-year average broker fees through 2019 is $418,700 and is included in FERC Account 557 transaction fees.

V. MODELING RESULTS

Q. Please summarize the results from power supply modeling.

A. The Model tracks our portfolio during each hour of the pro forma study. Many of the modeling results are shared earlier in my testimony. Overall fuel costs and generation for each resource are calculated and summarized in Exhibit No. 9, Confidential Schedule 1 and Schedule 2. Market sales and purchases, and their revenues and costs, are determined as well and shown in Table No. 7 below.

Table No. 7 – System Balancing Sales & Purchases

	2020 GRC	2019 GRC	Delta
	aMW	**aMW**	**aMW**
Market Purchases	13.0	20.1	(7.1)
Market Sales	(300.0)	(218.2)	(81.8)
Net	(287.0)	(198.0)	(88.9)
	$/MWh	**$/MWh**	**$/MWh**
Market Purchases	$28.12	$24.03	$4.09
Market Sales	$30.54	$25.49	$5.05
Net	$30.65	$25.64	$5.01
	($000)	**($000)**	**($000)**
Market Purchases	$4,686	4,251	435
Market Sales	($57,718)	($48,859)	($8,859)
Net	($53,032)	($44,608)	($8,424)

Market transactions, combined with other resource and contract revenues and expenses not accounted for directly in the Model (e.g., fixed costs), determine the net power supply expense.

VI. OVERVIEW OF PRO FORMA POWER SUPPLY ADJUSTMENT

Q. Please provide an overview of the pro forma power supply adjustment.

A. The pro forma power supply adjustment determines revenues and expenses associated with dispatch of Company resources and contract rights, as determined by the Model's simulation for the pro forma rate period under normal weather and median hydro generation conditions. Further adjustments are made to reflect contract changes between the historical test period and the pro forma period. Table No. 8 below shows total net power supply expense during the test period and the pro forma period. For information purposes only, the power supply expense currently in base retail rates, based on a calendar 2019 pro forma period, is shown.[9]

Table No. 8 – Net Power Supply Expense

Measure	System[(1)]	Idaho Allocation[(2)]
	($000s)	**($000s)**
Current Authorized Power Supply Expense [(3)]	$134,741	$ 46,634
Actual 2019 Test Period Power Supply Expense	$167,432	$ 57,530
Proposed 2021-2022 Pro Forma Power Supply Expense	$156,385	$ 53,734
Proposed 2021-2022 Expense versus 2019 Test Period	$ (11,047)	$ (3,796)
Proposed 2021-2022 Expense versus Current Rates	$ 21,644	$ 7,100

(1) Excludes Transmission

(2) Allocated based on ROO Current Production/Transmission Ratio of 34.36

(3) Adjusted for current weather normalized loads

The net effect of adjustments to the test year power supply expense is a decrease in 2021-2022 of $11.047 million ($167.432 million - $156.385 million) on a system basis and a $3.796 million Idaho allocation.[10] This value is provided to Company witness Ms. Andrews

[9] For the remainder of my testimony, for purposes of the power supply adjustment I will refer to the net of power supply revenues and expenses as power supply expense for ease of reference.

[10] Assumes 2020 Production/Transmission (P/T) ratio of 65.64% / 34.36% for Washington / Idaho.

for her testimony. Overall, however, the increase in net power supply expense, as compared to what is authorized in current base rates, is \$21.644 million, or \$7.1 million Idaho share.

VII. PRO FORMA POWER SUPPLY ADJUSTMENTS

Q. Please identify specific power supply cost items not already covered in your testimony and the total adjustments being proposed.

A. Exhibit No. 9, Schedule 2 identifies non-Model power supply expense and revenue items. These relate to power purchases and sales, fuel expenses, transmission expenses, and other miscellaneous power supply expenses and revenues.

Q. What is the basis for the adjustments to the test period power supply revenues and expenses?

A. The purpose of test period adjustments is normalization of power supply expenses for expected (average) weather and median hydroelectricity generation, to reflect current forward natural gas prices, and include other known and measurable changes for the pro forma period.

Q. Please describe each adjustment.

A. Exhibit No. 9, Schedule 3 provides a brief description of each adjustment line item of the pro forma. Detailed work papers demonstrate actual and pro forma revenues and expenses.

Q. How are long-term power contracts included in the pro forma?

A. In the past the Company included contract power rights and obligations in the Model, but separately calculated pro forma revenues and expenses outside of the model. In this filing the Model tabulates these items.

Q. How are term transactions accounted for in the pro forma?

A. The Company's risk management policy, sponsored by Mr. Thackston, executes term transactions to lessen power supply expense volatility. Our risk management policy enables term transactions out as far as three years. The Company takes power and natural gas positions into the future, using both physical and financial arrangements, in the forward markets; many of these transactions can fall within the pro forma period.

Where a portion or all of a contract for electricity falls within the pro forma period, its costs are included in the Model.[11] For physical electricity contracts falling within the proforma period, the Model also accounts for expected energy deliveries by increasing (for sales) or decreasing (for purchases) our net load obligations.[12]

The Model cannot value natural gas contracts. They are therefore valued outside of the model at their delivery basin. The valuation uses the same natural gas price as used in the Model. The pro forma value of our natural gas purchases may be found in my work papers.[13]

Q. How are short-term transactions included in the pro forma?

A. Short-term electric power prices, purchases and sales are an output of the Model. The Model calculates both the volumes and costs of short-term purchases and sales that balance the system's generation and long-term purchases with retail load and other obligations.

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[11] Financial contracts include only costs in the Model. Physical contracts include both costs and delivered energy.
[12] Net loads include retail load plus any obligations (up or down) to reflect contracts with 3rd parties resulting from these term transactions.
[13] See Kalich electronic workpapers, tab 'Conf Fuel Costs' of spreadsheet "Confidential Exhibit No. 9 - Schedules 1C-5.xlsx."

Transmission Expenses

Q. What changes in transmission expense are in the pro forma compared to the test-year and the expense in current base rates?

A. This case reflects the cost of an additional 50 MW of firm BPA transmission from our Coyote Springs 2 plant to our system. This incremental purchase will ensure the significant capacity from upgrades over the past decade can be delivered on a firm basis to our customers.

Natural Gas Transportation

Q. Please explain how natural gas transportation contracts are included in the pro forma.

A. The value of our firm natural gas transportation contracts from AECO to our power plants are discussed earlier in my testimony. Costs are included based on 2019 actual expense.

Summary

Q. Please summarize your proposed pro forma power supply expense that is provided to Company witness Ms. Andrews for the Company's electric Pro Forma study.

A. The net effect of my adjustments to the test year power supply expense is a decrease in 2021-2022 of $11.047 million ($167.432 million - $156.385 million) on a system basis and a $3.796 million Idaho allocation. Overall, however, the increase in net power supply expense in 2021-2022, as compared to what is authorized in current base rates, is $7.1 million (Idaho share).

VIII. PCA AUTHORIZED VALUES

Q. What is Avista's proposed authorized power supply expense and revenue for the PCA?

A. The proposed authorized level of annual system net power supply expense and revenues is $156.4 million for the pro forma. This is the sum of FERC Accounts 555 (Purchased Power), 557 (Other Expenses), 501 (Thermal Fuel), 547 (Fuel), 565 (Transmission of Electricity by Others, 537 (Montana Invasive Species), less Account 447 (Sale for Resale) and 456 (Other Electric Revenue). It also includes transmission revenue discussed by Company witness Mr. Schlect.

Q. What is the level of retail sales and the proposed Load Change Adjustment Rate for the PCA?

A. The proposed authorized level of retail sales to be used in the PCA is 2019 weather adjusted Idaho retail sales. The proposed Load Change Adjustment Rate is $25.72/MWh for the pro forma period[14], which is the energy related portion of the average production and transmission cost.

The proposed authorized PCA power supply expense and revenue, transmission expense and revenue, REC revenues, Load Change Adjustment Rate and retail sales are shown in Exhibit No. 9, Schedule 5.

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

A. Yes, it does.

[14] Also shown on Exhibit No. 9, Schedule 5 is the proposed Rate Year 2 Load Change Adjustment Rate of $26.52/MWh, which includes the impact of production and transmission costs for Rate Year 2 as pro formed by Ms. Andrews. The Company is not proposing to update power supply costs or the PCA base effective with the Rate Year 2 electric base rate change September 1, 2022.