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REPRESENTING AVISTA CORPORATION

Avista Power Cost Modeling Review

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Executive Summary

At the direction of the Washington Utilities and Transportation Commission (WUTC), a group of stakeholders has been engaged in a series of workshops focused on reviewing and potentially improving Avista's power cost modeling methodology. These stakeholders have included WUTC Staff, Avista (Company), the Public Counsel Unit of the Washington Attorney General's Office staff (PC) and the Alliance for Western Energy Consumers (AWEC).

While a large portion of a utility's costs are fixed, some are variable in nature and can be difficult to predict, especially when largely dependent on uncertain variables such as wholesale energy market prices or weather-dependent sources of electricity generation. Nonetheless, these variable costs must be accounted for in the retail rates charged to electricity customers, necessitating that they be estimated in advance. Differences between these advance estimates and the actual costs incurred are generally either collected from or returned to customers, depending on the direction of the variation. In some jurisdictions, including Washington, these cost variations are shared between customers and the utility shareholders, providing an earnings opportunity for the utility that does not depend on its prudent capital investments.

In Washington, Avista's power cost variations are tracked through the Energy Recovery Mechanism, or ERM, and allocated between customers and the Company. These variations have received significant scrutiny by stakeholders recently due to actual costs materializing lower than those authorized in base retail rates over the past several years, and a resulting portion of the cost savings being retained by Avista. Notably, the direction of cost variation was generally reversed in the early portion of the ERM's history (from inception in 2003 thorough 2009), resulting in the Company absorbing a portion of the excess costs.

At the request of workshop participants, Energy and Environmental Economics, Inc. (E3) was engaged by Avista to provide an independent, expert perspective on power cost modeling and to review Avista's current modeling practices. Over the past several months, E3 has conducted a review of Avista's power cost modeling process as well as those of other utilities across different jurisdictions. E3 has also reviewed the cost tracking and cost sharing mechanisms employed by regulators in different jurisdictions as a comparison for the ERM.

E3 has worked with the stakeholders over the past several months to identify the key areas of concern relative to Avista's power cost modeling approach, including any influence that the ERM design may have on this process. However, the findings and conclusions in this report constitute E3's independent perspective on these issues and are not intended to reflect a consensus view shared by all involved parties.

E3's review has produced the following findings:

1) Relative to other utilities' power cost modeling methodologies, Avista's approach is extraordinarily complex and time-intensive, resulting in a process that is difficult for stakeholders to follow and undermining stakeholders' confidence in the accuracy of the process.
   a) While Avista simulates the operation and market outcomes of the entire Western Interconnection using the AURORA production simulation model, it adheres to a requirement that its energy costs be based on published market prices at the Mid-Columbia trading hub. This requires Avista modelers to engage in significant effort to "force" the modeled electricity prices to match the forward market prices, adding complexity and introducing the potential for unintended consequences with respect to other aspects of system operations.
   b) This complexity is compounded by Avista's use of an 80-year record of Columbia River Basin runoff to reflect hydropower availability. This requires Avista's market benchmarking process to ensure that *average* electricity prices across 80 years of market simulations matches the Mid-C forward prices.
   c) Stakeholders are not able to replicate or even benchmark Avista's calculations, undermining confidence in the process.
2) The design of the ERM provides an incentive for bias by rewarding the Company for overestimating its energy costs.
   a) E3 is aware of the Commission's previous finding of a bias in Avista's calculations. E3 was not able, with the limited time and resources available for this review, to determine the source of the bias or even to verify whether there is, indeed, a bias. Nevertheless, E3 notes that the existence of a dead band within which Avista bears the risk of forecast errors provides an incentive for Avista to minimize the chance of a significant under-forecast of its energy costs.
   b) The existence of this incentive necessitates a substantial degree of Commission oversight into Avista's power cost calculations to avoid the potential for the Company to over-earn.
   c) The combination of the incentive inherent in the design of the ERM, the need for substantial oversight of the process, the complexity of Avista's calculations, and stakeholders' inability to replicate them creates a regulatory "perfect storm" that fosters perpetual mistrust and contention.
3) Avista has very little control over its actual energy costs.
   a) While E3 was unable to verify all of Avista's calculations, it is nonetheless clear that the majority of Avista's energy cost variations are due to fluctuations in continental commodities markets, particularly natural gas prices and natural gas basis spreads which have a downstream impact on electricity market prices. It is notable that the ERM resulted in under-forecasts of Avista's energy costs during years in which natural gas prices were generally rising (2003-2009) and over-forecasts during years in which natural gas prices were generally falling (2011-2019).
   b) One way that utilities can control energy costs is through hedging. Like most (but not all) utilities, Avista engages in hedging to reduce unpredictable fluctuations in energy costs. However, E3 notes that companies do not engage in hedging for the purpose of minimizing energy costs; rather the purpose of hedging programs is to manage energy cost *variability*. Due to transaction costs, hedging, like other forms of insurance, results in *higher* expected costs over time but lower variances in expected costs. This context is important for understanding Avista's use of hedging.

   c) While the structure of the ERM provides the Company with the ability to earn on energy cost variations where such costs end up lower than in base rates, most ERM-related earnings appear to have resulted not directly from Company business decisions but rather from unforeseen changes in continental commodities markets.

4) The ERM process, as a whole, is costly both to Avista and its stakeholders, however it is not clear that this investment of time and resources yields any gains in efficiency, i.e., whether it leads to lower power costs than less costly alternatives.

Based on these findings, E3 provides the following suggestions for Avista and the stakeholders to consider:

1. Avista should look for opportunities to simplify its modeling of power costs to reduce complexity and increase transparency, while maintaining sufficient accuracy.
    a) The most straightforward simplification would be to incorporate the market forwards directly into the modeling, treating Avista as a “price-taker,” rather than forcing simulated market prices to match the forwards. This is done by several other utilities that E3 interviewed during this process.
    b) In order to avoid mismatches in hydro conditions, it might be useful to consider modeling a single water year based on median or some percentile approach approximating the value of the full hydro record.
2. Avista and the Commission should consider updating forward market inputs as close to the rate implementation date as possible, as is done in “compliance runs,” due to the reliance on market forwards.
    a) This is enabled by the simplifications to the modeling process, which substantially reduce the time required to perform the calculations.
3. Finally, the stakeholder group should continue to discuss the merits and limitations of the current Energy Recovery Mechanism to better understand and potentially address the incentives it creates.
    a) The group should consider potential modifications to key ERM design features such as the existence and size of the dead band and the proportion to which deviations are shared between shareholders and ratepayers.
    b) Stakeholders should keep in the mind the balance between regulatory cost and efficiency gains, considering the degree to which the Company is able to control its energy costs.

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1) Introduction

The Washington Utilities and Transportation Commission (WUTC or "Commission") Staff, Avista ("Company"), the Public Counsel Unit of the Washington Attorney General's Office (PC) and the Alliance for Western Energy Consumers (AWEC) have been engaged in a series of workshops to "simplify and improve the Company's power cost modeling," and to explore "ways in which Avista may document the functionality and rationale of its power cost modeling and make changes to eliminate its directional bias," as directed by the Commission in 2018.[1] Together with the workshop participants, Avista and the WUTC Staff will report back to the WUTC commissioners with potential solutions to address concerns with the model.

Energy and Environmental Economics, Inc. (E3) was engaged by the workshop participants to provide an independent, expert perspective on power cost modeling and to review Avista's current modeling practices. In November 2019 E3 facilitated a stakeholder workshop to develop a common understanding of the different issues and concerns raised relative to Avista's current modeling approach and assumptions, and to provide an independent perspective on the fundamentals of power cost modeling more broadly.

Over the past several months, E3 has conducted a review and analysis of Avista's power cost modeling process and compared this approach to that of other utilities across different jurisdictions. Additionally, E3 has reviewed the Energy Recovery Mechanism (ERM) which tracks variations between the Company's authorized costs – as estimated through power cost modeling when setting base retail rates – and the actual costs incurred. The ERM refunds or surcharges customers for a portion of the difference, "to account for fluctuations in power costs outside of an authorized band for power-cost recovery in base rates,"[2] in recognition of the uncertainty inherent in setting retail rates prior to knowing actual costs. The ERM has been explored as part of E3's review of Avista's modeling practices given the perspective of some stakeholders that this mechanism has an important potential effect on the Company's power cost modeling approach due to the embedded financial incentives.

Reflective of the stakeholder process, this report attempts to develop a common understanding of the key issues at hand, and then assesses Avista's modeling approach and the ERM from this starting point. The findings and conclusions in this report nonetheless constitute E3's independent perspective and are not intended to reflect a consensus view shared by all involved parties.

The report is structured as follows:

- **Chapter 2** provides background context on different regulatory approaches to tracking cost variations, describes the ERM in particular, and documents its performance over time.

[1] Dockets No. UE-170485 and UG-170486 (consolidated). Order 07. April 26, 2018.
[2] Docket No. UE-011595. Fifth Supplemental Order. June 18, 2002.

- **Chapter 3** discusses the fundamentals of estimating power costs.
- **Chapter 4** summarizes Avista's power cost modeling approach.
- **Chapter 5** describes the review and analysis E3 has conducted and discusses key findings.
- **Chapter 6** provides a survey of the approach taken by utilities in other jurisdictions.
- **Chapter 7** concludes with recommendations as to how Avista's power cost modeling approach might be updated to allow for a more transparent and less contentious stakeholder process, while still allowing the Company to estimate costs with a reasonable degree of accuracy.

2) Cost Tracking and the Energy Recovery Mechanism

Energy costs – the cost of fuel purchased for combustion in utility-owned power plants and the cost of electricity market purchases – are generally considered differently than other costs in utility ratemaking processes. Capital investments on which utilities earn a rate of return are subject to prudency reviews where the utility commission makes a formal determination about whether the facilities are "used and useful" and can therefore be included in utility rates. Energy costs are variable expenses on which the utility does not earn profits and over which the utility has very little control; such costs generally are not subjected to the same level of regulatory scrutiny as capital investments. Additionally, these variable costs may change significantly after base retail rates are established, creating a discrepancy between actual costs and those embedded in tariffs which can persist for years in the absence of either new rates being established or some form of rate adjustment.

Many utility regulators therefore employ some form of cost tracking mechanism for variable utility expenses to account for the uncertainty in these costs at the time of rate setting, recognizing the fundamental difference between capital investments and variable cost outlays. The use of such cost trackers and adjustment mechanisms is intended to allow for fair recovery of expenses outside of the utility's control, without requiring a full General Rate Case (GRC) – including the administrative burden to the utility, the regulator, and any intervening parties. Some tracking mechanisms additionally incorporate a sharing mechanism structured to provide the utility an incentive to best manage those costs within its control and the potential for additional earnings through energy trading activities, while also recognizing that – in general – large cost variances will be outside of the utility's control.

Below we describe generalized versions of two common types of adjustment mechanism.

Fuel Adjustment Clauses

Fuel Adjustment Clauses (FACs), alternatively referred to as Fuel Adjustment Mechanisms (FAMs) or other similar names, are a widespread regulatory approach under which a utility is allowed to implement rate adjustments which reflect changes in its cost of fuel. Variations between forecast and realized fuel costs – whether positive or negative – are recovered from or refunded to customers through a FAC adjustment in subsequent rates. FAC mechanisms generally also cover purchased power expenses, but its inclusion as well as other cost items varies by jurisdiction and company.

FACs are used to address potentially large fluctuations in utility fuel costs. Without the use of such tracking mechanisms, the utility has the potential to either incur large costs or benefit from large windfalls due to exposure to market fluctuations in the cost of fuel. In either of these situations, actual net costs would deviate from those collected through base retail rates, ultimately resulting in deviations from the utility's authorized rate of return established in the previous GRC. FACs reduce such deviations by allowing for timely adjustments to rates for changes in fuel and purchased power costs without the regulatory cost and delays of traditional rate cases. FACs pass 100% of the cost variations on to customers.

Sharing Mechanisms

Unlike FACs, sharing mechanisms incorporate features that allocate cost variances – whether positive or negative – between customers and the utility. These mechanisms may or may not include a “dead band” around the authorized level of net costs established in the last GRC, expressed either as a dollar amount or as the dollar equivalent of a certain percentage of the utility’s authorized return on equity. Cost variances falling within the range of the dead band are absorbed by the utility, while variances outside of the dead band are shared between customers and the utility in some proportion, through “sharing bands.” The portion of costs (or savings) allocated to customers is then either incorporated into retail rates in the next GRC or deferred in a balancing account for future recovery or refunding. Balancing accounts for this purpose generally include predetermined thresholds for rate recovery, allowing the balancing account to fluctuate and absorb positive and negative cost variations over time until or unless the threshold (or “trigger”) is reached. Both dead bands and sharing bands can be structured symmetrically or asymmetrically, depending on whether it is deemed appropriate to have equal risk and benefit sharing between customers and the utility.

Avista’s Energy Recovery Mechanism

In Washington, Avista’s recovery of annual power expenses through retail rates is subject to adjustment through the Energy Recovery Mechanism (ERM), which is a form of sharing mechanism as described in the preceding section. The ERM was agreed upon through a stakeholder party settlement stipulation developed through a 2001 Avista general rate filing and was approved by the WUTC in June 2002.[3] Avista is required to file ERM annual review reports by April 1st of each year.

COST VARIANCES RECOVERED THROUGH THE ERM

The ERM is intended to account for ordinary variations in Avista’s power costs which are considered to be substantially outside of the Company’s control. The mechanism tracks expenses and revenues “from four FERC accounts (Accounts 447 [Sales for Resale], 501 [Thermal Fuel], 547 [Fuel] and 555 [Purchased Power]), together comprising the Company’s major power supply cost accounts.”[4] Additionally, the ERM tracks differences in thermal generating plant fuel expenses not included in Account 547 to reflect the net of natural gas revenues and expenses for thermal plants.[5] The other cost variations accounted for in calculation of the ERM energy cost deferrals include electricity transmission expense (FERC Account 565), third-party electricity transmission revenue (FERC Account 456), and broker fees.[6]

The variation between base and actual net expenses across these accounts represents the amount to be either recovered from or refunded to customers through the ERM. These variances are calculated on a

[3] Docket No. UE-011595. Fifth Supplemental Order. June 18, 2002.

[4] Docket No. UE-011595. Fifth Supplemental Order, at 15. June 18, 2002.

[5] These are tracked separately from Account 547, in Accounts 456 (revenue) and 557 (expense).

[6] Avista. Rebuttal Testimony of William G. Johnson (Exh. WGJ-6T), at 6. Docket No. UE-170485 and No. UG-170486.

monthly basis, with an annual review by the WUTC (following Avista's April 1st filing) in which the reconciliation between authorized and actual costs is made and any costs or savings to customers are deferred for later recovery or refunding (unless exceeding a threshold, as described further below).

ADDITIONAL COMPONENTS

Given that Avista operates a combined electric system between Washington and Idaho, the net cost variance described above is multiplied by a Washington "Production/Transmission" allocation factor to derive the portion of this variance to be attributed to Avista's Washington customers. This factor varies slightly based on the proportion of retail sales and peak loads between the two states but is consistently in the range of 65%.[7]

Additionally, the variance amount tracked through the ERM includes a retail revenue adjustment intended to account for the portion of cost variation due to changes in retail load. Dividing Avista's energy classified production costs (as determined through the Company's cost of service study) by the annual base retail sales produces a production related revenue figure. For example, in the initial 2002 settlement stipulation, this figure was $0.03208/kWh, while the current adjustment is $0.01811/kWh. This adjustment is calculated by dividing total pro forma power supply expense by total load. The production related revenue figure is multiplied by the difference between base and actual retail sales to derive an adjustment to the monthly ERM deferral amount. For example, if actual retail sales are greater than the base retail sales assumption, the retail revenue adjustment results in a credit to the ERM deferral balance.

COST SHARING AND DEFERRAL OF ERM BALANCES

ERM deferrals in most years are not directly passed through to customers and are instead subject to a "dead band," "sharing bands," and a rate adjustment "trigger."[8] The symmetrical dead band encompasses variations between base and actual net power costs of up to $4 million. Outside of this dead band, asymmetrical sharing bands allocate portions of the deferral amount to customers and the Company. Positive variances (where actual costs are greater than authorized base costs) between $4 million and $10 million are shared equally between customers and Avista, while positive variances greater than $10 million are allocated 90 percent to customers and 10 percent to the Company. Negative variances (where actual costs are lower than authorized base costs) between -$4 million and -$10 million are allocated 75 percent to customers and 25 percent to Avista, while negative variances larger than -$10 million are allocated ninety percent to customers and ten percent to the Company.

Figure 1 below provides a visual representation of the dead band and sharing bands.

[7] The Production/Transmission or P/T allocation factor is calculated as the simple average of a) Washington's percentage of Avista's total retail sales, and b) Washington's percentage of total peak load.

[8] The dead band, sharing bands and rate adjustment trigger described here reflect the current ERM. Band and trigger levels in use today are different from those originally established in 2002.

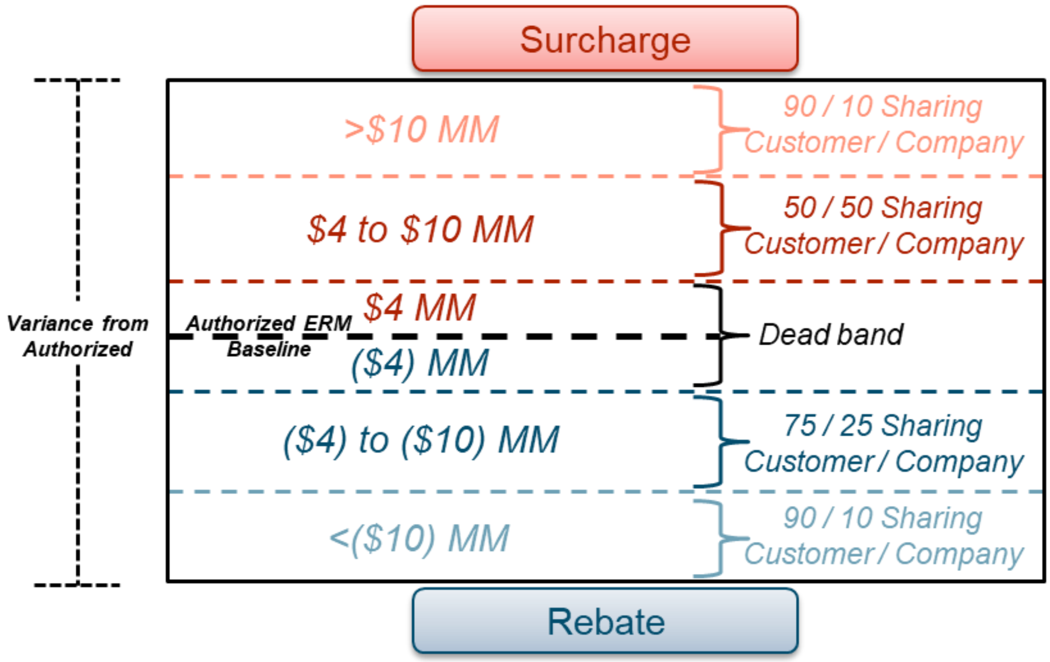

Figure 1: ERM Dead band and sharing bands

ERM deferral amounts are also subject to a rate adjustment trigger of $30 million. If accumulated deferral amounts in either the positive or negative direction reach this threshold, rates are adjusted by tariff.

Annual ERM Deferral Amounts

Since its inception, annual ERM deferral amounts have varied significantly. The largest surcharge to date ($22.3 million) was for 2003, the first full year in which the mechanism was in place. The largest rebate to date ($12.8 million) was for 2011.

While Avista collected surcharges from customers in the early years of the ERM to account for the costs of the 2000 – 2001 energy crisis, and has also refunded portions of the ERM deferral balance to customers through settlements in general rate cases, the $30 million threshold (trigger) in the rebate direction was only reached in 2018. Avista will be refunding the deferral balance (approximately $42.4 million, including interest accrued over the refund period) to customers over the next two years.

As demonstrated in Figure 2 below, the trend in the early years of the ERM was of actual net power costs exceeding authorized baseline amounts, while the trend in the more recent years has been the opposite, with actual net power costs being realized lower than authorized baseline amounts. The Company has explained the primary driver between these contrasting trends as the significant change in natural gas prices over this period, with rising prices in the 2000s giving way to extraordinary price declines in the 2010s.

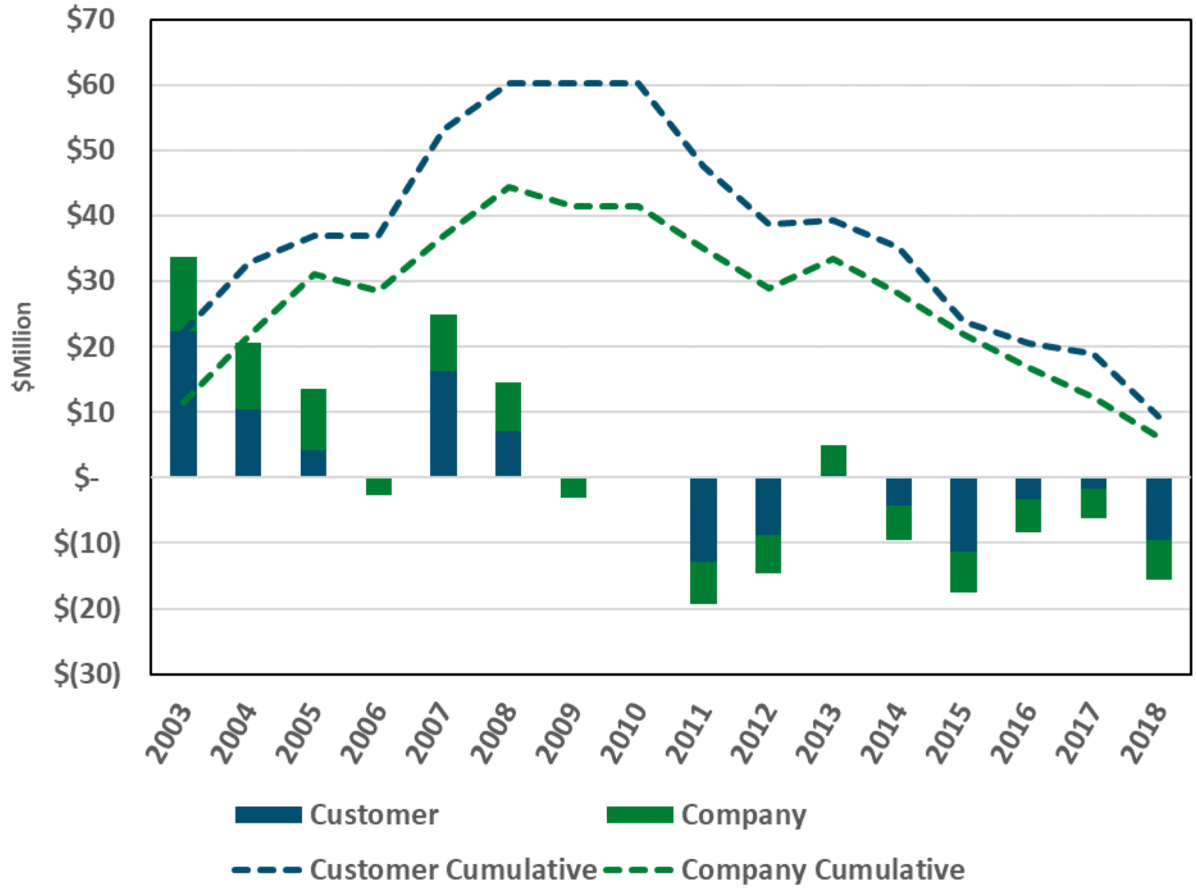

Figure 2: ERM Actual vs. Authorized, 2003 – 2018

Table 1 contains the annual customer and Company allocations, annual totals, and the cumulative total of ERM amounts (combining both the customer and Company portions).

Table 1: Annual ERM Allocations ($MM, nominal), 2003 – 2018

	Customer Allocation	Company Allocation	Annual Total	Cumulative Total
2003	$ 22.3	$ 11.5	$ 33.8	$ 33.8
2004	$ 10.5	$ 10.2	$ 20.7	$ 54.5
2005	$ 4.1	$ 9.5	$ 13.6	$ 68.1
2006	$ -	$ (2.6)	$ (2.6)	$ 65.4
2007	$ 16.3	$ 8.5	$ 24.8	$ 90.3
2008	$ 7.0	$ 7.4	$ 14.5	$ 104.8
2009	$ -	$ (3.0)	$ (3.0)	$ 101.7
2010	$ -	$ -	$ -	$ 101.7
2011	$ (12.8)	$ (6.4)	$ (19.2)	$ 82.5
2012	$ (8.7)	$ (6.0)	$ (14.7)	$ 67.8
2013	$ 0.5	$ 4.5	$ 5.0	$ 72.9
2014	$ (4.1)	$ (5.4)	$ (9.5)	$ 63.3
2015	$ (11.3)	$ (6.3)	$ (17.6)	$ 45.8
2016	$ (3.3)	$ (5.1)	$ (8.4)	$ 37.3
2017	$ (1.7)	$ (4.6)	$ (6.2)	$ 31.1
2018	$ (9.5)	$ (6.1)	$ (15.5)	$ 15.6

Avista has provided a categorization of the ERM variance drivers for each year. Figure 3 below presents a visual representation of this annual categorization, along with the net annual ERM variance total.

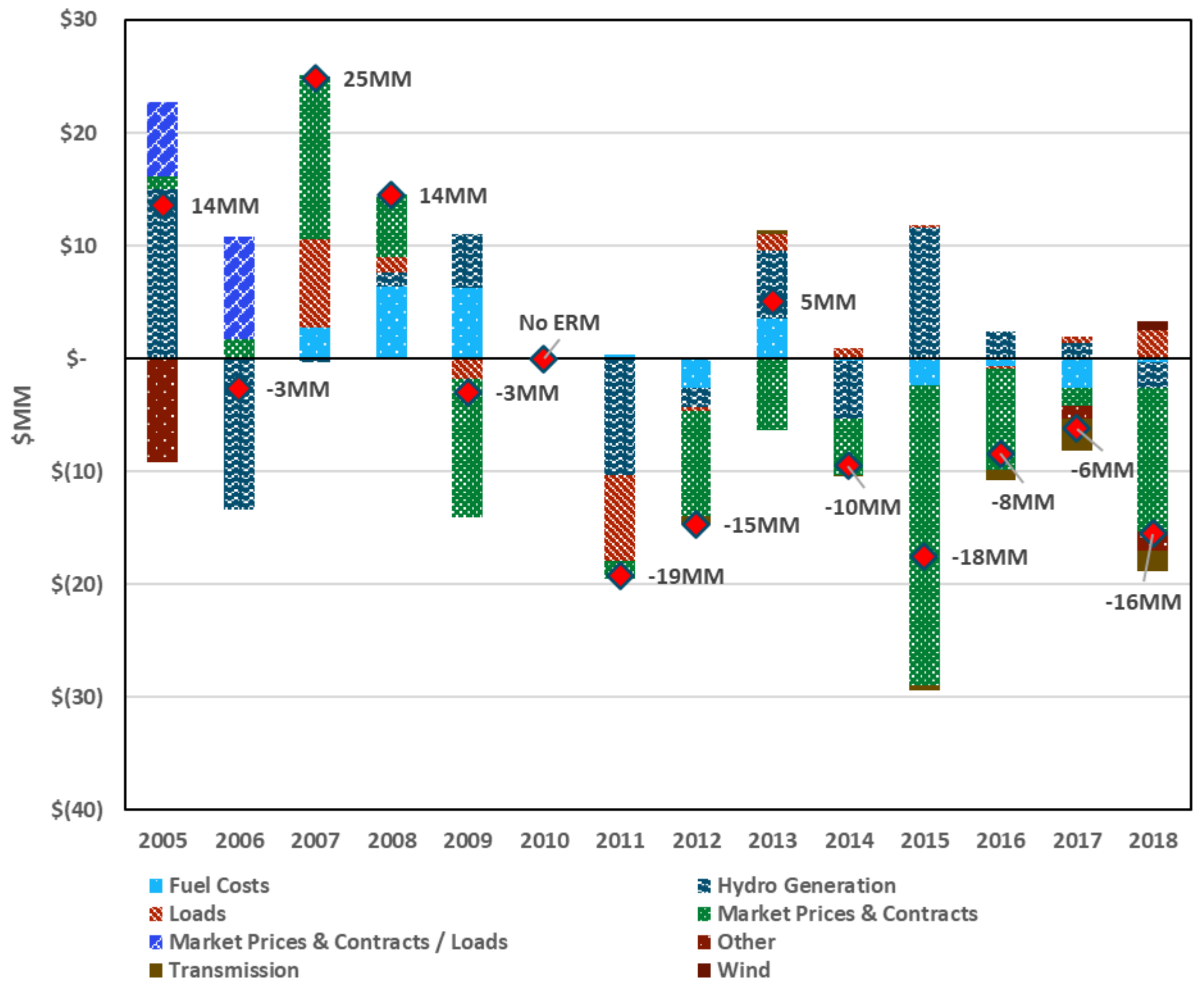

Figure 3: Annual ERM Variance by Category, $MM nominal, 2005 – 2018[9]

Positive values denote costs in each year which were greater than the costs included in authorized base rates, while negative values denote cost savings in the respective categories.

A review of this data highlights that – as reported by Avista – much of the annual variance stems from differences between the market prices and associated contract values included in authorized power costs and the actual market prices (and contract values) which occurred. This category includes a number of net expenses, such as electricity market purchases and sales, power and gas contracts indexed to market prices, and by extension the differences in authorized and actual net revenues for Avista's gas generator dispatch (which is based on market prices). Fuel costs are relatively small in this categorization given that they only cover Avista's coal and biomass (wood) costs. The other significant categories across the years include hydro generation and, to a lesser extent, retail loads.

[9] Variance categories reported by Avista and re-categorized by E3 in an attempt at creating better year-to-year consistency.

3) Power Cost Modeling

Balancing Priorities in Power Cost Modeling

One outcome of the November 2019 workshop was stakeholder alignment around the criteria that should define a successful power cost modeling methodology. Based on the workshop discussion, a successful modeling approach:

- Produces **accurate forecasts** of actual power costs.
- Is **simple** and **transparent**.
- Is **internally consistent**.
- Provides the utility with the **appropriate incentives to manage costs**.
- Provides the utility with a **fair opportunity to recover costs**.

Some tradeoffs between these criteria are inherent. For example, the most accurate forecasts are unlikely to be produced using the simplest methods. However, putting forth these criteria as guiding principles is a useful starting point for evaluating the success and appropriateness of a given power cost modeling approach.

Core Components in Power Cost Modeling

The core components which must be estimated in order to establish baseline net costs – and therefore base retail rates – include electricity market prices, production costs for utility-owned generators, and retail loads. Additionally, a utility such as Avista owning both gas transportation rights and electricity transmission rights must also estimate the value of these assets based on how they will be operated. If the utility engages in hedging practices to reduce market exposure and therefore reduce the volatility of customer bills, this component must also be considered, as hedges effectively change the expectation of power costs over different time periods (i.e., depending on the period for which the utility hedges parts of its portfolio).

Figure 4 presents an illustration of how the main components interact in a summary formula for net power costs. As described in the graphic, market electricity prices and anticipated native load are used to estimate the cost of serving load in each hour. Generation revenues – based again on the market price, as well as the operating and fuel costs of generators – reduce the net generation costs, as do the value of gas transportation and transmission rights, which allow the utility to arbitrage price differentials between different trading locations (gas trading hubs and electricity nodes). This formula is a simplification and does not include all components of a utility's net power costs, but does illustrate the basic concepts and the interactions between key variables.

$$Net\,Power\,Cost =$$

$$\sum_{h=1}^{8760}\left\{(L_h * EP_h) - \sum_{g=1}^{n}\left[\left(EP_{g,h} - C_{g,h}\right) * G_{g,h}\right] - GT(GP_1 - GP_2) - ET(EP_1 - EP_2)\right\}$$

Serving load at market prices reflects gross cost of meeting demand

Net generation revenues reflect total value of dispatch when plants are "in the money"

Gas transport rights provide value through basis differential

Transmission rights provide value through electricity arbitrage

Figure 4: Illustrative Net Power Cost Formula

Where,

- L = Load
- EP = Electricity Market Price
- GP = Gas Market Price
- G = Generation
- C = Cost
- GT = Gas Transportation
- ET = Electricity Transmission
- h = hour
- g = generator

The following sections discuss each key component and provide context as to the different manners in which they can be treated in estimating net power costs.

ELECTRICITY MARKET PRICES

One of the primary considerations in modeling future power supply costs is determining how to estimate future electricity market prices. This component is especially impactful on estimated power costs given that most utilities rely on wholesale markets to sell excess and/or purchase additional electricity when profitable to do so. Additionally, the relationship between wholesale market electricity prices and the cost of producing electricity using natural gas at market prices – often referred to as the "spark spread" – impacts utilities' decisions around using (combusting) natural gas versus selling it.

Three primary methods are used by utilities to estimate the unknown variable of electricity market prices: **forward market** trading prices, direct modeling of the **fundamentals** which drive market prices, and econometric or **regression analysis**.

Forward Prices

Leveraging forward market trading prices for a future period is a common manner by which to reflect expected future electricity prices. The main advantage of using forward prices is that they represent a collective (market) expectation of future period prices. Assuming that the market has a good sense of future patterns, forward prices will be a good proxy for the prices which actually occur. However, if market expectations are skewed or fail to anticipate large changes in supply or demand, the expected prices may differ significantly from those actually realized in the future period. Given that uncertainty in future prices increases over longer time periods, market forwards are generally more appropriate for shorter-term estimates than for longer-term forecasts.

Most utilities utilizing forward prices incorporate them directly as an input into their modeling, as the external market price for electricity. Alternatively, some utilities use forward electricity prices as a benchmark for their modeled prices to ensure that the modeling is reasonably aligned with market expectations. As discussed further in Chapter 5, Avista's power cost modeling methodology relies on benchmarking to market forwards, although it is unique in that it requires average prices in each monthly On and Off Peak period – developed using a full historical hydro record – to approximate forward prices.

Fundamentals Modeling

This method employs modeling of physical and economic factors on electricity prices, typically through a production cost model which provides granular estimates of hourly resource availability, costs and dispatch. Numerous third-party software programs are available to utilities for this type of modeling, including AURORA, PLEXOS, PROMOD, PROSYM, and GE-MAPS, among others. Within each of these models, users can choose to customize many inputs and assumptions based on expectations of how different factors may change over time. This can be useful when attempting to represent various parts of the electric power system's complexity. However, estimating this level of detail for a future period in a complex system under various forms of uncertainty is inherently a challenging process, and it is important to be aware of "false precision" in such exercises. Additionally, it is worth noting that most utilities using fundamentals modeling are still reliant on forward prices to some extent, given that natural gas price forwards are a standard input.

Fundamentals modeling is generally better for forecasting prices over a longer time period, especially when the expectation is that fundamental price drivers will change in the future. This is one potential limitation of using a fundamentals modeling approach for applications such as a utility's rate filing, which focuses on a relatively near-term period.

Regression Analysis

Using regression analysis to estimate future electricity market prices attempts to describe the relationship between different input variables and the outcome variable of interest (i.e., market prices). By considering how these input variables and electricity market prices change temporally, regression analysis aims to identify the underlying dynamics and thereby predict what future market prices will look like.

One limitation of regression analyses is their accuracy across varying parts of the year, as different market dynamics drive costs differentially across seasons. In the Pacific Northwest prices in the spring months are generally driven largely by hydroelectric generation, the availability of which can vary significantly year to year. Regression analyses of prices in the region have been shown to be more consistent for higher-cost months where the marginal generator is a natural gas unit rather than a hydroelectric dam.[10] However, annual variability in hydro generation and the resulting impact on market prices is a challenging dynamic to account for across the different price forecasting methodologies.

While this method is used by some utilities and other industry participants to estimate future electricity prices, none of the utilities surveyed for this report used regression analysis for this purpose.

VARIABLE GENERATION

The availability of low variable cost, weather-dependent generation sources such as hydro, wind and solar is another important yet difficult-to-estimate input to a utility's net power costs. The impact of hydroelectric generation on net power costs is especially significant in the Pacific Northwest given the large portion of the resource mix it represents.

Hydro

Various approaches to estimating the availability of hydro generation are used by different utilities, with the main distinction being the direct use of multiple years of data in the modeling versus the use of a single year. Some utilities leverage long historical records (e.g., 30, 80 or even 90 years of data) of hydro availability in each month of the year, modeling their costs and unit dispatch under each of the years' hydro records to reflect the significant annual and monthly variability in this resource. Other utilities instead simply model either an average year or a median year of hydro availability, developed using a historical record but without directly modeling costs based on each and every historic year.

Modeling net power costs for each individual hydro year – while holding other inputs constant – provides a detailed perspective on the range of results, including the variation between years and the significantly higher costs resulting from years with especially low hydro generation. However, this approach is significantly more complex than the use of a single modeled year, requiring more time to conduct the detailed modeling as well as more time for review and – as needed – auditing by any interested parties.

Conversely, using a single year for modeling hydro generation is a more straightforward process, but may not adequately capture the level of cost variation which can result based on different levels of hydro availability. Wholesale electricity prices tend to be lower during high water years when a utility such as Avista may have surplus hydro to sell, and higher during low water years when the utility may need to purchase electricity from the market. This asymmetry means that using average or median water conditions may result in an underestimate of energy costs because surplus revenues during wet years will not be sufficient to balance out energy purchases during dry years.

An alternative approach could be to find the percentile water year which approximately produces average or median costs across the entire hydro record and that best match up with the market's expectations, and use this water year as the input for modeling net power costs without the need for 80 iterative runs (or more, depending on the number of years in the current record). The utility and interested parties would need to engage in a process for identifying the appropriate water year to be used for modeling.

[10] DeBenedictis, A., D. Miller, J. Moore, A. Olson and C.K. Woo. *How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest*. The Electricity Journal. 2011.

However once complete the power cost modeling process would be much simpler and more transparent. The process could be conducted once to establish the appropriate or agreed-upon water conditions to use in power cost modeling for multiple rate filings, or could be repeated at the beginning of each GRC to identify the water year that produces a mean or median cost result for the specific inputs being used in that rate case.

Wind

While less impactful than hydro in the Pacific Northwest given the scale of existing generating resources, wind is another type of generation which is difficult to model accurately when estimating net power costs due to its variability. Utilities typically use either an average of historic years (over a much shorter historic period than that of hydro) or the estimates of production provided by wind developers when responding to RFPs for new wind generation. An alternate approach using the historic record is to randomly select a past year’s wind generation profile for each modeling run, thereby introducing some variability into each scenario in an attempt to emulate the unpredictability of this resource.

As wind generators become a larger portion of the resource mix in the Northwest the variability of their output may become a more significant driver of variations in net power costs. The approach described above for accounting for hydro generators’ year-to-year variability – identifying a historic year from which the output approximately produces average net power costs and using that as the basis for power cost modeling – could also be utilized for wind generation. While the variability in wind generation does not entail the same asymmetry in net power costs as that of hydro generation (at least at current penetration levels) this modeling approach could serve to establish a consistent methodology for accounting for variable generation and which would be durable as the resource mix evolves.

RETAIL LOADS

Forecasting utility customer demand in different time periods is an important input when estimating power costs. However, power cost trackers are generally not designed to include the effect of variable retail sales; rather, the utility bears this risk through the setting of its authorized rate of return. Therefore, this component of variability is incorporated in cost trackers and sharing mechanisms for the purpose of excluding cost variability based on this source.

Additionally, given the relative predictability of this variable (as compared to inputs such as market prices or variable generation), load forecasts are generally less impactful drivers of variance from estimated costs. Utilities use historic load patterns, correlations with weather fluctuations, estimates of changes in demand (e.g., based on macroeconomic trends, or due to the addition or loss of significant individual sources of load), and other data to formulate expectations of future loads. Some utilities employ econometric models for this exercise, while others use trend analysis (extending part growth rates into the future) or end-use analysis (building up demand based on individual end uses) to generate forecasts. Regardless of the method used, the retail load variable is one that utilities are generally successful at estimating within a reasonable range, and therefore this component of the power cost formula is both less problematic and less contentious.

PORTFOLIO VALUE, HEDGING AND "RESOURCE OPTIMIZATION"

In addition to estimating the cost to serve loads at market prices and the value of any additional generation capacity available to sell into a wholesale market – the primary focus of the variables discussed in the preceding sections of this chapter – utilities must also estimate the value of their other assets during the forward period of interest (e.g., the pro forma period for a rate case). For utilities that hold electricity transmission and gas transportation rights, this requires estimating the market price of both commodities at various geographic locations, as well as how these prices will interact over time. For example, the value of natural gas transportation rights to a utility such as Avista depends upon the difference between gas prices at two different locations – in Avista's case, between the AECO trading hub near the U.S.-Canadian border, and the Malin trading hub in southeastern Oregon – the cost to generate electricity at the Company's different gas-fired generators, and the market price of electricity at those generators' local nodes.

Additionally, to accurately forecast the value of these assets utilities must also incorporate their risk management or hedging activities into the modeling exercise. Some utilities sign various contracts – both for electricity and for fuel such as natural gas – in order to limit the impact of market fluctuations in commodity prices. Whether physical or financial hedges, these contracts serve similar purposes in reducing risk. The hedging activities undertaken serve primarily to benefit customers by reducing the utility's market exposure, thereby reducing the volatility of retail rates. Some utilities engage in more active and regular hedging in an ongoing attempt to maximize the value of their resource portfolio while limiting risk, changing their hedged and unhedged positions as market prices and forward contract values shift. Other utilities engage in more limited hedging practices, or none at all due to explicit instructions from their regulator. Ultimately, while hedging can and often does result in reduced power supply cost variability, accurately modeling the expected value of a utility's assets under such a risk management strategy is challenging, especially when the utility's exposure and the net position is constantly reevaluated based on market dynamics.

4) Avista's Power Cost Modeling Approach

As has been described in the previous sections of this report, the exercise of forecasting future power costs can be complex given the number of uncertain variables. Forecasts will be wrong, and the responsibility of a utility undertaking this exercise is therefore to estimate future costs using reasonable assumptions and methods, within the guidance or constraints provided by the regulator.

For Avista in Washington, this guidance has largely been defined by the approach of benchmarking modeled electricity market prices to forward contracts traded at the Mid-Columbia (Mid-C) hub. The steps taken to benchmark these prices are quite involved and have therefore added significant complexity to both the modeling exercise itself and to the stakeholder process of vetting and understanding the resulting power cost estimates. There are many steps involved, and a large number of intermediate workbooks and data files which must be prepared in order to conduct the modeling effort. As highlighted later in this report, the value of this complexity is not entirely clear relative to the more streamlined approach taken by other utilities.

Below we provide an overview of Avista's current modeling approach, followed by an assessment of this approach based on independent E3 analysis.

Avista Power Cost Modeling: An Overview

The core of Avista's approach to estimating net power costs entails using the third-party AURORA fundamentals model to simulate hourly electricity prices across the Western Energy Coordinating Council (WECC) region – including within Avista's service territory – and the resulting economic dispatch of Avista's generating units. While Avista therefore uses a fundamentals-based approach to estimate electricity prices, this modeling process is constrained by the requirement that the modeled prices for each period (On Peak and Off Peak, for each month, for a total of 24 periods) do not vary significantly from market forward prices.

DATA INPUTS AND ASSUMPTIONS

Avista begins its AURORA modeling process using the most recent database the Company has compiled for that tool, which is generally from its Integrated Resource Planning (IRP) process. Key inputs and updates to the model include:

- <u>Natural gas market forwards</u>: market gas prices are characterized using the average of the previous three-months' daily trading prices for natural gas forward contracts for the test year, at each hub in the Western Interconnect.

- Daily natural gas price curve: daily fluctuations are introduced into the forward gas prices within a month based on normalized daily prices within the same month in the previous five years.
- Avista generator characteristics: Avista's generators are updated to reflect the most recent data, including generation capacity, variable operations and maintenance costs, heat rates, and maintenance and forced outage rates (using five- or six-year historical averages for thermal resources, where available).
- Regional transmission constraints: availability of transmission capacity between the Pacific Northwest and California is reflected using historical capacity de-rating on the main transmission lines connecting these regions.
- Non-gas thermal fuel: forecasts of fuel costs for Kettle Falls (wood) and Colstrip (coal) are updated.
- Hydro: Avista's full (currently 80-year) water record and the BPA historical record are updated when new data is available. Avista uses the most recent five-year history to shape the Company's own hydro generation between the On/Off Peak periods.
- Wind: wind generation is updated with the latest available data from BPA. Avista's own wind generation is characterized either using a five-year historical average or, if unavailable, the developer's estimate of annual generation output and profile.
- Retail loads: Avista's test year hourly load is updated with monthly sales and weather-adjustments based on data from Avista's Regulatory team.
- Oversupply: regional clean energy resource price curves are adjusted to allow AURORA to create negative pricing during oversupply events (across the modeled cases using the full hydro record).
- Wholesale power contracts: Avista's short- and long-term power contracts are included in the AURORA modeling to account for contractual energy amounts.

In addition to these inputs, at this step Avista also calculates the average of the previous three-months' daily trading prices for electricity market forward contracts at the Mid-C hub for the test year, for each month and On/Off peak period. While these forward electricity prices are not incorporated directly into the modeling, they are used as the benchmark against which to calibrate the modeled prices produced by AURORA. Note that these electricity forwards are averaged using prices from the same three-month historic trading period over which the natural gas market forwards are averaged.

AURORA MODELING

After having input the updated data files and assumptions into AURORA, Avista runs the model to calibrate its own hydro dispatching based on a five-year historical average shape. For this initial calibration model run Avista uses an average water year (note that this average water year is not used in the ultimate modeling used to estimate net power costs). A hydro shaping feature within the AURORA model is used to adjust Avista's hydro dispatch until the shape approximates each month's On/Off Peak period split.

Once Avista's hydro dispatch is calibrated appropriately, the primary AURORA modeling takes place. Individual model runs are conducted for each of the 80 years of the historical water record, which are randomly paired with the smaller number of historical wind years from BPA. The goal of this exercise is to produce modeled electricity market prices approximating each month's On/Off Peak forward prices. This process does not require that the monthly On/Off Peak price in each of the 80 model runs equates to the market forward price for that period, but instead that the average price for each period across all of the model runs (water years) fall within this range. In this way Avista effectively creates a distribution of 80 prices around the Mid-C benchmark for each of the 24 periods to reflect the effect that different hydro conditions have on market electricity prices.

Adjustments are made to the inputs (on a monthly basis) in order to produce modeled electricity prices that on average meet this benchmarking constraint. Given the need to "match" these prices across twelve months, two monthly periods (On Peak and Off Peak), and eighty years of historical water data, this part of the process is both iterative and time-consuming. The primary adjustments which Avista makes include modifying the shape of regional (i.e., non-Avista) hydro dispatch between On/Off Peak periods, the dispatch margin or bidding factor for different generators, the assumed level of regional load, and the transmission constraint between the Pacific Northwest and California. These levers accomplish different types of adjustment. For example, if the average modeled price within a month is relatively close to the forward price for that month, while the prices within the On/Off Peak periods are not, Avista might modify the regional hydro shaping factor to change the relationship between those two periods. However, if the average modeled price within a month is considerably too high or too low, relative to the forward price, a more useful adjustment might be to change the transmission constraint in order to directly move prices (rather than price shapes) within that month.

AURORA OUTPUTS

After AURORA has been adjusted sufficiently to produce the desired average prices across the 80-year water record, the results are used for valuing different parts of Avista's portfolio.

- AURORA-generated electricity prices, fuel costs, and balancing and sales costs are used along with test year loads to estimate the value of serving native load.
- Fixed-price contracts are valued based on the appropriate contract rate multiplied by the energy amount produced by AURORA.
- Contracts based on index prices are valued by multiplying together the energy amounts and the market electricity prices calculated in AURORA.
- Financial electricity contracts (purchases and sales) are valued using the modeled energy prices for the relevant contract period (i.e., accounted for using mark-to-model prices).
- Forward gas contracts (purchases and sales) are valued based on the input gas forward prices.

The following section describes how Avista estimates the value of several other components of its net power costs outside of AURORA. At the end of this process, Avista sums the expenses and revenues developed both within and outside of AURORA to derive its estimate of net power costs for the pro forma period.

POWER COST ESTIMATES EXTERNAL TO AURORA

Transmission expenses are assumed to remain fairly stable and are therefore characterized using test year actual costs. Transmission revenues are estimated based on the average transmission revenues earned in recent years. Together these estimates represent the Company's net transmission expense. The small category of broker fees related to short-term purchases and sales of electricity and natural gas are also estimated based on the historic test year expenses for this category.

Gas transportation expenses are also estimated externally to AURORA, with the largest costs incurred for the combined cycle Lancaster and Coyote Springs 2 gas plants. This expense category is also based on historic test year costs, and Avista reports that this expense category has been relatively stable.

Finally, Avista estimates the value of optimizing its gas transportation rights between the lower-cost AECO and higher-cost Malin trading hubs. This optimization values both a) the "spark spread" between wholesale market electricity prices and the cost of producing electricity using natural gas at market prices, and b) Avista's ownership of rights to transport gas between trading hubs.

One part of this optimization is directly accounted for within AURORA, by dispatching generators based on the higher cost of natural gas at Malin rather than using the lower cost AECO price.[11] In this way AURORA is made to only dispatch the gas generators if it is economic to do so based on the higher cost Malin price, thereby implicitly incorporating the opportunity cost represented by ownership of the transport rights. In hours where it is not economic to dispatch these units based on the Malin gas price the effective assumption is that Avista will instead sell the gas and earn a margin on the basis differential between the trading hubs.

The second part of the optimization – valuing the transportation rights themselves – is not accounted for in AURORA. The amount being estimated is the value Avista will be able to obtain based on the volume of gas transportation rights and the basis differential between the AECO and Malin trading hubs. Avista estimates the value of the transportation rights through a combination of their hedged (closed) and unhedged (open) gas transportation positions at the time of the GRC filing. Closed positions are valued based on the prices and gas volumes included in contracts signed for the forward periods. Open positions are valued at the basis differential between the AECO and Malin trading hubs in gas market forward prices.[12]

Accurately estimating this gas transport optimization value has proven challenging given both the recent widening (and increasingly volatile) basis differential between these trading hubs and the volatility in gas prices themselves. Through its hedging program Avista undertakes regular updates to its positions based on market dynamics, in an attempt to reduce market exposure and take advantage of potential cost-saving opportunities.[13] This includes deals such as "heat rate swaps" where Avista contracts to buy gas and sell electricity at prices that lock in a positive margin, as well as other physical and financial contracts aimed at limiting the Company's exposure to commodity fluctuations. As both forward prices and Avista's

[11] Generators are dispatched based on Malin forward prices, with minor cost savings to account for not needing to transport the gas all the way to the trading hub.
[12] There was a departure from this process in the 2017 GRC, for the pro forma period of May 2018 – April 2019. Rather than using the $13.3 million gas transportation optimization revenue calculated for that period in the manner described in this section, Avista alternatively "tempered" this estimate to $9 million given skepticism that the basis differentials experienced in 2016 would persist.
[13] Commission Staff periodically reviews and acknowledges Avista's hedging program.

net position will evolve – sometimes significantly – between the time the gas transport optimization revenue is estimated for setting base retail rates, the value of the Company's gas transport assets has proven a challenging piece to accurately account for when estimating net power costs.

5) E3 Review and Analysis of Avista's Power Cost Modeling Approach

Given the complexity involved in Avista's modeling process – including the time required to run the AURORA model through multiple iterations using 80 historical water years – E3 chose to approach this review and analysis primarily through simplification and a focus on the key topics of interest to the stakeholder group, as well as through the industry survey described in the following chapter.

NATURAL GAS AND ELECTRICITY PRICE COMPARISON

Much of the ERM discussion has focused around the unprecedented decline in natural gas prices in recent years, as well as the effect this phenomenon has had on electricity prices. As a straightforward validation exercise, E3 compared the forward natural gas and electricity prices included in Avista's recent GRC filings to the actual prices which occurred. The following figures depict these comparisons for the AECO and Malin gas trading hubs and for the On and Off Peak Mid-C electricity trading prices.[14]

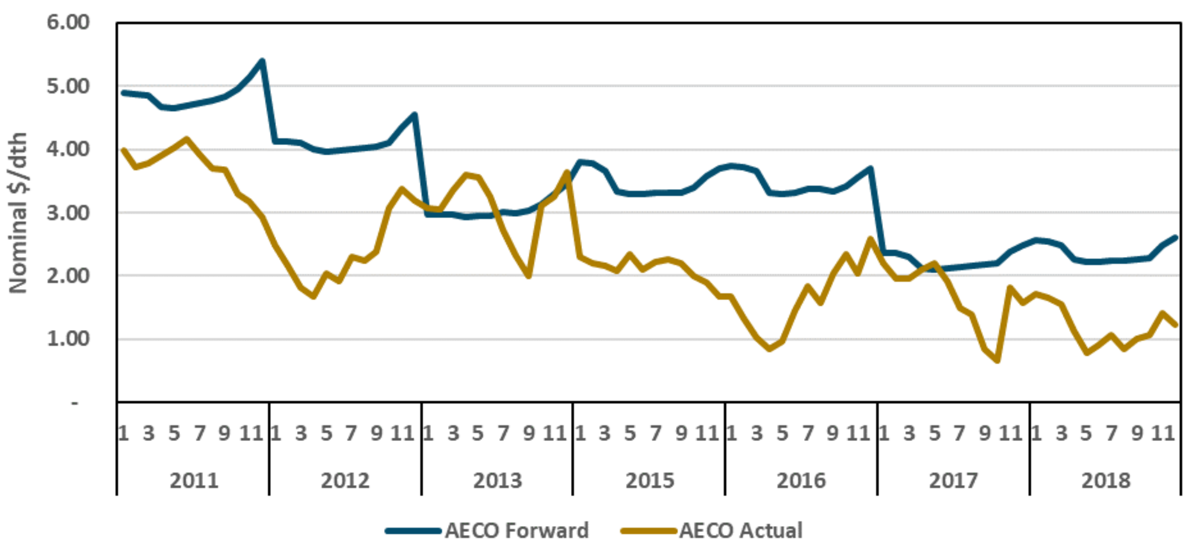

Figure 5: Forward vs. Actual Natural Gas Prices, AECO Trading Hub (2011-2013 and 2015-2018)

[14] These figures compare data from 2011-2013 and 2015-2018, given a lack of forward data availability for 2014.

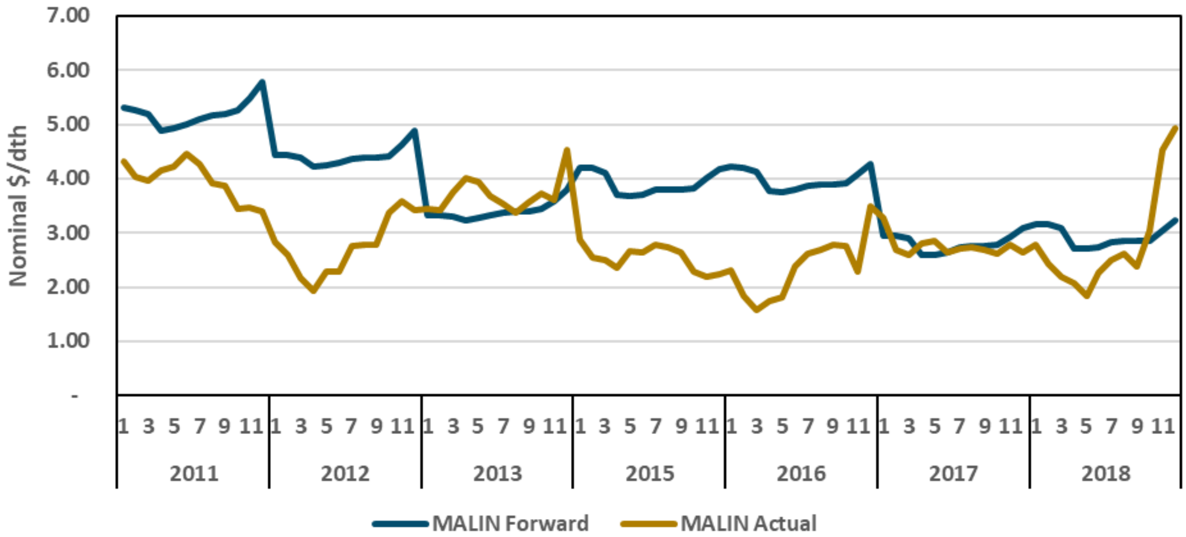

Figure 6: Forward vs. Actual Natural Gas Prices, Malin Trading Hub (2011-2013 and 2015-2018)

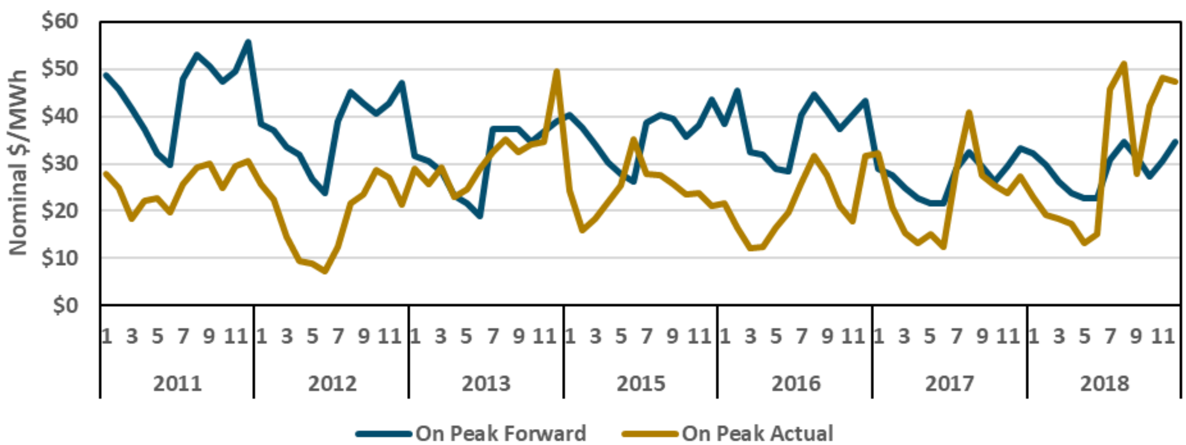

Figure 7: Forward vs. Actual Average Mid-C Electricity Prices, On-Peak (2011-2013 and 2015-2018)

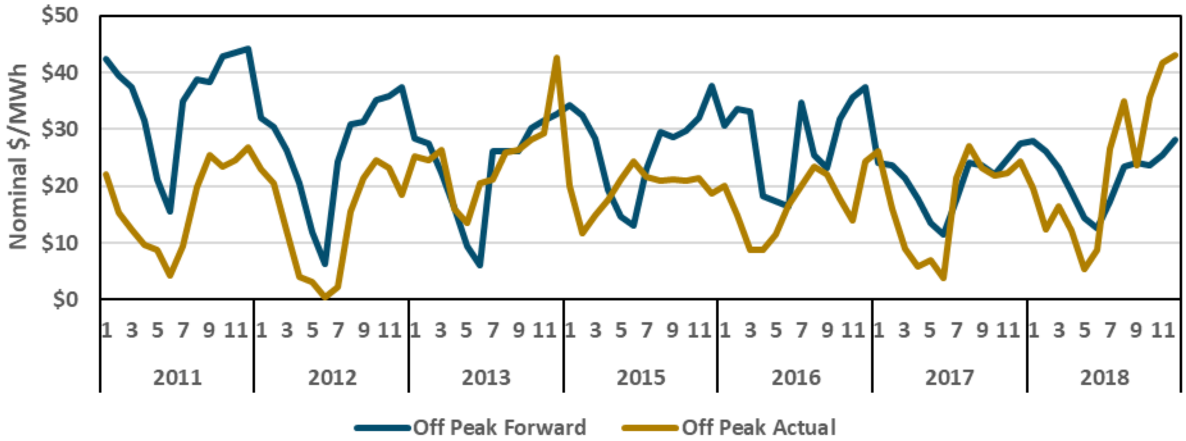

Figure 8: Forward vs. Actual Average Mid-C Electricity Prices, Off-Peak (2011-2013 and 2015-2018)

As can be seen in the price comparisons, both natural gas and electricity forwards since 2011 have generally overestimated commodity trading values. Additionally, the sustained decline in natural gas prices is evident, due largely to the increase in economically recoverable shale gas. The close tracking of electricity prices to natural gas prices is also clear, driven by the frequency with which natural gas generators serve as the marginal resource.

The results of this retrospective comparison are not surprising given the recognized trend towards inexpensive natural gas in recent years, but do serve to highlight that utility costs based on these forward price assumptions would likely overestimate true costs, simply due to the relationship between forward and actual prices and the relationship between natural gas and electricity prices. Avista has noted throughout the workshop series that the opposite was true during approximately the first half of the ERM history (between 2003 and 2009), when rising natural gas prices contributed significantly to the underestimation of actual net power costs.

VARIABLE GENERATION

Hydro

Much of the complexity involved in Avista's modeling derives from the long-standing precedent of benchmarking to the forward electricity prices, while modeling a full 80 years of water records. This requires adjusting different parameters such as transmission constraints and unit dispatch margins and makes the overall modeling process both time consuming and difficult to review from an external perspective.

The goal of modeling the entire hydro record is to reflect net power costs that account for the full range of potential outcomes, based on historic water records. This, in turn, is intended to account for the asymmetric effects of low and high hydro years on power costs, given that the low years cause disproportionately high prices. However, benchmarking to the Mid-C forward prices inherently reduces the value of this modeling exercise, given that these forwards are not based on an 80-year water record and instead effectively embed an assumption of median hydro availability. As median hydro does not reflect the full range of potential outcomes, its use as an input may provide a less accurate estimate of net power costs. However, given the ultimate use of the forward prices as a constraint in Avista's AURORA process, the value of modeling all 80 hydro years is diminished.

To further illustrate this point, Figure 9 provides a scatter plot of the normalized 80-year hydro records of BPA and of Avista's own hydro generators. There is clearly – and unsurprisingly – a strong correlation between these two records. Using the BPA water record as a proxy for how Mid-C prices incorporate expected hydro generation, the modeling process of benchmarking to these forward prices therefore results in an effective benchmarking to a median hydro assumption, despite Avista's use of the full hydro record to reflect variability within each of the monthly On and Off Peak periods across the 80 years.

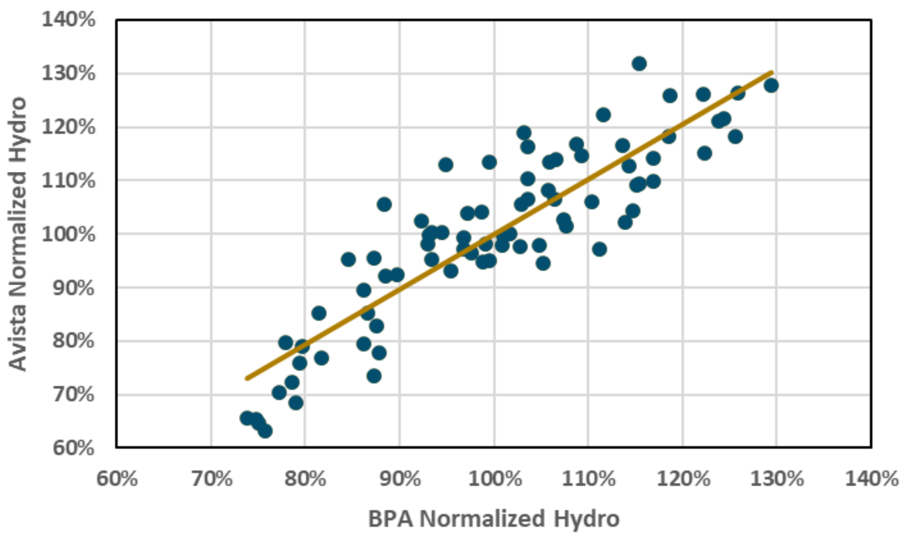

Figure 9: BPA vs. Avista Normalized Hydro (1929-2008)

As discussed in Chapter 3, an alternative approach would be to identify the percentile water year which approximately produces average costs across the entire hydro record, and then use this water year as the input for modeling net power costs used to establish the ERM baseline. In this way the entire hydro record could be leveraged within the overall process of establishing net power costs, but without introducing additional complexity into the dispatch modeling process conducted within AURORA. Avista and the parties would need to engage in a process for identifying the appropriate water year to be used for modeling.[15] However, this would significantly reduce the complexity of the overall process, while recognizing the variability in annual hydro conditions. Such a methodological change would likely merit

[15] Staff has suggested that one way in which to identify the appropriate water year for use in modeling would be to use the forecast of hourly Mid-C power prices for the rate year reported in the biannual BPA Power Market Price Study. This is not a proposal which E3 has evaluated, but it could be further explored by the stakeholders in subsequent discussions.

revisiting the asymmetrical nature of the current ERM sharing bands, to ensure that the asymmetry in hydro conditions' effect on net power costs was not being accounted for twice (once through the modeling and once through the mechanism).

Wind

The primary focus of workshop discussions and, accordingly, this review of Avista's practices relative to variable generating resources has been on hydro generators. However, it is worth noting that Avista plans to more than double its non-hydro variable generation levels in 2021,[16] and its exposure to weather-dependent generation variability will therefore magnify significantly, largely from wind generators.

Currently Avista models its wind resources in estimation of net power costs using either five-year historical averages or – where such data isn't yet available – estimates of generator outputs provided by developers. Both of these approaches are common, with the historical average data generally a better source to use when sufficient records are available. As discussed in Chapter 3, wind resources could also be modeled using a single historic year of generation data which approximately produces average net power costs, although there doesn't appear to be an imminent need for such a methodological change.

As Avista's resource mix incorporates greater amounts of wind generation in the coming years, differences between estimated and actual output from new resources may become a more significant source of variation in net power costs, especially given that renewable resources can lead to negative power prices in some hours. As variable generation becomes a larger portion of the resource mix – both for the Company and for the Pacific Northwest region – modeling these resources appropriately will become increasingly important. One manner by which the Company could potentially refine its estimation of these resources' generation would be through the use of third-party sources and tools such as those provided by the National Renewable Energy Laboratory. This could allow Avista to validate developers' estimates of generator output. However, it is worth noting that this would be more useful for validation of the profiles (shapes) of generation rather than overall output or capacity factor. Once these resources have operated for several years, they would be characterized using the current approach of averaging historical production data.

SIMPLIFIED DISPATCH MODEL

Beyond the price comparisons and hydro discussion above, E3's primary analytical approach to evaluating the Avista modeling process was to create a simplified unit dispatch model, with the intent of highlighting the main sources of discrepancy between authorized and actual costs. To do this the model is run once using input values filed in a GRC and a second time using actual values. The goal was not to definitively isolate the cause of ERM variations in each year, nor to reveal a "silver bullet" solution to the challenges faced by Avista and the stakeholder group. However, this exercise has proven useful in both validating the key drivers of variation between authorized and actual costs, and also in highlighting the complexity

[16] Avista. *2020 Electric Integrated Resource Plan*. Available at: https://www.myavista.com/about-us/integrated-resource-planning.

involved in attempting to accurately forecast variable costs given the inherent uncertainty. Below we describe the modeling approach and noteworthy results.

E3 developed a simple "stack" dispatch model to replicate some of the primary calculations taking place in the estimation of net power costs.[17] E3 modeled the years 2011 – 2013 and 2015 – 2018, as those were the years for which complete data was readily available. Inputs to the model were comprised of the key variables that were hypothesized to drive Avista's ERM – namely, market gas and electricity prices, hydro output, retail loads and resource availability (see Table 2 below).

Avista's generators were dispatched within the model on a monthly On/Off peak time scale based on the input assumptions, and production costs and revenues were quantified. As mentioned above, the model was designed with the goal of being able to switch between the key input variables as filed in Avista's GRCs and the values which actually occurred. By toggling between inputs (cost drivers) that were "filed" versus "actual" iteratively, one could determine which drivers produced the largest changes in net power costs. Ultimately, a stack model that reflects all key cost drivers in sufficient detail to capture the variation between authorized and actual costs would be able to predict both the direction of the ERM (rebate or surcharge), as well as the rough magnitude, across different years.

Table 2: Stack Model Input Variables

Input Variable	***Input Options for Cost Driver Variable in Simple Dispatch Model***		
Electricity Price	Actual	Filed	Forward
Gas Price	Actual	Filed	Forward
Gas Available Capacity	Actual	Filed (AURORA)	
Hydro Generation	Actual	Filed (80-yr average)[18]	Median
Coal/Wood Generation	Actual	Filed (Flat)	
Wind Generation	Actual	Filed (AURORA)	
Load	Actual	Filed (GRC)	

There are a number of assumptions in this simplified model that differ from a "typical" stack model, due both to time and data constraints and related to the treatment of different resources. Avista's hydro, coal, biomass, and wind generators were treated as "must-run" based on the selected inputs (i.e., "filed" vs. "actual"). Avista's gas units were therefore the only generators with decisions to commit or not commit, depending on the input price of electricity at Mid-C. If it was economic for a gas generator to produce electricity in a given period, it would produce as much as it could; otherwise, it would sit idle. If the total electricity generated from Avista's units was less than Avista's load, the remainder would be purchased from the market based on the input Mid-C prices. Alternatively, if the total electricity generated from

[17] The name stack model derives from the process of dispatching available resources in a "stacked" order of increasing marginal cost, such that load is first met with the lowest-cost resources.

[18] Given modeling all 80 years of the historical record was infeasible for this assessment, the 80-year average was utilized to represent the expectation included in filed cases. This was a known limitation of the modeling process, but a necessary simplification for this exercise.

Avista's units was greater than Avista's load, the excess would be sold to the market. This modeling approach is an oversimplification of how Avista's generators would perform in reality; however, the exercise has proven useful, nonetheless.

The main output of the dispatch model is a build up of costs and revenues for each year and for the two different scenarios ("Filed" or Authorized, and "Actual"). Comparing the net costs under each of the two cases produces an estimate of the ERM, which can in turn be compared with the reported ERM amount for each year to assess the performance of the simplified model. Table 3 provides a summary of the modeled net costs for recent years, and their relationship to the reported ERM amount. Please see Table 4 in the Appendix for additional detail on the dispatch model results summarized below.

Table 3: Modeled vs. Reported Annual ERM Values ($MM, nominal)

	Component	2011	2012	2013	2015	2016	2017	2018
a	Reported ERM	$ (19.2)	$ (14.7)	$ 5.0	$ (17.6)	$ (8.4)	$ (6.2)	$ (15.5)
b	E3 Modeled Actual System Costs	$ 139.1	$ 134.0	$ 219.5	$ 172.5	$ 129.3	$ 131.9	$ 24.0
c	E3 Modeled Authorized System Costs	$ 210.0	$ 193.8	$ 206.0	$ 177.2	$ 139.4	$ 152.5	$ 69.0
d	Difference [b - c]	$ (71.0)	$ (59.8)	$ 13.6	$ (4.7)	$ (10.1)	$ (20.5)	$ (45.0)
e	WA Allocation of Difference [d * 64.71%]	$ (45.9)	$ (38.7)	$ 8.8	$ (3.0)	$ (6.5)	$ (13.3)	$ (29.1)
f	WA Retail Revenue Adjustment	$ (9.8)	$ 0.7	$ (3.1)	$ 1.3	$ 1.1	$ (2.6)	$ -
g	E3 Modeled ERM [e + f]	$ (55.7)	$ (38.0)	$ 5.7	$ (1.7)	$ (5.4)	$ (15.8)	$ (29.1)
h	E3 Modeled ERM, % of Actual ERM [g / a]	290%	258%	113%	10%	64%	255%	187%

Line (a) reports the actual ERM amount for each year. Lines (b) and (c) report the system costs generated by the dispatch model for the two different cases. This includes modeling of the net load after accounting for "must take" resources,[19] gas generation costs, net electricity market costs based on net loads, and gas transport optimization costs.[20] Additionally, the net system costs incorporate non-modeled coal and wood fuel costs, gas fuel costs, and net transmission expenses sourced from ERM variance explanations provided by Avista. These latter costs were input to account for differences between the cases that would not be picked up by the model, given that the coal and wood units were run as "must-take" resources (without calculated operating costs), the gas units were run based only on their margin (as determined by the market gas and electricity inputs), and transmission was not feasible to model in this structure.

Line (d) reports the difference between the modeled costs under each scenario. Line (e) allocates a portion of that difference to Washington (using a Production/Transmission allocation factor), given the costs to this point have been calculated on an Avista system-wide basis. Line (f) adjusts for differences in retail

[19] This comparison uses the "Actual" coal/biomass dispatch in both cases, given the simplified (flat) modeling of these resources produced unrealistically uniform generation across the study period (compared with historic output).

[20] To approximate the gas transport optimization value available to Avista in each year, this comparison includes a 40% de-rate to the Company's pipeline rights, in an attempt to reflect that a portion of this pipeline capacity is hedged and therefore not exposed to the market basis differential between AECO and Malin.

sales, as this is external to the ERM. Finally, lines (g) and (h) report the modeled ERM for each year and its percentage of the reported ERM, respectively.

These results demonstrate that the simplified model is able to correctly predict the direction (positive or negative) in all years, although the magnitude varies considerably. The direction suggests that the simplified model is generally accounting for the correct categories, and that the differences between the core inputs can predict much of the variation between authorized and actual costs.

This model has not produced ERM estimates which closely track the actual ERM amounts in each year. However, given the complexity of the existing modeling process, this result is not surprising. This exercise has helped to validate that the hypothesized core drivers – namely, differences between forward and actual electricity and natural gas prices and the level of available hydro generation – do appear to be decent predictors of the ERM's direction when viewed retrospectively.

Relative to this modeling exercise, some elusive factors driving ERM variances remain. However, this again is unsurprising given the relative simplicity of this stack model approach, and the complexity involved in Avista's net power cost estimation process. While this modeling exercise and the other analyses described previously do not allow E3 to definitively rule out the possibility of bias, our investigation has neither produced results nor uncovered practices that suggest the Company is intentionally inflating (or "biasing") net power costs. Alternatively, this analysis has highlighted the significant complexity in the current process and has suggested that there are areas where it can be improved.

GAS TRANSPORT OPTIMIZATION

One concern raised by the stakeholder group has been the value of Avista's gas transport optimization, which was considerably above the values included in base rates in several recent years, ultimately reducing net power costs. Avista initially acquired these gas pipeline rights not for the purposes of speculation on a potential market arbitrage, but instead to provide firm gas delivery to its power plants. As the basis differential between the AECO and Malin trading hubs has widened in recent years, however, these rights have become increasingly valuable. This has allowed the Company's ownership of the transportation rights to provide not only firm gas delivery for its generators, but also significant value for customers given the inclusion of this net cost category in the ERM. However, stakeholders have expressed concerns over the estimation of gas transport optimization values when establishing net power costs given the structure of the ERM.

As highlighted by recent testimony from Public Counsel, there was a departure from Avista's standard process for valuing its open gas transport position during the 2017 GRC.[21] Rather than using the $13.3 million gas transportation optimization revenue calculated for that period in the manner described in Chapter 4, Avista alternatively reduced this estimate to $9 million given skepticism that the basis differentials experienced in 2016 – which were much larger than in previous years – would persist. It is understandable why stakeholders would question this change of approach, especially given that the actual

[21] Response Testimony of Avi Allison on Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Exh. AA-1T. Docket Nos. UE-190334 and UG-190335, UE-190222 (Consolidated). October 28, 2019.

revenues gas transport optimization revenues for 2018 were over $20 million. It is also understandable that Avista may have been skeptical as to the sustained basis differential between gas trading hubs and the implied value of the Company's transportation rights – despite forward price projections – due to the exceptional value which materialized in 2016 relative to earlier years.[22]

As discussed in Chapter 4, the primary challenge in estimating the future value of assets which depend on market prices – such as these gas transportation rights – is that ex-ante estimates of these prices will be incorrect, and active management of portfolio risk will respond to these changes by taking new positions and/or unwinding existing ones. Given the values involved in recent years, and the concern that stakeholders have shown on this issue, an improvement in this process would be to have some additional level of discussion and – if needed, negotiation – around the assumptions used for estimating the value of the gas transport optimization in particular. This does not need to be an entirely "black box" part of the process and incorporating additional transparency for the stakeholder group could alleviate considerable tension on this topic, despite the inherent uncertainty posed by the reliance on shifting market values.

To the extent that the stakeholder group remains uncomfortable with the volatile nature of the value of Avista's gas transportation rights, several options exist. One alternative approach would be to hedge the entire asset throughout the course of the year. This could be accomplished using financial swaps, which would eliminate the volatility by "locking in" prices in advance. While this would effectively eliminate concerns over the Company earning profits due to the volatility of gas prices and the basis differential between trading hubs, it would also eliminate a source of significant potential value for Avista's customers. A different approach would be to remove the gas transport optimization revenues from the ERM entirely, and instead treat net cost variances in this category as a direct pass-through to customers, reflective of the unpredictable nature of market prices and the basis differential between the gas trading hubs.

HEDGING AND PORTFOLIO VALUE

An additional topic of discussion during the workshops has been the degree to which hedging of different contracts and other portfolio assets plays into the estimation of net power costs. E3 has briefly reviewed Avista's daily position reports – which record the value of Avista's hedged and unhedged positions, based on current market values – and has not found any cause for concern in our understanding of the Company's hedging practices. Additionally, while E3 has not explored this program in depth, Avista conducts its various hedging activities under a hedging program periodically reviewed by Commission Staff, indicating another venue through which these practices can be reviewed if the stakeholder group believes there is a need to further investigate this component of estimating net power costs. The approach different utilities take to reflecting any hedging of their portfolios in their modeling of net power costs is discussed further in the following chapter.

[22] This episode has been described as an instance of bias on the Company's part by some stakeholders. E3 finds that rather than indicating bias this serves to highlight both the difficulty in forecasting natural gas and electricity market prices and the importance of the stakeholders and Avista aligning upon input assumptions during the power cost modeling process, as discussed further in this section.

RESOURCE MIX COMPARISON

In addition to a review of Avista's modeling practices, E3 found it useful to conduct a brief resource mix comparison between the Company and the two other regulated electric utilities in Washington State. PacifiCorp and Puget Sound are subject to similar sharing mechanisms as Avista, and as such are often referenced in comparison during discussion of the ERM.

Figure 10 shows the 2018 resource mix for each of the three utilities, as reported by the Washington Department of Commerce. While PacifiCorp and Puget Sound respectively obtained approximately 30 and 40 percent of their electricity from natural gas or hydro, Avista obtained over 75 percent of its electricity from these resources. The balance of the difference is due to the greater utilization of coal generation by PacifiCorp and Puget, in addition to unspecified power purchases (which could be from various sources). The increased reliance that Avista has on natural gas and hydro generation, relative to the other utilities, suggests that the Company's net power costs are likely especially sensitive to variation in the market price fluctuations of the former and the weather-dependent availability of the latter.

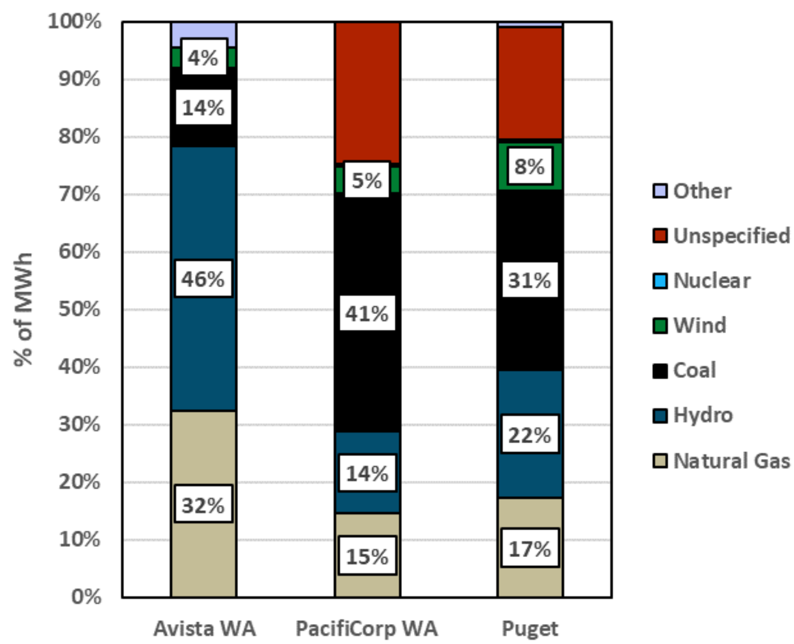

Figure 10: Washington Regulated Electric Utility Resource Mix (2018)[23]

[23] Developed using data from the *Washington State Electric Utility Fuel Mix Disclosure Reports* (November 8, 2019). Source report available at: https://www.commerce.wa.gov/wp-content/uploads/2019/12/2018-Preliminary-Disclosure-Data-03122019.pdf.

6) Industry Survey

E3 conducted this industry survey through phone interviews with utilities and other industry stakeholders, in addition to a review of relevant regulatory proceedings and industry publications. The utilities were selected to provide both geographic diversity and a range of different regulatory approaches to net power cost tracking and sharing mechanisms.

This chapter is structured to first discuss the practices of individual utilities, followed by two state-level profiles contrasting distinct regulatory approaches. Several tables in the Appendix present additional detail on the surveyed utilities. Table 5 provides the details of the sharing mechanisms in place for select Pacific Northwestern electric utilities, Table 6 reports the years in which the utilities surveyed filed for GRCs, while Table 7 lists each utility's rate base as included in the most recent rate filing.

Utility Case Studies

NORTHWESTERN ENERGY[24]

NorthWestern Energy	
Cost Tracking Mechanism	Power Cost & Credit Adjustment Mechanism (PCCAM)
Mechanism Type	Cost Tracking + Sharing Mechanism
Electricity Price Basis	Forward prices
Hydro Treatment	5-year historic average
Modeling Platform	Spreadsheet model

NorthWestern Energy serves customers in Montana, South Dakota and Nebraska. This review focuses on NorthWestern's practices in Montana, specifically, as that is the primary state in which the utility operates.

Electricity Market Prices

As with many of the utilities surveyed, NorthWestern uses forward market prices from the Mid-C trading hub as the basis for their electricity price forecasting.

Modeling Approach

NorthWestern inputs On and Off Peak forward market prices into a relatively simple spreadsheet model, which is then used to calculate expected revenues and dispatch patterns. NorthWestern does not use a third-party dispatch model, and instead relies on their own spreadsheet modeling approach. This model

[24] E3 conducted a phone interview with NorthWestern Energy on March 11, 2020, through which the information in this section was gathered.

incorporates generic operational constraints (e.g., heat rates, minimum output [P_{min}], variable operations and maintenance costs, etc.).

Variable Generation

Hydroelectric generation is forecast using a 5-year historic average. Wind generation is also projected based on an average of historic generation.

Hedging

NorthWestern has been directed by the Montana Public Service Commission to refrain from hedging power costs, and therefore does not model any hedged positions when forecasting net expenses. In the past the utility did engage in hedging practices to limit market price exposure. However, in several years the utility's hedged position resulted in significant losses and therefore higher retail rates for customers, and the utility was instructed to no longer take hedged positions over concerns that it would increase costs.

Adjustment Mechanism

In Montana, NorthWestern Energy is subject to a Power Cost & Credit Adjustment Mechanism (PCCAM). This mechanism includes a symmetrical dead band of $4.1 million from the established baseline of net power costs.[25] Cost variances beyond this dead band in either direction are shared between customers and shareholders, on a 90/10 basis, respectively.

In the 2017-2018 period, actual net power costs were below base revenues by approximately $3.4 million.[26] As this amount fell within the dead band, no refund was issued to customers. In the 2018-2019 period, actual net power costs were above base revenues by approximately $11.8 million, resulting in a surcharge of approximately $6.9 million.

Learnings

NorthWestern reports that in general the main variation between estimated net power costs and actual net power costs is driven simply by the differences between the forward market prices and actual market prices, which serve as the key input to their modeling exercise. The utility notes that the lack of hedging results in significant market exposure, but this approach has been required by the Montana Public Service Commission.

NorthWestern notes that stakeholders in the ratemaking process have generally been understanding regarding the complexity and difficulty of forecasting future electricity prices and the degree to which modeling can differ from actual costs. The variation in forecast versus actual costs has been accepted as part of the process given the uncertainty involved. Finally, despite the relative simplicity of its spreadsheet modeling approach NorthWestern has found that its net power cost forecasts are generally relatively close

[25] NorthWestern Energy. *Investor Update*. March 5-6, 2019. Available at: http://www.northwesternenergy.com/docs/default-source/documents/investor/PresentationBAML03052019.pdf.

[26] PR Newswire. *NorthWestern Reports 2018 Financial Results*. February 12, 2019. Available at: https://www.prnewswire.com/news-releases/northwestern-reports-2018-financial-results-300793724.html.

to realized costs. The utility notes that one improvement could be to update their modeling as close to the filing date as possible, so as to use the most recent information available.

XCEL ENERGY[27]

Xcel Energy	
Cost Tracking Mechanism	WI: Energy Cost Adjustment (ECA) MN: Fuel Cost Adjustment (FCA)
Mechanism Type	Cost Tracking + Sharing Mechanism
Electricity Price Basis	Fundamentals
Hydro Treatment	30-year average
Modeling Platform	PLEXOS

Xcel Energy serves customers across eight western and midwestern states. The following review encompasses the utility's general power cost modeling practices applicable across their different service territories, unless otherwise noted.

Electricity Market Prices

Xcel forecasts electricity prices using a fundamentals approach, modeling future prices in the markets in which the utility operates through the PLEXOS modeling platform. An important input to this process are natural gas market price forwards, which have a large impact on modeled electricity prices.

Modeling Approach

Xcel employs the third-party PLEXOS production simulation model in all of the jurisdictions in which it operates. Specific, geographically tailored versions of PLEXOS are used in different states, but the underlying modeling approach and assumptions are generally consistent. Xcel incorporates the operational constraints of their units into the model to more accurately reflect dispatch capabilities.

Variable Generation

Estimated hydro generation is based on a 30-year average of hydro production in the relevant jurisdiction. Unlike the Pacific Northwest, in Xcel's service territories hydro constitutes a considerably smaller portion of the resource mix, and also does not fluctuate with the same magnitude. Annual variations therefore do not have a large impact on net power costs. Xcel forecasts wind generation based simply on an average of the previous few years' wind production.

Hedging

Xcel incorporates most of their contracts and resource positions into their modeling. Unlike Avista, they do not own significant gas transportation rights. However, Xcel's subsidiary utilities conduct natural gas

[27] E3 conducted a phone interview with Xcel Energy on March 12, 2020, through which the information in this section was gathered.

price hedging activities approved by their respective state commissions in the interest of limiting market exposure and customer rate volatility.

Adjustment Mechanism

In a number of its service territories, Xcel is subject to a cost adjustment mechanism incorporating a dead band and – at times – a sharing band.

Learnings

Xcel is pleased with its process for estimating net power costs, finding it streamlined and also allowing for straightforward assessment of the sources of fluctuation. Additionally, Xcel has found that Commissioners responsible for regulating their service territories are generally understanding of the challenges inherent in price forecasting, and that the use of the dead band approach (such as in Wisconsin) has worked well. This is an interesting finding, and somewhat contradictory to the experience of other utilities in jurisdictions employing dead bands in their sharing mechanisms.

PUBLIC SERVICE COMPANY OF NEW MEXICO (PNM)[28]

PNM	
Cost Tracking Mechanism	Fuel and Purchased Power Cost Adjustment Clause (FPPCAC)
Mechanism Type	Cost Tracking
Electricity Price Basis	N/A
Hydro Treatment	N/A
Modeling Platform	AURORA

Public Service Company of New Mexico (PNM) is subject to a Fuel and Purchased Power Cost Adjustment Clause (FPPCAC). This mechanism is very different from the ERM, not only in that it doesn't include a sharing mechanism, but also because it is based entirely on historic costs and therefore does not require estimation of future electricity prices or the utility's net power costs.

Electricity Market Prices

PNM does not model electricity market prices for the purposes of their adjustment mechanism, given that the FPPCAC is strictly a retrospective true up using historic costs. The only forward-looking component of the mechanism is load forecasting for the upcoming period.

Modeling Approach

PNM uses AURORA to conduct dispatch modeling, but the outputs from this process do not affect the FPPCAC.

[28] E3 conducted a phone interview with PNM on March 27, 2020, through which the information in this section was gathered.

Variable Generation

PNM does not model variable generation for the purposes of the FPPCAC. When they do model these resources for other purposes, their forecasts are based on either historic generation profiles from existing resources, or on bidder expectations submitted in response to RFP solicitations.

Hedging

While hedging is not incorporated directly into the filings PNM makes for the FPPCAC, the utility's fuel costs are affected by hedging decisions overseen by the New Mexico Public Regulation Commission through a different process. Separately from the FPPCAC process, PNM files a hedging plan which must be approved by the regulator. PNM reports that the New Mexico Public Regulation Commission has generally preferred that the utility not hedge fuel and power costs extensively, and therefore the utility's overall position is more open to market fluctuations than it might be without this regulatory oversight.

Adjustment Mechanism

The Fuel and Purchased Power Cost Adjustment Clause, or FPPCAC, is a straightforward cost tracking mechanism intended specifically to adjust retail rates based on a comparison between realized fuel and purchased power costs and those embedded in base rates. On a monthly basis PNM files a report with the New Mexico Public Regulation Commission, which details differences between fuel and purchased power costs embedded in rates and those costs actually incurred during the month. This variance is held in a balancing (carrying) account and accrues interest. On a quarterly basis PNM resets the fuel and purchased power costs included in retail rates based on the actual costs incurred in the preceding quarter, with the new rates set to incorporate the balance of the carrying account.

Learnings

PNM has found that the FPPCAC process is straightforward and does not cause contention. This may be in part due to the absence of a dead band or sharing band, and the resulting full pass-through of any cost variances – positive or negative – to retail customers. Additionally, the limited forecasting portion of this process – with only their retail load forecast considering future periods – limits the scope of potential concerns from stakeholders.

NOVA SCOTIA POWER[29]

Nova Scotia Power	
Cost Tracking Mechanism	Fuel Adjustment Mechanism (FAM)
Mechanism Type	Cost Tracking
Electricity Price Basis	Unclear
Hydro Treatment	23-year rolling average
Modeling Platform	PLEXOS

[29] Bates White Economic Consulting. *Audit of Nova Scotia Power, Inc.'s Fuel Adjustment Mechanism for 2016-2017*. July 24, 2018.

Nova Scotia Power, Inc. or NSPI, provides 95% of the generation, transmission and distribution of electricity in the eastern Canadian province of Nova Scotia. NSPI serves approximately 500,000 customers and has a rate base of $4.3 billion. NSPI is a wholly owned subsidiary of Emera Inc., which owns and operates electric utilities in several Canadian provinces and U.S. states.

Electricity Market Prices

NSPI inputs export and import volume limits and prices to reflect transactions with neighboring New Brunswick. While the volume limits are based on the previous year's values, unfortunately the portion of the audit discussing the manner in which prices are forecast is redacted, leaving this assumption unclear.

Modeling Approach

NSPI employs the PLEXOS production simulation model to estimate unit dispatch.

Variable Generation

NSPI estimates wind and hydro generation externally to PLEXOS, based on historical information. Hourly wind profiles are based on an average of the past three years' production from each wind generator. Hydro generation is based on a 23-year rolling average for each generating unit. The third-party consultant notes that while the 23 years of hydro generation history provides a sufficiently large sample to reflect weather variations, the three-year average used for wind generation is likely too short of a window to provide a reliable basis for forecasting future wind production. The asymmetrical effects of hydro production in low and high years of power costs is unfortunately not discussed.

Hedging

NSPI uses a variety of different hedging approaches for the different fuels and electricity transactions covered under the Fuel Adjustment Mechanism, and overall appears to implement a very active hedging strategy. For certain categories such as solid fuel NSPI utilizes specific short-, medium- and long-term hedge limits or targets, while for other categories such as natural gas no specific targets are used, and instead the hedges are based on an assessment of "value at risk," which is in turn based on market prices. The third-party consultant notes that while a benefit of this approach to hedging natural gas supply is that it is geared towards risk management rather than price management, it is unfortunately more difficult to explain given the complexity involved. Overall, the audit finds that NSPI's hedging program "has resulted in a significant decrease in the value at risk at the portfolio level," and that this has been "achieved at a low cost."

Adjustment Mechanism

NSPI reports that fuel is its largest expense in providing customers with electricity, representing approximately 40 percent of its total costs. The Fuel Adjustment Mechanism (FAM) is used to enable NSPI to recover the cost of fuel and purchased power from its customers and is structured to pass through 100 percent of these costs without the need for a full GRC.

The FAM has three components: the Base Cost of Fuel (BCF), the Actual Adjustment (AA), and the Balancing Adjustment (BA). The BCF represents the test year forecast of fuel costs and is included in customer rates. This is typically reset either every two years or through a GRC. The AA and BA are used to true up the difference between these forecast costs and actual incurred costs. The former represents the difference between the *current* year fuel and purchased power expense and the expense included in base rates, while the BA represents the difference between these expenses in the *prior* year (if any). The BA is necessary because the AA uses ten months of actual cost data to calculate the true up, and two months of forecast data. As such, the BA is used to true up any differences due to the two-month forecast of expenses.

Learnings

The information presented in this section is based on a full audit of NSPI's FAM conducted by a third-party economic consulting firm. The audit represents a distinct regulatory approach from that employed in Washington, given that the FAM allows for full pass-through of fuel and purchased power costs but monitors the prudency of the utility's costs incurred for these categories through period, independent audits. This is therefore an extension of the prudency reviews conducted in GRCs, despite the variable nature of the costs covered under the FAM and the general lack of control which the utility has over these expenses. The scale of the audit, which resulted in a detailed 300+ page report, demonstrates that this approach is time- and resource-intensive.

IDAHO POWER[30]

Idaho Power	
Cost Tracking Mechanism	ID: Power Cost Adjustment (PCA) OR: Power Cost Adjustment Mechanism (PCAM)
Mechanism Type	Sharing Mechanism
Electricity Price Basis	Forwards
Hydro Treatment	Median hydro
Modeling Platform	AURORA

Electricity Market Prices

Idaho Power utilizes Mid-C electricity market forwards to reflect market prices in its estimation of net power costs.

Modeling Approach

Idaho Power uses AURORA to estimate net power costs.

Variable Generation

Idaho Power uses a median hydro year for rate setting purposes, based on a historical water record beginning in 1928.

Hedging

Idaho Power exercises a hedging program for managing fuel, power and commodity costs. It hedges its positions in coal, natural gas, power, and other commodities, as well as entering into financial hedge

[30] Information on Idaho Power was collected primarily from the company's 2018 Annual Report, available at: http://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_IDA_2018.pdf

transactions to partially mitigate its exposure to variability in commodity prices. For example, the utility financially hedges natural gas for physical delivery to its baseload Langley Gulch combined cycle plant, while managing the procurement of additional gas for its peaking units on the daily spot market or from storage inventory, as needed.

Adjustment Mechanism

Idaho Power is subject to sharing mechanisms in both Idaho and Oregon, known as the Power Cost Adjustment (PCA) and Power Cost Adjustment Mechanism (PCAM), respectively. Both mechanisms are structured similarly to those employed in Washington, with a dead band, sharing bands and a rate adjustment trigger. Notably, the Oregon PCAM does not employ asymmetrical sharing bands, but the dead band is structured asymmetrically to benefit customers. The dead band is set as the dollar equivalent of 250 basis points in the excess cost direction, and 150 basis points in the cost savings direction. Costs or savings beyond this band are shared 90 / 10 between customers and the utility, respectively. However, surcharges or rebates are only issued if Idaho Power's return on equity is 100 basis points below or above, respectively, the most recent level established by the Oregon Public Utilities Commission. In Idaho the PCA mechanism includes a symmetrical 95 / 5, customer / utility split, except for deviations in PURPA power purchases and demand response program incentives, which are allocated 100 percent to customers.

Learnings

The use of a 95 / 5 symmetrical sharing band, and absence of a dead band (in Idaho), removes some of the pressure and attention paid to variations between Idaho Power's estimated and actual net power costs. The absence of a dead band, symmetry of the sharing band, and relatively small portion of variations that the utility keeps provide very different incentives for the utility, given the limited ability to retain cost savings or absorb excess costs.

PACIFICORP

PacifiCorp	
Cost Tracking Mechanism	WA and OR: Power Cost Adjustment Mechanism (PCAM) ID and WY: Energy Cost Adjustment Mechanism (ECAM)
Mechanism Type	Cost Tracking + Sharing Mechanism
Electricity Price Basis	Forward prices, shaped using 5-yr average hourly prices
Hydro Treatment	Median year, based on 30-yr record
Modeling Platform	GRID production cost model (proprietary)

This summary describes PacifiCorp's power cost modeling practices as they have been in recent years. As raised in the stakeholder workshops that have been the central focus of this Avista review, PacifiCorp is in the process of transitioning to the use of a different dispatch model and interstate cost allocation approach, based on a Nodal Pricing Model to be provided by the California Independent System Operator

(CAISO).[31] Given this transition is ongoing, the following review focuses on how PacifiCorp has historically forecast net power costs, rather than reporting plans for a new approach that has yet to produce results. This information is based on testimony filed before the WUTC in June 2019,[32] supplemented by an Avista workshop presentation presented to stakeholders in August of 2018.[33]

Electricity Market Prices

PacifiCorp uses forward market prices from the Mid-C trading hub as the basis for their expectation of electricity prices. Unlike Avista's benchmarking approach, PacifiCorp directly incorporates forward prices, which are then shaped into hourly profiles using a five-year average of historic prices.

Modeling Approach

PacifiCorp uses a proprietary model – the Generation and Regulation Initiative Decision (GRID) tool – to simulate dispatch of their generators on an hourly basis and to estimate net power costs. E3 has not found details on the functionality or decision logic employed by the GRID tool.

Variable Generation

PacifiCorp assumes a single, median year of hydro generation in their modeling of net power costs, based on a 30-year historical water record. This allows the GRID tool to be run based on a single portfolio of available resources, as opposed to multiple model runs aimed at reflecting distinct historical water years as in Avista's approach.

Hedging

PacifiCorp engages in physical and financial hedging activities both to ensure the availability of electric power resources and to "reduce volatility of net power costs for [its] customers," which it considers "consistent with good industry practice."[34] PacifiCorp monitors its open power and gas positions on a daily basis, and limits the size of these exposed positions using prescribed time frames aligned with its Risk Management Policy. As do many utilities, PacifiCorp operates its hedging activities using dollar cost averaging, a reference to gradually hedging positions over time as opposed to all at once. In general, PacifiCorp's hedging activities appear similar to those of Avista, and have produced benefits to its customers in the form of less volatile net power costs. However, it is worth noting that as PacifiCorp does not own gas transportation rights it has not been subject to the same basis differential volatility and associated swings in the market value which have been included in Avista's ERM.

Adjustment Mechanism

The Washington Power Cost Adjustment Mechanism (PCAM) which PacifiCorp is subject to includes a +/- $4 million dead band and asymmetric sharing bands between $4 and $10 million in either direction,

[31] Docket UE-191024, PacifiCorp, Redacted Direct Testimony of Michael G. Wilding (Exhibit MGW-2), December 2019. https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/washington/filings/ue-191024/04_Direct_Testimony_and_Exhibits_of_Michael_G_Wilding.pdf

[32] Docket No. Ue-190458, PacifiCorp, Direct Testimony of Michael G. Wilding. June 2019.

[33] Avista. *PAC and PSE Power Supply Modeling Methods*. August 1, 2018.

[34] PacifiCorp. *2019 Integrated Resource Plan, Volume I*, at 300-301. October 18, 2019. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf

structured identically to the ERM (that is, with a 75 / 25, customer / company split for savings and a 50 / 50 split for excess costs). The credit or surcharge threshold in the PCAM is +/- $17 million, rather than the +/- $30 million included in the ERM, with the same sharing ratios (90 / 10, customer / company). Given the similarity of this structure, the PCAM presents the same incentives and disincentives as Avista's ERM.

Learnings

Two components of PacifiCorp's modeling approach make it considerably less onerous than that of Avista: the direct incorporation of forward market prices (i.e., treating PacifiCorp as "price-taker"), and the use of a median hydro year rather than a full historical record. While the use of a median hydro year may be less accurate than the use of a full, multi-year historical record, this approach is likely more consistent with the use of the Mid-C forward electricity prices (as discussed in the previous chapter).

PUGET SOUND ENERGY

Puget Sound Energy	
Cost Tracking Mechanism	Power Cost Adjustment Mechanism (PCAM)
Mechanism Type	Cost Tracking + Sharing Mechanism
Electricity Price Basis	Fundamentals modeling
Hydro Treatment	80-year record
Modeling Platform	AURORA

Electricity Market Prices

Unlike Avista and PacifiCorp, Puget Sound Energy (PSE) estimates its net power costs independently of forward electricity market prices, instead relying directly on fundamentals modeling through AURORA.[35]

Modeling Approach

PSE uses AURORA to model hourly dispatch of its units, relying largely on the "stock" database provided with the model. PSE inputs monthly forward natural gas prices and adds its own contracts, and then runs the model for 80 historical water years. The average results of these model runs inform PSE's estimated net power costs for use in setting base rates.

Variable Generation

As with Avista, PSE utilizes a full 80-year historical water record in its AURORA modeling. However, given that this modeling effort is not based on benchmarking to Mid-C electricity market forwards, PSE does not have to make the many, iterative adjustments which are involved in Avista's process. Instead, once the core inputs have been made the resulting energy amounts and net expenses are simply averaged, without the need to "tweak" many parameters based on an exogenous benchmark.

[35] Avista. *PAC and PSE Power Supply Modeling Methods*. August 1, 2018.

Hedging

PSE utilizes "forward physical electric and natural gas purchases and sale agreements, fixed-for-floating swap contracts, and commodity call/put options" as part of its programmatic hedging strategy, which extends out three years.[36] As with other utilities its hedging approach is focused on reducing costs and risks in order to optimize its energy portfolio, and the utility does not assume risk for the purpose of speculation. While details of PSE's hedging strategy are not readily available, the types of transactions and financial arrangements involved appear broadly similar to those of Avista and PacifiCorp in Washington.

Adjustment Mechanism

The PSE PCAM is similar to the PCAM and ERM mechanisms of PacifiCorp WA and Avista, respectively. The mechanism contains a symmetrical dead band of $17 million, followed by two sharing bands. The first is an asymmetric band between $17 million and $40 million (with a 50 / 50, customer / company split for under-recovered costs, and a 65 / 35, customer / company split for costs over-recovered). The second is a symmetric sharing band for all variations beyond $40 million (positive or negative) from baseline costs, in which customers are allocated 90 percent of the additional costs or savings. Costs or savings are deferred in a balancing account until the amount reaches a rebate or surcharge threshold of +/-$20 million, resulting in a rate adjustment. Given the similarity of this structure, the PCAM presents the same incentives and disincentives as Avista's ERM.

Learnings

PSE is one of the few utilities surveyed who did not rely on forward electricity prices in some fashion (i.e., either directly as an input or indirectly as a benchmark). Despite the use of a full 80-year water record, PSE's modeling process is considerably simpler than Avista's given that the AURORA parameters don't require adjustment, as they are not reliant on meeting external benchmarks. This may result in modeled electricity prices which differ considerably from forward prices, although it is worth noting that the forward prices themselves have not been consistent predictors of actual prices in recent years. This simplified modeling process (relative to that of Avista) is likely much easier for stakeholders to follow and understand. However, the departure from any relation to the forward electricity prices is noteworthy, given it is the exception to what most surveyed utilities use.

PORTLAND GENERAL ELECTRIC (PGE)[37]

Portland General Electric	
Cost Tracking Mechanism	Power Cost Adjustment Mechanism (PCAM)
Mechanism Type	Cost Tracking + Sharing Mechanism
Electricity Price Basis	Forward prices
Hydro Treatment	Average hydro
Modeling Platform	MONET power cost forecasting model (proprietary)

[36] Puget Sound Energy. *Form 10-Q*. October 31, 2018. Available at: https://pse.com/-/media/PDFs/PugetEnergy/PE-10Q-093018.pdf.

[37] Docket UE 335. Portland General Electric. *Net Variable Power Costs*. Direct Testimony and Exhibits of Mike Niman, Cathy Kim and Greg Batzler. February 15, 2018.

Electricity Market Prices

Portland General Electric (PGE) uses market forward prices to reflect expected electricity costs in the forward period. Their estimation of net variable power costs uses a "price-taker" model based on these exogenous market prices.

Modeling Approach

PGE uses a proprietary tool – the Multi-area Optimization Network Energy Transaction (MONET) model – to estimate net variable power costs. MONET was initially created in the 1990s and is actually the predecessor to AURORA. As with other models of this type, MONET produces estimates of the hourly economic dispatch of PGE's plants. Key data inputs include hourly load forecasts, forward electricity and natural gas prices, physical and financial contracts and market fuel commodity and transportation costs, generator characteristics including operating limits and forced outage rates, transmission costs, and physical and financial electricity contract purchases and sales.

Variable Generation

PGE incorporates "normal" hydro conditions into its modeling of net variable power costs through MONET, which it goes on to explain consists of an average hydro input based on the Northwest Power Pool Headwater Benefits Study. That study considers 80 years of historical data, but this is ultimately communicated through PGE's MONET model as a single average year.

Hedging

PGE has historically engaged in various physical and financial hedging activities to reduce volatility in customer rates through its "mid-term strategy."[38] The utility includes these contracts – both physical and financial – in its modeling, incorporating its current positions when estimating net variable power costs.

Adjustment Mechanism

The PGE PCAM is structured similarly to the mechanisms in place in Washington, with several distinctions. The dead band in PGE's PCAM is not symmetrical, with the positive side (where actual costs are above authorized) reaching up to $30 million, while the negative side reaches only -$15 million. This asymmetry builds in an incentive to manage costs efficiently, given that the utility has more to lose from being incorrect on the positive side than it has to gain from being incorrect on the negative side. Outside of this dead band on either side there is a 90 / 10, customer / company split. PGE's PCAM also incorporates a rate trigger, based on the utility's return on equity (ROE). The rate surcharge or credit is only triggered if the utility's ROE is +/- 100 basis points from its last authorized ROE.

Learnings

While the specifics of the MONET model are difficult to trace, the use of forward prices and a single average year water record make the PGE modeling approach considerably more straightforward than the

[38] Portland General Electric. *Integrated Resource Plan,* at 85. November 2016. https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning.

process Avista currently employs. PGE's PCAM is relatively similar to the mechanisms in place in Washington, although the asymmetrical dead band is a distinct feature, which more directly incorporates an incentive for the utility to ensure that actual costs do not exceed authorized baseline costs. However, given that dead bands generally seem to cause distrust among stakeholders, the use of this asymmetric dead band approach may introduce unnecessary contention into a process that is ultimately intended to streamline some aspects of ratemaking (i.e., variable costs deemed largely outside of the utility's control).

State Profiles[39]

INDIANA

The Indiana Utility Regulatory Commission (IURC) employs a number of different cost tracking mechanisms for specific expense categories. In addition to a Fuel Adjustment Clause, the IURC also utilizes trackers for capacity purchases and sales, off-system sales, environmental compliance costs, and capacity costs for participation in the Midcontinent Independent System Operator (MISO). In this way the IURC tracks independent costs separately, rather than using an all-inclusive approach as in some other jurisdictions.

For the FAC, base fuel costs are established during a GRC, with most utilities in the state using the PROMOD model as the basis for their anticipated fuel costs in the forward-looking test year. The FAC is reset on a quarterly basis, using two factors: a cost reconciliation for the previous three-month period, and a projection of costs for the forward-looking three-month period. This allows for relatively frequent reconciliation and re-setting of estimated costs. The FAC does not include any cost sharing between utilities and customers and is instead structured to pass through 100 percent of any cost variances. The quarterly hearings to approve the resetting of the FAC do not go uncontested, although in recent years Indiana utilities have been more proactive in reaching out to stakeholders to discuss and work to resolve issues. When contention arises within the FAC hearings, the IURC often chooses to open a separate docket, as the points of discussion are typically around prudency reviews.

Beyond the FAC, separate reconciliation proceedings are held for the other cost trackers. One of these – a tracker for off-system sales – does include a sharing mechanism, although the IURC has been considering changing this structure to instead simply pass through 100 percent of any cost variances, as is done through the FAC. This is because utilities are required to offer all of their resources into the MISO market, and therefore off-system sales will take place (without particular discretion on the part of the Indiana utilities).

The primary advantage of using individual cost tracking mechanisms for discrete expense categories appears to be the ability to separate out distinct issues from one another. As discussed above, some of the cost tracking proceedings are contested and result in further hearings before the IURC, indicating that this approach is not a panacea for the issues faced in Washington. However, there may be some value in

[39] E3 conducted a phone interview on March 31, 2020 with several contacts at Brubaker & Associates, Inc. (BAI) Consulting who have extensive experience working on utility cost tracking issues in Indiana and Michigan, through which the information in this section was gathered.

treating distinct costs separately, as one issue in Washington has been the difficulty in identifying the primary sources of variations in net power costs in a given year due to the combination of many expenses under a single tracker.

MICHIGAN

The approach taken by the Michigan Public Service Commission (MPSC) is quite different from that of the IURC and is more akin to that of the WUTC. The regulated electric utilities in Michigan are subject to a single, all-inclusive cost tracker known as the Power Supply Cost Recovery (PSCR) mechanism. The primary expense categories include variation in fuel, off-system sales, transmission expenses, short-term capacity purchases and sales, and long-term PPAs. Unlike the mechanisms in Washington, however, this mechanism does not employ dead bands or sharing bands, and instead all costs deemed to have been prudently incurred are fully passed through to customers.

The PSCR must be filed annually, regardless of whether or not a utility files a GRC. On an ongoing annual basis each utility participates in a PSCR proceeding through which the base costs included in rates are compared to actual costs incurred. Two separate proceedings for each utility are conducted each year: a Plan Case and a Reconciliation Case. The Plan Case is filed in the Fall of each year, and includes the estimated reconciliation for the current year, adjustments from past reconciliation cases, the projected PSCR costs for the coming year, the utility's proposed maximum PSCR factor for the coming year, and projected costs for the subsequent four years. The Reconciliation Case is filed in the Fall of each year, focused on the calendar year which has just finished, and deals with prudency of incurred costs. Any cost disallowances established in this reconciliation are then included in the following Plan Case.

Cost variations approved by the MPSC are either collected from or refunded to customers, as appropriate. Given the many components tracked in this common mechanism, there can be large swings depending on the difference between estimated and actual costs in different categories from year to year. While certain costs appear to be good candidates for tracking together, such as fuel cost variations and off-system sales, others are more challenging to "roll in" to a single mechanism. The comprehensive nature of this tracker has created some issues with cost allocation, given that certain components included in the PSCR mechanism must be allocated to utility customers in specific ways, making it difficult to break apart the aggregated variation between base and actual costs.

An interesting component of the PSCR is that utilities have the ability to reduce the rate charged to customers to cover these expenses at any time throughout the year, although they cannot increase it. In this way the utility can correct for overestimates of net power costs in real time to avoid excessive overcollection but cannot do the opposite in the event of underestimates and the resulting under collection. This is paired with the structure of the carrying charges on deferrals, which include a higher interest rate for money owed to customers than for money yet to be collected from customers through a surcharge. Despite the full pass through of costs, this approach includes an incentive for utilities to accurately estimate what these costs will be.

Industry Survey Conclusions

Through this survey E3 spoke with a broad range of utilities across the Western U.S. and beyond, aiming to identify similarities, differences and best practices in power cost modeling and regulatory approaches to cost tracking and adjustment mechanisms. Several key themes emerged from these conversations:

1) Most utilities interviewed leverage market forwards as a forecast of future electricity prices. Several utilities alternatively employed fundamentals modeling, while no utilities interviewed used an econometric model for the purposes of estimating net power costs.
2) The utilities surveyed appear to employ less complex power cost modeling processes than Avista.
3) Most other utilities in the Pacific Northwest do not individually model each year of a historical water record, and instead utilize some form of median or average year based on the historical record.
4) Hedging practices vary considerably across different utilities, often driven in part by direction from utility regulatory commissions. Most utilities do, however, engage in hedging of their power and fuel positions in order to limit price volatility for their customers.
5) Some utilities report that their cost tracking and adjustment processes are relatively straightforward and do not cause significant contention among involved stakeholders.
6) Of the utilities subject to sharing bands, those subject to symmetrical bands with only minimal sharing by the utility (e.g., a 95 / 5, customer / company split) appear to have more straightforward cost tracking proceedings due to the limited incentive or exposure for the utility.
7) Regulatory approaches to net power cost tracking and adjustment vary significantly, both in terms of the utility power cost modeling approaches endorsed by state commissions and the structure of mechanisms for allocating and/or sharing cost variations. There is no single, “best” approach.

7) Conclusions and Recommendations

As detailed in this report, E3 has conducted a review of Avista's power cost modeling process to develop a sense of how appropriate the different components and assumptions are, relative to general industry practices. E3 has also reviewed the Energy Recovery Mechanism related to Avista's power cost modeling to understand how it may influence any decisions made by the Company. Finally, E3 has conducted an industry survey to put both Avista's modeling approach and the ERM in a broader context and has reported key learnings from other utilities and jurisdictions.

E3 has worked with the workshop participants over the past several months to identify the key areas of concern relative to Avista's power cost modeling approach, including any influence that the ERM design may have on this process. However, the findings and conclusions in this report constitute E3's independent perspective on these issues and are not intended to reflect a consensus view from all involved parties.

E3's review has produced several clear conclusions:

1) Relative to other utilities' power cost modeling, **Avista's approach is complex and time intensive**.
    a) While Avista simulates the operation and market outcomes of the entire Western Interconnection using the AURORA production simulation model, it adheres to a requirement that its energy costs be based on published market prices at the Mid-Columbia trading hub. This requires Avista modelers to engage in significant effort to "force" the modeled electricity prices to match the forward market prices, adding complexity and introducing the potential for unintended consequences with respect to other aspects of system operations.
    b) This complexity is compounded by Avista's use of an 80-year record of Columbia River Basin runoff to reflect hydropower availability. This requires Avista's market benchmarking process to ensure that average electricity prices across 80 years of market simulations matches the Mid-C forward prices.
    c) Stakeholders are not able to replicate or even benchmark Avista's calculations, undermining confidence in the process.
2) The complexity involved in Avista's current power cost modeling approach results in a **relatively opaque process** which other **stakeholders find difficult to follow or audit**. This has been validated by our own experience with the many supporting workbooks, data files, and documentation files required to trace back the core calculations taking place.
3) Avista's power cost modeling process and the ERM are subject to a **more contentious and drawn out stakeholder process** than is common for cost tracking and/or sharing mechanisms, reducing the value of treating certain variable costs outside of a GRC.
4) Part of the **complexity arises** due to the requirement that **Avista benchmark its modeled electricity prices to the Mid-C forward market prices**. The value of doing this – rather than simply using the forward market prices as an input, as is the practice of many other utilities – remains unclear.

5) A **second contributor to the complexity** is the **use of the full 80-year water record** to reflect hydro availability, especially when paired with the requirement to benchmark to the market forwards, which necessitates much of the adjustment done to the AURORA model. These adjustments increase the complexity and opacity of the process, in addition to adding time and expense for all parties involved.
6) When combined with near annual rate cases, the design of **the ERM encourages bias** by providing incentives for the utility to overestimate its costs. Jurisdictions not utilizing a dead band, in general, appear to have stakeholder processes which do not become as entangled in discussions of potential "gaming" given the lack of utility incentive to do so, and the more straightforward recognition of the variable and uncertain nature of the costs being tracked and shared. This is also true in jurisdictions that utilize sharing mechanisms that symmetrically pass the majority of all cost variations along to customers (for example, through a 90 / 10 or 95 / 5, customer / company split in either direction).
   a) E3 is aware of the Commission's previous finding of a bias in Avista's calculations. E3 was not able, with the limited time and resources available for this review, to determine the source of the bias or even to verify whether there is, indeed, a bias. From our review, E3 has not found any evidence of intentional bias in Avista's approach to modeling power costs.
   b) Nevertheless, E3 notes that the existence of a dead band within which Avista bears the risk of forecast errors provides an incentive for Avista to minimize the chance of a significant under-forecast of its power costs. The existence of this incentive necessitates a substantial degree of Commission oversight into Avista's power cost calculations to avoid the potential for the Company to over-earn.
   c) The combination of the incentive inherent in the design of the ERM, the need for substantial oversight of the process, the complexity of Avista's calculations, and stakeholders' inability to replicate them creates a regulatory "perfect storm" that fosters perpetual mistrust and contention.
7) Avista has very **little control over its actual energy costs**.
   a) While E3 was unable to verify all of Avista's calculations, it is nonetheless clear that the majority of Avista's energy cost variations are due to fluctuations in continental commodities markets, particularly natural gas prices and natural gas basis spreads which have a downstream impact on electricity market prices. It is notable that the ERM resulted in under-forecasts of Avista's energy costs during years in which natural gas prices were generally rising (2003-2009) and over-forecasts during years in which natural gas prices were generally falling (2011-2019).
   b) One way that utilities can control energy costs is through hedging. Like most (but not all) utilities, Avista engages in hedging to reduce unpredictable fluctuations in energy costs. However, E3 notes that companies to do not engage in hedging for the purpose of minimizing energy costs; rather the purpose of hedging programs is to manage energy cost *variability*. Due to transaction costs, hedging, like other forms of insurance, results in *higher* expected costs over time but lower variances in expected costs.
   c) While the structure of the ERM provides the Company with the ability to earn on energy costs, most of the Company's earnings appear to have resulted not directly from the Company's business decisions but rather from unforeseen changes in continental commodities markets.

8) **The ERM process, as a whole, is costly both to Avista and its stakeholders**, however it is questionable whether this investment of time and resources yields any gains in efficiency, i.e., whether it leads to lower energy costs than less costly alternatives.

Based on our review and the above conclusions, E3 has several recommendations which we believe could help to improve this process and alleviate some of the contention which has developed around Avista's estimation of net power costs.

1) To increase transparency **Avista's current modeling process can be simplified**, while **maintaining sufficient accuracy**.
2) Given the primary source of modeling complexity is the practice of benchmarking to the market forwards, the most straightforward simplification would be to **incorporate the market forwards directly, treating Avista as a "price-taker."**
   a) This would still require that Avista shape the forward prices – which are reported simply for monthly On and Off Peak periods – into hourly profiles for use in modeling the dispatch of its generators. This can be done in several ways, including the use of a historical year's price shapes or an average of multiple years' shapes, each with advantages and disadvantages.
3) As the value of using the full water record is limited while still relying on external market prices (either directly through the forwards or indirectly via benchmarking to them), the stakeholder group should consider a **shift towards using either a median water year or a percentile water year that approximately produces average costs across the full water record.**
4) Due to the reliance on market forwards, there may be value in **standardizing the practice of updating forward electricity and natural gas inputs close to the rate implementation date**, as is done in "compliance runs." Incorporating such a "data refresh" – after the rate case had already been concluded – would allow for costs to be most reflective of the current market information, which generally improves as the forward period approaches.
5) Finally, the stakeholder group should **continue discussing the merits and limitations of the current ERM to better understand and potentially address the incentives it creates**.
   a) While cost trackers are intended to monitor costs outside of a utility's control, the mechanism as designed assumes some level of control on the Company's part. If the goal of the stakeholder workshop process is to eliminate bias, while the goal of cost tracking and sharing mechanisms like the ERM is to reduce administrative costs, one solution is to remove the incentive for bias from this process.
   b) Amendments could include, for example, a reduction in or removal of the dead band, isolating certain costs for full pass-through, adjustments to the sharing ratios or bands, or some combination therein. However, given varying opinions within the stakeholder group as to the appropriateness of the current mechanism, additional discussion and exploration is merited.
   c) Stakeholders should keep in the mind the balance between regulatory cost and efficiency gains, considering the degree to which the Company is able to control its energy costs.

To the extent that the stakeholder group finds the need to delve further into the details of Avista's processes, this could be done through a more formalized and intensive audit by a third party. However, this is not the most productive approach, in E3's perspective, due both to the lack of bias uncovered through our review and the resources which would be required.

Alternatively, the suggestions documented above provide our perspective on how this process can most effectively be moved forward in a manner that protects both the interests of Avista's customers and the Company itself.

Appendix

Dispatch Model Results

Table 4: Detailed Dispatch Model Outputs ($MM)

Panel	Group	Item	2011	2012	2013	2015	2016	2017	2018
1	ERM	WA ERM	$ (19.2)	$ (14.7)	$ 5.0	$ (17.6)	$ (8.4)	$ (6.2)	$ (15.5)
		Gross ERM	$ (29.7)	$ (22.7)	$ 7.8	$ (27.2)	$ (13.0)	$ (9.6)	$ (24.0)
2	E3 Modeled Actual Costs	Gas Generation Cost	$ 21.8	$ 29.3	$ 63.2	$ 60.4	$ 42.5	$ 62.4	$ 86.7
		Electricity Market Cost (Revenue)	$ 36.2	$ 26.9	$ 24.1	$ (5.4)	$ (0.4)	$ (11.3)	$ (64.1)
		Gas Transport Cost (Revenue)	$ (3.0)	$ (3.8)	$ (7.1)	$ (4.6)	$ (8.0)	$ (12.0)	$ (17.9)
		Coal / Wood Cost	*$ 29.1*	*$ 25.8*	*$ 23.0*	*$ 30.1*	*$ 28.7*	*$ 26.3*	*$ 19.3*
		Transmission Cost	*$ -*	*$ 5.0*	*$ 7.4*	*$ 0.2*	*$ (0.0)*	*$ (3.0)*	*$ -*
		Gas Cost (547)	*$ 55.0*	*$ 50.9*	*$ 108.9*	*$ 91.8*	*$ 66.5*	*$ 69.5*	*$ -*
		Net Cost	**$ 139.1**	**$ 134.0**	**$ 219.5**	**$ 172.5**	**$ 129.3**	**$ 131.9**	**$ 24.0**
3	E3 Modeled Authorized Costs	Gas Generation Cost	$ 103.3	$ 78.3	$ 83.4	$ 95.7	$ 82.3	$ 82.3	$ 61.4
		Electricity Market Cost (Revenue)	$ (20.3)	$ 5.4	$ (7.2)	$ (35.7)	$ (34.0)	$ (31.3)	$ (8.5)
		Gas Transport Cost (Revenue)	$ (3.7)	$ (3.4)	$ (3.8)	$ (4.8)	$ (6.4)	$ (6.4)	$ (6.3)
		Coal / Wood Cost	*$ 34.0*	*$ 31.7*	*$ 30.7*	*$ 28.4*	*$ 28.8*	*$ 29.1*	*$ 22.4*
		Transmission Cost	*$ -*	*$ 6.1*	*$ 7.0*	*$ 0.8*	*$ 1.4*	*$ 1.4*	*$ -*
		Gas Cost (547)	*$ 96.7*	*$ 75.7*	*$ 95.8*	*$ 92.9*	*$ 67.3*	*$ 77.3*	*$ -*
		Net Cost	**$ 210.0**	**$ 193.8**	**$ 206.0**	**$ 177.2**	**$ 139.4**	**$ 152.5**	**$ 69.0**
4	E3 Modeled Gross ERM	Gas Generation Cost	$ (81.5)	$ (48.9)	$ (20.2)	$ (35.2)	$ (39.8)	$ (19.9)	$ 25.3
		Electricity Market Cost (Revenue)	$ 56.5	$ 21.4	$ 31.3	$ 30.3	$ 33.5	$ 20.0	$ (55.6)
		Gas Transport Cost (Revenue)	$ 0.7	$ (0.4)	$ (3.3)	$ 0.2	$ (1.5)	$ (5.6)	$ (11.6)
		Coal / Wood Cost Var. Plug	*$ (5.0)*	*$ (6.0)*	*$ (7.8)*	*$ 1.7*	*$ (0.1)*	*$ (2.8)*	*$ (3.1)*
		Transmission Cost Var. Plug	*$ -*	*$ (1.1)*	*$ 0.4*	*$ (0.7)*	*$ (1.4)*	*$ (4.5)*	*$ -*
		Gas Cost (547)	*$ (41.7)*	*$ (24.9)*	*$ 13.0*	*$ (1.1)*	*$ (0.8)*	*$ (7.8)*	*$ -*
		Net Cost	**$ (71.0)**	**$ (59.8)**	**$ 13.6**	**$ (4.7)**	**$ (10.1)**	**$ (20.5)**	**$ (45.0)**
		% of Gross ERM	*239%*	*263%*	*175%*	*17%*	*78%*	*214%*	*187%*
5	E3 Modeled WA ERM	WA Retail Revenue Adjustment	*$ (9.8)*	*$ 0.7*	*$ (3.1)*	*$ 1.3*	*$ 1.1*	*$ (2.6)*	*$ -*
		Modeled WA ERM, pre Retail Rate Adj.	*$ (45.9)*	*$ (38.7)*	*$ 8.8*	*$ (3.0)*	*$ (6.5)*	*$ (13.3)*	*$ (29.1)*
		E3 Modeled WA ERM	*$ (55.7)*	*$ (38.0)*	*$ 5.7*	*$ (1.7)*	*$ (5.4)*	*$ (15.8)*	*$ (29.1)*
		% of Actual WA ERM	***290%***	***258%***	***113%***	***10%***	***64%***	***255%***	***187%***

Panel 1 reports the annual ERM amount (WA ERM), as well as the gross ERM value derived using the Production/Transmission allocation factor (that is, the WA ERM divided by 0.6471).

Panel 2 reports the dispatch model results generated using the actual values which occurred in each year, including the Mid-C On and Off peak electricity prices in each month, the monthly average natural gas prices at the Malin and AECO trading hubs, Avista's gas generator capacity factors, native loads, hydro generation, coal and biomass generation, and wind generation. The greyed-out values for Coal / Wood Cost, Transmission Cost, and Gas Cost (547) are not modeled costs and are instead actual cost values reported by Avista in the Company's annual ERM variance explanations. These costs were input to account for differences between the two modeled cases that would not be picked up by the model, given that the coal and biomass (wood) units were run as "must-take" resources (without calculated operating costs), the gas units were run based only on their margin (as determined by the market gas and electricity inputs), and transmission was not feasible to model in this structure.

Panel 3 reports the same outputs as Panel 2 but using model inputs based on the filed GRC values, with the exception of the coal and biomass dispatch. Both the "actual" and "filed" cases use the actual dispatch for these resources, given the simplified (flat) modeling of these resources produced unrealistically uniform generation across the study period compared with historic output.

Panel 4 reports the difference in costs between the two scenarios, as well as the percentage of the gross ERM that the difference in modeled net costs represents.

Finally, Panel 5 a) scales the modeled net cost difference down to the Washington-specific portion (again, using the Production/Transmission allocation factor of 0.6471), and b) adjusts this amount by the reported annual retail revenue adjustment to account for differences in retail sales (which are not covered directly under the ERM). The final row reports the percentage of the actual annual ERM represented by the modeled annual ERM amount.

Industry Survey Summary Tables

Table 5: Select Pacific Northwestern Utility Sharing Mechanisms

	Avista WA	Puget Sound Energy	PacifiCorp WA	Portland General	Idaho Power OR	PacifiCorp OR	Idaho Power ID	PacifiCorp ID
Adjustment Mechanism	ERM	PCAM	PCAM	PCAM	PCAM	PCAM	PCA	ECAM
Year Implemented	2002 (first full year 2003)	2002	2015	2007	2009	2012	1993	2009
Commission Order	Order 05 (UE-011595)	Order 12 (UE-011570)	Order 09 (UE-140762)	07-015	08-238	12-493	24806	30904
Symmetrical	No	No	No	No	No	No	Yes	Yes
Rate Surcharge / Credit Trigger	$30M	$20M	$17M	Based on ROE*	Based on ROE*	Based on ROE*		
Dead Band	+/-$4M	+/-$17M	+/-$4M	+$30M / -$15M	+250 / -150 basis points**	+$30M / -$15M	N/A	N/A
Savings Band (1) Cust. / Comp. Split	$4M - $10M 75% / 25%	$17M - $40M 65% / 35%	$4M - $10M 75% / 25%	$15M+ 90% / 10%	Varies (see above) 90% / 10%	$15M+ 90% / 10%	95% / 5%	90% / 10%
Savings Band (2) Cust. / Comp. Split	$10M+ 90% / 10%	$40M+ 90% / 10%	$10M+ 90% / 10%	N/A	N/A	N/A	N/A	N/A
Excess Cost Band (1) Cust. / Comp. Split	$4M - $10M 50% / 50%	$17M - $40M 50% / 50%	$4M - $10M 50% / 50%	$30M+ 90% / 10%	Varies (see above) 90% / 10%	$30M+ 90% / 10%	95% / 5%	90% / 10%
Excess Cost Band (2) Cust. / Comp. Split	$10M+ 90% / 10%	$40M+ 90% / 10%	$10M+ 90% / 10%	N/A	N/A	N/A	N/A	N/A

*A rate surcharge or credit is only triggered if the utility's ROE is +/- 100 basis points from its last authorized ROE.

**Idaho Power OR dead band is the dollar equivalent of + 250 / - 150 basis points of ROE.

Table 6: General Rate Case History (Electric), 2000 - 2019[40]

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total	Avg. Yrs./GRC
Avista																						
ID					x				x	x	x	x	x		x	x	x	x		x	**11**	1.82
WA		x				x		x	x	x	x	x	x		x	x	x	x		x	**13**	1.54
Idaho Power																						
ID				x		x		x	x			x									**5**	4.00
OR										x		x									**2**	10.00
Xcel Energy																						
MN						x			x		x		x	x		x				x	**7**	2.86
WI						x		x		x		x	x	x	x	x	x	x		x	**11**	1.82
NorthWestern																						
MT*																			x		**1**	20.00
PacifiCorp																						
ID						x		x	x		x	x		x							**6**	3.33
OR	x			x	x		x			x	x		x	x							**8**	2.50
WA				x		x	x		x	x	x	x		x	x	x					**10**	2.00
WY	x		x	x		x		x	x	x	x	x			x	x					**11**	1.82
PGE																						
OR	x						x		x		x			x	x	x		x	x		**9**	2.22
PNM																						
NM			x					x	x		x				x	x	x				**7**	2.86
PSE																						
WA		x			x		x	x		x		x		x				x	x		**9**	2.22
Grand Total	***3***	***2***	***2***	***4***	***3***	***7***	***4***	***7***	***9***	***8***	***9***	***9***	***5***	***7***	***7***	***8***	***4***	***5***	***3***	***4***	***110***	

Note, dataset only includes completed general rate cases in which the company requested a rate change of at least $5 million or was authorized a rate change of at least $3 million. This excludes cases which are pending, distribution-only, or focused on a limited-issue rider.

*Northwestern has had several distribution-only and limited-issue rider rate cases in Montana during this period.

[40] Data sourced from S&P Global Market Intelligence on April 13, 2020.

Table 7: Utility Rate Bases Filed in Recent GRCs[41]

	GRC Year	Rate Base ($MM)
Avista		
ID	2019	$ 836.8
WA	2019	$1,708.3
Idaho Power		
ID	2011	$2,355.9
OR	2011	$ 121.9
Xcel Energy		
MN	2019	$9,805.7
WI	2019	$1,482.8
NorthWestern		
MT	2018	$2,334.1
PacifiCorp		
ID	2011	$ 745.7
OR	2013	$3,384.5
WA	2015	$ 874.2
WY	2015	$2,120.4
PGE		
OR	2018	$4,857.6
PNM		
NM	2016	$2,381.2
PSE		
WA	2018	$5,101.8

[41] Ibid.