Exh. DCG-1CT
Dockets UE-170485/UG-170486
Witness: David C. Gomez
REDACTED VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **AVISTA CORPORATION, d/b/a AVISTA UTILITIES,** **Respondent.**	**DOCKETS UE-170485 and UG-170486** **(*Consolidated*)**

TESTIMONY OF

David C. Gomez

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Pro Forma Power Costs

October 27, 2017

CONFIDENTIAL PER PROTECTIVE ORDER - REDACTED VERSION

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David C. Gomez. My business address is the Richard Hemstad Building, 1300 S. Evergreen Park Drive S.W., Olympia, Washington 98504. My business email address is dagomez@utc.wa.gov.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission ("Commission") as the Assistant Power Supply Manager in the Energy Section of the Regulatory Services Division. I attained this position on July 1, 2012. Prior to my current position, I was the Deputy Assistant Director in the Solid Waste and Water Section of the Regulatory Services Division.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since May 2007.

Q. Please state your educational and professional background.

A. I hold a Bachelor of Arts degree in Business from Hamline University and a Masters of Business Administration degree from the University of Saint Thomas; both universities are located in Saint Paul, Minnesota.

Before joining the Commission, my relevant professional experience consisted of 25 years in a variety of fields, including management, contracting, supply chain, procurement, operations and engineering. I hold professional certifications from the Institute for Supply Management (ISM); APICS – The Association for Operations Management; Universal Public Procurement Council (UPPC); and QAI Global Institute (Software Testing).

Q. What are your duties with the Commission?

A. I perform accounting and financial analysis of regulated utility companies, as well as legislative and policy analysis. I presented testimony on behalf of Commission Staff in Docket UE-121373, regarding the Coal Transition Power Purchase Agreement between Puget Sound Energy and TransAlta Centralia Generation LLC; Dockets UE-130043 and UE-140762, PacifiCorp's 2013 and 2014 general rate cases; Docket UE-130617, Puget Sound Energy's 2013, 2014 and 2016 Power Cost Only Rate Cases (PCORCs); and Dockets UE-140188, UE-150204 and UE-160228, Avista's last three general rate cases. Most recently, I provided testimony on power supply issues in Puget Sound Energy's 2017 General Rate Case, Dockets UE-170033 and UG-170034. I have provided Staff recommendations to the Commission at numerous open meetings, and worked on various Commission rulemakings.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. My testimony addresses rate year and pro forma power supply costs and responds to the prefiled direct and supplemental testimonies of Avista Corporation's ("Avista" or "Company") witnesses:

- Mr. Clint Kalich, AURORA model inputs, settings and results;[1] and
- Mr. William Johnson, normalizing and pro forma adjustments to Avista's 2016 test period power supply revenues and expenses.

My testimony also addresses the Company's level of expense used to set the Energy Recovery Mechanism (ERM) baseline and Avista's proposal to update its power costs as part of a proposed three-year rate plan. In this case, my focus is primarily on the modeling assumptions in AURORA that Avista relies on to arrive at a power supply expense for the rate year of $114.8 million, a $16.0 million increase when compared to the power supply expense currently embedded in rates.[2]

Q. Can you summarize your recommendation regarding Avista's power cost expense for the 2018-2019 rate year and its proposed rate plan?

A. Yes. For the 2018 rate year, Staff recommends the Commission reject the Company's pro forma adjustments to its power supply expense and maintain the same levels currently authorized in rates, $98.8 million.[3] Staff also recommends the Commission reject Avista's rate plan proposal to annually update its level of power supply expense on May 1st of 2019 and 2020.[4] Instead, the Commission should accept Staff's alternative rate plan proposal and maintain the current power cost

[1] Staff is responding to Mr. Kalich's supplemental testimony filed on August 11, 2017.
[2] Johnson, Exh. WGJ-1T at 3:12 - 4:2. Amounts are on a Washington allocation basis.
[3] Johnson, Exh. WGJ-1T at 3:12-18, Table 1. Amounts are on a Washington allocation basis.
[4] Johnson, Exh. WGJ-1T at 10:11 - 12:1.

baseline until a) Avista's next general rate case or b) the total credit balance owed to ratepayers, currently at $21.9 million,[5] falls below $10 million, whichever occurs sooner.

III. BACKGROUND AND PURPOSE OF THE ERM

Q. Can you briefly describe Avista's ERM?

A. The ERM is a power cost recovery mechanism designed to equitably allocate between the Company and its customers the risk of ordinary variations in power costs that may occur between rate cases. The Commission established the ERM by its order approving a settlement among all parties in Docket No. UE-011595.[6] The ERM tracks Avista's actual monthly net power supply expenses and compares these amounts against "base" levels embedded in the Company's rates.

The Company and its customers share deviations in actual power costs from the baseline costs. After actual power costs exceed a dead band, the deviations are shared in two levels of "sharing bands." The current dead and sharing bands for the ERM are provided in Table 1 below. In the current version of the ERM, annual variations beyond the $4 million dead band fall into the sharing bands and, as their name implies, any resulting annual variation in power costs beyond $4 million is allocated between ratepayers and the Company accordingly.

[5] UE-011595, Per Avista's Cover Letter of October 16, 2017, for the September 2017 monthly report.
[6] *Wash. Utils. & Transp. Comm'n v. Avista Corporation*, Docket No. UE-011595, Fifth Supplemental Order (June 18, 2002) (2002 ERM Order).

Annual Power supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess over $10 million	90%	10%

Table 1: Current Avista ERM Bands

After each calendar year, customers' share of the positive or negative annual net difference in power costs is deferred to the Energy Cost Deferral Balance account. These deferrals accumulate each year until they reach a trigger amount of $30 million. At this point the Company must file a tariff change to pass back the Deferral Balance to customers via a surcharge or rebate.

Q. What is the purpose of the ERM?

A. The ERM has two core purposes: (1) to equitably allocate between Avista and its customers the risk of ordinary power cost variability; and (2) to incentivize Avista to effectively manage or even reduce its power costs.[7] The Commission sets rates that reflect an appropriate level of normalized net power supply costs and at a level that provides the Company with an opportunity to recover its power costs over time. However, the potential exists that the Company may experience power costs in the rate year that are significantly and materially above or below those embedded in rates. The ERM's purpose, therefore, is to mitigate the impacts of year-to-year variability in power costs fairly and equitably for both the Company and its

[7] *In the Matter of the Petition of Avista Corp. for Continuation of the Company's Energy Recovery Mechanism, with Certain Modifications*, Docket UE-060181, Order 03, ¶ 23, Finding of Fact 3 (June 16, 2006).

customers while providing an economic incentive for the Company to reduce its power costs.

Q. What was the context behind the creation of Avista's ERM?

A. The ERM came about as a result of the Western U.S. Energy Crisis of 2000 and 2001, which contributed significantly to a decline of Avista's financial condition during that period.[8] During the crisis, the Company managed to accrue over $200 million in deferred power costs attributed to a perfect storm of poor hydro conditions in the Pacific Northwest coupled with high wholesale electric market prices. To help ameliorate Avista's dire financial situation, the Commission took action by allowing deferral of certain power costs for potential later recovery through a combination of a surcharge on rates and general rate increases. The impact of the Commission's actions during that crisis were described in the testimony of Mr. Jon Eliassen, Avista's then Chief Financial Officer:

> The regulatory action and support received to date from this Commission has been a critical part of that progress [toward financial stability]. In particular, the surcharge implemented last fall was a key action that provided cash flows necessary to allow the Company to reduce the amount of money being borrowed to pay for power purchases. The deferral accounting order, prudence settlement and interim rate increase orders granted earlier this year have all been recognized by the financial community as positive steps by this Commission that show its commitment to the financial health of regulated utilities in Washington.[9]

In addition to the provisional actions described above, the Commission also implemented the ERM as a long-term solution to address the limits of traditional rate

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[8] 2002 ERM Order at ¶ 28.
[9] 2002 ERM Order at ¶ 6.

making to anticipate, in a general rate case, Avista's actual level of rate year power costs. Together, these actions helped restore investor confidence in Avista and stave off a bankruptcy of the utility.[10]

Q. Why are the ERM's bands so important?

A. As opposed to a dollar-for-dollar recovery mechanism, the ERM includes sharing bands which are designed to allow the equitable sharing of the inherent risk of variation in power costs between ratepayers and the Company. The existence of the dead band is designed to provide Avista with a strong incentive to not only improve the accuracy of its estimated rate year power costs, but to develop cost control strategies to mitigate its exposure to commodity price and weather risk.

Q. Why is the power cost baseline so important?

A. The ERM's power cost baseline reflects the amount of power costs that are included in rates. Therefore, the standard for changing the power cost baseline is the same standard that applies to rate increases generally—the Company bears the burden of proof to show that any increase it proposes is fair, just, and reasonable.[11]

Moreover, the proper functioning of the ERM bands requires a well-forecast baseline, especially if the baseline is adjusted annually. For example, if the baseline

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[10] Many of Washington State's electric utilities were experiencing financial difficulties as a result of the Western U.S. Energy Crisis. In the case of Puget Sound Energy (PSE), the Commission implemented the Power Cost Adjustment Mechanism (PCA) which is designed to "achieve an appropriate balance between risks to customers and risks to utility shareholders" and "result in a sharing of costs and benefits between PSE and its customers if power costs deviate significantly from those embedded in PSE's rates." *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Docket No. UE-011571, Twelfth Supplemental Order (June 20, 2002).

[11] RCW 80.04.130; *Wash. Utils. & Transp. Comm'n v. Avista Corporation,* Docket Nos. UE-160228 and UG-160229, Order 06, 57, ¶ 110 (Dec. 15, 2016).

is consistently set too low it will cause the Company to absorb yearly revenue shortfalls pursuant to the bands that deny its opportunity to recover its costs. Conversely, if the baseline is consistently set too high, customers will overpay for power costs and the Company will receive an undeserved windfall. Therefore, for the ERM to function properly, the baseline must be set at a level that provides an equal likelihood of power costs coming in above or below the baseline.

Q. Why do you feel it is necessary to revisit the ERM's history and purpose?

A. The ERM is not functioning as intended because Avista does not accurately model its power costs. Since 2011, despite almost annual revisions to its ERM baseline, Avista has over-collected its power costs from its customers by $64.6 million—an average of $10.8 million per year.[12]

Avista's failure to accurately forecast its power costs has produced a windfall for its shareholders and has harmed customers. The Company has profited in five of the last six years from the ERM bands. Since 2011, it retained a net total of $24.7 million—an average of $4.1 million per year—of the over-collected power costs before depositing the remaining $39.8 million in the deferral account.[13] Importantly, customers never received a rebate for the over-collected power costs because the ERM deferral balance has repeatedly been used to offset rate increases that were driven, in part, by Avista's inaccurate power forecasts.

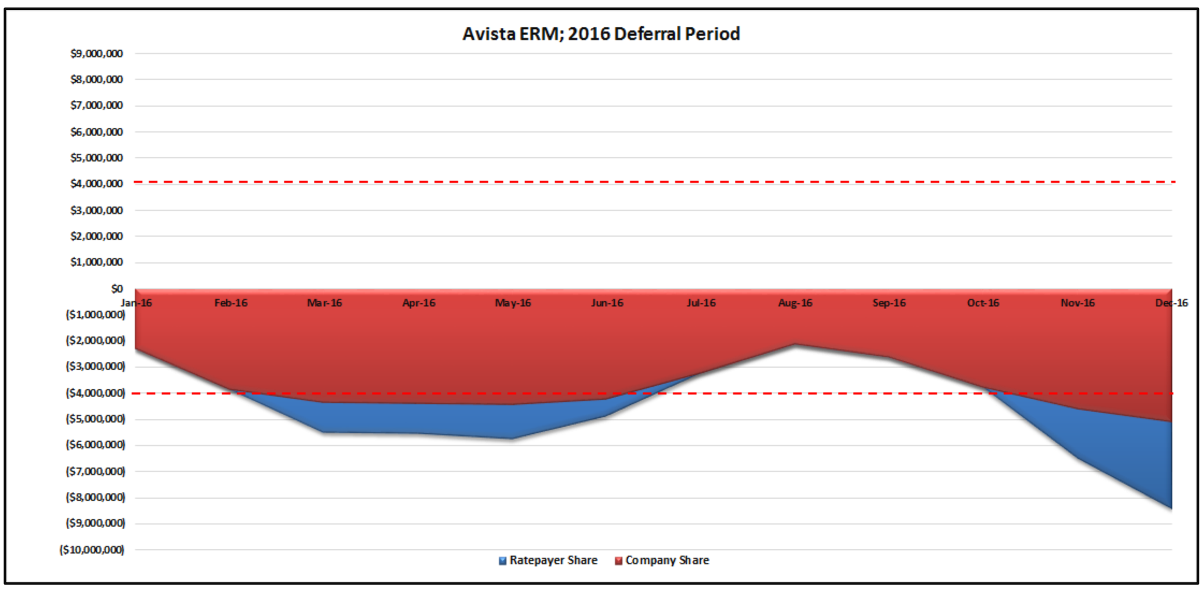
[12] Gomez, Exh. DCG-2, Column H, Row "Totals".
[13] Gomez, Exh. DCG-2, Column I & J, Row "Totals".

Q. What does your review of the performance of the ERM baseline demonstrate?

A. Avista's power cost forecast is biased towards over-estimating its power costs. As illustrated in Exh. DCG-3 and Exh. DCG-4, in 56 of the past 80-months (70 percent), Avista's actual monthly power costs were lower than those authorized in rates. Exh. DCG-4 and Exh. DCG-5, in particular, reveal a pattern of over-estimation on the part of Avista in determining its rate year power costs.

The presence of this bias in the Company's estimation of its rate year power costs naturally calls into question Avista's proposal to annually increase the ERM baseline as part of its rate plan in this case and, in general, whether the ERM, as it is functioning today, meets the Commission's objective of an equitable sharing of power cost variability risk and benefit between ratepayers and the Company.

Figure 1: Avista ERM 2016 Deferral Period
(ERM bands applied at end of year)



Q. How have Avista's recent annual rate case filings affected the ERM baseline?

A. Avista's practice of filing annual rate cases, which have included adjustments to the ERM baseline, have driven the over-collection of power costs. In UE-140188, a multi-party settlement was approved by the Commission, which included an increase in power costs of $5.6 million for the January through December 2015 rate year.[14] This 2015 power cost increase was offset entirely using credit balances (owed to ratepayers) from the ERM deferral account, leaving the ERM baseline unchanged in that year.[15] In Avista's annual filing to review and confirm its ERM power cost deferrals for 2015, the Company reported that its actual power costs (system) were lower than the baseline by almost $30 million.[16]

A month after Avista's rates became effective in UE-140188, Avista filed another general rate case in UE-150204, which resulted in a partial settlement that included a $35.8 million reduction to the ERM baseline for the 2016 rate year. At the end of 2016, in spite of a reduction to rate year power costs, actual system power costs were again lower than authorized amounts by $15.5 million.[17]

Twenty-six working days after the Commission issued its final order in UE-150204, Avista filed yet another general rate case in UE-160228. In that case, Avista sought an 18-month rate plan[18] that included two separate adjustments to the ERM

[14] *Wash. Utils. & Transp. Comm'n v. Avista Corporation*, Docket No. UE-140188, Order 05 (November 25, 2014), ¶ 19.
[15] In my Exh. DCG-2, the Authorized Power Cost values for 2013 and 2014 are both identical amounts of $181.2 million. Although the settlement provided $5.6 million in ERM balances to pay for increased power costs in the 2015 rate year, this increase is not reflected in the baseline amount and therefore not subject to the ERM dead and sharing bands.
[16] Gomez, Exh. DCG-2, Column E, Row 2015.
[17] Staff includes "Resource Optimization" in calculating annual power cost variances because this category, while sounding good, actually represents an overestimation on the part of Avista of its rate year fuel requirements for its thermal fleet.
[18] Avista's proposal included using ERM credit balances to pay for the second step of its rate plan.

baseline. Avista proposed an ERM baseline increase of approximately $20 million for the 2017 calendar year with an additional $5.5 million added to the ERM baseline for the first six months of 2018. On December 15, 2016, the Commission issued its final order rejecting Avista's proposed tariff revisions in UE-160228. The ERM baseline established in UE-150204 of just under $139 million currently remains in effect.

Q. Do you think the practice of using ERM credit balances to offset rate increases should continue?

A. No. This practice may seem reasonable, but it has actually harmed customers. Avista's serial rate case filings have been driven, in part, by its inaccurate power cost forecasts. Each year, the increases in power costs fail to materialize in the rate year, causing customers to pay more than they should. This over-collected power cost revenue is being returned to customers only after (1) the Company keeps a portion of the over-collected revenue pursuant to the sharing bands, and (2) the Company justifies another rate increase, in part, with another inaccurate power cost forecast. Using a positive deferral balance to pay for an increase in power costs that the Company did not actually need is unreasonable and contrary to the ERM's original purpose. In addition, reducing credit deferral balances for the purpose of paying down rate increases guarantees the ERM rebate trigger will never be reached, thereby thwarting an important feature of the ERM.

Q. What do you conclude regarding Avista's proposal to increase the baseline in this case?

A. Staff sees no reason why the baseline should not remain at its present level. In the case presently before us, Avista is seeking to recover an additional $19.7 million in power supply expense, which would increase the ERM baseline to $158.9 million. According to Avista, the major driver for this increase is the expiration of the PGE Exchange contract that it had previously cited in its rejected case as its principal justification for a change to the ERM baseline in the 2017 rate year. [19] With only three months left in the 2017 rate year, and no baseline change to account for the expiration of the PGE Exchange contract, there is an ERM credit balance in the current deferral period of $3.6 million in favor of customers—so far this year, Avista again over-collected for its power costs. This credit balance directly challenges the veracity of Avista's claims in this case regarding the alleged impact of the expired PGE contract. Had the Commission accepted Avista's proposed increases to the ERM baseline, which included an adjustment to account for the expiration of the PGE contract, the ERM credit deferral balance would have grown by another $20 million.

Q. What is Avista's explanation for its failure to accurately model power costs?

A. Avista attributes the discrepancy between its power cost forecasts and actual power costs to falling gas prices and favorable hydro production.[20]

[19] UE-170485, Supplemental Direct Testimony of Clint G. Kalich, Exh. CGK-3T at 5, Table No. 1: Summary of Changes to Power Supply Cost, Row 5. Also, at 3:1-3 of Mr. Kalich's supplemental testimony, he attributes 80 percent of the change in power supply expense to the expiration of the PGE contract.
[20] Kalich, Exh. CGK-3T at 27:14-15.

Q. Were you satisfied with this explanation?

A. No. Puget Sound Energy (PSE) has a similar mechanism to the ERM called the "Power Cost Adjustment" mechanism (PCA). While PSE is exposed to similar hydro production and gas price variability risk on its system, its annual variances from authorized power costs in its PCA mechanism are less than one percent.[21]

Year	PSE PCA Actuals vs Baseline	Avista ERM Actuals vs Baseline
2011	-2.5%	-7.7%
2012	-1.9%	-12.0%
2013	-2.9%	7.3%
2014	3.2%	-4.5%
2015	0.7%	-16.5%
2016	0.2%	-11.2%
Avg.	**-0.6%**	**-7.4%**

Table 2: PSE & Avista Actuals vs. Baseline

Q. Is the Company's approach to modeling rate year power costs contributing to its inaccurate forecasts of its ERM baseline?

A. Yes. Avista relies on AURORA model results to prognosticate its rate year power costs. The assumptions and approach employed by the Company in its power cost modeling using the AURORA model are fundamentally flawed and are at the heart of the ERM variance problem. As a result, I dedicate a large part of my remaining testimony to examining Avista's AURORA model input values and assumptions, run

[21] PSE's system power costs are roughly ten times larger than those of Avista. PSE also uses AURORA to model its calculation of pro forma power costs. See also *In the Matter of Puget Sound Energy for Approval of the 2016 Power Cost Adjustment Mechanism Report,* Docket UE-170334, Order 01 (October 12, 2017), ¶ 3.

settings (dispatch and commitment in each hour of the model's runs), as well as the Company's "out-of-model" adjustments to power costs.

IV. AVISTA'S ESTIMATION OF RATE YEAR POWER COSTS

A. Staff's Evaluation of Avista's AURORA Model Inputs

Q. Can you briefly summarize the purpose of this section in your testimony?

A. Yes. Staff's objective is to validate the efficacy of the Company's modeling assumptions in arriving at an ERM baseline. Avista operates the AURORA model by inputting numerous dispatch and operating assumptions. The Company also changes data that come preloaded in the AURORA model. Below I discuss several, but not all, of the changes made by the Company. Based on this analysis, it is clear that the Company has been using these changes to manipulate the model to overestimate power costs.

1. Rate Year Loads

Q. Why are rate year loads important to the AURORA model?

A. The AURORA model simulates the dispatch of generation resources owned and operated by Avista as well as other utilities to create an estimate of both imbedded power cost and market prices. The loads expected by Avista in every of hour of the rate year are the bedrock on which those dispatch and market simulations occur.

Q. Are Avista's load estimates reasonable?

A. No. The loads in AURORA are over 4.0 percent higher than its weather normalized test year load of 1,045 MW. This rate of load growth is significantly higher than the annual growth rate of 0.53 percent which Avista projected in its 2015 IRP.[22] My confidential Exh. DCG-6C, shows that applying the annual growth rate from the 2015 IRP to weather adjusted test period loads in this case results in rate year loads that are almost [redacted] lower than those Avista input into the model.[23] The reason for this discrepancy in the model's input is quite simple. In representing its level of rate year load in this case, Avista uses the much higher annual load forecast contained in its IRP, which ignores both the weather normalized test year load and the annual load growth factor presented in the "expected case" of that same IRP.[24]

Q. What would be a reasonable load estimate?

A. Weather normalized test year loads escalated by Avista's Average Annual Native Load Growth percentage.

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[22] UE-143214, Avista 2015 IRP, Table 3.5: Load Growth for High/Low Economic Growth Scenarios (2015-2035), page 3.19.

[23] In UE-160228, rate year loads input into AURORA were higher when compared to test year levels in that case by 2.8 percent. This annual growth rate is five times higher than the growth percentages cited in Avista's 2015 IRP, Table 3.6: Energy and Peak Forecasts.

[24] Avista's pro forma loads in this case are taken directly from the Company's 2017 IRP, Table 3.6: Energy and Peak Forecasts on pages 3-23, UE-161036.

Q. Do Avista's unreasonable load estimates have a big impact on the results of the model?

A. Yes, they do, especially in high-cost months. The biggest differences I observed were in the high-cost months of October through December, with loads being forecast by Avista in the rate year at levels averaging almost six-percent higher than loads derived by escalating test year levels. Avista has provided no evidence to support this kind of load growth and, in fact, its 2017 IRP reduces its annual load growth rate (expected case) from 0.53 to 0.47 percent. [25]

Q. What do you conclude about Avista's load inputs in Aurora?

A. The Company's rate year hourly and monthly loads in the model are overstated and inaccurate, and therefore, do not contribute to an accurate ERM baseline.

2. Hourly Shapes

Q. How do hourly load shapes affect the AURORA model?

A. Hourly shapes are the change in load for every hour of the year. This "shapes" the generation and market dispatch based on the natural swings in power consumption by consumers throughout the day and season. In my Exh. DCG-11, the Company explains how it shapes its rate year monthly loads into hourly amounts for use in the

[25] In a study titled, *Load Forecasting in Electric Utility Integrated Resource Planning,* sponsored by the U.S. Department of Energy's Office of Electric Delivery and Energy Reliability (October 2016), the accuracy of Avista's forecast of its average annual growth in load along with its peak demand forecasts are called into question. The report's Table 6 on page 22 and Tables 19 and 20, on pages 30 and 31, provide additional analysis on the performance of Avista's forecasts of its native loads in its 2006-2014 IRPs (See https://emp.lbl.gov/sites/all/files/lbnl-1006395.pdf).

AURORA model. Avista uses its actual hourly loads for 2016 divided by the corresponding 2016 actual average monthly load to arrive at its rate year percentage of monthly load for each hour of the simulation.

Q. Is this an acceptable approach for shaping hourly load?

A. No. This approach is unreasonable because it assumes this same hourly shape will be repeated in the upcoming rate year. Intuitively, one would expect the daily and hourly loads to vary from year-to-year due to different weather conditions. The difference in weather conditions must be accounted for and normalized in order to avoid introducing a bias into the model's rate year results.

Q. Avista defends the approach on the basis that normalizing hourly load shapes for use in AURORA would be inaccurate.[26] Do you agree with this statement?

A. No. The opposite is true. In my Exh. DCG-12, Staff averaged and compared these actual hourly loads to the hourly percentages from the single year the Company used. Doing so revealed that the hourly load percentages used by Avista, when compared to a three-year average, vary by about ten percent (plus or minus five percent) in the high load hours, which are typically also the most costly. Additionally, Staff referred to publicly available data sets available from the National Oceanic and Atmospheric Administration (NOAA), and from the National Centers for Environmental Information which provide historical hourly air temperatures in Spokane. Exh. DCG-7 provides NOAA's hourly temperatures for January 1st for the

[26] Gomez, Exh. DCG-11.

years 2013-2016, which can and should be normalized as part of Avista's AURORA study.

Q. What do you conclude about Avista's hourly shaping in Aurora?

A. The Company's shaping in the model is based on a faulty premise that does not contribute to an accurate ERM baseline.

3. Forced Outage Rates

Q. How do Forced Outage Rates affect the AURORA model?

A. Forced Outage Rates reduce the amount of available capacity from a specific generation resource. When a unit or plant has an unscheduled interruption, this is reflected in the model by a reduction in available generation.

Q. What did you learn about Avista's forced outage value inputs for its peaker plants?

A. For the Company's peaker plants, the forced outage values used by Avista in the model for its last three rate cases are provided in Table 3 below.

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 2: AURORA Forced Outage Rates for Avista Peakers

The workpapers supporting these values were not provided along with the prefiled direct or supplemental testimony of Mr. Kalich.[27] Consequently, Staff was forced to issue several discovery requests to Avista, attached as Exh. DCG-13.

Q. Why did Avista not update its values for Northeast and Rathdrum?

A. The Company claims that limited operation of these two plants does not provide a good enough sample size to calculate forced outage rates. The Company goes on to say that the values used for these two plants have remained unchanged since 2005 and that they are based on an "assumption" without further explanation.[28] Avista defends the assumed five percent outage factor by saying that these values result in lower power costs than would have been derived using the Generating Availability Data System (GADS) of North American Electric Reliability Corporation (NERC).

[27] In Part A of its response to Staff's discovery request contained in my Exh. DCG-13, Avista explains that Boulder Park's outage factor percentages in Table 2 (this case) were calculated using the workpapers originally provided to update station service costs in the model. The calculations in confidential Attachment A of the Company's response were not present in their station service cost workpapers at the time of their original filing and were provided after the fact in discovery.

[28] Gomez, Exh. DCG-13, Avista's Response to UTC Staff Data Request No. 200, at Part B.

Q. Does Avista's justification for the forced outage rates make sense?

A. No. The spreadsheet Avista used to update Boulder Park's outage factors contained the same information for both Rathdrum and Northeast. Further, Avista seems to assume Staff's objective in examining these and other AURORA values is to lower the Company's revenue requirement in this case, which is fundamentally incorrect.

Q. What about outage factors for Avista's other thermal resources?

A. Mr. Kalich's workpapers supporting the thermal resource settings in AURORA for forced outages relies on a five-year rolling average for Coyote Springs 2, Lancaster and Kettle Falls, and a six-year rolling average for Colstrip. These values appear to be calculated using methodologies agreed to in previous cases.

Q. What about outage factors for other non-Avista resources in the Western Interconnect?

A. Apparently, Avista periodically updates this data with new GADS data as the estimates of forced outage rates for these resources, which do not change materially from year to year.

Importantly, the forced outage rates for non-Avista resources, regardless of their value, "[have] no impact on the results of this case; electricity market prices are trued up to forward prices".[29] This last statement appears to contradict Mr. Kalich's supplemental testimony: "Avista models all Western Interconnect loads, resources

[29] Gomez, Exh. DCG-13 at 3 (emphasis added).

and transmission to properly emulate the electric marketplace Avista operates within."[30]

Q. Do the outage values reflect any reliability improvements?

A. No. Avista witness Mr. Scott Kinney reports that since 2012 the Company has expended over $2 million in capital to improve the reliability of the Company's peaker plants.[31] In response to discovery, Avista claims that capital projects are not always intended to improve a plant's reliability, but instead can be used to maintain the existing performance of the plants.[32] This response is out of step with the authors of the business case, Avista's Generation Production and Substation Support group, who expect as a result of this spending that, "forced outage rates and forced derates of these [peaker] facilities will decrease to a level one standard deviation less than the current average resulting in more economic benefits for the project."[33] Apparently, the Company's modeling of its rate year power costs does not reflect any benefit resulting from the capital project, which ratepayers have been funding.

Q. What do you conclude about Avista's forced outage rate assumptions?

A. The Company failed to rely on accurate data for the forced outage rates, which distorts the amount of imbedded low cost generation available for native loads or

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[30] Kalich, Exh. CGK-3T at 8:17-18.
[31] Kinney, Exh. SJK-4 at 64-66.
[32] Gomez, Exh. DCG-13 at 2.
[33] Kinney, Exh. SJK-4 at 64.

market sales. In addition, the Company has failed to account for the value of any reliability improvements it has performed as a part of its recent capital expenditures.

4. Variable Operating and Maintenance Values

Q. What is variable operating and maintenance (VOM)?

A. VOM is an important factor in determining when a plant generates electricity because it represents the marginal cost of a unit or plant. Under the rules of economic dispatch, resources are dispatched starting with the lowest cost option, generally those with a zero dollar, and sometimes lower, VOM. As more resources are dispatched to meet load, higher and higher VOM values for that hour are included in the variable operating costs of the power portfolio. The total VOM operating costs of all 8760 hours is a key component of the ERM baseline. Exh. DCG-14C provides a table containing Avista's AURORA model VOM inputs for its thermal generating resources from this rate case and the two prior.

Q. What were your findings regarding the VOM values in AURORA?

A. According to the Company, the AURORA values are:

> [E]ntered in 2012 dollars (the economic base year in the model set by the vendor), and are escalated for inflation by the model. Variable O&M come from the Company's Energy Position Report and have not been updated; the specific Energy Position Report from which these values were obtained is not known.[34]

[34] Gomez, Exh. DCG-14.

In other words, Avista's VOM model input *assumptions* do not reflect its thermal fleet's *actual* VOM values. Additionally, the VOM values for Coyote Springs 2, included in Exh. DCG-14, appear to be incorrect as they match VOM values in AURORA attributed to Colstrip 3 & 4.

Q. What do you conclude as a result?

A. Mr. Kalich's confidential Exh. CGK-2C shows that Avista's thermal resources account for [redacted] aMW ([redacted] percent) of Avista's total rate year load.[35] Given that over half of Avista's total generation in the rate year was arrived at in the model using incorrect VOM values, the overall model results are fundamentally flawed. The ERM baseline cannot be set using such faulty data.

5. Marginal Cost Adders

Q. What are Marginal Cost Adders?

A. Avista's practice since 2012 has been to assign large negative "adders" to the marginal cost of hydro projects and renewable resources within AURORA.[36] These adders change the dispatch order by changing the price point at which it is economical to dispatch. Importantly, these adders do not change the VOM costs

[35] *See, e.g.,* Kalich, Exh. CGK-2C at 3. Two-thirds of the Company's rate year thermal generation are from three plants: Colstrip 3 & 4, Coyote Springs 2 and Lancaster.
[36] In AURORA, these optional values can be specified by the user as an optional input in the Resources Table as a either a "VAR Cost Mod 1", "VAR Cost Mod 2" or "Bidding Adder".

reflected in the final portfolio; they just change when and how often a unit is dispatched to meet load.

Q. Is this an appropriate adjustment to the model?

A. No. The Company has no data to support these negative $MWh values.[37] It can provide no study or analysis that this adjustment to the model captures the "impacts of negative prices when the Northwest is oversupplied" or that it shapes "generation and resulting market prices [in the model] to emulate market conditions" as Mr. Kalich claims.[38] In my confidential Exh. DCG-9C, I provide a sample of the hydro and renewable resources modeled in AURORA along with their corresponding negative marginal cost adders going back to the 2015 general rate case.

Q. How has the Company historically assigned these costs?

A. According to Mr. Kalich's supplemental testimony, the typical negative marginal cost adder assigned to hydro projects is -$[redacted] per MWh with Avista's hydro resources receiving a lower adder of -$[redacted] per MWh.[39]

Q. In its last three rate cases has the Company assigned values for hydro in the model consistent with Mr. Kalich's statement?

[37] Gomez, Exh. DCG-15, Avista's Response to UTC Staff Data Request No. 202, at Part A.
[38] Kalich, Exh. CGK-3T at 12:14-16 and 13:7-9.
[39] Kalich, Exh. CGK-3T at 12:21 and 13:2.

A. No. As is shown in my confidential Exh. DCG-9C, the negative marginal cost adders employed by the Company in its last two rate cases are different than those in its current filing. For example, in this case Avista assigns a negative marginal cost adder of negative $[redacted] for Little Falls. In Avista's 2016 and 2015 cases, Avista assigned a negative $[redacted] marginal cost adder for Little Falls.[40] When asked about this inconsistency, the Company offers the following alternative explanation in discovery:

> The extra value was to reflect additional value on top of regional resources so the units would not turn off per our license obligation. In this case, rather than having both values, it was simpler to include a single higher value in the bidding adder.[41]

This answer fails to show how these adders improve in any way the accuracy of the model's results or reflect the actual operation of Avista's system.

Q. Are marginal cost adders limited to hydro resources?

A. No. Avista also applies negative marginal cost adders to the dispatch price of renewable resources (wind and solar) in order to model the effect of Production Tax Credits (PTC) and Renewable Energy Credits (REC).[42] In examining the values in the model from UE-150204 and the ones in this case, I found Avista applies negative marginal cost adders for wind resources ranging from -$[redacted] to -$[redacted] MWh in the model. The wind resources receiving the lowest marginal cost adder included values

[40] In the AURORA Resources Table, Var Cost Mod 1 of -$75 plus a Bidding Adder of -$50.
[41] Gomez, Exh. DCG-15, Avista's Response to UTC Staff Data Request No. 202, at 3, Part E.
[42] Kalich, Exh. CGK-3T at 12:21 - 13:3.

for both PTCs and RECs (-$[redacted] MWh)[43] with an additional amount included in the Bidding Adder column of -$[redacted] MWh. For solar PTCs, the Company assigns a negative marginal cost adder of -$[redacted] MWh except for its own solar resources, Rathdrum Solar and Avista Community Solar, which do not include a negative marginal cost adder for PTCs or RECs. For Rathdrum Solar and Avista Community Solar, the Company includes a negative marginal cost adder of -$[redacted] in this case and -$[redacted] in UE-150204.[44]

Q. Has the Company provided any evidence or analysis to justify negative marginal cost values for renewable resources in AURORA?

A. No. The Company has included no workpapers or analysis in support of these values.

Q. For Kettle Falls, the Company includes a marginal cost adder of negative $[redacted] to account for the REC value of this resource in the model's dispatch.[45] Were you able to validate this amount using workpapers from Avista's 2016 REC Revenue Mechanism annual filing?

A. No. In UE-160346, in its REC tariff adjustment filing, Avista reported that Kettle Falls generated $5.1 million in REC sales for the 12-month period spanning July

[43] PTC values are entered in the Var Cost Mod 1 field as an annual time series while REC values are input in the Var Cost Mod 2 field.
[44] These values are located in the "Bidding Adder" column in the AURORA model.
[45] See Mr. Kalich's response to UTC Staff Data Request No. 202, Part B, in my Exh. DCG-15.

2016 through June 2017.[46] Dividing the $5.1 million in REC revenues for 2016 with the level of generation reported for the plant on SNL produces an amount closer to $15 MWh. This further illustrates the disconnect between the Company's negative marginal cost adders in the model and reality.

Q. What are your conclusions regarding negative marginal adders?

A. The Company's inputs are not supported by facts or data that Staff or other parties can independently audit or rely on. These inputs directly affect the dispatch of hydro and renewable resources throughout the Western Interconnect in the rate year simulation. The lack of transparency in how Avista arrived at these input values projects serious doubt as to the accuracy of these forecasts, and thus, the Company's requested increase to the ERM baseline.

6. Resource Dispatch Margin

Q. What is the resource dispatch margin?

A. The "resource dispatch margin" is an additional percentage margin applied to all resources' marginal costs in the model's hourly dispatch.[47] Avista adjusts these margins to align the AURORA generated market prices to the Company's forward

[46] One large sale accounted for 80 percent of the REC revenue for this resource.

[47] AURORAxmp Model Help Menu; Dispatch and Demand. A resource dispatch margin is applied to all resources that do not have bidding already specified. However, the resource dispatch margin percentage is not applied to the marginal cost of an individual resource which contains values in the bidding adder or bidding factor fields. Hydro and wind resources in the 2015 GRC and this case are assigned large negative marginal cost adders (bidding adders) in the model. Therefore, the resource dispatch margin specified by Avista does not apply to these resources in the studies.

price curves.[48] This forecast is important as it underpins the results by which Avista calculates its rate year power costs.

Q. Why does Avista make adjustments to match market forwards?

A. Avista claims that these adjustments are in line with a 2005 Commission order that supports adjustments to the AURORA model results to match external forecast of energy market prices at the MidC trading hub.[49]

Q. Should the Company continue adjusting the AURORA model to match market forwards?

A. No. The Commission should reject this modeling practice. The abundance of inaccurate and unsupported inputs that Avista relies on casts serious doubt on the accuracy and usefulness of manipulating the model in this manner. Mr. Kalich's supplementary testimony also demonstrates that Avista has gone far beyond just simply making adjustments to AURORA "bidding factors" to make modeled market prices match forwards.

Moreover, the Commission qualified its support for adjusting the model to match market forwards on the basis that it produce "accurate estimates of actual costs that the Company will experience in the near and intermediate terms."[50] The

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[48] Kalich, Exh. CGK-3T at 10:1-6.
[49] *See Wash. Utils. & Transp. Comm'n v. Avista Corporation*, UE-050482, Order 05, ¶¶ 106-107 (Dec. 21, 2005).
[50] UE-050482, Order 05 at ¶ 106.

annual poor performance of Avista's power cost forecasts alone justifies no longer accepting this practice.

Q. Mr. Kalich uses the terms "bidding factor", "bidding adder" and "resource dispatch margin" interchangeably.[51] Do these terms refer to the same inputs in the AURORA model?

A. No. The terms "bidding factor" and "bidding adder" refer to separate inputs in the model which accomplish the same objective; to simulate bidding at prices that are greater (or less than) the cost of an <u>individual resource</u>.[52] Mr. Kalich's reference to these two inputs in his supplemental testimony is confusing since Avista is actually referring to the resource dispatch margin.[53]

Q. What is the Company's procedure or process to arrive at these resource dispatch margin percentages?

A. The Company offers the following explanation for how it arrives at resource margin percentages in the model:

> The Company staff estimates these values by running the model with a 5 percent margin. Then the Company compares the resultant monthly on and off peak electric prices to forwards. If the price is materially different, the dispatch margin by month is changed and the model is run again to determine if the change was adequate to match model prices to forward prices. If forward prices cannot be replicated in the model by changing dispatch margin between 0 and 10 percent, then other modeling assumptions are used (as

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[51] Kalich, Exh. CGK-3T at 9:14 - 10:16.
[52] AURORAxmp Model Help Menu; Resources Table. These values can be a positive or negative $MWh adjustment to the marginal cost of the resource.
[53] AURORAxmp Model Help Menu; Dispatch and Demand. A resource dispatch margin is applied to all resources that do not have bidding already specified.

> described in testimony). This is an iterative process and the Company does not retain the iterative studies.[54]

Earlier in my testimony, I identify issues with the marginal cost (VOM values) Avista assigns to its gas-fired resources in the model. The Company's application of dummy margin values, particularly because these higher margin adders are applied in the high cost winter months, further skews the already inaccurate marginal cost VOM values for these important resources.

Q. Did Staff evaluate the accuracy of previous forecasts of MidC prices presented by Avista in the last three rate cases?[55]

A. Yes. Staff evaluated Mr. Kalich's forecast of MidC energy prices presented in his testimony in the last three rate cases. Through discovery, Staff also asked the Company to provide these same forecasts before adjustments were made by the Company to match model prices to forward prices.[56] Staff then compared the Company's forecasts of monthly MidC market prices against actuals for both on and off-peak.

Q. Were Avista's previous forecasts of MidC prices accurate?

A. No. Staff's Exh. DCG-10 demonstrates that Avista's forecasts of MidC market prices are inaccurate. Importantly, the forecasts are inaccurate both before and after

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[54] Gomez, Exh. DCG-15, Avista's Response to UTC Staff Data Request No. 202, at Part G.
[55] Kalich, Exh. CGK-1T in UE-140188 at 5:6-16; Exh. CGK-1T in UE-150204 at 5:1-20; and Exh. CGK-1T in UE-160228 at 5:3-22.
[56] Gomez, Exh. DCG-16, Avista's Response to UTC Staff Data Request No. 224.

the Company adjusts the model's inputs to get the results to match its market forwards.[57] Avista has provided no back cast of model results or evidence in response to discovery which support the practice of matching prices to forwards.

Q. Is the resource dispatch margin the only way to match market forwards?

A. No. Mr. Kalich states that setting the resource dispatch margin too high can cause problems with how the model dispatches resources in the study. As a result, Avista has to tinker with other variables and settings in AURORA to get the model results they are looking for. For example, Mr. Kalich increased forecasted regional loads in the high cost winter and late summer months to make the model match forwards.[58]

Q. Are these other adjustments reasonable?

A. No. Staff compared the Company's adjustment to regional monthly loads in the model against the regional forecast of monthly loads from the Pacific Northwest Utilities Conference Committee (PNUCC) for the 2016-17 and 2017-18 operating year.[59] PNUCC is an organization of public and private utilities that assesses regional power supply in the West.[60] The results of this comparison are provided in Table 4 below. In Staff's opinion, these inflated regional load assumptions have no basis in

[57] In response to discovery, Avista states that it recreated MidC prices before adjustment by re-running the model using AURORA project files from the previous cases. The information provided is the Company's best estimate of the prices without the market adjustments. Gomez, Exh. DCG-16, Avista's Response to UTC Staff Data Request No. 224.
[58] Kalich, Exh. CGK-3T at 11:13-19.
[59] http://www.pnucc.org/system-planning/northwest-regional-forecast.
[60] http://www.pnucc.org/about-pnucc.

fact and, when combined with Avista's already overstated rate year loads, are a recipe for an inaccurate ERM baseline.

Month	Avista	PNUCC
Jan	+10%	0%
Feb	+10%	-1%
Mar	+8%	-1%
Apr	+7%	-1%
May	0%	-1%
Jun	0%	0%
Jul	0%	-2%
Aug	+8%	0%
Sep	+8%	-1%
Oct	0%	-1%
Nov	+5%	0%
Dec	+8%	0%

Table 3: Avista Regional Load Increase Modeled in AURORA vs PNUCC

B. Model Settings

Q. What changes did Avista make to the AURORA model system settings?

A. Mr. Kalich's supplemental testimony describes several changes the Company made in this case to the model's "Dispatch Settings."[61] According to his testimony, the previous dispatch setting used in UE-150204 "changes market prices in a way not tied to the cost of the regions' unit on the margin."[62]

[61] Kalich, Exh. CGK-3T at 16:15 - 17:6.
[62] Kalich, Exh. CGK-3T at 17:1-2.

Q. What rationale did the Company provide to justify these changes?

A. When asked by Staff in discovery for the purpose of these dispatch setting changes, Mr. Kalich provided the following explanation:

> Unlike in the previous case, this feature was not necessary to make modeled prices similar to forward prices for this case.[63]

This illustrates the difficulty faced by Staff and other parties in validating Avista's model results. The testimony provided by the Company is only a surface level discussion of the underlying issue. Only through discovery and weeks of analysis can Staff begin to understand the true impact of Avista's modeling adjustments. Effectively, this shifts the burden of proof from the Company to Staff and other responding parties to show why a modeling adjustment is unwarranted.

C. Out of Model Adjustments

Q. How are wholesale power and natural gas contracts incorporated into AURORA?

A. AURORA is not used to value Avista's wholesale power and natural gas contracts. According to Mr. Kalich, the summarization of costs from AURORA include these contract quantities at "no cost." Avista witness Mr. Johnson is then responsible for pricing these contracts.[64]

[63] Gomez, Exh. DCG-15, Avista's Response to UTC Staff Data Request No. 202, at Part H (emphasis added).
[64] Kalich, Exh. CGK-3T at 6:1-12.

Q. Does Staff have concerns with Avista's out-of-model adjustments to power costs?

A. Yes. Mr. Kalich's explanation of how these contracts are modeled and ultimately priced is not very clear.[65] Examining Mr. Johnson's workpapers,[66] Staff finds that rate year contract revenues and costs for Nichols Pumping, Energy America, and Priest Rapids are priced based on AURORA modeled prices at MidC. So in actuality, these contract's contribution to rate year power costs are determined entirely by the model.

For example, in the Nichols Pumping contract, Avista uses a negative $2.16 MWh price in the model to determine the amount of rate year sales (in MWhs), but it then uses an altogether different price of negative $19.21 MWh based on the model's MidC forecasts to calculate revenue. As a result, revenues associated with this contract are understated in the rate year.

WNP-3 provides another example. Mr. Johnson prices the contract in the rate year outside of the model at $44.325 MWh but the model determines the level of dispatch at a price of $41.61 MWh. This is a clear disconnect in price with no explanation provided.

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[65] Kalich, Exh. CGK-3T at 6:1 - 7:7.
[66] Johnson workpaper titled "Workpaper Index.xlsx".

V. SUMMARY AND RECOMMENDATIONS

Q. Given all the issues you have uncovered with Avista's power cost modeling, what is your recommendation regarding the proposed increase to the ERM baseline?

A. The Commission should reject the Company's proposed increase in power cost expense in this case and maintain the current ERM baseline. The Company has failed, for two reasons, to show that the baseline should be altered: (1) Avista's approach to modeling power costs has consistently produced inaccurate results which have allowed the Company to profit at the expense of its customers, and (2) Avista's manipulations within AURORA are undocumented and unsupported.

Avista provided jargon-filled testimony that masks numerous arbitrary adjustments. Avista relies on these adjustments to take a deterministic model and make it produce results that support their annual increases to the ERM baseline. As a result, Staff and other parties are unable to use the model in its present state to either validate the Company's results or offer an alternative baseline rate.

The present level of customer credit balance on the Company's books coupled with the protections afforded the Company under the ERM mechanism are sufficient for now.

Q. What about Avista's proposal for a three year rate plan?

A. The Commission should accept Staff's alternative rate plan proposal and maintain the current power cost baseline until a) Avista's next general rate case or b) the total credit balance owed to ratepayers of $21.3 million falls below $10 million, whichever occurs sooner. During the pendency of the rate plan, Avista can use the time to completely overhaul its power cost modeling and approach. Avista needs to shift its modeling paradigm away from arriving at inaccurate estimates of rate year power costs that maximize its share under the bands while minimizing its downside risk. Instead Avista should recommit itself to the original intent of the ERM, which is to equitably and fairly share risk and rewards with its customers.

Q. Do you think changes to the ERM are warranted at this point?

A. No. The ERM mechanism is more than just an accounting mechanism; it is a form of performance based regulation. For it to function effectively, Avista must produce a reasonable forecast at the beginning of the deferral period. Further, month-to-month and year-to-year variances of forecasts to actuals should be investigated by the Company to determine their source in order to improve future year estimates.

Q. Does this conclude your testimony?

A. Yes.