AVISTA

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April 6, 2017

Via Electronic Filing, Huddle and Overnight Mail

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3612

RE: Docket No. UG 325 – Reply Testimony of Avista Corporation

Attached are an original and five copies of the Reply Testimony of Avista Corporation, dba Avista Utilities, in Docket No. UG-325.

In addition, Avista's CONFIDENTIAL Exhibit Nos. 1101 and 1102 are being provided under sealed separate envelopes, marked CONFIDENTIAL.

Please direct any questions regarding this filing to Patrick Ehrbar at (509) 495-8620 or Jennifer Smith at (509) 495-2098.

Sincerely,

David J. Meyer
Vice President and Chief Counsel for Regulatory and Governmental Affairs

Enclosure

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served Reply Testimony and Exhibits in the Oregon Natural Gas General Rate Case Filing of Avista Utilities, a division of Avista Corporation, (Docket No. UG-325) upon the parties listed below by mailing a copy thereof, postage prepaid and/or by electronic mail.

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I declare under penalty of perjury that the foregoing is true and correct.

Dated at Spokane, Washington this 6th day of April 2017.

Patrick Ehrbar
Senior Manager, Rates & Tariffs

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

REPLY TESTIMONY OF KELLY O. NORWOOD
REPRESENTING AVISTA CORPORATION

Policy Response

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation?

A. My name is Kelly O. Norwood. I am employed by Avista Utilities as the Vice-President of State and Federal Regulation. My business address is 1411 E. Mission Avenue, Spokane, Washington.

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

A. Yes. I am a graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. I joined the Company in June of 1981. Over the past 35 years, I have spent approximately 24 years in the Rates Department with involvement in cost of service, rate design, revenue requirements and other aspects of ratemaking. I spent approximately 11 years in the Energy Resources Department in a variety of roles, with involvement in resource planning, system operations, resource analysis, negotiation of power contracts, and risk management. I was appointed Vice-President of State & Federal Regulation in March 2002.

Q. What is the purpose of your reply testimony in this docket?

A. Since Avista initially filed this case on November 30, 2016, a number of changes and corrections to the Company's proposed revenue requirement have been identified. Some of these changes/corrections were identified by the Company as we responded to discovery requests and/or received updated information, while other changes/corrections were identified by other parties to the case. I will summarize Avista's revised revenue requirement in its reply testimony that incorporates these changes/corrections.

I will also respond to a number of broad statements made by Staff and CUB witnesses in support of their adjustments to reduce rate base in this case. In addition, my testimony includes a summary of the reply testimony of each of the other Company witnesses.

Q. How is your testimony organized?

A. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits with your testimony?

A. Yes, I am sponsoring Exhibit No. 1001 which contains the results of analyses conducted in Synergi® for the La Grande, Medford, Roseburg and Klamath Falls areas of our service territory. This information was provided to the parties in response to CUB data request No. 115.

II. REVISED REVENUE REQUIREMENT AND AREAS OF AGREEMENT

Q. What is the Company's revised revenue requirement in this case?

A. The Company's revised revenue requirement is $6.748 million, or 7.2% on a billed revenue basis. This revised revenue requirement is approximately $1.8 million lower than the Company's original request of $8.539 million.

Q. Are there adjustments made by the parties that the Company accepts?

A. Yes. Table No. 1 below summarizes the adjustments for which Avista has either fully accepted or partially accepted. It also includes adjustments based on updated information and corrections since the original filing date, and the resulting revised revenue requirement of $6.748 million for Avista in this case.

Table No. 1:

SUMMARY OF ACCEPTED AND PARTIALLY ACCEPTED ADJUSTMENTS TO FILED REVENUE REQUIREMENT AND RATE BASE
000s of Dollars

		Rev. Req. Incr / (Dec)	Rate Base Incr / (Dec)
Revenue Requirement As Filed by Avista		**$ 8,539**	**$ 243,424**
Fully Accepted Adjustments Proposed by Staff			
S-11	Pension Adjustment	(265)	(170)
S-14	Underground Storage Adjustment	(21)	-
S-18	Load Forecasting Adjustment	(394)	-
S-19	Sales & Transportation Adjustment	39	-
S-26	Atmospheric Testing Adjustment	(66)	-
	Total of Adjustments Fully Accepted to Revenue Requirement and Rate Base	$ (707)	$ (170)
Partially Accepted Adjustments Proposed by Staff			
S-01.1	Uncollectible Expense Adjustment	(267)	-
S-01.2	Uncollectible Rate Adjustment	(52)	-
S-01.3	OPUC & Franchise Fees Adjustment	(47)	-
S-02	Interest Synchronization Adjustment	(20)	-
S-15	Other Gas Supply Adjustment	(18)	-
S-21.1	Information Technology Adjustment	(353)	(514)
S-21.2	General Plant Adjustment	(1)	(5)
S-22.1	Cost Allocation Adjustment	(92)	(236)
S-22.2	Affiliated Interest Adjustment	(15)	(34)
S-23	Utility Plant in Service Adjustment	(185)	(1,715)
S-27	Customer Service & Information Sales, Advertising and Promotional Expense Adjustment	(5)	-
S-32.1	Meals & Entertainment, Travel, Gifts and Awards	(31)	-
	Total of Adjustments Partially Accepted to Revenue Requirement and Rate Base	$ (1,084)	$ (2,504)
	Adjusted Revenue Requirement and Rate Base after Accepted Adjustments	**$ 6,748**	**$ 240,750**

Avista witness Ms. Smith provides additional details related to the adjusted revenue requirement.

Q. Are there other areas of general agreement related to non-revenue

requirement issues?

A. Yes. Although there is not full agreement on the details of the long-run incremental cost study (LRIC Study), both NWIGU and Staff agree that the guidance provided by the results of Avista's LRIC Study for rate-spread purposes, moves the rate schedules in the right direction. Avista supports Staff's rate design proposal, which would increase the basic charge for Schedule 410 by $1 per month to $10 per month, and keeping the basic charge for Schedule 420 unchanged at $17 per month.

Q. What are the major remaining differences in this case between Avista and the other parties?

A. There are four primary areas of disagreement between Avista and the other parties in this case that make up the majority of the difference in the proposed revenue requirement. These areas are: 1) the level of capital expenditures (or rate base) to include in this case; 2) the cost of capital; 3) certain utility expenses; and 4) allocations of rate base and expenses, common to all jurisdictions, to Oregon operations.

Avista's response to the specific proposed rate base adjustments by the parties will be addressed primarily by Company witnesses, Heather Rosentrater (distribution infrastructure), James Kensok (information technology), and David Machado (facilities common to all jurisdictions). The Company's response to cost of capital issues is provided by Company witness Mark Thies and Adrien McKenzie who is also sponsoring reply testimony on behalf of the Company.

Company witness Jennifer Smith responds to the proposed adjustments by the parties related to utility expenses, and Patrick Ehrbar addresses the issues raised by the parties related to allocations among the jurisdictions in which Avista operates.

III. RESPONSE TO BROAD STATEMENTS ON CAPITAL EXPENDITURES

Q. Commission Staff and CUB express concerns related to the level of Avista's capital investment, and in particular CUB witness Jaime McGovern suggests that Avista is putting shareholders first with regard to its capital investment decisions.[1] What is Avista's response to this testimony?

A. There is no evidence to support a claim that the capital investment included in this case is being driven by shareholder interests. There is substantial evidence presented by Avista, however, that demonstrates that both the completed and planned investments are necessary for the Company to continue to provide safe, reliable service to customers, and to meet the future needs and expectations of customers. As Mr. Thies explained in his opening testimony:

> Avista has typically chosen to not fund all of the capital investment projects proposed by the various departments, driven primarily by the Company's desire to mitigate the retail rate effects on customers. Decisions to delay funding certain projects are made only in cases where the Company believes the amount of risk associated with the delay is reasonable and prudent. In fact, in 2016 and 2017, the dollar amount of capital projects funded was below the amount requested by individual departments by $70 million and $62 million, respectively, for Avista as a whole.

The Company takes seriously its responsibility to provide reliable service to customers, and is investing where necessary to meet this responsibility. This is consistent with the Commission's urging of Avista "to maintain up-to-date analyses to ensure adequacy of supply to customers."[2]

Ms. McGovern makes reference to future rate base growth information and future earnings per share (EPS) growth information that is prepared by Avista and provided to

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[1] For example, Moore, page 5, line 1, and page 6, line 8, and McGovern, page 23, "the Company is putting its shareholders first."
[2] Docket No. UG-288, Order No. 16-109, page 13.

management of the Company, the board of directors, rating agencies and securities analysts, among others.[3] The fact is, responsible investment by Avista in the ongoing operation of its natural gas business will result in some level of rate base growth and EPS growth over time. These growth numbers over time reflect the results or outcome of the Company acting responsibly in carrying out its duties to provide a safe, reliable natural gas system for customers. The fact that these charts and graphs exist is not evidence that investment decisions are driven by the results shown on the graph. There is nothing in the presentation of those materials that represents evidence of Avista putting shareholders first, or that capital investment decisions are driven by earnings projections. In fact, just the opposite is true; the earnings projections result from the investment necessary to preserve a safe, reliable natural gas system.

Decisions by the Commission are to be based on sound evidence in the case. The Commission should not be misled by unsubstantiated allegations or the suggestion of appearances, such as those offered by Ms. McGovern.

Q. Beginning on page 6 of Staff witness Mitch Moore's testimony, he compares Avista's capital investment and retail rate adjustments to that of other natural gas utilities in Oregon.[4] Is this information relevant to Avista's capital investment and the proposed retail rate adjustment by Avista is this case?

A. No. Other utilities currently, as well as in recent years, may be facing circumstances that are far different than Avista. These differing circumstances may result in more frequent or less frequent revenue adjustments. The revenue adjustments proposed by Avista are specific to the investment needs and operating costs for Avista's Oregon operations, which are necessary for Avista to continue to provide safe, reliable service, and satisfy

[3] CUB/100, McGovern pp. 5-7, CUB/105 pp.1-12.
[4] Staff/800, Moore/pp 6-8.

numerous compliance requirements.

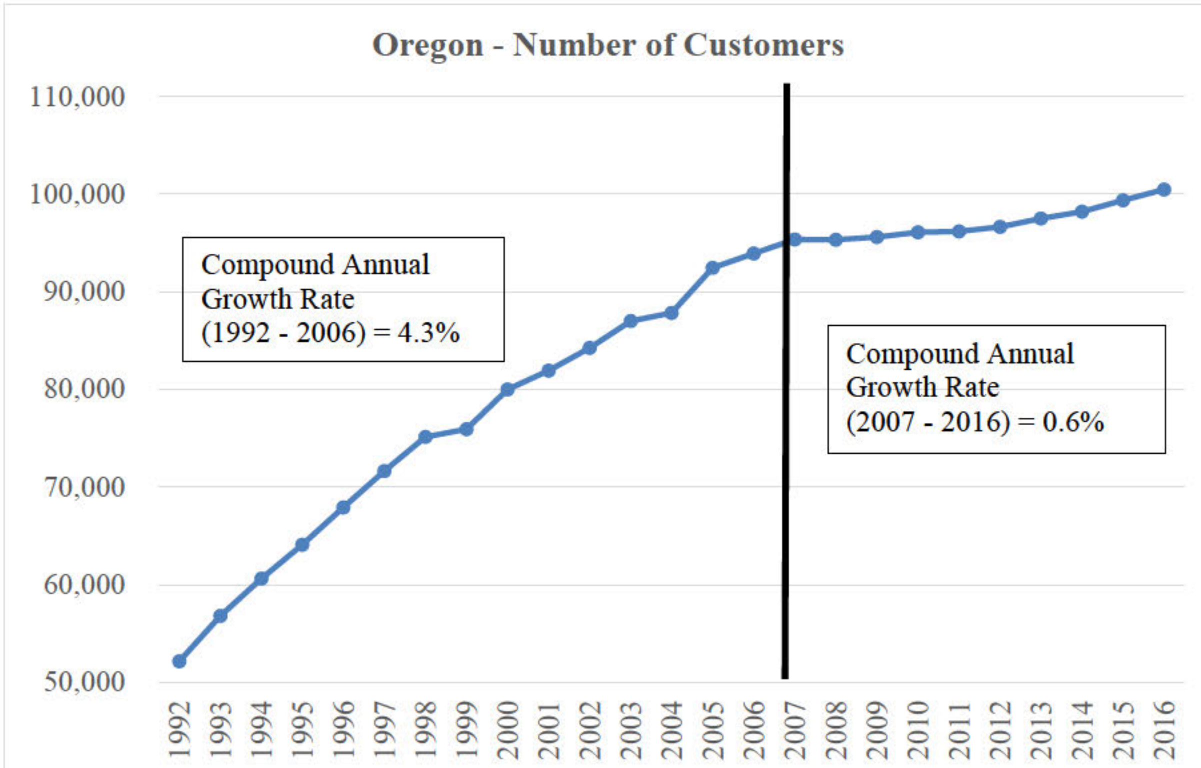
The frequency or magnitude of Avista's needed rate adjustments, as compared to other utilities, should have no bearing on whether Avista's proposed rate adjustments are reasonable and appropriate. Likewise, the level of capital investment currently being made by other regional natural gas utilities, as compared to that being made by Avista, should not be the "measuring stick" in the determination of whether Avista's capital investment is necessary and reasonable.

Q. With regard to Mr. Moore's suggested comparison of Avista's proposed revenue adjustments versus those of other natural gas utilities, has Avista experienced an extended period of time with little or no general rate increases?

A. Yes. In 1991 Avista acquired the Oregon and California natural gas service territories from CP National, and began doing business in Oregon as WP Natural Gas (WPNG). WPNG implemented a 0.50% decrease in base rates at that time and instituted a four and one-half year rate freeze. Between 1991 and 2003 Avista had two general rate cases, both of which resulted in <u>rate reductions</u> for customers. Limited rate adjustments during that period were based on the specific circumstances for Avista's Oregon utility operations during that time.

One of those circumstances was the higher level of customer growth, therm sales growth, and the resulting revenue growth that occurred during the period, which offset the need for base rate increases. As shown in Illustration No. 1 below, the Company experienced compound annual growth in number of customers of 4.3% from 1992 through 2006, as compared to 0.6% from 2007 to present.

Illustration No. 1: Oregon Number of Customers 1992-2016:



Avista's proposed revenue adjustment in this case should be evaluated based on the specific facts and circumstances facing Avista at this time, and not circumstances the Company experienced in the past, which are no longer relevant today.

Q. Is the slow growth in number of customers, as well as the continuing reduction in use-per-customer, contributing to the need for rate relief in this case?

A. Yes. One of the primary drivers of the need for a revenue increase in this case is the overall slow growth in the number of new customers and the continuing reduction in use-per-customer. The Company is simply not seeing therm sales growth in the system – growth which would help offset the costs associated with the Company's capital investment.

And just because the Company is not seeing major customer growth or therm sales growth does not mean that it does not need to invest in its system. Avista has demonstrated in prior cases, and in this case, that it needs to continue to maintain, upgrade, and expand its distribution facilities to meet reliability requirements and capacity needs. The need for capital investment is driven by, among other factors, capacity constraints, its 20-year program to systematically remove and replace select portions of the Aldyl-A pipe in the Company's natural gas distribution system, the systematic replacement of assets that have reached the end of their useful lives, compliance with federal regulations (e.g., PHMSA rules) or municipal requirements (e.g., street/highway relocations), connections of new customers, the systematic replacement of aged and obsolete technology, and the replacement of supporting facilities and technology.

Q. What is the Company's response to Mr. Moore's statement that Cascade Natural Gas (Cascade) is a "similarly situated Company?"

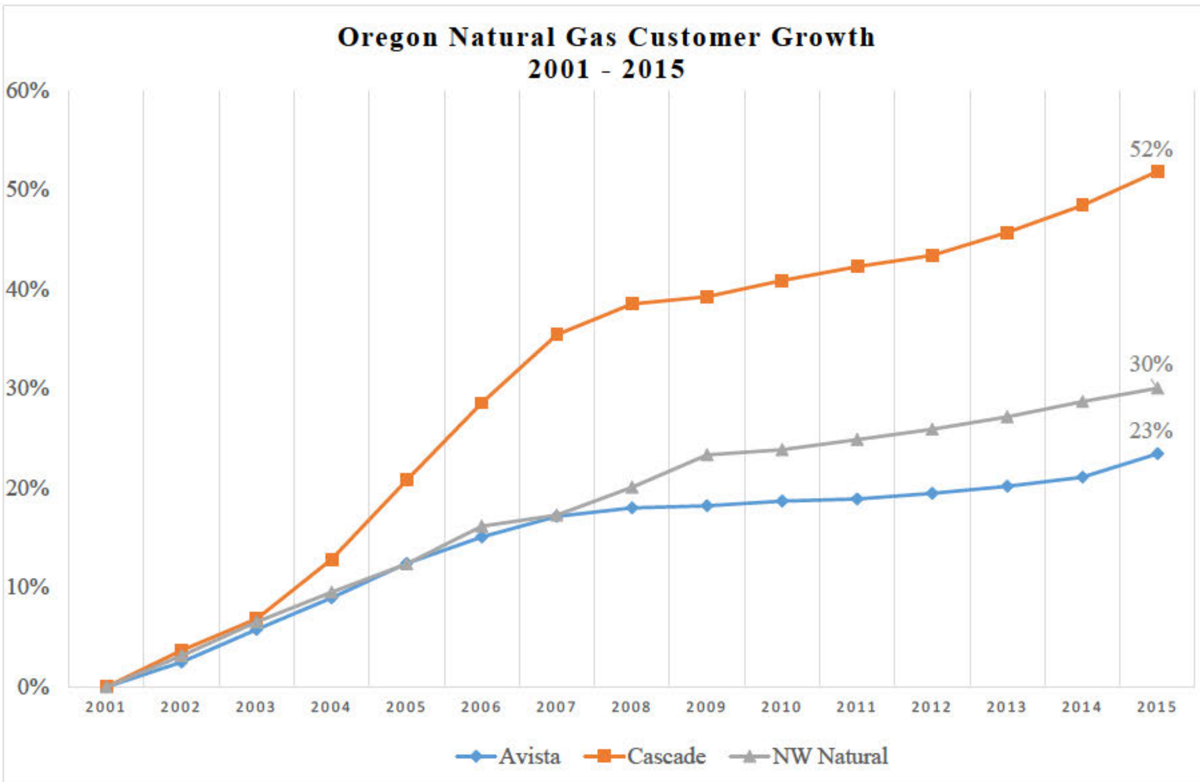
A. Mr. Moore states on page 7 of his testimony that Cascade's rates are 35% lower than Avista's in 2015. What Mr. Moore fails to recognize is that, using the same data he used to derive his rates analysis, Avista's use-per-customer is 493 therms per year while Cascade's is 637 for that same time period. Cascade's use-per-customer is approximately 30% higher than Avista's, meaning that Cascade has more volumes over which it can spread its costs. All other things being equal, Cascade's retail rates should be substantially lower than Avista's because it is not "similarly situated".

Customer growth rates among the three Oregon natural gas utilities is another major difference. In reviewing the Commission's "Oregon Utility Statistics" reports, as shown in Illustration No. 2 below, the cumulative growth rate in number of customers for Cascade Natural Gas is 52% from 2001 through 2015.[5/6] That compares to 30% for NW Natural, and

[5] 2015 Oregon Utility Statistics - http://www.puc.state.or.us/docs/statbook2015WEB.pdf
[6] 2010 Oregon Utility Statistics - http://www.puc.state.or.us/docs/statbook2010.pdf

23% for Avista. The three natural gas utilities are not as "similarly situated" as Mr. Moore suggests.

Illustration No. 2 – Oregon Natural Gas Customer Growth



Q. Do you agree with Mr. Moore's assertion on p. 8 that "[peer], or benchmarking, analysis is a common means of analysis so as to better understand both best practices and perhaps identify the causes that affect utilities"?

A. I do, as long as the benchmarking is done fairly. Staff does not, for example, present an analysis that details the specific conditions of Cascade's distribution system to determine if it is in the same "state," or condition, as that of Avista's. At issue in this case are the distinct issues facing Avista and the evaluation of Avista's request for rate relief based on Avista-specific information. It is not appropriate for Mr. Moore to suggest that, because

Cascade's recent rate base additions have been modest,[7] that the same should be true for Avista.

Q. Commission Staff and CUB witnesses make broad recommendations for the disallowance of capital investment,[8] as well as disallowance recommendations for certain specific projects. Do these recommendations appear to be based on a thorough understanding of the facts and circumstances driving Avista's decisions to make these investments?

A. No. The identification, assessment, design and execution of the capital investment in Avista's Oregon natural gas system is carried out by individuals that have significant training and experience in the design, construction and actual operation of a natural gas system, as well as what is necessary to comply with the many state and federal regulations related to the safe operation of the system. The design and execution of maintaining and expanding natural gas infrastructure is not a theoretical exercise. It involves real people with significant training and expertise, carrying out the work under sometimes very challenging conditions, and with the requirement that the work be completed in full compliance with safety and other regulations. Although the Company takes great care in planning and executing its capital replacement and expansion program, even the best efforts of experienced people will not allow them to foresee all circumstances that would cause the installation of new pipe or equipment to be delayed, or to cost more or less than the original estimates.

In their testimony, both Staff and CUB are making recommendations to the Commission to disallow recovery of capital expenditures based on measures that are unrelated to the criteria that should be used in the determination of the whether the investment is reasonable and appropriate. For example, some of the implied critieria in Staff's and CUB's testimony are as

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[7] Staff/800, Moore/7, l. 3.
[8] See Staff/700, Kaufman, Staff/800, Moore and CUB/100, McGovern

follows:

- How does Avista's annual investment compare with other utilities?[9]
- How does Avista's investment this year compare with last year or prior years?[10]
- How does Avista's actual total investment compare with what the Company estimated?[11]
- How did Avista's actual cost for each project compare with what it originally estimated?[12]
- Did the timing of the projects change from prior plans?[13]

The answers to these questions should not be the determining factors in whether Avista's investments are reasonable and appropriate. The questions that must be answered are: 1) whether Avista spent a reasonable amount of dollars on the specific projects that needed to be done; 2) in the time frame in which they needed to be done; and 3) under the specific conditions and circumstances the Company faced at the time the projects were carried out (e.g., permitting for the work, weather conditions, soil conditions, availability of personnel, municipal/county limitations on work hours/work days, repaving requirements, etc.).

Q. Is it fair to say that the capital spending addressed in Avista's last general rate case went "unchecked," as suggested by Ms. McGovern?[14]

A. No. The Commission addressed the level of capital spend of Avista in its Order No. 16-109. Among other things the Commission stated "(w)e allow Avista full recovery of its capital costs related to plant additions."[15] In addition, with the exception of the four major

[9] Staff/800, Moore/8
[10] Staff/800, Moore/8
[11] Ibid.
[12] CUB/100, McGovern/11
[13] Id. p. 18
[14] Id. p. 52
[15] UG-288, Order No. 16-109, p. 13.

projects, the Commission stated that, "the amount of capital additions is not extraordinary compared to historical and anticipated future expenditures."[16] Further, with regard to some of the larger capital projects, the Order states, "we find that Avista was justified in making the system upgrades to ensure it could meet firm demand in the two areas during extreme weather conditions."[17] In the end, the Commission did conduct a "check" of Avista's capital expenditures.

Q. What is Avista's response to Ms. McGovern's allegation that the Company failed to meet the "burden of proof" requirements of Order No. 16-109 with regard to capital investment?[18]

A. CUB's application of Order No. 16-109 is misplaced. On pages 12-13 of her testimony Ms. McGovern cites Order No. 16-109, page 14, which outlines six components that are required in analyses related to "distribution system upgrades". Starting on page 13 of the Order, the Commission speaks specifically to certain "distribution system upgrades" (i.e., East Medford and Ladd Canyon).[19] It is in the context of this discussion regarding <u>distribution system upgrades</u>, that the Commission requires further analyses be provided. CUB however liberally applies the <u>distribution system upgrades</u> standard to all capital projects, and then states that it does "not see evidence that the Company met the burden of proof".

A review of the six standards shows that they are only applicable to <u>distribution system upgrades.</u> For example, Avista would not be able to provide "evidence about projected loads and customers in the area" or "the use of interruptibility or increased demand-side measures to

[16] Ibid.
[17] Ibid.
[18] CUB/100, McGovern/13
[19] Footnote 11 of Order No. 16-109 points to Docket No. UG-221, Order No. 12-437 at 16-17. The Commission in that NW Natural Docket proffered the six components in response to NW Natural's investment in the Mid-Willamette Valley Feeder Project, a distribution system upgrade project.

improve reliability and system resiliency" as it evaluates replacing Aldyl-A pipe, replacing or upgrading software or computer systems, office furniture, security systems, and the like. Other evidence, however, supports the prudence of these expenditures. The Commission's standard is clearly related to those projects where the Company needs to increase the size of its delivery system in order to continue to provide safe and reliable service to customers.[20] CUB's assertion that Avista failed to comply with the Commission's Order should be rejected.

Q. Has the Company provided the parties with information regarding the need to reinforce its distribution system?

A. Yes. As an example of recent investment to ensure adequate pressure to serve customers, the East Medford High Pressure Reinforcement, which was placed in service in February of 2016, was completed to address areas of low pressure due to system capacity shortfalls. Mr. Morris' Exhibit No. 103 contains output from the Synergi® system model for the Medford area before and after the completion of the East Medford Reinforcement.[21] Completing this project reduced, by half, the number of customers at risk of an outage at design day temperatures. However, low-pressure areas remain on that system, as illustrated by the model output after the completion of the East Medford Reinforcement.

The Company not only included information in its original filing (specifically Company witnesses Mr. Thies and Mr. Machado), but also through the discovery process. For example, included in my Exhibit No. 1001 are the results of analyses conducted in Synergi® for the La Grande, Medford, Roseburg and Klamath Falls areas of our service territory (provided to the

[20] Included on pp., 27-29 of Mr. Machado's direct testimony, he provided an overview of how the Company complied with Order No. 16-109.

[21] Synergi® is a computer-based modeling tool for natural gas distribution systems, which uses data taken from monthly natural gas meter reads over a multi-year period to determine system dynamics, including system pressure under various circumstances. Avista uses this tool as a component in support of system capacity analysis and in identifying projects to alleviate capacity constraints.

parties in response to CUB Data Request No. 115). As illustrated in this exhibit, there are a number of areas that require reinforcement in the Company's Oregon distribution system. The pipe colored red or white at design heating day temperatures indicates modeled pressure below Avista's design standards.

In addition, beginning in the first quarter of 2016 Avista has included updates on the status of capital investment in its quarterly natural gas updates presented to Commission Staff. Exhibit No. 603 sponsored by Mr. Machado, along with his direct testimony, includes the capital investment related excerpts from the quarterly meetings for the first, second, third, and fourth quarters of 2016.

Q. What is Avista's response to CUB's proposed 10% across-the-board disallowance, and Mr. Moore's 10% "management adjustment" for all non-growth related distribution projects?

A. The proposed adjustments are not appropriate. CUB's adjustment is based on, at least in part, the application of the distribution system upgrade standard to each and every capital investment, which as explained above is not appropriate. Second, such "broad-brushed" adjustments run counter to the Commission's findings in Avista's last general rate case, where the Commission stated in Order No. 16-109 that "adjustments should be based solely on thorough assessments of individual projects and not be based on cuts across groupings of projects."[22]

While Mr. Moore did review the new growth projects on an individual basis, to simply adjust every other project in one broad stroke is not appropriate. <u>Further, this adjustment is in direct conflict with his own testimony on page 12</u>, where Mr. Moore stated that "(w)ith regard

[22] Order No. 16-109, p. 13.

to the programmatic gas distribution projects, Staff did not have specific concerns with the projects that were reviewed, and was satisfied with the Company's presentation demonstrating that the work being done is prudent."[23] (emphasis added)

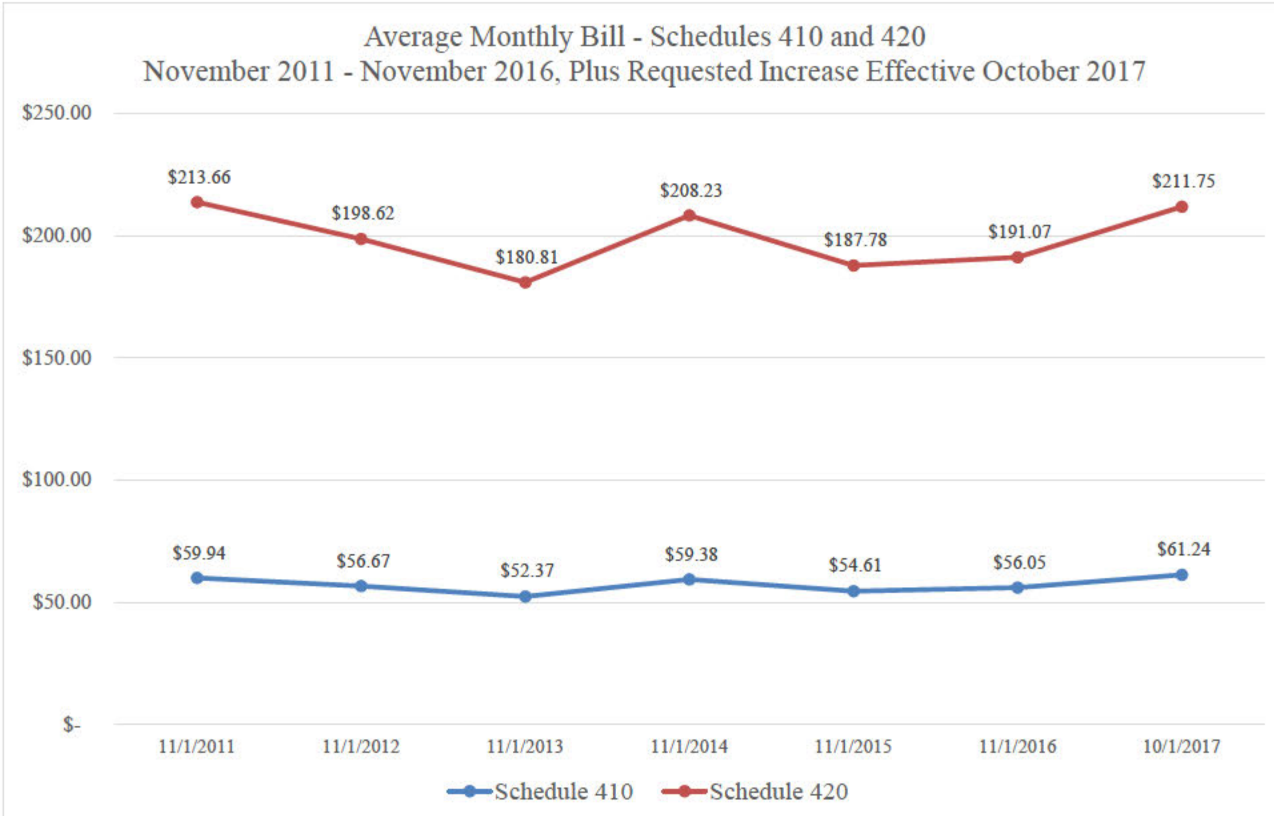
Other Avista witnesses (Mr. Machado, Ms. Rosentrater, and Mr. Kensok) have provided reply testimony in response to the recommendations of Staff and CUB witnesses regarding specific capital investment projects and programs.

Q. On page 8 of CUB's testimony, Ms. McGovern states that the Company's investment in systems and infrastructure necessary to provide safe and reliable service is causing a "severe customer impact". Is such a claim supported by facts?

A. No. Illustration No. 3 below, reproduced from Company witness Mr. Morris' direct testimony, at page 11, shows the monthly bills for residential (Schedule 410) and commercial (Schedule 420) customers have remained relatively flat over the past six years, even after including the full effect of the proposed increase in this general rate case.

[23] Exhibit Staff/800, Moore/12, ll. 3-6.

Illustration No. 3:



Q. Is it appropriate to broadly apply the general rate case activities in other jurisdictions to this general rate case?

A. No. CUB insinuates that the Commission in this case should in some way draw inferences from a recent case in the State of Washington as a basis to reject this general rate case in its entirety.[24] CUB did not participate in the proceedings in Washington, which involved both electric and natural gas operations, and CUB would have, at best, a very limited understanding of the issues in that case. For CUB to suggest an extension of any of the results of that case to Oregon is not appropriate.

Q. What is driving the Company's capital investment in its Oregon natural gas

[24] CUB/100, McGovern/11.

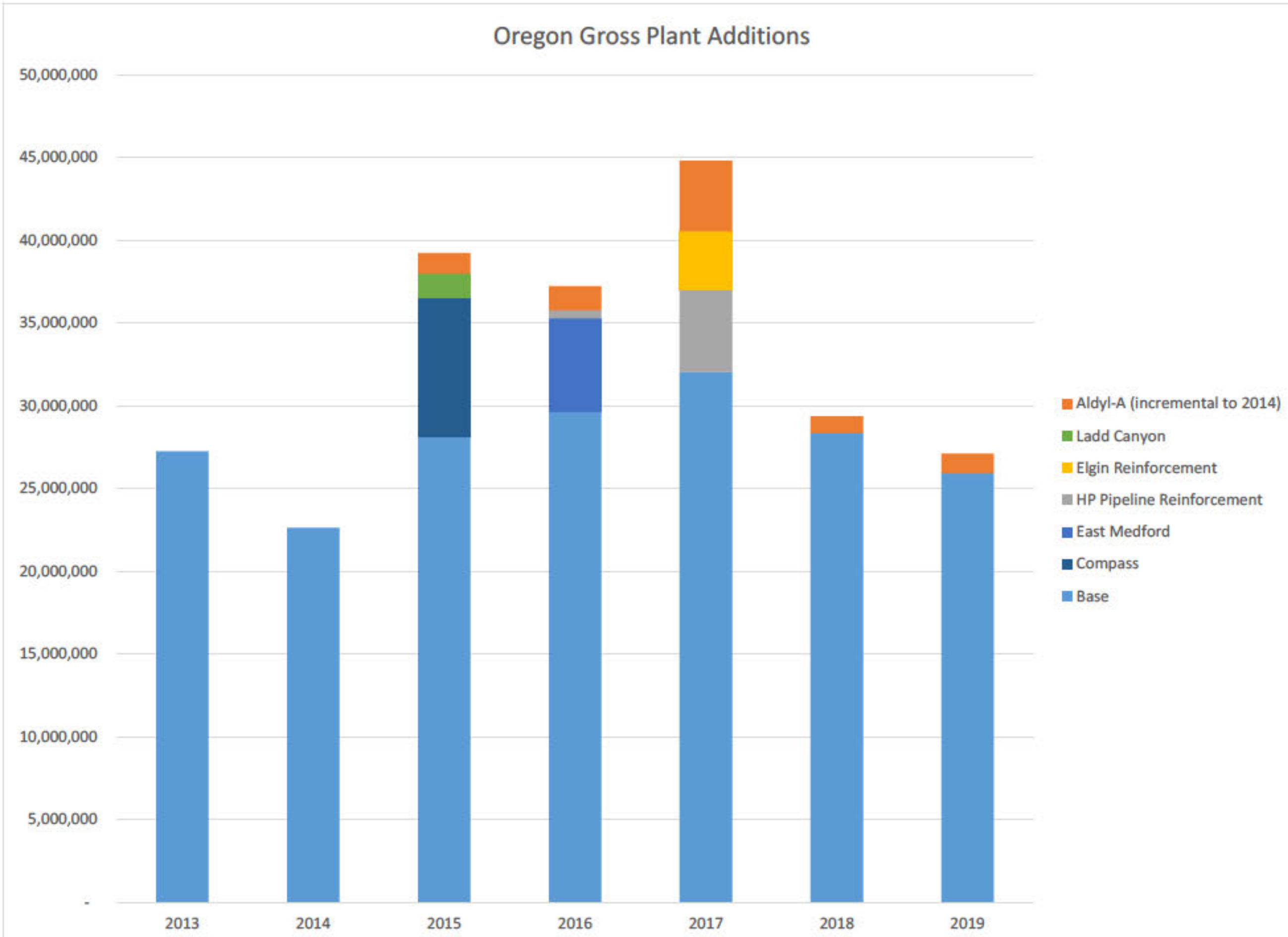
operations, and the recent retail rate requests?

A. The general rate requests in recent years have been driven largely by capital additions, as has been discussed in previous general rate cases, as well as in this case. The Company's capital investments have been driven primarily by the preservation and enhancement of safety, service reliability (capacity reinforcements) and the replacement of aging infrastructure and systems, including information technology. Capital additions accounted for 74% of the Company's revenue request in 2014 (Docket No. UG-284), 65% in Docket No. UG-288 (Avista's 2015 rate request), and 84% in this case. The capital investments have been found to be reasonable by the Commission in the Company's prior general rate cases, and are included in customer rates.

Q. What are the Company's planned capital investments for Oregon operations in the future?

A. As shown in Illustration No. 4 below, planned gross plant additions for Oregon in the 2018 and 2019 time period is approximately $27 million and $29 million, respectively. This is lower than the approximate $40 million annual level of investment that occurred in the 2015-2017 time period.

<u>Illustration No. 4 – Oregon Gross Plant Additions 2013-2019</u>:



As Company witness Ms. Rosentrater discusses in more detail in her testimony, the Company not only has had a base level of capital additions which are necessary to continue to provide safe and reliable service to our customers, but we have also had several larger projects in recent years. Some of the recent large projects include the replacement of the Company's customer information system ("Project Compass"), Aldyl-A pipe replacement, the East Medford High Pressure Reinforcement, the Ladd Canyon Gate Station, and this year, the Elgin (La Grande) High Pressure Reinforcement. Based on recent analysis conducted in concert with the Company's natural gas IRP, other than two gate station rebuilds, Avista does not foresee these types of large projects in the 2018 and 2019 time frame.

IV. OTHER COMPANY WITNESSES

Q. Would you please provide a brief summary of the reply testimony of the other witnesses representing Avista in this proceeding?

A. Yes. The following additional witnesses are presenting reply testimony on behalf of Avista:

Mr. Mark Thies, Senior Vice President and Chief Financial Officer, will reply to the testimony of Mr. Muldoon, submitted on behalf of the Staff, with respect to the Company's proposed capital structure (50 percent common equity), the return on equity (9.9 percent), the cost of debt (5.7 percent), and the overall rate of return (7.80 percent). His testimony, coupled with that of Company witness, Adrien Mckenzie, demonstrates that the capital structure, return on equity ("ROE"), cost of debt, and overall rate of return requested by Avista are reasonable and the Commission should reject the capital structure, return on equity, cost of debt and overall rate of return proposed by Mr. Muldoon.

Mr. Adrien M. McKenzie, Vice President of Financial Concepts and Applications (FINCAP), Inc., responds to the testimony of Mr. Matt Muldoon concerning the fair rate of return on equity ("ROE") for the jurisdictional gas utility operations of the Company. He also addresses the recommendation of Mr. Michael P. Gorman, on behalf of Northwest Industrial Gas Users, to maintain the ROE in this case at the same level that was granted in Avista's last case.

Ms. Jennifer Smith, Senior Regulatory Analyst, will summarize the Company's adjusted revenue requirement. She also responds to adjustments to the Company filed revenue requirement proposed by Staff to which Avista fully or partially accepts. In addition, her testimony will respond to the proposed adjustments by non-Avista parties the Company does not accept.

<u>Mr. David Machado,</u> Senior Regulatory Analyst, will reply to the testimony of Staff and CUB, as it relates to the Company's investment in utility plant. His testimony will provide details on the adjustments proposed by the parties that Avista accepts, in full or in part, as well as the adjustments with which Avista does not accept. He will also provide a discussion of the Company's concerns with portions of Staff's and CUB's approaches in proposing adjustments to the capital investment included in Avista's case.

<u>Ms. Heather Rosentrater</u>, Vice President of Energy Delivery, in response to the "broad-brush" statements of Staff and CUB, provides a better understanding of Avista's natural gas system in Oregon, an overview of the trends that have, and will continue to, drive investment, as well as an overview of our capital plant investment approach. Finally, Ms. Rosentrater provides the Company's response to certain specific Staff and CUB proposed adjustments to natural gas system and general plant in service.

<u>Mr. James Kensok</u>, Vice President and Chief Information Officer, responds to the proposed adjustments and disallowances associated with the Company's information technology capital investment. In his testimony, Mr. Kensok provides Avista's approach in making investments in information technology, and the five foundational areas that drive the need for capital investment.

<u>Mr. Joseph Miller,</u> Senior Regulatory Analyst, provides the Company's response to the long-run incremental cost ("LRIC") of service studies prepared by both Staff and NWIGU, as well as responds to CUB's assertion that the Company's LRIC Study is flawed.

<u>Mr. Patrick Ehrbar</u>, Senior Manager, Rates and Tariffs, responds to Staff's Affiliated Interest and Cost Allocation Adjustments, and explains the Company's allocation of common costs to Oregon is reasonable. Mr. Ehrbar also explains why the Company does not accept Staff's Fee Free Bankcard Adjustment, but can accept the Test Year Load Forecast Adjustment.

Mr. Ehrbar demonstrates that the spread of the revised annual margin/revenue increase among the Company's natural gas service schedules is reasonable. Next he provides the Company's response to the rate design proposals of the parties, accepting Staff's rate design proposal for Schedules 410 and 420. Finally, he demonstrates that Avista is in compliance with the Commission's order in Docket No. UG-288 regarding the treatment of new customers in the Company's decoupling mechanism.

Q. Does this conclude your reply testimony?

A. Yes it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

KELLY O. NORWOOD
Exhibit No. 1001

Policy Response

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	03/09/2017
CASE NO:	UG 325	WITNESS:	David J. Machado
REQUESTER:	CUB	RESPONDER:	David Machado / J. Webb
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	CUB – 115	TELEPHONE:	(509) 495-4554
		EMAIL:	david.machado@avistacorp.com

REQUEST:

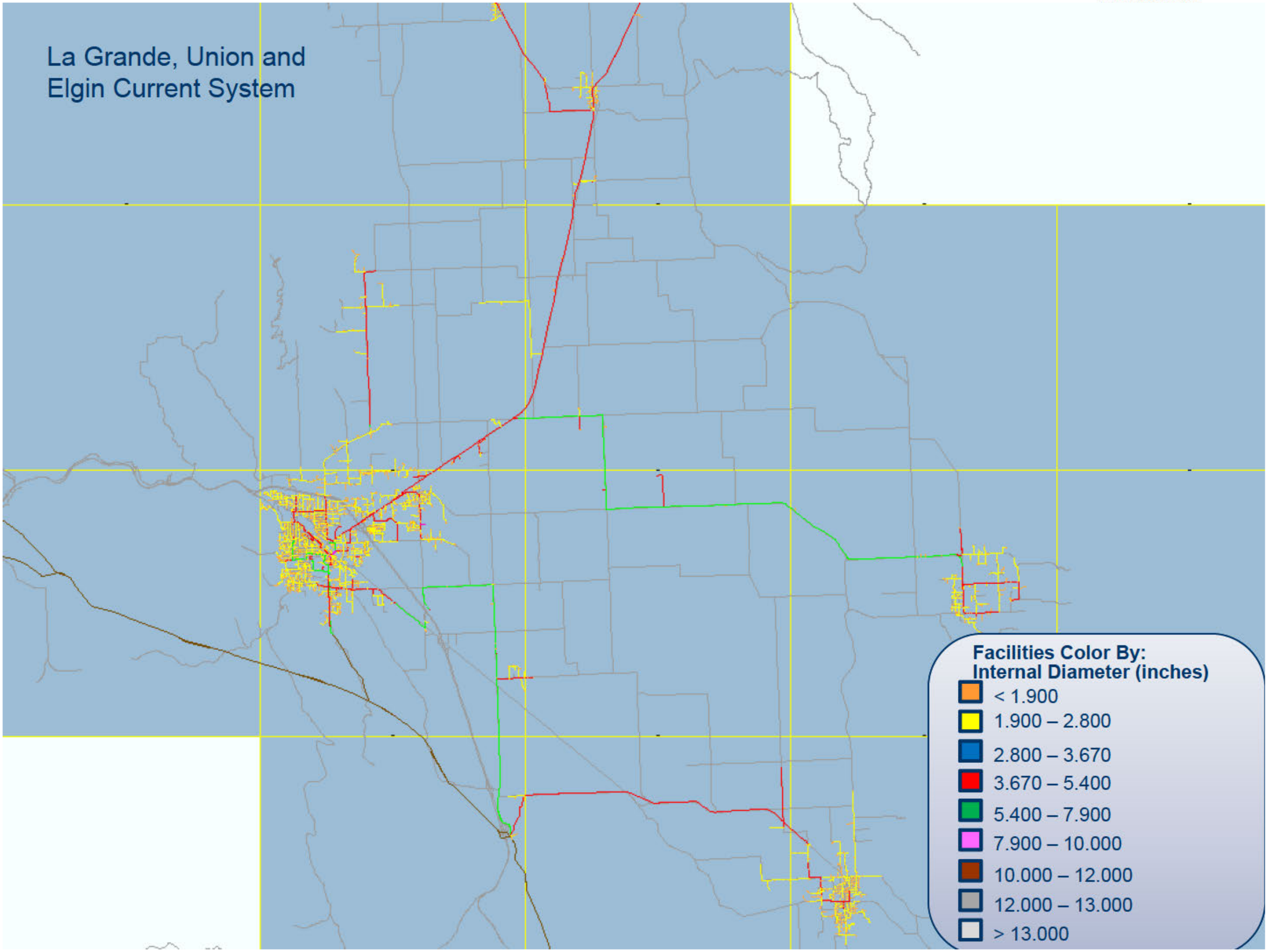
Please provide the Synergi map results, with the Company's existing infrastructure as of Sep 1, 2016 (or nearest pre-test year date), without the addition of any additional growth.

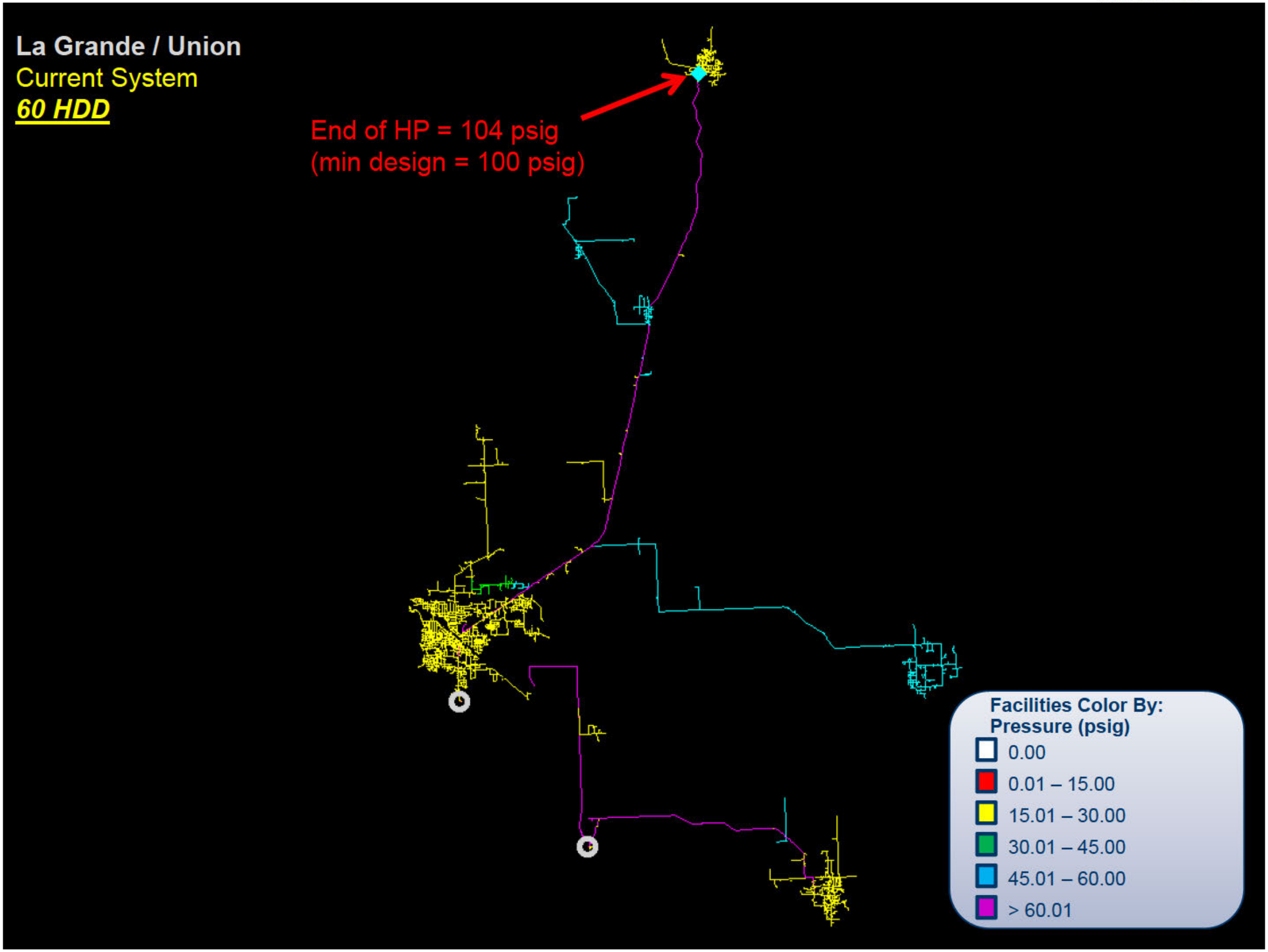
RESPONSE:

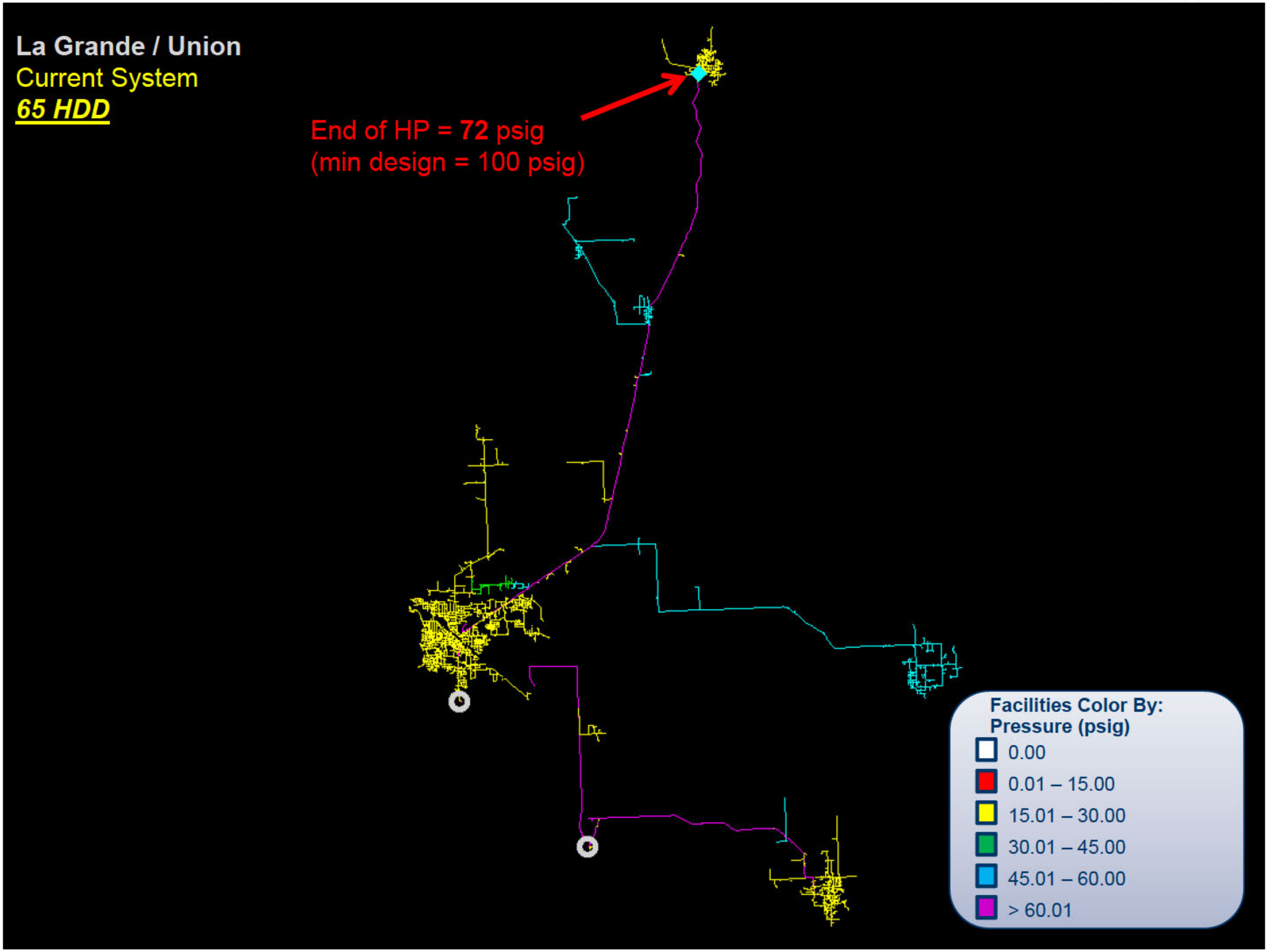
As discussed previously in the Company's response to CUB_DR_020 and CUB_DR_077, the Synergi® planning models are updated following the end of the winter weather period and are not available on an ad-hoc basis. The Company has previously provided the most recent Synergi® planning model output maps for the La Grande area (Avista/602, Machado/Page 56, and CUB_DR_007) and the Medford area (CUB_DR_020). The La Grande and Medford area maps have been reproduced here as CUB_DR_115 Attachment A and CUB_DR_115 Attachment B.

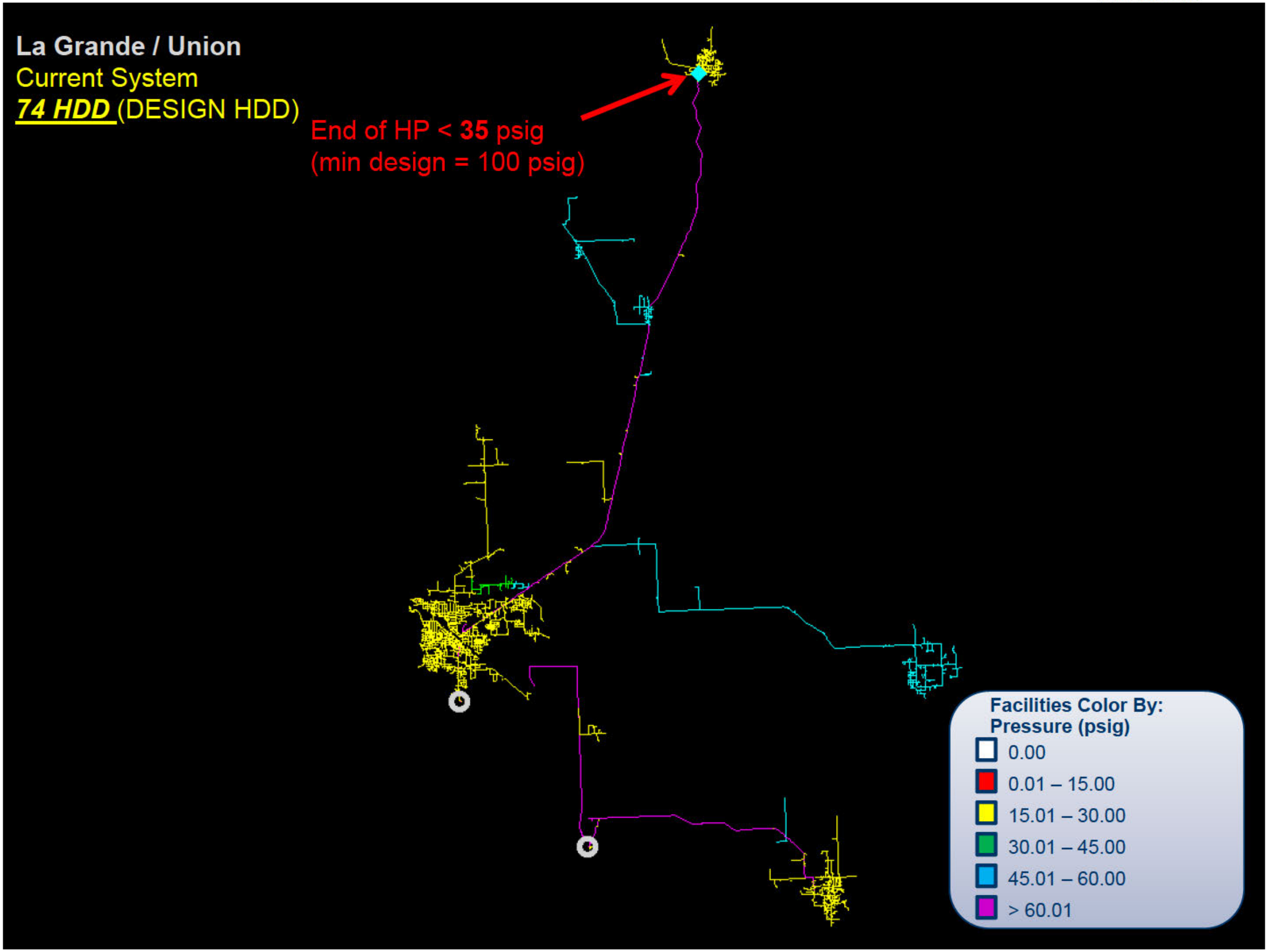
CUB_DR_115 Attachment C includes the most recent Synergi® planning model output maps for the Roseburg Area (including Roseburg: page 1; Canyonville: pages 2-3; Sutherlin: page 4; and Myrtle Creek: pages 5-6) and the Klamath Falls area (pages 7-8).

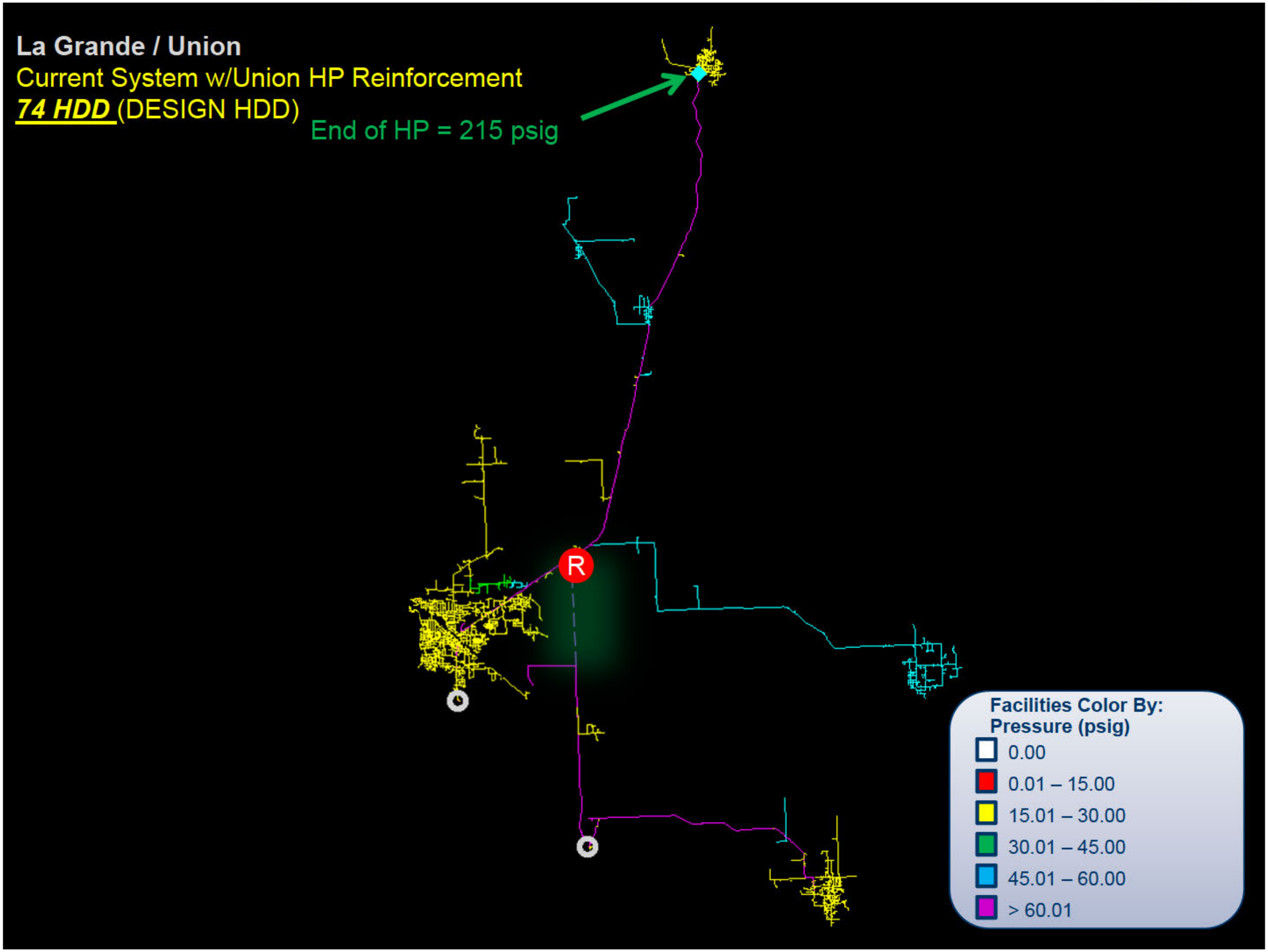
As shown illustrated in these attachments, there are a number of areas that require reinforcement in the Company's Oregon distribution system (pipe colored red or white at design heating day temperatures indicates modeled pressure below Avista's design standards). The Company's response in Staff_DR_182 Attachment AG details four reinforcement projects planned for completion in 2017—Medford west 6 psig system, Medford east 6 psig system, Jacksonville, and Myrtle Creek Phase 2. The first three of those projects will reinforce low pressure areas shown on the Medford area map, and the fourth (Myrtle Creek) will reinforce low pressure areas as illustrated in CUB_DR_115 Attachment C on pages 6 and 7. Additionally, the Canyonville and Myrtle Creek Phase 1 reinforcements were completed during the second half of 2016. The Sutherlin Synergi® planning model output map at CUB_DR_115 Attachment C, page 4, reflects the Sutherlin reinforcement completed in 2015.

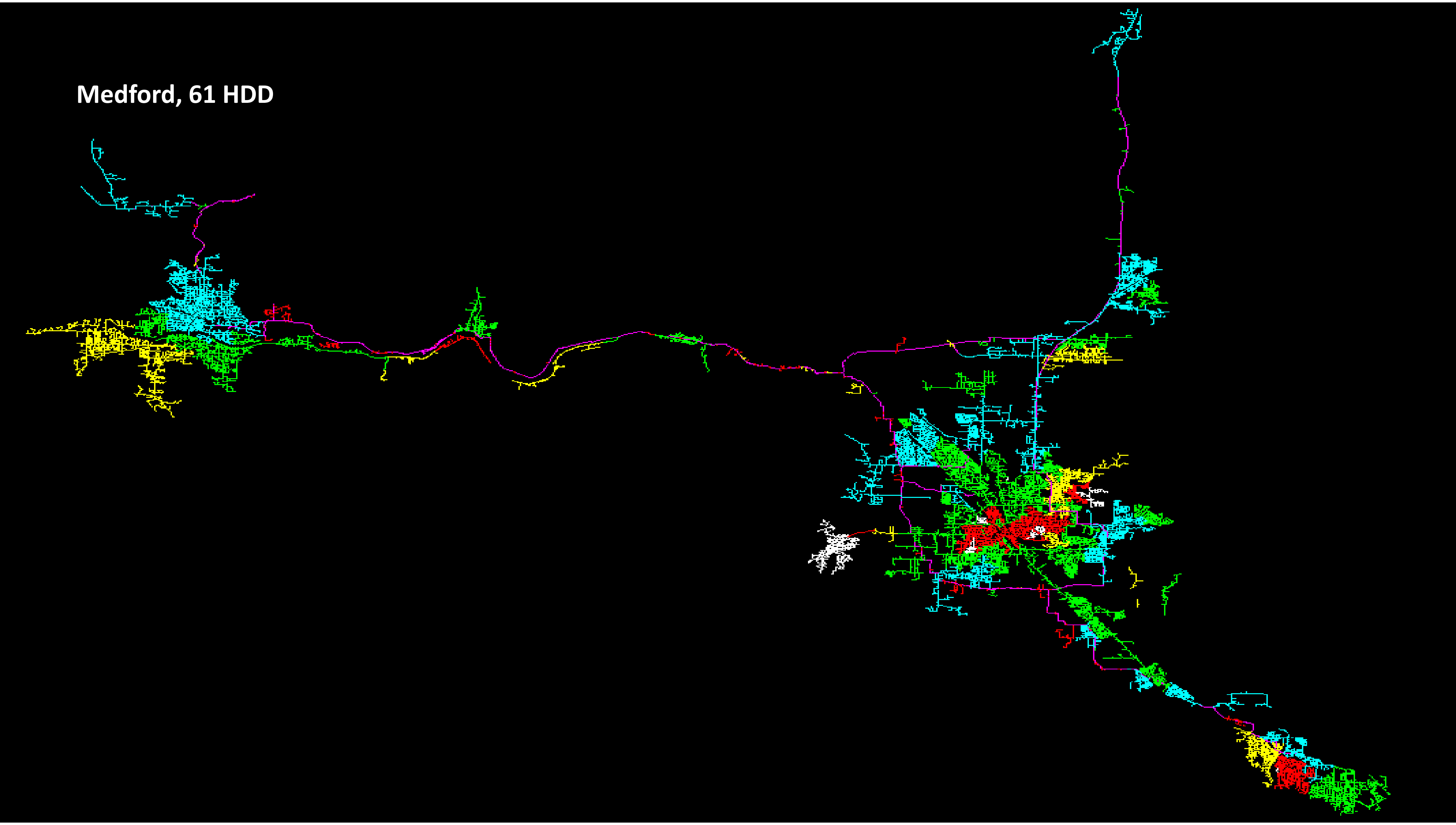

La Grande, Union and
Elgin Current System
Facilities Color By:
Internal Diameter (inches)
< 1.900
1.900 – 2.800
2.800 – 3.670
3.670 – 5.400
5.400 – 7.900
7.900 – 10.000
10.000 – 12.000
12.000 – 13.000
> 13.000

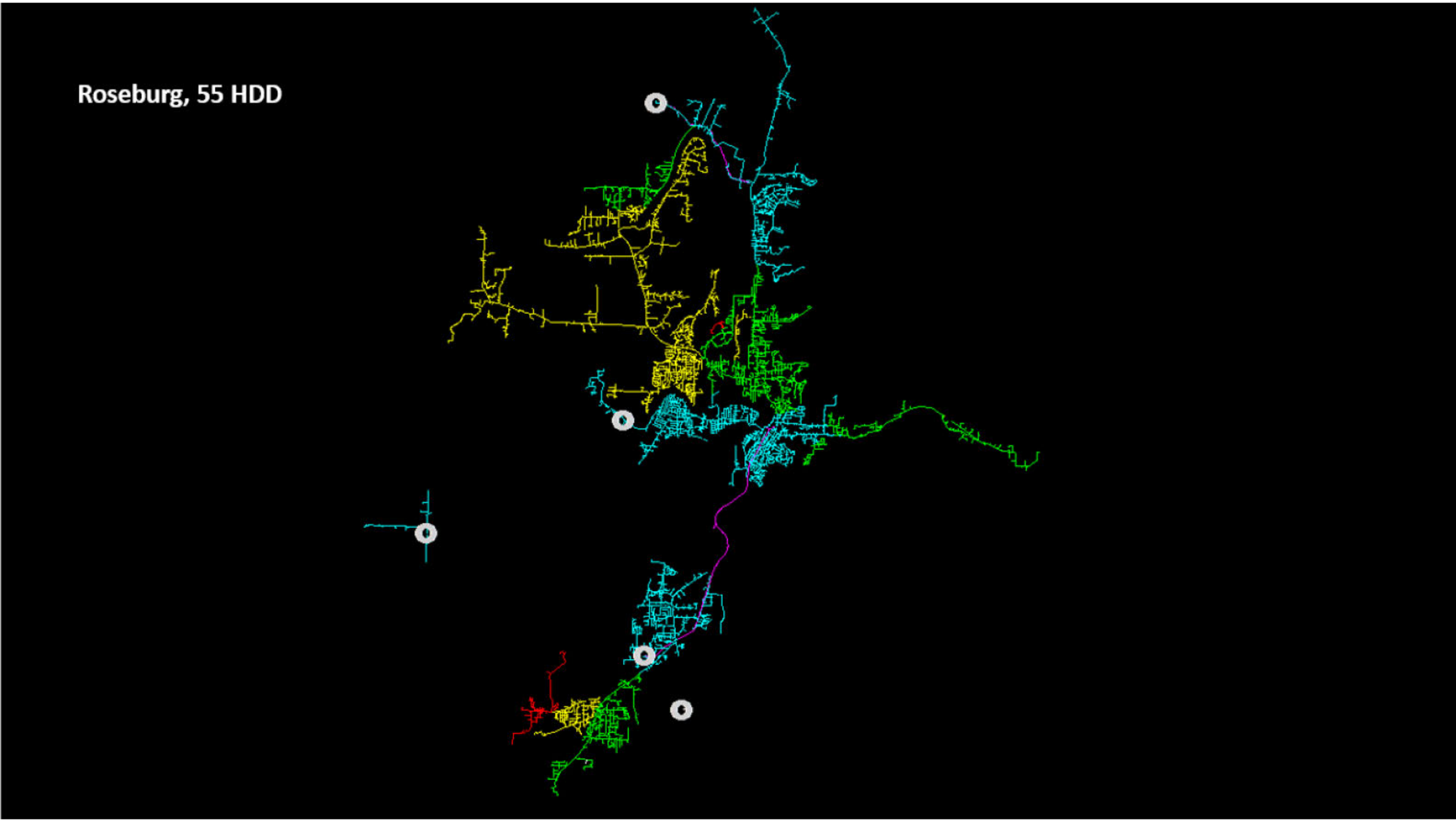

La Grande / Union
Current System
60 HDD
End of HP = 104 psig
(min design = 100 psig)
Facilities Color By:
Pressure (psig)
0.00
0.01 – 15.00
15.01 – 30.00
30.01 – 45.00
45.01 – 60.00
> 60.01


La Grande / Union
Current System
65 HDD
End of HP = 72 psig
(min design = 100 psig)
Facilities Color By:
Pressure (psig)
0.00
0.01 – 15.00
15.01 – 30.00
30.01 – 45.00
45.01 – 60.00
> 60.01


La Grande / Union
Current System
74 HDD (DESIGN HDD)
End of HP < 35 psig
(min design = 100 psig)
Facilities Color By:
Pressure (psig)
0.00
0.01 – 15.00
15.01 – 30.00
30.01 – 45.00
45.01 – 60.00
> 60.01


La Grande / Union
Current System w/Union HP Reinforcement
74 HDD (DESIGN HDD)
End of HP = 215 psig
R
Facilities Color By:
Pressure (psig)
0.00
0.01 – 15.00
15.01 – 30.00
30.01 – 45.00
45.01 – 60.00
> 60.01

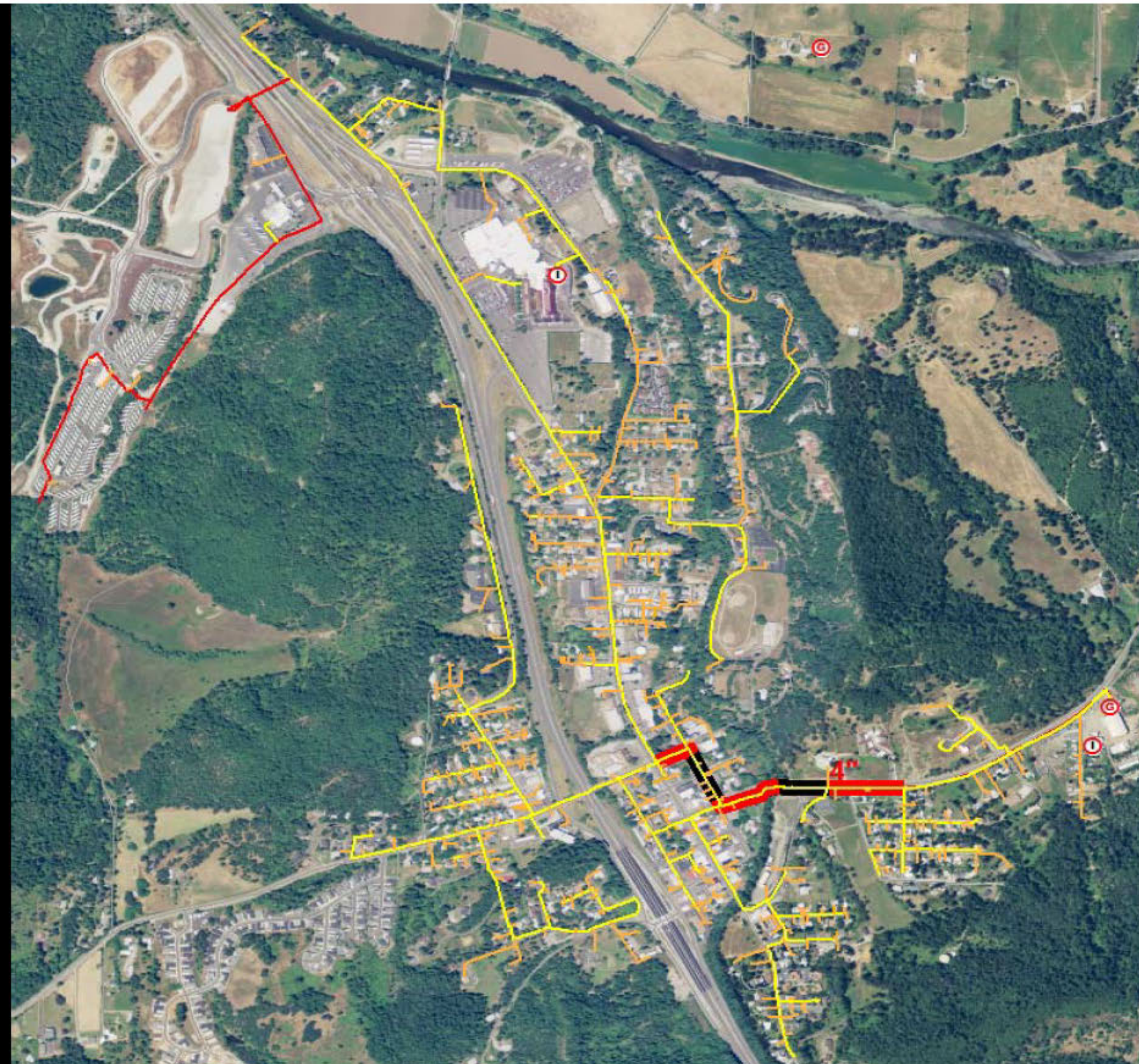

Medford, 61 HDD


Roseburg, 55 HDD

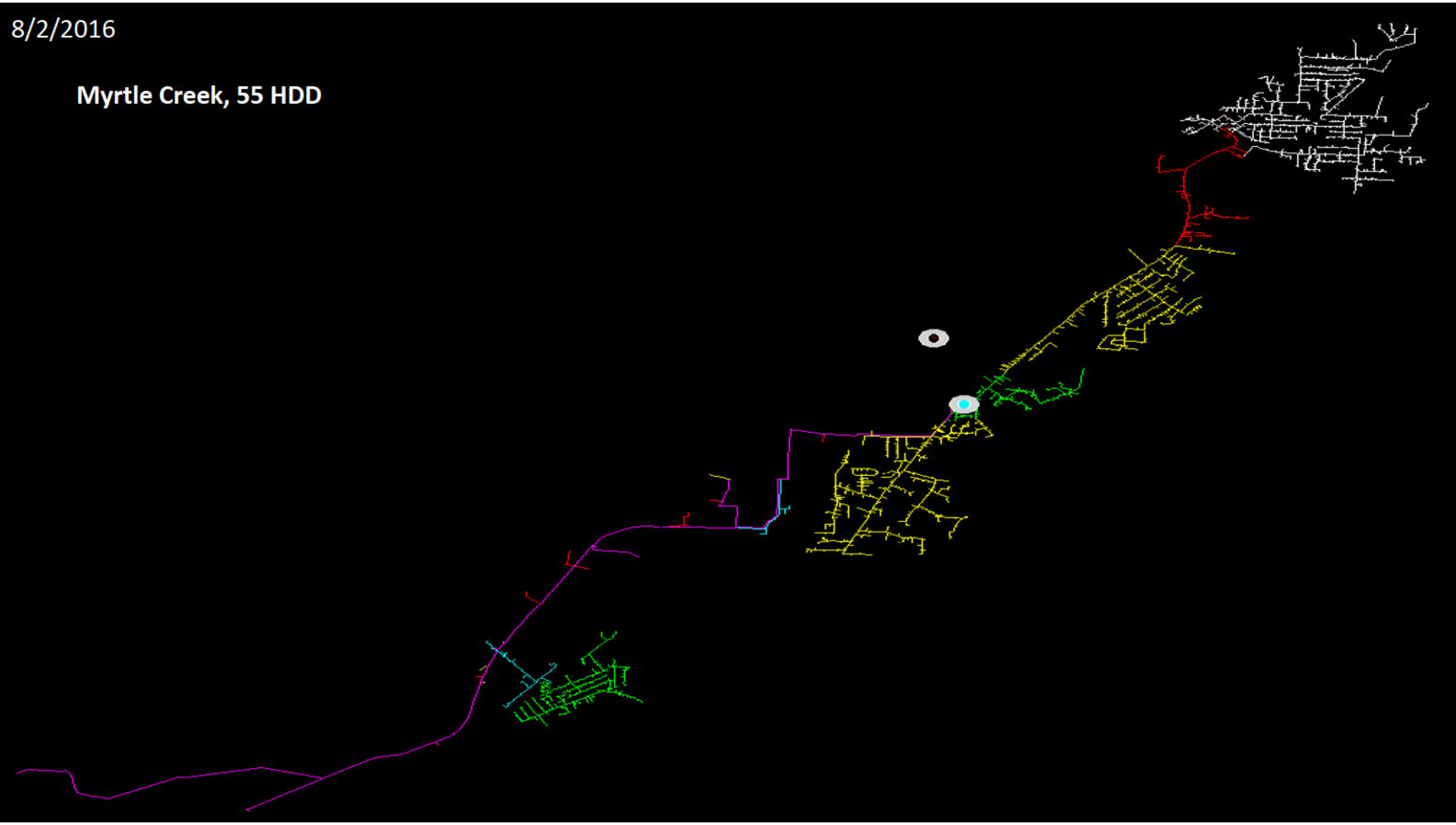

Canyonville, 53 HDD (Max Achievable)

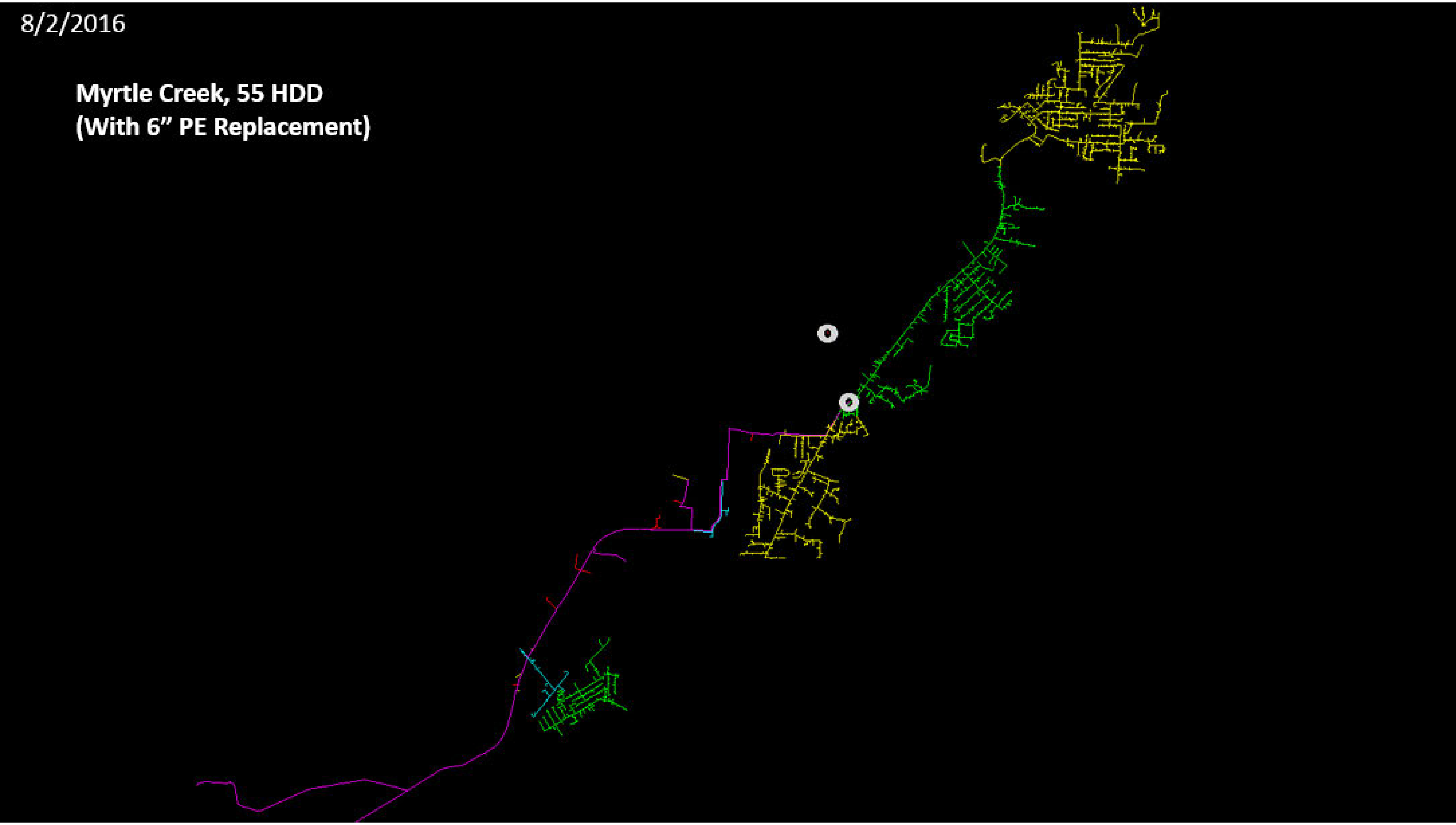
Canyonville, 55 HDD

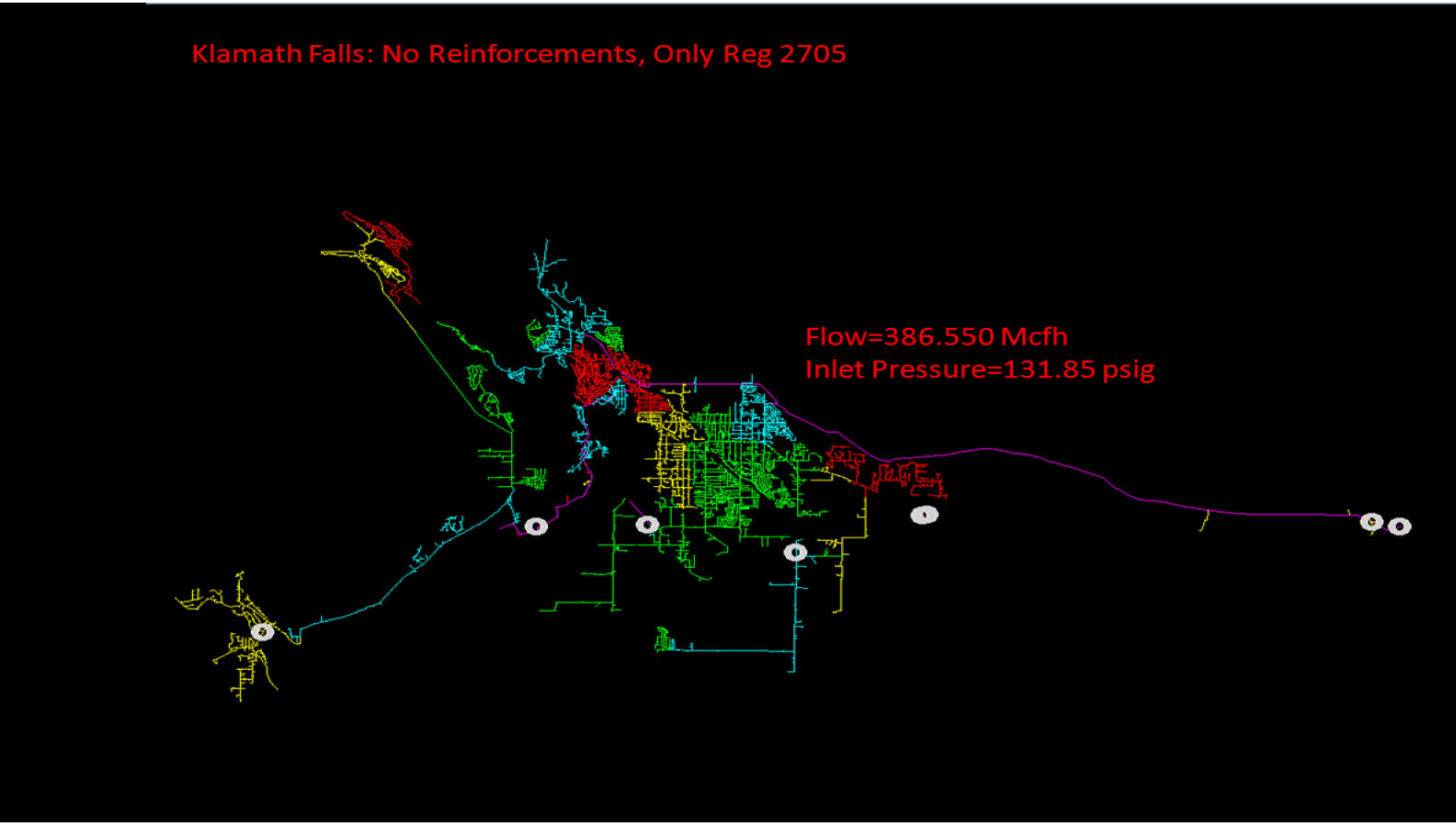
*Canyonville could achieve a design HDD if the pictured proposal was completed

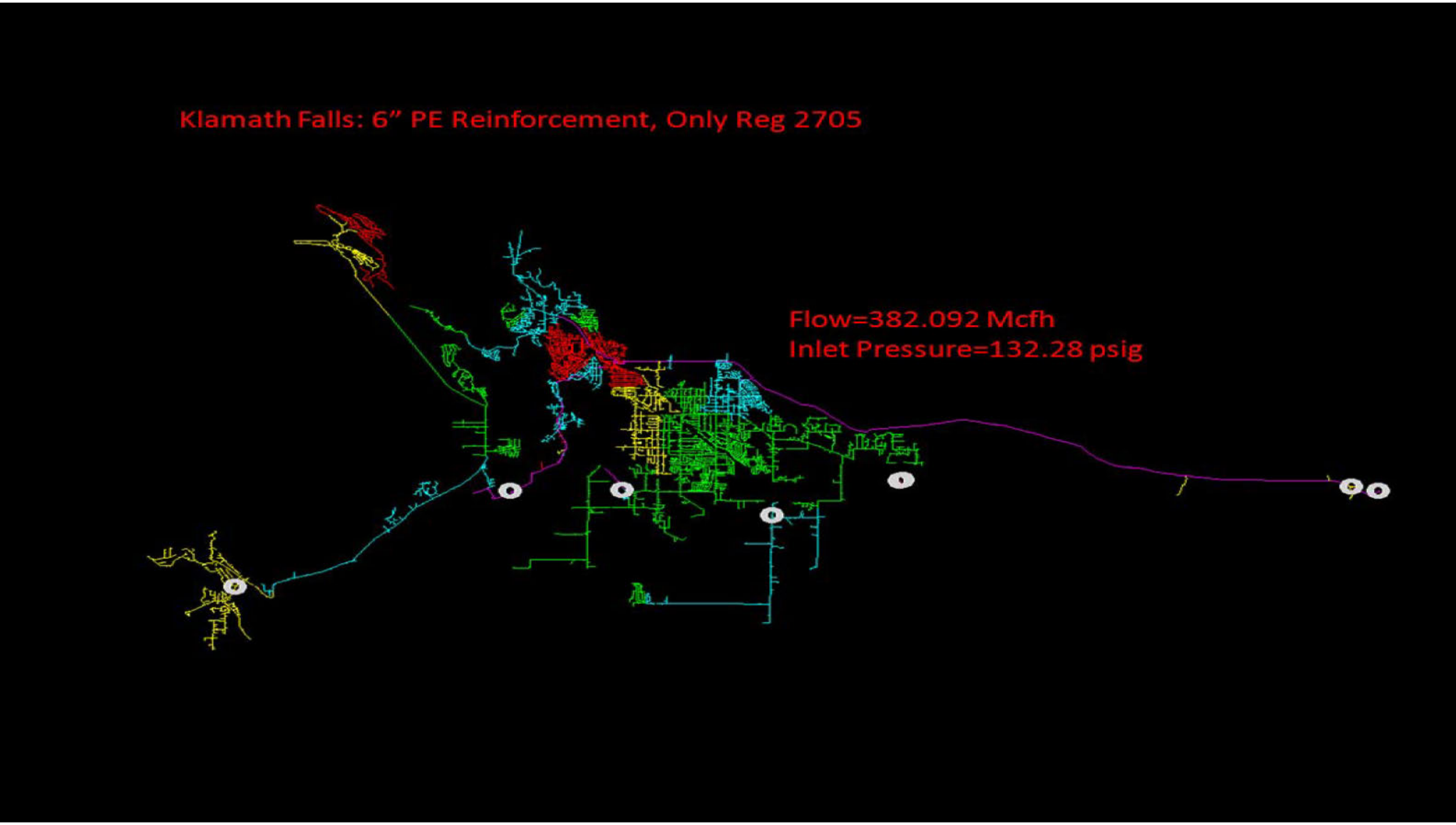



Sutherlin, 55 HDD
(With 4” PE Reinforcement)


8/2/2016
Myrtle Creek, 55 HDD


8/2/2016
Myrtle Creek, 55 HDD
(With 6" PE Replacement)


Klamath Falls: No Reinforcements, Only Reg 2705
Flow=386.550 Mcfh
Inlet Pressure=131.85 psig


Klamath Falls: 6" PE Reinforcement, Only Reg 2705
Flow=382.092 Mcfh
Inlet Pressure=132.28 psig

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG- 325

REPLY TESTIMONY OF MARK T. THIES
REPRESENTING AVISTA CORPORATION

Capital Structure, Rate of Return, Cost of Debt

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corp.

A. My name is Mark T. Thies. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed by Avista Corporation as Senior Vice President and Chief Financial Officer.

Q. Are you the same Mark T. Thies who sponsored prefiled direct testimony, on behalf of Avista Corporation (Avista)?

A. Yes, I sponsored direct testimony and exhibits, Avista/200-203, in this Docket.

Q. Please summarize the purpose of your Reply Testimony.

A. My testimony responds to the direct testimony of Mr. Muldoon[1], witness for the Staff of the Public Utility Commission of Oregon ("OPUC") with respect to capital structure and capital costs. This reply testimony, coupled with the reply testimony of Company witness Mr. McKenzie, demonstrates that the Commission should accept the capital structure, return on equity, and updated overall rate of return requested by Avista.

In brief, I will provide information that shows:

- A 50.0 percent common equity ratio is appropriate, consistent with the methodology used in prior years in Oregon, and provides a reasonable balance between safety and economy.

- The cost of debt as originally documented of 5.75 percent, updated to 5.70 percent as of September 2017, is appropriate for the rate year of October 2017 through September 2018.

[1] Staff/200/Muldoon

Q. Will you be addressing return on equity in your testimony?

A. No. Mr. McKenzie, on behalf of Avista, provides reply testimony related to the appropriate return on equity for Avista.

A table of contents for my testimony is as follows:

II. CAPITAL STRUCTURE

Q. As context for responding to the testimony of Mr. Muldoon, please summarize Avista's proposed capital structure.

A. See Illustration No.1 below for Avista's proposed capital structure.

Illustration No. 1:

AVISTA CORPORATION Proposed Cost of Capital			
	Proposed Structure	Cost	Weighted Cost
Debt	50.0%	5.70%	2.85%
Common Equity	50.0%	9.90%	4.95%
Total	100.0%		**7.80%**

Q. Is the cost of capital provided in Illustration No. 1 different from that originally presented by the Company?

A. Yes. The only change to the cost of capital presented above, versus what was provided in the Company's original filing, is the cost of debt component. The cost of debt has been updated to reflect current forward interest rates for issuance of debt during 2017, as well as for the actual issuance costs for debt issued on December 15, 2016. The estimated cost of debt as of September 30, 2017 of 5.70 percent is representative of debt costs for the test year. The support for the 5.70 percent cost of debt is provided on page 3 of Exhibit No. 1101. All other elements of the cost of capital are consistent with what was originally filed.

Q. What is Avista's recent actual and forecasted capital structure?

A. The Company's actual capital structure at December 31, 2016 was 50.1 percent debt and 49.9 percent common equity, as shown in Illustration No. 2 below. Also provided in that illustration are the forecasted capital structure for each quarter through September 30, 2018. While the equity ratio is not always exactly 50 percent, on average and over time, the goal is to maintain common equity at 50 percent.

Illustration No. 2:

AVISTA CORPORATION
Capital Structure

	12/31/2016 Actual	3/31/2017 Forecasted	6/30/2017 Forecasted	9/30/2017 Forecasted	12/31/2017 Forecasted	3/31/2018 Forecasted	6/30/2018 Forecasted	9/30/2018 Forecasted
Debt	50.1%	49.7%	49.7%	49.5%	50.1%	49.5%	49.0%	50.9%
Common Equity	49.9%	50.3%	50.3%	50.5%	49.9%	50.5%	51.0%	49.1%

As shown in Illustration No. 2, Avista's actual equity layer is near 50 percent at year-end 2016. Additionally, over the course of the next year and a half, Avista plans to maintain the equity component of 50 percent through its debt and equity financing.

Avista typically issues long-term debt once a year and relies on our line of credit and issuances of common stock through a periodic offering plan to meet liquidity needs throughout the year. This was the case in December of 2016 when $175 million of debt was issued, causing the ratio of debt to be slightly above 50 percent at 50.1 percent. However, for reasons outlined below, the Company targets a capital structure of 50 percent common equity and 50 percent debt.

Q. Why is a 50.0 percent equity ratio appropriate?

A. Maintaining a 50.0 percent common equity ratio has several benefits for customers. We are dependent on raising funds in capital markets throughout all business cycles. These cycles include times of contraction and expansion. A solid financial profile will assist us in accessing debt capital markets on reasonable terms in both favorable financial markets and when there are disruptions in the financial markets. Additionally, a 50.0 percent common equity ratio solidifies our current credit ratings and supports our long-term goal of moving our corporate credit rating from BBB to BBB+. We rely on credit ratings in order to access capital markets on reasonable terms. The requested 50.0 percent equity ratio appropriately balances safety and economy for our customers.

Q. Why is Mr. Muldoon's proposed 48.9 percent equity ratio not appropriate for Avista.

A. Mr. Muldoon proposes a 48.9 percent equity ratio based on an estimate at the end of the test year - September 2018.[2] Mr. Muldoon's estimate of capital structure is not reflective of past Company practice or what the Company's forecast reflects for the future. As demonstrated in Illustration No. 2, a 50 percent equity component is more reflective of the Company's current actual structure and estimated average equity throughout the October 2017 to September 2018 rate year. Additionally, Mr. Muldoon infers a degree of certainty in his

[2] Staff/200, Muldoon/3, line 5

equity level of 48.9 percent by the precision of his calculation, which he recognizes is simply "my best estimate of capital structure at the end of test year, concluding at the end of September, 2018".[3] (emphasis added) Quite simply the 50 percent equity layer proposed by the Company is more appropriate given the present equity layer of approximately 50 percent, and the expected 50 percent equity layer during the rate effective period.

Q. Is Avista's methodology for calculating capital structure consistent with that of Mr. Muldoon, and consistent with that included in prior proceedings?

A. Yes, both Avista and Mr. Muldoon utilize the same methodology in calculating capital structure, and have recognized that this methodology is consistent with past rate case proceedings before this Commission. The difference between the Company's calculation and Mr. Muldoon's calculation is that Mr. Muldoon uses one specific point-in-time (based on his best estimate), rather than looking at the Company's actual historical and forecasted capital structure on a quarter-by-quarter basis.

The Commission should accept the Company's 50 percent capital structure. The Company's capital structure is calculated utilizing the same methodology as Mr. Muldoon, is consistent with previous rate proceedings in Oregon, and is more reflective of the Company's actual capital structure at the beginning of, and during, the period when rates will be in effect.

III. RATE OF RETURN

Q. Should the Commission approve a 9.9 percent return on equity?

[3] Staff/200, Muldoon/3, line 7

A. Yes. As demonstrated by Mr. McKenzie, a 9.9 percent return on equity is an appropriate return. The cost of equity recommendations of Mr. Muldoon and NWIGU witness Mr. Gorman are simply too low and fail to reflect the risk perceptions and return requirements of real-world investors in the capital markets.

Q. If the Commission were to approve the capital structure derived by Mr. Muldoon, would this affect the Company's requested overall rate of return?

A. Yes. If the Commission were to approve a lower equity ratio of 48.9 percent compared to the Company's 50.0 percent, Avista would require a higher return on equity in order to recognize the increased leverage ratio.[4]

IV. COST OF DEBT

Q. Do you agree with Mr. Muldoon's calculation of the cost of long-term debt at 5.095 percent?

A. No, there are several flaws in Mr. Muldoon's calculation, and assumptions within the calculation. First and foremost, Mr. Muldoon chose to calculate the cost of debt as of the <u>end of the rate year</u> (i.e., the cost of debt at September 30, 2018), rather than the cost of debt that will be in effect during the rate effective period. The Company has calculated the cost of debt to be 5.70 percent at September 30, 2017, the approximate point in time when rates from this general rate case will go into effect.

Second, within Mr. Muldoon's calculation for the cost of debt as of September 30, 2018, he removed all of the debt maturing in 2018 (debt that will be in place during the test

[4] Company witness Mr. McKenzie

year), and replaced it with 3, 10 and 30 year maturities. It is not appropriate to remove the existing debt, because it will remain in place during the vast majority of the October 2017 to September 2018 test year. Nor is it appropriate to impute a cost of debt that will not be in effect for the majority of the rate year.

The Company does have a small debt maturity in May 2018 of $7 million, and a large one in June 2018 of $265.5. These maturities occur late in the test year.[5]

Q. How has the Company calculated the cost of debt for this rate case?

A. Consistent with past practices, the Company uses the current debt costs as a starting point in calculating the estimated debt cost. Known changes (i.e. debt maturities and forecasted debt issuances) are then incorporated to reflect the appropriate cost of debt for the rate year. Based on the Company's forecast, evaluation of market conditions, and forward interest rate curves, the Company determines an appropriate amount, tenor, and interest rate to be used for the forecasted debt issuances.

Q. What is the appropriate date to calculate estimated debt cost?

A. As stated earlier, the appropriate date to determine the cost of debt for this case is September 30, 2017, the beginning of the test year. This is consistent with how additions to plant in service are handled in this case, and best aligns with the cost of debt that will be in effect during the period customers' rates are in effect.

Debt financing is made to replace maturing debt, but also to fund new investment in plant in service (rate base additions). Staff has proposed to cut off rate base additions at the effective date for new rates in this case, i.e., September 30, 2017.[6] If rate base additions are

[5] Mr. Muldoon also left out of his calculation the amortization of repurchased debt, which amounts to just over $0.5 million.
[6] Staff/800, Moore/3, ln. 15.

cut off at September 30, 2017, then it is also appropriate to cut off changes to the debt financing used to fund those additions at the same point in time (September 30, 2017), consistent with the matching principle.

Q. Returning to Mr. Muldoon's recommendation to split the debt issuances in 2018 into 3, 10 and 30 year terms, what is Avista response to this testimony?

A. We do not agree with Mr. Muldoon's recommendation. There are a number of factors that should be taken into consideration in choosing the term of new debt issuances. For example, in the current interest rate environment where the interest rate spread for 30-year and 10-year terms is relatively narrow (i.e. presently there is a low premium for 30-year debt versus 10-year debt), it would support increased reliance on longer-term debt.

In addition, the average life of utility assets for Avista exceeds 30 years. A 30-year term for debt is a closer match to the average life of the underlying assets that are being financed.

Also, as explained earlier, the debt issuances in 2018 are toward the end of the October 2017 to September 2018 rate year. Decisions on the term of the debt are generally made closer to the time that new debt is issued. Based on information available today, although the Company will consider some amount of 10-year debt in 2018, the issuances will likely be heavily weighted toward a 30-year term, due in large part to the matching of the financing to the life of the assets being financed, and the narrow rate spread for 30-year vs 10-year terms.

Q. If the Commission were to determine that a prorated amount of the new debt to be issued toward the end of the rate year in this case should be included in this case, did you calculate a pro-rated cost of debt including the maturities and issuance of debt during the test year of October 1, 2017 through September 30, 2018?

A. Yes. Although the Company believes it is not appropriate to do so, should the Commission believe a pro-rated cost of debt is appropriate, the cost of debt would be 5.59 percent (as compared to Avista's proposed 5.7 percent, and Mr. Muldoon's proposal of 5.095 percent). This pro-rated cost of debt includes eight months of the existing $272.5 million debt which matures in June 2018, and four months of $250 million of new debt planned for issuance in June 2018. The calculation also includes one month of $80 million of new debt planned to be issued in September 2018. The replacement debt costs were calculated using forward market prices, including a 130 basis point credit spread, interest rate swap settlements and issuance costs. This cost of debt worksheet is provided in Exhibit 1102.

Q. Do you agree with Mr. Muldoon's exclusion of debt costs related to Pollution Control Revenue Bonds?

A. No, I do not. Mr. Muldoon claims that a portion of the repurchased debt (included on page 4, lines 24 and 25 of Exhibit No. 201) should be excluded because they are Pollution Control Revenue Bonds that support "thermal electric generation in Montana".[7]

With regard to these Pollution Control Revenue Bonds, in the Company's "Application for Approval of an Order Authorizing Security Issuance" in Docket No. UF-4253, which was approved in Order 08-577, on December 4, 2008, the Company specified that Avista:

> may use the funds from issuance and sale of the Securities for any or all of the following purposes: (1) the Applicant's construction, facility improvement, and maintenance programs, (2) retire or exchange one or more outstanding stock, bond, or note issuances, (3) to reimburse the treasury for funds previously expensed, and (4) for such other purposes, as may be permitted by law.[8]

[7] Staff/200, Muldoon/39, l. 12.
[8] Docket No. UF-4253, Section L, p. 3.

While the opportunity to issue Pollution Control Revenue Bonds is related to "electric generation", the funds are used to finance our overall organization, including our Oregon natural gas operations. This "avenue" of financing is a tax-exempt opportunity, resulting in a lower cost of debt for customers as compared to more traditional financing opportunities. The funds related to Pollution Control Revenue Bonds are used as a source of overall financing for the Company, and not the direct financing of pollution control equipment, and therefore should be included as part of Avista's overall cost of debt.

Q. Does that conclude your Reply Testimony?

A. Yes, it does.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

MARK T. THIES
Exhibit No. 1101

Capital Structure, Rate of Return, Cost of Debt

CONFIDENTIAL

Capital Structure, Rate of Return, Cost of Debt

Pages 1 through 2

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

MARK T. THIES
Exhibit No. 1102

Pro Rated Cost of Debt

CONFIDENTIAL

Pro Rated Cost of Debt

Page 1

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

REPLY TESTIMONY OF ADRIEN M. MCKENZIE

REPRESENTING AVISTA CORPORATION

Return on Equity

REPLY TESTIMONY OF ADRIEN M. MCKENZIE

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q. Did you previously submit Direct Testimony in this case?

A. Yes, I did.

Q. What is the purpose of your Reply Testimony?

A. My purpose is to respond to the testimony of Mr. Matt Muldoon, submitted on behalf of the Staff of the Public Utility Commission of Oregon ("OPUC), concerning the fair rate of return on equity ("ROE") for the jurisdictional gas utility operations of Avista Corp. ("Avista" or "the Company"). I will also address the recommendation of Mr. Michael P. Gorman, on behalf of Northwest Industrial Gas Users, to maintain the ROE in this case at the same level that was granted in Avista's last case.[1]

Q. Please summarize the principal conclusions of your Reply Testimony.

A. The cost of equity recommendation of Mr. Muldoon is simply too low and fails to reflect the risk perceptions and return requirements of real-world investors in the capital markets. His ROE recommendation is defective because it is essentially based only on a single, obscure estimation method incorporating a proxy group of only two companies. Without a realistic comparison to the results of other valid ROE approaches and checks of reasonableness, his proposal lacks credibility. My Reply Testimony demonstrates that:

- The OPUC is charged with providing Avista with an opportunity to earn a return that is competitive with other utilities, yet the allowed ROEs and expected earnings for utilities in a realistic proxy group of gas utilities demonstrates that Mr. Muldoon's recommendation is too low to meet this

[1] Avista's current ROE of 9.4% was set in its last Oregon rate case, Docket No. UG-288 (Final Order issued March 15, 2016).

end result test.

- Mr. Muldoon's proxy group, consisting of only two companies, is based on a flawed application of questionable criteria and is too small to provide reliable guidance as to a fair ROE.
- There is no basis to assume that investors reference long-term forecasts of gross domestic product ("GDP") in developing their expectations for utilities, and Mr. Muldoon's reference to this data should be rejected.
- Mr. Muldoon's multi-stage discounted cash flow ("DCF") approach is inconsistent with investors' views and characterized by errors and inconsistencies that undermine reliance on the resulting cost of equity estimates.
- The Capital Asset Pricing Model ("CAPM") analysis conducted by Mr. Muldoon is flawed and incomplete, and results in cost of equity estimates that are far below investors' required return.
- Mr. Muldoon's conclusion that investors would regard Avista as less risky than his proxy companies is without merit.
- Relevant benchmarks and expectations for higher near-term interest rates indicate that Mr. Gorman's proposal to maintain the Company's ROE at the previously-allowed level is short-sighted and not reasonable.

Finally, my Reply Testimony demonstrates that Mr. Muldoon's criticisms of my alternative applications and conclusions are misguided and should be ignored.

II. RESPONSE TO MR. MULDOON

Q. How did Mr. Muldoon arrive at his 9.1% recommended ROE for Avista?

A. Mr. Muldoon's recommended ROE was based solely on the results of two applications of the multi-stage DCF model. Specifically, Mr. Muldoon posited a three-stage scenario over a 30-year time horizon. During the first stage, from 2016 through 2020, Mr. Muldoon assumed that cash flows for each firm in his proxy group would be equal to the annual dividend per share ("DPS") projections published by the Value Line Investment Survey ("Value Line"). During the second stage, from 2021 through 2025, Mr. Muldoon calculated annual cash flows under the assumption that individual growth rates for his proxy firms would converge to that of the overall economy. For the third stage of his analysis, Mr.

Muldoon assumed that all of the proxy group firms would experience dividend growth equal to projected growth in GDP over the years 2026-2045. Finally, Mr. Muldoon calculated a terminal price based on alternative assumptions regarding the valuation of the proxy firms' stock price. Mr. Muldoon then calculated the discount rate that would equate these cash flows to a current average closing stock price.

Mr. Muldoon also calculated a theoretical adjustment to his DCF results to account for differences in financial risk using the "Hamada Equation," and included a 12.5 basis point adjustment for flotation costs. After incorporating these considerations, Mr. Muldoon recommended a 9.1% ROE that "is in the midpoint of a reasonable range of ROEs of 8.8 to 9.3 percent."[2]

Q. Is Mr. Muldoon's recommendation directly related to the results of his analyses?

A. No. There is only a tenuous relationship between the results of Mr. Muldoon's DCF analyses and his ultimate recommendation. For example, Mr. Muldoon's 9.1% ROE is above all of the results produced by his "Model X" application and exceeds all but two of the twelve "Model Y" results summarized on Exhibit Staff/203 Muldoon/1. The fact that Mr. Muldoon was compelled to ignore the vast majority of his own modeling results contradicts his conclusion that "Staff's results are unbiased and reasonable."[3]

A. Comparison of ROE Recommendation to Accepted Benchmarks

Q. Is it widely accepted that a utility's ability to attract capital must be considered in establishing a fair rate of return?

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[2] Staff/200, Muldoon/13.
[3] Staff/200, Muldoon/22.

A. Yes. This is a fundamental standard underlying the regulation of public utilities. The Supreme Court's *Hope*[4] and *Bluefield*[5] decisions established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence and adequate, under efficient and economical management, to maintain and support a utility's credit and enable it to raise money necessary to provide safe and reliable service to its customers.[6] In order to meet these capital attraction standards, an ROE recommendation must grant Avista the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments of similar risk.

Q. Have other regulators recently recognized the importance of these fundamental standards in evaluating a fair ROE?

A. Yes. The Federal Energy Regulatory Commission ("FERC") recently affirmed that its "ultimate task is to ensure that the resulting ROE satisfies the requirements of *Hope* and *Bluefield*."[7] While FERC looks initially to the DCF methodology when evaluating a fair ROE, it has also made clear that it is the result reached, not the method used, that determines whether an ROE is just and reasonable.[8] As FERC observed:

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic

[4] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[5] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[6] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 694 (1923) ("*Bluefield*"); *FPC v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944) ("*Hope*").
[7] *Coakley v. Bangor Hydro-Electric Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 144 (2014) ("Opinion No. 531").
[8] *See, e.g.,* Opinion No. 531 at P 142.

> anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns . . .[9]

FERC concluded that a mechanical application of the DCF model using GDP growth would result in an ROE that was insufficient to meet regulatory standards, and that "it is necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs," to determine a just and reasonable ROE.[10] In Opinion Nos. 531 and 551, FERC found that risk premium, CAPM, and expected earnings methodologies directly comparable to those applied in my Direct Testimony in this case were informative and FERC relied on these analyses to set the just and reasonable point ROE at the upper end of the DCF range.

Q. Does Mr. Muldoon's ROE recommendation meet these fundamental standards?

A. No. While Mr. Muldoon correctly recognized the importance of these underlying economic and legal standards,[11] the end-result of his analyses fails to meet these requirements. The illustration below summarizes the insufficiency of Mr. Muldoon's proposal as compared to accepted benchmarks.

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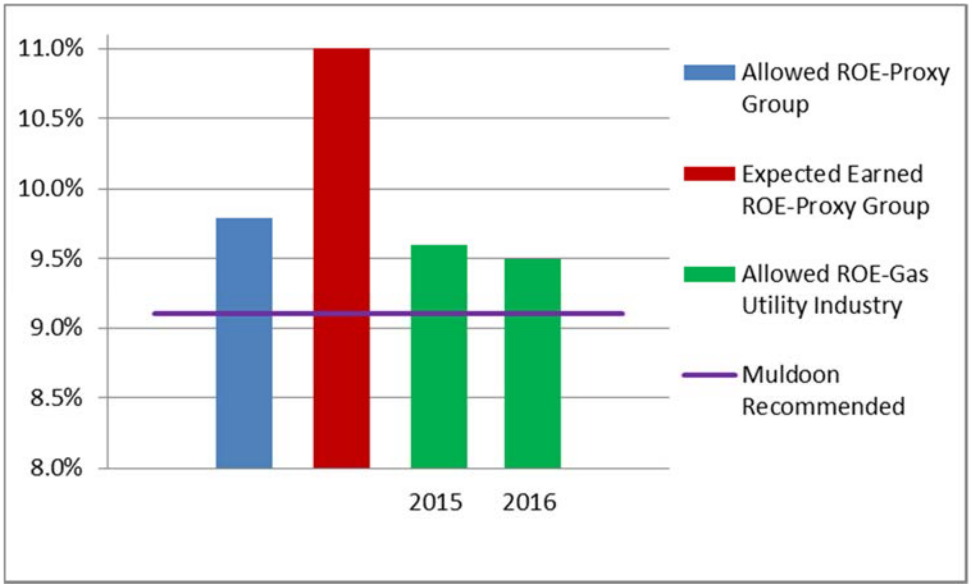
[9] *Id.* at P 41. Application of the two-step DCF method without the "mid-point of the upper half of the range" adjustment would have resulted in an ROE of only 9.39%, a value FERC found unreasonable. *Id* at P 142.
[10] Opinion No. 531 at P 145 (2014).
[11] Staff/200, Muldoon/6.

<u>Illustration No. 1:</u>

COMPARISON OF STAFF ROE TO ACCEPTED BENCHMARKS



Allowed ROEs (blue and green bars in chart above) provide one gauge of reasonableness for the outcome of a cost of equity analysis.[12] In considering utilities with comparable risks, investors will always seek to provide capital to the opportunity with the highest expected return. If a utility is unable to offer a return similar to that available from other investment opportunities posing equivalent risks, investors will become unwilling to supply the utility with capital on reasonable terms. While the ROEs approved in other jurisdictions do not constrain the OPUC's decision-making in this proceeding, it is important to understand that there would be a disincentive for investors to provide equity capital to Avista if the Commission were to apply an unreasonably low ROE, compared to entities of comparable risk.

[12] Mr. Muldoon acknowledged that his evaluation was "informed by authorized ROEs in other parts of the country." Staff/200, Muldoon/37-38.

The ROE proposed by Mr. Muldoon falls short of average returns authorized for other gas utilities. Table No.1 presents the average allowed ROEs for gas utilities reported by Regulatory Research Associates ("RRA") over the last eight quarters:

Table No. 1:

AUTHORIZED ROE - GAS UTILITIES

	2015	2016
Q1	9.47%	9.48%
Q2	9.43%	9.42%
Q3	9.75%	9.47%
Q4	9.68%	9.60%
Average*	**9.60%**	**9.50%**

*Weighted average based on the number of cases in each quarter.

Meanwhile, as shown on Exhibit Avista/1201, Schedule AMM-15, data reported by RRA and other sources indicates that the average authorized ROE for the firms in a realistic gas proxy group is 9.79%.[13] Mr. Muldoon's proxy group actually consists of just two companies (Northwest Natural Gas Company and Southwest Gas). The average allowed ROE for Mr. Muldoon's two proxy utilities is 9.61%. In other words, allowed ROEs for the utilities that are comparable to Avista indicate that his recommended ROE is too low to meet regulatory standards. Indeed, Mr. Muldoon grants that the results of his analyses "are low compared with regulated U.S. utilities' authorized return on equity capital in 2016..."[14]

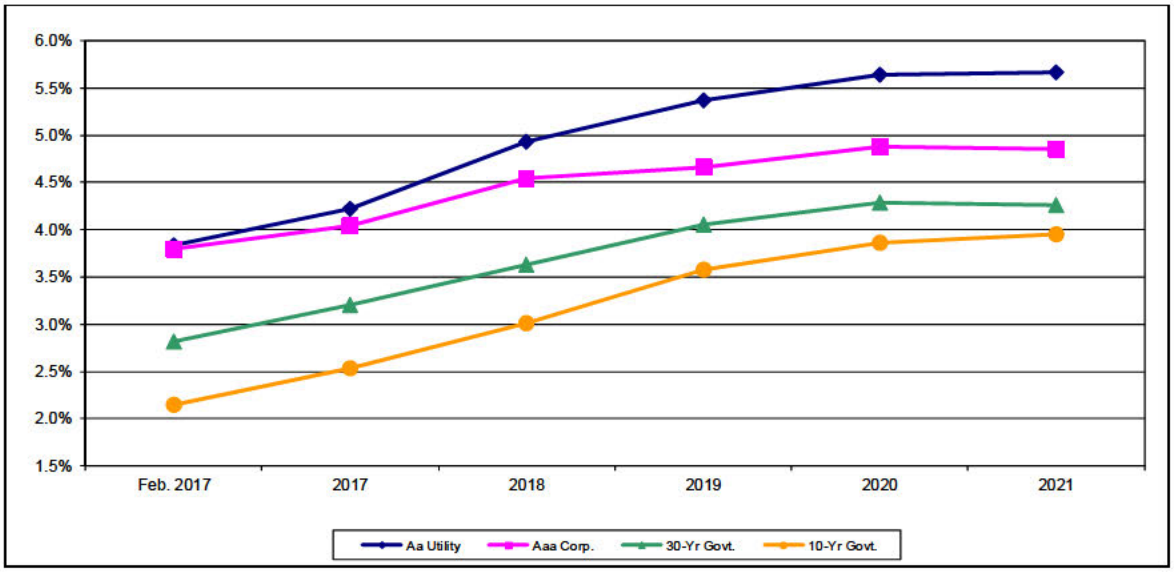
Q. What is the expected direction of interest rates and how does this impact the ROE analysis in this proceeding?

[13] As discussed later, I will show that Mr. Muldoon erroneously discarded six eligible utilities from the gas proxy group. When these companies are reinstated, the reasonable gas proxy group consists of the same eight firms that I reference in my Direct Testimony.
[14] Staff/200, Muldoon/26.

A. Interest rates are expected to increase. Below is an update of Illustration No. 4 (Interest Rate Trends) from my Direct Testimony:

<u>Illustration No. 2:</u>

INTEREST RATE TRENDS



<u>Source:</u>
Value Line Investment Survey, Forecast for the U.S. Economy (Mar. 3, 2017)
IHS Global Insight (Jan. 3, 2017; Nov. 30, 2016)
Energy Information Administration, Annual Energy Outlook 2017 (Jan. 5, 2017)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 12 (Dec. 1, 2016)

As the figure shows, investors continue to anticipate that interest rates will increase significantly from present levels. These projections are from forecasting services that are highly regarded and widely referenced, as I discuss in my Direct Testimony (at 11).

Q. Have recent decisions by the Federal Reserve reinforced investor sentiment that interest rates are increasing?

A. Yes. On March 15, 2017 the Federal Reserve increased its target range for the Federal Funds rate by another 25 basis points. This is in addition to a similar increase on December 2016. Several more rate hikes by the Federal Reserve are expected in 2017.

Q. Does Mr. Muldoon acknowledge that interest rates are expected to increase?

A. Yes. In applying the CAPM, Mr. Muldoon relies on "market forward" Treasury rates for the risk-free component of his analysis. The following table summarizes the increase in interest rates implied in his analysis.

Table No. 2:

MR. MULDOON'S IMPLIED INTEREST RATE INCREASES

	U.S. Treasury Rates	
	10-year	30-year
Feb. 2017 (a)	2.42%	3.03%
June 2018 (b)	3.68%	4.30%
Interest Rate Increase	**1.26%**	**1.27%**

Notes:
(a) https://fred.stlouisfed.org
(b) Staff/206 Muldoon/1

Q. What do these expectations imply with respect to the ROE for Avista more generally?

A. Current capital market conditions continue to reflect the impact of the Federal Reserve's unprecedented monetary policy measures. As a result, current capital costs are not representative of what is likely to prevail over the period when rates authorized in this proceeding will be in effect. In a recent opinion, FERC reiterated its position that current capital market conditions may undermine the reliability of the DCF model, for this reason, ROE model results should be evaluated with even more critical judgment and focus:

> As described above, evidence in the record regarding historically low interest rates and Treasury bond yields as well as the Federal Reserve's large and

> persistent intervention in markets for debt securities are sufficient to find that current capital market conditions are anomalous.[15]
>
> Similarly, while Complainants provide evidence that interest rates have been trending downwards, the current levels may be so low as to cause irregularities in the outputs of the DCF. Despite such yields remaining low for several years, we find that they are anomalous and could distort the results of the DCF model.[16]

Current capital market conditions make the process of setting a fair ROE even more demanding. In this environment, it is imperative that ROE model results be thoroughly tested against accepted benchmarks and compared to other checks of reasonableness.

Q. Are expected earned rates of return also a valid benchmark for evaluating Mr. Muldoon's ROE recommendation?

A. Yes. Expected earned rates of return for other utilities provide another useful measure to gauge the reasonableness of Mr. Muldoon's ROE recommendation. Reference to expected earnings is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope*. This test recognizes that investors compare the allowed ROE with returns available from other alternatives of comparable risk.

Importantly, the expected earnings approach explicitly recognizes that regulators do not set the returns that investors earn in the capital markets. Regulators can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This

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[15] *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 at P 124 (2016), *reh'g pending* ("Opinion No. 551").
[16] *Id.*

opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. Has the expected earnings approach been recognized as a valid ROE benchmark?

A. Yes. This method predominated before the DCF model became fashionable with academic experts, and it continues to be used around the country.[17] A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal," particularly when compared to the DCF and CAPM methods.[18] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[19] as well as sound regulatory economics. Similarly, *New Regulatory Finance* concluded that, "because the investment base for ratemaking purposes is expressed in book

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[17] For example, the Virginia State Corporation Commission is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. Similarly, FERC concluded that, "The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity." Opinion No. 531-B, 150 FERC ¶ 61,165 at P 128 (2015). Another example is the Idaho Public Utilities Commission, which also references return on book equity evidence. *See, e.g.,* Order No. 29505, Case No. IC-E-03-13 at 38 (Idaho Public Utilities Commission, May 25, 2004).
[18] Parcell, David C., THE COST OF CAPITAL – A PRACTITIONER'S GUIDE at 115-116 (2010).
[19] *Id.*

value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[20]

Q. Do expected earned rates of return for the gas proxy group also demonstrate that Mr. Muldoon's ROE recommendation is too low?

A. Yes. The year-end returns on common equity projected by Value Line over its forecast horizon for the firms in a realistic proxy group are shown on Exhibit Avista/1201, Schedule AMM-16. Once adjusted to mid-year,[21] reference to expected earnings implied an annual average cost of equity for the utilities referenced by Mr. Muldoon of 11.0%. These book return estimates are an "apples to apples" comparison to Mr. Muldoon's ROE recommendation. If Avista is only allowed the opportunity to earn a 9.1% return on the book value of its equity investment, as recommended by Mr. Muldoon, while other comparable utilities are expected to earn an average of 11.0%, the implications are clear – Avista's investors will be denied the ability to earn a return that is comparable to those available from investments with comparable risk.

Q. What other evidence indicates that Mr. Muldoon's recommended ROE fails to meet regulatory standards?

A. As discussed in my Direct Testimony,[22] expected rates of return for firms in the competitive sector of the economy are also relevant in determining the appropriate return to be allowed for rate-setting purposes. The idea that investors evaluate utilities against the

[20] Roger A. Morin, New Regulatory Finance, *Public Utilities Reports, Inc.* (2006) at 395.
[21] Because Value Line reports end-of-year book values, an adjustment factor was incorporated to compute an average rate of return over the year, which is consistent with the theory underlying this approach. Use of an average return in developing the sustainable growth rate is well supported. *See, e.g.*, Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 305-306 (2006), which discusses the need to adjust Value Line's end-of-year data. FERC has affirmed the need for this adjustment to "r" in *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008).
[22] Avista/300, McKenzie/54-58.

returns available from other investment alternatives – including the low-risk companies in my Non-Utility Group – is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless. It follows that utilities must offer a return that can compete with other risk-comparable alternatives, or capital will simply go elsewhere.

In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that the degree of risk, not the nature of the business, is relevant in evaluating an allowed ROE for a utility.[23] The cost of capital is based on the returns that investors could realize by putting their money in other alternatives, and the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment.

Q. Does Mr. Muldoon recognize this principal?

A. Yes. Mr. Muldoon cites the *Hope* and *Bluefield* standards and says that his recommendation is consistent with the requirement that it be "commensurate with the return on investments in other enterprises having corresponding risks."[24] Similarly, Mr. Muldoon notes that Avista's ROE should be "commensurate with that of other utilities *and other investment opportunities with risk exposure similar to Avista's*."[25] In other words, Mr. Muldoon recognized that investors gauge their required returns from utilities against those available from utility <u>and</u> non-utility firms of comparable risk. My reference to a low-risk

[23] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[24] Staff/200, Muldoon/6.
[25] Staff/200, Muldoon/6.

Non-Utility Group is entirely consistent with the guidance of the Supreme Court and the principles outlined in Mr. Muldoon's own testimony.

Q. Did Mr. Muldoon present any objective evidence that would support a finding that your Non-Utility Proxy Group is riskier than Avista or the companies in his proxy group?

A. No. Mr. Muldoon presented no meaningful evidence to rebut the results for my Non-Utility Group, or otherwise demonstrate that my Non-Utility Group is riskier than Avista or the gas and water utilities Mr. Muldoon considered as potential proxies. He says only that "two-thirds of investors in Avista's common stock are sophisticated fund managers for whom non-utility stocks would be acceptable substitutes."[26] In fact, this observation supports precisely the opposite conclusion from that drawn by Mr. Muldoon. Sophisticated fund managers would place more emphasis on returns and corresponding risks than on operational particulars such as product lines or marketing strategies.

In any event, my Direct Testimony did not contend that the operations of the companies in the Non-Utility Group are comparable to those of utilities. Clearly, operating a worldwide enterprise in the beverage, pharmaceutical, retail, or food industry involves unique circumstances that are as distinct from one another as they are from a gas utility. But as the Supreme Court recognized, investors consider the expected returns available from all these opportunities in evaluating where to commit their scarce capital. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return. So long as the risks associated with the Non-Utility Group are comparable to Avista the resulting DCF estimates

[26] Staff/200, Muldoon/31.

provide a meaningful benchmark for the cost of equity. As shown in Table No. 8 to Avista/300, McKenzie/57, average DCF cost of equity estimates for the Non-Utility Group ranged from 10.1% to 11.9%. The comparison of objective risk measures presented in my Direct Testimony demonstrates conclusively that the Non-Utility Group is regarded as less risky than Avista, making it a conservative benchmark for a fair ROE in this case.[27]

Q. Does the fact that utilities are regulated somehow invalidate this comparison of objective risk indicators?

A. Absolutely not. While I agree that utilities operate under a regulatory regime that differs from firms in the competitive sector, any risk-reducing benefit of regulation is already incorporated in the overall indicators of investment risk presented in Table No. 8 to my Direct Testimony. The impact of regulation on a utility's investment risks is one of the key elements considered by credit rating agencies and investment advisory services, such as Standard & Poor's Corporation ("S&P") and Value Line, when establishing corporate credit ratings and other risk measures. Meanwhile, the beta values supported by modern financial theory are premised on stock price volatility relative to the market as a whole, and are not dependent on an assessment of firm-specific considerations. As a result, the impact of regulatory differences on investment risk is accounted for in the published risk indicators relied on by investors and cited in my Direct Testimony.

Q. What do these benchmarks you discuss imply with respect to Mr. Muldoon's ROE recommendation?

[27] Table No. 7 at Avista/300, McKenzie/56.

A. As set forth above, objective consideration of regulatory standards and alternative benchmarks demonstrate that the 9.1% ROE recommended by Mr. Muldoon is too low and violates the economic and regulatory standards underlying a fair ROE.

Q. What other pitfalls are associated with an ROE that falls short of those authorized for other utilities?

A. Adopting an ROE for Avista that is well below the ROEs for utilities with even less investment risk could lead investors to view the Commission's regulatory framework as unsupportive, an outcome that would undermine investors' willingness to support future capital availability for investment in Oregon utilities. Security analysts study regulatory orders in order to advise investors where to invest their money. Moody's Investors Service ("Moody's) noted that, "[f]undamentally, the regulatory environment is the most important driver of our outlook."[28] Similarly, S&P concluded that "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[29] Value Line agrees when it states, "[a]s we often point out, the most important factor in any utilities success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates."[30]

Utilities and their investors must lock up large sums of capital and are exposed to many risks over the long time horizon when they invest in utility infrastructure. At the ROE proposed by Mr. Muldoon, the ability of Oregon utilities to attract and retain capital could be

[28] Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, INDUSTRY OUTLOOK (Feb. 19, 2014).
[29] Standard & Poor's Corporation, *Key Credit Factors For The Regulated Utilities Industry*, RATINGSDIRECT (Nov. 19, 2013).
[30] Value Line Investment Survey, *Water Utility Industry* (Jan. 13, 2017) at 1780.

compromised, leading investors to view the Commission's regulatory framework as unsupportive. This would have a long-term, chilling effect on investors' willingness to support capital investment in utility infrastructure, not just for the Company, but for all utilities in the state. On the other hand, if Commission actions instill confidence that the regulatory environment is supportive and provides the opportunity to earn a fair return, investors will provide the necessary capital, even in times of turmoil in the financial markets.

B. Proxy Group Evaluation

Q. How is it that Mr. Muldoon ended up with a proxy group of only two companies?

A. There are currently 10 gas companies included in Value Line's gas utility industry group and I agree with Mr. Muldoon that these firms provide a sound starting point in identifying a reasonable proxy group. From this list, I eliminated two companies: NiSource (due to its recent spinoff of Columbia Pipelines) and UGI (due to a predominance of propane operations). Mr. Muldoon also eliminated these two companies.

Mr. Muldoon went further, however, and eliminated six more potential proxy companies: Atmos Energy and Spire Inc. (due to a business sale and an acquisition, respectively); Chesapeake Utilities (due to his misguided claim that it is not included in Value Line's gas utility group); and New Jersey Resources, South Jersey Industries, and WGL Holdings (due to their failure to meet his "regulated revenue" criterion). Eliminating these six companies, coupled with our two mutual exclusions, left only two firms in his proxy group: Northwest Natural Gas and Southwest Gas.[31]

Q. What is the primary problem with Mr. Muldoon's proxy group?

[31] Muldoon workpaper, AVA UG 325 Exh 202 203 206 ROE Muldoon.xlsx, (tab "Peer Screen N Gas).

A. The group from which he draws his ultimate conclusions consists of only two companies. Conceptually, the issue of proxy group size is akin to the use of sampling in statistical analyses. In statistics, a "true" value is often estimated by reference to sample observations, with the analyst having greater confidence in the applicability of the estimated results as the size of the sample increases. The inherent limitations of the DCF model and other quantitative approaches mean that the potential to misjudge investors' required return increases as the size of the proxy group shrinks. Because our estimating tools (*e.g.*, applications of the DCF model based on observable data) provide imperfect readings, the results of the DCF approach may deviate from the accepted risk-return tradeoff. As a result, using a constrained group of proxy companies, as Mr. Muldoon has done, increases the potential for error when applying quantitative methods to estimate the cost of equity.[32]

To make matters worse, if Mr. Muldoon had strictly applied his own criteria, he would have been left in the even more untenable position of having a comparable group composed of only one company. Mr. Muldoon's workpapers indicate that regulated gas operations for Southwest Gas accounted for 67% of total revenues,[33] which falls below Mr. Muldoon's stated threshold of 75%. In other words, Southwest Gas does not meet Mr. Muldoon 's own proxy group criterion and should have been eliminated, leaving Northwest Natural Gas as the only remaining proxy company. Such an irrational result only serves to further reinforce the tenuous nature of his analysis and the lack of credible support for Mr. Muldoon's recommendations.

[32] This has been recognized by other regulators. *See, e.g.*, *Williston Basin Interstate Pipeline Co.*, 104 FERC ¶ 61,036, at 14-15 (July 3, 2003).
[33] Muldoon workpaper, AVA UG 325 Exh 202 203 206 ROE Muldoon.xlsx, (tab "Peer Screen N Gas, cell U19).

Q. Do you agree with Mr. Muldoon that the nature of a utility's revenues is a valid criterion in selecting a proxy group for Avista?

A. No. Mr. Muldoon argued for the elimination of companies if less than 75% of total revenues were attributable to regulated gas utility operations.[34] However, Mr. Muldoon failed to demonstrate how this subjective criterion translates into differences in the investment risks perceived by investors, while comparisons of objective indicators demonstrates that investment risks for the firms in my proxy groups are relatively homogeneous and comparable to Avista.

Q. Did Mr. Muldoon demonstrate any nexus between a subjective criterion based on regulated revenues and objective measures of investment risk?

A. No. Under the regulatory standards established by *Hope* and *Bluefield*, the salient criterion in establishing a meaningful proxy group to estimate investors' required return is relative risk, not the source of the revenue stream or the nature of the asset base. Mr. Muldoon presented no evidence to demonstrate a connection between the subjective revenue criterion that he employed and the views of real-world investors in the capital markets. Nor did Mr. Muldoon provide any evidentiary support for a 75% threshold. Mr. Muldoon's testimony offers no explanation why a revenue cut-off of 75%, rather than, say, 50% or 65%, supposedly impacts a utility's operations sufficiently to justify its exclusion. The fact that Mr. Muldoon's testimony in Avista's last rate proceeding argued for the elimination of companies if less than <u>80%</u> of revenues attributable to <u>regulated operations</u> further highlights the capriciousness of his evaluation.[35]

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[34] Staff/200, Muldoon/19.
[35] Docket No. UG-288, Staff workpapers at AVA UG 288 GRC Exh 202 Muldoon Workpapers.xlsx, tab "Peer

Due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as revenues and total assets, between regulated and non-regulated sources. As a result, even if one were to ignore the fact that there is no clear link between the nature of a utility's revenues or assets and investors' risk perceptions, it is generally not possible to accurately and consistently apply asset or revenue-based criteria. In fact, other regulators have rebuffed these notions, with FERC specifically rejecting arguments that utilities "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[36]

Q. Can you illustrate how a screen based on revenue composition can lead to an erroneous conclusion?

A. Yes. Consider Chesapeake Utilities, which Mr. Muldoon eliminated because its regulated revenue level of 62% was less than his 75% threshold.[37] However, upon further examination of Chesapeake Utilities' business segments it becomes clear that revenues are a faulty measure of its core business. Its unregulated business consists of, among other things, propane and crude oil wholesale marketing and natural gas marketing operations. These businesses tend to be low margin operations, which contribute a much smaller portion of operating income. In fact, regulated energy operations constitute 83% of Chesapeake Utilities' operating income and account for 82% of its investment in property, plant, and

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Screen N Gas."
[36] *Bangor Hydro-Elec. Co*., 117 FERC ¶ 61,129 at PP 19, 26 (2006).
[37] Mr. Muldoon also excluded Chesapeake Utilities based on the incorrect assertion that it is not followed by Value Line as a gas utility. I address this error subsequently.

equipment.[38] These indicators confirm Value Line's assessment that Chesapeake Utilities is, indeed, predominately viewed by investors as a regulated gas utility.

Q. Can this analysis be extended to other companies wrongfully eliminated by Mr. Muldoon?

A. Yes. Mr. Muldoon's 75% regulated <u>revenue</u> test eliminated three other eligible gas utilities: New Jersey Resources (25%), South Jersey Industries (50%), and WGL Holdings (49%).[39] An examination of <u>income</u> measures for these companies tells a different story, however. In their latest financial documents, New Jersey Resources reports that regulated natural gas operations contributed 58% of its total net income, South Jersey's regulated gas utility contributed 65% of its total operating income, and for WGL, its regulated utility contributed 71% of its earnings before interest and taxes.[40] All of these revised measures indicate these companies are, at their core, regulated gas utility companies. Thus, even ignoring the lack of a direct connection between Mr. Muldoon's revenue criterion and investment risk, this evidence indicates that these companies should all be included in the gas proxy group in this proceeding.

Q. Are there other apparent inconsistencies and practical problems associated with Mr. Muldoon's implementation of his peer group screens?

A. Yes. In addition to his flawed revenue screen, Mr. Muldoon excluded Chesapeake Utilities because he claims that it is a "diversified company…rather than a gas

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[38] Chesapeake Utilities Corporation, 2016 SEC Form 10-K.
[39] Staff/202, Muldoon/2.
[40] 2016 SEC Form 10-K for each company. Although, AltaGas Ltd. has since announced its intention to acquire WGL (on January 25, 2017), this action happened well after the analysis in this case was completed. For instance, the stock price data relied on by Mr. Muldoon was all gathered in 2016 (from the first day of the months, October, November, and December).

utility followed by [Value Line]."[41] This is incorrect. Value Line initiated coverage of Chesapeake Utilities in June 5, 2015, and classifies this company in its Natural Gas Utility Group, which also includes Mr. Muldoon's two peer companies. I have included a copy of Value Line's current report on Chesapeake Utilities from its Natural Gas Utility industry group as Avista/1201, Schedule AMM-17. Value Line's natural gas utility industry group consists primarily of gas utilities regulated by the jurisdictions in which they operate. Chesapeake Utilities is clearly a constituent of this group and there is no basis for Mr. Muldoon's contrary claim. Considering the comparability of objective risk measures documented in my Direct Testimony, and the fact that the investment community regards this group of gas utilities to be representative of the industry, there is no basis to subjectively and artificially narrow the proxy group.[42]

Q. Do you agree with Mr. Muldoon's implementation of his criterion based on mergers and acquisitions?

A. No. While I do not disagree that ongoing participation in a major acquisition or merger is a legitimate consideration in evaluating proxy companies, Mr. Muldoon's approach is not reasonable. Analytical methods used to estimate the cost of equity – including the multistage DCF model favored by Mr. Muldoon – are forward-looking and based on investors' future expectations, not on data over an arbitrary historical period.

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[41] Staff/200, Muldoon/19-20. Similarly, Mr. Muldoon's workpapers reports that, "Chesepeake [sic] Utilities Corp. (CPK) is a diversified company NOT followed by Value Line, as a Local Gas Distribution Co." AVA UG 325 Exh 202 203 206 ROE Muldoon.xlxs at tab "Peer Screen N Gas."

[42] In addition to its Natural Gas Utility group, Value Line also covers firms classified in the Natural Gas Diversified Group, which consists of businesses that produce, market, and transport natural gas. Included within this diversified gas industry group is the firm, Chesapeake Energy. It is possible Mr. Muldoon confused Chesapeake Energy, which is included in the gas diversified group, with Chesapeake Utilities, which is included in the gas utility group. In any event, Chesapeake Utilities is considered by the investment community to be a gas utility and should be included in the proxy group in this proceeding.

Current stock prices and expected growth rates already incorporate the investment community's assessment of completed mergers and acquisitions. Because there is no reason to expect that past transactions, which are well understood by the investment community, would lead to distortion in the inputs to quantitative methods such as the DCF model, there is no basis to exclude potential proxy companies on this basis.

For instance, Mr. Muldoon eliminates Atmos Energy from his proxy group apparently because it "sold off most of its non-regulated businesses to focus on natural gas core business."[43] But excluding a gas utility because it has become more focused on regulated gas utility operations makes no sense. Furthermore, Value Line reports that Atmos is selling its unregulated business for $38.3 million plus estimated working capital of $103.2 million.[44] Atmos Energy Corporation has a market capitalization of $8.1 billion. Thus, the impact of this transaction is immaterial and there is no basis to eliminate Atmos from the proxy group.[45]

Mr. Muldoon also eliminated Spire, Inc. (formerly the Laclede Group, Inc.) because of its September 2016 acquisition of EnergySouth, Inc., the parent company of Mobile Gas and Willmut Gas. The purchase consideration was $344 million.[46] With a market capitalization prior to the acquisition of approximately $3.0 billion, this transaction will not have a demonstrative impact on the financial parameters of Spire.[47] Spire is adding just over 100,000 new customers (85,000 from Mobile Gas and 19,000 from Willmut) to its existing base of roughly 1.6 million customers,[48] which represents a change of approximately 6.5%.

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[43] Staff/200, Muldoon/10.
[44] The Value Line Investment Survey (Mar. 3, 2017).
[45] Value Line concluded that the impact of the transaction "will not be substantial." *Id.*
[46] PR Newswire, Sep. 12, 2016.
[47] The Value Line Investment Survey (Sep. 2, 2016).
[48] PR Newswire, Sep. 12, 2016.

Both of the acquired utilities are purely regulated natural gas distribution companies and their businesses will fold seamlessly into Spire's existing gas utility organization. Mr. Muldoon has provided no evidence of any distortion related to this transaction that would support eliminating Spire from the proxy group.

Q. Are there other conceptual issues that you have with the proxy group selection process relied on by Mr. Muldoon?

A. Yes. Mr. Muldoon required that his peer companies have a capital structure composed of less than 56% long-term debt.[49] This criterion is not justified. Mr. Muldoon's focus on capital structure, and the relative risk associated with debt leverage, ignores the fact that this is only one facet of a company's overall investment risk. An assessment of a utility's risk relative to a proxy group should be based on the utility's total investment risk, not one aspect of risk such as relative financial leverage. For example, consider the credit ratings assigned to a utility by S&P and Moody's, which encompass a comprehensive evaluation of the utility's overall business and financial risks. The evaluation of financial risk involves an examination of financial data concerning earnings protection, capital structure, cash flow adequacy, and financial flexibility. Because the net impact of the financial risks associated with a utility's capital structure is already reflected in corporate credit ratings, there is no basis for Mr. Muldoon to focus on this single consideration, to the exclusion of all others. As a result, there is simply no basis for the capital-structure related criterion proposed by Mr. Muldoon.

Q. Mr. Muldoon elected to consider cost of equity estimates for water utilities, rather than the combination electric and gas utilities examined in your Direct Testimony.

[49] Staff/200, Muldoon/19.

Do you agree with Mr. Muldoon that water utilities provide a better fit for Avista's profile than the Company's peers?

A. No. The only support Mr. Muldoon offers for his reference to water utility companies is a cryptic assertion that water utilities "closely track average gas utility performance."[50] But considering the fact that Avista is principally engaged in providing regulated electric and gas utility service, the combination utilities examined in my Direct Testimony provide a more comparable benchmark for investors' expectations and requirements. Moreover, Mr. Muldoon has presented no evidence that would indicate that the investment community would view water companies as a superior benchmark to combination utilities when evaluating an investment in Avista. For example, while Moody's has determined that there are sufficient similarities between electric and gas utilities to warrant a combined approach to credit analysis under a shared framework, it explicitly excludes water utilities from this common ratings methodology:

> This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, *Regulated Water Companies*, and Natural Gas Pipelines.[51]

Finally, other factors also impinge on the relevance of the water utilities included in Mr. Muldoon's analysis. For example, with respect to The York Water Company included in his proxy group, Value Line noted that this company "is the smallest regulated utility in the water industry,"[52] and observed that:

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[50] Staff/200, Muldoon/20.
[51] Moody's Investors Service, "Regulated Electric and Gas Utilities," *Ratings Methodology* (Dec. 23, 2013) (emphasis added).
[52] The Value Line Investment Survey at 1789 (Oct. 16, 2015).

> Most institution accounts don't like owning more than 3% to 5% of any one company's stock for diversification reasons. A market cap of around $275 million just isn't large enough to take a position.[53]

This indicates that the investment community is unlikely to regard this small water company as a potential substitute for an investment in Avista's common stock, and further undermines Mr. Muldoon's reference to water utilities in his analysis.

Q. Please summarize your proxy group evaluation.

A. Mr. Muldoon has unnecessarily reduced his gas utility peer group to just two companies. Consequently, his analysis is unsound and subject to error. As I have demonstrated, six gas companies included in Value Line's group of regulated gas utilities were improperly eliminated by Mr. Muldoon. Adding back these legitimate utilities results in a reasonable gas proxy group of eight companies that is identical to the group that I relied on in my Direct Testimony.

C. Discounted Cash Flow Model

Q. What are the primary misconceptions underlying Mr. Muldoon's reference to GDP growth?

A. There are several:

1. Practical application of the DCF model does not require a long-term growth estimate over a horizon of 30 years and beyond – it requires a growth estimate that matches investors' expectations.
2. Evidence supports the conclusion that investors do not reference long-term GDP growth in evaluating expectations for individual common stocks, including those in the utility industry.
3. The theoretical proposition that growth rates for all firms converge to overall growth in the economy over the very long horizon does not guide investors' views, and growth rates for utilities can and do exceed GDP growth.

[53] *Id.*

4. There is no evidence that investors' growth expectations for regulated gas utilities have begun to converge to that of the economy.

Q. Does the multi-stage form of the DCF model used by Mr. Muldoon provide a better guide to investors' requirements?

A. No. While multi-stage analyses, such as that used by Mr. Muldoon, can be used to estimate the cost of equity, these approaches increase the number of inputs that must be estimated and add to the computational difficulties. This makes the results of non-constant growth DCF applications sensitive to changes in assumptions, and therefore subject to greater controversy in a rate case setting. Just as importantly, to the extent that each of these time-specific suppositions about future cash flows do not reflect what real-world investors actually anticipate, the resulting cost of equity estimate will be biased. Indeed, the benchmark for growth in a DCF model is <u>what investors expect</u> when they purchase stock. We can only infer investors' required return if we can replicate the expectations that are behind observable market prices. In practice, applying a non-constant model such as Mr. Muldoon's three-stage DCF would lead to error unless there is reason to believe that investors' expectations match the growth pattern assumed in the model.

Q. Are there times when a multi-stage DCF model could fit investors' expectations?

A. Yes. For example, in the 1990s when investors thought the electric utility was transitioning to non-regulated markets, two-stage models did fit investors' expectations. The first stage was based on expectations of growth rates under regulation and the second stage would be more akin to non-utility growth rates. A number of experts presented two-stage models based on investors' expectations of a transition and a number of regulatory agencies found these models to be reasonable. For example, Mr. Muldoon cites the OPUC's 2001 decision in Docket No. UE 115 as support for his sole reliance on the three-stage DCF model, which specifically highlighted the significance of "the ongoing restructuring of the electric industry."[54] But expectations of widespread deregulation have waned and Mr. Muldoon has presented no evidence that his three-stage model fits the expectations that investors currently build into utility stock prices.

Q. Is there any evidence to conclude that Mr. Muldoon's multi-stage DCF model currently reflects the expectations of real-world investors?

A. No. There is no basis to assume that the growth scheme of Mr. Muldoon's three-stage DCF model is at all related to the expectations that investors have when they purchase stock. While Mr. Muldoon asserts that his multi-stage rendition of the DCF model is "conventional,"[55] he has not shown that investors view the future the way he has constructed it in his model. That is, Mr. Muldoon's DCF analysis is a <u>mechanistic approach</u> that ignores the expectations and requirements of capital markets. While the complexity of multi-stage DCF models may impart an aura of accuracy, the fact remains that the investment community does not look to 20-year GDP growth rates ten years hence when evaluating an investment in one of Mr. Muldoon's comparable utilities, and investors' current view of gas utilities does not anticipate a series of discrete, clearly defined stages. As a result, there is no discernable transition that would support use of the multi-stage DCF approach.

Q. The DCF model is based on the assumption of an infinite stream of cash flows. Why wouldn't Mr. Muldoon's multi-stage model using GDP growth make sense?

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[54] *Public Utility Commission of Oregon*, Order No. 01-777 at 27 (2001).
[55] Staff/200, Muldoon/15.

A. This view confuses the theory underlying the DCF model with the practicalities of its application in the real world. Analytical models such as the DCF model are inherently abstractions of reality. The underlying theory requires any number of assumptions, many of which differ considerably from the situation that confronts actual investors in the capital markets. For example, apart from a constant growth rate into perpetuity, the theoretical model requires that dividends, earnings, and stock prices grow at exactly the same rate forever.

Such strict assumptions are never met in practice. While this notion of long-term growth should presumably relate to the specific firm at issue, or at the very least to a particular industry, there are no long-term growth projections available for the companies in Mr. Muldoons's proxy group or for the gas utility industry as a whole. Rather than applying the DCF model in a way that is consistent with the information that is available to investors and how they use it, the use of GDP growth seeks to mold investor behavior around the theoretical assumptions of a financial model. The only relevant growth rate is the growth rate used by investors. Investors do not have clarity to see far into the future, and there is little to no evidence to suggest that investors share the view that growth in GDP must be considered a limit on earnings growth over the long-term.

Q. Are long-term GDP growth rates commonly referenced as a direct guide to future expectations for specific firms, such as gas utilities?

A. No. Certainly investors consider broad secular trends in economic activity as one foundation for their expectations for a particular industry or firm. But the idea that investment advisory services view GDP growth as a direct guide to long-term expectations for a particular firm – much less every firm in an entire industry – is not borne out by evidence.

In contrast to this notion, a brief perusal of the *Wall Street Journal* or a few minutes watching CNBC confirm that in the financial media there are many references to three-to-five year earnings growth forecasts for individual companies and very few references to very long-term GDP forecasts. Long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for individual firms. For example, Value Line reports are routinely relied on as an important guide to apply the DCF model to utilities.[56] But despite Staff's suggestion that GDP has a fundamental role in shaping investors' growth estimates, Value Line does not even mention trends in GDP in its evaluation of the firms in the gas, electric, or water utility industries.

Value Line's singleness of purpose is to inform investors of the pertinent factors that impact future expectations specific to each of the common stocks it covers. If the trajectory of GDP growth out to the year 2045 and beyond had direct relevance in investors' evaluation of utility common stocks, it would be logical to assume that Value Line or other securities analysts would give at least passing mention to this fact. But they do not.

Q. How much confidence would investors be likely to place on long-term GDP projections?

A. Very little. Investors understand the complexities and inherent inaccuracies involved in forecasting, and that such uncertainties are significantly compounded for a long-term time horizon. Consider the example of IHS Global Insight, which is perhaps the world's foremost econometric forecasting service. IHS Global Insight currently publishes GDP projections for the U.S. economy for the next thirty years, but for other important economic

[56] As noted in *New Regulatory Finance*, "Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors." Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 71 (2006).

variables (*e.g.*, bond yields) their forecast simply holds projected values constant after a five-year horizon. As a result, in addition to the fact that there is no evidence to suggest that common stock investors reference GDP growth rates in their analysis of a specific gas utility's prospects, the difficulties in making long-term forecasts suggest they would be foolhardy to do so.

Q. Is there evidence that long-term GDP growth rates understate investors' expectations for utilities?

A. Yes. Actual historical growth rates for individual firms in Mr. Muldoon's own proxy group refute the notion that long-term growth for utilities is constrained by GDP. For example, Value Line reports that Southwest Gas achieved earnings growth over the last 5 years and 10 years of 10.0% and 8.5%, respectively.[57] These values for one of Mr. Muldoon's own proxy firms indicate that utilities can and do achieve growth over extended periods far in excess of the GDP growth rate he suggests as a limit in the multi-stage DCF model.

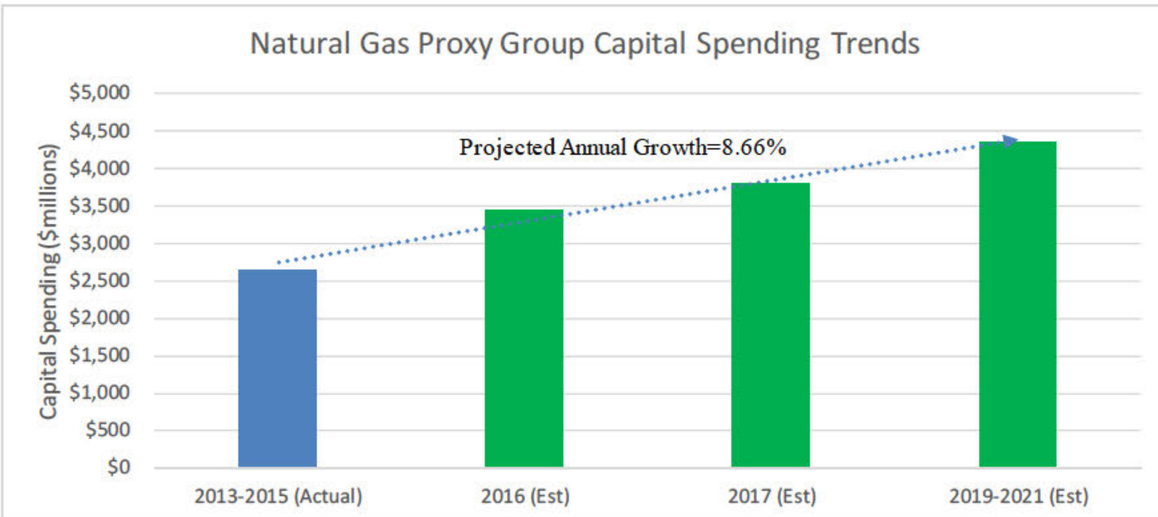
Q. Do expectations for the utility industry support a trend towards GDP growth?

A. No. Growth rates for utilities are not expected to collapse beyond the next three to five years. At least in part, growth in the utility industry is created by additional infrastructure investment. Contrary to the assumption that growth trends will somehow mirror GDP, investors recognize that the utility industry is facing the prospect of a long-term commitment to infrastructure investment. Gas utilities are facing significant investments for line replacements and other modernizations in order to meet capacity needs and enhance reliability and customer safety, as Avista witness Ms. Rosentrater discusses in her testimony

[57] The Value Line Investment Survey (Dec. 2, 2016).

(Avista/1500). These expectations suggest higher – not lower – long-term growth, and again confirm that GDP growth estimates almost certainly understate investors' expectations for utilities. The following figure illustrates this trend.

Illustration No. 3:



The Value Line Investment Survey (December 2, 2016).

Q. Does recent testimony from Mr. Gorman support the premise that growth for gas utilities will exceed expected growth in GDP for the foreseeable future?

A. Yes. In recent testimony, Mr. Gorman cites several reports emphasizing the strong growth expected for the industry. A few excerpts are highlighted below:[58]

- Capital expenditures throughout the U.S. power and gas sectors in calendar-2016 are projected to be at an all-time high;
- The nation's largest electric and gas utilities are investing in infrastructure to comply with sweeping environmental regulations, implement new technologies, build new natural gas, solar and wind generation and upgrade aging transmission and distribution systems;
- Moreover, their near-term capital spending forecasts continue to escalate;

[58] Montana Public Service Commission, Docket No. D2016.9.68, Direct Testimony of Michael P. Gorman, Feb. 2, 2017, p. 6.

- In addition, replacement of mature gas distribution infrastructure has gained widespread momentum and is likely to continue at material levels for many years, considering state and federal mandates to address safety; and,
- As shown in this graph, gas industry investment outlooks are expected to be considerably higher in the forecast (2016-2018), relative to the last 10-year historical period.

Mr. Gorman acknowledged that "gas industry investment outlooks are expected to be considerably higher in the forecast (2016-2018), relative to the last 10-year historical period.[59]

Q. What underlying fundamentals support investors' conclusion that gas utilities are embarking on a period of growth that will outpace the economy as a whole?

A. Recently, Deloitte published a report on utility capital expenditures and concluded the drivers behind continued strong spending included:

> - The need to upgrade and reinforce electric and gas infrastructure due to age, increasingly severe weather, and cyber and physical threats
> - The equally critical need to deploy information technology to boost the systems' efficiency, effectiveness, and resilience; accommodate the surge of new technologies and devices; and respond to customer demand for more flexible and customized products
> - The need to address environmental concerns with an increasingly clean energy slate
> - The opportunity to take advantage of burgeoning supplies of domestic natural gas
>
> Overall, company projections indicate that capital spending will likely remain substantial, which is not surprising, since key drivers behind the spending continue.[60]

Q. Did the founder of the DCF approach support the use of a generic long-term growth rate, such as the GDP growth under Mr. Muldoon's multi-stage approach?

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[59] *Id.*
[60] Deloitte, "From growth to modernization, the changing capital focus of the US utility sector," (2016).

A. No. Professor Myron J. Gordon, who originated the DCF approach, concluded that reference to a generic long-term growth rate, such as Mr. Muldoon advocates, was unsupported.[61] More specifically, Dr. Gordon concluded that any assumption of a single time horizon for a transition to a generic long-term growth rate was highly questionable and failed to reduce error in DCF estimates. Instead, Dr. Gordon specifically recognized that, "it is the growth that investors expect that should be used" in applying the DCF model, and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[62]

Similarly, a recent study reported in the *Journal of Investing* determined that there is no correlation between stock market returns or earnings growth and GDP, suggesting that investors' expectations built into observable share prices are driven by valuation measures, and not expected economic growth.[63]

Q. Have other regulators recognized that applying the DCF method using GDP growth rates results in cost of equity estimates that fail to reflect investors' expectations for utilities?

A. Yes. FERC concluded that a 9.39% cost of equity estimate produced by a multi-stage DCF model predicated on GDP growth is insufficient to meet regulatory standards under *Hope* and *Bluefield*.[64] FERC determined that a cost of equity of this magnitude "does

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[61] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies*, at 100-01 (1974).
[62] *Id.* at 89.
[63] Klement, Joachim, "What's Growth Got to Do with It? Equity Returns and Economic Growth," *Journal of Investing*, Vol. 24, No. 2 (Summer 2015): 74:78.
[64] Opinion No. 531 at P 142 (2014).

not represent a just and reasonable outcome" or "appropriately represent the utilities' risks."[65] In particular, FERC concluded that historically anomalous capital market conditions are leading to unrepresentative financial inputs to the DCF formula, which in turn results in a cost of equity "that does not satisfy the requirements of *Hope* and *Bluefield*."[66] In order to evaluate a fair and reasonable point-estimate ROE, FERC endorsed consideration of the results of the same risk premium, CAPM, and expected earnings approaches presented in my testimony in this case.[67] In addition, FERC stressed the relevance of ROEs allowed by state regulatory commissions in its evaluation of a fair ROE from within the zone of reasonableness.[68] Based on this evidence, FERC determined that a 10.57% ROE from the top end of the DCF zone of reasonableness was warranted for electric transmission operations. In September 20016, FERC affirmed these findings in Opinion No. 551.

Q. Are there also apparent computational errors affecting Mr. Muldoon's multi-stage DCF cost of equity estimates?

A. Yes. First, certain of Mr. Muldoon's dividend growth rates appear to be miscalculated. While referring to a growth rate for the period "2019-21 vs. 2013-15," the actual calculation computes growth from the "2012-14" period.[69] Second, Mr. Muldoon states that second stage growth in his model encompasses the period when dividend growth converges from the average rate over the first period to the growth rate used in the third stage. This does not appear to be the case, at least for Model X. For instance, the initial stage

[65] *Id.* at P 144.
[66] *Id.* at P 142.
[67] *Id.* at P 146.
[68] *Id.* at P 148-49.
[69] Muldoon workpaper, AVA UG 325 Exh 202 203 206 ROE Muldoon.xlsx, (tab "VL Gas Div & EPS, Col. AV).

growth for Northwest Natural terminates at an annual rate of 2.93%, while the third stage growth corresponds to the long-term GDP rate adopted by Mr. Muldoon of 5.46%. Following Mr. Muldoon's prescription, second stage growth should transition between 2.93% and 5.46% for Northwest Natural. Meanwhile, the actual data in Mr. Muldoon's workpapers indicates second stage growth in the range of 2.07%-2.10%.[70] There appears to be a breakdown between the stated assumptions of Mr. Muldoon's multi-stage model and its actual application.

Q. Mr. Muldoon implies that your DCF approach is not reasonable because you failed to remove the same number of low-end and high-end outliers from your results.[71] Is this a fair criticism?

A. No. As discussed in my Direct Testimony, low-end outliers were evaluated against the observable returns available from long-term bonds. But the fact that there are numerous results that fail this test of reasonableness says nothing about the validity of estimates at the upper end of the range of results, and there is no basis to discard an equal number of values from the top of the range. While the upper end cost of equity estimate of 14.1% from Avista/301, Schedule AMM-3, page 3, may exceed expectations for most utilities, the remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, this value provides a reasonable basis on which to evaluate investors' required rate of return.

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[70] *Id.* (tab "Model X", Row 14, comparison of data in Cols. L-U).
[71] Staff/200, Muldoon/30.

Q. Mr. Muldoon alleges that because Staff's results from its DCF model are higher using its gas peer group, as compared to using the Company's group, this suggests that Staff's results are "unbiased and reasonable."[72] Do you agree?

A. Absolutely not. Mr. Muldoon is making a false argument. The relative magnitude of results based on a two-company proxy group is far more likely to be a function of coincidence than anything else. For his results to be "unbiased" and reasonable" they must be rigorously tested against legitimate benchmarks using realistic proxy groups. This is the approach I have taken. Mr. Muldoon used one uncommon version of the DCF model with an abnormally small proxy group and compared these results to an invalid form of the CAPM. As my testimony demonstrates, this approach yielded downwardly biased and unreasonable outcomes.

Q. Mr. Muldoon criticizes you for making a number of assumptions in creating "synthetic" growth values.[73] Is this a valid criticism?

A. No. He says that I relied on "alternate values predicated on highly uncertain components, transformations and methods" and that "[t]his is concerning."[74] Of all the unfounded conclusions reached by Mr. Muldoon, this may be the most perplexing. In fact, my application of the DCF model relied on three primary sources of published analyst growth estimates – Value Line, IBES, and Zacks.[75] Projected growth rates from these entities are widely-available, widely-accepted, and well-respected. In addition to the reported earnings growth projections of securities analysts, I calculated "sustainable" growth rates using data

[72] Staff/200, Muldoon/21-22.
[73] Staff/200, Muldoon/26.
[74] Staff/200, Muldoon/26.
[75] Avista/301, Schedule AMM-3.

from Value Line, a source relied on almost exclusively by Mr. Muldoon. But again, this method is well known among rate of return analysts.[76] Contrary to Mr. Muldoon's allegations, the growth rates underlying my DCF application are commonly accepted, transparent and easy to follow.[77]

Q. Mr. Muldoon dismisses the constant growth DCF model like the one you used.[78] What is your reaction?

A. Mr. Muldoon first refers to the constant growth DCF model as "an extremely useful rule of thumb, but not more than that."[79] But unlike debt securities, there are no observable rates of return on common stock. The cost of equity can only be estimated and there is no one method that results in a precise quantification of investors' required return. Rate of return analysts can only make informed judgments using the best tools available, and the constant growth DCF model is one of those tools.

Mr. Muldoon goes on to attack the constant growth DCF modeling, arguing that it "makes the academic assumption that information about all future returns is contained in just a few values: namely the last dividend and an appropriate very long-term average growth rate."[80] He adds "[t]his assumption does not prove at all reliable in the real world."[81]

Mr. Muldoon is confusing complexity with accuracy. He seems to believe that, because he can build a DCF model with hundreds of inputs and extend it 30 years into the future, such a system will better estimate the Company's cost of equity. This claim is

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[76] For example, Mr. Gorman consistently incorporates this technique in his rate of return analyses.
[77] On the other hand, Mr. Muldoon's construction of a forward curve using UST TIPS break even points is a more apt example of a "synthetic" approach. Staff/200, Muldoon/26-27.
[78] Staff/200, Muldoon/30-31.
[79] Staff/200, Muldoon/30.
[80] Staff/200, Muldoon/31.
[81] Staff/200, Muldoon/31.

unfounded. Buried in the depths of Mr. Muldoon's Model X and Model Y are assumptions about the same "few" values that are in the constant growth formula: price, expected dividends, and growth. In order to apply his model, however, Mr. Muldoon must estimate some of these values for years into the future, requiring an entirely new level of assumptions. This added complexity and uncertainty begs the question: Are investors actually using such an approach to estimate Avista's cost of equity? I would argue that the simplicity of the constant growth DCF model is an advantage and renders it much more useful to real-world investors.

D. Capital Asset Pricing Model

Q. Does Mr. Muldoon's CAPM application provide a credible benchmark in evaluating the results of his DCF analyses?

A. No. The CAPM analyses conducted by Mr. Muldoon is not reliable for the purpose of evaluating his DCF results because he does not employ a methodology that is consistent with the underlying assumptions of this approach. Like the DCF model, the CAPM is an *ex-ante*, or forward-looking, model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market.

However, Mr. Muldoon's application of the CAPM approach was based entirely on backward-looking historical data over 85 years of history.[82] The primacy of current expectations was recognized by *Morningstar*:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information

[82] Staff/200, Muldoon/28.

> can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[83]

By failing to look directly at the returns investors are currently requiring in the capital markets, as I did in my Direct Testimony, Mr. Muldoon arrived at CAPM results that significantly understate investors' required rate of return. As Mr. Muldoon's own source noted, "Forecasting future [equity risk premiums] by extrapolating past excess returns is … fraught with peril."[84] Mr. Muldoon himself adds:

> As 2008 and 2009 conditions are rare or "black swan" events, there may be greater reliance on federal government referent sources for forward-looking long-run projections than long-historical extrapolations that are not informed by Federal macroeconomic policy changes since 2009.[85]

Q. Did Mr. Muldoon fail to consider other important factors in evaluating the CAPM?

A. Yes. As noted in my Direct Testimony,[86] empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. To account for this, *Morningstar* has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity.

Q. Mr. Muldoon says the equity risk premium you use in your CAPM analyses is "indefensible."[87] How do you respond?

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[83] *Morningstar*, "Ibbotson SBBI, 2012 Valuation Yearbook," at 21.
[84] Arnott, Robert D., "Equity Risk Premium Myths," *Rethinking the Equity Risk Premium,* Research Foundation of the CFA Institute at 81 (2011).
[85] Staff/200, Muldoon/33.
[86] Avista/300, McKenzie/40-41.
[87] Staff/200, Muldoon/4.

A. Defining a reasonable ROE for Avista is a forward-looking process. In describing the DCF model, Mr. Muldoon says that it estimates the cost of equity by "determining the present value of future cash flows that investors expect to receive from holding common stock."[88] The CAPM approach is no different; it is based on forward-looking expectations and my equity risk premium is based on this principle. Because my analysis is premised directly on current market expectations, it is much more relevant, theoretically sound, and "defensible" especially when compared to the backward-looking approach taken by Mr. Muldoon.

Q. Have other regulators relied on a forward-looking CAPM approach similar to the one presented in your Direct Testimony?

A. Yes. I based my CAPM approach on the methods used by the Staff at the Illinois Commerce Commission, whose witnesses have routinely relied on a forward-looking market rate of return estimate to apply the CAPM. For example, Illinois Staff witness Rochelle Langfeldt employed an expected market return based on an analysis analogous to the approach described in my Direct Testimony:

> Q. How was the expected rate of return on the market portfolio estimated?
>
> A. The expected rate of return on the market was estimated by conducting a DCF analysis on the firms composing the S&P 500 Index ("S&P 500"). … Firms not paying a dividend as of June 28, 2001, or for which neither Zacks nor IBES growth rates were available were eliminated from the analysis. The resulting company-specific estimates of the expected rate of return on common equity were then weighted using market value data from Salomon Smith Barney, Performance and Weights of the S&P 500: Second Quarter 2001. The estimated weighted averaged expected rate of

[88] Staff/200, Muldoon/15.

> return for the remaining 365 firms composing 78.31% of the market capitalization of the S&P 500 equals 15.31%.[89]

FERC has also repeatedly rejected the historical CAPM approach relied on by Mr. Muldoon and adopted the same size adjusted, forward-looking CAPM application that I have proposed in this proceeding.[90]

Q. Is the 4.50% market risk premium cited by Mr. Muldoon an accurate depiction of what is actually reflected in the complete historical record?[91]

A. No. First, the source relied on by Mr. Muldoon stated that "[i]n the 85 years covered by the Ibbotson data, stocks delivered a real return of 6.6 percent, against 2.1 percent for bonds,"[92] from which Mr. Muldoon derived his 4.5% equity risk premium. But this *ad hoc* and outdated observation does not accurately reflect the current historical record. First, in the same publication referenced by Mr. Muldoon, Roger G. Ibbotson reports arithmetic mean returns for large company stocks and long-term government bonds of 11.9% and 5.9%, respectively, which implies a historical risk premium of 6.0%.[93] *Duff & Phelps,* which now updates and publishes the historical rate of return data formerly compiled by Dr. Ibbotson, reported a more current long-horizon risk premium of 6.9% based on historical realized rates of return from 1926 through 2016.[94]

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[89] Direct Testimony of Rochelle Langfeldt, Illinois Commerce Commission Docket No. 01-0423 at 23-24 (2001).
[90] *Coakley v. Bangor Hydro-Elec. Co.,* Opinion No. 531-B, 150 FERC ¶ 61,165 at P 108-119 (2015) ("Opinion No. 531-B"); Opinion No. 551 at P 138.
[91] Staff/200, Muldoon/28.
[92] Arnott, Robert D., "Equity Risk Premium Myths," *Rethinking the Equity Risk Premium,* Research Foundation of the CFA Institute at 81 (2011).
[93] Ibbotson, Roger G., "The Equity Risk Premium," *Rethinking the Equity Risk Premium,* Research Foundation of the CFA Institute at 19 (2011). This actually understates the risk premium under Dr. Ibbotson's historical approach, which is more accurately calculated using the arithmetic mean income return on long-term government bonds of 5.2%. *See, e.g., Morningstar,* "Ibbotson SBBI 2011 Valuation Yearbook" at Table 2-1 & 55.
[94] *Duff & Phelps,* "2016 Valuation Handbook (Preview Version)" (2016).

Q. Does Mr. Muldoon's 4.50% market risk premium provide any meaningful corroboration or guidance as to investors' required rate of return?

A. No. Adding the 4.50% market risk premium used by Mr. Muldoon to his 4.30% risk-free rate based on 30-year Treasury bonds implies that equity returns for the stock market as a whole will amount to 8.80%. This figure falls 30 basis points *below* the return that Mr. Muldoon recommends for Avista in this case. Given that utilities are universally regarded as less risky than the overall market, this outcome is illogical and violates the fundamental relationship between risk and return.

Q. Do the yields on 10-year Treasury notes referenced in Mr. Muldoon's testimony provide an appropriate basis to estimate the cost of equity using the CAPM?[95]

A. No. Unlike debt instruments, common equity is a perpetuity. As a result, any application of the CAPM to estimate the return that investors require must be predicated on their expectations for the firm's long-term risks and prospects. This does not mean that every investor will buy and hold a particular common stock into perpetuity. Rather, it recognizes that even an investor with a relatively short holding period will consider the long-term, because of its influence on the price that he or she ultimately receives from the stock when it is sold. This is also the basic assumption underpinning the DCF model, which in theory considers the present value of all future dividends expected to be received by a share of stock.

In applying the CAPM, *Morningstar*, the source of Mr. Muldoon's historical return data, recognized that the cost of equity is a long-term cost of capital and the appropriate interest rate to use is a long-term bond yield:

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[95] Staff/200, Muldoon/29.

> The traditional thinking regarding the time horizon of the chosen Treasury security should match the horizon of whatever is being valued. … Note that the horizon is a function of the investment, not the investor. If an investor plans to hold a stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[96]

Accordingly, proper application of the CAPM should focus on long-term government bonds. As Mr. Muldoon noted, "A 30-year horizon is relevant for investors. This reflects investor consideration of 30-year U.S. Treasury (UST) Bond and alternative investment opportunities."[97] Similarly, FERC concluded that, "30-year U.S. Treasury bond yields are a generally accepted proxy for the risk-free rate in a CAPM analysis, and are also considered superior to short- and intermediate-term bonds for this purpose."[98]

Q. Was Mr. Muldoon justified in combining unadjusted betas from Yahoo Finance in applying the CAPM?[99]

A. No. All beta values are necessarily estimates using historical data, but unlike beta values reported by Value Line, those published by Yahoo Finance have not been adjusted to account for the observed tendency for beta values to converge to the market average over time. This tendency is well known and discussed in the financial literature.[100] As a result, Yahoo Finance beta values represent an inferior estimate of future risk expectations.

Q. Mr. Muldoon says that your size adjustment is an "outboard" adjustment that is normally addressed within the selection of peer groups.[101] Do you agree?

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[96] *Morningstar*, "Ibbotson SBBI, 2013 Valuation Yearbook" at 44.
[97] Staff/200, Muldoon/16.
[98] Opinion No. 531-B at P 114 (2015).
[99] Staff/200, Muldoon/29.
[100] *See, e.g.*, Blume, M.E., "Betas and Their Regression Tendencies," *Journal of Finance* June 1975 at 787-796.
[101] Staff/200, Muldoon/4.

A. No. The size adjustment methodology I rely on in my CAPM and ECAPM analyses has nothing to do with the proxy group selection process. First, Mr. Muldoon implies that I am proposing to apply a general size risk premium in arriving at a fair ROE for Avista, but this is not correct. Rather, this adjustment merely corrects for an observed inability of the CAPM to fully reflect the impact of size distinctions by market capitalization that the beta value does not otherwise capture, but which is acknowledged by empirical research. My consideration of the impact of firm size does not adjust for Avista's size relative to the proxy group; nor is it applied to the results of the DCF, risk premium, or expected earnings approaches. Rather, it is specifically tied to the CAPM because empirical research indicates that beta does not capture an increment of risk related to firm size.

Q. Does Mr. Muldoon provide a credible basis to ignore the results of the ECAPM?

A. No. First, he claims it is a "method not commonly used by finance academics and professionals,"[102] but then adds his suggestion that "this approach is interesting, but has not caught on and merits little weight here."[103] Of course, these very same criticisms could be levelled at his uncommon Model X and Model Y variants of the multi-stage DCF model. In any event, as I documented in my Direct Testimony the ECAPM is based on the findings of studies reported in the financial literature.[104]

In contrast to Mr. Muldoon's dismissal of this approach, the results of the ECAPM have been relied on by other regulators. For example, Staff witness Julie McKenna of the Maryland Public Service Commission noted that "the ECAPM model adjusts for the tendency

[102] Staff/200, Muldoon/5.
[103] Staff/200, Muldoon/34-35.
[104] Exhibit Avista/300, McKenzie/42-43.

of the CAPM model to underestimate returns for low Beta stocks," and concluded that, "I believe under current economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[105] The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[106]

E. Risk Premium Method

Q. What is Mr. Muldoon's primary criticism of your risk premium approach?

A. Mr. Muldoon's central criticism seems to be that historical spreads between stock returns and U.S. Treasury bonds may be subject to distortion because the Federal Reserve has driven interest rates to anomalously low levels through their unprecedented monetary policy actions.[107]

Q. Do Mr. Muldoon's observations regarding Federal Reserve actions undermine the risk premium results presented in your Direct Testimony?

A. No. First, my application of the risk premium approach was predicated on average yields for public utility bonds, not on the U.S. Treasury bond yields referenced in Mr. Muldoon's testimony. Second, my analysis covers the period 1980-2016. As such, it incorporates several business cycles and a range of economic conditions. Mr. Muldoon's misguided focus on only a two-year period (the 2008-2009 "downturn") as an attempt to

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[105] *Direct Testimony and Exhibits of Julie McKenna*, Maryland PSC Case No. 9299 (Oct. 12, 2012) at page 9.
[106] Regulatory Commission of Alaska, Order No. P-97-004(151) at 145 (Nov. 27, 2002).
[107] Staff/200, Muldoon/32-34.

discredit my analysis is not valid. In addition, in contrast to Mr. Muldoon's suggestion, this approach does not depend on the assumption of a constant risk premium over time. As explained in my Direct Testimony, my risk premium analyses specifically accounts for the fact that risk premiums vary with changes in interest rates and incorporated adjustments to account for differences in bond yields over the study period.[108] Furthermore, in applying the risk premium approach I specifically accounted for the decrease in the equity risk premium that would be implied by expectations of higher bond yields as the Federal Reserve moves to normalize its monetary policies.

Finally, while Treasury bond yields are not a direct input to the DCF model, DCF results are not immune to distortion when capital market conditions are outside the normal range. As FERC concluded, for example, "any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions."[109] In contrast to Mr. Muldoon's position, *New Regulatory Finance* concluded that DCF results may be more vulnerable to peculiarities in capital market conditions than those produced by the risk premium approach:

> One advantage of risk premium over DCF is that the former is a period-by-period (time series) study of the cost of equity over the cost of debt, in contrast to the latter which is a point-in-time cross-sectional estimate. In other words, the risk premium approach takes a broader time-series perspective rather than a snapshot point-in-time viewpoint, and is therefore less vulnerable to the vagaries of any one particular capital market environment.[110]

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[108] Avista/300, McKenzie/46-47.
[109] Opinion No. 531 at P 41 (2014).
[110] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 131 (2006).

Similarly, FERC specifically endorsed the use of a risk premium method analogous to that presented in my Direct Testimony as a "check" on DCF results.[111]

In contrast to Mr. Muldoon's singular adherence to the multi-stage DCF, I believe that other methodologies always should be considered when establishing an ROE. As explained in *New Regulatory Finance*, "[r]eliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data."[112]

F. Comparative Risk

Q. Please summarize Mr. Muldoon's position regarding Avista's investment risks relative to his proxy group of utilities.

A. Mr. Muldoon implies that Avista's investors have benefited from a "reduction in risk and regulatory lag,"[113] which appears to be based solely on his observation that Avista has made "frequent rate filings."[114] As a result, Mr. Muldoon argues that investors would view Avista as less risky than his peer group.

Q. Does reference to the frequency of rate filings support Mr. Muldoon's conclusion that Avista is less risky than his peer utilities?

A. No. The fact that Avista has exercised its statutory authority to file consecutive rate proceedings says nothing at all with respect to investors' perceptions of Avista's relative investment risk. In fact, a recurring shortfall between a utility's cost of providing service and the revenues it collects through rates that generally motivates repeated rate case filings is far

[111] Opinion No. 531 at P 174 (2014); Opinion No. 551 at P 200 (2016).
[112] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 428 (2006).
[113] Staff/200, Muldoon/12.
[114] Staff/200, Muldoon/35.

more likely to be viewed by investors as a challenge than an advantage. For example, S&P observed that its risk analysis focuses on the utility's ability to consistently <u>earn</u> a reasonable return:

> Notably, the analysis does not revolve around "authorized" returns, but rather on actual earned returns. We note the many examples of utilities with healthy authorized returns that, we believe, have no meaningful expectation of actually earning that return because of rate case lag, expense disallowances, etc.[115]

Similarly, Moody's concluded, "we evaluate the framework and mechanisms that allow a utility to recover its costs and investments and earn allowed returns. We are less concerned with the official allowed return on equity, instead focusing on the earned returns and cash flows."[116]

In evaluating competing alternatives, investors are focused on the extent to which Avista has the opportunity to actually earn a return that will maintain its financial integrity, facilitate capital attraction, and compensate for risk. The fact that Avista has been compelled to file serial rate proceedings in order to address a chronic deterioration of actual returns below the allowed ROE was recently acknowledged by Value Line:

> **Frequent rate filings are necessary to deal with the effects of regulatory lag.** This has caused Avista to underearn its allowed ROE for many years.[117]

In other words, Mr. Muldoon's conclusion that frequent rate case filings are evidence of a "reduction in risk and regulatory lag"[118] is diametrically opposed to the views of the investment community.

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[115] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," RatingsDirect (Nov. 7, 2008).
[116] Moody's Investors Service, "Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).
[117] The Value Line Investment Survey (Oct. 28, 2016) (emphasis in original).
[118] Staff/200, Muldoon/12.

Q. Is Avista's relative risk reduced because of its decoupling mechanism?

A. No. As noted in my Direct Testimony,[119] other firms in the gas utility industry operate under a variety of regulatory mechanisms. The majority of gas utilities benefit from revenue decoupling, along with a variety of other provisions that enhance their recovery of operating and capital costs on a timely basis. While Avista's decoupling mechanism serves to level the playing field related to the impact of actual versus authorized therm use per customer on cost recovery, it does not result in a "windfall" or otherwise penalize customers. Utilities across the U.S. that Avista competes with for new capital are increasingly availing themselves of similar adjustments. As a result, the effect of decoupling on ROE is already reflected in the cost of equity estimates determined in this case, and no separate adjustment to Avista's ROE is necessary or warranted.

Q. Does a comparison of objective risk measures support Mr. Muldoon's conclusion that Avista is less risky than a realistic peer group of utilities?

A. No. Avista/1201, Schedule AMM-18 presents a risk evaluation based on the same objective, published benchmarks relied on in the investment community that were discussed in my Direct Testimony.[120] As shown in Avista/1201, Schedule AMM-18, the BBB corporate credit rating assigned to Avista by S&P falls below every one of the companies in the gas utility peer group. Avista's Baa1 rating from Moody's also indicates higher risk than the A2 rating corresponding to the proxy group. Taken together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, and exposure to firm-specific factors, indicates that investors would

[119] Avista/300, McKenzie/58-62.
[120] Avista/300, McKenzie/15-18.

conclude that the overall investment risks for Avista are generally greater than those of the gas proxy group.[121] Similarly, as shown in the lower portion of Avista/1201, Schedule AMM-18, Avista's investment risks are also generally higher than other Oregon-jurisdictional utilities. More specifically, a comparison of Avista's risk measures with those of Northwest Natural Gas, which is the only gas utility that fully meets Mr. Muldoon's screening criteria, is presented in the table below.

Table No. 3:

COMPARISON OF RISK MEASURES

	Credit Ratings		Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Northwest Natural Gas	**A+**	**A3**	**1**	**A**	**0.65**
Avista	**BBB**	**Baa1**	**2**	**A**	**0.70**

Investors would view Avista's risks as being greater than those of Northwest Natural Gas. As a result there is no justification that would support a lower ROE for Avista. Northwest Natural's presently authorized ROE is 9.5%.

III. RESPONSE TO MR. GORMAN

Q. How did Mr. Gorman arrive at his recommended cost of equity?

A. Mr. Gorman recommendation is to leave the Company's ROE unchanged at the level approved in its last rate case, or 9.4%.

Q. What is wrong with this approach?

A. Mr. Gorman's recommendation is not based on any independent analyses of investors' required rate of return for Avista using current capital market data. Rather, it is

[121] These objective measures also indicate that Avista's risks exceed those of Northwest Natural Gas and Southwest Gas, the two companies included in Mr. Muldoon's proxy group.

predicated on his *ad hoc* observations regarding trends in interest rates and allowed rates of return for gas utilities.

Q. Does Mr. Gorman's portrayal of bond yield trends paint a complete picture?

A. No. With respect to interest rates, Mr. Gorman's cursory approach ignores the climate of rising bond yields currently faced by investors. As discussed earlier, the Federal Reserve is expected to continue raising interest rates in an effort to normalize its monetary policies, which will also impact the markets for long-term capital. This is demonstrated in Illustration No. 2 above, with interest rates projected to climb significantly over the near term. Indeed, yields on public utility bonds expected to increase over 100 basis points over the next two years alone, which also implies higher required returns for utility common stocks. As a result, Mr. Gorman's recommendation to hold Avista's ROE constant at the present level will only reinforce a continuation of earnings attrition as the allowed return falls below the required cost of equity over the period when rates are in effect.

Q. Do the allowed ROEs reviewed by Mr. Gorman support maintaining Avista's current ROE?

A. No. First, all of the average ROEs presented in Table No. 2 to Mr. Gorman's testimony are higher than Avista's current allowed return. This alone supports an increase to Avista's ROE, especially given the demonstrable evidence presented here and in my Direct Testimony that Avista's shareholders bear greater risk than other gas utilities. Similarly, a review of the allowed returns for gas utilities reported by RRA for the fourth quarter of 2016 also contradicts Mr. Gorman's recommendation to continue Avista's existing ROE. Specifically, the 9.6% average allowed ROE reported by Mr. Gorman was significantly impacted by two 9.00% observations pertaining to settlements for related utilities in New York. These proceedings involve multi-year rate plans that include earnings sharing provisions that would allow shareholders to benefit from excess earnings. As the New York Public Service Commission reported in its order:

> The Companies note that, although the Commission's methodology for establishing ROE results in returns that are among the lowest in the country for gas and electric utilities, they are willing to accept this result in light of the overall settlement reached by the parties.[122]

These circumstances are not comparable to those faced by Avista in this proceeding. Excluding these two related observations results in an average ROE in the fourth quarter of 2016 of 9.8% for gas utilities. After considering Avista's higher risks, this result disproves Mr. Gorman's claims and provides further support for the reasonableness of Avista's requested ROE of 9.9%.

Q. What other evidence supports an increase from the 9.4% ROE awarded to Avista in Docket No. UG 288?

A. Apart from the various benchmarks discussed in my Reply Testimony and interest rate trends, comparisons with other Oregon-jurisdictional utilities also support a higher ROE for Avista. Specifically, rates for Northwest Natural Gas, the only company meeting Mr. Muldoon's screens for comparability, are currently based on an ROE of 9.5%, which was authorized in November 2012.[123] This benchmark is all the more relevant since it was established in conjunction with a decoupling mechanism and a 50% common equity ratio, which are directly comparable to Avista's request in this proceeding. While public utility

[122] State of New York Public Service Commission, Case 16-G-0058 et al. (Dec. 16, 2016) at 27.
[123] *Supplemental Order*, Docket No. UG 221 (Nov. 16, 2012).

bond yields are largely unchanged from this time period,[124] this 9.5% ROE does not reflect Avista's higher relative risks. As indicated in Table No. 3, and reproduced below, Avista is rated triple-B, versus the single-A ratings assigned to Northwest Natural Gas.

Table No. 3

	Credit Ratings		Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Northwest Natural Gas	**A+**	**A3**	**1**	**A**	**0.65**
Avista	**BBB**	**Baa1**	**2**	**A**	**0.70**

Investors currently require approximately 40 to 50 basis points more to hold average triple-B public utility bonds versus those rated single-A,[125] which would imply a risk-adjusted ROE for Avista of at least 9.9% to 10.0%.[126]

Q. The 9.4% ROE advocated by Mr. Gorman was arrived at by subtracting 10 basis points from a base ROE of 9.5%.[127] Is a similar adjustment warranted in this case?

A. No. In Docket No. UG 288, the Commission determined that a 10 basis point downward adjustment to the ROE was warranted due to the lower risks associated with approval of a decoupling mechanism and higher base customer charges, as well as a "more equity-rich capital structure."[128] As I demonstrated in my Direct Testimony,[129] there is no

[124] Moody's reported an average yield on Baa-rated utility bonds in November 2012 of 4.51%, versus 4.58% in February 2017.
[125] Over the six-month period ending February 2017 the average spread between yields for Baa and A rated utility bonds was 52 basis points, or 40 basis points based on monthly yields for February 2017.
[126] I say "at least," because investors would undoubtedly require an even wider premium for bearing the higher risk associated with the more junior common stock of a utility with lower credit ratings.
[127] Order No. 16-109 (2016) at 10.
[128] *Id.*
[129] Avista/300, McKenzie/58-62.

evidence to support a downward adjustment to Avista's ROE for decoupling because the impact of similar mechanisms is already reflected in cost of equity estimates for the proxy utilities. As the Washington Utilities and Transportation Commission recognized:

> Circumstances in the industry today and modern regulatory practice . . . have led to a proliferation of risk reducing mechanisms being in place for utilities throughout the United States. . . **The effects of these risk mitigating factors was by 2013, and is today, built into the data experts draw from the samples of companies they select as proxies.**[130]

In other words, the increased mitigation in risks associated with the proxy utilities' greater ability to adjust revenues and attenuate the risk of cost recovery is captured in the cost of equity range determined from my proxy group analyses. As a result, there is no evidentiary support for a separate downward adjustment to Avista's ROE.

Similarly, my Direct Testimony documents that Avista's requested 50% equity ratio falls short of those maintained by the gas utility proxy group. As shown on Exhibit No. 301, page 1 of Schedule AMM-2, for the firms in the Gas Group, common equity ratios at December 31, 2015 averaged 53.1% of long-term capital, with Value Line expecting an average common equity ratio of 54.2% for its three-to-five year forecast horizon. Meanwhile, Mr. Muldoon reported 2016 common equity ratios for Northwest Natural Gas and Southwest Gas (the two firms in his proxy group) of 57.0% and 58.5%, respectively.[131] Accordingly, there is no basis to conclude that Avista's capital structure is "equity-rich" when compared with other natural gas utilities.

Q. Does this conclude your Reply Testimony in this case?

A. Yes, it does.

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[130] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-130130 and UG-130138 (consolidated) et al., Order 15.14 at 69, ¶ 155 (June 29, 2015). Internal citations omitted (Emphasis added).
[131] Muldoon workpapers at AVA UG 325 Exh 202 203 206 ROE Muldoon.xlsx, tab "Peer Screen N Gas."

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

ADRIEN M. MCKENZIE

Exhibit No. 1201

Return on Equity

<u>GAS PROXY GROUP</u>

Atmos Energy (1)	State or Division	**Allowed ROE**
Atmos Energy	TN	**9.80%**
Atmos Energy	CO	**9.72%**
Atmos Energy	KY	**9.80%**
Atmos Energy	KS	**9.10%**
Atmos Energy	Mid-Tex	**10.50%**
Average		**9.78%**
Chesapeake Utilities (2)		
Chesapeake Utilities-Delaware Division	DE	**9.75%**
Chesapeake Utilities-Florida Division	FL	**10.80%**
Average		**10.28%**
New Jersey Resources (1)		
New Jersey Natural Gas	NJ	**9.75%**
Northwest Natural Gas (1)		
Northwest Natural Gas	OR	**9.50%**
South Jersey Industries (1)		
South Jersey Gas Co.	NJ	**9.75%**
Southwest Gas (1)		
Southwest Gas	CA	**10.10%**
Southwest Gas-Southern Division	NV	**9.85%**
Southwest Gas-Northern Division	NV	**9.20%**
Average		**9.72%**
Spire Energy (3)		
Alagasco	AL	**10.80%**
Laclede Gas	MO	**9.70%**
MGE	MO	**9.75%**
Mobile Gas	AL	**10.80%**
Willmut Gas	MS	**9.23%**
Average		**10.06%**
WGL (1)		
Washington Gas Light	DC	**9.25%**
Washington Gas Light	MD	**9.50%**
Washington Gas Light	VA	**9.75%**
Average		**9.50%**
Proxy Group Average		**9.79%**

Data Sources:

(1) Regulatory Research Associates.

(2) SEC Form 10-K and Delaware Public Service Commission Order 8982.

(3) Spire Energy, Investor Presentation, Sep. 2016.

GAS PROXY GROUP

		(a)	(b)	(c)
	Company	Expected Return on Common Equity	Adjustment Factor	Adjusted Return on Common Equity
1	Atmos Energy Corp.	11.5%	1.0321	11.9%
2	Chesapeake Utilities	13.0%	1.0530	13.7%
3	New Jersey Resources	12.0%	1.0284	12.3%
4	Northwest Natural Gas	10.5%	1.0159	10.7%
5	South Jersey Industries	8.0%	1.0573	8.5%
6	Southwest Gas Corp.	11.5%	1.0231	11.8%
7	Spire, Inc.	9.0%	1.0304	9.3%
8	WGL Holdings, Inc.	9.5%	1.0426	9.9%
	Average			**11.0%**

(a) The Value Line Investment Survey (Dec. 2, 2016).

(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).

(c) (a) x (b).

CHESAPEAKE UTILITIES

CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE 66.00 | P/E RATIO 22.8 (Trailing: 24.4; Median: 15.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 1.9% | VALUE LINE

TIMELINESS 3 Raised 2/3/17
SAFETY 2 New 6/5/15
TECHNICAL 3 Lowered 2/17/17
BETA .70 (1.00 = Market)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
High:	23.8	24.8	23.2	23.3	28.1	29.7	32.6	40.8	52.7	61.1	70.0	68.8
Low:	18.6	18.7	14.6	14.7	18.7	24.0	26.6	30.6	37.5	44.4	52.3	63.0

Target Price Range 2020 | 2021 | 2022

2020-22 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+50%)	12%
Low	75	(+15%)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	9	0	0	0	0	0	0	0
to Sell	0	0	1	0	0	1	0	0	2

Institutional Decisions

	1Q2016	2Q2016	3Q2016
to Buy	86	83	68
to Sell	66	72	74
Hld's(000)	8673	8755	9375

% TOT. RETURN 1/17

	THIS STOCK	VL ARITH.* INDEX
1 yr.	5.9	31.2
3 yr.	78.0	25.8
5 yr.	158.9	84.9

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	© VALUE LINE PUB. LLC	20-22
40.82	17.12	19.11	20.70	26.02	23.05	25.41	28.46	19.07	29.93	29.13	27.26	30.73	34.19	30.07	28.80	30.30	31.70	Revenues per sh	40.00
1.95	1.93	2.42	2.26	2.35	2.18	2.52	2.50	2.15	3.50	3.69	3.95	4.35	4.73	5.05	4.95	5.40	5.85	"Cash Flow" per sh	7.50
.83	.69	1.17	1.09	1.18	1.15	1.29	1.39	1.43	1.82	1.91	1.99	2.26	2.47	2.68	2.75	2.95	3.15	Earnings per sh A	4.20
.73	.73	.73	.75	.76	.77	.78	.81	.83	.87	.91	.96	1.01	1.07	1.12	1.19	1.26	1.33	Div'ds Decl'd per sh B■	1.55
3.61	1.77	1.39	2.07	3.74	4.87	3.08	3.00	1.89	3.18	3.28	5.00	6.72	6.66	9.47	9.70	10.00	10.25	Cap'l Spending per sh	11.80
8.26	8.03	8.59	9.07	9.60	11.08	11.76	12.02	14.89	15.84	16.78	17.82	19.28	20.59	23.45	27.50	27.40	29.20	Book Value per sh	32.90
8.09	8.31	8.49	8.60	8.82	10.03	10.17	10.24	14.09	14.29	14.35	14.40	14.46	14.59	15.27	16.50	17.00	17.50	Common Shs Outst'g C	20.00
15.0	18.6	12.7	15.0	16.8	17.9	16.7	14.2	14.2	12.2	14.2	14.8	15.6	17.7	19.1	22.6	Bold figures are	Value Line	Avg Ann'l P/E Ratio	20.5
.77	1.02	.72	.79	.89	.97	.89	.85	.95	.78	.89	.94	.88	.93	.96	1.19	estimates		Relative P/E Ratio	1.30
5.8%	5.7%	4.9%	4.6%	3.8%	3.8%	3.6%	4.1%	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	1.9%			Avg Ann'l Div'd Yield	1.8%

CAPITAL STRUCTURE as of 9/30/16
Total Debt $310.1 mill. Due in 5 Yrs $230.0 mill.
LT Debt $143.5 mill. LT Interest $9.0 mill.
(LT interest earned: 7.7x; total interest coverage: 7.7x) (25% of Cap'l)
Leases, Uncapitalized Annual rentals $1.3 mill.
Pfd Stock None
Pension Assets-12/15 $51.0 mill.
Oblig. $75.9 mill.
Common Stock 16,301,161 shs.
as of 10/31/16

MARKET CAP: $1.1 billion (Mid Cap)

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018		20-22
258.3	291.4	268.8	427.5	418.0	392.5	444.3	498.8	459.2	475	515	555	Revenues ($mill)	800
13.2	14.4	15.9	26.1	27.6	28.9	32.8	36.1	40.2	43.0	48.0	53.0	Net Profit ($mill)	85.0
39.4%	39.1%	41.8%	39.7%	39.4%	40.1%	40.2%	39.9%	39.5%	40.0%	40.0%	40.0%	Income Tax Rate	41.5%
5.1%	4.9%	5.9%	6.1%	6.6%	7.4%	7.4%	7.2%	8.8%	9.1%	9.3%	9.5%	Net Profit Margin	10.6%
34.6%	41.3%	32.0%	28.4%	31.4%	28.4%	29.7%	34.5%	29.4%	25.0%	30.0%	30.0%	Long-Term Debt Ratio	30.0%
65.4%	58.7%	68.0%	71.6%	68.6%	71.6%	70.3%	65.5%	70.6%	75.0%	70.0%	70.0%	Common Equity Ratio	70.0%
182.8	209.5	308.6	315.9	351.1	358.5	396.4	458.8	507.5	605	665	730	Total Capital ($mill)	940
260.4	280.7	436.4	462.8	487.7	541.8	631.2	689.8	855.0	960	1060	1170	Net Plant ($mill)	1530
8.4%	7.9%	6.1%	9.1%	8.9%	8.8%	8.8%	8.5%	8.9%	8.0%	8.0%	8.0%	Return on Total Cap'l	10.0%
11.1%	11.7%	7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	9.5%	10.5%	10.5%	Return on Shr. Equity	13.0%
11.1%	11.7%	7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	9.5%	10.5%	10.5%	Return on Com Equity	13.0%
5.2%	5.2%	3.8%	6.6%	6.6%	6.4%	7.1%	7.4%	6.8%	5.0%	5.5%	6.0%	Retained to Com Eq	8.0%
53%	55%	50%	42%	42%	43%	40%	38%	40%	46%	45%	44%	All Div'ds to Net Prof	37%

CURRENT POSITION ($MILL.)	2014	2015	9/30/16
Cash Assets	4.6	2.9	1.5
Other	117.8	109.6	100.7
Current Assets	122.4	112.5	102.2
Accts Payable	44.6	39.3	41.3
Debt Due	97.3	182.5	166.6
Other	52.3	57.8	55.2
Current Liab.	194.2	279.6	263.1
Fix. Chg. Cov.	865%	898%	885%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '13-'15 to '20-'22
Revenues	3.5%	4.0%	3.5%
"Cash Flow"	7.0%	11.5%	7.0%
Earnings	8.0%	10.0%	8.0%
Dividends	3.5%	5.0%	5.5%
Book Value	9.0%	8.0%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	186.3	100.5	91.6	120.4	498.8
2015	170.1	92.7	91.9	104.5	459.2
2016	146.3	102.3	108.3	118.1	475
2017	170	110	110	125	515
2018	180	120	120	135	555

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2014	1.21	.35	.22	.69	2.47
2015	1.44	.35	.33	.56	2.68
2016	1.33	.52	.29	.61	2.75
2017	1.41	.45	.42	.67	2.95
2018	1.47	.49	.47	.72	3.15

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2013	.243	.243	.257	.257	1.00
2014	.257	.257	.27	.27	1.05
2015	.27	.27	.288	.288	1.12
2016	.288	.288	.305	.305	1.19
2017	.305				

BUSINESS: Chesapeake Utilities Corporation consists of two units: Regulated Energy and Unregulated Energy. The Regulated Energy segment (65% of 2015 revenues) distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation (35% of 2015 revenues) wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Officers and directors own 5.4% of common stock; T. Rowe Price, 8.3; BlackRock, 5.8% (3/16 Proxy). CEO: Michael P. McMasters. Inc.: Delaware. Address: 909 Silver Lake Boulevard, Dover, DE 19904. Tel.: (302) 734-6799. Internet: www.chpk.com.

***Value Line* looks for a stronger profit advance for Chesapeake Utilities in 2017.** That should be made possible partially by incremental benefits from the April, 2015 acquisition of Aspire Energy. Another plus is new projects, which include Eight Flags' CHP plant; continued natural gas infrastructure improvement initiatives; and additional expansions of the company's natural gas distribution and transmission systems. Generally favorable weather conditions would help, too. As a result, share net may well rise around 7%, to $2.95, relative to our anticipated 2016 tally of $2.75. (Please be aware that fourth-quarter earnings were expected to be released when we went to press.) Assuming further widening of operating margins, we think the bottom line can increase at a similar percentage rate, to $3.15 a share, in 2018.

The Financial Strength rating is decent, at B++. Through the first nine months of 2016, cash and equivalents stood at $1.5 million. Meanwhile, long-term debt was only 25% of total capital, and short-term commitments did not seem to pose a major obstacle. Also, Chesapeake possessed four unsecured bank credit facilities totaling $170 million. Lastly, it is able to issue more equity and debt, if the need arises. All things considered, *Value Line* believes the Delaware-headquartered firm is positioned to meet, for the time being, its capital requirements, such as investments in new plants and equipment and dividends.

Our 2020-2022 projections indicate that steady dividend hikes will take place. Too, the payout ratio over that span should be in the 35% to 40% range, which is reasonable. It's worth mentioning, however, that the current yield is not spectacular, when stacked against the other nine equities within our Natural Gas Utility Industry.

The stock has some notable characteristics. It holds a 2 (Above Average) rating for Safety. Furthermore, the Beta coefficient lies below the market average and the Price Stability score is relatively high, at 80 out of 100. Meanwhile, these shares' Timeliness rank now sits at 3 (Average), up one notch since our last full-page report in December.

Frederick L. Harris, III *March 3, 2017*

(A) Diluted shrs. Excludes nonrecurring items: '02, d23¢; '08, d7¢; '15, 6¢. Excludes discontinued operations: '03, d9¢; '04, d1¢. Next earnings report due early May.

(B) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available.

(C) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	90
Earnings Predictability	95

COMPARISON TO AVISTA

		(a)	(b)	(c)		
				Value Line		
		Issuer Ratings		Safety	Financial	
	Gas Proxy Group	**S&P**	**Moody's**	**Rank**	**Strength**	**Beta**
1	Atmos Energy Corp.	A	A2	1	A	0.70
2	Chesapeake Utilities	NA	NA	2	B++	0.65
3	New Jersey Resources	A	Aa2	1	A+	0.80
4	Northwest Natural Gas	A+	A3	1	A	0.65
5	South Jersey Industries	BBB+	A2	2	A	0.80
6	Southwest Gas Corp.	BBB+	A3	3	B++	0.75
7	Spire, Inc.	A-	Baa2	2	B++	0.70
8	WGL Holdings, Inc.	A+	A3	1	A	0.75
	Average	**A**	**A2**	**2**	**A**	**0.73**
	Oregon-Juristictional Utilities					
	Northwest Natural Gas	A+	A3	1	A	0.65
	Pacificorp	A	A3	NA	NA	NA
	Portland General Electric	BBB	A3	2	B++	0.70
	Average	**A-**	**A3**	**2**	**B++**	**0.68**
	Avista Corp.	**BBB**	**Baa1**	**2**	**A**	**0.70**

(a) www.standardandpoors.com (retrieved Mar. 10, 2017).

(b) www.moodys.com (retrieved Mar. 10, 2017).

(c) The Value Line Investment Survey (Dec. 3, 2016; Jan. 27, 2017).

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

REPLY TESTIMONY OF JENNIFER S. SMITH
REPRESENTING AVISTA CORPORATION

Reply Testimony in Response to Parties' Proposed Adjustments

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corporation.

A. My name is Jennifer S. Smith. I am employed by Avista Corporation as a Senior Regulatory Analyst in the State and Federal Regulation Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Have you previously provided direct testimony in this Case?

A. Yes. My testimony and exhibits in this proceeding cover the accounting and financial data in support of the Company's need for the proposed increase in rates. In my previous testimony, I explained the twelve-months ended September 30, 2018 test year operating results, including expense and rate base adjustments made to the twelve-months ended June 30, 2016 base year operating results and rate base. I also provided the Company's restated twelve-months ended June 30, 2016 net plant, planned 2017 plant additions, and twelve-months ended September 30, 2018 AMA customer growth capital additions adjustments and the revenue load adjustment. My testimony also included an overview of the Company's system and jurisdictional allocation methodologies that have been in place for many years.

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

A. My testimony will summarize the Company's adjusted revenue requirement. I will explain the adjustments to the Company filed revenue requirement proposed by Staff, which Avista fully or partially accepts. In addition, my testimony will summarize and/or respond to the proposed adjustments by non-Avista parties that the Company does not accept.

A table of contents for my testimony is as follows:

Description **Page**

II. ADJUSTMENTS ACCEPTED BY AVISTA

Q. Avista accepts certain adjustments to revenue requirement and rate base, as proposed by Staff, to arrive at the Company's adjusted revenue requirement. Have you prepared a summary table that reflects Staff's proposed adjustments to revenue requirement and rate base which have been accepted by the Company?

A. Yes, I have. Table No. 1, below, provides a summary of the adjustments to the Company's direct filed natural gas revenue requirement and rate base proposed by Staff, which the Company fully or partially accepts. As shown in Table No. 1 the results of those adjustments result in an adjusted proposed revenue requirement of $6,748,000 and rate base of $240,750,000, as compared to the initially proposed revenue requirement of $8,539,000 and rate base of $243,424,000.

Table No. 1:

SUMMARY OF ACCEPTED AND PARTIALLY ACCEPTED ADJUSTMENTS TO FILED REVENUE REQUIREMENT AND RATE BASE
000s of Dollars

Testimony Section			Rev. Req. Incr / (Dec)	Rate Base Incr / (Dec)
	Revenue Requirement As Filed by Avista		**$ 8,539**	**$ 243,424**
II.	**Fully Accepted Adjustments Proposed by Staff**			
A.	S-11	Pension Adjustment	(265)	(170)
B.	S-14	Underground Storage Adjustment	(21)	-
C.	S-18	Load Forecasting Adjustment	(394)	-
D.	S-19	Sales & Transportation Adjustment	39	-
E.	S-26	Atmospheric Testing Adjustment	(66)	-
		Total of Adjustments Fully Accepted to Revenue Requirement and Rate Base	$ (707)	$ (170)
III.	**Partially Accepted Adjustments Proposed by Staff**			
A.	S-01.1	Uncollectible Expense Adjustment	(267)	-
B.	S-01.2	Uncollectible Rate Adjustment	(52)	-
C.	S-01.3	OPUC & Franchise Fees Adjustment	(47)	-
D.	S-02	Interest Synchronization Adjustment	(20)	-
E.	S-15	Other Gas Supply Adjustment	(18)	-
F.	S-21.1	Information Technology Adjustment	(353)	(514)
G.	S-21.2	General Plant Adjustment	(1)	(5)
H.	S-22.1	Cost Allocation Adjustment	(92)	(236)
I.	S-22.2	Affiliated Interest Adjustment	(15)	(34)
J.	S-23	Utility Plant in Service Adjustment	(185)	(1,715)
K.	S-27	Customer Service & Information Sales, Advertising and Promotional Expense Adjustment	(5)	-
L.	S-32.1	Meals & Entertainment, Travel, Gifts and Awards	(31)	-
		Total of Adjustments Partially Accepted to Revenue Requirement and Rate Base	$ (1,084)	$ (2,504)
		Adjusted Revenue Requirement and Rate Base after Accepted Adjustments	**$ 6,748**	**$ 240,750**

Q. Please briefly describe each of the adjustments included in Section II of Table No. 1, representing adjustments that are fully accepted by Avista.

A. A brief description of each adjustment in Table No. 1 that Avista fully accepts is provided below.

A. Pension Expense Adjustment

Q. In adjustment S-11, Staff witness Mr. Muldoon proposed an adjustment to reduce pension expense to a level utilizing a 6.6% Expected Rate of Return (EROA). Does the Company agree with this adjustment?

A. Yes. In an effort to limit the number of issues in this case, the Company is willing to accept Staff's adjustment. While accepting Staff's 6.6% EROA, the Company continues to believe that the best estimate of future EROA is based on expert guidance from the Company's independent Compensation Consultants.[1] In setting the forward-looking EROA, Avista's Board of Directors considers several factors, including year-end investment assets and target asset allocation, prior to settling on the EROA utilized in the pension expense calculation. In order to have diversified independent input, the final EROA is based on an average of guidance provided from three different consultants. Accepting this adjustment reduces the Company's proposed revenue requirement by $265,000 and reduces rate base by $170,000.

[1] Avista works closely with its third party actuaries in order to develop and implement a strategy to maintain or improve the pension asset funding percent and keep pension/post-retirement medical expenses at a reasonable level. The Finance Committee of the Board of Directors approved in its November 2016 meeting a reduction in the Fixed Income Long Duration (FILD) investments within the Pension Plan from 58% to 45%. This information was based on preliminary information from Verus (third party pension consultant), coupled with scenarios from our actuary.

B. <u>Underground Storage Adjustment</u>

Q. In adjustment S-14, Staff witness Ms. Gorsuch proposes a reduction to Underground Storage Expense of approximately $20,000 based on a three-year moving average. Do you agree with this adjustment?

A. Yes. We agree that a reduction to Underground Storage expense of $20,000 results in a reasonable representation for underground storage expense for the test year. Accepting this adjustment reduces the Company's proposed revenue requirement by $21,000.

C. <u>Load Forecasting Adjustment</u>

Q. In adjustment S-18, Staff witness Mr. St. Brown, proposes three adjustments to the Company's Load Forecasting models, which resulted in a decrease to the Company's filed revenue requirement of $394,000. What is the Company's response to this adjustment?

A. Company witness Mr. Patrick Ehrbar provides testimony which explains the Company's acceptance of Staff's adjustment.

D. <u>Sales & Transportation Adjustment</u>

Q. Mr. St. Brown also proposed an adjustment to the Company's Sales & Transportation Revenue based on his adjustments to the Company's Load Forecasting models. Staff adjustment S-19 results in an increase to revenue requirement in the amount of $39,000. What is the Company's response to this adjustment?

A. Company witness Mr. Patrick Ehrbar provides testimony which explains the Company's acceptance of Staff's adjustment.

E. <u>Atmospheric Testing Adjustment</u>

Q. In adjustment S-26, Staff witness Ms. Anderson proposes two reductions to the Company's Atmospheric Testing (AT) Expense. Does Avista agree with this adjustment?

A. Yes. As Ms. Anderson stated, in Staff Data Request No. 263[2], the Company identified an error and proposed an adjustment to reduce AT expense by $61,762, which reduces the Company's filed revenue requirement by $64,076. The second adjustment proposed by Ms. Anderson, in the amount of $2,609, was to reduce AT expense for an adjusted inspection point growth rate. Due to the immateriality of the adjustment, and an effort to minimize issues in this case, the Company agrees to this adjustment, resulting in an overall reduction to revenue requirement of $66,000.

III. <u>ADJUSTMENTS PARTIALLY ACCEPTED BY AVISTA</u>

Q. Please briefly describe each of the adjustments included in Section III of Table No. 1, representing adjustments that are partially accepted by Avista.

A. A brief description of each adjustment in Table No. 1 that Avista partially accepts is provided below.

A. <u>Uncollectible Expense Adjustment</u>

Q. In adjustment S-01, Staff witness Ms. Gardner proposes a reduction to uncollectible expense in the amount of $303,000. Do you agree that the Company should make an adjustment to uncollectible expense?

A. Yes, however the Company does not agree with Staff's calculation of the adjustment. Ms. Gardner states that net write-off amounts "*differed significantly from the actual net write-off amounts provided by the Company in response to DR No. 208(a)*"[3]. As you can see

[2] Staff/904/Anderson/1
[3] Staff/100/Gardner/6, lines 7-9

in Ms. Gardner's exhibit[4], Staff Data Request No. 208 requested the actual net write-off amounts on a "*calendar year*" basis, while the net write-off amounts provided in Ms. Smith's filed workpapers, and provided as an exhibit in Ms. Gardner's reply[5] was provided on a twelve-months ended June 2016 basis. The numbers did not "differ significantly"[6]; the numbers were in fact net write-off amounts, but for two different time periods.

Q. As Ms. Gardner states on page 7 of her testimony, Avista identified an error in the calculation of the filed adjustment to uncollectible expense, please explain the result of this correction.

A. The Company's filed adjustment inadvertently provided the actual write-off number for 2014 rather than the actual **net** write-off amount for 2014. Net write-offs include write-offs, reinstatements and recoveries. Using the actual **net** write off number rather than the actual write-off amount, changes the three-year average uncollectible as a percent of revenues from .90996% to .62344%.

Q. Do you agree with Ms. Gardner, that the test year uncollectible expense is overstated?

A. Yes. As discussed in the Company's response to Staff Data Request No. 419[7], the Company temporarily stopped the collection process from December 2014 through July 2015, in order to accommodate the installation of the new Customer Care and Billing (CC&B) system. In August of 2015, the Company reinstated its collection process and trued-up its uncollectible expense related to the delayed period. The Company's base year is from July 1, 2015 through

[4] Staff/102/Gardner/2
[5] Staff/102/Gardner/1
[6] Staff/100/Gardner/6, line 7
[7] Staff/102/Gardner/7-8

June 30, 2016, which means the uncollectible expense included in the Company's filed base year was overstated, as there is seven months of collection activity included in the base year which was related to the first seven months of 2015.

Q. What adjustment does the Company believe is appropriate, to correctly adjust the base year?

A. The base year uncollectible expense should be adjusted using a three-year average[8] of the most recent calendar year ended December 31, 2016. In fact, Ms. Gardner acknowledges "it is a long-standing policy of the Commission Staff to apply a three-year average methodology to determine the test year uncollectible expense"[9].

Q. What adjustment is the Company proposing in its reply testimony?

A. The Company proposes to reduce the uncollectible expense from that included in the Company's direct filing by $258,498, for a reduction to revenue requirement of $267,000, as shown in Table No. 1 above.

B. <u>Uncollectible Rate Adjustment</u>

Q. Staff witness, Ms. Gardner proposes an adjustment to the uncollectible rate in adjustment S-1, which is a reduction to revenue requirement of $48,000. What is the Company's response to this proposal?

A. Based on Ms. Gardner's analysis of uncollectible expense in this adjustment, the Company agrees there should be an adjustment to the uncollectible rate, however, we do not accept the rate proposed by Staff.

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[8] See, e.g., In the Matter of Avista Corporation, OPUC Docket UG 246, Order No. 14-015 at 3 (January 21, 2014) and In the Matter of Avista Corporation, OPUC Docket UG 186, Order No. 09-422, Appendix A at 4 (October 26, 2009) (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average).

[9] Staff/100/Gardner/5/lines 15-16

Q. What does Ms. Gardner propose specifically in regards to the uncollectible rate?

A. Ms. Gardner proposes to use the "uncollectible rate of .5496 set in Docket UG 288"[10], which related to a three-year average for the period of 2012 – 2014. The Company believes this is not appropriate. Because Ms. Gardner has already performed the analysis of net write-offs, as she discusses on pages 5 through 9 of her testimony, she has available the twelve-months ended December 31, 2016 net write-off and direct gas revenues, which should be used to calculate the more current three-year average uncollectible rate, based on the 2014 – 2016 period.

Q. What is the impact to the Uncollectible rate using the twelve-months ended December 31, 2016 net-write off and direct revenue balances?

A. By using the twelve months ended December 31, 2016 net write-off and direct gas revenue balances, the uncollectible rate used to calculate the Company's conversion factor changes from the Company's filed rate of 1.0976% to .6242%. The Company is proposing to use this rate in the conversion factor which has an impact of a reduction to revenue requirement of $52,000, as shown in Table No. 1 above.

C. <u>OPUC & Franchise Fees Adjustment</u>

Q. On page 10 of Staff witness, Ms. Gardner's testimony she proposes an adjustment to the Company's revenue conversion factors for both the Franchise and OPUC fees. Does the Company agree these factors should be adjusted?

A. Yes. The Company recognizes that an adjustment should be made to both the Franchise Fee rate and the OPUC fee rate. Regarding the OPUC fee rate, at the time of filing the

[10] Staff/100/Gardner/9/lines 4-5

OPUC fee rate had not yet been adjusted by the Oregon Public Utility Commission. Order 17-065, entered on February 22, 2017, increased the annual OPUC fee from .275% to .3%.

The second portion of Ms. Gardner's proposed adjustment was to update the franchise and ERSA[11] fees, for adjustments made to the net write-offs, and the uncollectible rate. While the Company agrees these should be updated, the Company does not agree to the updates provided by Staff. The Company proposes to update the Company's filed conversion factor with revisions for the uncollectible rate, as proposed above by the Company, and OPUC fee rate, as well as updates to the Franchises fees as a result of using net write-off and direct revenue balances for the twelve-months ended December 31, 2016. Staff did not appropriately adjust the direct gas revenue balance to correctly arrive at a franchise fee rate.

The overall impact of these adjustments to the OPUC Fee and Franchise Fee rates is a decrease to revenue requirement of $47,000, as shown in Table No, 1 above.

D. Interest Synchronization Adjustment

Q. In adjustment S-2, Staff proposes an adjustment to increase revenue requirement for the impact of the federal and state tax impact on the cost of debt component of rate of return in the amount of $373,000. Does the Company accept this adjustment?

A. The Company accepts that an adjustment should be made to reflect the cost of debt impacts to adjustments made to rate base items; however, because the Company does not agree to the individual adjustments that Staff has proposed to various rate base items, the Company does not accept Staff's proposed amount. Instead, the Company is proposing a decrease to

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[11] Energy Resource Supplier Assessment (ERSA), Oregon Revised Statutes (ORS) 469.421 (8) (e) The amount assessed to an energy resource supplier shall be based on the ratio which that supplier's annual gross operating revenue derived within this state in the preceding calendar year bears to the total gross operating revenue derived within this state during that year by all energy resource suppliers. The assessment against an energy resource supplier shall not exceed 0.375 percent of the supplier's gross operating revenue derived within this state in the preceding calendar year.

revenue requirement in the amount of $20,000 reflecting the cost of debt impact of Company adjustments to rate base.

E. <u>Other Gas Supply Adjustment</u>

Q. In adjustment S-15, Ms. Gorsuch's proposes a reduction to Other Gas Supply expense in the amount of $118,000. What is Avista's response to this proposal?

A. Ms. Gorsuch's Other Gas Supply adjustment has two components. The first component adjusts expenses related to labor and labor loadings (benefits). The second component adjusts the Gas Technology Institute expenses and administrative and general expenses.

Q. Does the Company accept either components of Ms. Gorsuch's adjustment?

A. Partially. Due to the immateriality of the adjustment, and in an effort to minimize issues in this case, the Company agrees to Ms. Gorsuch's adjustment to Gas Technology Institute, and administrative and general expenses, which adjusts the base year to a three-year average. The effect of this adjustment is a reduction to revenue requirement of approximately $18,000, as shown in Table No, 1 above.

The Company does not agree with the adjustment to the expenses related to labor, and labor loadings, which will be discussed later in my reply testimony.

F. <u>Information Technology Adjustment</u>

Q. On pages 20 through 29 of Staff witness Mr. Kaufman's testimony[12], Staff proposes an adjustment (S-21.1) which reduces rate base by a total of $4.596 million and O&M expense by $202,000, relating to various information technology additions. What is Avista's response to Staff's adjustment?

[12] Staff/700/Kaufman/20-29

A. The Company has accepted a portion of this adjustment which decreases the Company's filed revenue requirement and rate base by $353,000 and $514,000, respectively, as shown in Table No, 1 above. Company witness Mr. Kensok provides reply testimony in response to Staff's adjustment, which supports the Company's partial acceptance of Staff's adjustment.

G. <u>General Plant Adjustment</u>

Q. On pages 29 through 34 of Staff witness Mr. Kaufman's reply testimony, (Staff/700, Kaufman), Staff proposes an adjustment (S-21.2) which reduces rate base by a total of $1.041 million and O&M expense by $17,000, relating to various general plant additions. What is Avista's response to Staff's adjustment?

A. The Company has accepted a portion of this adjustment which decreases the Company's filed revenue requirement and rate base by $5,000 and $1,000, respectively, as shown in Table No, 1 above. Company witness Ms. Rosentrater provides reply testimony in response to Staff's adjustment, which supports the Company's partial acceptance of Staff's adjustment.

H. <u>Cost Allocation Adjustment</u>

Q. Staff witness Mr. Kaufman, proposes an adjustment (S-22.1) which reduces rate base by a total of $3.513 million and revenue requirement by $365,000, relating to reductions of plant associated with Cost Allocations. What is Avista's response to Staff's adjustment?

A. The Company has accepted a portion of this adjustment which decreases the Company's filed revenue requirement and rate base by $92,000 and $236,000, respectively, as shown in Table No, 1 above. Company witness Mr. Ehrbar provides reply testimony in response to Staff's adjustment, which supports the Company's partial acceptance of Staff's adjustment.

I. Affiliated Interest Adjustment

Q. Mr. Kaufman's proposes an adjustment (S-22.2) which reduces rate base and revenue requirement, relating to various Affiliated Interest transactions. What is Avista's response to Staff's adjustment?

A. Mr. Kaufman's adjustment has three components. The first component reduces interest expense to re-price Avista's 2016 interest payments to Avista Capital at the Federal Reserve Economic Data National Rate on Jumbo Deposits. The second component makes an adjustment to reduce expenses for general support and administrative services, and the third adjustment removes the GridGlo costs from rate base.

Q. Does the Company accept these adjustments proposed by Mr. Kaufman?

A. Yes, in part. The Company agrees to remove the remaining GridGlo costs from rate base, which decreases the Company's filed revenue requirement and rate base by $15,000 and $34,000, respectively, for Oregon's share of the GridGlo transaction, as reflected in Table No. 1 above. Company witness Mr. Machado provides reply testimony in response to Staff's adjustment, which supports the Company's acceptance of this portion of Staff's adjustment.

However, the Company does not agree to the remaining two components. Please see Section IV. Item J later in my testimony for further discussion of these two items.

J. Utility Plant in Service Adjustment

Q. Staff witness Mr. Moore, proposes an adjustment (S-23) which reduces rate base by a total of $9.789 million and revenue requirement by $965,000, relating to natural gas utility plant in service investments. Does the Company agree with any portions of this adjustment?

A. Yes. The Company accepts a portion of this adjustment which decreases the Company's filed revenue requirement and rate base by $186,000 and $1.715 million, respectively, as shown in Table No, 1 above. Company witness Ms. Rosentrater provides reply testimony in response to Staff's adjustment, which supports the Company's partial acceptance of Staff's adjustment.

K. Customer Service & Information Sales, Advertising and Promotional Expense Adjustment

Q. In adjustment S-27, Staff witness Ms. Anderson proposes two reductions to the Company's Customer Service & Informational Sales Expenses, Advertising and Promotional Activities for a total of $20,000. Do you agree with this adjustment?

A. Partially. Ms. Anderson's adjustment has two components. The first component adjusts "Category E" advertising expenses for a decrease to expense of $15,596, for those expenses related to the Low Income Rate Assistance Program (LIRAP). The second component removes $3,390 of advertising expenses, which Ms. Anderson states "the flashlights display Avista's brand name more prominently than any safety information, this expense should be partially placed into the promotional and advertising account"[13].

Q. Does the Company accept either component of Ms. Anderson's adjustment?

A. Due to the immateriality and an effort to minimize issues in this case, the Company accepts the adjustment made to advertising expenses for which Staff categorizes as promotional advertising. However, the Company does not accept the component removing advertising

[13] Staff/900/Anderson/7, lines 13-14

expenses associated with the LIRAP program. Please Section IV, item M later in my testimony for further discussion.

L. Meals & Entertainment, Travel, Gifts and Awards Adjustment

Q. In adjustment S-32, Staff witness Mr. Barry proposes a blanket adjustment to remove 50 percent of various Operations & Maintenance (O&M) Expenses, because these costs are "discretionary expenses that should be shared equally by ratepayers and shareholders"[14]. What is Avista's response to this testimony?

A. Mr. Barry's "broad-brush" adjustment removed 50 percent of the expense categories identified below, for a total of $226,278. For ease of reference, Table No. 02 below provides a breakdown of the six components of the adjustment:

Table No. 02:

Adjustment Reference No.	Various O&M Expenses	50% Various O&M Expenses
S-32.1 Employee Business Meals Expense	$ 60,524	$ 30,262
S-32.2 Employee Airfare Expense	183,771	91,885
S-32.3 Vehicle & Transportation Expense	49,305	24,653
S-32.4 Lodging Expense	89,390	44,695
S-32.5 Office Supplies Expense	19,525	9,762
S-32.6 Miscellaneous Expense	50,042	25,021
Total S-32 Adjustment	**$ 452,556**	**$ 226,278**

[14] Staff/100/Barry/14/lines 10-11

Q. Does the Company accept the adjustment made by Mr. Barry?

A. Partially. Due to the immateriality of the adjustment, and an effort to minimize issues in this case, the Company agrees to remove 50 percent of the component S-32.1 for Employee Business Meals Expenses for a reduction to revenue requirement of $31,236, as shown in Table No, 1 above. However, the Company does not accept the remaining five components of the adjustment, which are discussed below in Section IV. R.

IV. <u>ADJUSTMENTS NOT ACCEPTED BY AVISTA</u>

Q. Staff, CUB, and NWIGU proposed adjustments, which have not been accepted by the Company. Please identify each of these adjustments and explain why Avista has not accepted these proposals.

A. Table No. 3 below lists the adjustments proposed by Staff and other Parties, which are not accepted by the Company. Avista's response to each of these proposed adjustments follow the Table.

Table No. 3:

ADJUSTMENTS NOT ACCEPTED BY AVISTA

Testimony Section			Staff Rev. Req. Incr / (Dec)	Staff Rate Base Incr / (Dec)	CUB Rev. Req. Incr / (Dec)	CUB Rate Base Incr / (Dec)	NWIGU Rev. Req. Incr / (Dec)	NWIGU Rate Base Incr / (Dec)
IV.		**Adjustments Not Accepted by Avista**						
S-10	A.	Cost of Capital	(2,998)	-	-	-	(971)	-
S-03	B.	Working Capital Adjustment	(327)	(3,356)	-	-	-	-
S-04	C.	Wage & Salaries	(970)	(81)	-	-	(109)	-
S-08	D.	Regulatory Expense	(183)	-	-	-	-	-
S-15	E.	Other Gas Supply	(100)	-	-	-	-	-
S-16	F.	D&O Insurance Adjustment	(51)	-	-	-	-	-
S-21.1	G.	Information Technology Adjustment	(289)	(4,080)	-	(4,685)	-	-
S-21.2	H.	General Plant Adjustment	(119)	(1,039)	-	(537)	-	-
S-22.1	I.	Cost Allocation Adjustment	(661)	(4,596)	-	-	-	-
S-22.2	J.	Affiliated Interest Adjustment						
S-23	K.	Utility Plant in Service Adjustment	(758)	(7,775)	-	(19,395)	-	-
S-25	L.	Other Revenues - Misc. Revenue Adjustment	(94)	-	-	-	-	-
S-27	M.	Customer Service & Information Sales, Advertising and Promotional Expense Adjustment	(15)	-	-	-	-	-
S-28	N.	Distribution O&M Adjustment	(37)	-	-	-	-	-
S-29	O.	Customer Accounting Adjustment	(113)	-	-	-	-	-
S-30	P.	Various A&G; Prepaid Adjustment	(4)	-	-	-	-	-
S-31	Q.	Membership Dues & Donations Adjustment	(55)	-	-	-	-	-
S-32.2	R.	Airfare Adjustment	(97)	-	-	-	-	-
S-32.3	R.	Vehicle Trans. Expense Adjustment	(25)	-	-	-	-	-
S-32.4	R.	Lodging Expense Adjustment	(46)	-	-	-	-	-
S-32.5	R.	Office Supplies Expense Adjustment	(10)	-	-	-	-	-
S-32.6	R.	Miscellaneous Expense Adjustment	(26)	-	-	-	-	-
S-33	S.	Medical Benefits Adjustment	(238)	-	-	-	-	-
S-36	T.	Fee Free Bankcard Adjustment	(45)	-	-	-	-	-
S-38	U.	Materials & Supplies - Non Fuel Adjustment	(12)	-	-	-	-	-
		Total Adjustments Not Accepted by Avista	**$ (7,274)**	**$ (20,927)**	**$ -**	**$ (24,617)**	**$ (1,080)**	**$ -**

A. <u>Cost of Capital</u>

Q. Staff witness, Mr. Muldoon, and Northwest Industrial Gas Users ("NWIGU") witness Mr. Gorman proposed adjustments to the Company's filed Return on Equity (ROE) Capital Structure, and Cost of Debt. Does the Company agree with the Parties' proposals?

A. No. The Company continues to support an ROE of 9.9 percent and a 50 percent common equity layer. Mr. Thies provides reply testimony in response to the Parties' proposals regarding Capital Structure and Cost of Debt, and Mr. McKenzie's reply testimony addresses ROE.

B. <u>Working Capital Adjustment</u>

Q. On pages 12-13 of her testimony Ms. Gardner proposes an adjustment (S-03) to remove $3,356,000 of rate base for working capital. Do you agree with this adjustment?

A. No, I do not. Ms. Gardner states that "Staff's position has been that the natural gas and electric industries are sufficiently different, which compromises the accuracy of the Working Capital allocation to Oregon."[15] Regardless of the differences between the natural gas and electric industry, the definition of working capital does not change. There will still be a lag in time between the collection of revenues for services rendered and the necessary outlay of cash by the Company to pay the expenses of providing those services. Staff does not provide any specific reasons why they do not support the calculation of the Company's working capital using the Investor Supplied Working Capital (ISWC) method justifying their removal of the Company's working capital balance. While there are various methods used to determine a Company's working capital, the Company has calculated its working capital in this proceeding using the Investor Supplied

[15] Staff/100/Gardner/12, lines 7-9

Working Capital (ISWC) method. The Company believes this is a reasonable approach to computing working capital, representing expended funds to provide reliable service to its customers.

C. <u>Wages and Salaries – Bonus & Incentives Adjustment</u>

Q. In adjustment S-04, Ms. Gardner proposes an adjustment for Wages and Salaries in the amount of $930,000 expense and $81,000 rate base. Does the Company agree with this adjustment?

A. No, the Company does not agree with any of the components included in Staff's Adjustment S-04. Provided in the following pages is Avista's response to the five components of Staff's Adjustment S-04. For ease of reference, Table No. 04 below provides a breakdown of the five components of the adjustment:

<u>Table No. 04:</u>

Adjustment Reference No.	O&M Expense	Capital
S-04.1 Wages & Salaries	$ (152,000)	$ (27,000)
S-04.2 Overtime	(186,000)	(52,000)
S-04.3 Bonus & Incentive	(387,000)	
S-04.4 Restricted Stock Units	(109,000)	
S-04.5 Payroll Tax	(96,000)	(2,000)
Total S-04 Adjustment	**$ (930,000)**	**$ (81,000)**

Q. In "Adjustment S-4.01 Wages and Salaries", Staff proposes an adjustment of approximately $152,000 in reduced expense and $27,000 in reduced rate base. Why does the Company disagree with this adjustment?

A. The Company's non-union labor expense adjustment included in the case is based on <u>actual</u> increases of 3.0 percent that have been incurred and already in effect for the 2015-2017 time period, and a current estimate of 3 percent for 2018.[16] Staff, for its part, limits increases in labor expense to the Oregon All-Urban Consumer Price and Wage Index (CPI), an increase that is less than Avista's actual and estimated level of expense. Staff's use of a CPI does not even reflect increases <u>currently in effect</u>, nor does it appropriately reflect regional and national labor market conditions or competition within our industry, or specifically to our Company. The appropriate salary increase for a specialized labor force should be competitive regionally and nationally and be benchmarked against the industry in which we compete for talent. To aid in this determination, Avista participates in numerous confidential salary surveys provided by third-party consulting firms. The overall results of these surveys indicated an approximate 3% increase was the appropriate non-union wage increase amount for 2015-2017. These increases were approved by the Company's Board of Directors.[17]

In addition, if one were to use the data provided in the Occupational Labor Statistics specific to Natural Gas Distribution Utilities[18] (published by the Bureau of Labor Statistics), the median hourly wage increase for the 2005-2015 time period averaged 3%. This growth rate is also consistent with the extremely low unemployment rate in our industry (approximately 2.5% vs. national unemployment rate of 4.7%).[19] In the end, the increase proposed by Staff related to non-union labor falls short of what should be allowed for recovery in customer rates.

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[16] The Company annualized the impact of the March 1, 2015 adjustment (.75%), includes 3% for 2016 and 2017, and limits the March 1, 2018 (2.25%) increase to six months (March 1 – September 30). Union increases are based on approved contract terms for 2015-2018.

[17] For instance, the Company has reviewed over 72 surveys (some multipart) between 2012 and 2016. These surveys were provided in Staff_DR_98 and summarized in Staff_DR_360.

[18] This industry comprises: (1) establishments primarily engaged in operating gas distribution systems (e.g., mains, meters); (2) establishments known as gas marketers that buy gas from the well and sell it to a distribution system; (3) establishments known as gas brokers or agents that arrange the sale of gas over gas distribution systems operated by others; and (4) establishments primarily engaged in transmitting and distributing gas to final consumers.

[19] Bureau of Labor Statistics - Industries at a Glance NAICS 22, February 2017 and Economy at a Glance United States February 2017.

Q. In "Adjustment S-04.02 Overtime", rather than accept the level of overtime included in the case by the Company, Staff proposed to simply escalate the overtime included in the base year by increasing by CPI, resulting in a decrease in expense of approximately $186,000 and a decrease in rate base of $52,000. Does the Company agree with this adjustment?

A. No, Avista does not agree with this adjustment for the following reasons:

<u>First</u>, as stated in the Company's response to Adjustment S-4.01 Wages and Salaries, Staff's use of CPI does not reflect increases <u>currently in effect</u>, nor does it appropriately reflect regional and national labor market conditions or competition within our industry, or specifically to Avista.

<u>Second</u>, Staff erroneously removed overtime costs related to Construction Work in Progress (CWIP) in their adjustment. Avista did not include CWIP <u>in this case</u> and, therefore including an overtime adjustment related to CWIP is not appropriate. An adjustment to reduce expense should not be incorporated in a rate case when the overall expense itself was not included in the case at all.

Q Prior to addressing Staff "Adjustment S-04.03 Incentive Compensation", please provide a brief overview of the Company's approach to overall compensation.

A. Avista is committed to providing <u>total compensation</u> to employees that will attract and retain qualified people required to meet the needs and expectations of all utility stakeholders, including but not limited to, customers, shareholders and regulators. To that end, the Company provides employees with cash compensation (base pay and variable pay in the form of pay-at-risk incentive compensation) and comprehensive benefits including medical and retirement. The overall package is designed to meet the following goals:

- Clearly identify the specific measures of Company performance that are likely to create long-term value for the Company's customers and shareholders;
- Keep employees focused on cost control, customer satisfaction, reliability and operational efficiencies by awarding variable pay (pay-at-risk) for meeting pre-determined metrics;
- Promote a culture of safety;
- Pay competitively compared to others within our market;
- Reward outstanding performance; and
- Align elements of the incentive plans among all Company employees, including executive officers.

Each component is carefully considered and balanced with all other compensation components in order to provide total compensation which will be cost-effective for the Company, remain attractive to employees, and provides an effective recruitment tool. As previously noted, the Company relies on several salary surveys for non-executive and executive officers to aid in benchmarking. The cash component (base pay and pay-at-risk) and the benefits component are both benchmarked against industry-standard surveys. Compensation components may be adjusted over time to achieve the goal of recruiting and retaining qualified employees. Both components (cash and benefits) are targeted to be within a range that is 15% above or below the median of Avista's peer group – ensuring overall compensation that is competitive within the market.

Q. Please explain why Avista does not agree with Staff's "Adjustment S-04.03 Incentive" related to incentive compensation.

A. Incentive compensation is just one component within overall compensation and does not represent additional compensation over and above what is competitive. Rather, incentive compensation is a method to provide the appropriate competitive level of cash compensation, while controlling costs and keeping employees motivated and focused on measures which provide long-term customer benefits. As such, incentive compensation should not be subject to a different standard than the base salary (wages and salaries) component of cash compensation, unless the incentive compensation is tied to stock price performance or earnings per share measures. The incentive compensation proposed to be removed by staff is not related to these types of measures. The incentive pay at issue in this case is tied to measures such as customer satisfaction, reliability of service, and the level of success by employees at keeping costs low for customers.

For comparison purposes, approximately 85 percent[20] of companies in the energy sector offer some form of variable pay within their cash compensation structure. Through the inclusion of a variable pay as part of overall cash compensation, the Company has the ability to meet our goal of being within the +/- 15 percent of market median for total cash compensation. <u>If we were to eliminate or reduce the incentive compensation, base salaries would need to be adjusted upward in order to remain competitive with our peers.</u>

The inclusion of incentive compensation is consistent with guidance provided in previous Commission orders which contained disallowances for plans with metrics <u>related to the financial performance</u> of the Company. For example, in Order No. 97-171, three incentive plans for US West Communications ("USWS") were reviewed in Docket No. UT-125. Two of USWS's plans contained both financial metrics and customer-focused metrics, and one plan was based entirely on financial metrics. This order states:

> "Staff notes that in the past, the Commission has not allowed a utility's revenue requirement to include employee bonuses that were based on the *utility's financial results of operations*." (emphasis added) (Order at page 69)

[20] For example, 2015-2016 Mercer US Compensation Planning Results July, page 42 is 84%, 2016-2017 Willis Towers Watson General Industry Salary Budget Survey Results, page 20 is 88%. These surveys were provided in Staff_DR_98 and summarized in Staff_DR_360.

In a recent Portland General Electric general rate case proceeding, Docket No. UE 283 as cited in Staff testimony,[21] the rationale contained within Staff's testimony for disallowance is based on increased earnings or financial metrics:

> "In accordance with Commission policy, Staff proposed to disallow 100 percent of officers' bonuses because they are *based on increased earnings* (Order 99-033 at 62; Order 97-171 at 74-76)" (emphasis added)

The costs associated with the Company's incentive plan included in Avista's case[22], however, is based entirely on metrics related to ratepayers – O&M cost per customer, customer satisfaction, reliability, and response time. None of the metrics included in the Company's adjustment are based on the utility's earnings per share results or common stock performance. Any incentive compensation related to financial results or common stock performance is already recorded as non-utility and is excluded from this case by the Company, and borne by shareholders. Past Commission orders actually support recovery of the incentive-related costs Avista has included in this case.

Q. In "Adjustment S-04.04 Restricted Stock Units", Staff proposes to disallow 100 percent of Restricted Stock Units (RSUs) because they "appear to be performance based"[23] resulting in a reduction of approximately $109,000 in expense. Are RSUs "performance based"?

A. No, RSUs are not performance based, but rather they are awarded if, and only if, the qualifying employee remains employed by Avista for the specified period of time. The RSUs are time-based, which means the number of stock-units are provided to the employee after the

[21] Staff/100, Gardner/3 section S-13
[22] Avista/501 Smith, Adjustment 2.12 Incentive Pay Adjustment
[23] Staff/100, Gardner/15, lines 4-6.

employee remains employed for the specified time period. The award of RSUs are not based on the performance of the Company, or any other financial metrics. It represents a portion of the employees overall competitive compensation related solely to remaining employed with the Company (time-based) much like cash compensation.

Consistent with the Short-term Incentive Plan[24], RSUs are not extra pay but rather a component of overall employee compensation. The purpose for this portion of the plan is retention – i.e., to provide an incentive for certain key employees to remain with the Company. It is important that certain key individuals who have extensive knowledge of the utility industry, and Avista in general, are retained by the Company for the benefit of its customers.

If RSUs were eliminated, base pay would need to be increased in order for the overall compensation package to be competitive. Compensation to employees is a necessary utility cost to enable Avista to provide safe, reliable service to its customers.

Q. NWIGU proposes to eliminate RSU units because the "Because shareholders are the primary beneficiary of the RSU incentive compensation, they should pay the RSU costs".[25] Do you agree with this statement?

A. No, as stated above, RSU units are not performance based, but rather are awarded if, and only if, the qualifying employee remains employed by Avista for the specified period of time. The award itself is granted on time vesting only and is not a performance-based award. Each year the participant remains employed additional RSUs are granted, providing the incentive to remain employed year after year.

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[24] The Company has excluded the components of Executive Officer STIP related to Earnings-Per-Share. In addition, the Performance Shares portion of the Long Term Incentive Plan (LTIP) for non-CEO employees is excluded due to metrics related to shareholder financial metrics. The entire LTIP is excluded for our CEO because it includes performance metrics related to RSUs.
[25] NWIGU/100 Gorman/7

Taken to the extreme, one could argue that almost all utility operating expenses provide some benefit to customers and shareholders. For example, the expenses associated with envelopes and postage enable the receipt of payments from customers, which result in revenues to provide the return on investment to shareholders. It is not appropriate to apportion necessary utility operating costs between customers and shareholders based on an arbitrary determination of benefits to each. In exchange for providing safe reliable service to customers, Avista should have the opportunity to recover the necessary, reasonable and prudent operating costs, and a fair return on its investment. Apportioning necessary utility operating costs to shareholders would not allow the Company the opportunity to earn a fair return.

The RSU component, which is time-based, is in contrast to the "Performance Shares" portion of the LTIP, where the employee receives the compensation only if certain share price or earnings per share targets are met. For this reason, the Company has excluded the Performance Share portion of the LTIP, and all costs associated with this portion are borne by shareholders.

Q. In "Adjustment S-04.05 Payroll Tax", Staff proposes to reduce payroll tax by approximately $96,000 in O&M expense and $2,000 in depreciation expense as a result of adjustments S-04.01 through S-04.04. Do you agree with this adjustment?

A. No. Given the Company does not agree with Staff's proposed adjustments for Wages and Salaries, there is no need for this adjustment. Further, Staff witness Mr. Barry proposes an adjustment to payroll tax loading in adjustments S-29 and S-30. Including both an adjustment in S-04 as well as in S-29 and S-30 would effectively double-count adjustments related to payroll tax.

D. Regulatory Expense Adjustment

Q. On pages 21 through 22 of Ms. Gardner's reply testimony, in adjustment S-8, she proposes to adjust regulatory expense, excluding regulatory fees, to a three-year average of 2013 – 2015 actual expense. Do you agree with this adjustment?

A. No, I do not. The regulatory expenses, excluding fees, included in the base year are labor and non-labor expenses directly related to Oregon's regulatory activities. Adjusting regulatory expense using a three year average would eliminate the opportunity to recover the Company's regulatory expenses, including costs to file general rate cases and to fulfill regulatory filing requirements mandated by the Public Utility Commission of Oregon.

Q. Ms. Gardner states that "Staff noticed an increase in the Base Year expense as compared to years 2013 through 2015 actual expense"[26]. Please explain why this increase occurred?

A. Table No. 05 below shows Oregon's share of Regulatory Expenses, excluding regulatory fees, as a percentage of total system regulatory expenses. The overall increase in expense is directly related to costs for general rate cases filed in Oregon and the associated discovery (related to preparation, filing, and litigation of general rate cases, including but not limited to internal labor costs, administrative and production costs, and costs of outside services).

[26] Staff/100/Gardner/22, lines3-5

Table No. 05:

Oregon Share of Regulatory Expense as a Percentage of Total System	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
General Regulatory Activity	10%	10%	11%	11%	11%	11%	12%
General Rate Case Preparation & Process	0%	0%	1%	59%	16%	34%	20%
General Rate Case Discovery	0%	0%	0%	76%	34%	24%	6%
Total Regulatory Expense *(less Regulatory Fees)*	**10%**	**10%**	**9%**	**16%**	**13%**	**16%**	**13%**

In 2013, three things occurred: first, the Company began directly charging and tracking the labor and non-labor costs of general rate case expenses in each jurisdiction, rather than using its standard allocations. Secondly, 2013 was the first year in which the Company filed a rate proceeding in Oregon, which required the preparation of approximately 130 Standard Data Requests to be filed with the case, which resulted in additional general rate case expenses directly charged to Oregon. Finally, Washington and Idaho's regulatory expenses were reduced in 2013 and 2014 because in both states they had multi-year rate plans in effect, resulting in no general rate case proceedings in those years.

Q. Why did the Company begin directly charging and tracking the labor and non-labor costs of general rate case expenses?

A. In Order No. 6, approving the Settlement Stipulation in Docket Nos. UE-110876 and UG-110877, in Washington, the Order required Avista to begin tracking its Washington general rate case expenses. The Settlement Stipulation in its Washington Docket Nos. UE-110876 and UG-110877 agreed to by the parties specifically stated at Page 12, Paragraph 15:

> Avista agrees to begin separately accounting for all internal and external costs related to preparation, filing, and litigation of Washington general rate cases. The Company will present the overall amount of test year rate case expenses, including but not limited to internal labor costs, administrative and production costs, and costs of outside services, beginning with the 2012 test year.

Effective January 1, 2012, the Company began specifically tracking its electric and natural gas general rate case (GRC) activities in all services and jurisdictions.

E. <u>Other Gas Supply Adjustment</u>

Q. As previously discussed above, the Company was in partial agreement with Ms. Gorsuch's adjustment S-15. Which component of the adjustment is the Company contesting?

A. The components of adjustment S-15 which the Company does not agree to, are the components related to labor and labor loadings (benefits). Staff's adjustment to Other Gas Supply and labor loadings effectively double-counts labor and benefit adjustments proposed by Staff witnesses Ms. Gardner (Adjustment S-04), Mr. Muldoon (Adjustment S-11.1) and Mr. Gibbens (Adjustment S-33) and is therefore not appropriate. These components represent approximately $98,000 of Staff's adjustment and should be rejected.

F. <u>Directors & Officers Insurance Adjustment</u>

Q. In Staff adjustment S-16, Staff witness Ms. Johnson proposes an adjustment to remove 50 percent of the Company's Directors & Officers (D&O) insurance, to reflect an equal sharing of D&O insurance costs between ratepayers and shareholders. Do you agree with this adjustment?

A. No. I do not agree with Staff's reduction of 50 percent of the D&O insurance expense. As explained below, D&O insurance is a necessary and reasonable utility operating expense. The proposal to disallow half of the amount charged to Avista's ratepayers for D&O liability insurance costs is entirely arbitrary.

As I explained earlier in my testimony, one could argue that almost all utility operating expenses provide some benefit to customers and shareholders. For example, the expenses associated with envelopes and postage enable the receipt of payments from customers, which result in revenues to provide the return on investment to shareholders. It is not appropriate to apportion necessary utility operating costs between customers and shareholders based on some arbitrary determination of benefits to each. In exchange for providing safe reliable service to customers, Avista should have the opportunity to recover the necessary, reasonable and prudent operating costs, and a fair return on its investment. Apportioning necessary utility operating costs to shareholders would not allow the Company the opportunity to earn a fair return.

Q. What is Directors & Officers' liability insurance?

A. D&O insurance was created as a means to address the financial risks incident to serving as a director or officer of a corporation. The insurers that underwrite D&O liability coverage aggregate the risks of many companies and their respective directors and officers. D&O insurance policies typically have an annual term.

Q. What would happen if Avista did not purchase D&O insurance?

A. The Company would be unable to attract or retain capable individuals for the board of directors or to otherwise serve as officers. No qualified individual would agree to serve as a board member or officer without the coverage provided by such insurance. The fundamental governance and direction of the Company would not be possible without these individuals, therefore it is an essential part of the operation of a utility. D&O insurance is the means to remove the financial risk that is inherent in America's corporate governance legal environment.

The amount of coverage and its terms are important considerations. The ability of the selected insurers to cover claim occurrences is also of paramount importance. Avista has carefully placed its D&O coverage to assure the amount is adequate, terms are written to respond as desired to potential claims, and insurers are willing and able to respond if necessary. Staff has not taken issue with the level of these coverages only the general idea of having such coverage.

Q. Is D&O insurance a necessary business expense?

A. Yes. D&O coverage is a necessary adjunct to operating as a publicly traded company, which needs access to capital markets to finance its operations for the benefit of customers.

The purpose of D&O insurance is consistent with other insurance that the company must obtain, such as property insurance and general liability coverage. Insurance transfers risks of financial loss to third party insurers, reducing expense volatility in the company buying the insurance, and drastically reducing the threat of catastrophic financial losses.

Q. If a sharing of the D&O costs were to occur between customers and shareholders, how should the sharing be determined?

A. If the Commission were to determine that some level of sharing of D&O insurance is appropriate, then the Company would propose a sharing consistent with how directors and officers dedicate their time during the base year. This is consistent with how director and officer compensation is allocated between utility and non-utility operations.

During the twelve-months ended June 30, 2016 base year, the officers actual timesheet allocations were allocated approximately 89% customer / 11% shareholder percentage split for this rate year[27]. With regard to directors, the Company regularly requests each of its directors to estimate the time they spend on utility versus non-utility duties and responsibilities, based on their actual experience. The responses from the directors (from the November 2016 survey) indicated that, in the aggregate, approximately 97% of the directors' time is dedicated to utility matters, and approximately 3% to non-utility.

Based on the premiums included in the Company's case, using an allocation of approximately 89% customer / 11% shareholder, this split would equate to a revenue requirement reduction of $10,597, from the Company's filed case.

G. Information Technology Adjustment

Q. On pages 20 through 29 of Staff witness Mr. Kaufman's testimony[28], Staff proposes an adjustment (S-21.1) which reduces rate base by a total of $4.596 million and O&M expense by $202,000, relating to various information technology additions. What is Avista's response to Staff's adjustment?

A. As discussed above, the Company has accepted a portion of this adjustment which decreases the Company's filed revenue requirement and rate base by $353,000 and $514,000, respectively. Company witness Mr. Kensok[29] provides reply testimony in response to Staff's adjustment, which the Company does not accept.

H. General Plant Adjustment

Q. On pages 29 through 34 of Staff witness Mr. Kaufman's reply testimony, (Staff/700, Kaufman), Staff proposes an adjustment (S-21.2) which reduces rate base by a

[27] Avista/500/Smith/18,lines 4-5
[28] Staff/700/Kaufman/20-29
[29] Avista/1600/Kensok

total of $1.041 million and O&M expense by $17,000, relating to various general plant additions. What is Avista's response to Staff's adjustment?

A. As discussed above, the Company has partially accepted a portion of the adjustment proposed by Staff, and Ms. Rosentrater will discuss both the portions accepted and those not accepted by the Company.

I. Cost Allocation Adjustment

Q. Staff witness Mr. Kaufman, proposes an adjustment (S-22.1) which reduces rate base by a total of $3.513 million and revenue requirement by $365,000, related to reductions of plant associated with Cost Allocations. What is Avista's response to Staff's adjustment?

A. As discussed above, the Company has accepted a portion of this adjustment which decreases the Company's filed revenue requirement and rate base by $92,000 and $236,000, respectively. Company witness Mr. Ehrbar[30] provides reply testimony in response to Staff's adjustment, regarding the remainder of the adjustment the Company does not accept.

J. Affiliated Interest Adjustment

Q. As discussed above, in Section III. Item I., the Company does not agree to two components of the adjustment related to affiliated interests. What is the Company's response to these two components of the adjustment?

A. The Company does not agree with Mr. Kaufman's statements that the two following transactions "appear" to be in violation of transfer pricing requirements.

[30] Avista/1800/Ehrbar

Regarding the adjustment to interest expense, Mr. Kaufman argues that the Company "should pay the lower of the cost to Avista Capital or the market rate available to Avista"[31]. Any excess cash that Avista Capital loans to Avista Corp is compensated at the rate Avista Corp is avoiding. If Avista Corp is borrowing under the line of credit, then that cost of borrowing is avoided. Currently that cost is LIBOR plus 0.775 basis points (the adder is under 1 basis point).

In accordance with the Company's Cash Management Guidelines and Procedures, which is filed with the Commission, the process in place creates an equitable transfer price and in the case of where Avista Corp is borrowing under the line of credit, any cash from Avista Capital is used to "avoid" paying third party banks LIBOR plus 0.775 basis points. Therefore, the transfer pricing is appropriate.

The second component of the adjustment related to the General Support and Administrative services provided by Avista to affiliates is further discussed in Company witness Mr. Ehrbar's reply testimony.

K. <u>Utility Plant-in-Service Adjustment</u>

Q. As discussed in Section III. Item J. above, Staff witness Mr. Moore, proposes an adjustment (S-23) which reduces rate base relating to natural gas utility plant-in-service investments. The Company agreed with a portion of this adjustment, but please explain the Company's response to the portion of the adjustment the Company does not accept.

A. Company witness Ms. Rosentrater provides reply testimony explaining why the Company does not accept the adjustment.

[31] Staff/700/Kaufman

L. <u>Other Revenues Adjustment</u>

Q. On page 15 of Ms. Anderson's testimony, she adjusts the Company's Miscellaneous Revenues, to account for what she hypothesizes are uncollected fees for reconnect charges. What is the Company's response to this adjustment?

A. Staff recommends an adjustment of $90,644 based on its analysis of the number of seasonal reconnect fees Avista charged in 2015 (28) and 2016 (22). Staff claims that the Company is not collecting an adequate number of reconnect fees, based on its analysis, because Avista has a normal decrease in customers in the summer months of more than 1,200 customers and Avista only reported 28 seasonal reconnects in 2015 and 22 in 2016.

Q. Does Avista agree with the proposed adjustment of $90,644?

A. No, it does not. Only customers that request that their gas service be disconnected and then reconnected in a twelve-month period are considered "seasonal customers". All other disconnects are for other reasons like non-payment or home construction. To assume that the Company only reconnected the customers classified as "seasonal reconnect" during the base year is false. The Company collected over 1,800 reconnect fees during the base year. These reconnect fees were properly charged per Rule No. 20.

Q. Did Avista include an appropriate amount for reconnect fees in the test year?

A. Yes, Avista charged $57,040 in reconnect fees between July 1, 2015 and June 30, 2016 to approximately 1,800 customers and $40,250 in returned payment fees between July 1, 2015 and June 30, 2016. The total amount of $97,290 included in the Company's direct filing in FERC Acct. 488 is the appropriate amount for the base year.

M. <u>Customer Service & Information Sales, Advertising and Promotional Expense Adjustment</u>

Q. As discussed above, adjustment S-27, consists of two components, of which the Company does not agree to the component which removes $15,596 of "Category E" advertising expenses related to the LIRAP program. Please explain why the Company does not accept this adjustment.

A. The expenses identified by Ms. Anderson are administrative expenses incurred by Avista employees in order to manage the LIRAP program. Schedule 493, for the Residential Low Income Rate Assistance Program (LIRAP) in Oregon, states in the Special Conditions, item 3, "All funds collected under this program, less program administration and delivery costs paid to the individual agencies, will be distributed to income-eligible Residential Customers of Avista Utilities." Only the "program administration and delivery costs <u>paid to the individual agencies</u>" can be charged to the tariff; the Company's internal administrative expenses do not qualify to be charged to the Schedule 493 tariff. These costs are required for program implementation and need to be recovered in some fashion. For these reasons, the Company does not accept Staff adjustment.

N. <u>Distribution O&M Adjustment</u>

Q. In adjustment S-28 Staff proposes to reduce Distribution O&M expenses by $36,000. Do you agree with this adjustment?

A. No. Staff adjusted the level of expense in Distribution – Other Expense to reflect a level of increase of four percent based on a historical trend calculation. In Staff Data Request No. 371[32], Staff asked why there was a 43 percent increase from 2015 – 2016. In the Company's

[32] Staff/1002/Barry/3

response to the request, the Company explained there was a "glitch" in our Maximo system that was not appropriately recording employee mileage. When the correction was made, the correction was recorded to the incorrect FERC account. The correction should have been recorded to FERC 879000, but was recorded to FERC 880000, which explains why the increase in FERC account 880000 Distribution – Other Expenses shows a significant increase. Staff's analysis fails to account for the correction that was made during the base year, as described in the Company's response to Staff Data Request No. 371[33]. If Staff would have adjusted its analysis for this error, Distribution – Other expense would have experienced a net reduction, not a 43% increase.

O. Customer Accounting Adjustment

Q. In adjustment S-29 Staff proposes to reduce Customer Accounting expenses for associated payroll tax loadings by approximately $109,729. Do you agree with this adjustment?

A. No. Given the Company does not agree with Staff's adjustments for Wages and Salaries, there is no need for this adjustment. In addition, including both an adjustment to payroll tax in S-04.5 and in S-29 would effectively double-count adjustments related to payroll tax.

P. Various A&G and Prepaid Adjustment

Q. In adjustment S-30 Staff proposes to reduce Administrative and General Expenses for associated payroll tax loadings by approximately $3,640. Do you agree with this adjustment?

[33] Ibid

A. No. Given the Company does not agree with Staff's adjustments for Wages and Salaries, there is no need for this adjustment. In addition, including both an adjustment to payroll tax in S-04.5 and in S-30 would effectively double-count adjustments related to payroll tax.

Q. <u>Membership Due & Donations Adjustment</u>

Q. In adjustment S-31, Staff witness, Mr. Barry proposes an adjustment to remove Subscription expenses in the amount of $48,496. Does the Company accept this adjustment?

A. No. Mr. Barry provides no basis to remove the subscription expenses, other than stating Avista's response to Staff Data Request No. 391[34] "is not sufficient to indicate that these subscriptions are required for the provision of safe and reliable services to Oregon ratepayers".[35] The Company holds various subscriptions that provide industry knowledge and tools that benefit the performance and operations of our utility. For Mr. Barry to propose a "blanket" adjustment to reduce expenses associated with all subscriptions is simply arbitrary. In response to Staff DR_391[36], the Company provided very detailed explanations of the purpose of the subscriptions. For example, the Company explained how more than half of the $48,496 is related to the following:

> "$27,933 is related to Gas Market Data Subscriptions and Gas Market Publications from the vendors PLATTS and IHS Global Inc. These two companies provide subscriptions for daily fundamental pricing and analysis and provide industry knowledge and consulting that assist the Company to make well informed purchase decisions."[37]

[34] Staff/1003/Barry13
[35] Staff/1000/Barry/13, lines12 - 14
[36] Staff/1002/Barry
[37] Staff/1002/Barry

These specific subscriptions are necessary for the Company's natural gas traders to make the most efficient purchases in order to keep customers rates as low as possible by locking in the best pricing on natural gas purchases, and this is a tool utilized daily.

R. <u>Meals & Entertainment, Travel, Gifts and Awards Adjustment</u>

Q. As previously discussed, the Company accepted the Employee Business Meals Expense component of the adjustment S-32.1, however there are five remaining components of the adjustment the Company does not accept. What is the Company's response to the remaining components of Mr. Barry's adjustment?

A. The Company does not agree with the remaining five components included in Staff's Adjustment S-32.2 – S-32.6, including Airfare, Vehicle & Transportation, Lodging, Office Supplies and various miscellaneous expenses. These are necessary operating expenses of the Company's Oregon natural gas operations, and should not be subject to a sharing between ratepayers and shareholders.

Q. Did Order No.09-020, of Docket UE 197, specifically address this issue?

A. Yes, but only with respect to meals and certain incidental expenses. In Commission Order No. 09–020 (UE 197), the Commission adopted Staff's recommendation:

> "Staff proposes that 50 percent of the meal and entertainment expenses, office refreshments and catering, gifts of flowers, and awards be disallowed." [38]

In Commission Order No. 09–020 (UE 197), the Commission adopted Staff's recommendation concerning meals and entertainment expenses[39], however the Commission <u>did not</u> rule on employee

[38] OPUC Docket UE 197, Order No. 09-020, page 20
[39] Ibid.

airfare, vehicle and transportation expenses, lodging expenses, office supplies, or the other miscellaneous expenses as categorized by Mr. Barry in adjustments S32.2 – S-32.6.

Q. Did Mr. Barry request any additional information in the form of data requests to determine if any of these categories of expenses were necessary in order to "reasonably lead to the provision of safe and reliable service"[40]?

A. No, he did not specifically ask any data requests in regards to any of the expense categories adjusted in S-32. Had Mr. Barry, done so, he would have found that these expenses "reasonably lead to the provision of safe and reliable service"[41] as most of the expenses included in S-32 are associated with employees' attendance at either meetings, conferences, or training programs. These costs allow Company personnel opportunities to attend meetings, such as those at the Commission building, to attend conferences or educational training, all of which are necessary as part of the provision of safe and reliable service to our customers.

Furthermore, in Order No. 16-109 in Docket No. UG-288, in regards to Staff's approach in adjusting capital projects, the Commission stated that "Generally, adjustments should be based solely on thorough assessments of individual projects and not based on cuts across groupings of projects"[42]. The same approach should be taken in adjusting O&M expenses as well.

S. <u>Medical Benefits Adjustment</u>

Q. Staff proposes an adjustment to reduce medical expense by $216,000, based on information contained within the Kaiser Family Report "2016 Health Benefits", to reflect an employee premium sharing amount of 18% for non-union employees and a three-year

[40] Staff/1000/Barry/14/lines 14-15
[41] Ibid
[42] Order 16-109, Docket No. UG-288, page 13

average of historical medical expense.[43] Is it reasonable to assume this sharing percentage for the Company?

A. No, it is not. In this adjustment Staff is reviewing only one component of the overall compensation. If one were to reduce health benefits, other changes would need to be made to other components of employees' total compensation, in order to maintain a total compensation package (salaries and benefits) that would be competitive with that of other similar companies.

Further, the basis for the recommendation for premium sharing of 82/18 (employer/employee), from the Kaiser Family Foundation "Employer Health Benefits 2016 Summary of Findings", is not an appropriate basis for determining the amount of premium contributions employees should make to Avista's medical plan. The report is not specific to a geographic location, lacks information pertinent to the utility industry, and more specifically lacks information related to those companies with whom we compete for talent.

In fact, the report itself acknowledges there can be wide variations between not only premiums, but other components within overall health care costs. In relation to overall premiums, the report at page 1 states[44]:

> Premiums vary significantly around the averages for single and family coverage, resulting from differences in benefits, cost sharing, covered population, and geographical location.

The report also goes on to discuss employee premium sharing, providing information as to the distribution of premiums paid by covered workers based on company size and type of medical

[43] O&M Only, See UG325 Exhibit 1105 Gibbens CONF.
[44] Kaiser Family Foundation "Employer Health Benefits - 2016 Annual Survey" page 1

plan (among other things). In relation to premium sharing, the report again references significant variances, which can occur:[45]

> As with total premiums, the <u>share of premiums contributed by workers varies considerably among firms</u>" (emphasis added)

If the Company were to change the premium sharing component, as proposed by Staff, co-pays, out-of-pocket minimums, etc. would need to be adjusted in order to maintain an overall salary and benefits package that is competitive with that offered by other similar utilities.

Q. As it relates to the proposed sharing percentages proposed by Staff, has the Commission previously ruled on this issue?

A. Yes. In Docket No. UG-288 (Order No. 16-109), the Commission rejected Staff's use of an 82/18 premium sharing. In Order No. 16-109, The Commission stated:[46]

> We adopt Avista's proposed medical benefit cost. <u>We recognize the difficulty of isolating the reasonableness of individual elements of a compensation package</u>. There does not appear to have been any material changes in Avista's premium sharing agreement that would trigger a closer examination of this single component, relative to other elements of the package. (emphasis added)

Q. Has there been any material changes in Avista's premium sharing agreement which would "trigger a closer examination of a single component"?

A. No.

Q. Staff witness Gibbens recommends premium sharing of 82/18 for non-union employees[47]. Does he recommend a different sharing percentage for union employees?

A. Yes. In testimony Mr. Gibbens states[48]:

[45] Kaiser Family Foundation "Employer Health Benefits - 2016 Annual Survey" page 2
[46] UG 288 Order No. 16-109 page 16, item number 2
[47] Staff/1100, Gibbens/3 at 21
[48] Staff/1100, Gibbens/15 at 15-20

> Staff typically proposes no adjustment to sharing between the Company and its bargaining employees unless the sharing percentage is deemed unreasonable upon review. These rates are negotiated between the Company and the union, include a wide range of total compensation elements and are difficult to adjust without upsetting the carefully negotiated compensation balance. (emphasis added)

It is important to note that the premium sharing for non-union employees, like that for union employees, is also a part of a carefully constructed compensation package, and changing the sharing for those employees would upset the non-union compensation package. As discussed earlier, medical benefits are only one portion of the overall benefit package intended to recruit and retain employees, whether they are union or non-union. Once the appropriate amount of medical benefits are determined, each component (premium, co-pays, out-of-pocket maximums, etc.) is carefully considered in order to maintain its balance within the benefit package and ultimately within the total compensation package. Finally, there is no basis for distinguishing between union and non-union in this regard. It is appropriate for both union and non-union employees to share premiums with the Company in a 90/10 ratio.

Q. Turning now to Staff's recommendation to further adjust medical expense based on a historical 2013-2016 trend analysis. Is the use of a trend analysis the appropriate basis to determine medical expense for the Test Year?

A. No, it is not. The best estimate for the Company's medical expenses is provided by an independent compensation consultant, Mercer, taking into consideration factors such as claims experience, medical trend, member demographics, geographical location and the impact of health care reform. Staff's use of purely historical information lacks information on known changes occurring within the ever-evolving health care industry, such as health care reform, much less the other factors compensation consultants take into account. Staff's method is not an appropriate method to determine costs for the twelve-months ending September 30, 2018 rate year. A historical trend also does not take into account Company-specific changes to, for example, recent actual claims experience[49].

Q. As it relates to the use of a historical average in the determination of medical expense as proposed by Staff, has the Commission previously provided guidance on this issue?

A. Yes. In Docket No. UG-288 (Order No. 16-109), the Commission rejected Staff's use of a historical average. The Commission stated:[50]

> Regarding the escalation factor, we recognize that health care reform may have a material effect on healthcare costs that are not captured in the historical trend approach to estimate healthcare costs.

For the reasons discussed above the Commission should reject Staff's adjustments to medical benefits.

T. <u>Fee Free Adjustment</u>

Q. On pages 2 through 8 of Staff witness Mr. Boyle's reply testimony, (Staff/1300, Boyle), Staff proposes an adjustment (S-36) to reduce the level of expected fee free bankcard transaction expense, which reduces revenue requirement by $45,000. What is Avista's response to Staff's adjustment?

A. Company witness Mr. Ehrbar provides reply testimony in support of recovery of the expected level of expense included in the Company's direct filed case.[51]

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[49] The Company is experiencing a significant increase in medical expense, primarily related to an increase in large claims experience, increases in medical and prescription drug costs, and utilization/population profile. This trend is expected to continue into the test year. See Avista/500, Smith/Pages 25-32.
[50] UG 288 Order No. 16-109 page 16, item number 2
[51] Avista/1800, Ehrbar/7

U. Materials & Supplies Adjustment

Q. In adjustment S-38, Staff witness Ms. Zarate proposes a reduction to Materials & Supplies for $127,000 based on a three-year moving average. Do you agree with this adjustment?

A. No. Ms. Zarate first adjusts for a three-year average, then projects a monthly growth rate and applies it to the three year average to arrive at a projected materials and supplies balance for the rate year. This approach is not appropriate given our capital spend is not adjusted using the same approach. The level of materials and supplies included in the Company's filing is appropriate and the Commission should not accept this adjustment proposed by Staff.

As Ms. Zarate stated, "The Commission has typically authorized natural gas utilities to include an allowance for materials and supplies inventory in rate base" and "in UG 246 parties agreed to allow materials and supplies in rate base"[52]. As the Company stated in its response to Staff Data Request No. 340, included as one of Ms. Zarate's exhibits[53], there is a correlation in our inventory balances and the capital spend. As our capital spend has increased, our inventory balance has increased as well to ensure frequently used inventory items are available for projects when they are needed.

Q. Does this conclude your reply testimony?

A. Yes.

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[52] Staff/1400/Zarate/5 lines 8-10
[53] Staff/1403/Zarate/1

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

REPLY TESTIMONY OF DAVID J. MACHADO
REPRESENTING AVISTA CORPORATION

Capital Investment

I. INTRODUCTION

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

A. My name is David J. Machado. I am employed by Avista Corporation as a Senior Regulatory Analyst in the State and Federal Regulation Department. My business address is 1411 East Mission, Spokane, Washington.

Q. Have you previously provided direct testimony in this case?

A. Yes. My direct testimony (Avista/600) in this proceeding covered the Company's capital investments in utility plant included for rate recovery in this case.

Q. What is the scope of your Reply testimony?

A. My reply testimony responds to certain adjustments proposed by Staff and CUB related to capital investment. I present a table summarizing the adjustments that Avista accepts, in whole or in part, and a table summarizing the proposed adjustments with which Avista does not agree; and I refer to the Avista witnesses who respond to these adjustments. In addition, I describe a proposed adjustment to the depreciable life associated with the Company's investment in its meter data management system. My testimony concludes with a discussion of the Company's concerns with portions of Staff's and CUB's approaches in proposing adjustments to the capital investment included in this case.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit Nos. 1401, 1402, 1403, and 1404. A summary of the Exhibits is as follows:

- Exhibit No. 1401 is a project charter for the Oracle E-Business Suite Upgrade project included in the Company's capital investment under its "Technology Refresh to Sustain Business Processes" business case (ER 5005).

- Exhibit No. 1402 is the Company's response to CUB DR 118, which discusses the Company's recent history of transfers to plant.

- Exhibit No. 1403 includes excerpted pages from Attachment B of the Company's response to Staff DR 245 and from Attachment A of the Company's response to Staff DR 247, which illustrate the Company's transfers to plant in the last six months of 2016.

- Exhibit No. 1404 is the Company's response to CUB DR 117, which discusses the Company's process to determine the expected plant investment in Oregon for its natural gas distribution plant investments.

A table of contents for my testimony is as follows:

II. ADJUSTMENTS FULLY OR PARTIALLY ACCEPTED BY AVISTA

Q. Do you have a table that summarizes the parties' adjustments that the Company accepts, either in whole or in part?

A. Yes. Table No. 1, below, provides a summary of those adjustments which Avista is accepting all or a part of the proposed adjustment. The Revenue Requirement column reflects the reduction to Avista's originally filed overall revenue requirement for each of these adjustments. Likewise, the Rate Base column reflects the corresponding reduction to Avista's originally filed rate base. The Avista witnesses addressing each of these adjustments are shown in the Avista Witness column.

Table No. 1

SUMMARY OF ACCEPTED AND PARTIALLY ACCEPTED ADJUSTMENTS TO CAPITAL INVESTMENT
000s of Dollars

			Rev. Req. Incr / (Dec)	Rate Base Incr / (Dec)	Avista Witness
Fully Accepted Capital Adjustments Proposed by Staff / CUB					
S-21	(1)	Microwave Replacement with Fiber	(13)	(122)	Machado
S-21.1	(1)	Compressed Natural Gas Fleet Conversion	(1)	(5)	Rosentrater
S-22.1		Affiliated Interest - GridGlo	(15)	(34)	Machado
S-23		Bonanza Development	(80)	(740)	Rosentrater
S-23		Granite Hill Road	(3)	(27)	Rosentrater
		Total of Capital Adjustments Fully Accepted to Revenue Requirement and Rate Base	**(112)**	**(928)**	
Partially Accepted Capital Adjustments Proposed by Staff / CUB					
S-21	(1)	Meter Data Management	(314)	(155)	Machado/Kensok
S-21	(1)	Technology Expansion Program	(26)	(237)	Machado/Kensok
S-22		Allocation Plant Adjustment	(92)	(236)	Ehrbar
S-23		Old Midland Development	(16)	(147)	Rosentrater
S-23		2017 New Growth - Residential	(87)	(800)	Rosentrater
Subtotal - S-23			(535)	(1,575)	
		Total of Fully and Partially Accepted Adjustments to Revenue Requirement and Rate Base	(647)	(2,503)	

(1) Proposed by both Staff and CUB.

Q. Please explain Avista's acceptance of Staff's proposed adjustment related to the Company's Microwave Replacement with Fiber, as shown in Table No. 1 above.

A. In the Company's response to Staff data request No. 195, the Company notified the parties that the Microwave Replacement with Fiber was inadvertently allocated to all of the Company's jurisdictions, versus being allocated specifically to Washington and Idaho operations. The Company agrees with Mr. Kaufman[1] that the $122,000 adjustment to Oregon plant should be excluded from the calculation of the revenue requirement in this case.

[1] Staff/700, Kaufman/Page 25, lines 8-12.

Q. Please explain Avista's acceptance of an adjustment related to an affiliated interest of the Company.

A. GridGlo is an affiliated interest of the Company, from which Avista has purchased software and services. As discussed in the Company's response to Staff data request Nos. 129 and 410, we believe that the data segmentation and analysis provided by GridGlo will provide information that will allow our Company to make decisions to create operational efficiencies, which will better enable us to respond to customer needs more effectively. It will also provide our customers with information that gives them more options to better manage their energy costs.

Avista has not yet fully developed the data sets that will be used to provide these operational efficiencies or benefits to our customers. Until applications are more fully developed, Avista agrees to charge these costs to non-utility. This is consistent with Staff's recommendation for the exclusion of GridGlo costs from recovery in rates until such time as the products have a demonstrable benefit to gas customers.[2] This adjustment removes $15,000 in revenue requirement and $34,000 in rate base (Oregon-allocated) from this case.

Q. Please explain Avista's partial acceptance of Staff and CUB's adjustment related to Meter Data Management.

A. Both Staff and CUB propose adjustments that exclude the full balance of capital investment associated with the meter data management system in this case. A full adjustment is not appropriate. As stated in my direct testimony, the Meter Data Management system will replace the custom functionality that the Company added onto the Oracle's Customer Care and Billing (CC&B) system as a temporary meter data solution until a fully functional MDM

[2] Staff/700, Kaufman/Page 9, lines 6-8.

system could be implemented. The temporary solution was not designed to support meter data with large volumes of data. The MDM implementation will support the collection of data from meters in all of Avista's jurisdictions, including Oregon. Company witness Mr. Kensok provides further information regarding Meter Data Management in his reply testimony.

Avista agrees, however, that the amount of revenue requirement and rate base included in this case for Meter Data Management should be lower than what the Company originally requested. First, the current expected completion cost associated with the meter data management system is $2.2 million dollars lower on a system basis ($26.1 million versus $28.3 million). For Oregon, this results in a reduction to revenue requirement of $61,000, and a reduction to rate base of $198,000.

Second, the Company has determined that the depreciable life associated with the software portion of this investment should be 12.5 years, instead of the five year depreciable life including in our original filing.[3] The meter data management system will be tightly integrated into CC&B, which had a 15 year depreciable life when it was placed in service at the beginning of 2015. At the time the meter data management system is placed in service this July, CC&B will have a remaining life of approximately 12.5 years. In 12.5 years, both systems will need to be replaced, at the same time. For Oregon, the change in depreciable life results in a reduction to revenue requirement of $253,000, and an increase to rate base of $45,000.[4]

Taking into account <u>both</u> the reduction in overall cost, as well as the changed depreciable life, Avista is proposing a reduction to revenue requirement of $314,000 (Oregon-allocated) and a reduction to rate base of $153,000 (Oregon-allocated), as shown in

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[3] Avista will file a separate accounting petition under ORS 757.140 to request the approval of this 12.5 year depreciable life.
[4] The increase in rate base is related to the treatment of accumulated depreciation (AD) and accumulated deferred federal income tax (ADFIT) over a 12.5 year time period versus a five year time period.

Table No. 1, above.

Q. Please explain the portion of Staff's and CUB's proposed adjustments to the Technology Expansion Program (ER 5006) that Avista accepts.

A. While Avista does not accept the full level of adjustment proposed by Staff (gross plant reduction of $1,097,000, Oregon-allocated) or CUB (gross plant reduction of $605,000, Oregon-allocated), the Company agrees to a reduction to gross plant of $237,000. This adjustment is based upon a review of projects included in this business case, which identified certain projects[5] that do not provide benefit to Oregon customers. Mr. Kensok discusses this program in greater detail in his reply testimony at Avista/1500.

III. ADJUSTMENTS NOT ACCEPTED BY AVISTA

Q. Do you have a table that summarizes the parties' adjustments that the Company does not accept?

A. Yes. Table No. 2, below, provides a summary of the adjustments proposed by the parties for which Avista is not accepting any part of the proposed adjustments. The Avista witnesses sponsoring reply testimony responding to these adjustments are shown in the Avista Witness column of Table No. 2.

[5] Enhanced 911 System Expansion Phase I, Washington/Idaho LMP Coverage Enhancements Phase II, Northwest Sub – Implement Fiber Route Diversity, Fiber Expansion between Millwood and Irvin Substations, Millwood Substation Fiber Approach, DPC-SUN Fiber Expansion, Settlement Solutions Implementation, Wireless Expansion to Warehouse Yards (Washington sites), Garden Springs to Sunset Fiber Expansion, Network Improvement – Colville, IT Facilities Cabinet Gorge Engineering Office, IT Facilities Clark Fork Living Facility Communications Equipment, and IT Facilities Clark Fork Living Facility Hardware.

Table No. 2

STAFF AND INTERVENOR ADJUSTMENTS NOT ACCEPTED BY AVISTA

		OPUC Staff Rev. Req. Incr / (Dec)	OPUC Staff Rate Base	CUB [(1)] Rate Base	Avista Witness
Contested Adjustments					
S-21 / CUB	ER 5005 - Information Technology Refresh Program	(54)	(557)	(902)	Kensok
S-21 / CUB	ER 5006 - Information Technology Expansion Program	(81)	(860)	(368)	Kensok
S-21 / CUB	ER 5010 - Enterprise Business Continuity	(3)	(34)	(35)	Kensok
S-21 / CUB	ER 5106 - Next Generation Radio System	(25)	(254)	(783)	Kensok
S-21 / CUB	ER 5144 - Mobility in the Field	(6)	(60)	(54)	Kensok
S-21 / CUB	ER 5147 - Avista Facilities Management COTS Migration	(208)	-	(228)	Kensok
S-21 / CUB	ER 2586 - Meter Data Management	88	(2,315)	(2,315)	Kensok
Subtotal - S-21		(289)	(4,080)		
S-21.1	ER 7001/7003 - Structures and Improvements and Furniture	(3)	(34)	-	Rosentrater
S-21.1	ERs 7005/7006 - Capital Tools and Stores Equipment	(13)	(134)	-	Rosentrater
S-21.1 / CUB	ER 7126/7131 Long Term Campus Restructuring Plan	(85)	(871)	(537)	Rosentrater
S-21.1	ER 7144 Ergonomic Equipment	(18)	-	-	Rosentrater
Subtotal - S-21.1		(119)	(1,039)		
S-22	Allocation Plant Adjustment	(161)	(3,277)		Ehrbar
S-23	ER 7206 Jackson Prairie Land Purchase	(24)	(245)		Rosentrater
S-23	Old Midland Development	(50)	(511)		Rosentrater
S-23	2016 - New Growth Residential	(210)	(2,153)	-	Rosentrater
S-23	2017 - New Growth Residential	(264)	(2,713)	-	Rosentrater
S-23	Management Adustment	(312)	(3,200)		Norwood
Subtotal - S-23		(860)	(8,822)		
CUB	ER 3000 - Gas Reinforcement Program			(379)	(2)
CUB	ER 3001 - Replace Deteriorating Gas System			(94)	(2)
CUB	ER 3002 - Regulator Station Reliability			(253)	(2)
CUB	ER 3003 - Gas Replace - Street & Highway			(1,122)	(2)
CUB	ER 3004 - Cathodic Protection Program			(93)	(2)
CUB	ER 3005 - Gas Distribution Non-Revenue			(1,018)	(2)
CUB	ER 3006 - Overbuilt Pipe Replacement Blanket			(604)	(2)
CUB	ER 3007 - Isolated Steel Replacement			(927)	(2)
CUB	ER 3008 - Aldyl A Pipe Replacement			(1,832)	(2)
CUB	ER 3054 - Gas ERT Replacement Program			(326)	(2)
CUB	ER 3057 - Gas HP Pipeline Remediation Program			(5,625)	(2)
CUB	ER 3117 - Gas Telemetry			(192)	(2)
CUB	ER 3203 - East Medford Reinforcement			(28)	(2)
CUB	ER 3209 - Pierce Road La Grande HP Reinforcement			(3,500)	(2)
CUB	ER 3303 - Ladd Canyon Gate Station Upgrade			(5)	(2)
CUB	ER 7201 - Jackson Prairie Storage			(46)	(2)
CUB	Test Year New Customer Connections			(2,900)	(2)
CUB	ER 2277 - SCADA Upgrade			(34)	(2)
CUB	ER 5014 - Security Systems			(325)	(2)
CUB	ER 5151 - Customer Facing Technology			(8)	(2)
CUB	ER 7000 - Transportation Equipment			(84)	(2)
Subtotal - CUB				(24,617)	
Total of Staff and Intervenor Adjustments Not Accepted by Avista		(1,429)	(17,218)	(24,617)	

(1) CUB did not propose revenue requirement adjustments associated with its proposed rate base adjustments. Therefore, only rate base adjustments have been included in this table.

(2) Avista responds to CUB's general approach herein and in Mr. Norwood's testimony (Avista/1000). Ms. Rosentrater's testimony (Avista/1600) includes responses to certain of CUB's positions regarding ERs 3001, 3008, and 3209.

Capital Investment

IV. STAFF'S APPROACH TO ENTERPRISE TECHNOLOGY AND GENERAL PLANT ADJUSTMENTS

Q. Please explain Avista's concerns with Mr. Kaufman's approach to his proposed adjustments to Enterprise Technology and General Plant rate base items.

A. Avista observes two general themes that surface in a number of Mr. Kaufman's proposed adjustments. The first is the application of a net present value approach to the review of the Company's capital investments without consideration of other important factors that drive the need for those investments. The second is the proliferation of errors in Staff's use of the net present value model, as well as the inclusion of adjustments for capital not included in the Company's rate case.

Q. How does Mr. Kaufman utilize a net present value model in the determination of his adjustments to certain of Avista's capital investments included in this case?

A. Mr. Kaufman bases his proposed adjustments associated with four business cases[6] on the application of a net present value model. Under this approach, Mr. Kaufman determined his proposed adjustments to capital investment <u>based solely</u> on the determination of a level of capital investment that would result in no increase to the net present value of fixed costs.[7]

Q. Why is Mr. Kaufman's <u>sole reliance</u> on a net present value model to determine the prudence of certain of Avista's capital investment decisions incorrect?

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[6] ER 5005 (Technology Refresh to Sustain Business Process), ER 5144 (Mobility in the Field), ER 5147 (Avista Facility Management Commercial Off-the-Shelf Migration), ER 7005/7006 (Capital Tools and Stores Equipment).

[7] Staff/700, Kaufman/Pages 20-21; Staff/700, Kaufman/Pages 26-27; Staff/700, Kaufman/Pages 27-28; and Staff/700, Kaufman/Pages 31-32.

A. The problem with this approach is two-fold. First, this approach ignores the consideration of other important factors driving the need for the capital investment. As discussed by Mr. Kensok in his testimony, the ERs for which Mr. Kaufman has proposed an adjustment are primarily driven by a number of qualitative considerations, rather than solely by a mechanistic application of a net present value model. For example, the Technology Refresh to Sustain Business Processes investment (ER 5005) is driven by the need to maintain the technology infrastructure utilized by the business in its day-to-day operations. As technology products reach manufacturer-planned or real obsolescence, and product maintenance and support provided by vendors ceases, the value provided by these business systems is jeopardized and business risk is increased.

An example of capital investment under this business case is the upgrade of the Company's Oracle E-Business Suite to version 12.1.3 to maintain vendor support of our system and avoid security vulnerabilities. The project charter describing this project was provided to the parties in this case, and is included as Exhibit No. 1401.[8] The Oracle E-Business Suite supports accounting, procurement, and inventory management functions, among others. The primary factor driving this investment is maintaining the functionality of business critical systems and managing business risk. The Company is not completing this project because there are cost savings, Avista is completing this project so that the Company can continue to manage its business appropriately. Mr. Kaufman's exclusive reliance on quantitative measurements to determine prudence is inappropriate, and his adjustment should be rejected.

Q. What is the second reason Mr. Kaufman's adjustments using a net present

[8] Staff DR 190 Attachment G.

value model should be rejected?

A. Mr. Kaufman's utilization of the net present value model contains several errors. Mr. Kaufman's calculations did not accurately account for the book and tax lives of the assets for which he was calculating adjustments. Using incorrect inputs or assumptions in a financial model will lead to calculation errors. Drawing conclusions from erroneous data is not proper. The proposal of prudence disallowances while simultaneously <u>acknowledging that one's calculations are likely in error</u> is not a reasonable approach to rate making.

For example, in Mr. Kaufman's use of the net present value model to determine his proposed adjustment for the Company's Mobility in the Field business case project (ER 5144), Mr. Kaufman used a tax depreciation life of 20 years and a book life of seven years. The correct lives would be a tax depreciation life of three years and a book life of five years (the respective lives for software). The difference in tax and book lives also affects how other costs and benefits in the model are allocated. In the end, by using improper inputs in the model, any results from the model will be erroneous and cannot be relied upon.

Additionally, in the application of the net present value model to the Company's Avista Facility Management Commercial Off-the-Shelf ("COTS") business case, Mr. Kaufman adjusted O&M expense based on future investment for which the Company is not seeking rate recovery in this case.[9] Given that the determination of a revenue requirement involves determination of the level of rate base used in the provision of service to customers, it is incorrect to propose to derive an O&M expense adjustment from investment balances that <u>were not included in the first place</u>. Again, this is an error in the application of the net present

[9] Mr. Kaufman utilized total business case requested capital funds of $25,196,212 on a system level ($1,196,212 in 2015, $7,000,000 in 2016, $9,000,000 in 2017, and $8,000,000 in 2018). In contrast, only $7,858,000 of system level investment is included as an adjustment to the base period in this case ($2,621,000 in 2016 and $5,237,000 in the first nine months of 2017).

value model.

As Mr. Kaufman himself acknowledged, "this [net present value] model was intended for analysis of tangible plant and may not accurately calculate revenue requirement for intangible plant."[10] Mr. Kaufman's adjustments should be rejected because he ignores other criteria that are critically important in a Company's decision to expend capital, as well as the errors embedded in his analysis.

V. ADJUSTMENTS TO GROSS PLANT PROPOSED BY CUB

Q. Please summarize Avista's concerns with the basis of the adjustments proposed by CUB.

A. CUB witness Ms. McGovern addresses, in varying levels of detail, each of the business cases included by the Company in this case.[11] For each business case, Ms. McGovern includes a table illustrating the Company's filed additions to gross plant along with CUB's proposed balance of additions to gross plant associated with the given business case. CUB's basis for its proposed adjustments is generally based upon historical differences between budgeted transfer to plant balances and actual transfers to plant in service.

Q. Does Avista agree that historical transfer to plant variances represent a basis from which to exclude investment from recovery in base rates?

A. No. For example, at the beginning of her discussion of Avista's capital projects, Ms. McGovern includes a table comparing the Company's 2015 actual transfers to plant for natural gas distribution and storage ERs included in this case to the budgeted transfer to plant balances for those same ERs.[12] This table illustrates that in 2015, Avista had budgeted

[10] Staff/700, Kaufman/Page 21, footnote 42.
[11] CUB/100, McGovern/Pages 41-66.
[12] CUB/100, McGovern/Page 41.

transfers to plant of approximately $28.5 million for 2015, while actual transfers to plant for the same period were $24.1 million (a difference of $4.3 million). While this does show that Avista transferred a smaller balance to plant in service during 2015 than had been budgeted, this difference is primarily related to the Company's East Medford Reinforcement Project, for which completion was delayed from the fourth quarter of 2015 to February of 2016 due to encountering difficult, rocky conditions, which slowed project progress. The estimated transfer to plant balance associated with this project was $5 million. Excluding this project, the remainder of Avista's projects experienced net transfers to plant slightly larger than that budgeted.

Q. How do planned versus actual transfers to plant compare for recent years?

A. Table No. 3, from Avista's response to CUB data request No. 118 (included as Exhibit Avista/1402), shows budgeted versus actual transfers to plant from 2011 through 2016 for Avista's Oregon operations.

Table No. 3

	2011	2012	2013	2014	2015	2016
Budgeted Transfers to Plant:						
Natural Gas Plant	6,720,493	8,855,594	10,645,927	17,689,810	28,485,856	24,148,261
Common Plant	2,472,177	4,805,493	4,072,030	3,963,820	5,537,967	6,780,432
	9,192,670	13,661,088	14,717,957	21,653,630	34,023,823	30,928,693
Actual Transfers to Plant:						
Natural Gas Plant	10,131,176	6,347,953	21,095,531	20,473,298	24,141,166	31,831,459
Common Plant	2,111,603	2,922,333	3,896,170	3,280,578	5,052,175	5,536,131
	12,242,779	9,270,285	24,991,701	23,753,875	29,193,342	37,367,590
Actuals Greater/(Less) than Budget	3,050,109	(4,390,803)	10,273,743	2,100,245	(4,830,481)	6,438,897

In 2015, as discussed above, the shortfall in transfers to plant was primarily driven by the delay in completion of the East Medford Reinforcement. In 2012, the shortfall in transfers to plant was primarily driven by the fact that certain capital investments which occurred in 2012 were not transferred to plant until 2013, the Company's next generation radio project was delayed into 2013 and 2014, and customer growth in 2012 was lower than expected. In the end, but for the few factors discussed above, Avista's actual transfers to plant were reasonably close to those planned.

Various factors can cause actual transfers to plant to differ from planned or budgeted transfers, both in terms of timing and cost. Although the Company takes great care in planning and executing its capital replacement and expansion program, even the best efforts of experienced people will not allow them to foresee circumstances that would cause the installation of new pipe or equipment to be delayed, or to cost more or less than the original estimates.

Q. Ms. McGovern implies in her testimony that Avista's actual rate base at the time new retail rates went into effect on March 1, 2016 was lower than the amount authorized by the Commission. Is that correct?

A. No. The authorized level of net plant[13] from Docket No. UG-288 was $255.6 million.[14] Avista's net plant balance as of February 29, 2016 (the day before new rates went into effect from Docket No. UG-288) was $255.7 million. These balances are summarized in Table No. 4, below.

<u>Table No. 4</u>

Actual Net Plant (millions)	$ 255.7
Authorized Net Plant (millions)	255.6
Actual Net Plant in Excess of Authorized (millions)	$ 0.1

As explained earlier, there are circumstances, largely beyond the Company's control,

[13] Net plant is gross plant less accumulated depreciation.
[14] The revenues set in Docket No. UG-288 included new customer capital additions during the rate period (March 1, 2016 through February 28, 2017), on an average of monthly averages basis, to match the new customer revenues included in the rate period for customer growth during the rate period. In order to appropriately compare net plant balances as of the beginning of the rate period, this new customer investment should be removed from the authorized net plant balance.

that will cause some projects to be completed earlier or later than planned, and to cost more or less than the original estimates. This is normal. It is not appropriate for CUB to isolate a single project that was delayed, and then conclude that customers are paying for a level of rate base that is not completed. CUB's statement that "the Company has been able to keep the revenue collected on behalf of this program for work that never materialized or transferred to plant"[15] is not correct.

Q. Ms. McGovern expresses concerns that, on a project-by-project basis, what the Company budgets, and ultimately spends, can be different. Is that unusual?

A. No. While the Company works hard to create accurate budget estimates, other forces may cause costs to change, or timing to shift. Many of the Company's capital projects make use of the same labor force. The number of natural gas crews available in each of the Company's Oregon service regions is fixed in the short term. This means that if one project experiences a greater demand, the crew time spent on that project is not available to work on another project. For example, in 2015 the Gas Revenue Blanket program (ER 1001) experienced a higher level of demand than had been forecast. Additionally, the Gas Distribution Non-Revenue Blanket program (ER 3005) also experienced a higher level of demand than originally estimated.

Likewise, in 2015, the Technology Expansion program (ER 5006) experienced a higher level of demand than originally estimated, which resulted in a shift from the Technology Refresh program (ER 5005). In circumstances like this, the timing of other projects will shift simply due to labor availability.

Q. How did the Company's transfers to plant in the six month period from

[15] CUB/100, McGovern/45. This statement is in regards to the Company's Gas Replacement Street and Highways business case (ER 3003).

July 1, 2016 through December 31, 2016 compare to the balances included in this case for the same period?

A. As shown in Exhibit No. 1403, over this six month period, natural gas distribution and storage related transfers to plant in Oregon were $15.055 million, while enterprise technology and general plant transfers to plant on an Oregon basis were $3.012 million, for a total of $18.067 million. In comparison, the Company's filing included $14.487[16] million of natural gas distribution and storage related transfers to plant, and $3.357[17] million of enterprise technology and general plant transfers to plant, for a total of $17.844 million of total transfers to plant over the same period of time. Table No. 5, below, shows the actual transfers as compared to the planned estimates included in this case.

<u>**Table No. 5**</u>

July 1 – December 31, 2016 Actual Transfers to Plant (millions)	$ 18.067
July 1 – December 31, 2016 Transfers to Plant per Filed Case (millions)	17.844
Actual Net Plant in Excess of Filed Case (millions)	$ 0.223

Q. Does the Company agree with CUB's claim that there is a lack of transparency due to allocation of investment costs rather than the direct assignment of investment costs?[18]

A. No. With regard to the Company's Aldyl A replacement project (ER 3008) in particular, CUB states "CUB does not appreciate the allocation of this program, and thinks that it would be more appropriately and accurately accounted for by direct assignment"[19] and that "CUB also recommends a 10% adjustment for both 2016 and 2017 for lack of

[16] Avista/600, Machado/Page 12, Table No. 1.
[17] Avista/600, Machado/Page 13, Table No. 3.
[18] For example, see CUB/100, McGovern/Page 49.
[19] CUB/100, McGovern/Page 49.

transparency due to allocation over direct assignment."[20] As described in the Company's response to CUB's DR 117, included as Exhibit No. 1404, when natural gas distribution capital investments are placed in service, the investments are directly assigned to the jurisdiction in which the investment is located. For forecasts of transfers to plant, regardless of whether a forecast natural gas distribution item is included in a jurisdiction-specific line item or a line item to which an allocation is applied, when the Company is preparing its filing, it works with the Gas Engineering department to best reflect the expectation of the transfers to plant that will occur. In the case of the Aldyl A Replacement program, the investment included in this case for Oregon is based upon the program manager's expectation of the capital investment that will occur in Oregon prior to the rate effective period.

Furthermore, during the July 1, 2016 through December 31, 2016 period, the Company placed in service \$4.089 million[21] of capital investment associated with Aldyl A in Oregon, compared to the \$3.842 million that had been included in the case for this period.[22] The fact that CUB would like to approve a reduced amount of investment from the Company's planned investment, and then reduce the allowed recovery by a further 10 percent is not appropriate, nor is it reflective of the actual costs of capital investment providing service to customers in the rate period.

Q. Does this conclude your Reply testimony?

A. Yes, it does.

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[20] CUB/100, McGovern/Page 49.
[21] Exhibit No. 1403.
[22] Avista/600, Machado/Page 12, Table No. 1.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

DAVID J. MACHADO
Exhibit No. 1401

Avista's Response to Staff DR 190 Attachment G

Project Initiation Charter

Planning Phase Approval
Project Name: Oracle E-Business Suite 12.1.3 Upgrade – Phase 2
Clarity Project ID: PR00011236
Business Case Name: Business Application Refresh
ERBI: 5005-05P97

1 Key Roles

Business Sponsor	Ryan Krassalt	**Business Case Owner(s)**	Andy Leija
Project Sponsor(s)	Hossein Nikdel/Jim Corder	**Program Manager**	Leianne Raymond
Steering Committee	Graham Smith, Adam Munson, Jim Corder, Mike Mudge, Jason Pitts	**Other Stakeholders**	Catherine Mueller, Laurie Heagle, Tami Judge, Cam Mallon
Project Manager	Kelly Dengel	**Product Owner**	Colleen Robisch

2 Project Overview

The Oracle E-Business Suite's base components require an upgrade to version 12.1.3 to maintain support, increase functionality, and avoid security vulnerabilities. This upgrade will prevent failures while attempting to install components as a pre-requisite for refreshing our Java Runtime Environment (JRE) on the Enterprise Business Suite application server. The recommendation from Oracle Support and Security is to bring the Oracle E-Business Suite application up to the 12.1.3 baseline by upgrading these core modules.

In addition, Avista is in the process of upgrading all Oracle databases to version 12.1.0.2, which is required for enhanced functionality, availability of security patches and support from Oracle, and avoidance of increased licensing fees. EBS version 12.1.3 is certified to run on Oracle 12.1.0.2 so this upgrade will enable moving to the 12c database platform.

2.1 Strategic Initiative

	Strategic Area
X	Financial Performance
	Community Vitality
X	Safe & Reliable Infrastructure
	Effective Regulatory Outcomes
	Customer Engagement & Value
	People & Performance
	Responsible Resources

2.2 Who Benefits? (What is the anticipated business value to be derived from the project?)

Upgrading the Oracle E-Business Suite application will put the application on a version that will be supported by Oracle through 2019 and will enable the team to proceed with the Java server-side upgrade, which is being advocated strongly by the Security team.

Avista customers benefit from accurate and up-to-date accounting systems, information, and practices.

Project Initiation Charter

Planning Phase Approval

2.3 High Level Project Requirements

The Oracle E-Business Suite 12.1.3. Upgrade project will encompass the following steps:

- **12.1.3 Application Upgrade**
  - Verify all Avista application customizations to ensure they are not overwritten
  - Verify Prerequisite patches/component versions
  - Apply missing pre-requisite patches/component upgrades
  - Apply any required application/database patches for 12.1.3/12C compatibility
  - Apply 12.1.3 Release Update Pack
  - Verify Customizations and reapply any that were affected by patch

- **12.1.3 + Recommended Patch Set & CPU's**
  Oracle has released the EBS 12.1.3+ RPC3 patch set which includes the latest recommended patches and their dependencies for the following Oracle E-Business Suite products and product families:
  - Applications Technology (ATG)
  - Oracle Customer Relationship Management (CRM)
  - Oracle Financials (FIN)
  - Oracle Human Resource Management System (HRMS)
  - Oracle Procurement (PRC)
  - Oracle Projects (PJ)
  - Oracle Supply Chain Management (SCM)
  - Oracle Value Chain Planning (VCP)
  - Oracle Business Intelligence (BIS)

- **Database Upgrade**
  A new Linux Redhat 6 database server and 12c (12.1.0.2) database will be built by the 12C project team. A second Linux Redhat 6 server will also be built to house an additional application environment (Model Office) for the project.
  - Configure database server
  - Configure application server
  - Install 12.1.0.2 database
  - Configure database
  - Perform data conversion

- **Java Runtime Environment (JRE) Upgrade**
  - Download the Latest JRE version available
  - Apply JRE EBS interoperability patch
  - Run JRE upgrade script
  - Configure appsweb.cfg file
  - Coordinate with Distributed Systems to rollout appropriate Client Ruleset changes

- **Testing**
  - Functional Testing
  - System Integration Testing (SIT)
  - User Acceptance Testing (UAT)

- **Evaluate the Oracle Application Testing Suite to determine the benefits of supplementing automated user testing.**

- **Provide and configure monitoring for the identified critical business transactions**

2.4 Where will technology be deployed?

To Avista Corporation Oracle E-Business Suite users.

3 Milestones

Description	Target date for completion/approval (MM/YY)
Project Initiation (Expense)	
• Charter Approved	4/2016
• Product Selected	N/A
• Supply Chain Engaged	4/2016
Planning	
• Scope Approved	9/2016
• PMP Approved	11/2016
Execution	
• Go Live/In-Service Date[1]	2/2017 (Integrated Release)
• Warranty	3/2017
• Operational Handoff	1/2017
• Approval to Close	4/2017
Closing	
• Lessons Learned	4/2017
• Project Performance Report	5/2017

4 Risk Management

4.1 Assumptions

- Development and Testing Oracle 12.1.0.2 environments will be available to perform the upgrades in the timeframe required.
- Critical Patch Updates (CPU's) that have been outlined in a recent security audit will be applied to bring the application up to the most recent status possible.

4.2 Constraints

- Resource availability required to support this upgrade (ET and stakeholders).

4.3 Dependencies

- Power Plan upgrade completion – 7/2016
- All requirements are complete prior to code freeze and integrated release 2/2017.

5 Compliance and Controls

The Compliance section is NOT optional. This sections must be filled out for every project by sending the approved Charter to each of the designated representatives for their review and feedback.

[1] The Go Live/In-service date is important since it denotes "used and useful" and contributes to Transfer to Plant (TTP).

Project Initiation Charter

Planning Phase Approval

	Required (Y/N)
Compliance Impact Assessment (contact: James McDougall)	Y
SOX Business Controls Impact Assessment (contact: Stacey Wenz)	Y
SOX Computer Controls Impact Assessment (contact: Rob Jacobs)	Y
Business Continuity Plan (contact: Erin Swearingen)	Y

6 Project Cost Estimates

6.1 Planning Estimates

	Expense			Capital			
Planning	**Physical Product ($)**	**Labor and Other ($)**	**Total ($)**	**Physical Product ($)**	**Labor and Other ($)**	**Total ($)**	**Planning Total ($)**
Pre-Charter	$0	$1,000	$1,000				$1,000
Hardware	$0	$0	$0	$0	$0	$0	$0
Communications Equipment	$0	$0	$	$0	$0	$0	$0
Software	$0	$0	$0	$0	$30,000	$30,000	$30,000
Estimated Planning Cost:	**$0**	**$1,000**	**$1,000**	**$0**	**$30,000**	**$30,000**	**$31,000**

6.2 Total Project Estimates

	Expense			Capital			
Project	**Physical Product ($)**	**Labor and Other ($)**	**Total ($)**	**Physical Product ($)**	**Labor and Other ($)**	**Total ($)**	**Project Total ($)**
Hardware	$0	$0	$0	$0	$0	$0	$0
Communications Equipment	$0	$0	$0	$0	$0	$0	$0
Software	$0	$0	$0	$10,000	$137,732	$147,732	$147,732
Estimated Total Cost:	**$0**	**$0**	**$0**	**$10,000**	**$137,732**	**$147,732**	**$147,732**

6.3 Operational Impact (if known)

Three year Operational Impact	Org Code	Review and Approved	Year 1	Year 2	Year 3	Total
Licensing			$NA	$NA	$NA	$NA
Staff / Labor for O&M			$NA	$NA	$NA	$NA
Training			$NA	$NA	$NA	$NA
Other Annual Operational Costs			$NA	$NA	$NA	$NA
Total			$NA	$NA	$NA	$NA

No impact identified at this time. During planning, we will evaluate the monitoring tool to better understand what impact the success of that product could have on O&M costs.

6.4 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories**. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service.

Project Initiation Charter

Planning Phase Approval

	Installation		Removal	
Accounting Asset Category	**Physical Product ($)**	**Labor and Other ($)**	**Labor and Other ($)**	**Total ($)**
Hardware	$0	$0	$0	$0
Communications Equipment	$0	$0	$0	$0
Software	$10,000	$137,732	$0	$147,732
Estimated Total Capital Cost:	**$10,000**	**$137,732**	**$0**	**$147,732**

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

DAVID J. MACHADO
Exhibit No. 1402

Avista's Response to CUB DR 118

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	03/16/2017
CASE NO:	UG 325	WITNESS:	David J. Machado
REQUESTER:	CUB	RESPONDER:	David Machado
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	CUB – 118	TELEPHONE:	(509) 495-4554
		EMAIL:	david.machado@avistacorp.com

REQUEST:

For all projects on Machado/602, please provide:

a. Annual transfers to plant, system wide, with allocation factors (similar to the Company's response to Staff DR 182 AI) from 2011-2016.
b. Budgets, system wide, with allocation factors (similar to the Company's response to Staff DR 182 AI) from 2011-2016.
c. If the Company has explanations for variations from budgets, in any given year (or in summation for ongoing or multiyear projects), please provide.

RESPONSE:

a. As discussed with CUB telephonically on March 10, 2017, actual transfers to plant are placed in service in the jurisdiction and service with which the plant investments are associated—that is to say, transfers to plant are assigned to a specific service (natural gas, electric, or common) and jurisdiction (Oregon, Washington, Idaho, common to all, or common to WA/ID). For example, a section of natural gas distribution main placed in service in Oregon will be transferred to plant as directly assigned Oregon natural gas plant. Likewise, plant investments which serve multiple jurisdictions and services are transferred to plant as common assets. It is only after a specific service and jurisdictional assignment has been made that the Company's standard allocation factors (e.g., the common service, common jurisdiction four-factor, etc.) are applied to plant in service that is not directly associated with a specific state and service.

   CUB_DR_118 Attachment A includes actual annual transfers to plant from 2011-2016 for natural gas plant included in Table No. 1 on Avista/600, Machado/Page 12—both total System transfers to plant and Oregon-specific transfers to plant. This attachment also includes the Oregon-specific transfers to plant as a percentage of the total System transfers to plant. Because natural gas plant is generally placed in service in the state in which the investment is located, no allocations are associated with these transfers to plant (the lone exception is the gas telemetry investment which is common to all jurisdictions).

   CUB_DR_118 Attachment B includes actual annual transfers to plant from 2011-2016 for common plant (e.g., enterprise technology, facilities, other general plant) included in Table No. 3 on Avista/600, Machado/Page 13. This attachment includes the current allocation factors associated with common service and common jurisdiction combinations (the current allocations factors are included because the current allocation is applied to all common plant in service associated with the given allocation factor). This attachment also includes the Oregon-allocated share of these transfers to plant as a percentage of the total system transfers to plant for each ER ("expenditure request").

b. Additionally, the referenced attachment Staff_DR_182 Attachment AI is a spreadsheet recently developed (during 2015) by the Company to reduce the manual process steps involved in determining the jurisdictional balances of expected transfers to plant. For simplicity of the presentation of information, the attachments (discussed below) which provide the budgeted transfers to plant have aggregated information for each of the referenced years and presented the information in a single location.

   CUB_DR_118 Attachment C includes the annual budgeted transfers to plant on a System basis from 2011-2016 for natural gas plant. This attachment includes percentages which reflect the expected transfers to plant on an Oregon basis. As discussed in the Company's response to CUB_DR_117, these percentages are based on direct assignment of transfers to plant to jurisdictions, historical trends in proportion of transfers to plant among jurisdictions, and/or information provided by the Gas Engineering department.

   CUB_DR_118 Attachment D includes the annual budgeted transfers to plant on a System basis from 2011-2016 for common plant. This attachment includes the current allocation factor for common service, common jurisdiction ("CD AA") assets, to maintain consistency with the use of the current allocation factor, as described in part "a."

c. Descriptions of variations between actual and budgeted transfers to plant have been provided in the Company's response to Staff_DR_245 Attachment D and Staff_DR_247 Attachment C.

   The information provided in these attachments is summarized in the table below.

	2011	2012	2013	2014	2015	2016
Budgeted Transfers to Plant:						
Natural Gas Plant	6,720,493	8,855,594	10,645,927	17,689,810	28,485,856	24,148,261
Common Plant	2,472,177	4,805,493	4,072,030	3,963,820	5,537,967	6,780,432
	9,192,670	13,661,088	14,717,957	21,653,630	34,023,823	30,928,693
Actual Transfers to Plant:						
Natural Gas Plant	10,131,176	6,347,953	21,095,531	20,473,298	24,141,166	31,831,459
Common Plant	2,111,603	2,922,333	3,896,170	3,280,578	5,052,175	5,536,131
	12,242,779	9,270,285	24,991,701	23,753,875	29,193,342	37,367,590
Actuals Greater/(Less) than Budget	3,050,109	(4,390,803)	10,273,743	2,100,245	(4,830,481)	6,438,897

   In 2015, the Company transferred $4.8 million less than the budgeted amount from the beginning of the year. This difference was primarily due to the delay of the East Medford Reinforcement Project (from the fourth quarter of 2015 to the first quarter of 2016), which had a budgeted transfer to plant amount of $5 million. This also was a primary cause of the Company's actual transfers being more than budget in 2016.

The actual transfers to plant were greater than budget in 2013, primarily related to three factors. The first factor is that certain projects transferred to plant in 2013 included capital expenditure from 2012 (this contributed to the transfers to plant being less than budget in 2012). The second factor is that both customer growth and work in request of others (related to road moves) both occurred at rates above what had been expected. The third factor is that the Aldyl A pipe replacement budget was increased during 2013 to reflect the outcome of the Aldyl A request for proposal and contract execution process.

The actual transfers to plant were less than budget in 2012, primarily related to three factors. The first factor (as noted above) is that certain capital investment in 2012 was not transferred to plant until 2013. The second factor is that transfers to plant associated with the ER 5106 were partially delayed from 2012 into 2013 and 2014. The third factor is that forecast growth investment for Oregon was lower than expected at the beginning of the year.

The table above illustrates that the Company generally transfers to plant as much, or more than, the amount of transfers to plant originally budgeted at the beginning of the year.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

DAVID J. MACHADO
Exhibit No. 1403

Excerpts from Staff DR 245 Attachment B and Staff DR 247 Attachment A

Avista Corp
2016 Transfers to Plant, by Month (Gas Distribution Capital Projects - Oregon)
Staff DR 245 Attachment B

Sum of Current Activity Cost SUM		YEAR	Gl Postyyyymm						
		2016							
Erval	Jurisdiction	201601	201602	201603	201604	201605	201606	201607	201608
1001	OR	228,766	278,871	254,786	369,449	1,522,496	921,225	475,085	486,408
1050	OR		54,643	80,406		35,144		37,364	62,235
1051	OR				362	7,416			
1053	OR	(277,998)			383,502	3,304	10,946	162,232	192,067
3000	OR	507	946	2,906	205,091		1,733	2,700	
3001	OR	2,762	175	245,032	74,553	22,258	28,941	27,779	9,299
3002	OR	22,120	9,231	2,329	1,571	101,759	76,523	21,312	81,564
3003	OR	9,122	9,916	482,306	6,784	14,738	167,108	125,436	59,108
3004	OR	1,551	110	52	13,248	2,266			
3005	OR	151,437	286,238	(63,476)	349,083	1,021,057	339,724	526,811	372,940
3006	OR	17,878	67,959	57,040	24,579	11,164	2,840	9,785	2,442
3007	OR	2,687	65,755	55,066	73,834	84,393	68,076	18,701	1,081
3008	OR	63,576	199,440	361,233	579,420	335,028	1,089,718	1,007,549	447,552
3054	OR	395,547	86,753	20,319	(408,424)		689	46,272	
3055	OR	25,596	67,811	41,373	77,670	67,183	80,678	86,053	54,454
3057	OR								
3117	AA								-
	OR		98	716			-	34,329	2,920
3203	OR		5,223,090	17,549	3,580	349,965	3,698	4,922	589
3303	OR	3,453	18,404	10,126	7,470	1,441	2,823	4,060	(0)
7201	OR	4,654	6,191	5,493	8,628	28,931	2,651	3,020	1,789
Grand Total		651,659	6,375,630	1,573,257	1,770,400	3,608,546	2,797,374	2,593,409	1,774,450

[A] During the December 2016 close process, a review identified that certain balances had not been closed and transferred to plant.
This column includes the additional transfers.

Avista Corp
2016 Transfers to Plar
Staff DR 245 Attachm

Sum of Current Activity							[A]	
	2016				2016 Total	Grand Total	2016 Late Tx	Adj. 201612
Erval	201609	201610	201611	201612				
1001	493,947	527,615	646,368	109,990	6,315,007	6,315,007		109,990
1050	33,322	33,322	35,251		371,688	371,688	117,643	117,643
1051	95		572		8,445	8,445		-
1053	218,600	82,982	5,402		781,037	781,037	44,383	44,383
3000	(263)	6,267	547,800	221,675	989,362	989,362	2,006	223,681
3001	55,102	33,322	118,762		617,986	617,986	54,758	54,758
3002	40,084	104,089	10,388	793	471,763	471,763		793
3003	96,163	261,889	112,826	860,784	2,206,179	2,206,179	34,300	895,084
3004		22,889		121,800	161,917	161,917		121,800
3005	380,939	463,294	336,246		4,164,291	4,164,291	735,689	735,689
3006	1,587	11,420	15,690		222,382	222,382	117,388	117,388
3007	2,572	24,413	87,118		483,696	483,696	69,569	69,569
3008	236,043	680,842	924,001		5,924,404	5,924,404	793,577	793,577
3054	758	300			142,214	142,214	3,501	3,501
3055	22,355	39,371	38,523		601,068	601,068	52,948	52,948
3057		43,558	409,227	22,909	475,694	475,694		22,909
3117		-			-	-		-
		58,007			96,070	96,070		-
3203	19,270	684	5,453	1,881	5,630,681	5,630,681		1,881
3303					47,778	47,778		-
7201	7,508	8,722	13,786		91,373	91,373	2,661	2,661
Grand Total	1,608,081	2,402,986	3,307,412	1,339,832	29,803,035	29,803,035	2,028,424	3,368,256

[A]

Sum of highlighted (green) cells: 15,054,594

Avista Corp
2016 Transfers to Plant, by Month (Enterprise Technology & General Plant - System & Oregon)
Staff DR 247 Attachment A

`			YEAR	Gl Postyyyymm						
			2016							
Erval	Jurisdiction	Asset Service	201601	201602	201603	201604	201605	201606	201607	201608
2277	AA	CD	45,735	2,092	33,001	16,684	1,577	10,998	12,070	183,348
		GD						-		-
5005	AA	CD	410,955	761,078	1,091,581	2,743,450	575,831	1,589,144	1,021,898	910,982
		GD								
	OR	GD						19,440	442	85
5006	AA	CD	80,922	233,062	1,786,417	583,958	275,409	307,721	880,880	2,282,684
		GD								
5010	AA	CD	679					-	15,320	
		GD								
5014	AA	CD	19,531	40,268	32,652	33,009	184,322	10,254	21,206	598,737
	OR	GD						-		
5106	AA	CD			5,625					
5143	AA	CD	6,870	23,202	16,003	15,264	17,213	46,757	9,350	5,267
5144	AA	CD	12,213	7,316	5,462	252,049	52,217	5,279	3,485	2,794
5147	AA	CD								2,590,064
7000	AA	CD	216					-		
	OR	GD	110,187	72,239	503	172,011	916	35,122	31,692	170
7001	AA	CD	(140,699)	46,587	17,472	255	576,853	67,042	53,303	7,923
	OR	GD							-	-
7003	AA	CD	31,384	17,512	3,473	35,802	64,370	44,577	27,779	55,041
7006	AA	CD	204,124	46,577	88,494	185,827	144,317	232,584	196,064	33,958
		GD	3,999	64,858	163,430	56,209	77,535	44,502	33,228	35,535
7126	AA	CD	192,756	23,957	40,097	10,512	5,208,348	363,069	39,183	177,968
7127	AA	CD								
7131	AA	CD	791	1,996	6,334	2,427	(38,478)	629	1,130	-
7139	AA	CD		-			3,670,446	340,359	33,233	38,823
7200	AA	CD							-	
Grand Total			979,663	1,340,744	3,290,545	4,107,455	10,810,877	3,117,476	2,380,263	6,923,377

[A] During the December 2016 close process, a review identified that certain balances had not been closed and transferred to plant. This column includes the additional transfers.

Avista Corp
2016 Transfers t
Staff DR 247 Atta

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	2016				2016 Total	Grand Total	**2016 Late TTP**	**Adj. Total 2016 TTP**	**OR Allocation**
Erval	201609	201610	201611	201612					
2277	18,700	16,706	18,293	73,195	432,398	432,398	35,526	108,721	8.716%
					-	-		-	30.366%
5005	929,046	870,038	390,414	2,165,991	13,460,409	13,460,409	403,938	2,569,928	8.716%
		-			-	-		-	30.366%
					19,966	19,966		-	100.000%
5006	739,491	720,975	1,424,063	1,298,732	10,614,313	10,614,313	352,305	1,651,037	8.716%
		-			-	-		-	30.366%
5010		-			15,999	15,999		-	8.716%
		-			-	-		-	30.366%
5014	28,103	459,312	32,358	1,182,420	2,642,173	2,642,173		1,182,420	8.716%
				-	-	-		-	100.000%
5106		-		5,593,950	5,599,576	5,599,576		5,593,950	8.716%
5143	3,836	314	5,296	523	149,895	149,895		523	8.716%
5144	171,809	25,640	16,688	157,934	712,887	712,887		157,934	8.716%
5147	171,382	215,975	74,942	37,275	3,089,638	3,089,638		37,275	8.716%
7000		-			216	216		-	8.716%
	143,192	356	91,980	94,345	752,713	752,713		94,345	100.000%
7001	510,211	970	57,541	468,400	1,665,859	1,665,859		468,400	8.716%
	-				-	-		-	100.000%
7003	9,176	10,791	171,894	-	471,798	471,798	(3,548)	(3,548)	8.716%
7006	111,646	-	210,843		1,454,434	1,454,434	27,133	27,133	8.716%
	3,520	28,350	30,116		541,281	541,281	151,838	151,838	30.366%
7126	146,352	9,695	253,609	86,643	6,552,188	6,552,188		86,643	8.716%
7127		-			-	-		-	8.716%
7131			412,132		386,961	386,961		-	8.716%
7139	6,125	22,601	3,986	4,509	4,120,082	4,120,082		4,509	8.716%
7200		-		52,855	52,855	52,855		52,855	8.716%
Grand Total	2,992,590	2,381,722	3,194,155	11,216,773	52,735,639	52,735,639			

[A]

Avista Corp
2016 Transfers t
Staff DR 247 Att

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Erval	201601	201602	201603	201604	201605	201606	201607	201608	201609	201610	201611	201612	Grand Total
2277	3,986	182	2,876	1,454	137	959	1,052	15,981	1,630	1,456	1,594	9,476.13	40,784
	-	-	-	-	-	-	-	-	-	-	-	-	-
5005	35,819	66,336	95,142	239,119	50,189	138,510	89,069	79,401	80,976	75,833	34,029	223,994.96	1,208,416
	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	19,440	442	85	-	-	-	-	19,966
5006	7,053	20,314	155,704	50,898	24,005	26,821	76,778	198,959	64,454	62,840	124,121	143,904.37	955,850
	-	-	-	-	-	-	-	-	-	-	-	-	-
5010	59	-	-	-	-	-	1,335	-	-	-	-	-	1,394
	-	-	-	-	-	-	-	-	-	-	-	-	-
5014	1,702	3,510	2,846	2,877	16,066	894	1,848	52,186	2,449	40,034	2,820	103,059.77	230,292
		-	-	-	-	-	-	-	-	-	-	-	-
5106	-	-	490	-	-	-	-	-	-	-	-	487,568.72	488,059
5143	599	2,022	1,395	1,330	1,500	4,075	815	459	334	27	462	45.62	13,065
5144	1,064	638	476	21,969	4,551	460	304	244	14,975	2,235	1,455	13,765.53	62,135
5147	-	-	-	-	-	-	-	225,750	14,938	18,824	6,532	3,248.85	269,293
7000	19	-	-	-	-	-	-	-	-	-	-	-	19
	110,187	72,239	503	172,011	916	35,122	31,692	170	143,192	356	91,980	94,345.22	752,713
7001	(12,263)	4,061	1,523	22	50,278	5,843	4,646	691	44,470	85	5,015	40,825.78	145,196
	-	-	-	-	-	-	-	-	-	-	-	-	-
7003	2,735	1,526	303	3,120	5,611	3,885	2,421	4,797	800	941	14,982	(309.22)	40,813
7006	17,791	4,060	7,713	16,197	12,579	20,272	17,089	2,960	9,731	-	18,377	2,364.92	129,133
	1,214	19,695	49,627	17,068	23,544	13,513	10,090	10,791	1,069	8,609	9,145	46,107.22	210,473
7126	16,801	2,088	3,495	916	453,960	31,645	3,415	15,512	12,756	845	22,105	7,551.82	571,089
7127	-	-	-	-	-	-	-	-	-	-	-	-	-
7131	69	174	552	212	(3,354)	55	98	-	-	-	35,921	-	33,727
7139	-	-	-	-	319,916	29,666	2,897	3,384	534	1,970	347	393.00	359,106
7200	-	-	-	-	-	-	-	-	-	-	-	4,606.83	4,607
Grand Total	186,837	196,844	322,645	527,194	959,898	331,160	243,990	611,367	392,307	214,054	368,886	1,180,950	5,536,131

[A]

Sum of highlighted (green) cells 3,011,554

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

DAVID J. MACHADO
Exhibit No. 1404

Avista's Response to CUB DR 117

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	03/13/2017
CASE NO:	UG 325	WITNESS:	David J. Machado
REQUESTER:	CUB	RESPONDER:	David Machado
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	CUB – 117	TELEPHONE:	(509) 495-4554
		EMAIL:	david.machado@avistacorp.com

REQUEST:

See Avista's response to staff DR 189. Please explain in ER 3000:

a. How the 30.3% allocation factor was calculated for Oregon?
b. Why do Washington and Oregon have 3000 accounts directly assigned at 100%, in addition to the minor blanket allocation across all three states? Why does Idaho not have any directly assigned minor blanket?

RESPONSE:

a. The 30.3% allocation factor is consistent with (and slightly lower than) the previous three year weighted average (2013-2015—the most recently available complete years as of the filing of this case) of actual transfers to plant as a percentage of total system transfers to plant for ER 3000. Additionally, this expectation is lower than the previous five year weighted average (2011-2015) of actual transfers to plant for this ER. These weighted averages (as well as the weighted averages updated to include the full 2016 year) are included in the following table, and also included in CUB_DR_117 Attachment A. As illustrated in this table, the transfers to plant in a given year, as a percentage of the total, may vary from year to year as reinforcement projects are prioritized across Avista's jurisdictions. Reinforcements of the Oregon natural gas distribution system planned for completion in 2017 include the Myrtle Creek Phase 2 Reinforcement, the Medford-West 6 psig ("pounds per square inch gage") reinforcement, the Medford-East 6 psig reinforcement, and the Jacksonville Reinforcement. These projects are included in the listing of 2017 projects included in Staff_DR_182 Attachment AG.

ER 3000			
	Transfers to Plant:		
Year	**Oregon**	**System**	**Oregon as a Percent of System**
2011	636,707	636,707	100.0%
2012	27,021	213,870	12.6%
2013	4,563	1,158,132	0.4%
2014	196,867	1,022,034	19.3%
2015	930,193	1,314,945	70.7%
2016	991,367	1,803,000	55.0%
Three Year Weighted Avg (2013-2015)			32.4%
Five Year Weighted Avg (2011-2015)			41.3%
Three Year Weighted Avg (2014-2016)			51.2%
Five Year Weighted Avg (2012-2016)			39.0%

Given the planned reinforcements in Oregon and the recent historic averages of Oregon-situs transfers to plant as a percentage of total system transfers to plant under this ER, the 30.3% allocation is reasonable.

b. When natural gas distribution capital investments are placed in service, the investments are directly assigned to the jurisdiction in which the investment is located. For forecasts of transfers to plant, regardless of whether a forecast natural gas distribution item is included in a jurisdiction-specific line item or a line item to which an allocation is applied, when the Company is preparing its filing, it works with the Gas Engineering department to best reflect the expectation of the transfers to plant that will occur. The process results in the identification of appropriate allocation percentages, as described specifically for ER 3000 in item “a.”

The line items for ER 3000 which are directly assigned (approximately $13,000 assigned to Washington) are related to 2016 capital expenditures, which are recorded to jurisdiction-specific project numbers as incurred, and reflect the expected year-end 2016 CWIP balances as of the filing of this case. Idaho did not have a directly assigned minor blanket because it did not have an expected year-end 2016 CWIP balance.

The remaining 2017 transfers to plant for ER 3000 (approximately $784,000 for the nine months ended September 30, 2017) were input as a line for gas investment in all jurisdictions. Therefore, to reflect the Company’s expectation of the 2017 transfers to plant associated with this ER, the subject allocation percentage was identified, as discussed in item “a.”

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

REPLY TESTIMONY OF HEATHER L. ROSENTRATER
REPRESENTING AVISTA CORPORATION

Natural Gas Operations and Capital Investment

I. INTRODUCTION

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

A. My name is Heather Rosentrater and I am employed as the Vice President of Energy Delivery for Avista Utilities, at 1411 East Mission Avenue, Spokane, Washington.

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

A. Yes. I received a Bachelor of Science degree in electrical engineering from Gonzaga University, and hold a Professional Engineer (PE) credential. I joined Avista in 1996, and worked initially as an electrical engineer at Avista's former subsidiary Avista Labs, where I developed electrical systems for fuel cells. I joined Avista Utilities in 2003, and have broad experience on both the electric and natural gas side of the business, having managed departments and projects in gas supply, transmission, distribution, SCADA, asset management and supply chain, as well as business process improvement using LEAN and Six Sigma techniques. I was named to my current position in December 2015. In this role, I am responsible for electric and natural gas engineering, operations, customer service, shared services – fleet, facilities and business process improvement.

I currently serve on the board of directors for the Vanessa Behan Crisis Nursery and the West Valley Education Foundation in Spokane. In addition, I am a member of the Washington State University School of Engineering and Computer Science Executive Council.

Q. Please provide an overview of your reply testimony.

A. Commission Staff witness Mitch Moore and CUB witness Jaime McGovern make a number of "broad-brush" statements related to Avista's capital investments including, among other things, comparing Avista's capital expenditures to other regional natural gas utilities and comparing current spend levels to prior years. In response to this testimony, I will present information to provide better understanding of Avista's natural gas system in Oregon, which we purchased in 1991. Next I will provide an overview of our approach to capital plant investment, and the trends that have, and will continue to, drive investment. Finally, I will provide the Company's response to certain specific Staff and CUB proposed adjustments to general plant and natural gas system plant in service. A table of contents for my testimony is as follows:

Description **Page**

II. HISTORY OF OREGON NATURAL GAS OPERATIONS

Q. In response to the testimony of Mr. Moore and Ms. McGovern, would you please provide a brief history of Avista's natural gas system in Oregon?

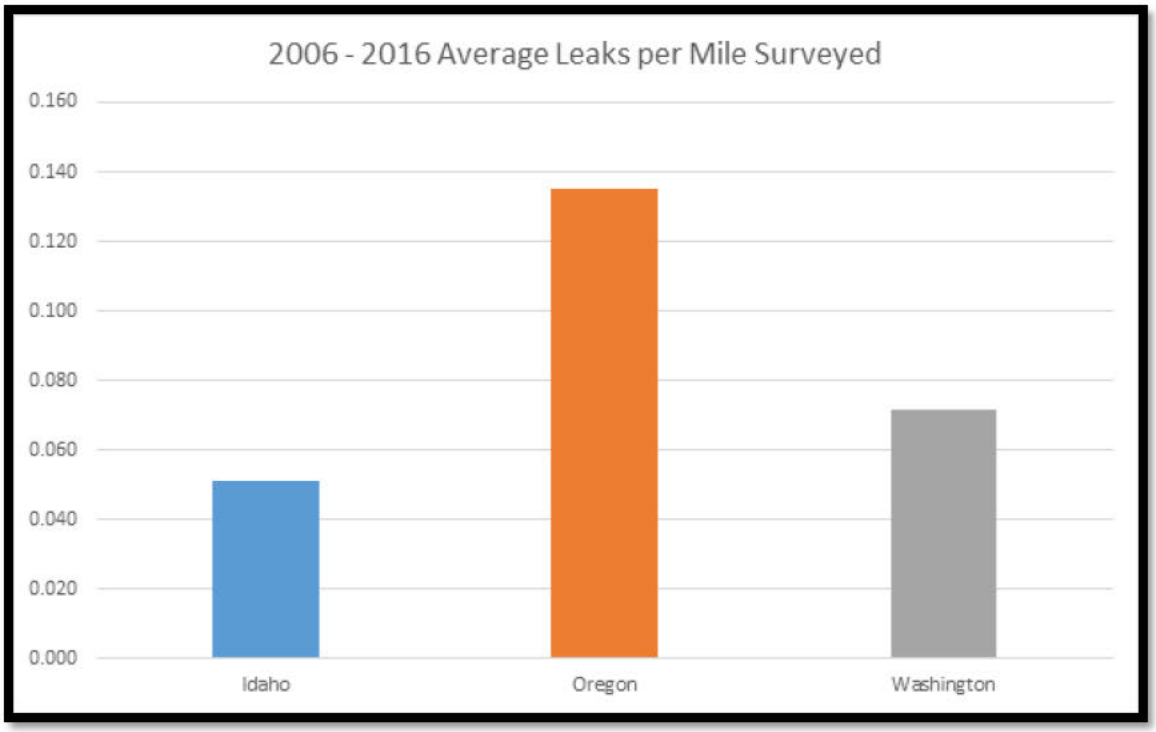
A. Yes. The CP National gas properties were purchased by Avista in 1991. In 1992, a Manager of Gas Engineering and a Senior Gas Engineer were hired to focus on improving the gas system operationally.

One of the Senior Gas Engineer's first tasks was to write a new Operations Manual. This "Gas Standards" manual was required by the Oregon Public Utilities Commission (OPUC), as the previous manual was seen as being deficient. This manual today has evolved through many iterations and is titled the Gas Standard Manual/Gas Emergency Services Handbook and serves as the basis for Avista's natural gas operating and service standards and policies.

Shortly after purchase of the Oregon properties, due to system deficiencies experienced by two extensive system outages in the Medford, Oregon area, an additional interstate pipeline feed was built into the area. This second gas feed into the area enhanced service reliability and supported the subsequent growth in customer energy usage.

Oregon's overall system, relative to Washington and Idaho, at the time of its purchase was generally less reliable and in a lesser state of repair. Efforts were focused at that time to improve the system as well as integrate system operational practices and those efforts continue. Illustration No. 1 includes a bar chart comparing Oregon's gas pipeline leak rates as compared to Washington and Idaho's gas pipeline leak rates for Avista operations. We believe the overall leak rate is a good overall comparator of system quality and demonstrates the need for continued focus on the Oregon system.

Illustration No. 1:



Q. What did the Company do to enhance the Oregon deficiencies?

A. Since the purchase of our Oregon properties, Avista has implemented and/or enhanced programs designed to identify deficiencies and/or threats to our natural gas pipeline system. Many of these threats require immediate remediation, others are tracked and risk-ranked using one of our integrity management programs to determine the appropriate mitigation response to align with industry best practices and in full compliance of today's safety sensitive environment.

Q. How does the Company make capital investment decisions involving the integrity management of its <u>transmission</u> pipeline facilities?

A. In 2004, Avista began development of a Transmission Integrity Management Program (TIMP) in high consequence areas to enhance safety by identifying and reducing gas transmission pipeline integrity risk to the public, customers, employees and the environment.

Avista integrated available information about its pipeline that was used for risk decisions. This federally mandated program helps Avista determine which transmission pipelines could have an effect on high consequence areas[1] and identifies evaluation and improvement opportunities to reduce the operating risk of these pipelines.

Q. How does the Company make capital investment decisions involving the integrity management of its distribution pipeline facilities?

A. In August of 2011, Avista began the Distribution Integrity Management Program (DIMP). This program was implemented to maintain the integrity of Avista's natural gas pipelines. Avista's pipelines vary in age as well as being built within different terrains (sand, clay, rock) and consist of several types of pipe (steel, plastic). All of these factors impact the useful life of the pipeline. Through analysis and prioritization of failure risks, pipelines are replaced to maintain safety and reliability. This federally mandated program promotes the ongoing improvement of pipeline safety by requiring operators to identify and invest in risk control measures.

Q. Which programs contribute to Avista's Distribution Integrity Management Program (DIMP)?

A. Avista's federally-mandated Leak Survey and Atmospheric Corrosion Inspection Programs contribute to the DIMP. Avista's Leak Survey Program uses sensitive leak detection equipment to survey 100% of our business districts and 20% of the remaining system annually, resulting in 100% coverage every five years. Since recognizing the higher rate of failure in our pre-1984 manufactured Aldyl A pipe, we now survey 100% of this pipe annually.

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[1] Pipeline safety regulations use the concept of "High Consequence Areas" (HCAs), to identify specific populated areas where a natural gas release could have the most significant adverse consequences. Populated areas include both high population areas (called "urbanized areas" by the U.S. Census Bureau) and other populated areas (called "designated place" by the Census Bureau). Once identified, operators are required to devote additional focus, efforts, and analysis in HCAs to ensure the integrity of pipelines (https://primis.phmsa.dot.gov/comm/FactSheets/FSHCA.htm)

The Atmospheric Corrosion Inspection Program visually inspects one-third of all of the above ground steel pipe system annually. This includes a detailed inspection for atmospheric conditions that, if left unmitigated, could result in premature failure of the facility.

Results of these mandated inspection programs, support and inform the seven elements[2] of the DIMP and help direct maintenance and capital replacement. These inspection programs and the DIMP are audited frequently by OPUC Pipeline Safety Engineers.

Q. Does Avista benchmark itself against other utilities to ensure alignment with industry?

A. Yes. Avista has continued to align its gas operations with industry best practices. In an effort to benchmark our practices with fellow gas distribution companies, we are active participants in multiple industry organizations. Our primary industry participation is through involvement with the American Gas Association (AGA); the Western Energy Institute (WEI); and the Gas Technology Institute – Operations Technology Development section (GTI-OTD). Furthermore, we meet bi-annually with our fellow western natural gas distribution companies (Southwest Gas Co., NW Natural Gas Co., Cascade Natural Gas Co., Questar and Intermountain Gas Co.). Each of these meetings cover two days at the host utility's headquarters, and we discuss relevant agenda items that we each have submitted. Subject matter routinely covered includes how to implement new code requirements, enhance construction practices and improve customer satisfaction/experience.

[2] The seven elements of the DIMP, as defined in 49 CFR 192.1007, are: 1. Knowledge (of your system); 2. Identify threats (to you system); 3. Evaluate and Rank Risks (to your system); 4. Identify and implement measure to address risks; 5. Measure performance, monitor results, and evaluate effectiveness (of the program); 6. Periodic evaluation and improvement (of the program); and 7. Report results (of the program).

The AGA represents more than 200 energy companies. Of the many activities that AGA is involved in, they sponsor many committees supporting all lines of the natural gas business. Avista participates in Gas Engineering and Gas Measurement Committees as well as Gas Construction/Operations Committees, among others. We also send natural gas employees each year to the AGA Spring Operations Conference, which routinely has attendance of approximately 1,000 utility and industry representatives. Papers are presented on a variety of topics, including a significant focus on best practices.

AGA promotes, and Avista actively participates in, an annual AGA Best Practice Benchmarking survey. Each year approximately 90 of the 200 AGA member utilities participate by providing company data and answers to questionnaires for the three subject topics being benchmarked for that year. Subject matter changes each year. From these data collections, "best practice" utilities are identified and then subject matter experts from these participating utilities attend three national meetings to view presentations from the best practice utilities and learn best practices. Avista's Director of Natural Gas serves on the AGA Best Practices Benchmarking Steering Committee.

Another notable event that AGA hosts is Peer-to-Peer reviews. Avista participated in an extensive, week long review in March 2015. Eight utilities from across the nation, selected by AGA with consideration to similar pipeline systems and overall size, came to learn various aspects of Avista's natural gas operations. Based on their findings, recommendations at the end of the week were made on how to improve our gas operations. To do our part to support this program, our gas employees also are asked by AGA to participate in evaluations of other utilities in their week long reviews. Our employees return from these visits with learnings to enhance our operations.

We also routinely participate in WEI's regional Operations Conference where natural gas employees present papers or listen to presentations of others, again to glean best practices.

Avista promotes and participates in research and development (R&D) in the area of new tools and operational practices through its involvement in GTI-OTD. Participating utility representatives from across the nation meet to develop needs for which GTI-OTD works to develop solutions. Through its membership, Avista utility representatives are able to drive new technology towards areas for which it has needs.

Q. How does Avista work with the Commission's Staff on matters of safety and reliability?

A. Avista works with Commission Staff in several ways. First, Avista and Commission Staff meet, informally, on a quarterly basis to discuss current issues facing Avista, Staff, and the natural gas industry, and exchange ideas and best practices. These are so-called "fireside chats". On a more formal basis, Avista works with Commission Staff during their regular natural gas system inspections. Those inspections are made to ensure compliance with state and federal (PHMSA) mandates.

III. <u>OREGON CAPITAL PLANT INVESTMENT APPROACH</u>

Q. What is Avista's overall approach to making investments in its natural gas system and general utility plant in service?

A. Avista identifies and invests in its natural gas system and general plant assets based on identified needs required to keep our system operating in a safe, reliable, compliant, and cost effective manner. Our investment approach is generally driven by legal and regulatory requirements, studies of customer load growth and options for serving those loads in the future, such as our Integrated Resource Planning (IRP) process, cost effective replacement of assets at the end of their life, line extensions to connect new customers, cyber security systems to protect our customers data and critical utility operations, more efficient and cost effective work processes, training, and tools, and a host of other examples.

Q. Generally speaking, are there specific categories of natural gas and utility plant investment which Avista's uses to identify, vet and prioritize capital spend?

A. Yes. Avista recently began categorizing its capital investment into the following groups:

A. Customer Requested
B. Customer Service Quality and Reliability
C. Mandatory and Compliance
D. Asset Condition
E. Performance and Capacity
F. Failed Plant and Operations

Avista's objective by using these categories is to better explain the "why" of our investments by creating more clarity around the particular needs being addressed as well as simplifying the organization and understanding of our overall capital investment. It will also promote greater transparency and visibility around why these investments are necessary in the timeframe proposed.

Q. Please briefly describe the capital investment categories and provide some examples of projects that fall into these categories.

A. A general description of the categories along with a few examples is provided below.[3]

A. Customer Requested - (ER 1001, 1050, 1051, 1053)

This category includes customer requests for new service connections, line extensions, or system reinforcements to serve a single large customer. We have often referred to new service connects as "growth." A request for new gas service comes to Avista through our Customer Call Center. Customers either request service for a new construction or for an existing structure they desire to convert from some other fuel source to natural gas. These calls are directed to our Customer Project Coordinators who then contact customers to better understand their requests and complete service requests per the applicable tariffs.

B. Customer Service Quality and Reliability - (ER 5143)

This category includes investments required to maintain or improve the quality of service we currently provide our customers, and/or to introduce new types of services and options based on an analysis of customer needs and expectations.

An example of a project in this category that will provide benefit to our Oregon customers is Avista's website redesign project. As explained in more detail in Mr. Kensok's testimony, the website is connected to relevant systems of record, such as the customer information system for bill presentment and payment, as well as the outage management system for outage reporting, among other things.

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[3] Also included are some of the Expenditure Requests (ER), four-digit numbers assigned to identify and track the costs of capital budget items. The ER is the highest level of capital budgeting summarization, and each business case contains one or more ERs. Each ER contains one or more budget items ("BI") and each BI contains one or more projects. Capital expenditures are accounted for at the project level.

C. <u>Mandatory & Compliance</u> - (ER 3003, 3004, 3006, 3007, 3008, 3055, 3057)

A portion of our capital investment is mandated and or compliance driven. The capital investments in this category are driven by compliance with laws, rules, and contracts that are driven by factors external to the Company. Many of these rules are required by the Department of Transportation, Pipeline Hazardous Materials Safety Administration (PHMSA), and can be found in Title 49 of the Code of Federal Regulations, Part 192.

Q. Please provide an example of work completed under the Mandatory & Compliance category.

A. Our Gas High Pressure Remediation Program is an example, which includes projects like the rerouting of high pressure pipeline in Klamath Falls, Oregon that crosses a fault line near a school. This risk reduction project was recently identified for completion in 2017 and was discussed with Staff during the telephonic quarterly update meeting on November 7, 2016. Other work underway in this program, and expected to be completed by the beginning of the test year, is the remediation of high pressure pipe, as well as the installation of regulator stations in the Medford area in order to allow for traceable, verifiable, and complete maximum allowable operating pressure (MAOP) records for high pressure pipeline in the area. This programmatic annual investment is designed to replace segments of high pressure pipelines as determined by Avista's TIMP, DIMP, and/or subject matter experts. Additionally, high pressure pipelines without traceable, verifiable, and complete MAOP records will be replaced or mitigated within this program.

D. <u>Asset Condition</u> - (ER 3001, 3002, 3054)

These are projects to replace assets based on established asset management principles adopted by the Company, which are designed to optimize the overall lifecycle value of the investment for our customers. Examples include: 1) Gas Deteriorated Steel Pipe Replacement Program; 2) Gas Regulator Station Replacement Program; and 3) Gas ERT Replacement Program.

Sections of existing steel piping within Avista's gas distribution systems in Oregon are aging and showing signs of deterioration. The replacement of deteriorated steel pipe has been prioritized and risk-ranked by Gas Engineering in collaboration with the Gas Operations Districts. Deteriorated steel pipe may have poor coating, threaded fittings or substandard welds. While deteriorated steel pipe does not necessarily show a high incidence of leakage, it should be replaced prior to leakage.

E. <u>Performance and Capacity</u> - (ER 3000, 3117, 3209)

Performance and Capacity includes a range of investments that address the capability of assets to meet defined performance standards, or to maintain or enhance the performance level of assets based on need or financial analysis.

As an example, the Company's Pipeline Reinforcement Program continues to remediate system capacity deficiencies to ensure adequate pressure to serve customers at design temperatures. Avista evaluates its natural gas distribution system on the basis of its performance on design heating degree days. Avista considers the design heating degree day to be the coldest day on record for a given region. Evaluation of the natural gas system relative to the design heating degree day is standard industry practice. Avista experienced design day temperatures as recently as 2013 in Klamath Falls. Prior to 2013, the design heating degree day last occurred in Klamath Falls in 1990. These facts illustrate the unpredictable nature of design heating degree days and the prudence of the use of this measure as a planning standard. As an example of recent investment to ensure adequate pressure to serve customers, the East Medford High Pressure Reinforcement, which was placed in service in February of 2016, was completed to address areas of low pressure due to system capacity shortfalls. Mr. Morris' Exhibit No. 103 contains output from the Synergi® system model for the Medford area before and after the completion of the East Medford Reinforcement. Completing this project reduced, by half, the number of customers at risk of an outage at design day temperatures. However, low-pressure areas remain on that system, as illustrated by the model output after the completion of the East Medford Reinforcement. Portions of the capital investment under the Gas Reinforcement Program (discussed further in section IV) target areas in the Medford distribution system where design day conditions would result in substandard delivery pressure.[4]

Q. What are the consequences of a loss of delivery pressure?

A. The loss of delivery pressure can lead to the loss of service for customers. As delivery pressures drop on the system, ultimately customers may lose their pilot lights. Depending on the severity of the cold weather that could cause the loss of service, customers may be out for a sustained period of time. As discussed in detail in the Company's last general rate case (Docket No. UG-288), the Company does have a Cold Weather Action Plan which includes a decision tree intended to initiate high-level manual intervention activities in particular areas at a pre-defined temperature. The plan is what I would call a back-up plan. The Company's priority, however, is to be able to serve customers through its distribution system on peak days automatically (e.g., without the need for manual intervention or customer-use modifications).[5]

[4] Avista/600 Machado/4-5.

[5] The Cold Weather Action Plan is used in certain areas where reinforcement projects or system upgrades have not yet been completed or are in progress. In order to continue to be able to serve customers on peak days in these areas, the Company has developed certain activities that it may undertake, as necessary. These particular activities include: (1) a review of low-pressure areas to ensure identification of areas of concern; (2) identification of customers to notify (either a request to shed load or a notification of possible curtailment of service); and (3) assignment of field personnel to monitor pressures at gas meter sets and regulator stations. The Cold Weather Action Plan specifies a particular temperature at which local Operations Managers need to assess the general health of the gas system by completing these three actions. After initiating the Cold Weather Action Plan and assessing the three activities mentioned above,

F. <u>Failed Plant and Operations</u> - (ER 3005)

Failed Plant and Operations includes a range of investments that address assets that have failed and which must be replaced in order to provide continuity and adequacy of service to our customers.

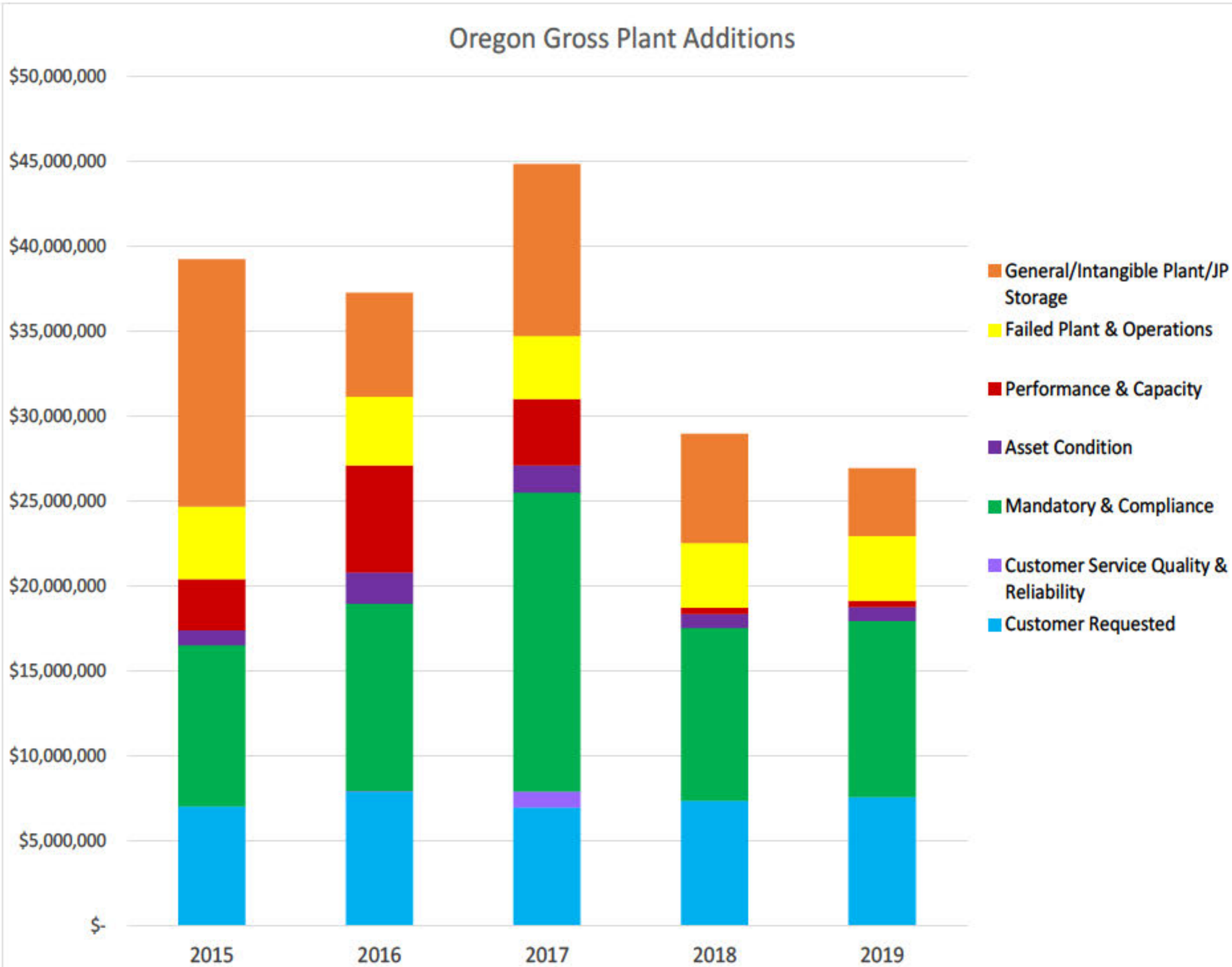
The bulk of the work in this category is performed in our Gas Distribution Non-Revenue Program. The program includes replacement of facilities that are at the end of their useful life or have failed, as well as projects to improve public safety and/or improve system reliability. For example, when shallow natural gas facilities are discovered, an appropriate response to the situation is determined by Local District personnel. The project will be prioritized and risk-ranked against other similar type of projects. These types of projects allow Avista to remain in compliance, avoid financial penalties, and operate the gas facilities in a safe manner.

Q. How do the Company's prior and ongoing capital additions to plant fall into these six categories?

A. Illustration No. 2 shows the actual gross plant additions in Oregon for 2015 and 2016, and the expected transfers to plant for 2017 through 2019, categorized into the six natural gas distribution plant categories discussed above. A seventh category on the following chart includes Oregon-related capital investment related to General Plant, Intangible Plant, and Jackson Prairie Storage.

Operations Management has the responsibility to take further actions to support the system as necessary. Depending on the assessment, these actions could include the continuation of monitoring, requesting a media blast to request a temporary thermostat turndown, taking extraordinary measures to manually improve the capacity of the system by bypassing regulator stations or manually shedding load, and/or preparing relight lists (to restore service to customers who lost gas service).

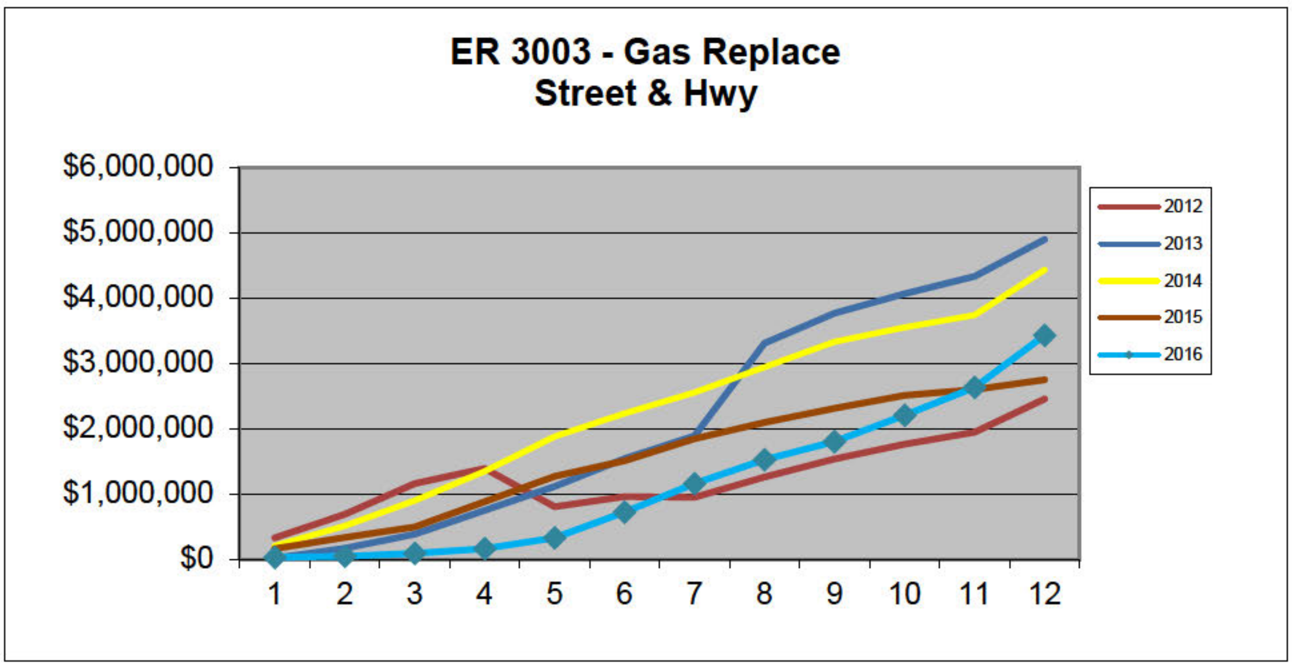
Illustration No. 2:



Q. The Mandatory & Compliance additions, shown in green above, increased significantly in 2017, as compared to 2016 and 2015. What drove this increase?

A. One significant mandatory requirement is the need to relocate facilities at the request of others (ER 3003: Gas Replacement Street and Highways). It is very difficult to forecast year-to-year what the cost in this category will be. Virtually all of Avista's pipelines are located in public utility easements (PUEs) which are controlled by local jurisdiction franchise agreements. Avista is mandated under these agreements to relocate its facilities, when local jurisdictional projects necessitate. Often these come without significant lead time by the local jurisdictions. It is often the case that meetings are called in the Spring to notify franchisees (natural gas, electric, cable, phone etc.) that they will need to relocate their facilities. This does not enable ideal planning and often may cause Avista to spend unbudgeted funds and do so in a manner that is not of the utmost efficiency. Illustration No. 3 below includes a graph showing recent actual spending in this ER:

Illustration No. 3:



In addition, Gas facility overbuilds, when identified, are often replaced in the same year they are found (ER 3006: Gas Overbuilt Pipe Replacement Program). Gas Pipeline Safety codes do not permit natural gas mains or services to be constructed under buildings unless they are encased in protective sleeves that would vent gas from under the building, should a leak occur. It is common to find our facilities have been overbuilt through underground locate/811 calls as well as our Leak Survey and Atmospheric Corrosion inspection programs. While we budget for this program, again variances will occur depending on what is found.

Another driver in 2017 is the ongoing work under ER 3008. The Aldyl A Replacement Program is a 20-year program to systematically remove and replace “at risk” Aldyl A pipe. “At risk” pipe for Avista is defined as pre-1984 manufactured pipe in diameters from 1-1/4 inch through 4-inch. In addition, Avista is replacing short sections of Aldyl A service pipe that transitions from steel tees as part of this program. Scheduling for projects within this program are dictated primarily by our DIMP, and some scheduling variances are necessary to enable efficiencies in construction and to reduce mobilization expenses or impacts to our customers. The entire southeast Klamath Falls project in the original planning stage was to be constructed in two years, 2017 and 2018. For efficiency gains, the 1.19 miles of this originally scheduled project for 2018 is now scheduled to be constructed with the 2017 planned work.

Finally, Federal Gas Pipeline Safety Regulations are being created at a fast pace. There are currently nine new pipeline safety rules, as shown in Illustration No. 4 below, which are in interim or completed status, and three that are in NPRM (Notice of Proposed Rule Making) status. While Avista participates actively in workshops within AGA to follow and understand the impact of these regulations as they are being developed, there is significant uncertainty as to the final form of these new regulations, the timing of them (if approved), and the ultimate impact on capital investment and operating costs for Avista’s Oregon natural gas operations.

<u>Illustration No. 4:</u>

Notices of Proposed Rulemaking

	Estimated DOT Submission to OMB	Estimated NPRM Publication
Valve Installation & Rupture Detection	January 24, 2017	May 3, 2017
Standards Update - 2015 and Beyond	n/a	July 2016
State Pipeline Safety Program Certification	n/a	August 2016

Final Rules (& Interim Final Rules)

	(Estimated) DOT Submission to OMB	(Estimated) Final Rule Publication	Effective Date
Safety of Gas Transmission & Gathering Lines	*AGA Estimate*: Q2 2017	*AGA Estimate*: Q4 2017	-
Safety of On-Shore Hazardous Liquid Pipelines	**Sent back to DOT*	January 19, 2017	-
Plastic Pipe Rule	n/a	*AGA Estimate*: Q3 2017	-
Operator Qualification, Cost Recovery, Accident & Incident Notification, and other Pipeline Safety Changes	**-**	**January 23, 2017**	**March 24, 2017**
*Final Rule to Address OQ	-	*AGA Estimate: Q4 2017*	-
Excess Flow Valves Beyond Single Family Homes	-	**October 14, 2016**	**April 14, 2017**
Enhanced Emergency Order Procedures *(Interim Final Rule)*	-	**October 14, 2016**	**October 14, 2016**
Underground Storage (Interim Final Rule)	-	**December 19, 2016**	**January 18, 2017**

Information Collection Request

	Estimated DOT Submission to OMB	Estimated Information Collection Request Publication
National Pipeline Mapping System	**June 22, 2016**	*AGA Estimate*: Q4 2016/Q1 2017

Dates are estimated per December 2016 DOT Significant Rulemaking Report or provided by AGA.
Bolded dates are actual.

American Gas Association 2

IV. <u>OTHER GENERAL TRENDS IMPACTING CAPITAL SPEND</u>

Q. Are there unforeseen, unpredictable costs placed on Avista by others?

A. Yes. Beyond an increase in capital projects, Avista has also experienced increased costs associated with requirements placed on Avista by municipalities, above what is considered standard work practices. One requirement is unique to Medford, our largest district in Oregon. Medford has instituted a reduced work day when working on an arterial street, whereby the working hours are limited to 9 AM to 4 PM, considerably less than we experience in other areas in our service territories. This shortened workday, coupled with the requirement to reopen the street to traffic every night, has a direct impact on efficiency.

V. AVISTA'S RESPONSE TO NATURAL GAS SYSTEM ADJUSTMENTS

A. New Growth/JP Storage

Q. What are the six adjustments related to new growth/JP Storage made by Mr. Moore?

A. As shown on p. 1 of Mr. Moore's testimony (Exhibit No. 800), Staff proposes adjustments to the following six projects:[6]

1. Bonanza Development
2. Granite Hill Road
3. Old Midland Development
4. 2017 New Growth - Residential
5. Jackson Prairie Storage
6. 2016 New Growth - Residential

Q. Does the Company agree with any of the six adjustments Mr. Moore made to new growth projects?

A. The Company agrees with the Bonanza and Granite Hill adjustments. We agree, in part, with the Old Midland Development and 2017 New Growth – Residential adjustments. We do not agree to the Jackson Prairie Storage and 2016 New Growth – Residential adjustments. Table No. 01 below provides Staff's Adjustment and Avista's Proposed Adjustments:

[6] Mr. Moore makes a seventh adjustment, "Management Adjustment", which is addressed in Mr. Norwood's reply testimony.

Table No. 01: New Growth Projects:

	Rate Base Adjustment	
	Staff Adjustment	**Avista's Adjustment**
Accepted Adjustments:		
Bonanza Development	$ (740,000)	$ (740,000)
Granite Hill Road	$ (27,000)	$ (27,000)
Partially Accepted Adjustments:		
Old Midland Development	$ (658,000)	$ (147,873)
2017 New Growth - Residential	$ (3,513,000)	$ (800,000)
Adjustments Not Accepted:		
Jackson Prairie Storage	$ (245,000)	$ -
2016 New Growth - Residential	$ (2,153,000)	$ -
Total Adjustment	**$ (7,336,000)**	**$ (1,714,873)**

Q. Please explain the Company's agreement with the Bonanza Development and Granite Hill Road adjustments? (Full Agreement)

A. After further review of the Bonanza and Granite Hill projects, the Company agrees that the current and/or expected near-term loads do not fully support the investment. As such, Avista agrees to include Staff's recommended capital costs of $442,000 in this case for Bonanza[7], and exclude all capital costs associated with Granite Hill. The effect of these two capital adjustments reduces net plant investment in this case by $767,000.

Q. What is the Company's proposal for future ratemaking treatment for the Bonanza Development and Granite Hill Road projects?

[7] In the Company's original filing, Avista included capital costs of $1,182,000 for Bonanza Development. Staff proposed $442,000. The net reduction from the Company's filing is $740,000.

A. For the Granite Hill project, the Company will write off the capital investment of $27,000. However, for Bonanza, while the project initially is not as economically viable as originally analyzed, over time the level of future connected load to that particular main extension may support the investment. As such, Avista agrees to Staff's removal of $740,000 in capital in this case, but would plan to seek recovery of some or all of that investment as increased customers and load supports the investment. The $740,000 will be excluded from Oregon ratebase, for regulatory purposes, until such time as all or a portion of that balance is supported by customer load.

Q. What is Avista's response to Staff's adjustment related to the Old Midland Development? (Partial Agreement)

A. Staff asserts on p. 14 of Exhibit No. 800 that Avista's own analysis related to the installation of natural gas pipe to serve 90 customers in Midland, Oregon showed an internal rate of return of 4.33 percent: below the Company's authorized cost of capital of 7.46 percent. As a result of being below the authorized rate of return, Staff excluded the entire project from this case. Upon reviewing the project specifics and model, the number of customers and therm sales supports a level of investment of $510,127, as opposed to the $658,000 included in the Company's case. The Company agrees to remove $147,873 in capital costs from this case.[8]

Q. What is the Company's proposal for future ratemaking treatment for Old Midland Development?

[8] The calculation of the supported level of investment has been included in the Company's workpapers that accompanied this testimony.

A. Future connected customers and load may support this investment. For example, in the next few years, a small reinforcement project in that area may be required.[9] Such a reinforcement, which will continue to allow Avista to provide adequate service in the area, would not have been possible without the Old Midland project. Avista agrees to exclude $147,873 from Oregon ratebase, for regulatory purposes, until such time as all or a portion of that balance is supported by customer load or the reinforcement is placed in service.

Q. Turning now to Staff's adjustment for 2017 New Growth-Residential, why is Staff's rate base adjustment of $3.513 million not appropriate? (Partial Agreement)

A. First, to clarify Staff's adjustment for 2017 New Growth-Residential, Mr. Moore states that the "2017 forecast is for three quarters of the year" – i.e., January 1, 2017-September 30, 2017. Staff's asserts that Avista included $6.376 million in its case for 2017 growth, as shown on Staff/800, Moore/1. Staff then multiplies $2,500[10] by Staff's estimate of residential customer hookups – 1,145 – to arrive at an allowable investment of $2.863 million. Staff's adjustment removes $3.513 million from Avista's request.

The actual amount included for 2017 growth, as shown on Avista/600, Machado/12, for the first three quarters of 2017 is $4.9 million.[11] Included in that amount is new growth revenue related to commercial and industrial customers, not just residential customers. Assuming that 25% of the costs for new growth are actually related to commercial and industrial customers (based on Staff's 2016 analysis showing that 75% of projects were residential), that would leave $3.7 million in costs for providing new service to residential customers. Upon review of the 2017 residential

[9] The Company is currently evaluating a 1,000 foot extension from the Old Midland Development to another portion of Avista's distribution system for reinforcement purposes.
[10] This budget estimate is discussed in the 2016 New Growth Residential later in my testimony.
[11] Avista/600, Machado/12, ER 1001 ($3.720 million), ER 1050 ($0.456 million), ER 1051 ($0.071 million), and ER 1053 ($0.668 million).

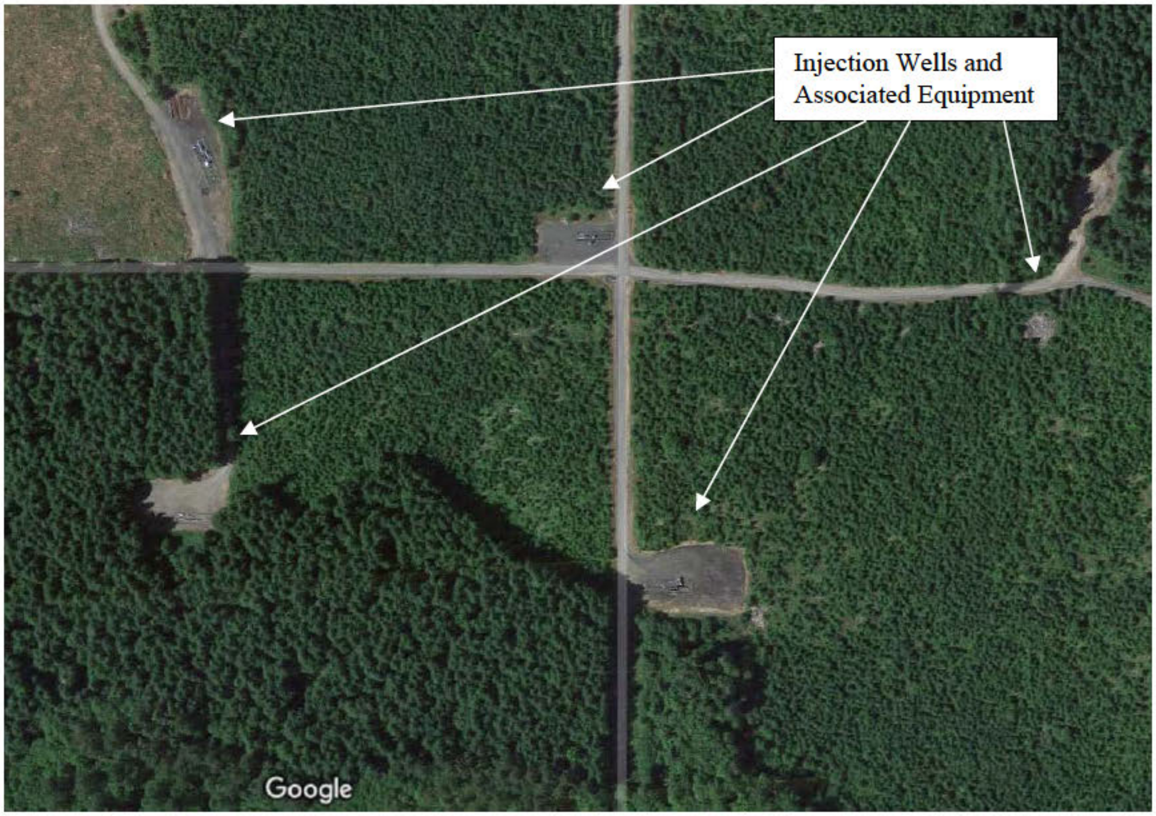
new growth analysis included in the Company's original filing, we did discover that the line extension allowance in Washington, which is at a higher level than Oregon, inadvertently affected the level of revenue requirement calculated for Oregon residential capital.

Taking Staff's residential customer estimate of 1,145, multiplied by the $2,500 budget estimate of the cost to hook up a new residential customer, the allowable investment for residential customers is $2.9 million. Therefore, Avista agrees to exclude $0.8 million in capital in this case (the difference between the $3.7 million included in the case for residential customers, and the revised $2.9 million noted above).

Q. Why is Staff's $245,000 adjustment related to Jackson Prairie Storage not appropriate? (No Agreement)

A. Staff's states that the 680 acres of land the Company purchased at the Jackson Prairie Underground Natural Gas Storage Project is "adjacent to the storage facility" and is not "used and useful for providing service to customers". What Staff failed to recognize is that the Company has been leasing this same land from Weyerhaeuser since 1955. It is <u>not adjacent</u> to the Jackson Prairie Storage Project, but rather is directly <u>above</u> the Jackson Prairie <u>Underground Natural Gas Storage</u> Project ("JP"). Illustration No. 5 below is a snapshot of a portion of the 680 acres purchased. The picture shows a portion of the land in question (natural gas is stored below ground), as well as some of the injection wells and associated equipment on the property:

Illustration No. 5 – Portion of 680 Acres Purchased at Jackson Prairie



Further, the land is encumbered by certain pipelines (underground) and natural gas injection wells and associated equipment related to the operation of JP as shown in the image above. Finally, the Weyerhaeuser lease terms did not prohibit Weyerhaeuser from developing that acreage for residential and commercial development, which, had that occurred, would require the JP ownership group to relocate portions of its natural gas facilities. It was determined that the prudent course of action would be a purchase of the land from Weyerhaeuser. Through the land purchase, the JP owners were able to avoid: (1) a new monthly lease payment that would be higher than the present monthly lease rate of $21,000 per month, and (2) the relocation of the current JP facilities located on the 680 acres – such a relocation would have been at a cost equal to or greater than the purchase price of the land. Therefore, Staff's adjustment is not appropriate.

Q. Turning now to Staff's adjustment for 2016 New Growth-Residential, why is Staff's rate base adjustment of $2.153 million not appropriate? (No Agreement)

A. Staff states on p. 14 of Exhibit No. 800 that Avista spent approximately $5.7 million in 2016 to connect 1,414 residential customers. Staff concludes that only $3.5 million should be recoverable, because the cost to hookup those customers exceeded $2,500.

Staff's analysis is faulty. First, Staff apparently uses Avista's budget estimate of $2,500 as a threshold, above which any incremental balance of investment is not prudent. The budget estimate of $2,500 is just that, an estimate, which the Company uses for purposes of estimating, prospectively, what the cost to serve a new customer will be. As discussed in more detail below, actual costs paid by the Company are governed by two Commission-approved tariffs, Rules 15 and 16. Avista actually spent $4.7 million to provide service (main and service extensions) to residential customers in 2016, as shown in Exhibit No. 1502.[12] Of that amount, $1.8 million was related to main extensions (governed by Rule 15 of the Company's tariff), and $2.9 million was related to service costs (governed by Rule 16 of the Company's tariff).

For the main extension costs of $1.8 million, the allowable investment is set forth in Rule 15. Rule 15 states: "Gas main extensions will be made by the Company, provided the estimated total cost of the required extension from existing distribution mains to the premises to be served does not exceed three (3) times the estimated annual gross revenue as determined by the Company to be derived from bonafide applicants for such service." Three times annual revenue for

[12] The difference between Mr. Moore's balance and this balance is that Mr. Moore included the transfers to plant associated with ERs 1050, 1051, and 1053. These ERs include the purchases of meters, regulators, and Encoder Received Transmitters (ERTs), respectively, for both the connection of new customers and the replacement of these assets under the company's periodic meter change out program, ERT replacement program, or for the replacement of failed plant.

residential customers is approximately $1,986.[13] The actual main extension cost was $1,253, well below the allowable investment.

The remaining portion of the costs for new residential customers in 2016 was $2.9 million related to service costs. Rule 16 of the Company's tariff provides for the treatment of these costs as follows:

> Upon application, the Company will furnish and install <u>at its own expense</u> a service pipe of suitable capacity from its gas main to the property line of property abutting upon any public street, highway, alley, lane or road along which it already has or will install street mains, and will install, <u>at its own expense</u>, a further extension of 40 feet on the private property, or as much of such extension as may be necessary to reach a meter location that is satisfactory to the Company. (emphasis added)

The same applies to meters, which is also specified in Rule 16, where it states:

> The Company <u>at its expense</u> will provide, install, own and maintain a suitable meter. (emphasis added)

Based on the Commission-approved tariff, Avista must provide, at its expense, the services and meters for new customers.

In conclusion, for Staff's 2016 New Growth Residential adjustment, for the reasons set forth above, no adjustment should be made to the level of investment included in this case, and Staff's $2.2 million rate base adjustment should be rejected.

B. <u>ER 3001 – Replace Deteriorating Gas Systems</u>

Q. Please provide your understanding of CUB's testimony regarding ER 3001, Replace Deteriorating Gas Systems.

[13] Average residential use per customer is 46 therms per month. Using a present billing rate of $1.00381 per therm and a $9 monthly basic charge, monthly revenue is $55.18. That amount, multiplied by 12 months, and then 3 years, is $1,986.31.

A. CUB recognizes the need for this program and proposes that the approved capital investment associated with this program be set equal to the average of actual transfers to plant over the four year average (from 2013-2016) of actual transfers to plant.[14] Using an average of actual transfers to plant is not appropriate in this circumstance. Avista has included the actual level of investment that will be in service in the test year. Additionally, CUB asserts that as the system is modernized, the proportion that is deteriorating should decrease.[15] Earlier in my testimony, I discussed the capital projects that have been undertaken to address specific asset conditions. The Company's DIMP analysis has identified deteriorated steel pipe as an area of risk requiring capital investment to remediate, and CUB's adjustment should be rejected.

C. ER 3008 – Aldyl A Pipe Replacement

Q. What is Avista's respond to CUB's testimony regarding the Aldyl A Pipe Replacement Program? [16]

A. First, CUB recommends a 10% adjustment (reduction) to the level of Aldyl-A Pipe replacement included in this case for "lack of transparency due to allocation over direct assignment."[17] As Mr. Machado states in his reply testimony, the actual Aldyl-A pipe investment is not allocated but rather is directly assigned. The 10% adjustment proposed by CUB should not be accepted.

In addition, Exhibit No. 1503 includes the Company's response to CUB DR 011. In this response, the Company states that the outcome of consolidated Washington Dockets UE-160228 and UG-160229 is independent of the investments included in this case (Docket UG-325). The

[14] CUB/100, McGovern/Page 44.
[15] CUB/100, McGovern/Page 44.
[16] CUB/100, McGovern/Page 49.
[17] Ibid.

Aldyl A Replacement program is a program driven by the Company's DIMP analysis and is a risk-reduction program. This capital investment should be made for the safety of the system. CUB's proposed adjustment regarding ER 3008 should be rejected.

D. <u>ER 3309 – Pierce Road La Grande High Pressure Reinforcement</u>

Q. What is the Company's response to CUB's removal of $3.5 million related to the Pierce Road La Grande High Pressure Reinforcement Project?

A. The Company does not agree with this adjustment. As discussed in Mr. Machado's direct testimony,[18] this project helps to remediate an existing design heating degree day capacity shortfall in the town of Elgin, Oregon, as well as a gate station capacity shortfall at the La Grande city gate station. The Company has provided ample support for the need and timing of this project, first through the IRP process, as well as in quarterly meetings held with Commission Staff, NWIGU, and CUB. Further, the Company has met all of the conditions related to distribution system upgrades, and the requirements for recovery in rates, as set for in the Commission's Order No. 16-109. Given the existing natural gas pressure shortfalls in the Elgin area, as discussed in the Company's direct filing, the Company disagrees with the assertion that Avista has not demonstrated the prudence of the timing of this project.

Q. When is this project expected to be completed?

A. Due to a delay in the completion of the design of this project caused by a need to re-assign resources to customer service requests, the Company now expects this project to be completed by the end of October 2017.

[18] Avista/600, Machado/Pages 27-28.

VI. AVISTA'S RESPONSE GENERAL PLANT ADJUSTMENTS

A. ER 7000 – Transportation Equipment

Q. With regard to ER 7000 – Transportation Equipment, what is Avista's response to Mr. Kaufman's testimony related to the Utilimarc Report?[19]

A. Although Staff did not actually quantify an adjustment related to the Utilimarc Report, Mr. Kaufman recommends that "the cost of the Utilimarc report be excluded from rates because it uses unrealistic assumptions and is not used by Avista in actual fleet management."[20] Mr. Kaufman expresses concern that the model uses a cost of capital of three percent.[21] The three percent interest rate is utilized by Utilimarc to standardize its model across all utilities. While Avista's cost of capital may be a more appropriate interest rate, this difference does not invalidate the usefulness of adopting a lifecycle cost analysis methodology.

The Company disagrees with Mr. Kaufman's statement that the report "is not used by Avista in actual fleet management."[22] Exhibit No. 1501 contains pages excerpted from Avista's response to Staff DR 200, Attachment A. These pages illustrate that the differences between the fleet investment scenario using Utilimarc's recommended lifecycles and Avista's selected lifecycles are not significant. The fact that Avista's selected lifecycles are slightly different from the Utilimarc recommendation does not mean that Avista is not using the Utilimarc report for fleet management; rather, it shows that Avista has generally adopted the Utilimarc recommendations, with some differences—that is to say, the Utilimarc report informs and helps guide Avista's fleet

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[19] Staff/700, Kaufman/30, lines 2-7. Staff states that it will propose an adjustment in "subsequent testimony".
[20] Ibid.
[21] Staff/700, Kaufman/30, line 1.
[22] Staff/700, Kaufman/30, lines 4-5.

management, but it does not dictate a single approach. Therefore, Avista disagrees with Mr. Kaufman's position that the cost of the Utilimarc study should be excluded from recovery in rates.

B. <u>ER 7001 / 7003 – Structures, Improvements, and Office Furniture</u>

Q. Does Avista agree with Staff's proposal regarding ERs 7001 and 7003?

A. No. ERs 7001 and 7003 are related to the purchases of structures, improvements, and office furniture. Mr. Kaufman proposes a disallowance to ER 7001 of $394,000 ($34,000 Oregon-allocated) based upon his conclusion that photographs and observations of office furniture during Staff's site visit to the Company's Mission Campus did not indicate that the office furniture was in disrepair.[23]

With regard to the Kellogg office furniture mentioned by Staff,[24] the majority of the existing office furniture product (modular office panels and work surfaces) in use was originally purchased in the mid-1990s. This office furniture has been relocated at least four times over its life and the frame color and work surface laminate is no longer available for purchase. Given these factors, the Company's Facilities Management department had limited ability to reconfigure or retrofit this furniture based on their current office design standards. Similarly, the furniture referenced in Conference Rooms 50 and 60 dates from the mid-1990s. The furniture product in these rooms does not have stock available to accomplish the new layout that maximizes the use of available space. As a result, the decision was made to standardize the employee space using current workspace design standards, which required the use of new furniture. In both of these cases, the electricity power base feeds at the base of the panels are beginning to fail, resulting in power loss at employee's work spaces. The manufacturer recommended life of these panels is 20 years. Given

[23] Staff/700, Kaufman/31, lines 5-18.
[24] Staff/700, Kaufman/31, lines 6-8.

that this furniture was purchased in the mid-1990s, the Company has utilized these portions of its furniture fleet for their full recommended life.

Avista believes a cursory examination of photographs, or general impressions based on a site visit where "furniture was in need of cleaning, but did not appear to be in disrepair,"[25] is not evidence to warrant a disallowance. Mr. Kaufman's adjustment should be rejected.

C. ER 7005 / 7006 – Capital Tools and Stores Equipment

Q. Does Avista agree with Staff's proposal regarding ERs 7005 and 7006, Capital Tools and Stores Equipment?

A. No. ERs 7005 and 7006 involve the Company's "Capital Tools and Stores". Mr. Kaufman proposes a disallowance of $1.55 million ($134,000 Oregon-allocated) based on his assessment that one alternative option included in the business case appeared less expensive than the investment option selected by the Company. The business case[26] includes two alternatives (in addition to the option chosen). Both of those alternatives, in concert, would be required to meet the project requirements, and it is only in evaluating those two together, compared to the option chosen by the Company, that one would see Avista chose the prudent option. The first alternative is primarily associated with the cost of repairing capital tools,[27] while the second alternative is primarily associated with the use of rental equipment (e.g., lifts and other power operated equipment). In the business case, Avista explains that, "Increased labor and shipping costs to distribute rental equipment, specialized rental equipment is in high demand and hard to source.

[25] Staff/700, Kaufman/31, ln. 11.
[26] Avista/602, Machado/Page 111.
[27] The description of the alternative includes the following: "*Increased labor and shipping cost to repair tools and/or send to outside repair shops – (90% capital [of] capital equipment cannot be repaired in-house). Lack of equipment availability will delay crew response time and lower productivity*."

Major equipment is not always available for rental and must be purchased."[28] Finally, there are other considerations that Avista takes into account, such as the potential lack of training or operational efficiency when using tools different than what our employees are accustomed to using. When both alternatives are considered together, the new investment decision is the prudent decision.

D. <u>ER 7144 – Ergonomic Equipment</u>

Q. Does Avista agree with Staff's proposal regarding ER 7144, Ergonomic Equipment?

A. No. ER 7144 is related to the purchase of ergonomic workstation equipment to mitigate potential workplace injuries (i.e., lower back pain, carpal tunnel syndrome, etc.). Mr. Kaufman proposes a reduction of $195,000 to system A&G operating expenses ($17,000 Oregon-allocated) on the basis of the expected reduction in medical expenses associated with this investment. While the Company agrees that this investment is expected to reduce medical expenses going forward, the Company's medical premiums[29] are set annually by an independent consultant, as described by Company witness Ms. Smith.[30] In fact, Ms. Smith provides a detailed explanation of how medical expenses are determined.[31] Because medical premiums are based upon an actuarial calculation, the benefits associated with the implementation of the Company's ergonomics program are embedded in actuarial estimates, i.e., there is an expectation that Avista will implement ergonomic programs, as well as other employee wellness programs, comparable to those of other

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[28] Avista/602, Machado/Page 111.
[29] Total medical costs including both the Company and employee contributions (Avista/500, Smith/Page 25, footnote 7).
[30] Avista/500, Smith/Page 25-26.
[31] Avista/500, Smith/Pages 25-32

organizations. An adjustment outside of the context of the medical expense adjustment is not appropriate. Therefore, Avista disagrees with this adjustment proposed by Staff.

Q. Does this conclude your Reply testimony?

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

HEATHER ROSENTRATER
Exhibit No. 1501

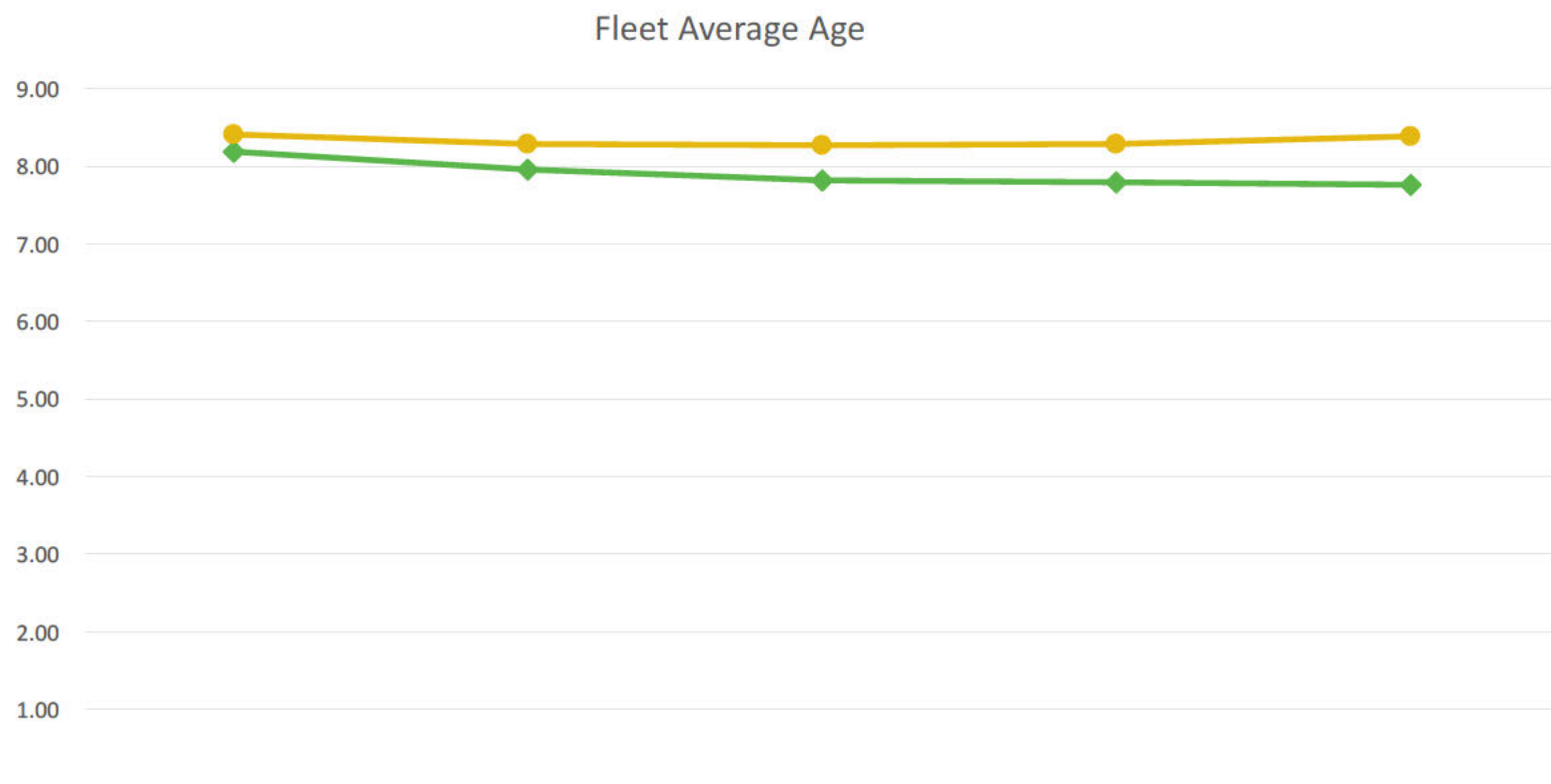
Utilimarc Report

Projections

The following graphs compare the effect of each replacement scenario on metrics including vehicle average age, fleet maintenance cost, capital investment and more. Each graph shows the effect of each replacement scenario over the next five years. The green line represents the replacement scenario based on Utilimarc's recommended lifecycles (Utilimarc). The blue line represents the replacement scenario based on Avista's chosen lifecycles.

Unit Average Age

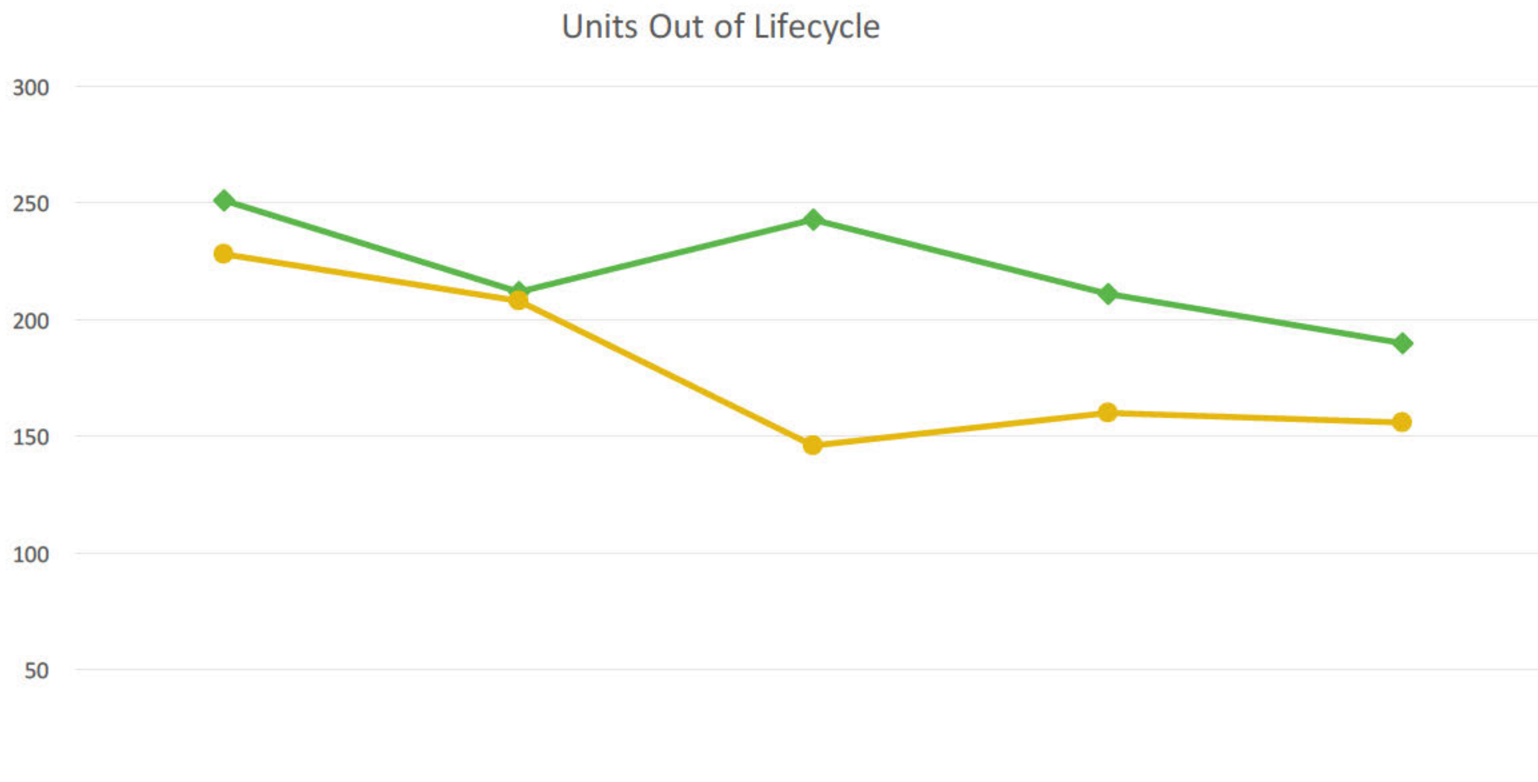
This graph shows average unit age of fleet over the next five years. Avista can expect a slight decrease in average age under the Avista scenario, while average age remains relatively constant under the Utilimarc scenario.



	2016	2017	2018	2019	2020
Avista	8.18	7.96	7.82	7.79	7.76
Utilimarc	8.41	8.29	8.27	8.28	8.38

Units Out of Lifecycle

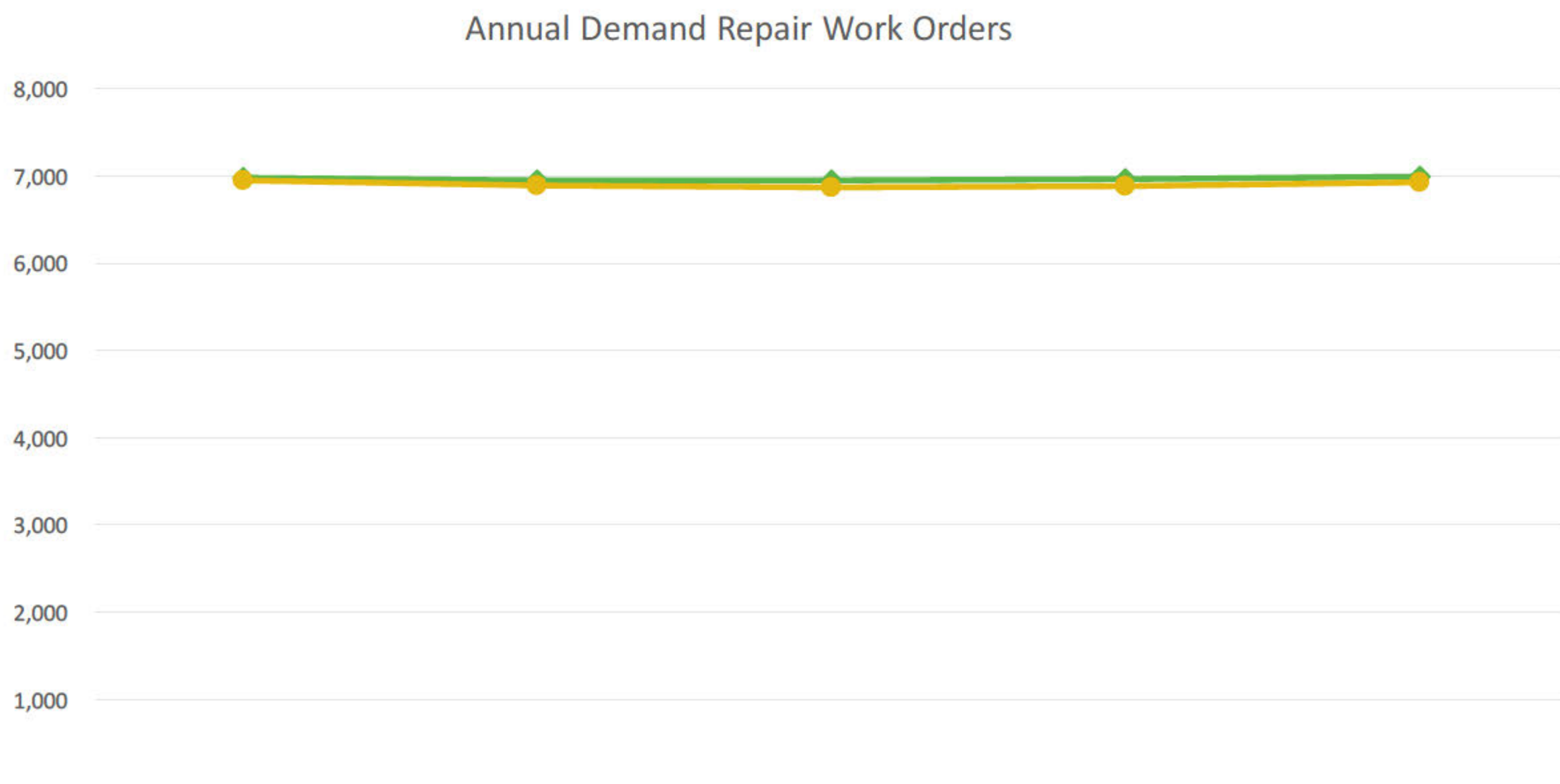
This graphs shows the number of units outside of the stated lifecycle for each scenario. The target value for this metric is close to zero. This graph demonstrates how quickly Avista will "catch-up" on replacement based on each scenario. Avista achieves this goal fastest when following Utilimarc's recommendations.



	2016	2017	2018	2019	2020
Avista	251	212	243	211	190
Utilimarc	228	208	146	160	156

Annual Unscheduled Work Order

This graph shows the number of demand repair or unscheduled work orders required to support fleet under each scenario. Decreases in labor demand often translate into reduced downtime and reduced labor cost.

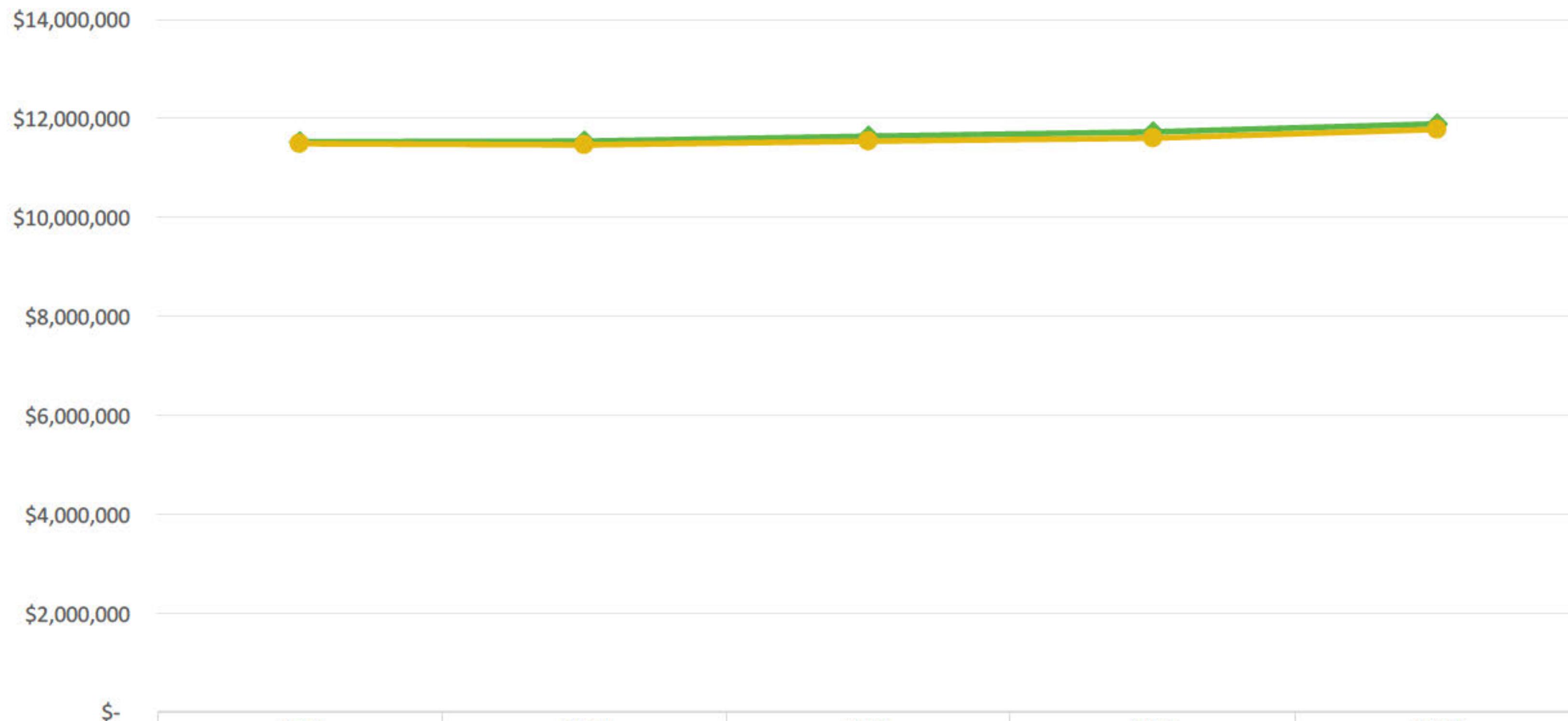


	2016	2017	2018	2019	2020
Avista	6,975	6,947	6,951	6,962	6,995
Utilimarc	6,950	6,890	6,869	6,882	6,926

Annual Total Cost

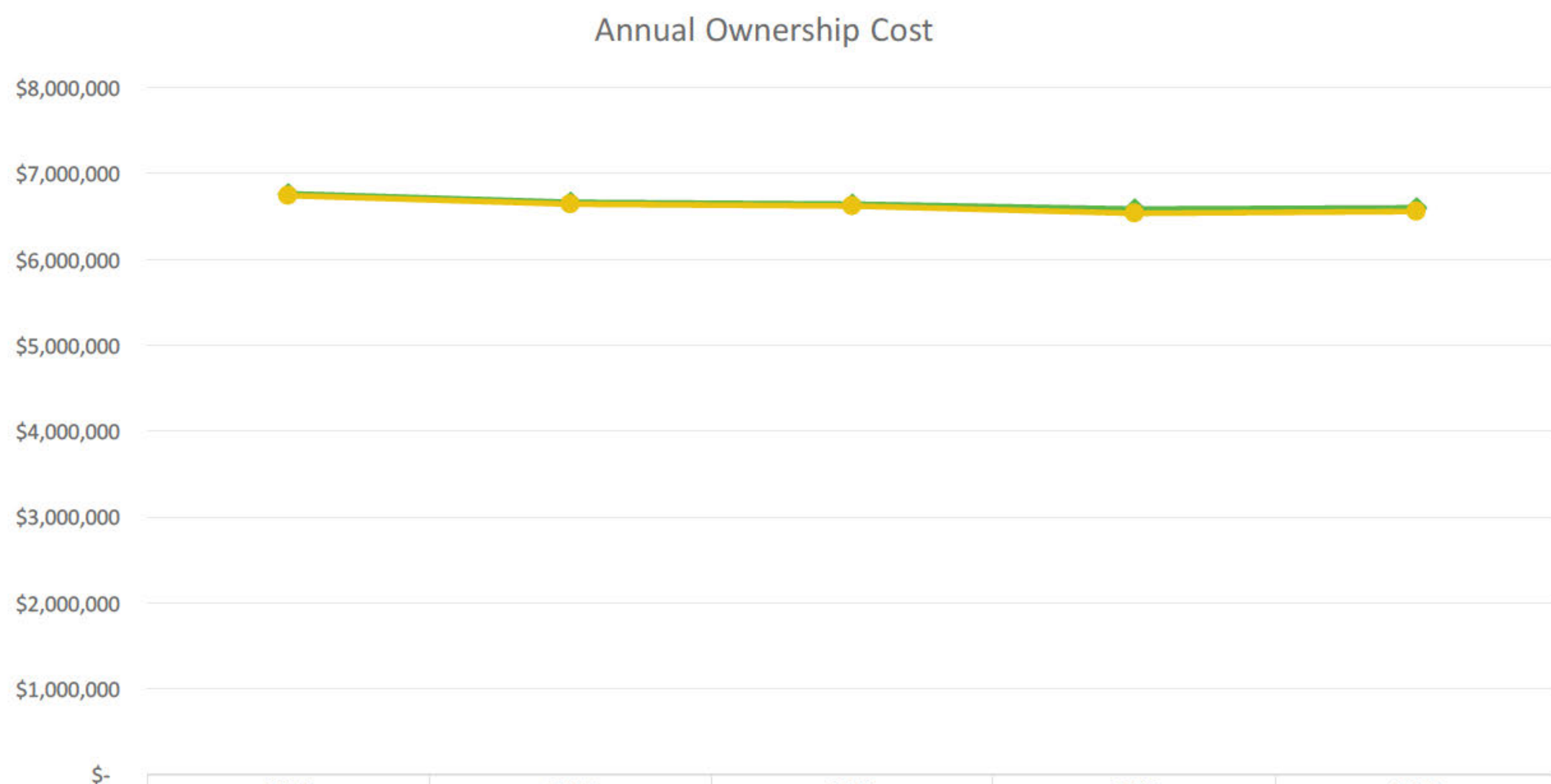
Annual total cost remains relatively similar under both replacement scenarios.

Annual Ownership & Maintenance Cost



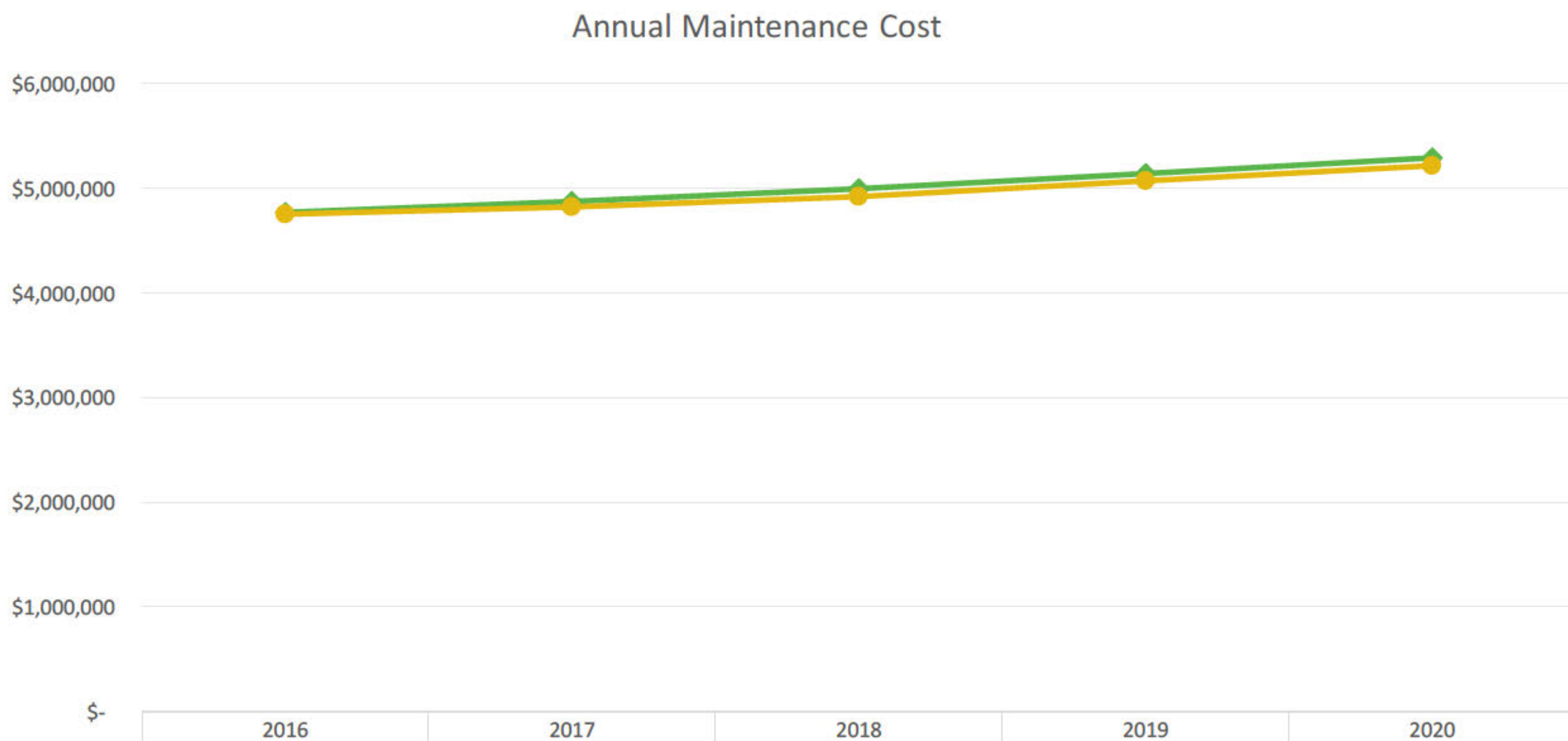
	2016	2017	2018	2019	2020
Avista	$11,531,782	$11,540,551	$11,635,081	$11,720,201	$11,889,921
Utilimarc	$11,490,883	$11,461,775	$11,540,205	$11,605,884	$11,771,189

Annual Ownership Cost



	2016	2017	2018	2019	2020
Avista	$6,766,418	$6,668,289	$6,643,738	$6,585,232	$6,603,927
Utilimarc	$6,743,293	$6,645,635	$6,625,402	$6,539,567	$6,557,317

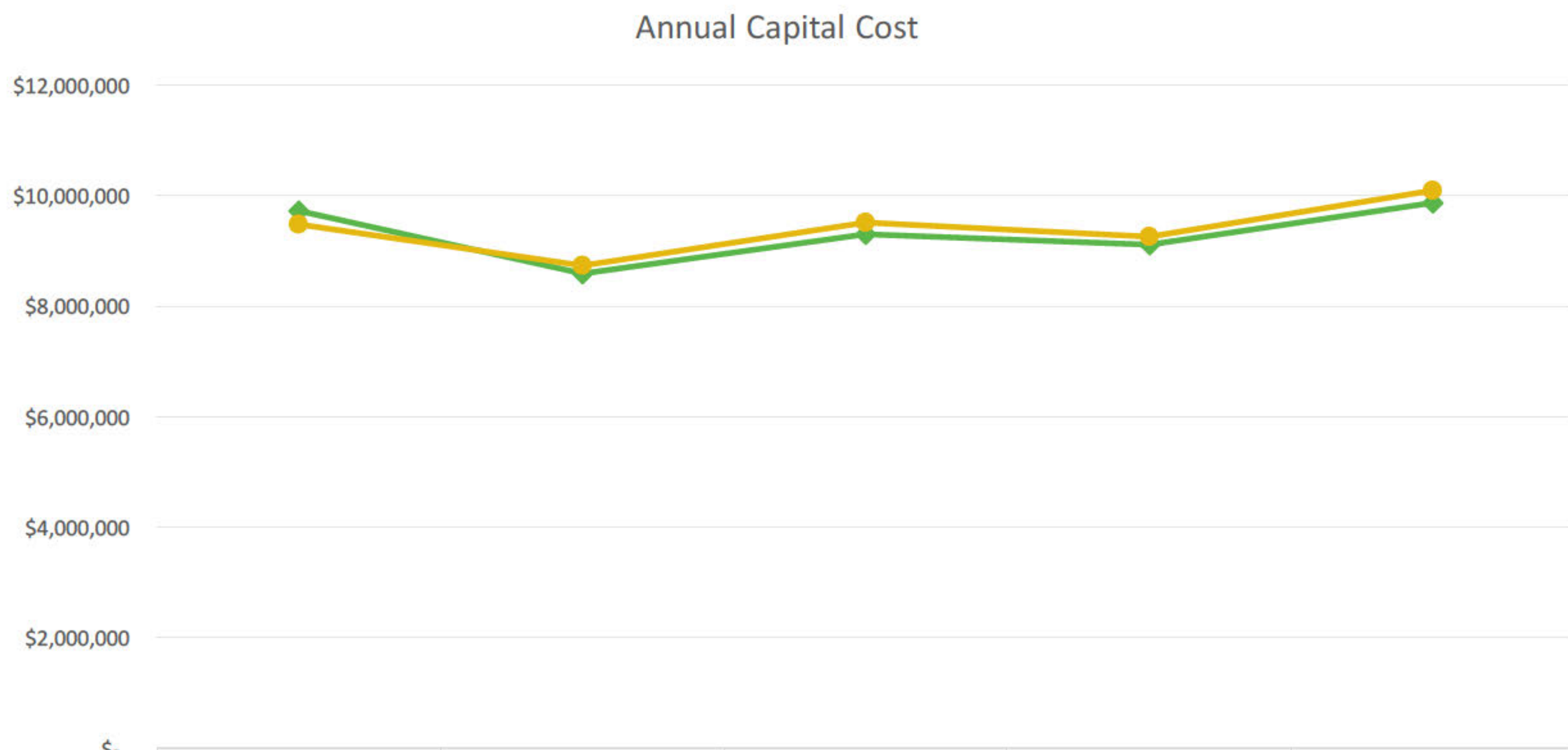
Annual Maintenance Cost



	2016	2017	2018	2019	2020
Avista	$4,765,364	$4,872,263	$4,991,343	$5,134,969	$5,285,994
Utilimarc	$4,747,590	$4,816,140	$4,914,804	$5,066,316	$5,213,871

Annual Capital Investment

This graph shows the amount spent on replacement each year under each scenario.



	2016	2017	2018	2019	2020
Avista	$9,715,138	$8,587,440	$9,299,938	$9,110,415	$9,866,304
Utilimarc	$9,478,564	$8,726,231	$9,505,018	$9,257,659	$10,083,874

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

HEATHER ROSENTRATER
Exhibit No. 1502

New Customer Cost to Serve Analysis

ER	BI_SPONSOR_ORGANIZATION	REVENUE_TYPE	PROJECT_NUMBER	PROJECT_DESC	ACTUAL	Mains	Services
						$1,772,220.76	**$2,864,752.81**
1001	A81	0-Residential	98401110	Gas New Mains - Medford	$943,383.57	$943,383.57	
			98401111	Gas New Res Serv-Medford	$1,790,545.36		$1,790,545.36
			98401130	Gas New Mains-Medford	($9,271.48)	($9,271.48)	
			98401131	Gas New Res Services-Medford	$1,548.16		$1,548.16
			98401132	Gas Meters/Regulators-Medford	$2,241.27		
			98501110	Gas New Mains - Grants Pass	$35,132.03	$35,132.03	
			98501111	Gas New Res Serv-Grants Pass	$48,100.65		$48,100.65
			98505043	Rogue Lea Estates Gas Main	$9,087.25	$9,087.25	
		0-Residential			**$2,820,766.81**		
		1-Non Residential	98401112	Gas Commercl Mains-984	$83,385.46		
			98401113	Gas New Com Servcs - Medford	$256,138.04		
			98405252	Blackwell Rd. Extension & Svcs	$259.94		
			98501113	Gas New Com Servcs-Grnts Pass	$6,414.14		
		1-Non Residential			**$346,197.58**		
		2-Development	98401115	Development Gas Rev-Medford	$168,543.49	$168,543.49	
		2-Development			**$168,543.49**		
			98505044	Swanson Lumber Ph 2	$70.06		
			98505046	New SSFT STA #8615	$25,365.77		
					$25,435.83		
	A81				**$3,360,943.71**		
	A82	0-Residential	98601110	Gas New Mains - Roseburg	$84,790.17	$84,790.17	
			98601111	Gas New Res Serv-Roseburg	$343,352.17		$343,352.17
			98601130	Gas New Mains-Roseburg	$111.13	$111.13	
			98601132	Gas Meters/Regulators-Roseburg	$395.17		
		0-Residential			**$428,648.64**		
		1-Non Residential	98601112	Gas Commercl Mains-986	$12,844.23		
			98601113	Gas New Com Servcs - Roseburg	$33,278.97		
			98601114	Gas New Ind Servcs - Roseburg	$513.73		
			98605095	Del Rio Asphalt-Service & MSA	$203.08		
		1-Non Residential			**$46,840.01**		
		2-Development	98601115	Development Gas Rev-Roseburg	$445.29	$445.29	
		2-Development			**$445.29**		
		4-Gas Availability	98605094	Rolling Hills Estates	$255,597.89	$255,597.89	
			98605104	Kooken Estates Gas Growth	$93,963.47	$93,963.47	
			98605109	Santa Maria Gas Growth Opp.	$751.01	$751.01	
		4-Gas Availability			**$350,312.37**		
			98605096	Roseburg ForestProd#4 MSA#2462	$519.87		
					$519.87		
	A82				**$826,766.18**		
	A83	0-Residential	98701110	Gas New Mains - Klamath Falls	$155,616.86	$155,616.86	
			98701111	Gas New Res Serv-Klamath Falls	$511,797.27		$511,797.27
		0-Residential			**$667,414.13**		
		1-Non Residential	98701112	Gas Commercl Mains-987	$5,072.12		
			98701113	Gas New Com Servcs-Klmth Flls	$18,765.66		
		1-Non Residential			**$23,837.78**		
		2-Development	98701115	Development Gas Rev-Klmth Flls	$350.80	$350.80	
		2-Development			**$350.80**		
		4-Gas Availability	98705080	Bonanza Oregon-Growth Project	$452,765.79		
		4-Gas Availability			**$452,765.79**		
	A83				**$1,144,368.50**		
	C83	0-Residential	98801110	Gas New Mains - LaGrande	$33,719.28	$33,719.28	
			98801111	Gas New Res Serv-LaGrande	$122,284.28		$122,284.28
			98801131	Gas New Res Services-LaGrande	$47,124.92		$47,124.92
		0-Residential			**$203,128.48**		
		1-Non Residential	98801112	Gas Commercl Mains-988	$30,123.24		
			98801113	Gas New Com Servcs - LaGrande	$35,723.50		
		1-Non Residential			**$65,846.74**		
	C83				**$268,975.22**		

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

HEATHER ROSENTRATER
Exhibit No. 1503

Data Request Response (CUB-011) – Aldyl-A Pipe Replacement

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	01/20/2016
CASE NO.:	UG 325	WITNESS:	Jennifer S. Smith
REQUESTER:	CUB	RESPONDER:	Jennifer S. Smith
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	CUB – 011	TELEPHONE:	(509) 495-2098
		EMAIL:	Jennifer.Smith@avistacorp.com

REQUEST:

Assuming that the recent Washington Commission Order 06 in consolidated docket UE-160228 and UG-160229 holds, are any of the investments in this case, affected, or also investments in the Washington case? If so, please explain the impact in this case.

RESPONSE:

The outcome of Commission Order 06 in consolidated docket UE-160228 and UG-160229, will have no impact on any of the investments in this case docket UG-325.

Avista's response to the Commission's order in its petition for reconsideration/rehearing points to evidence in the case that demonstrates, contrary to the Commission's findings, the following:

- Current retail rates are not sufficient for the 2017 rate period, and therefore a revenue increase is necessary. Commission Staff agrees that current rates are not sufficient.
- The costs associated with the growth in rate base and operating expenses are growing at a faster pace than retail sales, and therefore a revenue adjustment is necessary to cover this gap in the growth in costs and sales revenue. The revenue adjustment to close this gap has been referred to as an attrition adjustment. Commission Staff agrees that a revenue adjustment is necessary to close this gap.
- All of the capital projects and operating expenses included in the case by Avista are necessary in the time frame proposed in order for the Company to continue to provide safe, reliable service to customers. No party in the case identified a single capital project that should not be completed in the time frame proposed by Avista (other than general opposition to Advanced Metering Infrastructure).
- Avista presented modified test year studies and analyses in the case, consistent with the prior practice of the Commission, and the Commission Staff acknowledged that Avista provided such studies.
- Avista earned close to its allowed return on equity (ROE) during each of the years 2013 through 2015, and into 2016. This opportunity was possible only with the revenue increases related to an attrition adjustment, and an attrition adjustment continues to be necessary for 2017.

The Commission Staff itself supported electric and natural gas revenue increases of $25.6 million and $2.1 million, respectively. Commissioner Jones dissented and did not support the decision. In his dissent, Commissioner Jones supported an electric revenue increase of $26 million, and a natural gas increase of $2.4 million.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

REPLY TESTIMONY OF JAMES M. KENSOK
REPRESENTING AVISTA CORPORATION

Information Technology Capital Spend

I. INTRODUCTION

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

A. My name is James M. Kensok. I am employed by Avista Corporation as the Vice-President and Chief Information and Security Officer. My business address is 1411 E. Mission Avenue, Spokane, Washington.

Q. Mr. Kensok, please provide information pertaining to your educational background and professional experience?

A. I am a graduate of Eastern Washington University with a Bachelor of Arts Degree in Business Administration, majoring in Management Information Systems and from Washington State University with an Executive MBA. I have experience through direct application and management of Information Services over the course of my 34-year information technology career. I joined the Company in June of 1996. Over the past 20 plus years, I have spent approximately one year in Avista's Internal Audit Department as an Information Systems Auditor with involvement in performing internal information systems compliance and technology audits. I have been in the Information Services Department for approximately 19 years in a variety of management roles directing and leading information systems, infrastructure technology and security strategy, system delivery and operations, complex communication networks, cyber security, applications development, outsourcing agreements, contract negotiations, technical support, cost management, and data management. I was appointed Vice-President and CIO in January of 2007 and Chief Security Officer in January of 2013.

Q. Please provide an overview of your reply testimony.

A. I respond to Staff's proposed adjustments and disallowances associated with the Company's information technology capital investment.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit Nos. 1601, 1602, 1603, and 1604. A brief description of each exhibit is provided below:

- Exhibit No. 1601 is Avista's response to Staff data request 190, which discusses the Company's Technology Refresh capital investment program.

- Exhibit No. 1602 is Avista's response to CUB data request 114, which discusses the Company's Technology Expansion capital investment program.

- Exhibit No. 1603 is Avista's response to Staff data request 192, which addresses Avista's Enterprise Business Continuity capital investment program.

- Exhibit No. 1604 is Avista's response to Staff data request 181 Supplemental – Attachment C, which provides project documentation associated with the Company's Next Generation Radio System project.

II. INFORMATION TECHNOLOGY CAPITAL INVESTMENT APPROACH

Q. Commission Staff and CUB witnesses make a number of disallowance recommendations for certain specific information technology projects. Do these recommendations appear to be based on a thorough understanding of the facts and circumstances driving Avista's decisions to make these investments?

A. No. In their testimony, both Staff and CUB make recommendations to the Commission to disallow recovery of capital expenditures based on measures that are unrelated to the ultimate criteria that should be used in the determination of the whether the investment is reasonable and appropriate. For example, some of the implied measures in Staff's and CUB's testimony are as follows:

- Does Avista's investment result in a positive net present value?[1]
- How does Avista's investment this year compare with previous cases?[2]
- How did Avista's actual cost for each project compare with what it originally estimated?[3]
- Did the timing of the projects change from prior plans?[4]

It appears that Staff and CUB do not appreciate the complexity, interconnectedness, and extent of the technology necessary to operate the utility business, both in terms of compliance requirements as well as meeting the needs and expectations of the many stakeholders of the utility. Before addressing the specifics of what Staff and CUB propose, it is important to understand the general framework for the Company's investments in information technology.

[1] Staff/700, Kaufman/Page 21
[2] CUB/100, McGovern/Pages 37-39
[3] For example, see CUB/100, McGovern/Page 55
[4] Id. Page 57

Q. What is Avista's approach to making investments in information technology?

A. Avista identifies and invests in foundational technologies and an experienced workforce that support an evolving digital business model aligned with industry best practices and customer needs (e.g., safe and reliable, real-time customer engagement and cyber security). The Company's overall information technology investment strategy is generally driven by the need for cyber security systems to protect our customer data and critical utility operations, legal and regulatory requirements, cost effective replacement of assets, managing technology obsolescence, more efficient and cost effective work processes, training, and a host of other examples. The core technology investments focus on the following five foundational areas:

A. Networks

B. Data and Analytics

C. Mobility

D. Security, Emergency Conditions and Business Continuity

E. Technology Refresh and Expansion (includes: managing technology obsolescence)

Making investments in these five areas in the utility industry is not new — networks, data and analytics, mobile transactions, security and technology refresh/expansion have been around for decades — but these areas are experiencing significant change as a result of new enabling technologies, increases in volume and velocity of data and the sophistication of cyber-attacks. Therefore, Avista's customers across its territory benefit by having: 1) all available crews and dispatchers hear and respond to emergencies on a single radio frequency; 2) real-time integrated data and analytics to improve customer satisfaction and employee productivity; 3) the opportunity for customers to interact real-time with Avista through varying mobile devices on the WEB; and

4) the ability to defend against increasingly sophisticated nation-state cyber threats to the utility industry.

Q. Please provide an overview of the five foundational areas of Avista's technology investment, and a few examples of projects that fall under these areas?

A. A brief summary, with examples, is provided below:

A. <u>Networks</u>

An example of a foundational network investment is the land mobile radio communications infrastructure. In making the investment decision for the land mobile radio communications infrastructure, Avista considered the following external and internal factors:

<u>External Factors:</u>

1. Regulatory requirements
2. A single service providers' (i.e., Verizon) ability to support connected, offline or mixed-mode dedicated usage
3. Governance regarding security and privacy
4. Timeliness of spectrum license requirements and weather impact on installation windows
5. Availability of radio tower sites
6. Cost to lease vs. own spectrum

<u>Internal Factors:</u>

1. Improved efficiency through a centralized dispatching business model
2. Improved customer response time and employee safety
3. The mix of communication systems (private and public, radio, cellular and satellite)
4. Investment protection from future narrow band mandates
5. Inter-operability with existing communication systems

6. Scalability
7. Life-cycle management and cost

B. <u>Data Analytics</u>

Through research with other utilities (e.g., CenterPoint Energy with 3.2 million natural gas customers) Avista is learning about foundational data and analytics technology platforms and business use cases that support customer-focused programs. As such, Avista is focusing on additional uses of data and analytics to help advance workforce efficiency, as well as existing and new customer programs.

New opportunities to work with Avista customers can be enhanced through the investment in a meter data management application. The meter data management application provides a single consolidated data repository for all meter data. With a centralized meter data repository, data quality is improved by having a single source of data for each business use (i.e. billing, stopped meters, etc.).

C. <u>Mobility</u>

Improved technology in areas such as mobility, analytics and cloud technology is changing what it means to digitally enable a utility workforce and its customers. Mobile technology has been one of the fastest-growing technology areas in the past five to 10 years, mainly as a result of the rapid growth in consumer technology and applications. New form factors — such as tablets and smart phones — hold significant promise for use in the utility industry. These new devices are a key component of future mobile workforce enablement at Avista. For example, Mobile system design tools provide improved customer response time and quality for facility and project design requests for natural gas and electric service.

The mobile customer interaction channel enables Avista to deliver information and services to customers using smartphones or tablet computers. Communications and services delivered via short message service (SMS) or text messaging are included. With responsive design (allows desktop webpages to be viewed in response to the size of the screen or web browser the customer is viewing with), Avista can interact with a broader mobile customer base (i.e., customers who use smartphones, tablets, desktops, etc.).

A mobile-friendly responsive design website is a logical starting point for Avista. The website will be connected to relevant systems of record, such as the customer information system for bill presentment and payment, outage management system for outage reporting and the meter data management system for consumption analytics.

The SMS channel also remains important because it provides immediate access to Avista services without requiring an application download for those customers whose mobile device is not application capable. SMS can also play an important role in bill presentment and payment, and in proactive alert messaging as part of demand-response or energy-efficiency programs.

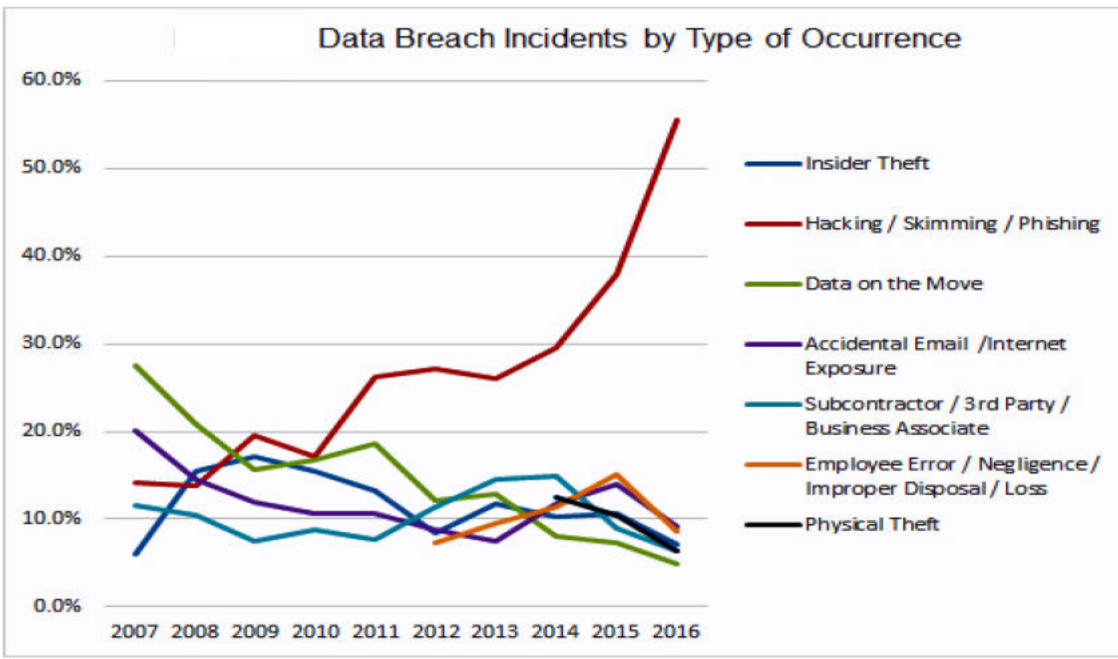
Mobile customer interaction channels help improve customer-facing functions and outbound notification. Mobile access can reduce call center volumes resulting in reduced hold times and enhance customer satisfaction. It can also increase adoption of electronic billing and payment transactions resulting in lower processing costs.

D. Security, Emergency Conditions, and Business Continuity

Security in the electric and natural gas utility industry is critical to the protection of the United States energy infrastructure and Avista’s customer, operating, and financial data. Investments are necessary to prepare for the appropriate response and recovery of utility assets when there is a security incident, data breach, or when a disaster event takes place. Avista’s security program focuses on protecting its physical and cyber assets, as well as against a data breach.

The number of U.S. data breaches tracked in 2016 hit an all-time record high of 1,093 according to a new report released by the Identity Theft Resource Center (ITRC) and CyberScout (formerly IDT911). This represents a substantial hike of 40 percent over the near record high of 780 reported in 2015. Avista's security program is critical to defend against a data breach. Illustration No. 01 is a graph from ITRC showing the steep increase in data breach incidents through 2016.

Illustration No. 01:



Avista is a member of the AGA/EEI Cyber security task force that follows best security practices for protecting the utility industry using the NIST (National Institute of Standards and Technology) framework. Avista is an active participant in industry security groups, such as the DNG-ISAC that serves natural gas utility (distribution) companies, the E-ISAC that serves electric utilities, the Cyber Mutual Assistance (serves gas and electric utilities), and the use of Transportation Security Administration's (TSA) Pipeline Security Guidelines, as well as others.

In addition to being an active participant in protecting U.S. critical infrastructure and following best practices in security, Avista appropriately invests in its business continuity program. The program is critical when following the industry standard NIST framework, which focuses on the following: Identify, Protect, Detect, Respond, and Recover, as well as applying the Federal Emergency Management Administration (FEMA) Incident Command System (ICS) for planning, response and recovery efforts.

E. <u>Technology Refresh and Expansion</u>

With a technology refresh and expansion program, Avista can evaluate the direction of its information technology ("IT") portfolio and weigh the costs of trying something new or maintaining the status quo. The program considers: Is the current environment something Avista wants to move forward with? If so, for how long? If not, what other options are available that would better suit the needs of Avista and its customers?

Q. What are the primary considerations in Avista's decisions related to the technology refresh and expansion programs?

A. These considerations are as follows:

1. Why do we need a technology refresh and expansion program?

Technology refresh is a necessary process for Avista to effectively manage its technology portfolio. Some IT components last longer than others (servers tend to have a shorter lifespan while network switch lifespans are a bit longer, for example), but at some point IT components naturally become outdated or reach technology obsolescence. In fact, according to 451 Research, more than 32 percent of enterprises were planning a major server and storage refresh in 2016. Outdated or deteriorating technology can negatively affect not only IT, but can have an adverse impact on Avista and its customers, such as increased failure rates, inefficient work practice, employee/public safety incidents due to system failures, and reduced customer satisfaction, among other impacts.

2. What are the warning signs that a technology refresh is necessary?

A common indicator that a technology refresh is needed is a noticeable decrease in system performance and stability. This can lead to frustrated employees and customers, and it becomes more obvious that the current solution is simply not meeting the needs of the business. Most often, however, warning signs that a technology refresh is needed are hard to come by. That is part of what makes outdated technology so dangerous: it can hurt the business with no warning at all. Avista has to take proactive action to get out in front of these hidden problems before it is too late, (e.g. it takes more than one year to upgrade the customer information system).

3. Can consolidating refresh and expansion cycles save time?

There is no defined amount of time a refresh cycle should or will last, as it depends on the details of the technology and business needs. Rate of expansion, performance requirements, and physical limitations of the technology can all influence the upgrade or expansion decision. With that said, traditional technology refreshes can be very time-consuming because there are so many vendors to deal with, new technology for the team to be trained on, and many components that must be synchronized with one another (e.g., Internet Explorer and business applications). Refresh and expansion cycles can seem like a constant process because IT components don't last the same amount of time – so servers might need to be refreshed one year, then the next year storage may need to be upgraded, and then network switching needs to be updated, and before you know it the servers need to be refreshed again.

4. How can Avista cut costs during a refresh and/or expansion initiative?

The cost of a refresh is dependent on several factors. During the time spent evaluating, vetting, and negotiating with vendors, we work with Supply Chain to identify the best products and service pricing. Avista has to take into consideration the IT component(s) being refreshed and the new replacement. For multiple components, multiple vendors and subject matter expert teams will often be needed. However, integrated solutions offer a single-vendor solution that may help cut costs by integrating a portion, or in some cases, components of a traditional IT application portfolio into a platform (e.g., CC&B and Meter Data Management share a common Oracle platform).

III. AVISTA'S RESPONSE TO STAFF/INTERVENER ADJUSTMENTS TO SPECIFIC INFORMATION TECHNOLOGY CAPITAL INVESTMENT

Q. Please summarize the adjustments proposed by other parties in this case, related to information technology capital investment, for which Avista does not agree.

A. Table No. 1, below, includes the information technology related capital investment proposals with which Avista does not agree. I will respond to each of these proposed adjustments following the table.

Table No. 1:

STAFF AND INTERVENOR ADJUSTMENTS NOT ACCEPTED BY AVISTA

		OPUC Staff Rev. Req. Incr / (Dec)	OPUC Staff Rate Base	CUB (1) Rate Base	Avista Witness
Contested Adjustments					
S-21 / CUB	ER 5005 - Information Technology Refresh Program	(54)	(557)	(902)	Kensok
S-21 / CUB	ER 5006 - Information Technology Expansion Program	(81)	(860)	(368)	Kensok
S-21 / CUB	ER 5010 - Enterprise Business Continuity	(3)	(34)	(35)	Kensok
S-21 / CUB	ER 5106 - Next Generation Radio System	(25)	(254)	(783)	Kensok
S-21 / CUB	ER 5144 - Mobility in the Field	(6)	(60)	(54)	Kensok
S-21 / CUB	ER 5147 - Avista Facilities Management COTS Migration	(208)	-	(228)	Kensok
S-21 / CUB	ER 2586 - Meter Data Management	88	(2,315)	(2,315)	Kensok
Subtotal - S-21		(289)	(4,080)	(4,685)	
Total of Staff and Intervenor Adjustments Not Accepted by Avista		(289)	(4,080)	(4,685)	

(1) CUB did not propose revenue requirement adjustments associated with its proposed rate base adjustments. Therefore, only rate base adjustments have been included in this table.

A. ER 5005 - Technology Refresh Program

Q. Does the Company agree with Staff's recommendation of a permanent rate base disallowance of $557,000 (Oregon-allocated) associated with the Company's Information Technology Refresh Program (ER 5005) on grounds of prudence?[5]

A. No, Avista does not agree with Staff's recommendation. In suggesting an adjustment associated with capital investment associated with this program, Mr. Kaufman derives a proposed disallowance based on his determination of what level of investment would result in a net present value of investment of zero dollars. The determination of a disallowance in this manner does not reflect the other important factors that drive the need for a technology refresh program.

Q. What other factors should be considered, with regard to a technology refresh program?

A. As mentioned earlier in my testimony, one of the foundational areas of Avista's core technology investment approach is the Technology Refresh and Expansion area. As discussed in the Company's response to Staff data request 190, included as Exhibit 1601, Avista's Technology Refresh Business Case supports technology replacement across six technology domains: 1) Distributed Systems, 2) Central Systems, 3) Communication Systems, 4) Network Systems, 5) Environmental Systems, and 6) Business Applications. Each technology domain is governed by a Program Steering Committee that guides annual project priority in response to the Company's overall approach to technology and technology roadmaps, while balancing the risk of reliability and functionality. The Technology Refresh Business Case refreshes existing technology in alignment with roadmaps for application and technology lifecycles.

[5] See Staff/700, Kaufman/Page 20 through Page 21, line 10.

At the most elementary level, Avista's technology refresh program is necessary to allow Avista to effectively manage its technology portfolio, given that information technology ("IT") assets are foundational in the provision of utility service in the 21st century, coupled with the fact that IT components naturally become outdated or reach technological obsolescence over a period that is much shorter than the life of natural gas pipe in the ground. As technology products reach manufacturer-planned or real obsolescence, vendor support for these assets is reduced, or ceases altogether. As vendor support ends, the risk associated with Avista's business systems that rely upon these technology products increases and the value provided by these business systems is jeopardized. These factors present a risk to Avista in the form of increased failure rates, inefficient work practice, employee/public safety incidents due to system failures, and reduced customer satisfaction, among other areas of risk.

Q. Mr. Kensok, you mentioned that the Technology Refresh Program refreshes existing technology in alignment with roadmaps for applications and technology lifecycles; would you please explain this concept further?

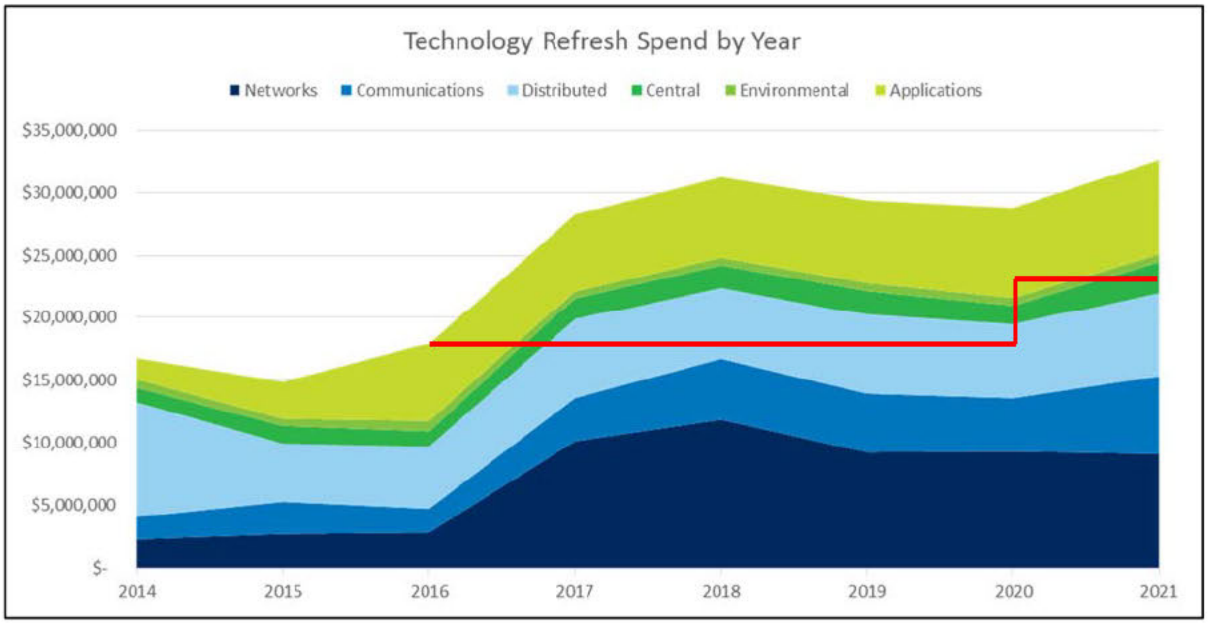
A. Yes. Information technology components have varying useful lives. For example, servers tend to have a shorter lifespans, while the lifespan of network switches tends to be longer. Additionally, software vendors regularly update their products to provide improved functionality, maintain and improve security, and implement bug fixes. Understanding the costs associated with refreshing technology, it is generally Avista's practice to replace technology within an acceptable failure tolerance outside of the vendor recommended lifecycles. For example, Avista completed its upgrade to Microsoft Office 2013 in 2015 and 2016. Prior to this upgrade, the Company had been using Microsoft Office 2007.[6] By prudently managing its upgrade cycles and using Microsoft Office 2007 for an extended period, the Company was able to avoid the intermediate upgrade to Microsoft Office 2010.

With that said, approximately 25% of the Company's asset base of more than 10,000 units recorded in the technology asset management system have exceeded the manufacturer suggested lifecycle. As a result, the demand for technology refresh investment has continued to grow over time (a natural outcome of the growth in the installed base of information technology assets as the modern utility continues to rely more and more on enabling technologies).

Illustration No. 1, below, shows the level of demand for capital investment within the Technology Refresh Business Case, along with the level of capital investment approved by the Capital Planning Group (approximately $18 million from 2016 through 2020, and $23 million in 2021, as indicated by the red line). This illustrates the work the Company is doing to limit the amount of capital investment, while remaining attentive to the risk associated with not making timely investments to refresh its technology assets.

[6] Microsoft has indicated Extended Support for Microsoft Office 2007 will end April 11, 2017.

Illustration No. 1



B. **ER 5006 - Technology Expansion Program**

Q. With regard to ER 5006, the Company's Technology Expansion Program, does Avista agree with Mr. Kaufman's proposed disallowance of $1.01 million (Oregon-allocated)?[7]

A. No. Mr. Kaufman bases his proposed disallowance associated with this program on three factors: (1) that the approved funding level was 93 percent higher than the requested funding level and the increase was not explained, (2) that certain project charters did not appear to support Oregon operations, and (3) that the business risk analysis is focused on electric service related risks.

First, the Company disagrees with the proposal of a disallowance based on summary level observations, rather than project specific considerations, as discussed by Company witness Mr.

[7] See Staff/700, Kaufman/Page 21, line 4 through Page 22, line 10.

Norwood.[8] Second, the Company's response to CUB data request 114, which has been included as Exhibit No. 1602, further explains the growth in investment associated with this program.

Q. Please explain the growth in investment associated with this program.

A. As described in Exhibit No. 1602, the growth in investment in recent years has primarily been driven by Applications and Networks. This program addresses many types of application investment projects, including projects that increase end user counts of existing COTS[9] applications, functionality enhancements of existing COTS applications, functionality enhancements of custom applications, and investments in new COTS applications. Examples of application enhancement during the referenced period of time include: Customer Care and Billing (CC&B) and Work and Asset Management (Maximo) systems, Energy Settlements & Risk Management (Nucleus) system, Geographical Information System (GIS), Oracle Financials & Power Plant System, and other enhancements and license expansion. During this time frame, the technology planning group was not able to work within the budget constraints set by the Capital Planning Group (CPG), which resulted in incremental requests throughout the year that are not reflected in the business case document, but are captured as revisions to the allocation in the monthly CPG minutes.

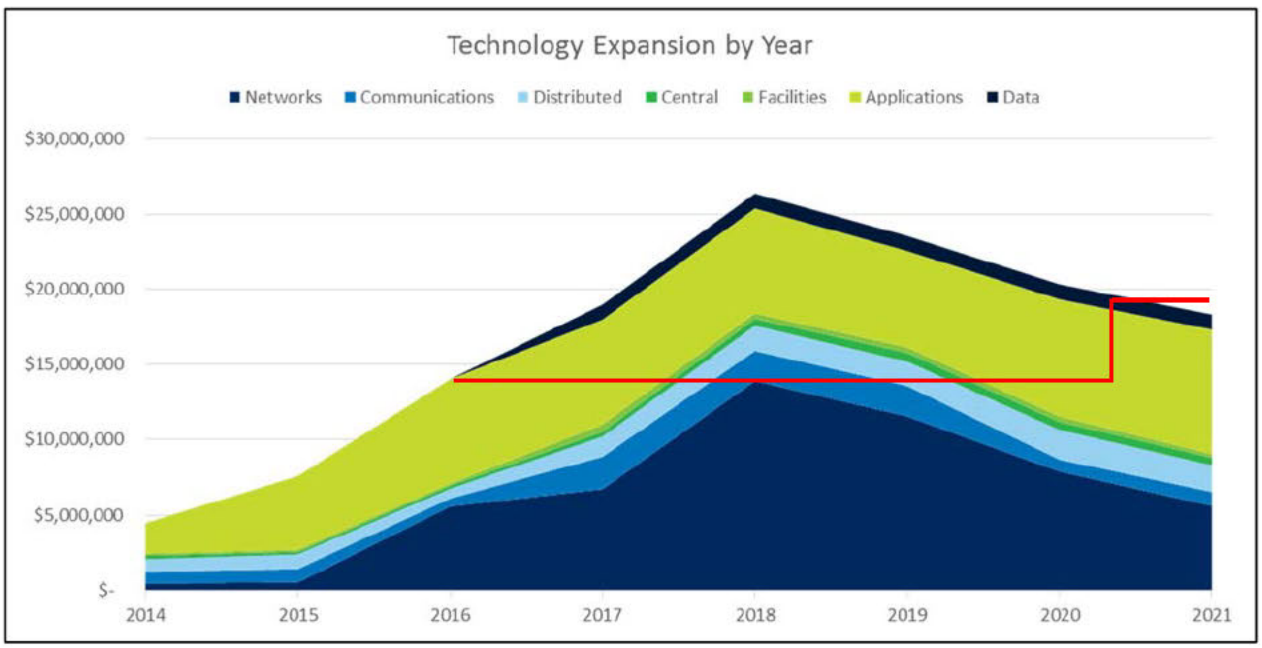
Additionally, this program addresses many types of network investment projects, including projects that expand the Company's network infrastructure (e.g., in offices, substations, plants, meters, and data centers, etc.). Examples of investment under this program include hardware, software, fiber optic products, and services for inside and outside construction. The network sub-program within this Business Case is experiencing growth within the data center, among other

[8] Avista/1000, Norwood/Pages 12-13.
[9] Commercial Off-the-Shelf applications.

areas. Primary drivers within the data center have been increasing numbers of applications, increasing security controls, and an increasing need for enhanced network management systems. Data center operations support the Company's business applications and are beneficial to all jurisdictions, and to all customers.

Illustration No. 2, below, shows the level of demand for capital investment within the Technology Expansion Business Case, along with the level of capital investment approved by the Capital Planning Group ($14.6 million in 2016, $14 million from 2017 through 2020, and $19 million in 2021, as indicated by the red line). This illustrates the work the Company is doing to limit the amount of capital investment, while remaining attentive to making timely investments to enable or enhance business process automation.

<u>Illustration No. 2:</u>



Q. Is Avista implementing or installing leading-edge or first-of-its-kind technology and applications?

A. No. The system and application investments under this program represent fundamental technology necessary to run our utility. As stated previously, investment in this program includes, for example, increasing the license count of existing applications, functionality enhancement for existing applications, and expansion of data center operational infrastructure.

Q. Would you please respond to Staff's and CUB's claims that investment in this program does not benefit Oregon customers?[10]

A. As described previously, examples of the investment included in this program include functionality enhancements to the Company's COTS systems. These systems are foundational components of Avista's ability to serve customers in all of its jurisdictions and for natural gas and electric operations. The Company disagrees with the position that this program does not provide benefits to Oregon customers.

With that said, after further review, the Company determined that certain projects should be removed, as they are not designed to provide benefits or service to Oregon customers. Mr. Machado identifies and quantifies the portion of capital investment that should be removed from this case.[11]

Q. What is your response to Mr. Kaufman's assertion that the business risk analysis included in the business case is primarily focused on electric service?[12]

A. Mr. Kaufman's focus on PCB spills as a disqualifying factor is misguided in two ways. First, the risk analysis section of the business case includes five risk assessment categories, only one of which, "Environmental," includes discussion of PCBs. This business case also includes

[10] See Staff/700, Kaufman/Page 21 and CUB/100, McGovern/Page 56.
[11] See Avista/1400, Machado/Page 10.
[12] See Staff/700, Kaufman/Page 22.

risk assessment for the "Legal, Regulatory, External Business Affairs" category in addition to the environmental category.

Second, within each risk assessment category, there are five levels of severity that can be selected, with an example included for each. Simply because the example listed for a given level of environmental risk includes discussion of PCBs does not mean that the entire project's risk mitigation is electric in nature. Therefore, the Company disagrees with this position taken by Staff relative to the risk analysis included in this business case.

C. ER 5010 – Enterprise Business Continuity

Q. Turning, now, to Mr. Kaufman's proposed exclusion of all $388,000 ($34,000 Oregon-allocated) 2017 plant investment associated with the Company's Enterprise Business Continuity Program (ER 5010),[13] why does the Company disagree with this proposal?

A. The Company appreciates Mr. Kaufman's general recognition that there is a clear, ongoing need for capital investment with regard to emergency business continuity.[14] The Enterprise Business Continuity business case is a program to manage projects that address gaps in business continuity initiatives. A Business Impact Assessment (BIA) typically drives the need for improvement projects, however, some projects are funded based on quality issues with existing infrastructure identified following an annual recovery exercise or actual event. Projects within this business case may also address regulatory requirements.

The Company disagrees with Mr. Kaufman's conclusion that Avista appears to have complete back-up facilities and emergency plans in place at this time based upon his observations

[13] Staff/700, Kaufman/Page 22, line 11 through Page 23, line 4.
[14] Staff/700, Kaufman/Page 22, lines 17-19.

during Staff's on-site visit.[15] The Company's Enterprise Business Continuity Program is overseen by Avista's Senior Manager of Security Engineering and Operations, with whom Staff did not request to meet during its visit. Additionally, by their nature, assets supporting business continuity operations are not necessarily readily visible during a facility tour.

Furthermore, the Company's response to Staff data request 192, included as Exhibit No. 1603, includes discussion of investments included under this business case for 2017, including the enabling of a backup gas control center, network redundancy for gas telemetry, and supporting the Company's disaster recovery capabilities. Therefore, Staff's assertion that Avista was unable to provide a description of the projects included in 2017 is in error.[16] Staff's recommended adjustment should be rejected.

D. <u>ER 5106 – Next Generation Radio Systems</u>

Q. Does Avista agree with Staff's proposed disallowance of $2.9 million system ($254,000 Oregon-allocated) associated with the Company's investment in ER 5106 – Next Generation Radio System?[17]

A. No. The Next Generation Radio project involved the implementation of a Land Mobile Radio ("LMR") system. The LMR is a fully integrated Company-wide communication system for field operations. The application resides on server and storage systems located in the Spokane, Washington data center; Medford, Oregon service center; Coeur d'Alene, Idaho service center; and Pullman, Washington service center. Communication between Avista workers and the Spokane main office is across a converged network using a combination of carrier services, private

[15] See Staff/700, Kaufman/Page 22, line 19 through Page 23, line 1.
[16] See Staff/700, Kaufman/Page 22, lines 15-17.
[17] Staff/700, Kaufman/Page 24 through Page 25, line 7.

telecommunication systems, and private spectrum. The LMR system is configured according to a standard that optimizes worker training, training material, provisioning, operation and maintenance, and end user interface across all territories.

Q. How does the Company respond to Staff's claim that the need for this project was not driven by a need for land mobile radio, but by the expiration of a FCC spectrum lease?[18]

A. The project objective was to deploy a single LMR system to be used by all jurisdictions for productivity, safety, and customer benefits. An LMR system is considered the most critical communication tool for field operations, from both a productivity view point and for personal and public safety. The potential unreliability of cellular or land line communication systems during emergency conditions associated with a minor or major disaster in Oregon was a factor in our consideration for the Oregon deployment, however, it should not be considered the single or key driver of the investment.

One use case example for natural gas operations in Oregon is the enabling of concurrent communications from multiple field workers to Central Dispatch during "Code 9 – Blowing Gas" events. Prior to the deployment of the LMR system, staff would use consumer cellular telephones to communicate with each other and with Central Dispatch, calling individual telephones, leaving voice mails, waiting for return calls, and trying to communicate over saturated cellular carrier networks during emergency events. With the implementation of a LMR system, acknowledgement and response from staff in the field is concurrently heard by all crews in the area, while Central Dispatch facilitates the rapid response to the emergency event.

[18] See Staff/700, Kaufman/Page 24, lines 15-17.

Avista's Next Generation Radio project cost consists of 615 mobile radios, 62 contractor issued mobile radios, and 38 desktop radio consoles, and communication infrastructure equipment on mountaintops and at office locations deployed in Oregon, Washington, Idaho, and Montana locations using a LMR product from Tait Communications and a private Federal Communication Commission (FCC) licensed 220MHz network spectrum. The project objectives were to meet both the FCC mandate for narrow banding in Washington, Idaho, and Montana, as well as the replacement of obsolete technology systems. The project also had the objective to deploy a single LMR system to be used by all jurisdictions for productivity, safety, and customer benefits.

The order of completion for the project was prioritized to meet the FCC narrow banding mandate through implementation of the new LMR system in Washington, Idaho, and Montana, prior to the Oregon implementation. Additionally, the purchase of the 220MHz spectrum had an FCC construction deadline for Washington, Idaho, Montana, and Oregon that also influenced the schedule. The 220MHz spectrum had to be substantially in service by April 27, 2015. Implementation in Washington, Idaho, and Montana met the deadline. To align with the remaining Oregon construction schedule and season, an extension was filed with the FCC extending the date to December 31, 2015. On December 9, 2015, Avista filed a construction notification with the FCC demonstrating that it had met the requirements in the Oregon territory.

Q. How does Avista respond to Mr. Kaufman's assertions that Avista did not re-evaluate the validity of the project after the cost was revised to be higher than expected?[19]

A. Contrary to Mr. Kaufman's assertion, the Company did review the project throughout its duration. The Company provided documentation of the changes in project cost

[19] See Staff/700, Kaufman/25, lines 3-5.

estimates in Staff data request 181 Supplemental – Attachment C, which has been included herein as Exhibit No. 1604. The initial project estimate of $2.3 million was based on estimates at the outset of the project, with formal project planning to occur as the initial stage of the project.[20] The project planning phase began in March 2014. The planning phase included coverage analysis and design for base station location and site specific engineering designs for each of the five mountain top sites to provide LMR coverage to the Oregon service territories. In addition, communication and network engineering design were completed for each of the four Oregon service centers. The planning phase was completed March 2015 and produced the Project Management Plan (PMP).[21] The project cost estimate based on the PMP was $4.3 million and had a scheduled completion date of December 2015. The PMP execution phase began in March 2015. Between August 2015 and December of 2016, five change requests adjusting scope, schedule, and budget were submitted to the project Steering Committee.[22] All were evaluated by the Steering Committee and ultimately approved. The scheduled project completion changed to March 2017 and the project budget increased to $5.5 million. Again, Mr. Kaufman's assertions are incorrect. The Company has reiterated the need for this project in our Oregon service territory and corrected the belief that the Company did not evaluate the project as estimated costs changed. Staff's recommended adjustment should be rejected.

E. <u>ER 5144 – Mobility in the Field</u>

Q. Does the Company agree with Staff's proposed disallowance $692,000 ($60,000 Oregon-allocated) regarding Avista's Mobility in the Field business case (ER 5144)?[23]

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[20] See Exhibit No. 1604, pages 3-5.
[21] See Exhibit No. 1604, pages 11-22.
[22] See Exhibit No. 1604, pages 23-25, 26-30, 31-36, 37-41, and 42-45.
[23] Staff/700, Kaufman/Page 26, line 9 through Page 27, line 4.

A. No. The Company disagrees with the proposed disallowance and finds fault in the approach used to determine the prudence of the investment. Mr. Machado discusses the Company's disagreement with the sole reliance on a net present value calculation.[24] Mr. Kaufman's proposal excludes consideration of other important criteria that must be factored into the capital investment decision under this program. Some examples of the solutions that this investment has enabled include the gas availability application and the leak survey application. The Gas Availability for Customer Service Representatives application provides customer service representatives with quick electronic access to Avista's gas service areas to provide information to customers who are interested in requesting new gas service or other information about the location of gas service.

The Leak Survey application assists leak survey inspectors in the field by providing electronic maps that includes the locations of the statistical sample of locations to be surveyed, as well as the ability to electronically report the results of their survey work. In contrast, the preceding leak survey process utilized paper maps and required manually recording survey results following field work. The ability to electronically record work as it is completed in the field is another example of deployed technology reducing risk by providing more accurate tracking of work.

F. ER 5147 – Avista Facility Management COTS Migration

Q. With regard to ER 5147—Avista Facility Management COTS Migration, Staff recommends a reduction to general operating expense of $2.33 million system ($202,000 Oregon-allocated) on the basis of reflecting operating efficiencies. Does the Company agree with this proposed adjustment?[25]

[24] See Avista/1400, Machado.
[25] Staff/700, Kaufman/Page 27, line 7 through Page 28, line 4.

A. No. Mr. Kaufman points to the Avista Facility Management ("AFM") COTS Migration business case summary sheet[26] and asserts that the investment for both the Mobile Dispatch and Construction Design Tool is supported by improving operating efficiencies. In fact, the referenced business case summary sheet does not include any discussion of improving operating efficiencies. Rather, the business case is driven by the need to replace an aging internally developed application with a commercial off-the-shelf application. Additionally, the AFM system replacement is intended primarily to improve the customer experience.

Q. Would you elaborate on your statement that Avista Facility Management is an aging, internally developed application?

A. Yes. Information technology applications, such as AFM, have dramatically improved the efficiency and level of service quality we have been able to provide our customers over the past two decades. AFM was originally developed in the early 2000s and is considered a "legacy" system because it relies on key technologies that generally are no longer manufactured, commercially available, or supported. Like the systems implemented by many utilities of this era, our software applications were designed and developed by Avista staff, and are often referred to as "homegrown." The decisions of companies to 'self build' resulted in part from the lack of, or the then-high-cost of commercially available software products, as well as the desire to tailor systems to the utility's own unique business processes. Over time, the Company has developed additional applications and capabilities that have been integrated with these legacy systems, usually by point-to-point integrations using complex custom programming referred to as middleware. These

[26] Avista/602, Machado/Page 97.

investments have extended the useful life of our legacy applications and allowed us to derive greater value for our customers from the initial investment.

Q. With that said, why then, does the Company need to migrate its AFM system to Commercial Off-the-Shelf applications?

A. Legacy systems such as AFM meet our basic service needs today because we've made managed investments to extend their value, cost effectiveness, and service life. But while there have been incremental and long-term benefits associated with this approach, there are also less-obvious but important costs and business risks that accumulate with time as the technology platform ages. These latter costs and risks compete with the benefits of extending the service life, and the Company has remained aware of the inevitability that our legacy systems and the complex integration programs supporting these applications will have to be replaced.

The practical service life of these legacy technology platforms has been defined by the rapid evolution of information science technologies that have enabled significant improvements in the service capabilities of each new generation of application systems. As new technology platforms emerge, however, they impact the life-cycle of aging software and hardware products and services, which at some point are no longer serviceable. This rapid cycling of product and service innovation erodes the foundational integrity of legacy technology. The key areas of vulnerability and challenge in managing legacy systems have to do with older computer hardware and operating systems, computer applications and programming languages, and the availability of qualified technical and development support.

Given these considerations, Avista has made the decision to replace its legacy applications with what are referred to as commercial "off-the-shelf" applications (or COTS), in lieu of developing the replacement applications in house, as was done with the legacy systems. Not only is the initial cost of these off the shelf applications much less than the alternative, but they are also supported by a community of users, and may be readily updated by periodic new releases from the software vendor. Ultimately, the primary factor driving Avista's investment in the AFM COTS migration is the replacement of a foundational asset that has reached the end of its useful life (and not operating efficiencies, as stated by Mr. Kaufman). Therefore, the Company does not agree with Staff's proposed reduction in O&M expense.

G. ER 2586 – Meter Data Management

Q. What is the Company's response to Staff's claim that the need for a sophisticated meter data management system appears to be driven by Avista's electric jurisdiction transition to AMI?[27]

A. As discussed in Mr. Machado's direct testimony:

> The Meter Data Management (MDM) system consists of computer hardware and software applications that store, validate, edit, and analyze the interval consumption data for use with Avista's billing system, as well as coordinate specified metering commands.[28]

The decision to make the Meter Data Management ("MDM") system the system of record for all meter usage data was based on the premise that it would not be prudent to implement two or more separate meter data systems of record with increased technical risk and cost. For example, CC&B expects a single source of billable usage, which will be provided by the MDM system. Therefore, the integration of a separate billable usage source would require additional systems modification to support conditional logic enabling multiple sources of billable usage. Additionally, storing usage in different systems would add complexity to the tasks of Avista's Customer Service Representatives ("CSRs"), as they would be required to utilize different system locations to find

[27] Staff/700, Kaufman/Page 28, line 13 through Page 29, line 3.
[28] Avista/600, Machado/Page 24, lines 30-33.

usage data, depending on the location of the customer meter. The custom configuration to the CC&B system that allowed the importing of meter data to determine billing was an interim solution to meet project deadlines and control costs. At the time, the Company deferred the decision on a full MDM system, knowing AMI was on the horizon with additional requirements, and would establish an enterprise system for meter data management and storage. Finally, operating multiple meter data management systems would have required different meter head end solutions. A high level estimate of the cost to install an Oregon meter management system separate from Avista's other jurisdictions was approximately $3.4 million, with recurring annual expense of $260,000, as compared to the Oregon-allocated investment of $2.275 million associated with this MDM system.

Q. Does Avista agree with Staff's proposed exclusion of capital investment associated with the Company's meter data management system from the calculation of the revenue requirement in this case?

A. No. As discussed previously, there are technology interdependencies between systems and there would be increased costs and complexities associated with the use of multiple meter data solutions. The new single source MDM system will provide benefit to all customers, including those in Oregon, and operational efficiencies for Avista, versus running separate systems.

Q. Does this conclude your reply testimony?

A. Yes.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

JAMES M. KENSOK
Exhibit No. 1601

Avista's Response to Staff DR 190

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	01/13/2017
CASE NO:	UG 325	WITNESS:	David J. Machado
REQUESTER:	PUC Staff - Kaufman	RESPONDER:	David Machado/A. Leija
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 190	TELEPHONE:	(509) 495-4554
		EMAIL:	david.machado@avistacorp.com

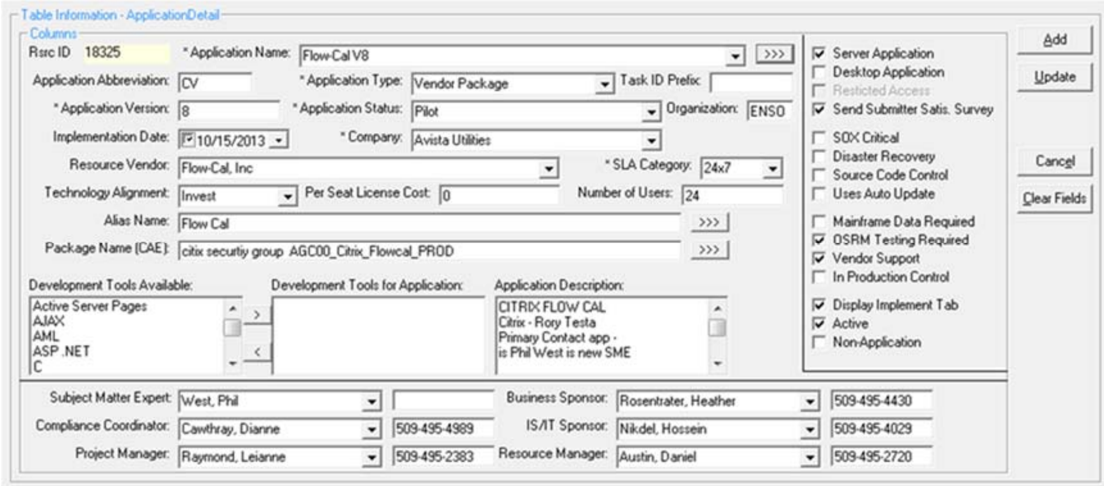
REQUEST:

Please refer to Avista/602 Machado/67-69. Please provide all documentation related to this capital project, including but not limited to the following information:

a. Continuing property records for existing technology which will be refreshed by this program before September 2017.
b. Please identify each aging technology that is currently experiencing increased failure rates. Please describe what constitutes a failure, provide documentation of the technology failure rate, and explain the impact of the technology's failure on company operations.
c. Please identify each aging technology that is currently causing inefficient work practice. Please identify the inefficient work practice and explain how the work practice was determined to be inefficient. Please explain how the Company measures the efficiency of the work practice and when the company first became aware of the inefficiency. Please identify the expected cost savings that will result from eliminating the inefficiency.
d. Please identify each aging technology that is currently causing safety incidents due to system failures. Please provide a brief description of each safety incident including the date of the incident and any expenses caused by the incident.
e. Please provide Avista's roadmaps for application and technology lifecycles.
f. Please provide all general planning documents regarding the Technology Refresh to Sustain Business Processes program and the Distributed Systems, Communication Systems, Network Systems, Central Systems, Environmental Systems, and Business Applications sub programs.
g. Please explain how the Technology Expansion Program differs from the Technology Refresh to Sustain Business Processes program.
h. Please refer to Avista/602 Machado/68. Is the avoided labor cost associated with the 62 staff member reduction incorporated into the cost analysis of the "Unfunded Program" analysis? If no, why not?
i. Please explain the reason for the $2.6 million difference between the 2016 "Approved" value of $17,917,613 and the "Capital Cost" value of $15,417,613.

RESPONSE:

a. Avista's Technology Refresh Business Case supports technology replacement across 6 technology domains: Distributed Systems, Central Systems, Communication Systems, Network Systems, Environmental Systems, and Business Applications. Each technology domain is governed by a Program Steering Committee that guides annual project priority in response to company strategy, technology roadmaps, and available funding allocation, while balancing the risk of reliability and functionality. In 2017, over 100 projects will replace aging technology across the 6 technology domains. The projects will include various type of technologies, such as servers, computers, mobile radios, audio/visual equipment, telephone systems, applications, etc. These project upgrades consist of various interdependent technologies that will be replaced simultaneously to support one another. Each technology asset is entered into Avista's asset management system of record, which holds over 14,000 technology asset records. See sample below.



Each technology asset record includes an implementation date of when the asset was put into services, as well as a retirement date based on its asset life cycle. These records are reviewed annually by the Program Steering Committees to recalibrate project priority within each technology domain.

b. Avista's technology operations team supports daily break/fix requests, which include failing technology. Generally, it is Avista's practice to replace technology within an acceptable failure tolerance outside of the vendor recommended lifecycles. In 2016, Avista replaced its aging rugged laptops for field staff. The older model was used past its life cycle and began incurring higher than acceptable failure rates, coupled by the inability to find parts or a vendor that could repair them. This project began in 2015 and went into service in 2016.

Additionally, Avista was required to upgrade all aging server Operating Systems (OS) from an unsupported version. This OS upgrade is nearly complete, and resulted in legacy application upgrades to align version compatibility. The failure to not upgrade in vendor supported hardware and software results in incompatibility between highly integrated systems when vendor driven system changes occur.

A technology failure is defined as an unwanted error from the aforementioned technology. Generally, these failures can occur through human error, equipment failure or system incongruity. Following restoration efforts, a root cause analysis is conducted for each reported failure to determine cause of failure. Avista's operations management team reviews each root cause analysis report and recommends a course of action to mitigate similar future failures by initiating technology upgrades or ancillary system updates, and/or changes in business process. An example of such a report is shown in the following illustration.

Report Prepared by:
Ethan Angele
Outage Description:
Internal Netscalers lost connectivity with one of the Secure Ticket Authorities. This caused half of the connections to work and half to fail. The failure was due to a bug with the Netscaler no longer being able resolve the hostname of the STA even though DNS was working.
Date(s) and Time(s) of Outage:
10/06/2016 06:00am – 10/06/2016 09:00am
Date(s) and Time(s) of Restoration:
Duration of Outage:
Approximately 3 hours.
System(s) Involved:
Nccmis240f, nccmis240e, h1386, h1387
Business Units / People / Circuits Affected:
Users who use the Citrix environment for Virtual Desktops or Virtual Applications.
Brief Synopsis of Events:
06:00AM as users started to come into work, NetOps and DS started to receive calls that when they attempted to connect to their applications or to their desktop it was giving errors. 07:30AM Several parties were brought in to further look into the issue. Specifically the team that performed maintenance the night before. 09:00AM the issue with the STA was discovered and changed to IP instead of hostname and the issue was resolved.
Root Cause Analysis:
A bug with the Netscaler no longer being able resolve the hostname of the STA even though DNS was working. This was unrelated to the work from the previous night.
Mitigation Plan:
Bug related. Fix/Workaround was changing the configuration from DNS name to IP address.

Avista takes technology failures very seriously, as it can have great impact on daily operations. Although, Avista takes every precaution to reduce technology failures through system redundancy and a reliability architecture, failures can still occur. As soon as a technology failure is reported to our technology operations team, a trouble ticket is assigned an Urgent, High, Medium or Low level of impact and sent to the appropriate technology team to troubleshoot. Urgent and High severity technology failures impacting various interdependent systems will trigger Avista's Emergency Operating Procedure (EOP). The EOP process includes management oversight of the incident until resolution. Failures can span from an individual employee to as much as an entire operations unit not being able to service our customers.

c. Avista replaces technology before it results in inefficient work practices. However, when technology is used past its intended life, it can result in high failure rates and increased operational downtime, thereby requiring inefficient manual workarounds due to the failure or incompatibility.

The work practice is determined to be inefficient when the throughput is reduced or unable to meet the demand generally required when the technology is available. A backlog of work will result from the inefficient work practice.

Each operational manager measures work practice efficiency and reports when the work practice becomes inefficient.

Technology upgrades have allowed for traditional manual efforts to be done more efficiently. Cost savings are in the form of increased productivity and/or quality of service.

d. It is Avista's practice to design technology systems, supporting safety functions, to withstand predicted failures and not affect the safety of our employees.

A failure of a land mobile radio or communication system would impact an employee's ability to communicate with emergency services should an incident occur.

e. Avista's Enterprise Architecture Office, under the Technology Department established a Domain Architect Working Group to develop and maintain a technology architecture framework for the company, responsible for technology asset lifecycle management, defining technology roadmaps, and identifying dependencies through collaboration across the technology domains. The Working Group will be producing an integrated roadmap in alignment with Enterprise Architecture goals that meet business initiatives.

f. Staff_DR_190 Attachments A – S represent project artifacts associated with all (known to-date) projects under this business case with 2017 in-service dates.

The following index identifies the project associated with each given attachment:

Attachment:		**Project:**
Staff_DR_190 Attachment A		Charter-PMP Combo 2016 Mission Servers
Staff_DR_190 Attachment B		Communications Mgmt Systems Refresh 09905788
Staff_DR_190 Attachment C		Customer Segmentation R1 - Trove Upgrade_Project Initiation Charter
Staff_DR_190 Attachment D		DC Plant Refresh Clarkston Sve Ctr Office
Staff_DR_190 Attachment E		DS REF Remote Access 09906103
Staff_DR_190 Attachment F		DS REF SCCM Software Package 09906071
Staff_DR_190 Attachment G		EBS Upgrade Charter_3
Staff_DR_190 Attachment H		Envision+ Software Upgrade Charter
Staff_DR_190 Attachment I		MAN Transport Backhaul Refresh Project Initiation Charter
Staff_DR_190 Attachment J		Mission Fiber Refresh Phase 2 09905873
Staff_DR_190 Attachment K		Mission In-Building Cellular Booster 09905964
Staff_DR_190 Attachment L		Office Communicator & Smart Phone 09906059
Staff_DR_190 Attachment M		Oracle 12C Database Upgrade GCA R3 - Charter-PMP Combo
Staff_DR_190 Attachment N		Phoenix R1 Payment System Replacement 09906049
Staff_DR_190 Attachment O		PMP Combo 2016 GCN Servers Refresh
Staff_DR_190 Attachment P		Spokane Field Area Network Refresh Phase 1 Charter
Staff_DR_190 Attachment Q		WAN Head End Network Refresh 09905936
Staff_DR_190 Attachment R		WebDMZ Refresh 09905899
Staff_DR_190 Attachment S		Medford OR Network Refresh Chrtr-PMP

g. The Technology Expansion Business Case facilitates the adoption of new technology to support efficient business processes throughout Avista and is driven by customer and business needs. The Technology Refresh Business Case refreshes existing technology in alignment with the roadmaps for application and technology lifecycles.

h. The “Unfunded Program” analysis reflects the absence of capital investment (i.e., if the business case were not funded, no associated investment would occur). Additionally, the business case reflects incremental “other costs” reflecting the increase in expense associated with maintaining existing technology. As described in part “b” and “g” of this response, Avista’s existing technology requires continuous upkeep. If Avista did not regularly reinvest in its technology, the maintenance demands associated with existing technology would only increase.

i. As discussed in Staff_DR_183, business summaries are updated in the event of material changes to the scope, schedule, or budget. In addition, business cases for Programs (bodies of work that are long-lived over an extended period) are periodically refreshed. Additionally, updated requests for capital investment funding during the Capital Planning Group’s (“CPG”) five-year planning process each year are submitted separately from the business case summary. As a result, certain business cases may have “Capital Cost” balances that are less than the amount requested and/or less than the balance ultimately approved by the CPG.

   As shown in Staff_DR_185 Confidential Attachment A, the amount requested for 2016 capital investment funding under this business case was approximately $21.3 million, of which $15.4 million was approved by the CPG. Throughout the course of 2016, additional funding requests and releases of funds (as planning circumstances change) for this business case were submitted (a net incremental increase of $2.5 million through October of 2016, after which the business case summary included in this business case was printed). These additional approvals were reflected in the business case form over the course of the year, for a total approved amount of $17.9 million.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

JAMES M. KENSOK
Exhibit No. 1602

Avista's Response to CUB DR 114

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	03/17/2017
CASE NO:	UG 325	WITNESS:	David J. Machado
REQUESTER:	CUB	RESPONDER:	Jim Corder / D. Machado
TYPE:	Data Request	DEPT:	Information Tech. / State & Fed. Reg.
REQUEST NO.:	CUB – 114	TELEPHONE:	(509) 495-4445/4554
		EMAIL:	jim.corder@avistacorp.com david.machado@avistacorp.com

REQUEST:

Please provide support for the project ER 5006.

a. In particular, please support the need for transfers to plant at a level of 300 times the budget.
b. Given that the project is a ten year (or ongoing) project, please explain how the company chooses to manage costs over time, or smooth spending.
c. Please explain why the Company did not anticipate the large amount of over budget spending, yet considered it urgent and prudent enough to deploy in 2016?
d. Please explain, given page 70 of Machado/602 and page 20-21 of Machado/600, how the large growth in this program (essentially doubling annual transfers to plant from 2011, 2012, 2013, 2014) benefits gas customers specifically?

RESPONSE:

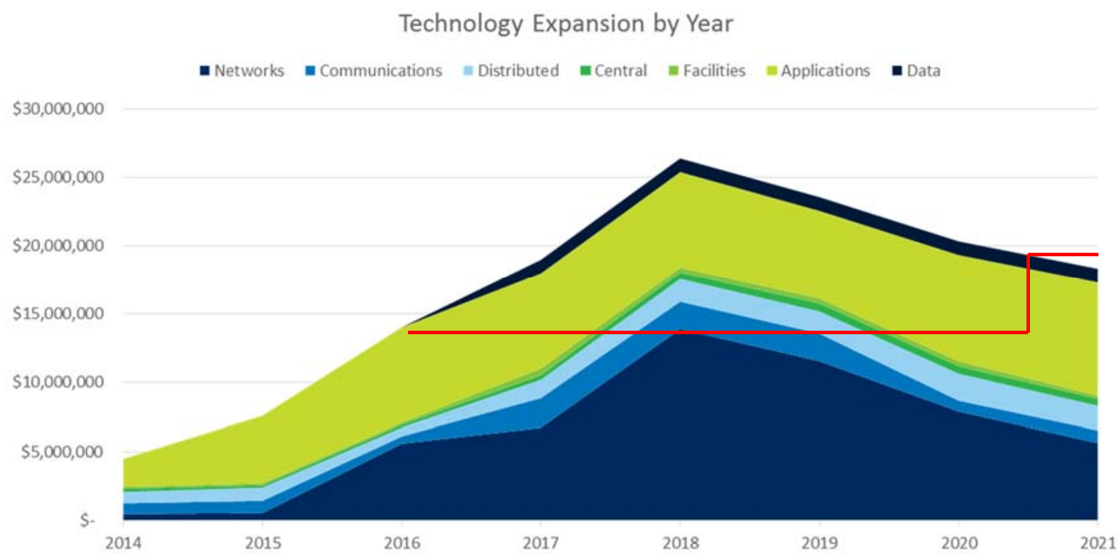
ER 5006 refers to the Company's "Technology Expansion to Enable Business Process" business case.

a. The Company does not agree that the transfers to plant associated with this business case are 300 times the budget for this project. As illustrated at Avista/602, Machado/Page 70, the capital investment approved by the Capital Planning Group ("CPG") for this business case for 2016 and 2017 combined is approximately $27,497,000 (system basis). Expected transfers to plant for the six months ended December 31, 2016 were approximately $6,749,000 (system) and the expected transfers to plant for the nine months ended September 30, 2017 were approximately $11,798,000 (system)—for a total of $18,547,000. Additionally, see the Company's response to Staff_DR_191 for additional discussion of this business case.

b. Requests for project work are initially facilitated by a Business Technology Analyst or a member of IT Management. The projects and Business Cases are prioritized by program steering committees.

   A Business Case is largely governed by two resource constraints, funding and capacity (staff). The funding constraint is generally managed at the Business Case level by the Capital Planning Group ("CPG") and the Technology Planning Group. The capacity constraint is generally managed by the Technology Planning Group and the Business Case owner. Once the resource constraints are established, the Business Case owner works with steering committee(s) to set project priority and sequence over the five year planning period.

The chart below illustrates the demand for projects is greater than established constraints. The red line represents the balance of capital investment approved by the CPG ($14.6 million in 2016, $14 million from 2017-2020, and $19 million in 2021).



c. The Company does not agree with the characterization that (1) the level of investment was not anticipated, nor (2) that there was a large amount of over budget investment in 2016. As explained in the Company's response to Staff_DR_191, the total request made to the CPG for this business case in 2016 was $12.7 million, which was approved by the CPG.

d. The Business Case is composed of seven programs. Growth over the referenced period of time was primarily in two areas; applications and networks. Company initiatives continue to seek ways to optimize productivity. Investments in automation that increase productivity are often funded by this Business Case.

This Business Case addresses many types of application investment projects. Projects that increase end user counts of existing Commercial off-the-Shelf ("COTS") applications, functionality enhancements of existing COTS applications, functionality enhancements of custom applications, and investments in new COTS applications. Two examples of new project demand during the referenced period of time are investments for functionality enhancement to the Customer Care and Billing ("CC&B"—the company's customer information system) COTS application and the Asset and Work Management COTS application.

This Business Case addresses many types of network investment projects. Projects that expand the Company's network infrastructure—for example: in offices, substations, plants, meters, and data center, etc. Investment examples include hardware, software, fiber products, and services for inside and outside construction. The network program within this Business Case is experiencing growth within the data center and the digital grid. Primary drivers within the data center have been increasing numbers of applications, increasing security controls, and an increasing need for enhanced network management systems. Data center operations support the Company's business applications and are beneficial to all jurisdictions.

At this time, growth associated with the digital grid is most beneficial to jurisdictions outside the Oregon territory. During preparation of rebuttal testimony and in conjunction with responding to this request, the Company identified certain projects included within this business case which should be excluded from consideration in the development of a revenue requirement in this case in Oregon. Following the exclusion of these projects, the balance of transfers to plant from January-September 2017 for this ER (ER 5006) is $9,376,000 System, or $817,000 Oregon (rather than $12,113,000 System and $1,054,000 Oregon originally included in this case). The removal of these projects from the calculation of the revenue requirement in this case results in a reduction of $67,000 to revenue requirement.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

JAMES M. KENSOK
Exhibit No. 1603

Avista's Response to Staff DR 192

AVISTA CORP.
RESPONSE TO REQUEST FOR INFORMATION

JURISDICTION:	Oregon	DATE PREPARED:	01/13/2017
CASE NO:	UG 325	WITNESS:	David J. Machado
REQUESTER:	PUC Staff - Kaufman	RESPONDER:	David Machado/C. Storey
TYPE:	Data Request	DEPT:	State & Federal Regulation
REQUEST NO.:	Staff – 192	TELEPHONE:	(509) 495-4554
		EMAIL:	david.machado@avistacorp.com

REQUEST:

Please refer to Avista/602 Machado/73-75. Please provide all documentation related to this capital project, including but not limited to the following information:

a. Please explain the reason for the $100,000 difference between the 2016 “Approved” value of $350,000 and the “Capital Cost” value of $450,000.
b. Please provide all currently effective communications, escalation, and operational procedures developed as part of this investment.

RESPONSE:

a) In 2016, the amount requested for 2016 capital investment funding under this business case was $450,000. The Capital Planning Group approved $450,000 of investment for 2016 in its five-year plan (2016-2020). In September 2016, this business case released $100,000 as a result of changes in scope for the year. The updated approved amount of $350,000 is reflected in the business case form referenced in this request.

b) No communication, escalation, or operational procedures where developed as part of this capital business case. These procedures are generally created using expense dollars. Avista’s Emergency Management Program advances the communication, escalation, and operational procedures. The mission of Avista’s emergency management program is to build, sustain and improve our capabilities to prepare for, respond to and recover from all hazards through a standardized, comprehensive and integrated emergency response program including business continuity, disaster recovery and emergency response plans. The infrastructure investments made by the Enterprise Business Continuity capital business case support the Emergency Management Program. Examples of investments made under this business case include enabling a backup gas control center, network redundancy for gas telemetry, and supporting our disaster recovery capabilities.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

JAMES M. KENSOK
Exhibit No. 1604

Avista's Response to Staff DR 181 Supplemental – Attachment C

UG 325 Discovery Workshop #2, February 6-7, 2017

ER No.: 5106 **Project No.:** 09905752

ER Name: Next Generation Radio System **Project Name:** NGR Oregon South

ER Description:

This project refreshes Avista's 20-year-old Land Mobile Radio system. The Company maintains this private system because no public provider is capable of supporting communications throughout our rural service territory. Additionally, because our systems comprise a portion of our nation's critical infrastructure, Avista is required to have a communication system that will operate in the event of a disaster. This project fulfills a mandate from the Federal Communications Commission that all licensees in the Industrial/Business Radio Pool migrate to spectrum efficient narrowband technology.

Attachment Index:

09905152

Asset-NEXGEN # 00

Revision

AVISTA Corp.

CAPITAL PROJECT REQUEST FORM (CPR)

ER	Budget Category	Use Tab Key / Service Code	Project Title (30 Characters)	Request Type	Project(s)
5106	8-Mandated	CD-Common Direct	NGR South	New	
				Project Title Count: 9	

Long Project Name (100 Characters): Next Generation Radio Southern AO Project

'Parent' Code:

Approved Budget	Will This Project Include Retirement of Materials or Equipment?	Long Project Name Count	ER Sponsor	BI Number	WMS Job #	Rate Jurisdiction
x	No	41	N09	YY826		AA-Allocated All
Billing		Revenue Type: NA- Not Applicable	Billing Contact		Location: 099-Common-WA/ID/OR	Project Start Date: 01-01-2013

Project Description (Include Purpose and Necessity - 240 Characters)
Design and install a Two-Way Radio System to provide coverage to Avista's gas infrastructure in five Oregon and two Central Washington locations

Long Name Count: 144

CONSTRUCTION

Office Use only Task	FERC 3XXXXX	Estimated Amount By FERC Number	As Built Amount By FERC Number
300100			
1076XX	397000	$2,216,581 ~~$2,285,135~~	
1076100	391100	$68,554	
GROSS ADDITIONS		$2,285,135	

Cost of Removal By FERC (3XXXXX)

Total Removal

Salvage By FERC (3XXXXX)

Total Salvage

Total Removal Less Salvage

Non Standard Work Breakdown Structure Needed (Optional)

Peer Task

Sub Task

Date Prepared: 01-23-13

TOTAL COST OF PROJECT $2,285,135

Questions: contact Project and Fixed Asset Accounting (Sue ext-4472 or Howard ext-2936)

Budget Authorized: $2,285,135

Office Use Only		Date
Project Set Up By		2/27/13
Approved By		
		2/27/13
		9-2-15

APPROVALS

SIGNATURE	DATE
Signature / Print Name: Jim Corder	21 FEB 2013
Signature / Print Name: Jim Kensok	2-21-13
Signature / Print Name: Dennis Vermillion	2-25-13
Signature / Print Name:	
Signature / Print Name	

Project Contact & Extension: Bill Kelley x4454

APPROVAL SIGNATURE(S) REQUIRED
To $99,999 - Director
$100,000-$499,999 - VP or GM Utility
$500,000-$2,999,999 - Sr Vice President/CFO
$3,000,000-$9,999,999 - President/CEO/COO
Over $10,000,000 - Board Chair
Out-of-Budget - Capital Budget Committee

THE PROJECT SPONSOR IS RESPONSIBLE FOR CLOSING THIS JOB. IMMEDIATELY UPON COMPLETION OF WORK, SIGN THIS FORM, COMPLETE 'AS BUILT' INFO AND FORWARD TO UTILITY ACCOUNTING.

Date Work Completed
Foreman/ Supervisor

audited 9-2-15
9-1-15

Revised October 2011

Project Initiation Charter

Planning Phase Approval
Project Name: Next Generation Radio Oregon
Clarity Project ID: 09905752

1 Key Roles

- Project Sponsor: Jim Kensok
- Steering Committee: Jim Corder, Al Fisher, David Howell, Heather Rosentrator
- Other Stakeholders: Brian Taylor (Medford), Jeff Daniels (Klamath), Harold Sheeran (Roseburg), Donald Kellogg (La Grande)
- Program Manager: Matt Reding
- Project Manager (if known): Helen Monn

2 Project Profile

2.1 Business Need

There is not currently, an Avista 2-Way radio system to provide coverage for Avista's gas infrastructure in Avista's four Oregon locations. Avista's resources in these areas use cell phones for dispatching and emergency services. Due to the demonstrated extreme difficulty including up to the inability to communicate using cell phones during an emergency, it was determined that a local use 2-Way radio system would be an appropriate solution for local dispatch and coordination with emergency services.

2.2 Who Benefits?

Avista gas construction in the four Oregon locations will benefit by having a robust and reliable 2-Way radio communications system for providing local dispatch capabilities during emergencies which will be independent from less reliable cell phones. Indirectly, their customers will benefit through better response time during emergencies.

2.3 High Level Project Deliverables

- Build out in OR will be minimal to meet the FFC guideline requirement of 50% of the coverage area population in order to maintain frequencies.
- Install trunked radio system – one each in the Roseburg, Klamath Falls, and La Grande, and the Medford-Grants Pass OR corridor.
- Install radio communication equipment into each Oregon office: LaGrande, Roseburg, Klamath Falls, and Medford.
- Install mobile radios in the Avista Fleet vehicles that service the Oregon territory
- Order out the system preliminary design, the preparation and filing of the FCC mandated Interference Mitigation Plan, the RFI and RFP preparation for the installation of the NGR South radio system to Avista's engineering consulting firm Gillespie, Prudhon & Associates of Clackamas, OR.
- Avista will secure lease agreements with sites capable of providing reliable communications hosting and environmental services.
- Bid out all of the equipment, services, and maintenance of a Tait 2-Way radio system in Oregon..
- Devlop and deliver a maintenance and support contract (with defined SLA's) for all equipment in Oregon territory.
- Develop a sparing model for all radio equipment types within Oregon territories

Project Initiation Charter

Planning Phase Approval

-

2.4 What will NOT be delivered?

Description	Reason for being out of scope
Backhaul network to Spokane and tie into northern AO radio system	TBD
Avista health and status monitoring of NGR South radio system	TBD
Electronic Security	At least initially, there will be no connectivity to the LMR network and information passed over the radio will be unclassified
2-Way radio system in Golden Dale and Stevenson WA	Separate Project

2.5 Where will technology be deployed?

The technology will be deployed at and in the nearby areas of the Avista construction offices in Medford, Klamath Falls, Roseburg, and La Grande, OR and in the respective company vehicles that service these areas. The exact location of sites will be determined later in the planning process.

3 Artifacts and Milestones

3.1 Project Artifacts to be delivered

- Project Initiation Charter
- Statement of Scope
- Project Management Plan
- Go-Live approval
- Approval to Close

3.2 Milestones

Description	Target date for completion/approval
Project Initiation/Charter	1/31/14
Scope Approval w/VROMs (Go / No-go decision point)	3/1/14
Work Packages & ITE Design Review	N/A
PMP: Approval to Execute	3/1/14
Go-Live Approval (Go / No-go decision point)	2/28/15
Approval to Close	3/30/15

4 Assumptions & Constraints

4.1 Assumptions

- For work on remote sites which must be accomplished during the months of June through September it is assumed that:
  - There will be no extraordinarily disruptive weather during these months.
  - The vendor will provide sufficient installers in order to complete installation work in advance of unfavorable local weather.

Project Initiation Charter

- The radio and associated equipment manufacturers and suppliers will not encounter any production or transportation delays which could materially impact the project schedule.
- Prior to the award of the project bid all lease arrangements will be successfully concluded.
- Prior to completion of this project there will not be any new rulings by the FCC or other applicable regulatory agency which could materially alter the functional or technical requirements for this project.
- In order to conserve resources, storage space, and provide for possible future interoperability, the same type of equipment used for Avista's southern AO project will be virtually identical to equipment used in the northern AO region.

4.2 Constraints

- Time: April 26th, 2015 (FCC requirement)
- Time: Due to elevations of sites and climate, summer and fall are the best seasons for site installation
- Time: RFP process 4-8 weeks
- Time: Factory production lag time is 8-12 weeks
- Resources: Total project cost should not exceed $2.3M
- Time: Allow time for FCC review and comment on Interference Mitigation Plan
- Time: Lag time for some site approvals
- Scope: Project installation may need to be phased to avoid failure to meet substantial build out date

5 Compliance and Controls

NOTE: For each "yes", add a bullet point to your "scope" stating that this listed item is a deliverable of the project

Area	Required (Y/N)
Business Controls impact assessment (contact: Stacey Wenz)	Yes
Business Continuity Plan (contact: Erin Swearingen)	Yes
Computer Controls Impact Assessment (contact: Jeff Anderson)	YES
Production Migration (Does project system become production or is it dev, test, model office, then production)	Yes
Test Plan	Yes

6 Planning Cost Estimate

- Estimated Pre-project costs (Expense): $0
- Capital Funding source: ET Dept.
- Estimated cost of planning: $250,000
- Estimated total project cost: $2.3M

Project Statement of Scope

Use Cases and Deliverables

Project Name: Next Generation Radio South (NGR South)
Project Manager: Tatiana Plett
Clarity Project ID: PR00010606
Acctg Project#: 09905752

1 Key Roles

- Project Sponsor: Jim Kensok
- Steering Committee: Jim Corder, David Howell, Bryan Cox
- Other Stakeholders: Jeff Daniels, Don Kellogg, Brian Taylor, Alan Smith
- Program Manager: Matt Reding

2 Project Manager (if known): Project Profile

2.1 Business Need

Avista does not currently have a 2-Way Land Mobile Radio (LMR) system in its Oregon locations. Avista Gas Service resources in these areas rely on cell phone communication for dispatching and coordination. Expansion of the LMR system into Oregon will provide a fault tolerant communication system with dedicated capacity. Additional benefits include a reliable and consistent communication method, central dispatching capabilities, and dedicated communication channels for emergency and disaster situations.

2.2 Who Benefits?

Beneficiaries	How beneficiaries are benefited from the project
Avista Gas Customers - Oregon	Customers will be served more effectively with service calls and faster response times for emergencies
Avista Gas Controllers	Standard communications protocols will now be available throughout the Avista gas service territory
Avista Gas Facilities - Oregon	Facilities will be outfitted with office equipment that will provide a wider view of ongoing field operations and will be able to efficiently communicate to field crews using standard protocols in dynamic situations.
Avista Gas First Responders - Oregon	Crews will be outfitted with intrinsically safe (IS) radios and will have the ability to communicate using standard protocols in real time with Gas Control and other crews in an emergency situation.
Avista Gas Maintenance Crews - Oregon	Crews will be outfitted with radios and will have the ability to communicate using standard protocols in real time with Gas Control, facilities, and other crews for improved work efficiency.
Avista Gas Revenue Collection Teams – Oregon	Teams will be outfitted with radios with emergency button for instant communication to Gas Control and service centers in the case of personal safety
Avista Gas Construction Crews - Oregon	Crews will be outfitted with radios and will have the ability to communicate using standard protocols in real time with Gas Control, facilities, and other crews for improved work efficiency.

Project Statement of Scope

2.3 Who is impacted by this project?

System, Processes, and/or Teams	How the system, process, and/or team is impacted
Avista Gas Customers - Oregon	Customers will be served more effectively with service calls and faster response times for emergencies
Avista Gas Controllers	Gas Control needs to determine new standard communication protocols or implement the standards from the Washington/Idaho territories.
Avista Gas Facilities - Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Avista Gas First Responders - Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Avista Gas Maintenance Crews - Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Avista Gas Revenue Collection Teams – Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Avista Gas Construction Crews - Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Network Operations	Network Operations will need to monitor the LMR radio system, the network hardware, and the mountain top communications sites.
Operational Support / Maintenance Team	This group will be the front line in maintaining, troubleshooting, and repairing all the LMR and microwave radio equipment in the Avista Oregon service territory.
Standard Communication Protocols	These will need to be disseminated to the crews and facilities in Oregon

2.4 Use Cases

1. Avista requires a radio solution that provides a reliable communication network to quickly assess, contain, and resolve gas emergency issues (ex: Code 9 – blowing gas).
2. Avista requires dedicated radio channels to facilitate collaborative communication for planned and unplanned work pertaining to Avista's gas infrastructure in the Oregon territories
3. Avista requires a solution that fully integrates with the current dispatch communication monitoring system (Zetron).
4. Avista requires the ability to locate gas crew and servicemen positions for both normal dispatching and emergency response situations.
5. Personal Safety: Avista requires the ability for a radio operator initiated emergency notification to our Gas Control Room.
6. Avista requires a radio system solution with the ability to communicate with emergency first responder services (Police/Fire/Medical).
7. Avista requires a radio solution that supports point-to-point communication capabilities

Project Statement of Scope

Use Cases and Deliverables

8. Avista requires a radio solution that provides redundant communication paths to accommodate continued operation during outages
9. Avista requires a radio solution that provides coverage across our entire Oregon service territory

2.5 Project Requirements and Deliverables

1. **FCC Mandate** – Avista will provide coverage models, interference mitigation plans, narrow- banded equipment and all applicable documentation.
2. **Licensing** – Licensing UHF frequencies for vehicular crossband repeaters.
3. **Mountain top build out** – These locations will house the LMR infrastructure required to comply with the FCC rules on significant coverage for the Automated Maritime Telecommunications System (AMTS) frequency spectrum.
4. **Service center infrastructure networking** (IP/Microwave) – These locations are required to provide the backhaul connectivity to the control nodes of the LMR trunked radio system for both the service centers/office and the mobile radios.
5. **Vehicle installs** – These are the mobile radios that will be the backbone of the standard communication protocols set forth by the Gas Control Room. This will be the most commonly used component of the radio system.
6. **Portable Radios** – First responders will be provided with intrinsically safe (IS) portable radios for use/access outside the vehicles (in a radio no longer than 4 miles from the truck).
7. **Service center office equipment installation** – These installations are the equipment that allows office staff to monitor and utilize the radio system
8. **Training** – There will be comprehensive training materials that will provide technical background and hands-on use of the radio system.
9. **Monitoring** –The Network Operations group will monitor radio node communications infrastructure placed at remote sites.
10. **Documentation** – Documentation for operation of the LMR radio will be available to all operators.
11. **Operational hand off** – The project will define an operational support model. Preventative maintenance documents will be provided to Avista Network Operations and to the operational support / maintenance teams for onsite preventive maintenance
12. **Security** - Avista will comply with all physical and cyber security policies.

2.6 Constraints

1. Avista requires contracting the professional services of Telecommunication Engineers to perform the required work for this project in Oregon because we do not have Telecom Shop resources in Oregon.

   The required services include: engineering, consulting, construction, interference mitigation, coverage verification, and integration testing work pertaining to the build-out and stand-up of Avista's Land Mobile Radio (LMR) system in the Oregon territory.

   Gillespie, Prudhon & Associates (GP&A) performed the same services referenced above for Avista in the deployment of the LMR system in the Washington, Idaho, and Montana territories. GP&A is familiar with the Next Generation Radio project team, Avista's RF infrastructure, and expectations about quality. In an effort to maintain consistency and minimize ramp up time it would be in Avista's best interest to assign this job to GP&A.

2. Avista must meet substantial service criteria of the FCC for WQKP818 and WQKP819 by April 26, 2015. Substantial service is 65% of the population in these licensed areas.

Project Statement of Scope

Use Cases and Deliverables

2.7 What will not be delivered?

Description	Reason for being out of scope
Radio system integration with cellular and landline telephones	As part of the initial deployment of this project, this element was not considered necessary.
Tait GPS-AFM integration	This item will be assessed as part of the AFM Refresh project.
Stevenson/Goldendale radio coverage	It is not cost-effective to implement radio coverage at these locations as one person covers both areas. Additionally, there are no Avista facilities at these locations to house equipment.

2.8 Where will technology be deployed?

Mountain Top Site Build-out

1. Hogback Mountain (Klamath Falls)
2. Mt. Emily (La Grande)
3. Elk Mountain (Medford)
4. Mt. Baldy-Safley (Medford)
5. Mt. Scott (Roseburg)

Office Location Build-out

6. Medford Service Center
7. Klamath Falls Service Center
8. La Grande Service Center
9. Roseburg Service Center

2.9 Task Analysis - Very rough order of Magnitude (VROM)

Chg Code	Role	Planned Hrs	Actual Hrs	Var Hrs
Capital	Program Manager (Matt Reding)	206	98	108
Capital	Project Manager (Tatiana Plett)	2,090	38	2,052
Capital	Project Coordinator (Kristi Wheeldon)	2,013	130	1,883
Capital	NS Architect Sean Chambers	115	8	107
Capital	NS RF Engineer (Paulo Tabino)	1,092	194	898
Capital	Facilities (Marcial Laude)	408	0	408
Capital	CO Program Engineer (Walter Roys)	956	117	839
Capital	NS IP Engineer (Jacob Huss)	471	31	440
Capital	SS Engineer (Jennifer Truman)	60	0	60
Capital	CT Tech JM (Hector Garza)	113	5	108
	Total	**7,525**	**622**	**6,903**

*Planned hrs are considering from 1-2-14 until 12-31-15
*Actual hrs would be 1-2-2014 until 12-19-2014

Project Statement of Scope

Use Cases and Deliverables

2.10 Non-Labor costs

NGR Oregon is implementing the same solution used in the Washington, Idaho and Montana territories.

Description	Estimated Cost
Purchase TAIT radio equipment	559,450
Purchase additional TAIT radio equipment (25 portables)	25,000
Purchase additional TAIT radio equipment (25 repeaters)	68,273
Network equipment	79,846
Non TAIT radio infrastructure equipment	646,000
GP&A Professional Services	1,519,987
Legal Services (Keller and Heckman)	48,000
Mobile Radio Installation (Day Wireless)	21,828
Mobile Radio Training materials (Day Wireless)	2,000
Site visits (5 mtn. tops, 4 serv. centers, 2 p.)	4,000
AFUDC	212,604
Total	**3,703,408**

3 Compliance and Controls

Area	Required (Y/N)	Requirements added to Scope? (Y/N/NA)
Business Controls impact assessment (contact: Stacey Wenz)	Yes	No
Business Continuity Plan (contact: Erin Swearingen)	Yes	No
Computer Controls Impact Assessment (As indicated above, the security engineer will address this as part of the VROM analyses process – contact: Jeff Anderson)	Yes	No
Compliance Requirements (contact: Rob Jacobs)	Yes	No
Production Migration (Does project system become production or is it dev, test, model office, then production)	No	No
Test Plan	Yes	Yes

4 Funding Checkpoint

- Current approved CPR: $ 2,285,135
- Actual spending life to date: $ 232,188
- Forecast $ 3,471,220
- Estimated cost to complete project (EAC) $ 3,703,408

Project Management Plan

Project Name: Next Generation Radio South (NGR South)
Project Manager: Tatiana Plett
Clarity Project ID: PR00010606
Acctg Project#: 09905752

1 Key Roles

- Project Sponsor: Jim Kensok
- Steering Committee: Jim Corder, David Howell, Bryan Cox
- Other Stakeholders: Jeff Daniels, Don Kellogg, Brian Taylor, Alan Smith
- Program Manager: Matt Reding
- Project Manager: Tatiana Plett

2 Project Profile

2.1 Business Need

Avista does not currently have a 2-Way Land Mobile Radio (LMR) system in its Oregon locations. Avista Gas Service resources in these areas rely on cell phone communication for dispatching and coordination. Expansion of the LMR system into Oregon will provide a fault tolerant communication system with dedicated capacity. Additional benefits include a reliable and consistent communication method, central dispatching capabilities, and dedicated communication channels for emergency and disaster situations.

2.2 Who Benefits?

Beneficiaries	How beneficiaries are benefited from the project
Avista Gas Customers - Oregon	Customers will be served more effectively with service calls and faster response times for emergencies
Avista Gas Controllers	Standard communications protocols will now be available throughout the Avista gas service territory
Avista Gas Facilities - Oregon	Facilities will be outfitted with office equipment that will provide a wider view of ongoing field operations and will be able to efficiently communicate to field crews using standard protocols in dynamic situations.
Avista Gas First Responders - Oregon	Crews will be outfitted with intrinsically safe (IS) radios and will have the ability to communicate using standard protocols in real time with Gas Control and other crews in an emergency situation.
Avista Gas Maintenance Crews - Oregon	Crews will be outfitted with radios and will have the ability to communicate using standard protocols in real time with Gas Control, facilities, and other crews for improved work efficiency.
Avista Gas Revenue Collection Teams – Oregon	Teams will be outfitted with radios with emergency button for instant communication to Gas Control and service centers in the case of personal safety
Avista Gas Construction Crews - Oregon	Crews will be outfitted with radios and will have the ability to communicate using standard protocols in real

Project Management Plan

	time with Gas Control, facilities, and other crews for improved work efficiency.

2.3 Who is impacted by this project?

System, Processes, and/or Teams	How the system, process, and/or team is impacted
Avista Gas Customers - Oregon	Customers will be served more effectively with service calls and faster response times for emergencies
Avista Gas Controllers	Gas Control needs to determine new standard communication protocols or implement the standards from the Washington/Idaho territories.
Avista Gas Facilities - Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Avista Gas First Responders - Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Avista Gas Maintenance Crews - Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Avista Gas Revenue Collection Teams – Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Avista Gas Construction Crews - Oregon	The crews will need to learn the operation of the new radio system and the new standard communication protocol as set by Gas Control.
Network Operations	Network Operations will need to monitor the LMR radio system, the network hardware, and the mountain top communications sites.
Operational Support / Maintenance Team	This group will be the front line in maintaining, troubleshooting, and repairing all the LMR and microwave radio equipment in the Avista Oregon service territory.
Standard Communication Protocols	These will need to be disseminated to the crews and facilities in Oregon

2.4 Use Cases

1. Avista requires a radio solution that provides a reliable communication network to quickly assess, contain, and resolve gas emergency issues (ex: Code 9 – blowing gas).
2. Avista requires dedicated radio channels to facilitate collaborative communication for planned and unplanned work pertaining to Avista's gas infrastructure in the Oregon territories
3. Avista requires a solution that fully integrates with the current dispatch communication monitoring system (Zetron).
4. Avista requires the ability to locate gas crew and servicemen positions for both normal dispatching and emergency response situations.
5. Personal Safety: Avista requires the ability for a radio operator initiated emergency notification to our Distribution Dispatch team.
6. Avista requires a radio solution that provides redundant communication paths to accommodate continued operation during outages.

Project Management Plan

7. Avista requires a radio solution that provides coverage over its Oregon Gas service territory according to our coverage model maps.
8. Avista requires a radio solution that provides unique talk groups for specific purposes (i.e. Avista personnel, contractors and an ALLCALL group in case of emergencies)
9. Avista will provide a radio system that allows communication by the users when away from their trucks.

2.5 Project Requirements and Deliverables

2.5.1. Project Requirements

1. **FCC Mandate** – Avista will provide coverage models, interference mitigation plans, narrow-banded equipment and all applicable documentation.
2. **Licensing** – Licensing of VHF or UHF frequencies for vehicular cross band repeaters.
3. **Mountain top build out** – These locations will house the LMR infrastructure required to comply with the FCC rules on significant coverage for the Automated Maritime Telecommunications System (AMTS) frequency spectrum.
4. **Service center infrastructure networking** (IP/Microwave) – These locations are required to provide the backhaul connectivity to the control nodes of the LMR trunked radio system for both the service centers/office and the mobile radios.
5. **Service center office equipment installation** – These installations are the equipment that allows office staff to monitor and utilize the radio system
6. **Security** - Avista will comply with all physical and cyber security policies.

2.5.2. Project Deliverables

7. **Vehicle installs** – These are the mobile radios that will be the backbone of the standard communication protocols set forth by Gas Control Room. This will be the most commonly used component of the radio system.
8. **Portable Radios** – All trucks will be equipped with intrinsically safe (IS) or equivalent certification portable radios for use or access outside the vehicles.
9. **Training** – There will be comprehensive training sessions and materials that will provide technical background and hands-on use of the radio system.
10. **Monitoring** –The Network Operations group will monitor radio node communications infrastructure placed at remote sites.
11. **Documentation** – Documentation for operation of the LMR will be available to all operators.
12. **Operational hand off** – The project will define an operational support model. Preventative maintenance documents will be provided to Avista Network Operations and to the operational support / maintenance teams for onsite preventive maintenance

2.6 What will not be delivered?

Description	Reason for being out of scope
Radio-telephone interface	As part of the initial deployment of this project, this element was not considered necessary.
Tait GPS-AFM integration	This item will be assessed as part of the AFM Refresh project (ATLAS).
Stevenson/Goldendale radio coverage	It is not cost-effective to implement radio coverage at these locations as one person covers both areas. Additionally, there are no Avista facilities there in which to house equipment.

Project Management Plan

2.7 Critical Success Factors

The critical success factors to meeting the goals of this project are:

a) Comply with the FCC requirements before April 26th, 2015
b) Complete project at or under budget
c) Complete project before Dec 31st, 2015.
d) New Radio System provides coverage as designed. This will be measured by the Coverage Verification Test (CVT).

3 Assumptions, Risks, & Constraints

3.1 Assumptions

The following assumptions have been made:

1) All sites will be secured by the end of March 2015.
2) All Oregon site build out or installation and documentation work will be contracted out with Avista oversight.
3) Contractor will be awarded the bid in January 2015.
4) All construction of sites will be accomplished by beginning Q4 2015.
5) Mobile Radios and office equipment will be installed by beginning Q4 2015.
6) For work on remote sites it is assumed that:
   a. There will be no extraordinarily disruptive weather during those months.
   b. Vendors will ramp up their workforce and logistics support in advance for work.
   c. We assume that the sites will be accessible via existing roads.
7) The radio and associated equipment manufacturers and suppliers will not encounter any production or transportation delays which could materially impact the project schedule.
8) An acceptable solution will be found wherever there is a need to acquire/lease land in support of this project. Leasing sites is the preferred option for Oregon.
9) Prior to completion of this project there will not be any new rulings by the FCC or other applicable regulatory agency which could materially alter the regulatory, functional, or technical requirements for this project.
10) Avista will use third party vendors to install equipment at the mountain tops and service centers.
11) The project will pay for the cost of a spare base station as a replacement for the Oregon territory.

Project Management Plan

3.2 Risk Management

Name	Probability		Impact		Calculated Risk		Value at Risk ($)
	Value	Color	Value	Color	Value	Color	
Contractor doesn't meet FCC deadline	Medium		High		6		20,000
Contractor Performance	Low		Low		1		0
Equipment Availability	Medium		High		6		5,000
Laws and Regulations changed	Low		Low		1		10,000
Management Reserve	Low		Medium		2		100,000
Permitting and Zoning	Low		High		3		10,000
Project Design Complexity	Medium		Medium		4		14,000
Site Acquisition failure	High		High		9		90,000
Weather	Low		High		3		140,000
							$ 369,000

3.3 Constraints

- Given a fixed schedule, we will choose a scope and adjust resources as necessary.

Flexibility Matrix	Low Flexibility	Medium Flexibility	High Flexibility
Scope		X	
Schedule	X		
Budget/Resources			X

- *Note: Quality is always expected to be high*

4 Major Milestones

Description	Actual or Planned Completion Date
Project Initiation – *Actual approval date*	03/18/2014
Scope approval w/VROMs (Go / No-go decision point) – *Actual approval date*	01/12/2015
Enterprise Technology Engineering Review – *Actual approval date*	02/18/2015
PMP / Approval to Execute – *Planned date*	02/27/2015
Go-Live Approval – *Planned date*	09/30/2015
Approval to Close – *Planned date*	12/31/2015

5 Compliance and Controls

5.1 Business Controls impact statement and requirements

From: Wenz, Stacey   Sent: Thu 12-18-2014 3:11 PM
To: Plett, Tatiana
Cc:
Subject: RE: NGR Oregon -Statement of Scope

There should be no impact to business controls resulting from this project. Thank you!

Project Management Plan

5.2 Business Continuity impact statement and requirements

From: Swearingen, Erin Sent: Fri 12-19-2014 9:05 AM
To: Plett, Tatiana
Cc:
Subject: RE: NGR Oregon -Statement of Scope

No EBC requirements.

Erin Swearingen
509-495-4981
509-389-8961 (C)

5.3 Computer Controls impact statement and requirements

From: Anderson, Jeff Sent: Fri 12-19-2014 12:48 PM
To: Plett, Tatiana
Cc:
Subject: RE: NGR Oregon -Statement of Scope

Sure ☺

Looks like you have a security engineer requested for the project (Jennifer Truman). That should cover you from an IT Security perspective.

Thanks,

Jeff

5.4 Test strategy and rollback plan

NGR Oregon will not present a rollback plan since there is no need because this land mobile radio system will be deployed in Oregon for the first time.

Test Strategy:

The following tests will be performed by various entities. In the following lines we will describe them as actors in the testing process:

- Tait Communications is the provider of the radio system and all the radio equipment for the project.
- Gillespie, Prudhon & Associates (GPA) is the contractor firm that will perform the construction and assembly required in the mountain tops as well as in the Avista Service Centers in Oregon.
- Avista performs as the customer or client for the following services.

1. **Customer Acceptance Test (CAT)**: Tait shall conduct a customer-witnessed CAT in a customer facility of the staged system in accordance with the customer-approved System Test Plan. Avista team and Contractor's representatives will be present for the CAT. Tait shall deliver a CAT Procedure for customer review 15 days prior to the test event. Results of the system level testing shall be captured, and a Certificate of Conformance (COC) shall be delivered to the customer in a CAT Report within 7 days of successful completion of the test event. Customer signature of the COC will be required prior to commencing the installation of the system at the customer site(s).

Project Management Plan

2. **The Site Acceptance Test (SAT),** also known as "Commissioning", is performed in the field, on a site by site basis, once the equipment has been installed and power and network connectivity is complete. The purpose of the Site Acceptance Test is to validate that radio system at each site powers up and operates as expected, at that particular location. The SAT verifies that the system design configuration (frequencies, RF subsystems, network parameters, etc.) meets design specifications. Tait shall conduct a customer-witnessed SAT, also known as "Commissioning", of the installed system for each site in accordance with the customer-approved System Test Plan. Tait shall deliver a SAT Procedure for customer review 15 days prior to the test event. Results of the system level testing shall be captured, and a Certificate of Conformance (COC) shall be delivered to the customer in a SAT Report within 7 days of successful completion of the test event. Customer signature of the COC will be required prior to commencing the operation of the system with warranty and support, or Final System Acceptance Testing if applicable. This test will be oversight by the Avista team and the contractor's team.
3. **The Coverage Verification Test (CVT)** is performed after the sites have completed their Site Acceptance Tests, and therefore have been fully installed with final RF systems. CVT drive testing capture over-the-air RF transmissions of the radio system after all sites have been installed and optimized. The CVT validates that the coverage performance meets coverage design specifications including coverage boundary, channel performance criteria (CPC), and delivered audio quality or bit error rate (BER), as based on final coverage prediction maps and as-built installation data. Tait shall conduct a customer-witnessed CVT of the complete integrated system in accordance with the customer-approved System Test Plan. Tait shall deliver a CVT Plan for customer review 15 days prior to the test event. Results of coverage verification testing shall be captured, and a Certificate of Conformance (COC) shall be delivered to the customer in a CVT Report within 7 days of successful completion of the test event.
4. **The Microwave Testing** will be performed in the lab environment and in the field. The initial testing will comprise of the configuration of the microwave radios in the lab environment. During this testing the units will be configured per the engineering specifications without the waveguides or antennas inserted into the path. The units will be cabled directly to each other with an inline attenuator in the path. Various functionality aspects and performance metrics will be tested and recorded to include, but not limited to, transmit and receive frequency verification, transmit output power verification, packet error rate or bit error rate verification, and redundant stability (verify redundancy operational). The second part of the testing will be the removal of the equipment from the lab environment, the transport to the designated location, and the installation of the equipment at the final destination. Prior to the microwave radio installation the installation of the antennas, waveguide, DC power, and all additional ancillary hardware must be accomplished per Motorola R56 standards. This installation will be verified and will include, but not limited to, the physical inspection of the antennas, waveguide, DC Power cabling, and all additional ancillary equipment. Once the support equipment for the radios has been verified the microwave radios will be installed. Once the entire system has been verified as cabled and connected correctly, similar functionality and performance metrics will be tested and recorded to include, but not limited to, transmit and receive frequency verification, transmit output power verification, packet error rate or bit error rate verification, and redundant stability (verify redundancy operational). Once all the tests have been completed and the microwave radios at both ends of the link are verified to be operating within the specified parameters the microwave radio link will be considered operational. In the event that the microwave radio system cannot be verified as operational according to the specified parameters, then the radio equipment will be re-evaluated for the services it is trying to provide.

5.5 Production Migration path

Non Applicable.

Project Management Plan

6 Budget & Resources

6.1 Labor Summary

Requirement Name	Project Role	Actuals	ETC
Angele, Ethan	NS Ops Engineer	0	1
Chambers, Sean	NS Lead - Traffic Routing and Switching	8	107
Garza, Hector	CT Tech JM	5	68
Huss, Jacob	NS Lead - Traffic Routing and Switching	40	84
McMath, Stuart	NS ITD - Traffic Routing and Switching	17	333
Plett, Tatiana	Project Manager	177	1,913
Raymond, Robb	NS Program Manager	0	0
Reding, Matt	CO Program Manager	119	101
Roys, Walter	CO Program Engineer	137	793
Tabino, Paulo	NS Lead - Transport (Wireless)	259	1,004
Truman, Jennifer	SS Engineer	0	60
Wheeldon, Kristi	Project Coordinator	191	1,812
	Total hrs for Execution Phase		**6,276**

6.2 Financial Summary

Accounting summary for CPR modification

Account Summary (Year-to-date plus forecast)	Costs
Actual costs to date as of: *1/31/15*	995,403
Forecast for Execution and Closing[1]	3,019,442
Estimate at Completion	4,014,845
Contingency Funding Requested[2]	369,000
Total Planned Cost of the Project	**4,383,845**
Funded Amount, Excluding Contingency	2,285,135
Additional CPR Funding Required	**1,729,710**

6.3 FERC Allocation of Project Costs

	Installation (107600)		Removal (108000)	
Accounting Asset Category	**Physical Product ($)**	**Labor and Other ($)**	**Labor and Other ($)**	**Total ($)**
Hardware (FERC Account 391)	$ 79,846	$ 46,494	$0	$ 126,340
Communications Equipment (FERC Account 397[3])	$ 1,324,634	$ 2,932,871	$0	$ 4,257,505
Software (FERC Account 303)	$ 0	$ 0	$0	$ 0
Estimated Total Cost:	**$ 1,404,480**	**$ 2,979,365**	**$0**	**$ 4,383,845**

[1] *Ensure that AFUDC has been calculated and included in the forecast for execution and closing. Do not include project contingency.*

[2] *Use the Clarity Risk Register to quantify risks which will be translated into project contingency funds. After the PMP is approved, add a task called "Contingency" in your project plan (use "aaOther") with the approved contingency funds.*

[3] Property Removal Notification (PRN) may be due if equipment will be removed. Consult with ET Finance Manager.

7 Operational Impact

Three year Operational Impact	Year 1	Year 2	Year 3	Total
Licensing	$0	$ 0	$0	$ 0
Staff / Labor for O&M	$TBD	$TBD	$TBD	$TBD
Training	$ 0	$ 0	$0	$
Other Annual Operational Costs	$131,914	$132,920	$134,037	$ 398,911
Total	**$131,914**	**$132,920**	**$ 134,037**	**$398,911**

8 Grade of Service

The Business Technology Grade of Service (GoS) is displayed on the Our Focus site (click on the link then select "Agile Technology"). This is the integrated measurement of the success of Enterprise Technology group to align with Avista's corporate strategy and contribute in achieving Avista's vision and strategic objectives.

The end of planning is defined for GoS purposes as the date this Project Management Plan (PMP) is approved. Once the PMP is approved a baseline is created. During the Closing phase the baseline is compared to actuals to measure how performance deviated from the baseline plan. Execution completion is defined as the date the Steering Committee approves the "Approval to Close" document, which should occur as soon as possible after final Execution tasks are complete.

8.1 Investment Performance to Budget

This GoS compares the *planned* total project cost as of the end of Planning plus approved CRs to the *actual* cost of the project at Closing. The amount listed below is the baseline. This should match the "Total at Completion" shown in the Clarity Dashboard. The goal is for cost at completion to be within 90% to 100% of the planned cost. If Actual project cost exceeds approved project cost a CR must be submitted prior to closing.

Planned total cost at completion:	**4,383,845**

8.2 Finish Performance to Schedule

This GoS compares the *planned* Execution completion date as of the end of planning to the *actual* Execution completion date. The date shown below should match the date shown in the Milestone table above and the date shown in Clarity for this milestone. The goal is +/- 1 month.

Planned date of Execution completion:	**11/30/2015**

8.3 Labor Performance to Estimate

This GoS compares *planned* labor hours as of the end of planning to *actual* labor hours at execution completion. The number below should match the total shown in the "Labor Summary" section of this document as well as the labor hours in Clarity for Execution tasks. The goal is +/-10%.

Project Management Plan

Planned labor hours during Execution:	**6,276**

8.4 Project Management Performance to Cost Standard

This GoS measures the percentage of total project cost that is attributable to Project Management efforts. The goal is for PM costs to be 10% or less of total project cost. Calculate 10% of the "**Planned total cost at completion**" listed above and input the result below. The PM should manage PM costs to this number. Remember to classify Business Analyst tasks using the "Input Type" of "Other" on your Clarity Timesheet. If you are not sure how to do this, please check with your program manager.

Planned PM labor cost:	**438,385**

8.5 Change Order Performance

This GoS is based on the number of Change Requests submitted within 30 days of project closure. There is no baseline number for this measurement. When a PM is monitoring and controlling a project successfully, changes to scope, schedule, or budget should be known in a timely manner so change requests during the last 30 days of project should be uncommon. Please note that Change Requests within the last 30 days of closing only update the Capital Project Request (CPR), which is the total funded amount. They do not update baseline costs, dates, or labor hours for the purpose of Grade of Service.

8.6 Business Value Performance to Strategic Result Area

This GoS measures the success of the project in providing value to the company. Results are based upon a survey sent out to the steering committee and stakeholders. The survey should be sent as soon as possible after the steering committee approves project closure so that the project is fresh in the minds of the stakeholders. There are instructions in the "Approval to Close" and "Project Progress Report" templates related to the survey process.

Here are the questions asked in the survey:

- This project met or exceeded expectations for business process improvement. *(our focus)*
- This project provided adequate opportunity to discuss values and review options before the solution was delivered. *(shared values, choice)*
- This project maintained good priority and completed without negative impact on business opportunities. *(priority, opportunities)*
- This project replaced a technology system or improved a business process with automation. *(balanced partnership)*
- This project improved our ability to run, grow or transform the business. *(agility)*
- This project was aligned with one or more of the strategic result area(s) from Our Focus. *(integrated planning)*

9 Project Governance and Reporting

The purpose of these procedures is to provide effective mechanisms to control the scope of the project manage issues and risks and monitor progress.

9.1 Financial Control

Financial Control will be managed through the Clarity Project and Portfolio Management System.

9.2 Change Control

Change Control will be managed within the Clarity Project and Portfolio Management System. Below are the steering committee decisions regarding change control for this project:

9.2.1 Describe the level of authority that PMs, Engineering Managers, and Application Leads have to carry out risk mitigation and contingency plans:

- PM: High level of authority regarding risk mitigation and contingency plans
- Engineering Manager: N/A
- Application Leads: N/A

9.2.2 Describe types of risks, issues, and changes that must have steering committee approval before action can be taken.

- Project Charter, Scope Statement, Project Management Plan and Milestones.
- Strategies for dealing with risks and issues
- Changes to scope, schedule and budget
- Change requests
- Key organizational and business decisions
- Engineering design
- Project priority

10 Roles and Responsibilities

10.1 Sponsor and Steering Committee

The Sponsor will provide oversight, guidance, and approval for all major elements of the Project. The Sponsor works closely with the Steering Committee and Project Manager in reviewing project plans, scope, budget, and change control and facilitates the resolution of issues to ensure successful completion of the initiative.

Responsible for:

- Champion the project and raise awareness at senior level
- Approving strategies, implementation plan, project scope and milestones
- Approving key organization/business decision for the project
- Resolving certain issues, policies, and change management
- Drive and manage change through the organization
- Ensuring that an appropriate project priority is established and resources are allocated to the project
- Ensuring the timely and effective cooperation of all departments in providing information and other required assistance to the project teams
- Actively helping to remove obstacles and solve problems that are beyond the control of the Project Managers

10.2 Project Manager

The primary responsibility of the Project Manager is the complete and satisfactory execution of the project. The project manager offers expertise in project management methodologies.

Responsible for:

- Project planning and execution
- Facilitate issue resolution
- Resolve scheduling issues
- Provide written plans and schedules templates

- Define, track and maintain project schedule and budget
- Ensure project follows project management principles
- Manage communication between stakeholders
- Ensure project is delivered to schedule and budget (report on deviations)
- Manage project execution
- Coordinate resource requirements

10.3 Project Team

Responsible for:

- Support Project Manager
- Identify product or business requirements
- Ensure that the project requirements meet the needs and expectations of the project
- Ensure adherence to schedule commitments
- Reporting on progress/issues
- Execute project tasks

10.4 Special considerations for contract PMs and team members from the same agency

The project manager will be responsible for managing the project within the approved project budget. Since the project manager and project staff members work for the same contractor the following steps are included in the process to assure financial controls and separation of duties:

- The "Application Team Lead / ITD Program Manager" is responsible for reviewing all estimates and forecasts related to contract staff assignments to assure that the estimates are reasonable for the task.
- The "Project Manager" is responsible to validate that the work hours reported stay within the approved estimate.
- The "Project Manager" is responsible for managing to an approved project plan and to assure that hours worked by individuals on the project are in line with schedule expectations.
- The "Application Team Lead / ITD Program Manager" is responsible for validating that the hours invoiced match the expected hours per the approved plan and that they are reasonable for the task.
- The "Application Team Lead / ITD Program Manager" is responsible for validating that the hours identified in proposed Change Requests are reasonable.
- Audits may be performed at any time to validate that the standard process is being utilized

Change Request Form

Project Name: Next Generation Radio South (NGR South)
Phase: Execution
Project Manager: Tatiana Plett
Project #: 09905752
Clarity Project ID: PR00010606
CR Control #: 01
Date Submitted: August 20th, 2015
Functional area to change: Scope and Cost

1 Key Roles

- Project Sponsor: Jim Kensok
- Steering Committee: Jim Corder, David Howell, Bryan Cox, Mike McAllister, Carey Mourin
- Other Stakeholders: Jeff Daniels, Don Kellogg, Brian Taylor, Alan Smith
- Program Manager: Matt Reding

2 Summary

This Change Request references Risk RSK00001305 as defined in the project risk register. **Funding identified in Section 5 (below) is a request to access predefined contingency funds tied directly to this project risk**. No additional funds are being requested for project estimate at complete (EAC).

Scope change:

- UHF vehicular repeater solution will now be deployed as a VHF vehicular repeater solution.
- Quantity of repeaters has been increased from 30 to 60.

Benefits of scope change:

- Many gas servicemen work alone. This solution will allow users to utilize the full power of the 25W mobile radio (via a VHF handheld) when working away from their trucks to communicate with each other as well as Dispatch.
- Will enable a "no delay" point-to-point communication function for crews and contractors. Current mobile radio and handheld is unable to accommodate this.
- Will enable communication with MedStar emergency services for emergency response situations. The current mobile radio and UHF repeater solution are unable to accommodate this.
- This solution reduces the number of handhelds in our portfolio to 1, minimizing confusion and the need to carry additional equipment.
- The VHF frequency between the repeater handheld and the repeater unit is the same frequency used in the north (our legacy VHF frequency), which allows vehicles to travel to all regions of our service territory and remain functional. No need for equipment reprogramming.

3 Consequences / Risks

The main risk of not implementing this change is the safety of Avista's crews. Without repeaters in the vehicles, crews will not be able to communicate with Dispatch when working away from their vehicles. This becomes problematic when trying to resolve gas emergency issues. Communicating with Dispatch while away from the vehicle will improve safety for both employees and customers. Avista requires the ability for a radio operator to

Change Request Form

initiate an emergency notification to the Gas Control Room as well as have contact with emergency first responders if necessary. Consistent, reliable communications and processes throughout the gas service territories increase safety for all.

4 Scope Change:

Before Change	This change
a) 30 UHF repeaters b) 30 UHF portables	a) 60 VHF repeaters b) 60 VHF portables

5 Cost /Resource Change

We request that this cost change will be funded from NGR-Oregon contingency funds.

Resources	Before Change	This Change	After Change
Total Hours:	**6,276**	**0**	**6,276**
Description (why are additional hours needed? skill set changes, etc.) a) b)			
Cost	**Before Change**	**This Change**	**After Change**
Clarity Blended Labor:	$0	$0	$0
Product:	$ 623,906	$ 22,814	$ 646,720
Professional Services:	$0	$0	$0
Other:	$0	$0	$0
AFUDC:	$0	$0	$0
Non-ET Labor:	$0	$0	$0
Total:	**$ 623,906**	**$ 22,814***	**$ 646,720**

*For clarification: the total quote for VHF equipment is $168,587, we have a credit for $52,500 (reduced) as well as $93,273 already in budget for this purpose. The only money we request to use from contingency funds is $22,814.

FERC Allocation of Project Costs

	Installation *(107600)*		Removal *(108000)*	
Accounting Asset Category	**Physical Product ($)**	**Labor and Other ($)**	**Labor and Other ($)**	**Total ($)**
Hardware *(FERC Account 391)*	$ 79,846	$ 46,494	$0	$ 126,340
Communications Equipment *(FERC Account 397)*	$ 1,347,448	$2,910,057	$0	$4,257,505
Software *(FERC Account 303)*	$0	$0	$0	$0
Estimated Total Cost:	**$1,427,294**	**$2,956,551**	**$0**	**$4,383,845**

Change Request Form

6 Schedule Change

Phase	Target date for completion	
	Before Change	This Change
Planning Phase	03/10/2015	No change
Execution Phase	12/31/2015	No change

Project Name: Next Generation Radio South (NGR Oregon)
Project Phase: Execution
Project Accounting Number: 09905752
Clarity Project ID: PR00010606
Risk or Issue ID: Unplanned Scope Increase (RSK00001305), Project Design Complexity (RSK00000919), Management Reserve (RSK00001207), Equipment specification changes (RSK00001306)
Capital Funding Source: Next Generation Radio (5106-YY826)
Constraint(s): Scope and Schedule and Funding

1 Key Roles

Business Sponsor	Jim Kensok	**Business Case Owner**	Jim Corder
IS/IT Sponsor	Jim Corder	**Project Manager**	Tatiana Plett
Program Manager	Matt Reding	**Steering Committee**	Jim Corder, Walter Roys, Mike Faulkenberry, Bryan Cox, Mike McAllister, Carie Mourin
Other Stakeholders	Jeff Daniels, Don Kellogg, Brian Taylor, Alan Smith		

2 Summary of Change(s)

2.1 SCOPE:

A. La Grande Service Center scope addition:

Electrical Service Capacity - In the original plans to provide power to the new communications shelter at La Grande, a single trench was to be dug to provide both electrical and fiber connectivity. It was recently determined that there is not enough capacity in the current electrical panel in the service center building to power the new shelter. As a result, the Oregon Trail Electric Cooperative (OTEC) proposed different alternatives to provide electrical service to the shelter. The option chosen involves the installation of a new power pole to provide service to the La Grande shelter. This work will be performed by OTEC with Avista approval and oversight. This electrical service upgrade is a prerequisite to obtaining a permit from Island City to proceed with the remaining site work. However, before we can proceed with OTEC's plan, there's a need to document the electrical system load at the La Grande service center and design a new electrical system and service for a new wireless communication site to be constructed on the same site.

B. Klamath Falls Service Center scope additions:

B1. **Klamath Falls Tower foundation** - During the project planning phase, Valmont Industries provided Avista with a microwave antenna tower design that included a pad and pier style foundation. The original pad was to be 5.5 feet deep using an 8ft by 8ft wide concrete pad at 2ft thick. The pier portion of the foundation was designed to be 3.5ft tall at 3.5ft in diameter. Upon completion of the pre-construction soil study at the Klamath Falls location, Valmont changed their foundation requirement to a drilled shaft that is 25ft deep at 3.5ft in diameter. The reason for this was the high level of the ground water in the area (approximately 3ft down from the surface).

B2. **Klamath Falls Electrical Trench** - In the original plans to provide power to the new communications shelter at Klamath Falls, a single trench was to be dug to provide both electrical and fiber connectivity to the new shelter. Pacific Power has since determined that there is not enough room in the current electrical panel in the service center building to power the new shelter. As a result Pacific Power requires a new transformer and new trench with 3" conduit be installed to allow for service to the new building. This electrical service is a requirement for the newly installed shelter.

C. Hogback Mountain scope increase: To accommodate the site expansion construction work that Avista is performing at the Hogback Mountain site, site access road reinforcements are required to support the transportation of building material and labor crews to and from the construction site. This has been defined as a requirement from the road and property owner.

D. Alcatel-Lucent Microwave technology: This project is introducing at Avista, Alcatel-Lucent technology (hardware and software) for microwave equipment. This fact requires additional labor from the engineering team for learning, design, and training, relative to designing and integrating the new technology into portfolio. The Alcatel operating system and management tools (SAM, CPAM, and Service Portal) will require a significant knowledge transfer for Avista Engineering, NetOps and Utility Telecom as well as require data center resources to implement and maintain.

E. Avista Labor: Increases in scope and complexity of the project deliverables necessitate an increase in Avista engineering, project management, project coordination and telecom shop labor hours.

Project Role	Original EAC	Current EAC	Labor Variance
IT Ops - Central Sys - Engineer	-	2	2
IT Ops - Network Sys - Engineer	1	7	6
IT Ops - Shop - Com Tech JM	73	392	319
Network Eng - Telecom (Circuits and Paths)	-	10	10
Network Eng - Traffic Routing & Switching	474	1,224	750
Network Eng - Transport (Fac & Env)	-	120	120
Network Eng - Transport (Wireless RF)	1,263	1,484	221
Network Eng & Domain Arch	115	19	(96)
Program Manager	220	399	179
Project Coordinator	2,003	1,446	(557)
Project Manager	2,090	2,343	253
Security Engineer - Cyber	60	66	6
Security Operations I&A Administrator	-	9	9
System Engineer - Communication	-	37	37
System Engineering Manager	930	646	(284)
	7,229	**8,200**	**971**

F. Mobile Radio Installation scope increase: The mobile radio installation contractor is required to perform additional radio equipment programming, functionality verification, bench testing and code plug troubleshooting. Contractor needs to purchase ancillary materials, not provided by Avista, necessary to complete the mobile radio installations. Avista requires contractor to purchase external speakers required for the Pyramid repeater installations.

2.2 BUDGET:

A. Mountain top lease agreements: Requesting that all site lease agreement fees be captured (based on a pro-rated amount) and charged to the project for the duration of the Execution phase.
B. Funding to accommodate the requested scope changes outlined above. For cost breakout, please refer to the table in Section 6 below.

2.3 SCHEDULE:

Schedule extensions to accommodate the scope changes above. For specific schedule change details, please refer to Section 5 below.

3 Business Impact

If these changes are not approved, the following impacts will occur:

- The FCC has granted several licenses to install Avista's Oregon radio system in the AMTS frequencies. In the case that we could not complete the construction work required for this project, Avista would become non-compliant with the FCC spectrum licensing terms and could be penalized with monetary fines, or a request to forfeit said licensing.
- Inconsistency in the way that we perform dispatch between Avista's northern territories (WA, ID, MT) and the southern territories (OR) regarding the LMR system.

4 Scope Change Details:

Existing Deliverables	Changes to Deliverables
1. **FCC Mandate** – Avista will provide coverage models, interference mitigation plans, narrow-banded equipment and all applicable documentation.	
2. **Licensing** – Licensing of VHF or UHF frequencies for vehicular cross band repeaters.	
3. **Mountain top build out** – These locations will house the LMR infrastructure required to comply with the FCC rules on significant coverage for the Automated Maritime Telecommunications System (AMTS) frequency spectrum.	a. Hogback Mountain scope increase (please refer to Section 2.1 Item C) b. Mountain Top Lease Agreements (please refer to Section 2.2 Item A)
4. **Service center infrastructure networking** (IP/Microwave) – These locations are required to provide the backhaul connectivity to the control nodes of the LMR trunked radio system for both the service centers/office and the mobile radios.	c. La Grande Service center scope addition (please refer to Section 2.1 Item A) d. Klamath Falls Service center scope additions (please refer to Section 2.1 Items B1 and B2)
5. **Service center office equipment installation** – These installations are the equipment that allows office staff to monitor and utilize the radio system	
6. **Security** - Avista will comply with all physical and cyber security policies.	
7. **Vehicle installs** – These are the mobile radios that will be the backbone of the standard communication protocols set forth by Gas Control Room. This will be	e. Mobile Radio Installation scope increase (please refer to Section 2.1 Item E)

the most commonly used component of the radio system.	
8. **Portable Radios** – All trucks will be equipped with intrinsically safe (IS) or equivalent certification portable radios for use or access outside the vehicles.	
9. **Training** – There will be comprehensive training sessions and materials that will provide technical background and hands-on use of the radio system.	
10. **Monitoring** –The Network Operations group will monitor radio node communications infrastructure placed at remote sites.	
11. **Documentation** – Documentation for operation of the LMR will be available to all operators.	
12. **Operational hand off** – The project will define an operational support model. Preventative maintenance documents will be provided to Avista Network Operations and to the operational support / maintenance teams for onsite preventive maintenance	

5 Schedule Change Details:

Phase	Target date for completion		Description
	Planned Date	Revised Date	
Planning			
Execution	12/2015	10/2016	• Negotiating and securing mountain top lease agreements took longer than expected and delayed construction commencement • Winter weather conditions are currently holding the project from completing construction work at the mountain tops • Scope changes referenced in section 2.1 of this document require additional time
Closing	12/2015	12/2016	Allowing enough time for warranty period and closing activities.

6 Funding Change Details:

We request that this cost change will be funded from NGR-Oregon contingency funds.

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Clarity Blended Labor:	$608,526	$50,232	$657,440
Product:	$1,451,727	$37,885	$1,489,611
Professional Services:	$1,995,158	$144,197	$2,139,355
Other:	$31,620	$57,118	$88,738
AFUDC:	$158,423	$202,968	$361,390
Non-ET Labor:	$1,376	$692	$2,067
Total:	**$4,246,829**	**$493,091**	**$4,739,920**

7 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service.

	Installation *(107600)*		**Removal *(108000)***	
Accounting Asset Category	**Physical Product ($)**	**Labor and Other ($)**	**Labor and Other ($)**	**Total ($)**
Hardware *(FERC Account 391)*	$	$	$	$
Communications Equipment *(FERC Account 397)*	$1,489,611	$3,250,309	$	$4,739,920
Software *(FERC Account 303)*	$	$	$	$
Estimated Total Cost:	$1,489,268	$3,250,309	$	$4,739,920

Project Name:	NGR Oregon
Project Phase:	Execution
Project Accounting Number:	09905752
Clarity Project ID:	PR00010606
Risk or Issue ID:	Unplanned scope increase (RSK00001305), Project Design Complexity (RSK00000919), Management Reserve (RSK00001207)
Capital Funding Source:	Next Generation Radio (5106-YY826)
Constraint(s):	Scope, Schedule and Funding

1 Key Roles

Business Sponsor	Jim Kensok	**Business Case Owner**	Jim Corder
IS/IT Sponsor	Jim Corder	**Project Manager**	Tatiana Plett
Other Stakeholders	Jeff Daniels, Don Kellogg, Brian Taylor, Alan Smith	**Steering Committee**	Jim Corder, Walter Roys, Mike Faulkenberry, Bryan Cox, Mike McAllister, Carie Mourin, Mike Busby

2 Summary of Change(s)

2.1 SCOPE

2.1.1 Construction work additions:

Gillespie, Prudhon and Associates (GP&A), Avista's selected engineering and system implementation vendor, requires a change order to address project scope additions that both their team and the Avista project team deem necessary to deliver a working 2-way radio solution in the Oregon territory. A summary of the changes are below and directly reference deliverable-based tasks from the open Work Authorization with GP&A.

- [010PM - Project Management and Cost Reporting]: delays in the project due to adverse weather for performing construction, require additional time for project management tasks from GP&A.
- [040HF - Hogback Mountain Site final Configuration] : this site has several challenges that increase the cost of the project, such as: road cribbing to protect the access road to the mountain top from damage (this was a requirement of the site owners), several concrete truck short loads, mixing concrete on site, foundation changes from a surface pad to a more intensive pad and pier, new electrical trench, extra time on permitting, additional freight costs and crane fees for the generator and building delivery from Klamath Falls Service Center to Hogback due to an unplanned road closure.
- [050BM - Mount Baldy, Medford, OR]: additional labor and costs are due to: delays by Jackson County issuing the permits, extra freight and crane cost due to the long permitting process and road closures, installation of a new ice-bridge to protect the waveguide from the tri-pole tower to the existing ice bridge, and additional charge to install liquid propane gas lines by Amerigas.
- [080ME - Mount Emily, La Grande, OR]: requires additional funds to cover work to install a face mount for the VHF antenna. Two extra personnel are required to install this due to the size of the mount.
- [090LG - La Grande Service Center, Island City, OR]: Additional funds are requested to cover work to coordinate construction at the La Grande Service Center due to the complex approval process for Island City's planning department.

- [100KF – Klamath Falls Service Center, Klamath Falls, OR]: Additional funds are requested to cover unplanned mobilizations, snow removal necessary to continue work, and procurement and installation of a new fiber optic storage vault and fiber optic splicing for connection from the communications building to the existing router at the service center.

2.1.2 **La Grande Service Center – Electrical findings:** As a result of the electrical study performed at the La Grande Service Center, it was determined that the current electrical panel is using only 25% of its capacity, so there is no need to upgrade the electrical service in the La Grande facility. Therefore, there is no need for Oregon Trail Electric Cooperative (OTEC) to perform any work at this facility.

2.1.3 **Unplanned Trips to Oregon:** As the project approaches completion at several sites, there is a need to send Avista engineers to confirm that the microwave links are fully operational when turned on and troubleshoot if necessary. Five additional unplanned trips are necessary and outlined below:

a) Trip to Clackamas, Oregon: The purpose of this trip is on-site integration for IP service routers with microwave equipment. Avista, Alcatel and GP&A engineers will work together on this effort.

b) Trip to Mt. Scott and Blanton Heights: enable the microwave radio system at Mt. Scott and Blanton Heights. Two Avista engineers will be required (one at each site).

c) Trip to Elk Mountain, Mount Baldy-Safley, Hogback Mountain and Klamath Falls Service center to enable the microwave radio system at all four locations in Southern Oregon. Two Avista engineers are required on-site.

d) Trip to Mount Emily and La Grande service center in Northern Oregon to enable the microwave radio system. Two Avista engineers are required on-site to complete this task.

e) Trip for site commissioning: The purpose of this trip is the site acceptance test at all sites in Oregon. This work will be done in conjunction with GP&A, who are the firm performing construction on behalf of Avista. Three Avista engineers are required to visit all sites and complete this task.

f) Trip for the RTUs: late deployment of the RTUs will require additional trips to the mountain tops to connect these devices.

2.1.4 **Installation services for equipment located at Day Wireless' sites:** The project's sites at Elk Mountain and Mt. Scott belong to Day Wireless Systems. No other contractor is allowed to install equipment at these sites. For that purpose, we require Day Wireless to install the microwave radios and antennas at both sites.

2.1.5 **Professional Services – Alcatel-Lucent:** The project requires Alcatel-Lucent on-site configuration and integration support services for the IP service routers and microwave equipment.

2.1.6 **IP phones to be installed at Elk Mountain, Mount Safley-Baldy, Mount Scott and Hogback Mountain:** the project requests to install four (4) IP phones at the locations mentioned above as a backup form of communication in the event that cell phone use isn't available.

2.2 FUNDING

2.2.1 **Updated blended rates**: In January 2016, Avista's Project and Portfolio Management System was upgraded to a more current version. This upgrade included a change affecting role-based blended labor rates that were retroactive to the beginning of the project. This, for certain resources on this project, caused a negative variance between budgeted cost and actual cost. This creates an additional cost for the project.

2.2.2 **RTUs for the project**: In the original design for this project, the Network Operations group would monitor radio node communications infrastructure placed at remote sites using Remote Telemetry Units (RTUs). The deployment of these devices within the NGR Oregon project has been delayed due to design and product selection being performed in a different project, Communications Management Systems Refresh (CMS). In an effort to get these devices approved in a timely manner for deployment in the NGR Oregon project, we require additional engineering time and to perform site surveys for cellular coverage at all 5 mountain tops so they can be connected to the system via cellular modem.

2.2.3 **Lease agreement fees:** Requesting to add 2 more months of monthly lease fees for Mt Baldy as well as 1 trimester of Elk Mountain lease fees to the project while construction is finalized at these sites.

2.2.4 **AFUDC:** The changes described above push the completion of the execution phase of the project until Nov 2016 and closing until Dec 2016 according to the current schedule. We request funding for AFUDC until the end of the year.

2.2.5 **Labor:** The scope additions mentioned above require additional time from Avista resources from several areas of expertise.

Project Role	Actuals	ETC	Actuals + ETC = EAC
IT Ops - Central Sys - Engineer	2.70	-	2.70
IT Ops - Network Sys - Engineer	-	32.00	32.00
IT Ops - Shop - Com Tech JM	438.50	190.00	628.50
Network Eng - Telecom (Circuits and Paths)	9.50	64.00	73.50
Network Eng - Traffic Routing & Switching	1,294.50	387.00	1,681.50
Network Eng - Transport (Fac & Env)	165.00	94.00	259.00
Network Eng - Transport (Wireless RF)	1,566.75	556.00	2,122.75
Network Eng & Domain Arch	19.00	-	19.00
Program Manager	408.75	89.00	497.75
Project Coordinator	1,447.00	145.51	1,592.51
Project Manager	2,459.05	588.00	3,047.05
Security Engineer - Cyber	69.70	19.00	88.70
Security Operations I&A Administrator	9.25	80.00	89.25
System Engineer - Communication	36.50	0.00	36.50
System Engineer & Domain Arch - Comm	0.00	138.00	138.00
System Engineering Manager	574.00	261.85	835.85
	8,500.20	**2,644.36**	**11,144.56**

3 Business Impact

If these changes are not approved, the following impacts will occur:

- The FCC has granted several licenses to install Avista's Oregon radio system in the AMTS frequencies. In the case that we could not complete the construction work required for this project, Avista would become non-compliant with the FCC spectrum licensing terms and could be penalized with monetary fines, or a request to forfeit said licensing.

- Inconsistency in the way that we perform dispatch between Avista's northern territories (WA, ID, MT) and the southern territories (OR) regarding the LMR system.

4 Scope Change Details:

Existing Deliverables	Changes to Deliverables
1. **FCC Mandate** – Avista will provide coverage models, interference mitigation plans, narrow-banded equipment and all applicable documentation.	
2. **Licensing** – Licensing of VHF or UHF frequencies for vehicular cross band repeaters.	
3. **Mountain top build out** – These locations will house the LMR infrastructure required to comply with the FCC rules on significant coverage for the Automated Maritime Telecommunications System (AMTS) frequency spectrum.	Please refer to sections 2.1.1., 2.1.3., 2.1.4. and 2.2.2.
4. **Service center infrastructure networking** (IP/Microwave) – These locations are required to provide the backhaul connectivity to the control nodes of the LMR trunked radio system for both the service centers/office and the mobile radios.	Please refer to sections 2.1.2., 2.1.5.
5. **Service center office equipment installation** – These installations are the equipment that allows office staff to monitor and utilize the radio system	
6. **Security** - Avista will comply with all physical and cyber security policies.	
7. **Vehicle installs** – These are the mobile radios that will be the backbone of the standard communication protocols set forth by Gas Control Room. This will be the most commonly used component of the radio system.	
8. **Portable Radios** – All trucks will be equipped with intrinsically safe (IS) or equivalent certification portable radios for use or access outside the vehicles.	
9. **Training** – There will be comprehensive training sessions and materials that will provide technical background and hands-on use of the radio system.	
10. **Monitoring** –The Network Operations group will monitor radio node communications infrastructure placed at remote sites.	
11. **Documentation** – Documentation for operation of the LMR will be available to all operators.	
12. **Operational hand off** – The project will define an operational support model. Preventative maintenance documents will be provided to Avista Network Operations and to the operational support / maintenance teams for onsite preventive maintenance	
	13. IP phones will be installed at Elk Mountain, Mount Safley-Baldy, Mount Scott and Hogback Mountain. They will constitute a safety feature in case an

	emergency occurs at the mountain tops that could present danger to the safety of the personnel or equipment there.

5 Schedule Change Details:

Phase	Target date for completion		Description
	Planned Date	Revised Date	
Planning			
Execution	10/2016	11/2016	Permitting process for La Grande is taking longer than initially estimated.
Closing	12/2016	12/2016	Time for warranty period and closing activities

6 Funding Change Details:

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Clarity Blended Labor:	$622,982	$250,989	$873,971
Product:	$1,489,612	$0	$1,489,611
Professional Services:	$2,139,355	$278,243	$2,417,598
Other:	$124,514	$0	$124,514
AFUDC:	$361,390	$63,134	$424,524
Non-ET Labor:	$2,067	$0	$2,067
Total:	**$4,739,920**	**$592,366**	**$5,332,286**

7 Compliance and Controls

	Required (Y/N)
Compliance Impact Assessment (contact: James McDougall and Erin McClatchey)	N
Business Continuity Plan (contact: Erin Swearingen)	N
SOX Business Controls Impact Assessment (contact: Stacey Wenz)	N
SOX Computer Controls Impact Assessment (contact: Rob Jacobs)	Y

8 Where will technology be deployed?

1. Klamath Falls Service Center, Klamath Falls, OR
2. La Grande Service Center, La Grande, OR
3. Medford Service Center. Medford, OR
4. Roseburg Service Center, Roseburg, OR
5. Mount Baldy-Safley, Phoenix, OR
6. Elk Mountain, Pleasant Valley, OR
7. Hogback Mountain, Klamath Falls, OR
8. Mount Scott, Sutherlin, OR
9. Blanton Heights, Eugene, OR
10. Mount Emily, La Grande, OR

9 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service.

	Installation *(107600)*		**Removal *(108000)***	
Accounting Asset Category	**Physical Product ($)**	**Labor and Other ($)**	**Labor and Other ($)**	**Total ($)**
Hardware *(FERC Account 391)*	$	$	$	$
Communications Equipment *(FERC Account 397)*	$1,489,611	$3,842,675	$	$5,332,286
Software *(FERC Account 303)*	$	$	$	$
Estimated Total Cost:	**$1,489,611**	**$3,842,675**	**$**	**$5,332,286**

Project Name:	NGR Oregon
Project Phase:	Execution
Project Accounting Number:	09905752
Clarity Project ID:	00010606
Risk or Issue ID:	Permitting and Zoning (RSK00000923), Project Design Complexity (RSK00000919), Equipment specification changes (RSK00001306)
Capital Funding Source:	Next Generation Radio (5106-YY826)
Constraint(s):	Scope and Schedule and Funding

1 Key Roles

Business Sponsor	Jim Kensok	**Business Case Sponsor**	Jim Kensok
Project Sponsor(s)	Jim Corder	**Business Case Owner(s)**	Jim Corder
Program Manager	Matt Reding	**Project Manager**	Tatiana Plett
Other Stakeholders	Jeff Daniels, Don Kellogg, Brian Taylor, Alan Smith	**Steering Committee**	Jim Corder, Walter Roys, Mike Faulkenberry, Bryan Cox, Mike McAllister, Carie Mourin, Mike Busby

2 Summary of Change(s)

SCOPE:

2.1 La Grande Service Center-Facility improvements: The project requires a construction permit to install a communications building and a monopole with microwave equipment at the La Grande Service Center. Island City is one of the approver entities. Island City has agreed to provide us with a construction permit if we comply with the following conditions:

1) Remove front parking lot striping and install a curb or temporary curb along the S “F” Street right-of-way;
2) Prepare a landscaping and maintenance plan showing:
   A. Irrigated landscaping along S “F” Street capable of fully screening the outdoor storage area at the southeast corner of the site;
   B. Five (5) feet of irrigated landscaping in front of the fence and building areas along S "F" Street; and
   C. Five (5) feet of irrigated landscaping along the eastern property line;
3) Sign a waiver of remonstrance to allow for future right-of-way improvements to local street standards along S “F” Street;
4) A stormwater management plan shall be prepared demonstrating stormwater retention and management on site.

The above described requirements cause changes in scope, budget and in the schedule of the project. To be compliant with the FCC deadline we need to address the requested changes immediately.

2.2 File construction extension to FCC: The permitting process for the La Grande service center is complex and very long. Due to additional improvements required by the city (detailed in section 2.1), and given that we are on a deadline with the FCC (2/17/2017), we need to request a construction extension because the city requirements may delay the completion of the radio project at this location.

2.3 Additional equipment required for office installations of network gateways and Zetron Control Stations at the Oregon service Centers: The engineering team requires the following equipment:

- Shelves for modems
- Shelves for some of the DSPs for NCSes
- SFPs and cables to connect RTUs to network
- SFPs and cables to connect LAG and KLA Nokia equipment to the respective office network infrastructure
- Connecting parts for the RTUs
- DC-DC converters for cellular modems

The need for the specified equipment was determined in the course of engineering the respective solutions and sites.

2.4 Lease agreement fees: Requesting to add 6 more months of monthly lease fees for Mt Emily to the project while construction is finalized at these sites.

2.5 Labor: The engineering team requires additional time to get the entire system fully operational.

Project Role	Actuals	ETC	Actuals + ETC = EAC
IT Ops - Central Sys - Engineer	4.70	-	4.70
IT Ops - Distributed Sys - Field Tech	7.25	-	7.25
IT Ops - Network Sys - Engineer	2.50	18.00	20.50
IT Ops - Shop - Com Tech JM	552.00	-	552.00
Network Eng - Telecom (Circuits and Paths)	112.00	73.00	185.00
Network Eng - Traffic Routing & Switching	1,700.00	369.00	2,069.00
Network Eng - Transport (Fac & Env)	188.50	30.00	218.50
Network Eng - Transport (Wireless RF)	1,785.75	336.00	2,121.75
Network Eng & Domain Arch	19.00	-	19.00
Program Manager	437.45	47.00	484.45
Project Coordinator	1,510.50	106.61	1,617.11
Project Manager	2,727.30	326.00	3,053.30
Security Eng & Domain Arch - Cyber	-	14.00	14.00
Security Engineer - Cyber	92.20	36.00	128.20
Security Operations Analyst	3.00	-	3.00
Security Operations I&A Administrator	10.25	34.34	44.59
System Engineer - Communication	36.50	-	36.50
System Engineer & Domain Arch - Comm	60.00	84.00	144.00
System Engineering Manager	574.00	125.85	699.85
	9,822.90	**1,599.79**	**11,422.69**

3 Business Impact

If these changes are not approved, the following impacts will occur:

- The FCC has granted a license for microwave communications from Mount Emily to the LaGrande Service Center to install Avista's microwave radio system. In the case that we could not complete the construction work required for this project, Avista would become non-compliant with the FCC spectrum licensing terms and could lose the granted license.
- Inconsistency in the way that we perform dispatch between Avista's northern territories (WA, ID, MT) and the southern territories (OR) regarding the LMR system.

4 Scope Change Details:

Existing Deliverables	Changes to Deliverables
1. **FCC Mandate** – Avista will provide coverage models, interference mitigation plans, narrow-banded equipment and all applicable documentation.	
2. **Licensing** – Licensing of VHF or UHF frequencies for vehicular cross band repeaters.	
3. Mountain top build out – These locations will house the LMR infrastructure required to comply with the FCC rules on significant coverage for the Automated Maritime Telecommunications System (AMTS) frequency spectrum.	Please refer to section 2.4 and 2.5
4. Service center infrastructure networking (IP/Microwave) – These locations are required to provide the backhaul connectivity to the control nodes of the LMR trunked radio system for both the service centers/office and the mobile radios.	Please refer to section 2.1, 2.2 and 2.5
5. Service center office equipment installation – These installations are the equipment that allows office staff to monitor and utilize the radio system	Please refer to section 2.3.
6. Security - Avista will comply with all physical and cyber security policies.	
7. Vehicle installs – These are the mobile radios that will be the backbone of the standard communication protocols set forth by Gas Control Room. This will be the most commonly used component of the radio system.	
8. Portable Radios – All trucks will be equipped with intrinsically safe (IS) or equivalent certification portable radios for use or access outside the vehicles.	
9. Training – There will be comprehensive training sessions and materials that will provide technical background and hands-on use of the radio system.	
10. Monitoring –The Network Operations group will monitor radio node communications infrastructure placed at remote sites.	
11. Documentation – Documentation for operation of the LMR will be available to all operators.	
12. Operational hand off – The project will define an operational support model. Preventative maintenance documents will be provided to Avista Network Operations and to the operational support / maintenance teams for onsite preventive maintenance	
13. IP phones will be installed at Elk Mountain, Mount Safley-Baldy, Mount Scott and Hogback Mountain. They will constitute a safety feature in case an emergency occurs at the mountain tops that could present danger to the safety of the personnel or equipment there.	

5 Schedule Change Details:

Phase	Target date for completion		Description
	Planned Date	Revised Date	
Planning			No change
Execution	11/2016	12/2016	Permitting process for the La Grande Service center is taking longer than initially estimated
Closing	12/2016	02/2017	Time for warranty period and closing activities

6 Funding Change Details:

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Clarity Blended Labor:	$873,972	$26,647	$900,619
Product:	$1,489,611	$37,600	$1,527,212
Professional Services:	$2,417,598	$98,236	$2,515,835
Other:	$124,514	$11,431	$135,945
AFUDC:	$424,524	$15,791	$440,316
Non-ET Labor:	$2,067	$4,000	$6,067
Total:	**$5,332,287**	**$193,706**	**$5,525,993**

7 Compliance and Controls

Area	Required (Y/N)
Compliance impact assessment (contact: James McDougall)	N
Business Continuity Plan (contact: Erin Swearingen)	N
SOX Business Controls impact assessment (contact: Stacey Wenz)	N
SOX Computer Controls impact assessment (contact: Rob Jacobs)	Y

8 Where will technology be deployed?

1. Klamath Falls Service Center, Klamath Falls, OR
2. La Grande Service Center, La Grande, OR
3. Medford Service Center. Medford, OR
4. Roseburg Service Center, Roseburg, OR
5. Mount Baldy-Safley, Phoenix, OR
6. Elk Mountain, Pleasant Valley, OR
7. Hogback Mountain, Klamath Falls, OR
8. Mount Scott, Sutherlin, OR
9. Blanton Heights, Eugene, OR
10. Mount Emily, La Grande, OR

9 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service.

	Installation *(107600)*		**Removal** *(108000)*	
Accounting Asset Category	**Physical Product ($)**	**Labor and Other ($)**	**Labor and Other ($)**	**Total ($)**
Hardware *(FERC Account 391)*	$	$	$	$
Communications Equipment *(FERC Account 397)*	$1,527,212	$3,998,781	$	$5,525,993
Software *(FERC Account 303)*	$	$	$	$
Estimated Total Cost:	**$1,527,212**	**$3,998,781**	**$**	**$5,525,993**

Project Name: NGR Oregon
Project Phase: Execution
Project Accounting Number: 09905752
Clarity Project ID: 00010606
Risk or Issue ID: Permitting and Zoning (RSK00000923)
Capital Funding Source: Next Generation Radio (5106-YY826)
Constraint(s): Scope, Schedule and Funding

1 Key Roles

Business Sponsor	Jim Kensok	**Business Case Sponsor**	Jim Kensok
Project Sponsor(s)	Jim Corder	**Business Case Owner(s)**	Jim Corder
Program Manager	Matt Reding	**Project Manager**	Tatiana Plett
Other Stakeholders	Jeff Daniels, Don Kellogg, Brian Taylor, Alan Smith	**Steering Committee**	Jim Corder, Walter Roys, Mike Faulkenberry, Bryan Cox, Mike McAllister, Carie Mourin, Mike Busby

2 Summary of Change(s)

SCOPE:

2.1 De-scope La Grande Service Center-Facility improvements:

The NGR Oregon project was granted funding to comply with the facility improvements required by Island City as a condition to issue the construction permit to Avista. Avista, fulfilling Island City requirements, performed RFP R-41199 in October. The RFP was extended to four (4) construction companies to bid for this work, however each company had a full schedule between now and the end of the year and would not be able to accommodate Avista's requested work until 2017. This is a formal request to remove scope item 2.1 from NGR Oregon, with the assumption it will be completed in a separate project in 2017.

3 Business Impact

There is no business impact for this particular change. Avista's commitment to perform the facility improvements will remain under a separate project.

4 Scope Change Details:

Existing Deliverables	Changes to Deliverables
1. **FCC Mandate** – Avista will provide coverage models, interference mitigation plans, narrow-banded equipment and all applicable documentation.	
2. **Licensing** – Licensing of VHF or UHF frequencies for vehicular cross band repeaters.	
3. Mountain top build out – These locations will house the LMR infrastructure required to comply with the FCC rules on significant coverage for the Automated Maritime Telecommunications System (AMTS) frequency spectrum.	

4. **Service center infrastructure networking** (IP/Microwave) – These locations are required to provide the backhaul connectivity to the control nodes of the LMR trunked radio system for both the service centers/office and the mobile radios.	Scope item 2.1.
5. **Service center office equipment installation** – These installations are the equipment that allows office staff to monitor and utilize the radio system	
6. **Security** - Avista will comply with all physical and cyber security policies.	
7. **Vehicle installs** – These are the mobile radios that will be the backbone of the standard communication protocols set forth by Gas Control Room. This will be the most commonly used component of the radio system.	
8. **Portable Radios** – All trucks will be equipped with intrinsically safe (IS) or equivalent certification portable radios for use or access outside the vehicles.	
9. **Training** – There will be comprehensive training sessions and materials that will provide technical background and hands-on use of the radio system.	
10. **Monitoring** –The Network Operations group will monitor radio node communications infrastructure placed at remote sites.	
11. **Documentation** – Documentation for operation of the LMR will be available to all operators.	
12. **Operational hand off** – The project will define an operational support model. Preventative maintenance documents will be provided to Avista Network Operations and to the operational support / maintenance teams for onsite preventive maintenance	
13. **IP phones will be installed at Elk Mountain, Mount Safley-Baldy, Mount Scott and Hogback Mountain.** They will constitute a safety feature in case an emergency occurs at the mountain tops that could present danger to the safety of the personnel or equipment there.	

5 Schedule Change Details:

Phase	Target date for completion		Description
	Planned Date	Revised Date	
Planning			No change
Execution	12/2016		No change
Closing	02/2017	03/2017	Allowing additional time for closing activities

6 Funding Change Details:

Cost	Budget Column	Dollars associated with identified constraint(s)	New EAC
Clarity Blended Labor:	$900,620	$0	$900,620
Product:	$1,527,212	$0	$1,527,212
Professional Services:	$2,515,835	-$60,418	$2,455,416
Other:	$135,945	$0	$135,945
AFUDC:	$440,316	-$14,151	$426,164
Non-ET Labor:	$6,067	$0	$6,067
Total:	**$5,525,994**	**-$74,569**	**$5,451,425**

7 Compliance and Controls

Area	Required (Y/N)
Compliance impact assessment (contact: James McDougall)	N
Business Continuity Plan (contact: Erin Swearingen)	N
SOX Business Controls impact assessment (contact: Stacey Wenz)	N
SOX Computer Controls impact assessment (contact: Rob Jacobs)	Y

8 Where will technology be deployed?

1. Klamath Falls Service Center, Klamath Falls, OR
2. La Grande Service Center, La Grande, OR
3. Medford Service Center. Medford, OR
4. Roseburg Service Center, Roseburg, OR
5. Mount Baldy-Safley, Phoenix, OR
6. Elk Mountain, Pleasant Valley, OR
7. Hogback Mountain, Klamath Falls, OR
8. Mount Scott, Sutherlin, OR
9. Blanton Heights, Eugene, OR
10. Mount Emily, La Grande, OR

9 FERC Allocation of Project Costs

FERC requires the cost of the project to be broken down into fixed asset types for depreciation and asset valuation purposes. Of the total project cost estimate, break out the costs into the following asset categories. Note that these cost breakouts include the amount of effort (equipment, labor, loadings, and professional services) to put the asset into service.

	Installation *(107600)*		Removal *(108000)*	
Accounting Asset Category	**Physical Product ($)**	**Labor and Other ($)**	**Labor and Other ($)**	**Total ($)**
Hardware *(FERC Account 391)*	$	$	$	$
Communications Equipment *(FERC Account 397)*	$1,527,212	$3,923,804	$	$5,451,016
Software *(FERC Account 303)*	$	$	$	$
Estimated Total Cost:	**$1,527,212**	**$3,923,804**	**$**	**$5,451,016**

Project Name: NGR Oregon
Clarity Project ID: 00010606
Acctg Project#: 09905752
Business Case Name: Next Generation Radio
ERBI: (5106-YY826)

1 Key Roles

Business Sponsor	Jim Kensok	**Business Case Owner(s)**	Jim Corder
Project Sponsor(s)	Jim Corder	**Project Manager**	Tatiana Plett
Program Manager	Matt Reding	**Steering Committee**	Jim Corder, Walter Roys, Mike Faulkenberry, Bryan Cox, Mike McAllister, Carie Mourin, Mike Busby
Other Stakeholders	Jeff Daniels, Don Kellogg, Brian Taylor, Alan Smith		

2 Scope Review

Item#	Approved Scope Item	Completed? Yes? In process? Canceled?	Status or description of remaining work
1	**FCC Mandate** – Avista will provide coverage models, interference mitigation plans, narrow-banded equipment and all applicable documentation.	Completed	
2	**Licensing** – Licensing of VHF or UHF frequencies for vehicular cross band repeaters.	Completed	
3	**Mountain top build out** – These locations will house the LMR infrastructure required to comply with the FCC rules on significant coverage for the Automated Maritime Telecommunications System (AMTS) frequency spectrum.	Completed	
4	**Service center infrastructure networking** (IP/Microwave) – These locations are required to provide the backhaul connectivity to the control nodes of the LMR trunked radio system for both the service centers/office and the mobile radios.	In Process	Construction at La Grande service center is scheduled to be completed by 11/30/2016 (Go-live date). La Grande Site Commissioning and Coverage Verification Test will happen during the warranty period.
5	**Service center office equipment installation** – These installations are the equipment that allows office staff to monitor and utilize the radio system	Completed	

6	**Security** - Avista will comply with all physical and cyber security policies.	Completed	
7	**Vehicle installs** – These are the mobile radios that will be the backbone of the standard communication protocols set forth by Gas Control Room. This will be the most commonly used component of the radio system.	Completed	
8	**Portable Radios** – All trucks will be equipped with intrinsically safe (IS) or equivalent certification portable radios for use or access outside the vehicles.	Completed	
9	**Training** – There will be comprehensive training sessions and materials that will provide technical background and hands-on use of the radio system.	Completed	
10	**Monitoring** –The Network Operations group will monitor radio node communications infrastructure placed at remote sites.	In process	Installation of the Remote Telemetry Units (RTUs) is scheduled to happen during the warranty period. Router & SAR monitoring dependent upon ongoing configuration updates to local and backhaul network.
11	**Documentation** – Documentation for operation of the LMR will be available to all operators.	Completed	
12	**Operational hand off** – The project will define an operational support model. Preventative maintenance documents will be provided to Avista Network Operations and to the operational support / maintenance teams for onsite preventive maintenance	In process	Three (3) hand-off sessions have been scheduled during the month of Nov 2016.
13	**IP phones will be installed at Elk Mountain, Mount Safley-Baldy, Mount Scott and Hogback Mountain.** They will constitute a safety feature in case an emergency occurs at the mountain tops that could present danger to the safety of the personnel or equipment there.	Completed	

2.1 Where will technology be deployed?

1. Klamath Falls Service Center, Klamath Falls, OR
2. La Grande Service Center, La Grande, OR
3. Medford Service Center. Medford, OR
4. Roseburg Service Center, Roseburg, OR

5. Mount Baldy-Safley, Phoenix, OR
6. Elk Mountain, Pleasant Valley, OR
7. Hogback Mountain, Klamath Falls, OR
8. Mount Scott, Sutherlin, OR
9. Blanton Heights, Eugene, OR
10. Mount Emily, La Grande, OR

2.2 Financial Summary

Project budget will be managed in Clarity. Below is a summary of the financial information for the project.

Financial Summary

	Actuals Thru	Actual	Forecast	EAC	Budget	Var
Blended Clarity Labor	9/30/16	781,471	118,023	899,494	900,620	1,126
Product	9/30/16	1,513,498	13,714	1,527,212	1,527,212	0
Professional Services	9/30/16	1,913,843	601,991	2,515,834	2,515,835	0
Other	9/30/16	105,327	30,617	135,944	135,945	0
AFUDC	9/30/16	341,530	98,786	440,315	440,316	0
Non-ET Labor	9/30/16	2,067	4,000	6,067	6,067	0
Subtotals		4,657,736	867,132	5,524,867	5,525,994	1,126
Funded Amount, Excluding Contingency					5,525,993	
Contingency Funding					0	
Total Funded Amount					5,525,993	
Contingency Funds Required						0
Additional Funding Required						0

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3 Compliance and Controls

Area	Required (Y/N)
Compliance impact assessment (contact: James McDougall)	N
Business Continuity Plan (contact: Erin Swearingen)	N
Reliability Compliance (NERC) (contact: Ryan Walker)	N/A
SOX Business Controls impact assessment (contact: Stacey Wenz)	N
SOX Computer Controls impact assessment (contact: Rob Jacobs)	Y

4 Pre Go-Live Operational Walk Through

Network	Y
Applications	N/A
Communications	Y
Security	Y
Distributed Systems	N/A
Central Systems	N/A

5 Implementation Risks and Issues

Item#	Outstanding work, risks, issues	Reason this is unresolved
1	RISK: Natural Disasters	Out of human control
2	RISK: Contractor performance	This risk should stay open until all work is completed and accepted
3	RISK: Too short time for erecting the monopole and alignment of antennas at the La Grande site. There is no margin for errors or unforeseen difficulties.	Delays in the permitting process for La Grande cause this risk to remain open until all work is complete
4	RISK: Weather could make access to the mountain top impossible and affect the site commissioning	Delays in the permitting process for La Grande cause this risk to remain open until work is complete
5	RISK: There are still RTU software adjustments to be resolved before Go Live.	RTU engineering work remains. The project team is currently working on getting this resolved before the Go-Live date.

Project Transactions Accounting Period : <All> , Report Category : CAP , Task Number : <All> , Source Id : <All> , Ferc Acct : <All> , Accounting Year : <All> * *Transation Data is available beginning January 2005

Accounting Perioc	Report Catego	Task Number:<All>	Source Id:<All>	Ferc Acct:<All>	Accounting Year:<All>
					Transaction Amt SUM
Project Number	Summary Exp Category	Expenditure Category	Expenditure Type	Vendor Name	-
09905752	Labor	Labor	320 Overtime Pay - NU		224.43
			325 Overtime Pay - Union		5,156.84
			340 Regular Payroll - NU		143,460.16
			345 Regular Payroll - Union		21,134.32
		Sum			169,975.75
	Non-Labor	AFUDC	535 AFUDC - Debt		148,103.43
			540 AFUDC - Equity		262,405.98
		Centralized Assets	601 Dedicated Circuits	CENTURYLINK	1,663.09
				DAY WIRELESS SYSTEMS	2,400.00
			613 Telephones	CERIUM NETWORKS	1,523.28
				0	-
			617 Hardware	COMPUNET INC	6,645.98
				INLAND EMPIRE DISTRIBUTION SYSTEMS INC	2,319.88
				0	-
			626 Hardware Purchases	COMPUNET INC	40,124.21
			640 Radio Installation	DAY WIRELESS SYSTEMS	42,280.48
		Contractor	010 General Services	FEDEX	673.89
			012 Combo Goods & Services	COFFMAN ENGINEERS	3,370.65
				DAY WIRELESS SYSTEMS	137,213.05
				GILLESPIE PRUDHON & ASSOCIATES INC	1,333,207.19
				0	-
			015 Construction Services	KLAMATH FOREST PROTECTIVE ASSOCIATION	26,400.00
			020 Professional Services	ALCATEL LUCENT USA INC	41,085.00
				COFFMAN ENGINEERS	13,798.90
				DAY WIRELESS SYSTEMS	79,245.33
				EMERGENCY COMMUNICATIONS OF SOUTHERN OREGON	16,250.00
				GILLESPIE PRUDHON & ASSOCIATES INC	481,428.53
				OREGON TRAIL ELECTRIC CO-OP	150.00
				PACIFIC POWER	2,459.00
				PACIFIC POWER GROUP	2,354.12
				PARAMETRIX INC	8,517.50
				TAIT NORTH AMERICA INC	104,492.65
				0	(18,411.50)
			035 Workforce - Contract	CERIUM NETWORKS	3,785.97
				HP ENTERPRISE SERVICES	101.33
				RIGHT SYSTEMS INC	34,887.20
				VOLT MANAGEMENT CORP	471,744.49
				0	-
		Employee Expenses			22,257.13
		Overhead			191,957.50
		Vehicle	710 Rental Expense - Vehicle	ENTERPRISE RENT A CAR	102.77
			720 Vehicle Fuel Gasoline	CORP CREDIT CARD	19.15

Project Number	Summary Exp Category	Expenditure Category	Expenditure Type	Vendor Name	-
		Voucher	815 Computer Equip Hardware	COMPUNET INC	39,722.02
				0	-
			837 Equipment-Stores and Lab	ALCATEL LUCENT USA INC	(993.76)
			838 Fees - General	CERIUM NETWORKS	342.99
				NUVODIA LLC	153.00
				VOLT MANAGEMENT CORP	2,756.27
				0	-
			840 Freight Costs	TAIT NORTH AMERICA INC	455.93
			855 Land and Land Rights	EMERGENCY COMMUNICATIONS OF SOUTHERN OREGON	12,880.00
				KLAMATH FOREST PROTECTIVE ASSOCIATION	3,390.00
				MOUNT BALDY COMMUNICATION SITE LEASING LLC	20,489.50
				UNION COUNTY	5,307.00
				0	-
			880 Materials & Equipment	ALCATEL LUCENT USA INC	122,068.02
				AMERIGAS	14,131.18
				ANIXTER INC	1,856.64
				COMPUNET INC	2,717.50
				CONNECTION	866.43
				CORP CREDIT CARD	205.87
				DPS TELECOM	31,472.39
				FEDEX	11.52
				FEENEY WIRELESS	2,163.75
				GLOBAL FIBERVISION INC	1,851.17
				GRAYBAR	35,433.72
				Huss, Jacob Craig	13.86
				INTERSTATE BATTERIES OF EASTERN WA	27,684.26
				MOREDIRECT INC	4,160.27
				PACIFIC POWER PRODUCTS	76,663.44
				PLATT ELECTRIC	1,385.83
				TAIT NORTH AMERICA INC	(44,889.51)
				TESSCO INCORPORATED	47,756.02
				VALMONT STRUCTURES	31,487.00
				WORLDWIDE SUPPLY LLC	4,600.68
				0	-
			881 Material & Equip Non Burdn	INLAND EMPIRE DISTRIBUTION SYSTEMS INC	2,009.17
				REIFF MANUFACTURING	99,015.53
				TAIT NORTH AMERICA INC	622.01
				0	-
			882 Materials - Large Purchase	ALCATEL LUCENT USA INC	254,482.33
				TAIT NORTH AMERICA INC	711,119.25
				0	-
			885 Miscellaneous	AMERIGAS	428.16
				CODESOURCE	915.39
				INLAND EMPIRE DISTRIBUTION SYSTEMS INC	67.71
				0	-
			915 Printing	RICOH USA INC	23.91
		Sum			4,979,382.63
	Total for 09905752				5,149,358.38
Total					5,149,358.38

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

REPLY TESTIMONY OF JOSEPH D. MILLER
REPRESENTING AVISTA CORPORATION

Long-Run Incremental Cost of Service Study

I. INTRODUCTION

Q. Would you please state your name, business address and present position with Avista Corporation?

A. My name is Joseph D. Miller. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Have you filed direct testimony in this proceeding?

A. Yes. I have filed direct testimony in this case presenting the natural gas long-run incremental cost of service ("LRIC") study.

Q. What is the scope of your Reply testimony?

A. My testimony will provide the Company's response to the LRIC Study prepared by Commission Staff ("Staff") and the LRIC modifications proposed by the Northwest Industrial Gas Users ("NWIGU"). In addition, my testimony will address the Citizens' Utility Board's ("CUB") concerns regarding the Company's proposed LRIC Study and rate spread.

Q. Please summarize the conclusions of your Reply testimony?

A. The results of the long-run incremental cost studies presented by the Company, Staff and NWIGU demonstrate that, at current rates, on a relative margin-to-cost basis, residential customers (Schedule 410) are close to their relative cost of service, and small commercial customers (Schedule 420) are paying less than their relative cost of service. All other schedules including large general (Schedule 424), interruptible (Schedule 440), seasonal (Schedule 444), and transportation (Schedule 456) exceed their relative cost of service, to varying degrees. Arguments provided by CUB, with reference to the LRIC Study performed by the Company, are fundamentally flawed, and are not backed by empirical evidence, nor does

CUB present its own LRIC Study.

Q. Did other parties prepare independent LRIC studies and/or propose methodological changes to the LRIC studies in this proceeding?

A. Yes. Staff prepared an independent LRIC Study, and NWIGU proposed a methodological change that the Company was able to replicate and produce LRIC Study results.[1]

Q. Did the other LRIC Study results closely match Avista's?

A. Yes. While there may be differences of opinion on the treatment of certain LRIC Study components, the results are similar.

Q. Have you prepared a table which summarizes the results of the studies presented in this proceeding?

A. Yes. In addition to the studies prepared by Avista and Staff, and the methodological change proposed by NWIGU, the Company has prepared a fourth study which incorporates the proposed methodology changes of both Staff and NWIGU into one LRIC Study. Table No. 1 below shows the relative margin-to-cost ratios at present rates for each rate schedule.

Table No. 1: Long Run Incremental Cost Study Results of the Parties

Customer Class	Rate Schedule	Avista	Staff	NWIGU	Staff/NWIGU
Residential	410	1.03	1.03	1.02	1.01
General Service	420	0.90	0.89	0.90	0.89
Large General Service	424	1.32	1.36	1.51	1.55
Interruptible Service	440	1.22	1.27	1.46	1.52
Seasonal Service	444	1.40	1.43	2.01	1.98
Transportation	456	1.14	1.22	1.27	1.36
Total		1.00	1.00	1.00	1.00

[1] Staff/600 and NWIGU/100.

The results of the four LRIC Studies provide consistent results which demonstrate that residential customers are relatively close to cost of service and small commercial customers are paying less than their relative cost of service. Conversely, interruptible, large general, seasonal, and transportation customer groups exceed their relative cost of service to varying degrees.

Table No. 2 below shows the LRIC Target Increase by Schedule, which represents the distribution margin revenue from each schedule that would be required to align the originally filed revenue requirement with the cost study to achieve 100% unity among all schedules.

Table No. 2: Long Run Incremental Cost Target Increase by Schedule

Customer Class	Rate Schedule	Avista	Staff	NWIGU	Staff/NWIGU
Residential	410	$ 4,395	$ 4,511	$ 4,917	$ 4,991
General Service	420	$ 4,114	$ 4,293	$ 4,245	$ 4,426
Large General Service	424	$ (78)	$ (95)	$ (146)	$ (158)
Interruptible Service	440	$ (29)	$ (49)	$ (107)	$ (121)
Seasonal Service	444	$ (8)	$ (9)	$ (19)	$ (19)
Special Contract	447	$ 123	$ 97	$ (39)	$ (51)
Transportation	456	$ 22	$ (209)	$ (312)	$ (529)
Total		$ 8,539	$ 8,539	$ 8,539	$ 8,539

While the overall increase or decrease required to move the schedules to unity based on the Company's originally filed revenue requirement varies, all four studies demonstrate that certain schedules should receive increases, and others should not.

Q. Given that the final revenue requirement may be different from what the Company originally filed, is it the Company's expectation that the LRIC Study results will materially change from the Company's filed case?

A. No, while the results may alter slightly given different revenue requirements, the Company believes the results are directionally accurate and are an appropriate basis for informing rate spread.

Q. Do you have any general comments on the LRIC changes proposed by both Staff and NWIGU?

A. Yes, while the Company does not endorse all of the specific attributes of the methodologies employed by Staff or NWIGU, the Company recognizes that their respective results are similar to the Company's own independent study prepared for this proceeding. The fact that all three studies show similar results provides a solid basis to inform rate spread.

Q. Would you briefly describe the differences between the LRIC Study of the Company and the LRIC Study proposed by Staff?

A. Yes. Staff recommends computing the cost of system mains per therm using test year loads (October 2017 – September 2018) rather than 2015 loads in theory to avoid overstating the cost of system mains.[2] In general terms, however, Staff's LRIC results were not materially different than the results of the Company's own study as shown in Table No. 1 above.

Q. Do you agree with Staff's proposed change to the LRIC Study?

A. Yes. The Company believes that using test year loads provides a reasonable basis for computing the cost of system mains and would agree to make this change in future LRIC studies.

Q. Would you briefly describe the methodological change to the Company's LRIC Study as proposed by NWIGU?

A. NWIGU took issue with the Company's usage of a peak and average ratio when allocating the capacity and commodity components of system main investment.[3] NWIGU

[2] Staff /1300, St. Brown/4, line 15 – St. Brown/7, line 4.
[3] NWIGU/100, Gorman/10, line 10 – Gorman/11, line 11.

prefers the usage of design day demand as the basis for allocating system main costs. NWIGU contends that their LRIC Study indicates that the same classes that are above unity, as shown in Table No. 1 above, are <u>even further</u> away from cost of service than the Company's LRIC Study results.

Q. Do you agree with NWIGU that throughput, or average demand, is not an appropriate basis for allocating distribution main costs?[4]

A. No. The purpose of the Peak and Average methodology is to provide a balance between the way the system is designed (to meet peak demand) and the way it is used on an annual basis (throughput based on gas usage that occurs during all conditions, not only peak conditions). Distribution plant is built to deliver natural gas year-round, not just on a peak day. By splitting the distribution main costs between peak demand and average throughput, the cost allocations appropriately reflect the dual use of the assets.

Q. NWIGU states that a major flaw of the Peak and Average calculation is that it double counts the "average" component of demand.[5] Do you agree?

A. No, the Peak and Average method reflects two separate allocators apportioning costs based on peak demands and throughput to reflect the dual use of the assets. The purpose of the peak and average calculation is to look at the two allocators in isolation. When the Company experiences a peak day on its system, the usage that makes up that peak includes both the usage that would occur under normal operating conditions (average usage) and usage that is attributable to extreme weather and any other factor that contributes to the peak. Therefore it is appropriate to include all usage in the peak portion of the allocator. The average or

[4] NWIGU/100, Gorman /10, line 20 – Gorman/11, line 2.
[5] NWIGU/100, Gorman/11, lines 3-8.

throughput portion is designed to capture the "everyday" use of the system which is independent from the peak conditions. That is to say, the throughput portion represents the initial and continued investments made to deliver gas year round, irrespective of the peak. It is common practice in cost of service studies to use multipart allocation factors in an attempt to characterize the multiplicity of reasons that are driving the investments companies make.

Q. Did CUB conduct an independent LRIC Study for this proceeding?

A. No, it did not.

Q. Did CUB provide any quantitative analysis to support any of its testimony related to the LRIC Study?

A. No, it did not.

Q. Please summarize your understanding of CUB's testimony related to the rate spread proposal and LRIC Study prepared by the Company?

A. CUB proffered two general concerns in support of its assertion that the revenue spread proposed by the Company is not justified.[6]

Issue 1: New investment is driven by increased loads by large industrial customers.

Issue 2: Avista's distribution system is not accurately sized on a LRIC basis.

<u>Issue 1: CUB's assertion that industrial customer load is driving new investment</u>

Q. Please describe CUB's argument that new plant investment is being driven by increased loads by large industrial customers?

A. CUB attempts to tie the increase in large customer load growth (Schedules 424,

[6] CUB/100, McGovern /28 – McGovern/29 and McGovern /34 – McGovern/35.

440, 444, 447 & 456) to the increase in Avista's capital spending. CUB asserts that because large industrial load is forecasted to increase, and the proposed capital in this proceeding is used to serve all customer classes, these customers should receive a rate increase.[7]

Q. Can you provide a summary of the capital investment included in the Company's filed case, broken down by general categories?

A. Yes, as shown in Table No. 3 below, 21% of rate base growth is due to gas distribution growth plant. Approximately 79% of new capital investment, as described in detail by Company witnesses Mr. Machado, Ms. Rosentrater and Mr. Kensok, is related to reinforcements, safety, pipe replacement, mandated work, storage, general plant and IS/IT.

Table No. 3: Summary of Capital Transfers to Plant Included in this Docket:

Plant Category	Investment ('000's)	Percent of Total
Distribution Growth Plant	$ 11,838	21%
Distribution Plant *	31,997	58%
General Plant/IT	11,621	21%
Total	55,456	100%

* Distribution Plant includes reinforcements, safety, pipe replacement, mandated work and storage

Q. Is the distribution growth plant caused by large commercial and industrial customers?

A. No, actually quite the opposite is true. Table No. 4 below demonstrates that the drivers of customer growth from the base year to the test year are new residential (Schedule 410) and small commercial (Schedule 420) customer hookups.

[7] CUB/100, McGovern/28 – McGovern/29.

Table No. 4: Forecasted Customer Growth Summary (Base Year – Test Year)[8]

Customer Class	Rate Schedule	Customer Growth	Percent of Total
Residential	410	2016	97.3%
General Service	420	53	2.6%
Large General Service	424	1	0.0%
Interruptible Service	440	2	0.1%
Seasonal Service	444	0	0.0%
Special Contract	447	0	0.0%
Transportation	456	0	0.0%
Total		2072	100.0%

Q. What is driving the other non-growth related capital?

A. The majority of the other non-growth capital is related to reinforcements, safety, pipe replacement, mandated work (road moves, cathodic protection), capital projects at the Jackson Prairie Natural Gas Storage Facility, IS/IT and general plant (common assets).

Q. Is this other non-growth related capital being driven by large commercial and industrial load?

A. No, the majority of these projects are required to be completed irrespective of any increase in load. These projects include remediation of capacity limitations on the natural gas system, system reliability, public safety and health, employee safety and health, environmental impacts, and regulatory impacts. Generally speaking, these considerations are not impacted by increases in large load as asserted by CUB.

Q. Is the non-growth capital, which is being installed in part, to ensure there is enough capacity on a design day, attributable to all rate schedules?

A. No. As detailed in the Company's 2016 IRP, the design day criteria used to

[8] The new customer growth from the base year to the test year is derived from the Company's load forecast.

support new plant investment assumes that interruptible Schedule's 440 & 456 would be interrupted on a design day, and therefore those customers' usage is not being served on a design day. In addition, Seasonal Service Schedule 444 is contractually obligated to only take service from March 1 through November 30 of each year. Because Schedule 444 customers are not taking service during the winter, when a design day event is likely to occur, they are also excluded from the design day planning criteria.

Issue 2: CUB's assertions that Avista's distribution system is not accurately sized on a LRIC basis

Q. Please summarize CUB's assertion that the LRIC Study does not reflect an accurately sized system on an LRIC basis.

A. CUB asserts that Avista's distribution system is not properly sized because the usage characteristics of customers today are different than the usage characteristics of customers when the system was built. As a result, CUB asserts that an appropriate cost study should be based on the incremental cost of a hypothetical natural gas distribution system, sized to meet current customers expected loads.[9] This is in contrast to the Company's LRIC Study, which calculates the theoretical cost of replacing Avista's present natural gas distribution system.

Q. Does CUB's view that the LRIC Study does not reflect an accurately sized system on an LRIC basis have merit?

A. No it does not. The LRIC Study should be based on the replacement cost of the

[9] CUB/100, McGovern/35.

actual facilities that will be in the Company's revenue requirement. The LRIC Study is a forecast of the marginal replacement costs that the Company expects to incur in the future. CUB's view of an accurately sized system is based on a hypothetical replacement of the distribution system that could not and will not happen. The Company acknowledges that if it could rebuild its distribution system from scratch, it would look different from what's in place today. But we know that of course cannot happen. Therefore, the Company's approach which reflects a more realistic expectation of what will actually be installed over time is the most appropriate measure for calculating the long-run marginal cost.

Q. Has the Company allocated distribution system costs in a similar way in past general rate case proceedings.

A. Yes, the Company has used a similar approach for allocating distribution main costs in all of its past LRIC Studies.

Q. Did CUB put forth a similar argument in the Company's prior general rate case filing (Docket No. UG-288)?

A. Yes it did.

Q. In the Company's prior general rate case (Docket No. UG-288) did CUB itself place doubt on its own theory that the LRIC Study should look at the forward cost of a new system?

A. Yes. CUB acknowledged this when it stated, "This line of inquiry may be dismissed as irrelevant because the Company cannot feasibly scratch the entire system and start anew." (emphasis added)[10]

[10] Docket No. UG – 288, CUB/100, McGovern-Jenks/23, lines 3 - 4.

Q. Did CUB provide any analysis or calculations supporting its "hypothetical system" in this case?

A. No, CUB did not. CUB relies on limited theoretical concepts and data in an attempt to draw doubts as to the usefulness of the LRIC Study as a whole. CUB provided no analysis, other than broad conceptual ideas, in order to show how its limited theoretical concept could be applied on an actual basis for purposes of conducting an LRIC Study. As such it should be rejected.

Q. Given the testimony sponsored by CUB related to the LRIC Study in this proceeding, is there any practical way to incorporate their LRIC theories into an actual LRIC Study with corresponding results?

A. No. CUB provided no practical quantitative or qualitative analysis that would inform the Commission of how to incorporate any of its theories on a prospective basis into an actual LRIC Study.

Q. Does this conclude your Reply testimony?

A. Yes, it does.

AVISTA/1800
Ehrbar

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

REPLY TESTIMONY OF PATRICK D. EHRBAR
REPRESENTING AVISTA CORPORATION

Allocations, Fee Free, Load Forecast, Rate Spread/Design, Decoupling

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation?

A. My name is Patrick D. Ehrbar and my business address is 1411 East Mission Avenue, Spokane, Washington. My present position is Senior Manager of Rates and Tariffs.

Q. Have you filed direct testimony in this proceeding?

A. Yes. I have filed direct testimony in this case addressing the Company's revenue adjustment, rate spread, rate design, and the Fee Free adjustment.

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

A. My testimony will respond to a number of different issues raised by Commission Staff ("Staff"), Citizens' Utility Board ("CUB"), and the Northwest Industrial Gas Users ("NWIGU"). First, I will provide the Company's reply to Staff's Affiliated Interest and Cost Allocation Adjustments, as well as the Fee Free Bankcard Adjustment and Test Year Load Forecast Adjustment. I will then address the rate spread and rate design issues raised by the parties, and provide the proposed rate spread of Avista's revised revenue requirement, and corresponding rate design. Finally I will address issues raised by Staff regarding the Company's natural gas decoupling mechanism. A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits that accompany your testimony?

A. Yes. I am sponsoring Exhibit No. 1801 which is related to the spread of the revised revenue requirement provided by Company witness Ms. Smith. I am also sponsoring Exhibit No. 1802 which is a copy of the Company's 4th Quarter 2016 natural gas decoupling report. These exhibits were prepared under my supervision.

II. AFFILIATED INTEREST AND COST ALLOCATION ADJUSTMENTS

Q. Staff witness Mr. Kaufman reduces Oregon expenses $610,000 and Oregon rate base $3,513,000 related to allocation of common costs to affiliates, and the reassignment of common costs and rate base to other Avista jurisdictions. This represents a reduction to the revenue requirement of approximately $972,000. Do you agree with his adjustments?

A. No, I do not. Avista makes every effort to properly record all transactions to the appropriate jurisdiction during the year. Due to the size of Avista's operations, with hundreds of employees recording transactions and hundreds of thousands of transactions being recorded, there are instances where expenses may have been recorded improperly. During the course of this rate case, Avista has identified transactions that should be removed from its revenue requirement, which will be discussed in detail below. The identified adjustments would reduce Oregon expenses $64,000, and Oregon rate base $236,000, which represents a reduction to the revenue requirement of approximately $92,000, as compared to Mr. Kaufman's proposed adjustment of $972,000.

Q. Before describing Mr. Kaufman's adjustments and Avista's proposed adjustment, would you describe the effort Avista makes to properly record transactions?

A. Yes. The Company has provided Company-wide employee training on the Company's Regulatory Accounting Guidelines and Policies for affected employees, educating employees on the appropriate use of FERC accounts, proper use of expense descriptions, certain new and existing accounting policies, and recording of utility versus non-utility expenditures. The Company is in the process of updating its training to an interactive format so the required annual training can be monitored.

In addition, the Company sends to all employees semiannually a written reminder to properly label and record transactions (including appropriate utility/non-utility, service and jurisdictional allocations).

All transactions, including both labor and vendor invoices, are reviewed by each employee's supervisor for proper accounting. In addition, Corporate Accounting personnel reviews transactions, notifying individual employees or departments of any questionable transactions, requesting they be reviewed and corrected if found inappropriately charged on a periodic basis. This same review, for transactions recorded in the base year, was subsequently performed by Rates Department personnel during the process of preparing the Company's calculation of its revenue requirement in this case, resulting in the Miscellaneous Restating adjustment.[1]

Because there are hundreds of employees recording hundreds of thousands of transactions, some level of errors will occur. Accounting controls and audits are designed to keep the dollar impact of these errors to a minimal level. The Company believes it has, and

[1] See Avista/500, Smith/Page 10 – Adjustment (1.02)

continues to, take steps to minimize the accounting errors found in its test period results.

Q. Why does Avista allocate costs and rate base rather than directly assigning all costs and rate base to each jurisdiction?

A. Avista directly assigns revenues, operating costs and rate base whenever possible. For costs and rate base that cannot be directly assigned, because they support the operations of more than one jurisdiction, Avista records these costs as "common" costs. These common costs and rate base are then allocated to the appropriate jurisdictions using allocation factors derived from directly assigned costs and rate base and customers. <u>Because the allocation factors are determined by the amount of direct costs, direct net plant and customers</u>, the size of the various jurisdictions impacts the amount of common costs that will be allocated. For example, for common costs that support operations in all three states (Oregon, Idaho and Washington), they are allocated 71.326% to electric operations, 19.958% to Idaho and Washington natural gas operations and 8.716% to Oregon natural gas operations.

The fact that the common facilities (rate base) and common utility expenses are more related to Avista's electric operations and Avista's natural gas operations in Washington and Idaho, than to the Oregon operations, is incorporated into the development of the allocation factors themselves.

Q. Please summarize Mr. Kaufman's affiliated interest and cost allocation adjustments.

A. Mr. Kaufman stated that he reviewed the following transactions:

- Transfers to plant during 2011 through 2016 that were recorded as common plant,
- Transactions recorded as common costs for airfare recorded 2014 through 2016, and

- Other O&M and A&G expenses, excluding airfare and labor, recorded in the base year (July 1, 2015 through June 30, 2016).

From this review, he removes rate base and expenses for the following:

- He identified costs and rate base that he believed were not common and should have been directly assigned to a non-Oregon jurisdiction. His adjustment removes Oregon's allocated share of these transactions identified.
- He adjusts the Company's common costs and rate base allocation factor for the reassignment of these costs. His adjustment removes Oregon rate base and expenses using this revised Oregon allocation factor on common plant and costs.
- He adjusts the Company's common costs and rate base allocation factor used to allocate common costs and rate base for affiliated interest transactions and rate base. His adjustment removes rate base and expenses using this revised Oregon allocation factor.

A summary of Staff's adjustments are shown below in Illustration No. 1.

Illustration No. 1:

Staff Adjustment - Affiliated Interest and Cost Allocations Adjustment
($000s)

Line #		System	OR Share	Revenue Requirement
1	Plant	$ (30,001)	$ (3,513)	$ (342)
	Expenses:			
2	Depreciation Expense	(2,531)	(221)	(228)
	O&M/A&G:			
3	Airfare	(126)	(11)	(11)
4	O&M/A&G - Excluding Labor & Airfare	(740)	(71)	(73)
5	Labor	(647)	(61)	(63)
6	Change to Allocation Factors - for O&M/A&G Cost Assignments		(48)	(50)
7	Change to Allocation Factors - for Affiliated Interest Transactions		(198)	(204)
8	Total O&M/A&G	(1,513)	(389)	(401)
9	Total Expenses	$ (4,044)	$ (610)	$ (629)
10	Revenue Requirement			$ (972)

Q. Avista reviewed Mr. Kaufman's adjustment and accepts the removal of a portion of the rate base and expenses that were proposed by Mr. Kaufman. Please provide a summary of those adjustments that Avista accepts.

A. A summary of the adjustments that Avista accepts is provided below in Illustration No. 2.

Illustration No. 2:

Avista's Revised Staff Adjustment - Affiliated Interest and Cost Allocations Adjustment
($000s)

Line #		System	OR Share	Revenue Requirement
1	Plant	$ (2,749)	$ (236)	$ (26)
	Expenses:			
2	Depreciation Expense	(232)	(18)	(19)
	O&M/A&G:			
3	Airfare	(48)	(4)	(4)
4	O&M/A&G - Excluding Labor & Airfare	(159)	(15)	(15)
5	Labor	(155)	(14)	(14)
6	Change to Allocation Factors - for O&M/A&G Cost Assignments		(13)	(13)
7	Change to Allocation Factors - for Affiliated Interest Transactions		-	-
8	Total O&M/A&G	(362)	(46)	(47)
9	Total Expenses	$ (594)	$ (64)	$ (66)
10	Revenue Requirement			$ (92)

Q. For Line #1 in Illustration Nos. 1 and 2 above, why does Avista agree to remove $2.749 million from system rate base rather than $30.001 million as proposed by Staff?

A. Staff reviewed a listing of common plant additions by project description for 2011 through 2016. Based on their site review at a few of Avista's Spokane locations, Staff identified portions of the Avista campus and other outlying locations that they believe do not support the Oregon operations. The project descriptions from the plant additions listing were used to segregate these locations.

This process used by Staff identified projects that they thought did not support Oregon operations, but do in fact, support Oregon operations. The project descriptions do not always describe the actual location of the project and there was some apparent misunderstanding gained on the site visit about specific operations at the various sites visited. A detailed listing of the projects identified by Staff and those projects agreed to be removed by Avista are shown in Illustration No. 3 below.

Illustration No. 3:

Cost Allocations Adjustment - Common Plant

Description	Staff Amount	Avista Amount
Main Campus Service Building	$ 2,700,792	$ -
Main Campus Warehouse	6,777,993	-
Main Campus Construction	4,442,333	-
Hazardous Waste Recovery	3,214,843	-
Materials Recovery	1,510,903	-
Main Campus Fleet Maintenance	1,318,044	1,215,116
Downtown Spokane Service Center	2,778,968	561,132
Lewiston Service Center	1,186,020	-
Other (1)	6,071,106	972,597
Total	$ 30,001,002	$ 2,748,845

(1) Includes $112,855 counted twice by Staff in error.

Avista's main campus in Spokane, Washington is comprised of several buildings, including a six floor general office building, a cafeteria and auditorium building, a two floor service building, a fleet/vehicle repair garage, a warehouse, an investment recovery building and parking for employees and visitors. All of the buildings are primarily used to support the operations in Washington, Idaho and Oregon. The various buildings are described in some detail below. Since the entire campus is used to support operations in all three states, the campus is recorded as a common asset and associated rate base and costs are allocated to the jurisdictions using a 4-factor allocation factor. The allocation factor is based on direct costs (labor and non-labor), customers and direct net plant. Electric and gas north (Washington and Idaho) operations are assigned approximately 91% of the cost and rate base while Oregon operations are assigned approximately 9% of the cost and rate base. Avista has consistently used this method for the main campus since acquiring the Oregon operations in 1991.

Staff has analyzed the function of each building based on their understanding, and proposes to account for each building separately. The additional time and cost that would be required to account for the campus separately by building would be very labor intensive, administratively inefficient, and would result in increase in costs for all customers. Most of the buildings are used for operations in all three states, and the functions of the buildings can change over time, so the tracking of these changes and all of the costs would be very labor intensive.

As explained earlier, the development of the allocators themselves result in a lower amount of those common plant and common expenses being allocated to Oregon customers.

An explanation of why it would be improper to remove from rate base the assets identified by Staff follows:

- **Main Campus Service Building –** Mr. Kaufman states that the service building does not support Oregon operations.[2] However, there are many departments that work in the service building that support Oregon operations, including, Accounts Payable, Remittance Processing, Graphics and Mailroom, Gas Engineering and Compliance, and

[2] See Staff/700, Kaufman/13.

the Gas Meter Shop. Therefore, it is appropriate to allocate approximately 9% of the cost of the service building to Oregon operations.

- **Main Campus Warehouse –** Mr. Kaufman states that the main campus warehouse does not house gas supplies and therefore, the building should not be allocated to Oregon.[3] However, two employees (material planner and inventory coordinator) who provide service to all regional warehouses, including Oregon, are located in the main campus warehouse. Therefore, it is appropriate to allocate approximately 9% of the cost of the warehouse to Oregon operations.
- **Main Campus Construction –** Mr. Kaufman has separately identified the cost of "Main Campus Construction" using the description of the project. However, there is no separate building for the construction department. Rather, a portion of the service building houses the gas construction department. The capital project that was identified as the construction building was actually the cost of updating the HVAC system in the service building. The name of the project led to the confusion of these capital costs. Since the service building provides support to the Oregon operations, as described above, it is appropriate to allocate approximately 9% of the cost of the HVAC system of the service building (identified by Staff as the Main Campus Construction) to Oregon operations.
- **Main Campus Hazardous Waste Recovery –** Mr. Kaufman states that the building primarily supports electric operations[4], which is not accurate. All hazardous waste that needs to be disposed by Avista is managed by the Environmental Compliance

[3] See Staff/700, Kaufman/13.
[4] See Staff/700, Kaufman/13.

department. All light bulbs, spray paints, chemicals, oils, etc. used by Avista, including the Oregon operations, are managed by this group to ensure compliance with environmental regulations and are processed in the HAZMAT portion of Investment Recovery building identified by Staff. Therefore, it is appropriate to allocate approximately 9% of the cost of the Hazardous Waste Recovery building to Oregon operations.

- **Main Campus Materials Recovery –** The Investment Recovery building recovers not only meters, as stated by Mr. Kaufman, but all materials that are required to be recycled. All of the recyclable material that is generated in the main office building and service building are processed in the materials recovery portion of the Investment Recovery building. Those employees that work in the main office building and service building support Oregon operations and therefore, this building supports the Oregon operation. Therefore, it is appropriate to allocate approximately 9% of the cost of the Materials Recovery building to Oregon operations.
- **Main Campus Fleet Maintenance –** Staff identified $1.318 million of capital costs related to the fleet building that they removed from common costs, since they state that the Company has a regional fleet in Oregon. The Company agrees that one project for the CNG fleet conversion that cost $1.215 million should have been assigned to non-Oregon. However, the remaining costs of approximately $100,000 should not be reassigned. The Company's fleet department is located at the main Spokane campus. All administrative staff are located in the fleet building and manage the fleet used by the Oregon operations. This includes the purchase and pre-delivery process[5] of all

[5] During the pre-delivery process, the fleet personnel review vendors work to identify any deficiencies in the build

vehicles. In addition, there are certain repair and maintenance work[6] on Oregon vehicles that are required to be performed at the Spokane location. Therefore, it is appropriate to allocate approximately 9% of the cost of the Fleet building to Oregon operations.

- **Downtown Spokane Service Center –** The Company's main campus does not have the office space or parking required for all employees and contractors[7], therefore the Company has leased office space in various locations in Spokane. When a building with parking and land became available for purchase, the Company purchased the building to consolidate the employees at the various leased locations. The Downtown Service Center has two primary functions. First, the building and parking is being used as a "Projects Center" where projects that will support all operations, including Oregon operations, are being developed. The second function is a planned downtown network location. Half of the land that was included in the downtown purchase was vacant. This vacant land will be developed into the downtown network location and will be assigned to electric service. Therefore, the Company agrees that one-half of the land purchase price ($561,132) should not be recorded as common and therefore, allocated to Oregon.

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process. Tests are performed on electrical systems, body integrity, gas by-pass systems and complete radio/mobile work force technology systems.

[6] The repair and maintenance work completed on Oregon domiciled vehicles is completed primarily by vendors located in the communities where we serve. However, due to the complexity of compliance requirements by DOT and CGA it is necessary for Avista to transport that equipment to Spokane for the completion of those inspections. Additionally, there are several cases where Avista may bring vehicles to our Spokane area shops to complete maintenance and repairs, including the periodic maintenance "C level" service that is performed on a 4 year or 60,000 mile interval on class 56 vehicles that have additional components. These components require ANSI and OSHA inspections and due to the potential risk from missed defects, Avista employees with expertise in these areas are used to inspect for abnormalities. Finally, Avista's light duty CNG truck conversions sometimes experience failures that require repairs. Local vendors are typically not certified or trained to work on the alternative fuel system. Additionally, the NFPA 52 standard limit a non-compliant shops ability to work on the CNG fuel system. In most cases, there are work-arounds that can be made, however, periodically issues arise that require that unit be brought to Spokane for a more significant repair.

[7] Examples of projects include upgrading the HVAC system in the main office building and service building, installation of Project Compass, etc.

However, the cost of the Projects Center itself supports the Oregon operations and is appropriate to record as common. Therefore, it is appropriate to allocate approximately 9% of the cost of the Downtown Service Center, excluding the portion of land that will be developed in the future for electric operations, to Oregon operations.

- **Lewiston [Customer] Service Center**[8] - Avista's Customer Service employees are spread across three different service centers located in Spokane, Washington, Coeur d'Alene, Idaho, and Lewiston, Idaho. 33 employees reside in the Lewiston office, 32 in the Coeur d'Alene office, and the remainder in the Spokane office. The three service centers are networked together to operate as a single Customer Service Center supporting all of Avista's customers. Every employee is trained in their role to work with customer accounts or take phone calls from customers in all three of the Company's jurisdictions, including Oregon. All customer phone calls come in through a single number, 1-800-227-9187, and are answered by the next available representative, regardless of the location they reside. The Lewiston service center employees are comprised of a Customer Service Manager, Customer Service Representatives, and the Customer Service billing team. As previously mentioned the Customer Service Representatives in Lewiston take customer calls from customers in all three of the Company's service jurisdictions. The billing team also works on billing issues across all three jurisdictions. All three service centers making up the Customer Service department support Oregon, along with the Company's other jurisdictions. Therefore,

[8] Mr. Kaufman refers to the Lewiston building as the Lewiston Service Center. The only building located in Lewiston is the Customer Service Center.

it is appropriate to allocate approximately 9% of the cost of the Lewiston Call Center to Oregon operations.

- **Other Assets** - Mr. Kaufman identified a number of other assets, including the Pullman office, the Kettle Falls facility, the Noxon and Clark Fork Living facilities, and other miscellaneous assets that he has proposed to remove from common plant. Of the $6.071 million identified, the Company agrees that $0.972 million should have been recorded directly to non-Oregon operations. The remaining $5 million that is appropriate to record as common includes approximately $3.7 million for expansion of the main campus in Spokane and approximately $1.3 million for IT systems upgrades. The main campus is being expanded to add additional office space and to increase security. The expanded facilities will support operations in all jurisdictions, including Oregon. The IT system upgrades are performed in all locations throughout the Avista service territory. Because these assets are not individually tracked or can be moved between jurisdictions, Avista records all of these IT projects as common assets, including those that are for systems located in Oregon. Since Oregon is assigned an allocated share of the system investment, and is not directly assigned those projects located in Oregon, Avista's method of assigning these IT projects is appropriate. Therefore, it is appropriate to allocate approximately 9% of the cost of the other assets to Oregon operations.

Q. For Line #2 in Illustration Nos. 1 and 2 above, which is an adjustment for depreciation expense, please explain the difference between Staff's proposal of $221,000 compared to Avista's proposed adjustment of $18,000.

A. This adjustment represents the impact of the removal of plant on Line #1 from

Oregon rate base. Avista used Staff's method to estimate the amount of depreciation expense on the plant removed of $2.749 million, which represents approximately $18,000 for Oregon's share of depreciation expense.

Q. For Line #3 in Illustration Nos. 1 and 2 above, please explain the difference between Staff's removal of $126,000 of system common costs for airfare compared to Avista's proposed adjustment of $48,000 of system common costs.

A. Staff specifically identified approximately $63,000 of airfare costs for 2016 and estimated an additional $63,000 for "ambiguous" airfare costs. Avista does not agree with Staff's calculation of the costs removed or the method used to determine the amount.

First, the $63,000 of airfare specifically identified is for costs in all of 2016. The Company base year used in this case is July 1, 2015 through June 30, 2016. As stated by Mr. Kaufman, Avista, in its response to a Staff data request, pointed out that many of these airfare costs were not included in the base year.[9] It is not appropriate to remove costs that are not included in the rate case. By using the data that Mr. Kaufman used to compute his specifically identified airfare costs, Avista determined that $22,000 of system costs, rather than $63,000, of airfare costs should have been removed from the rate case, since these were the costs identified in the base year.

Second, Mr. Kaufman states that many of the airfare transactions are "poorly documented" with only words like "airfare" or employees name in the transaction description. Because of this, he allocates a portion of all what he characterizes as "ambiguous" airfare costs as non-Oregon costs. He uses the specifically identified costs from 2016 to determine his allocation factor. The Company does not agree with his assessment that these costs are poorly

[9] See Staff/700, Kaufman/17, lines 14 through 15.

documented. Each transaction is assigned to a <u>project</u>, an <u>expenditure type</u>, an <u>organization</u> and a <u>voucher number</u>. Using all of this data, and not just the transaction description, provides adequate information about the transaction. Rather than review the thousands of transactions that were identified as "ambiguous" to determine if any should be recorded as non-Oregon transactions, Avista used Mr. Kaufman's method to allocate a portion of these costs. Using the appropriate data (only base year costs and not all of 2016), the Company agrees to remove an additional $26,000 of common system costs, rather than the $63,000 calculated by Mr. Kaufman.

Q. For Line #4 in Illustration Nos. 1 and 2 above, please explain the difference between Staff's removal of $740,000 of common costs for O&M/A&G, excluding labor and airfare, compared to Avista's proposed adjustment of $159,000 of common costs.

A. In this adjustment, Mr. Kaufman removes $740,000 of common costs for O&M/A&G based on a review of "operating groups or transaction descriptions that provide service to non-Oregon jurisdictions."[10]As explained above, Avista makes every effort to record transactions appropriately. After the vendor invoices are coded and reviewed by a manager, a second review is performed by Corporate Accounting personnel on a periodic basis. Then, when a rate case is being prepared, the Rates Department performs a third review. In this rate case, the Company removed expenses found during this third review in a Miscellaneous Restating adjustment.[11] As stated in Company witness Ms. Smith's direct testimony, "Column (1.02), Miscellaneous Restating, restates the twelve-months ended June 30, 2016 base year results for miscellaneous restating items such as <u>removal of non-utility related items, and</u>

[10] Staff/700, Kaufman/18 ln. 11-12.
[11] See Avista/500, Smith/Page 10 – Adjustment (1.02)

reclassification of items to their appropriate service and jurisdiction."[12] (emphasis added) The difference between Staff's adjustment of $740,000 and the Company's adjustment of $159,000 is $581,000 of costs that were already removed by Avista when the case was initially filed.

Q. For Line #5 in Illustration Nos. 1 and 2 above, please explain the difference between Staff's removal of $647,000 of system common costs for labor, compared to Avista's proposed adjustment of $155,000 of system common costs.

A. Staff determined the adjustment for labor using an allocation based on the airfare and other O&M/A&G expenses identified above. Avista believes it is not appropriate to remove labor costs without identifying the exact reason. However, Avista has used Staff's method to determine the amount that would be removed, using corrected airfare and O&M/A&G costs. Using the corrected airfare and other O&M/A&G non-labor costs that Avista has agreed to remove from this case, the labor amount removed would be $155,000 of system common costs, or $14,000 on an Oregon allocated basis.

Q. For Line #6 in Illustration Nos. 1 and 2 above, please explain the difference between Staff's removal of $48,000 of Oregon costs compared to Avista's proposed adjustment of $13,000 of Oregon costs.

A. Using the adjustments of costs and rate base identified by Staff on Lines #1 through Line #5 in Illustration Nos. 1 and 2, Staff updated the allocation factor that Avista used to allocate all common costs. Before making any adjustments, Oregon's share of common costs used by Avista was 8.716%. This was computed using direct costs, rate base and customers with calendar year 2015 data. When Staff updated this allocation factor to remove the rate base and costs identified on Lines #1 through #5 in Illustration Nos. 1 and 2, the Oregon allocation

[12] Ibid.

factor changed to 8.676%. As described above, many of these costs identified by Staff were for 2016,[13] and therefore were not part of the calculation to compute the original 8.716% allocation factor. Using Staff's methodology and 2015 data, Avista determined the adjustments that would be appropriate to update the allocation factor. The updated Oregon allocation factor using 2015 data is 8.706% (rather than 8.676% computed by Staff). Using this revised allocation factor, Oregon costs would be $13,000 less than the amount originally filed in this case.

Q. For Line #7 in Illustration Nos. 1 and 2 above, please explain the difference between Staff's removal of $198,000 of Oregon costs compared to Avista's proposed adjustment of zero of Oregon costs.

A. Staff's adjustment to remove $198,000 from this case was to account for overhead expenses, such as office space, for the services Avista provides to affiliated companies. Staff recognizes that Avista directly charges employee time and associated payroll costs (taxes and benefits) directly to the affiliate or to non-utility, so Oregon customers are not supporting the affiliates. However, Staff erroneously states "Avista does not account for other employee overhead expenses such as office space."[14] Avista does indeed record monthly the value of the use of office space and computer equipment to non-utility. Avista has determined the cost of the main campus and the cost of employees' computer equipment and has converted this cost to an hourly rate. Monthly, the hours spent working on affiliated interests by Avista employees is accumulated and the hourly rate is applied to determine the costs that are reclassified from utility costs and recorded as non-utility. Avista has very few subsidiaries with

[13] Since the base year was July 1, 2015 through June 30, 2016, Staff adjustments included data recorded in 2016. The allocation factors used in this rate case, were the factors prepared in 2016 with calendar year 2015 data.
[14] See Staff/700, Kaufman/8, Lines 21-22.

actual operations, and the overhead costs already removed from the base year were $50,190. It is not appropriate to adjust its allocation factors for affiliated costs, as proposed by Staff, because these costs have already been removed.

Q. Please summarize your proposed adjustment for Staff's affiliated interest and cost allocations adjustment.

A. Avista reduces Oregon expenses $64,000 and Oregon rate base $236,000, which represents a reduction to the revenue requirement of approximately $89,000. This represents reassignment of transactions from common to non-Oregon operations that were improperly recorded and not identified with other corrections the Company made when preparing this case. Staff's adjustment for affiliated interest costs should be rejected, since all direct costs and overhead costs are properly recorded to non-utility during the year.

III. FEE FREE BANKCARD ADJUSTMENT

Q. Regarding the Fee-Free Payment Program, do you agree with Staff's analysis of the potential growth curve and adoption rate of payments made for the test period?

A. No I do not. Mr. Boyle's conclusion that the adoption rate will be less than that proposed by the Company is not realistic.[15] First, based on the Company's review and discussion with other utilities that offer similar programs, and the experience of our payment processing vendor, which works with several utilities that have made the change from a fee based payment structure to a fee free payment structure, Avista projected that the adoption rate during the test period of October 2017 through September 2018 will double from the level

[15] Staff/1300, Boyle/7, ll. 4-6.

experienced prior to launching the program. Avista's payment processing vendor expressed to the Company that it should expect a doubling of adoption rates in the first 12 months after offering its Fee-Free Program. With the test period starting approximately eight months after the launch of its Fee-Free Payment Program, an adoption rate of 10 percent is likely conservatively low.

Second, Mr. Boyle's exhibit (Staff/1304) provides Avista's projected adoption rates, his own projection for Avista, and the growth rates of NW Natural and Portland General Electric. The graph shows that in the first 12 months after offering a fee-free option, NW Natural and Portland General Electric experienced average adoption rates of 6.4 percent and 5.6 percent. Prior to the launch of their programs, NW Natural experienced an adoption rate of 2.0 percent[16] and Portland General Electric experienced an average adoption rate of 3 percent.[17] This means that in their first 12 months after launching their respective programs, those utilities experienced an increase in adoption of 220 percent and 87 percent, respectively. Further, during months 8 – 19 after launching their programs (coinciding with Avista's test period in this case), NW Natural experienced an average adoption rate of 8.61 percent (an almost 330 percent increase) and Portland General Electric averaged 6.9 percent (a 130 percent increase). Based on the experience of both of these utilities, the Company's projection that it will experience a doubling of adoption rates in months 8 – 19 is reasonable.

The Company is also aware of the experience of Snohomish PUD, who began offering a fee-free bank card program in 2009. In the quarter prior to launching their fee free program Snohomish PUD's adoption rates of payments by bank card was 1.2 percent. In the 12 months

[16] UE 283 / PGE / Exhibit 1005 Stathis – Dillin Page 1
[17] UE 294 / PGE / 900 / Stahis – Dillin / 14:18-21

following the launch their adoption rate was 7.3 percent, for an increase of approximately 500 percent.[18] Again, this shows that the Company's projected adoption rate is very reasonable.[19]

Q. Since the Fee Free Program went into effect in February 2017, has the Company experienced an increase in adoption?

A. Yes. The Company successfully launched the Fee-Free Payment Program on February 19, 2017. Following the launch on February 19th, and through the end of February, the Company received 26,220 payments from residential customers in Oregon. Of those payments, 2,374, or 9.1%, paid their bill through the Fee-Free Payment Program. This compares to the average of 5.1% as noted on p. 13 of my original testimony. While this represents a limited time period to understand the impact of adoption rates of the Fee-Free Payment Program, it further supports the Company's conservative estimate that its adoption rates will double during the test period from the adoption rate experienced prior to launching the program.

Q. Is Staff's recommendation to allow the Company to only recover 90 percent of the payment transaction fee appropriate?

A. No, it is not appropriate because Staff provided no analysis detailing either potential levels of savings (if any) that would justify a sharing, nor the development or justification of how a 90/10 sharing band is appropriate. To the extent there are savings related to the Fee Free Payment Program, this payment channel should not be treated any differently than how the potential benefits associated with other payment channels are treated. The

[18] UE 283 / PGE / Exhibit 1005 Stathis – Dillin Page 1

[19] It should also be noted that NW Natural and Snohomish PUD's fee-free card programs are only available to customers via its website and IVR system. For Avista, its Fee-Free Payment Program is available to its residential customers through its website, IVR system, and by phone through a Customer Service Representative. By including the additional Customer Service Representative payment channel, it is likely the Company may see an even higher increase of adoption rates as a result.

Company is not required to impute some level of savings associated with traditional electronic payments, or payments made by customers at pay stations. To the extent savings do occur related to this program, like all other payment methods, those savings will flow through to customers through reduced O&M expenses in future rate cases.

IV. TEST YEAR LOAD FORECAST (ADJUSTMENTS S-18 AND S-19)

Q. What is the Company's response to Staff's load forecast adjustments S-18 and S-19 sponsored by Staff witness Max St. Brown?

A. The Company accepts Staff's revenue adjustment to the load forecast. Staff's load forecast provides results that are reasonably close to the results of the Company's forecast. As discussed later in my testimony, the Company has incorporated the load forecast adjustments in its billing determinants for the test year.

Q. Staff proposed a number of methodological changes to Avista's load forecast. Are any of these changes agreeable to the Company?

A. Yes. The Company will add employment as an economic driver to the forecast of commercial Schedule 424 commercial customers for Medford, Roseburg, and Klamath regions. The Company will focus on the Schedule 424 customers in these regions, because they account for Staff's observed correlation between large commercial customers' employment. Also, when selecting forecasting models, the Company will use the Akaike Information Criteria (AIC) rather than the root-mean-square error (RMSE). However, the Company will continue to select models "by hand" rather than using an automatic selection routine, as suggested by Staff. This reflects the need to carefully consider each model in light of the empirical difficulties (outliers, missing data, etc.) that often arise when modeling with billed data.

Q. What load forecast methodological changes does the Company not accept?

A. After conferring with Avista's Chief Economist Dr. Forsyth, the Company does not accept Staff's opinion regarding the use of intervention variables. As has been discussed with Staff in past rates cases, billed customer data is subject to sudden changes in behavior due to events such as billing errors and inter-schedule customer migrations, unrelated to weather or economic factors. Therefore, failing to use a certain number of intervention variables results in model error terms that violate the normality assumption. Normality is one of the key assumptions of the regression models being used by the Company. In addition, the ARIMA error correction process can be sensitive to the presence of outliers. The Company typically uses the Shapiro-Wilk normality test to confirm the assumption of error normality. Therefore, the choice of observations that need intervention variables is based a distributional analysis of the errors of a given model. However, the Company will continue to review its use of intervention variables to try to minimize their use.

Q. Did the Company try to replicate any of the models suggested by Staff using its own SAS/ETS software?

A. Yes. Using the data set provided to Staff for this rate case, the Company used its software to estimate Staff's proposed use per customer (UPC) model for Medford commercial Schedule 420 and Medford residential Schedule 410. In the case of the Schedule 420 model, the error terms failed the Shapiro-Wilk test for normality because of the impact of large outliers. In the case of Schedule 410, Staff's model could not be estimated because SAS/ETS failed to converge to a set of stable coefficient estimates. In the past, it has been the Company's experience that significant outliers can cause non-normal error terms and other estimation issues in SAS/ETS. The Company will continue to work with Staff to better understand the use of intervention variables and how SAS/ETS and the "R" software used by Staff may be producing different estimation results.

V. RATE SPREAD

Q. By way of background, would you please summarize the Company's originally-filed rate spread proposal?

A. Yes. The Company utilized the results of the LRIC sponsored by Company witness Mr. Miller as a guide to spread the proposed margin/revenue increase by service schedule. The Company spread the proposed increase in a manner that results in the margin-to-cost ratios for the various service schedules moving closer to 1.00 (unity). Based on the results of the LRIC, and past Commission guidance, the Company proposed to increase Schedule 410 rates by the same amount as the overall percentage increase in margin revenue. The Company proposed to keep the rates for Schedules 424, 440, 444 and 456 unchanged. The remaining revenue requirement was applied to Schedule 420. Table No. 1 below summarizes the proposed rate spread on a margin, and total revenue, basis using Avista's original proposed revenue requirement of $8,539,000:

Table No. 1:

Proposed % Natural Gas Increase by Schedule

Rate Schedule	Increase in Margin Revenue	Increase in Total Revenue
Residential Schedule 410	14.5%	9.3%
General Service Schedule 420	18.9%	10.8%
Large General Service Schedule 424	0.0%	0.0%
Interruptible Service Schedule 440	0.0%	0.0%
Seasonal Service Schedule 444	0.0%	0.0%
Transportation Service Schedule 456	0.0%	0.0%
Overall	**14.5%**	**9.0%**

Table No. 2 below shows the effect on the margin-to-cost ratios from the proposed rate spread:

Table No. 2:

Present and Proposed Margin-to-Cost

	Margin-to-Cost at Present Rates	Margin-to-Cost at Proposed Rates
Residential Schedule 410	1.03	1.03
General Service Schedule 420	0.90	0.94
Large General Service Schedule 424	1.32	1.15
Interruptible Service Schedule 440	1.22	1.06
Seasonal Service Schedule 444	1.40	1.23
Transportation Service Schedule 456	1.14	0.99
Overall	**1.00**	**1.00**

Q. Did Staff and NWIGU agree with the Company's proposed rate spread?

A. Yes. Staff witness Mr. Gibbens stated that "Avista has proposed a cost-based rate spread which is fair and reasonable given the LRIC results."[20] NWIGU witness Mr.

[20] Exhibit Staff/1100, Gibbens/10, ll. 16-17.

Gorman stated that the Company's "proposed spread of [the] increase is reasonable and consistent with cost of service."[21]

Q. What is the Company's response to Staff's proposed rate spread should the approved revenue requirement in this rate case be lower than Avista's original request?

A. Avista agrees with Mr. Gibbens' proposed rate spread outlined on pp. 11-12 of his opening testimony. In summary, Schedule 420 would receive a percentage increase that is twice the overall increase (on a margin basis). Such an increase to Schedule 420 would be capped at 18.9% (the same proposed margin increase in the Company's filing).

Q. Do you agree with CUB that all customers should receive a rate increase, which it proposed to do on an "approximate" 3 to 1 spread?

A. I do not support a rate increase for all customer schedules. First, the Commission in the Company's last general rate case, Docket No. UG-288, spread the results of the final revenue requirement to Schedules 410 and 420 only. Second, the results of the cost of service study in this case, as in prior cases, continue to show that Schedules 424, 440, 444 and 456 are misaligned. Illustration No. 4 and Table No. 3 below show the margin-to-cost ratios at present rates from the Company's LRIC studies presented in its last four general rate cases (Docket Nos. UG-248, UG-284, UG-288 and UG-325):

[21] Exhibit NWIGU/100, Gorman/8, ll. 10-11.

Illustration No. 4: Margin-to-Cost Ratios from Avista's Last Four General Rate Cases

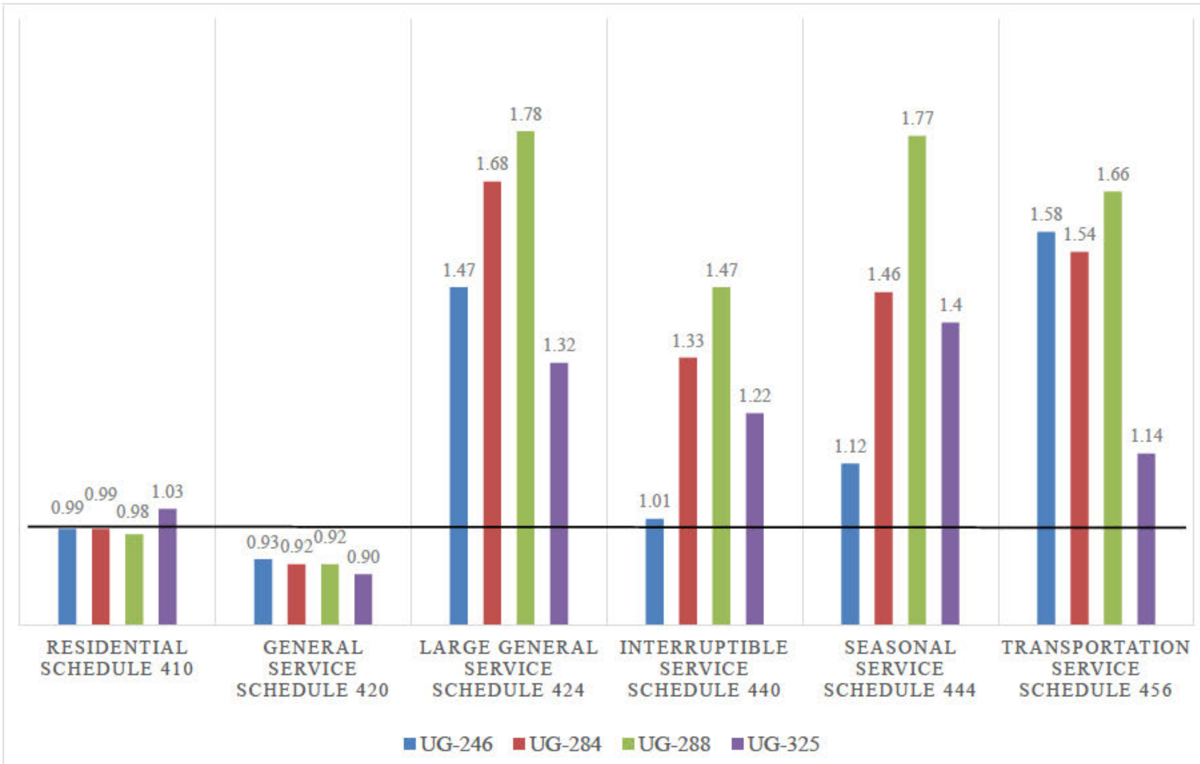

Table No. 3: Margin-to-Cost Ratios from Avista's Last Four General Rate Cases

	UG-246	UG-284	UG-288	UG-325
Residential Schedule 410	0.99	0.99	0.98	1.03
General Service Schedule 420	0.93	0.92	0.92	0.90
Large General Service Schedule 424	1.47	1.68	1.78	1.32
Interruptible Service Schedule 440	1.01	1.33	1.47	1.22
Seasonal Service Schedule 444	1.12	1.46	1.77	1.40
Transportation Service Schedule 456	1.58	1.54	1.66	1.14

As can be seen in Illustration No. 4 and Table No. 3, the margin-to-cost ratios for service schedules 424, 440, 444 and 456, are still well above their cost of service. This is true even after incorporating the fact that the Commission in Docket No. UG-288 ultimately ordered that those specific rate schedules receive no rate increase. Given that the margin-to-cost ratios calculated in this case, along with the results of prior LRIC studies, continue to demonstrate a substantial misalignment of rates, the Company continues to believe that applying the increase to Schedules 410 and 420 is reasonable at this time and will help to more closely align rates with costs.

Q. What are the effects of the revised revenue requirement for each service schedule?

A. Table No. 4 below provides the revised revenue requirement for each service schedule:

Table No. 4:

Rate Schedule	Reply Revenue Request	Revenue % Change (Margin)	Revenue % Change (Revenue)
Residential Schedule 410	$3,854	9.9%	6.4%
General Service Schedule 420	$2,894	18.9%	11.0%
Large General Service Schedule 424	$0	0.0%	0.0%
Interruptible Service Schedule 440	$0	0.0%	0.0%
Seasonal Service Schedule 444	$0	0.0%	0.0%
Transportation Service Schedule 456	$0	0.0%	0.0%
Overall	**$6,748**	**11.4%**	**7.2%**

VI. RATE DESIGN

Q. Do you agree with CUB's testimony that the Schedule 410 residential basic charge should remain at $9/month?

A. No. CUB's primary reason for keeping the Schedule 410 basic charge at $9 per month is that "(h)igh customer charges encourage customers to seasonally disconnect from the utility."[22] In this case the Company has not proposed to increase the basic charge to a "high" level. Avista is proposing to increase the customer charge by $1/month.

[22] Exhibit No. CUB 100, McGovern/36.

Q. Did Staff take issue with the Company's proposed basic charge increase for Schedule 410?

A. No, Staff did not take issue with the proposed $1/month increase for Schedule 410. In Staff's analysis, Mr. Gibbens in his Table No. 2 shows that only approximately 50% of the costs related to "Billing, meter reading, meters and services" is recovered from a $9 or $10 per month basic charge. Staff and Avista believe that $10 is reasonable in this case.

Q. What is your response to Staff's recommendation to leave the basic charge for general service schedule 420 at $17/month?

A. While Avista believes that $20 per month is reasonable in this case, for purposes of minimizing the issues in this case, Avista would agree to keep the basic charge for Schedule 420 unchanged at $17/month.

Q. Has the Company incorporated the revised billing determinants (from Staff's load adjustments S-18 and S-19) into its revised revenue adjustment?

A. Yes, the Company has included Staff's load adjustments into the revised billing determinants.[23]

VII. DECOUPLING

Q. Staff witness St. Brown on pages 22-23 of his testimony refers to Commission Order No. 16-076 which directs Avista to treat new customers different than

[23] For purposes of Staff's customer adjustment, referred to by Staff as for new large commercial customers, the Company has included these customers within rate schedule 424 (Large General Service). The Company backed into the increased therm usage from these three additional customers by taking Staff's revenue change of $26,343 and backing out the basic charge revenue of $1,800 (3 x $50 x 12 months), leaving a net change of $24,543. The Company then divided the remaining $24,543 by the Schedule 424 distribution margin rate of $0.13887, to obtain the imputed therm usage of 176,734. For purposes of the decoupling mechanism non-residential base, the Company proposes to spread the additional 176,734 therms on a monthly basis by a pro-rata allocation of the Company's proposed Schedule 424 forecast, updated with Staff's monthly load adjustment changes as detailed in Staff's response to the Company's data request number Avista - 02.

existing customers in its natural gas decoupling mechanism? Has Avista followed the Commission's Order regarding the treatment of new customers?

A. Yes, the Company at the inception of the mechanism has treated new customers in a manner consistent with the Commission's order. Included as Exhibit No. 1802 is a copy of the Company's 4th Quarter 2016 natural gas decoupling deferral report which provides the calculations necessary to effectuate the Commission's Order.[24] In its Compliance Filing in Docket No. UG-288, Avista inadvertently did not include the provisions related to new customers in its filed tariff. Avista will file Schedule 475 in the near future to reflect how new customers are treated in the mechanism.

Q. Does this conclude your reply testimony?

A. Yes it does.

[24] In Exhibit No. 1802, the comparison of the "Rate Year Allowed Customers" is compared to "Total Actual Billed Customers" in lines 1 and 2. The spreadsheet from that point has custom formulae which calculates "Rate Year Adjusted" customers, base rate revenue, and fixed charge revenue.

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

PATRICK D. EHRBAR
Exhibit No. 1801

Rate Spread and Rate Design

Avista Utilities
Proposed Revenue Increase by Schedule
Oregon - Gas
Pro Forma 12 Months Ended September 30, 2018
(000s of Dollars)

Line No.	Type of Service	Schedule Number	Distribution Revenue Under Present Rates	Proposed GRC Increase	Distribution Revenue Under Proposed Rates	Therms (000s)	**Distribution Revenue Percentage Increase**	Billed Revenue Under Present Rates	Proposed GRC Increase	Billed Revenue Under Proposed Rates	**Billed Revenue Percentage Increase**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential	410	$39,110	$3,854	$42,964	50,644	**9.9%**	$60,543	$3,854	$64,396	**6.4%**
2	General Service	420	$15,314	$2,894	$18,208	26,929	**18.9%**	$26,412	$2,894	$29,306	**11.0%**
3	Large General Service	424	$643	$0	$643	4,260	**0.0%**	$2,359	$0	$2,359	**0.0%**
4	Interruptible Service	440	$502	$0	$502	4,308	**0.0%**	$1,208	$0	$1,208	**0.0%**
5	Seasonal Service	444	$45	$0	$45	265	**0.0%**	$152	$0	$152	**0.0%**
6	Transportation Service	456	$3,252	$0	$3,252	40,757	**0.0%**	$3,302	$0	$3,302	**0.0%**
7	Special Contract	447	$213	$0	$213	5,773	**0.0%**	$213	$0	$213	**0.0%**
8	Total		$59,079	$6,748	$65,827	132,935	**11.4%**	$94,189	$6,748	$100,937	**7.2%**

Avista Utilities
Comparison of Present & Proposed Gas Rates
Oregon - Gas

Present Base Rates	Change	Proposed Base Rates
Residential Service Schedule 410		
$9.00 Customer Charge	$1.00/month	$10.00 Customer Charge
All Therms - $0.58062/Therm	$0.05480/therm	All Therms - $0.63542/Therm
General Service Schedule 420		
$17.00 Customer Charge	$0.00/month	$17.00 Customer Charge
All Therms - $0.48015/Therm	$0.10747/therm	All Therms - $0.58762/Therm
Large General Service Schedule 424		
$50.00 Customer Charge	$0.00/month	$50.00 Customer Charge
All Therms - $0.13887/Therm	$0.00000/therm	All Therms - $0.13887/Therm
Interruptible Service Schedule 440		
All Therms - $0.11652/Therm	$0.00000/therm	All Therms - $0.11652/Therm
Seasonal Service Schedule 444		
All Therms - $0.17155/Therm	$0.00000/therm	All Therms - $0.17155/Therm
Transportation Service Schedule 456		
$275.00 Customer Charge	$0.00/month	$275.00 Customer Charge
1st 10,000 Therms - $0.14978/Therm	$0.00000/therm	1st 10,000 Therms - $0.14978/Therm
Next 20,000 Therms - $0.09014/Therm	$0.00000/therm	Next 20,000 Therms - $0.09014/Therm
Next 20,000 Therms - $0.07409/Therm	$0.00000/therm	Next 20,000 Therms - $0.07409/Therm
Next 200,000 Therms - $0.05799/Therm	$0.00000/therm	Next 200,000 Therms - $0.05799/Therm
Over 250,000 Therms - $0.02942/Therm	$0.00000/therm	Over 250,000 Therms - $0.02942/Therm
		Schedule 456 Monthly Minimum Charge
		18,750 @ $0.09014 = $1,690.13

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG-325

PATRICK D. EHRBAR
Exhibit No. 1802

Decoupling

Avista Utilities
Natural Gas Decoupling Mechanism (Oregon)
Development of OR Natural Gas Deferrals (Calendar Year 2016)
Docket No. UG-288 Rates Effective March 1, 2016

Line No.		Source	Oct-16	Nov-16	Dec-16	Q4 Total
	(a)	(b)	(l)	(m)	(n)	
	Residential Group					
1	Rate Year Allowed Customers	Appendix 5, Page 3	86,866	87,585	88,200	
2	Total Actual Billed Customers	Revenue Reports	87,434	88,202	88,640	
3	Total Actual Usage (Therms)	Revenue Reports	3,168,968	4,966,685	9,269,970	
4	Total Actual Base Rate Revenue	Revenue Reports	$ 2,724,721	$ 3,708,712	$ 6,147,539	
5	Total Actual Fixed Charge Revenue	Revenue Reports	$ 790,287	$ 796,678	$ 801,793	
7	New Hook-up Customers Billed	Revenue Reports	1,109	1,326	1,448	
8	New Hook-up Usage (Therms)	Revenue Reports	14,443	37,822	89,047	
9	New Hook-up Base Rate Revenue	Revenue Reports	$ 17,542	$ 33,051	$ 64,140	
10	New Hook-up Fixed Charge Revenue	Revenue Reports	$ 9,155	$ 11,090	$ 12,437	
11	**Actual Customers**	**Rate Year Adjusted**	86,866	87,585	88,200	
12	Monthly Decoupled Revenue per Customer	Appendix 5, Page 3	$18.60	$36.67	$53.55	
13	**Decoupled Revenue**	(11) x (12)	$ 1,615,934	$ 3,211,322	$ 4,722,886	
14	Actual Base Rate Revenue (Excludes Gas Costs)	Rate Year Adjusted	$ 2,715,731	$ 3,693,323	$ 6,128,055	
15	Actual Fixed Charge Revenue	Rate Year Adjusted	$ 785,595	$ 791,515	$ 798,015	
16	**Customer Decoupled Payments**	(14) - (15)	$ 1,930,136	$ 2,901,809	$ 5,330,040	
17	Residential Revenue Per Customer Received		$22.22	$33.13	$60.43	
18	Deferral - Surcharge (Rebate)	(13) - (16)	$ (314,202)	$ 309,513	$ (607,155)	$ (611,843)
19	Deferral - Revenue Related Expenses	Rev Conv Factor	$ 9,711	$ (9,566)	$ 18,765	$ 18,910
20		Authorized ROR	7.46%	7.46%	7.46%	
21	Interest on Deferral	Avg Balance Calc	$ 9,535	$ 9,581	$ 8,744	$ 27,860
22	**Monthly Residential Deferral Totals**		**$ (294,955)**	**$ 309,528**	**$ (579,646)**	**$ (565,074)**
23	Cumulative Deferral Balance	Σ((18) ~ (21))	$ 1,391,554	$ 1,701,082	$ 1,121,436	
24	Weather Related Deferred Revenue		$ (13,662)	$ 675,256	$ (395,098)	
25	Revenue Related Expenses		$ 422	$ (20,869)	$ 12,211	
26	Interest		$ 8,307	$ 10,351	$ 11,259	
27	**Total Residential Weather Related Deferral Surcharge (Rebate)**		**$ (4,933)**	**$ 664,737**	**$ (371,628)**	
28	Cumulative Weather Related Deferral Balance		$ 1,338,257	$ 2,002,994	$ 1,631,365	
29	Conservation (Non-Weather) Related Deferred Revenue		$ (300,539)	$ (365,743)	$ (212,057)	
30	Revenue Related Expenses		$ 9,288	$ 11,304	$ 6,554	
31	Interest		$ 1,229	$ (770)	$ (2,515)	
32	**Total Residential Conservation (Non-Weather) Related Deferral Surcharge (Rebate)**		**$ (290,022)**	**$ (355,209)**	**$ (208,018)**	
33	Cumulative Conservation (Non-Weather) Related Deferral Balance		$ 53,298	$ (301,912)	$ (509,930)	
34	**Residential Cumulative Deferral Surcharge (Rebate) Balance**		**$ 1,391,554**	**$ 1,701,082**	**$ 1,121,436**	

Avista Corporation Decoupling Mechanism
Oregon Jurisdiction
Quarterly Report for 4th Quarter 2016

Avista Utilities
Natural Gas Decoupling Mechanism (Oregon)
Development of OR Natural Gas Deferrals (Calendar Year 2016)
Docket No. UG-288 Rates Effective March 1, 2016

Line No.		Source	Oct-16	Nov-16	Dec-16	Q4 Total
	(a)	(b)	(l)	(m)	(n)	
	Non-Residential Group					
1	Rate Year Allowed Customers	Appendix 5, Page 3	11,431	11,511	11,588	
2	Total Actual Billed Customers	Revenue Reports	11,664	11,718	11,792	
3	Total Actual Usage (Therms)	Revenue Reports	2,474,028	3,089,029	5,501,142	
4	Total Actual Base Rate Revenue	Revenue Reports	$ 1,173,201	$ 1,423,957	$ 2,545,661	
5	Total Actual Fixed Charge Revenue	Revenue Reports	$ 201,050	$ 201,928	$ 203,440	
7	New Hook-up Customers Billed	Revenue Reports	145	168	189	
8	New Hook-up Usage (Therms)	Revenue Reports	16,098	26,757	66,972	
9	New Hook-up Base Rate Revenue	Revenue Reports	$ 8,251	$ 13,341	$ 32,502	
10	New Hook-up Fixed Charge Revenue	Revenue Reports	$ 2,407	$ 2,773	$ 3,010	
11	**Actual Customers**	**Rate Year Adjusted**	11,431	11,511	11,588	
12	Monthly Decoupled Revenue per Customer	Appendix 5, Page 3	$97.49	$134.01	$172.56	
13	**Decoupled Revenue**	(11) x (12)	$ 1,114,446	$ 1,542,577	$ 1,999,678	
14	Actual Base Rate Revenue (Excludes Gas Costs)	Rate Year Adjusted	$ 1,159,962	$ 1,407,515	$ 2,510,624	
15	Actual Fixed Charge Revenue	Rate Year Adjusted	$ 197,187	$ 198,511	$ 200,195	
16	**Customer Decoupled Payments**	(14) - (15)	$ 962,775	$ 1,209,005	$ 2,310,428	
17	Non-Residential Revenue Per Customer Received		$84.22	$105.03	$199.38	
18	Deferral - Surcharge (Rebate)	(13) - (16)	$ 151,672	$ 333,572	$ (310,750)	$ 174,493
19	Deferral - Revenue Related Expenses	Rev Conv Factor	$ (4,688)	$ (10,309)	$ 9,604	$ (5,393)
20	Interest Rate	Authorized ROR	7.46%	7.46%	7.46%	
21	Interest on Deferral	Avg Balance Calc	$ 4,935	$ 6,427.37	$ 6,536	$ 17,899
22	**Monthly Non-Residential Deferral Totals**		**$ 151,920**	**$ 329,690**	**$ (294,610)**	**$ 186,999**
23	Cumulative Deferral Balance	Σ((18) ~ (21))	$ 872,540	$ 1,202,230	**$ 907,619**	
24	Weather Related Deferred Revenue		$ 969	$ 285,746	$ (182,322)	
25	Revenue Related Expenses		$ (30)	$ (8,831)	$ 5,635	
26	Interest		$ 3,470	$ 4,355	$ 4,693	
27	**Total Non-Residential Weather Related Deferral Surcharge (Rebate)**		**$ 4,409**	**$ 281,269**	**$ (171,994)**	
28	Cumulative Weather Related Deferral Balance		$ 562,223	$ 843,492	$ 671,498	
29	Conservation (Non-Weather) Related Deferred Revenue		$ 150,703	$ 47,827	$ (128,429)	
30	Revenue Related Expenses		$ (4,658)	$ (1,478)	$ 3,969	
31	Interest		$ 1,466	$ 2,073	$ 1,843	
32	**Total Non-Residential Conservation (Non-Weather) Related Deferral Surcharge (Rebate)**		**$ 147,511**	**$ 48,421**	**$ (122,617)**	
33	Cumulative Conservation (Non-Weather) Related Deferral Balance		$ 310,317	$ 358,738	$ 236,121	
34	**Non-Residential Cumulative Deferral Surcharge (Rebate) Balance**		**$ 872,540**	**$ 1,202,230**	**$ 907,619**	
35	**Total Oregon Cumulative Deferral Balance Surcharge (Rebate)**	**Residential (34) + Non-Residential (34)**	**$ 2,264,094**	**$ 2,903,312**	**$ 2,029,055**	