Exhibit No. ___(HLR-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-14________

DIRECT TESTIMONY OF

HEATHER L. ROSENTRATER

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Heather Rosentrater. I am employed by Avista Corporation as Director, Engineering and Transmission Operations. My business address is 1411 East Mission, Spokane, Washington.

Q. Please briefly describe your educational background and professional experience.

A. I am a 1999 graduate of Gonzaga University with a degree in Electrical Engineering. I have been a registered Professional Engineer in the State of Washington since 2004. I joined the Company in 1996 and have spent 17 years in various engineering and leadership positions. I spent several years supporting the planning and design of Avista's Distribution System in engineering roles and managerial roles. For the last five years, I have been a Director with responsibilities ranging from Asset Management to Gas Supply to my current role leading the Engineering and System Operations Departments. I currently hold budgeting responsibilities for all transmission, substation, and distribution projects.

Q. What is the scope of your testimony?

A. My testimony presents Avista's transmission revenues and expenses for the 2015 rate year. I also discuss Avista's Transmission and Distribution capital expenditures, for the period June 2013 through the 2015 rate year. The information included within my testimony, related to transmission revenues, expenses and capital additions is provided for informational purposes only.[1] As explained by Company witness Ms. Andrews, the Company is basing its electric revenue increase reflected in this case based on its electric Attrition Study. However, as a "cross check" to the Company's request, Ms. Andrews has also prepared an electric Pro Forma Cross Check Study, which incorporate Washington's share of the pro forma or 2015 rate year adjustments for revenues, expenses and capital additions described further in my testimony.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exhibit No. __(HLR-2) provides the transmission revenue and expense adjustments.

II. TRANSMISSION EXPENSES FOR 2015

Q. Please describe the adjustments to 2012-2013 test year transmission expenses to arrive at transmission expenses for the 2015 rate year.

[1] As discussed by Ms. Andrews, the electric Attrition Study analysis, however, does include Washington's share of the 2015 rate year transmission revenues described within my testimony. These revenues are included in Ms. Andrews' electric Attrition Study, Exhibit No. __(EMA-2), page 4, column [I]. Washington's share of the $16.0 million system amount of Account 456 Other Electric Revenue, shown on Exhibit No. __(HLR-2), are also included in the Energy Recovery Mechanism (ERM) authorized base. See Company witness Mr. Johnson Exhibit No. __(WGJ-7) for the "ERM Authorized Power Supply Expenses" included in this case.

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the July 2012 through June 2013 test year to the 2015 rate year. The changes in expenses and a description of each is summarized in Table No. 1, and following the Table, I have provided an explanation of each change.

TABLE NO. 1
Transmission Expense Adjustment

	***2015 Test Year (System)**
Northwest Power Pool (NWPP)	$ 20,000
Colstrip Transmission	(18,000)
ColumbiaGrid RTO	-
ColumbiaGrid Transmission Planning	37,000
ColumbiaGrid OASIS	(23,000)
Transmission Line Ratings Confirmation Plan (NERC Alert)	(1,339,000)
Electric Schedule & Accounting Services (OATI)	21,000
NERC CIP	(8,000)
OASIS Expenses	5,000
BPA Power Factor Penalty	64,000
WECC Total Dues - WECC Sys Secur & Admin- Net Oper Comm Sys	58,000
WECC Admin & Net Oper Comm Sys	196,000
WECC - Loop Flow	50,000
Total Change in Transmission Expense	**$ (937,000)**

*Representing the change in expense above or below the 2012-13 test year level.

Northwest Power Pool (NWPP) ($20,000) – Avista pays its share of the NWPP operating costs. The NWPP serves the electric utilities in the Northwest by providing coordinated transmission operations including contingency generation reserve sharing, Columbia River water coordination and providing support to coordinated regional transmission planning. The increase in 2015 is equal to the actual increase that occurred from the 2012-13 test year to the 2013-14 NWPP billing cycle.

Colstrip Transmission (-$18,000) – Avista is required to pay its portion of the O&M costs associated with its joint ownership share of the Colstrip transmission system pursuant to the Colstrip Transmission Agreement. In accordance with NorthWestern Energy's (NWE) proposed Colstrip transmission plan provided to the Company, NWE will bill Avista an estimated $348,000 for Avista's share of the Colstrip O&M expense during the 2015 rate year period. This is a decrease of $18,000 from the actual expense of $366,000 incurred during the 2012-13 test year.

ColumbiaGrid RTO ($0) – Avista became a member of the ColumbiaGrid regional transmission organization in 2006. ColumbiaGrid's purpose is to enhance transmission system reliability and efficiency, provide cost-effective coordinated regional transmission planning, develop and facilitate the implementation of solutions relating to improved use and expansion of the interconnected Northwest transmission system, reduce transmission system congestion, and support effective market monitoring within the Northwest and the entire Western interconnection. Avista supports ColumbiaGrid's general developmental and regional coordination activities under the ColumbiaGrid Fourth Funding Agreement, signed July 1, 2010, and supports specific functional activities under the Planning and Expansion Functional Agreement and the Order 1000 Functional Agreement. Avista's ColumbiaGrid general funding expenses for the 2012-13 test year were $169,000 while 2015 rate year general funding expenses are $169,000. No change is reflected for the 2015 rate year.

ColumbiaGrid Transmission Planning ($37,000) – The ColumbiaGrid Planning and Expansion Functional Agreement (PEFA) was accepted by the Federal Energy Regulatory Commission (FERC) on April 3, 2007 and Avista entered into the PEFA on April 4, 2007. Coordinated transmission planning activities under the PEFA allow the Company to meet the coordinated regional transmission planning requirements set forth in FERC's Order 890 issued in February, 2007, and outlined in the Company's Open Access Transmission Tariff, Attachment K. Additional FERC Order 1000 requirements are accommodated under the Order 1000 Functional Agreement which was executed by Avista on December 13, 2013. Funding under the PEFA is on a two-year cycle with provisions to adjust for inflation. Actual PEFA expenses for the 2012-13 test year were $203,000. The Company's PEFA and Order 1000 agreement expenses for 2015 are $240,000, reflecting ColumbiaGrid's staffing levels to support the PEFA and Order 1000 activities and the reallocation of a portion of ColumbiaGrid's administrative expenses (previously paid under the general funding agreement) to these functional agreements.

ColumbiaGrid OASIS Agreement (-$23,000) – This contract, and its associated expense, was terminated due to lack of use by the parties to the agreement and their transmission customers.

Transmission Line Ratings Confirmation Plan (NERC Alert) (-$1,339,000) – The Transmission Line Ratings Confirmation Plan was developed to address a "NERC Alert" issued on October 7, 2010. The North American Electric Reliability Corporation (NERC) issued a "Recommendation to Industry addressing Consideration of Actual Field Conditions in Determination of Facility Ratings" based on a vegetation contact conductor-to-ground fault by another Transmission Owner. The NERC Alert was issued to provide the industry an opportunity to review actual field conditions and compare them to design values to ensure system reliability. Avista initiated a three year program to perform Light Detection and Ranging (LIDAR) surveying of all Avista 230kV transmission lines and five (5) 115kV transmission lines. A total of 1400 miles of transmission lines was evaluated at a total system cost of $2.945 million. The total Washington share of this project is $1.914 million. Per Order No. 06, Docket UE-11086 and UE-11087, the Company amortized these costs over a three-year period beginning in 2011. This project was completed in 2013 and therefore, there are no expenses for this project in the 2015 rate year. Over the life of the project, these O&M expenses totaled a system cost of $2.146 million.

Electric Scheduling and Accounting Services ($21,000) – The $21,000 increase in the rate year compared to test year expense for electric scheduling and accounting services is a result of annual increases and additional services provided by our third party vendor. These services are required to assist in meeting the requirements of the NERC mandatory reliability standards. The rate year scheduling and accounting costs are $210,000 that reflects an increase of $21,000 from the actual 2012-13 test year expense of $189,000.

NERC Critical Infrastructure Protection (-$8,000) – The Company has purchased two software products to assist in protecting critical transmission system data from intrusion and to meet applicable NERC standards. The Company's 2015 rate year expense of $35,000 reflects a decrease of $8,000 from the actual 2012-13 test year expense of $43,000.

OASIS Expenses ($5,000) – These Open Access Same-time Information System (OASIS) expenses are associated with travel and training costs for transmission pre-scheduling and OASIS personnel. This travel is required to monitor and adhere to NERC reliability standards, regional criterion development, and FERC OASIS requirements. The costs associated with OASIS expenses in the rate year are $8,000 compared to only $3,000 of actual expenses in the 2012-13 test year. This variance is due to a timing difference on when actual travel occurred versus the test year months.

Bonneville Power Factor Penalty ($64,000) – Power factor penalty costs are associated with the Bonneville Power Administration's (Bonneville) General Transmission Rate Schedule Provisions. Bonneville charges a power factor penalty at all interconnections with Avista that exceed a given threshold for reactive power flow during each month. If the reactive flow from Bonneville's transmission system into Avista's system or from Avista's system to Bonneville's system exceeds a given threshold, then Bonneville bills Avista according to its rate schedule. The charge includes a 12-month rolling ratchet provision. While termed a "penalty" rate, charges under this rate schedule are predominantly a result of the performance of the broader interconnected system where the reactive flow at certain times is not controllable by Avista. Avista has on a number of occasions petitioned Bonneville for a waiver or adjustment of these charges at specified locations on our system. To date, Avista has been successful in some of these petitions and unsuccessful in others. Additionally, Bonneville's power factor penalty charge is not a true "penalty" in that its basis is a portion of its transmission system revenue requirement, not a "penalty" above and beyond simple recovery of certain transmission assets. Bonneville is simply allocating a portion of its transmission asset recovery to reactive power flow associated with its neighboring systems instead of recovering these costs from its wheeling customers. Avista currently pays Bonneville a power factor penalty at several points of interconnection. Avista incurred $68,000 of power factory penalty charges during the 2012-13 test year. The Company's 2015 rate year expenses are expected to be $132,000 representing an average of the power factor penalty charges incurred from 2011 to 2013.

<u>WECC – Reliability Coordination</u> ($58,000) – The Company's total WECC fees are scheduled to increase 23% in 2014 and an additional 15% in 2015, following a 12.5% increase in 2013. The fees paid in the 2012-13 test year for reliability coordination functions were $208,000. The above increases in the WECC assessments are due to a FERC requirement that the WECC Reliability Function be corporately and physically

separated from the remaining WECC requirements and obligations. This so called "bifurcation" is primarily the result of a transmission system outage on September 8, 2011. A reference to the disturbance including "Causes and Recommendations" may be found at http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf

WECC – Administration Dues, Operating Committee and Planning Committee Fees ($196,000) – WECC is the designated Regional Entity under federal statute responsible for coordinating and promoting Bulk Electric System reliability throughout the western interconnection. The scheduled increases in WECC fees, as noted above, are driven primarily by increased compliance requirements associated with mandatory national reliability standards. WECC is responsible for monitoring and measuring Avista's compliance with the standards and has substantially increased its staff and other resources to meet these FERC requirements. The Company's 2012-13 test year WECC dues and fees were $360,000. The Company's total for dues and fees in the 2015 rate year are expected to be $556,000 per the expected 2014 increase of 23% and 2015 increase of 15%.

WECC - Loop Flow ($50,000) – Loop Flow charges are spread across all transmission owners in the West to compensate utilities that make system adjustments to eliminate transmission system congestion throughout the operating year. WECC Loop Flow charges can vary from year to year since the costs incurred are dependent on transmission system usage and congestion. Loop Flow payments have varied over the past several years between $16,000 and $49,000. Loop Flow expenses for the 2012-13 test year are zero due to invoice and payment timing during the test year. The actual Loop Flow payment for 2012 of $28,337 occurred in May, 2012 and the 2013 payment of $47,380 occurred in August, both outside the test year. Loop Flow expenses are budgeted to meet expected costs. Loop

Flow expenses are estimated to be $50,000 in 2013 and have been held flat through the 2015 rate year.

III. TRANSMISSION REVENUES FOR 2015

Q. Please describe the adjustments to 2012-2013 test year transmission revenues to arrive at transmission revenues for the 2015 rate year.

A. Adjustments have been made in this filing to incorporate updated information associated with known changes in transmission revenue for the 2015 rate year as compared to the 2012-13 test year. Each revenue item described below is at a system level and is included in Exhibit No.__ (HR-2). Table No. 2 below provides a summary of the changes in transmission revenues, and an explanation of each change follows the Table.

TABLE NO. 2
Transmission Expense Adjustment

	*2015 Test Year (System)
Borderline Wheeling Transmission & Low Voltage	$ 39,000
OASIS, non-firm, & short-term firm (Other Wheeling)	457,000
Seattle/Tacoma Main Canal	(8,000)
Seattle/Tacoma Summer Falls	-
PacifiCorp – Dry Gulch	12,000
Spokane Waste to Energy Plant	-
Grand Coulee Project	-
Palouse Wind	-
Palouse Wind O&M	11,000
Stimson Lumber	-
Hydro Tech Systems – Meyers Falls	-
BPA Parallel Operation Agreement	(10,096,000)
Morgan Stanley Capital Group	300,000
Kootenai Electric Cooperative	(6,000)
	$ (9,291,000)

*Representing the change in revenue above or below the 2012-13 test year level.

Borderline Wheeling Transmission and Low Voltage ($39,000) - Total borderline wheeling revenues for the 2012-13 test year were $8,064,000. Total borderline wheeling revenue in the 2015 rate year has been set at $8,103,000, which reflects a slight increase over the test year.

These wheeling revenues consist of the following elements:

- Borderline Wheeling – Transmission ($39,000) - Total Network Integration Transmission Service revenues from Transmission for the 2012-13 test year were $6,993,000. Total revenue in the 2015 rate year has been set at $7,032,000, which reflects a slight increase over the test year. These revenues consist of wheeling activities specifically associated with Bonneville Power Administration (increase of $39,000 to $6,919,000 for the 2015 rate year versus $6,880,000 in the 2012-13 test year) and Other Customers ($113,000 in 2015 unchanged from the 2012-13 test year).

  In the past, the pro forma borderline revenue has been developed using a five-year rolling average of revenues from borderline wheeling service provided to Bonneville and other customers since a large portion of the revenue is dependent upon usage. However, with billing adjustments implemented in 2009 and new transmission rates and contracts that went into effect in 2010, use of the previous five-years of actual revenues would not properly reflect the new level of revenues. Therefore, 2015 rate year revenue has been set equal to the three-year average of 2010 through 2012 actual revenue (adjusted to remove low voltage revenues).

- Borderline Wheeling Low Voltage ($0) – Actual test year revenue from borderline wheeling service across low-voltage facilities provided during the 2012-13 test year was $1,070,357 and will remain unchanged for the 2015 rate year. These revenues consist of low voltage wheeling specifically for Bonneville Power Administration ($929,000 in 2015 unchanged from the 2012-13 test year) and Other Customers ($141,000 in 2015 unchanged from the 2012-13 test year).

The other customers for both Transmission and Low Voltage Services are as follows:

- Borderline Wheeling – Spokane Tribe of Indians ($0) – The Company provides borderline wheeling service over both transmission and low-voltage facilities to the Spokane Tribe of Indians under two agreements. Total transmission and low-voltage wheeling revenue under these contracts for the 2012-13 test year was $48,000 ($30,000 transmission and $18,000 low voltage). Revenue associated with the transmission contract is adjusted annually under the current contract, so 2014 transmission revenue will be $30,000. The current agreements with the Spokane Tribe expire December 31, 2014, but follow-on agreements are expected to be negotiated and executed during 2014. Accordingly, 2015 rate year revenue is expected to remain at $48,000.
- Borderline Wheeling – East Greenacres Irrigation District ($0) – The Company restructured its contract to provide borderline wheeling service to the East Greenacres Irrigation District in April 2009, resulting in monthly wheeling revenue of $5,000 under two agreements ($1,400 transmission and $3,600 low voltage). Revenue under these agreements for the 2012-13 test year was $60,000 ($17,000 transmission and $43,000 low voltage). The current agreements with Consolidated Irrigation expire September 30, 2014, but follow-on agreements are expected to be

negotiated and executed in 2014. Accordingly, revenue for the 2015 rate year is expected to remain at $60,000.

- Borderline Wheeling – Consolidated Irrigation District ($0) – The Company provides borderline wheeling service over both transmission and low-voltage facilities to the Consolidated Irrigation District under two agreements that run through September 30, 2016. Total transmission and low-voltage wheeling revenue under these contracts for the 2012-13 test year was $119,000 (transmission $39,000 and low voltage $80,000) and remains unchanged in the 2015 rate year.
- Borderline Wheeling – Grant County PUD ($0) – The Company provides borderline wheeling service to two Grant County PUD substations under a Power Transfer Agreement executed in 1980. Charges under this agreement are not impacted by the Company's transmission service rates under Avista's Open Access Transmission Tariff so a five-year average is used to determine the rate year revenue of $27,000. The 2012-13 test year revenue was $27,000. There is no Low Voltage Wheeling revenue associated with this contract.

OASIS Non-Firm and Short-Term Firm Transmission Service ($457,000) – OASIS is an acronym for Open Access Same-time Information System. This is the system used by electric transmission providers for selling and scheduling available transmission capacity to eligible customers. The terms and conditions under which the Company sells its transmission capacity via its OASIS are pursuant to FERC regulations and Avista's FERC Open Access Transmission Tariff. The Company is calculating its rate year adjustments using a three-year average of actual OASIS Non-Firm and Short-Term Firm revenue. OASIS transmission revenue may vary significantly depending upon a number of factors, including current wholesale power market conditions, forced or planned generation resource outage situations in the region, current load-resource balance status of regional load-serving entities and the availability of parallel transmission paths for prospective transmission customers. The use of a three-year average is intended to strike a balance in mitigating both long-term and short-term impacts to OASIS revenue. A three-year period is intended to be long enough to mitigate the impacts of non-substantial temporary operational conditions (for generation and transmission) that may occur during a given year and it is intended to be short-enough so as to not dilute the impacts of long-term transmission and generation topography changes (e.g. major transmission projects which may impact the availability of the Company's transmission capacity or competing transmission paths, and major generation projects which may impact the load-resource balance needs of prospective transmission customers). However, if there are known events or factors that occurred during the period that would cause the average to not be representative of future expectations, then adjustments may be made to the three-year average methodology. In this filing, the Company is using the most recent three-year average (2010 to 2012) with some adjustments associated with 2011 revenues due to additional revenue received from Puget Sound Energy as a result of an outage on BPA's transmission system. The outage resulted in additional revenue of $1.6 million. The OASIS revenue for the 2012-13 test year is $2.778 million and the three-year average results in 2015 rate year revenue of $3.235 million.

<u>Seattle and Tacoma Revenues Associated with the Main Canal Project</u> (-$8,000) – Effective March 1, 2008, the Company entered into long-term point-to-point transmission service arrangements with the City of Seattle and the City of Tacoma to transfer output from the Main Canal hydroelectric project, net of local Grant County PUD load service, to the

Company's transmission interconnections with Grant County PUD. Service is provided during the eight months of the year (March through October) in which the Main Canal project operates and the agreements include a three-year ratchet demand provision. Revenues under these agreements totaled $295,000 during the 2012-13 test year. Revenues for the 2015 rate year are $287,000 based on a reduction in the ratchet demand.

Seattle and Tacoma Revenues Associated with the Summer Falls Project ($0) – Effective March 1, 2008, the Company entered into long-term use-of-facilities arrangements with the City of Seattle and the City of Tacoma to transfer output from the Summer Falls hydroelectric project across the Company's Stratford Switching Station facilities to the Company's Stratford interconnection with Grant County PUD. Charges under this use-of-facilities arrangement are based upon the Company's investment in its Stratford Switching Station and are not impacted by the Company's transmission service rates under its Open Access Transmission Tariff. Revenues under these two contracts totaled $74,000 in the 2012-13 test year and are expected to remain unchanged for the 2015 rate year.

PacifiCorp Dry Gulch ($12,000) – Revenue under the Dry Gulch use-of-facilities agreement has been adjusted to $220,000 for the 2015 rate year, which is a $12,000 increase from the 2012-13 test year actual revenue of $208,000. The Company is calculating its adjustment using a three-year average of actual revenue (2010 through 2012). Revenue under the Dry Gulch Transmission and Interconnection Agreement with PacifiCorp varies depending upon PacifiCorp's loads served via the Dry Gulch Interconnection and the operating conditions of PacifiCorp's transmission system in this area. The use of a three-year average is intended to mitigate the impacts of potential annual variability in the revenues under the contract. A three-year average is also consistent with the methodology used for the Company's OASIS revenue. The contract includes a twelve-month rolling ratchet demand provision and charges under this agreement are not impacted by the Company's open access transmission service tariff rates.

Spokane Waste to Energy Plant ($0) – This revenue has historically been associated with a long-term transmission service agreement with the City of Spokane that expired December 31, 2011. Avista decided to purchase the energy from the Spokane Waste to Energy facility beginning January 1, 2012, after the project's prior contract with Puget Sound Energy (PSE) expired. With the new power sale to Avista, Spokane Waste to Energy no longer pays for transmission service to move the energy to PSE, but instead pays a use-of-facilities charge for the ongoing use of its interconnection to Avista's transmission system. The 2015 rate year revenue associated with the use-of-facilities charge is $28,000, the same as the 2012-13 test year.

Grand Coulee Project Hydroelectric Authority ($0) – The Company provides operations and maintenance services on the Stratford-Summer Falls 115kV Transmission Line to the Grand Coulee Project Hydroelectric Authority under a contract signed in March 2006. These services are provided for a fixed annual fee. Annual charges under this contract totaled $8,100 in the 2012-13 test year and will remain the same for the 2015 rate year.

Palouse Wind ($0) – Palouse Wind signed a transmission service contract with the Company based on its initial intent to sell the output from a wind facility to an entity other than Avista. Avista has since signed a power purchase agreement with Palouse Wind which voided its need for transmission service. Palouse Wind intends to delay use of the 100 MW of reserved transmission service for up to five years unless they are able to re-market the capacity. However, according to Avista's Open Access Transmission Tariff and the contract signed with Avista, Palouse Wind must pay an annual reservation fee equal to one month's worth of service to extend its start date for service. The 2012-13 test year includes a $200,000 extension of service payment and the 2015 rate year also includes an expected payment amount of $200,000, per the terms of Avista's Tariff.

Palouse Wind O&M ($11,000) – Per Avista's interconnection agreement with the Palouse Wind project, the interconnection customer pays O&M fees associated with directly-assigned interconnection facilities owned and operated by Avista. O&M revenue, applicable only during a portion of the 2012-13 test year, was $41,296. Revenue in 2014 and during the 2015 rate year is expected to be $11,000 greater, or $52,163.

Stimson Lumber Agreement ($0) – The Company has received revenue associated with sole-use, or directly assigned, low-voltage facilities related to the integration of small generation resources. In the 2015 rate year, the Company will receive annual use-of-facilities revenue of $9,000, or approximately $790 per month, from Stimson Lumber for the dedicated use of low-voltage facilities in the Company's Plummer Substation. The 2012-13 test year revenue was $9,000.

Hydro Tech Systems Agreement ($0) – Low-voltage facilities in the Company's Greenwood Substation are dedicated for use by the Meyers Falls generation project resulting in annual low voltage use-of-facilities revenue of $6,000, or $510 per month. The 2015 rate year revenue from this agreement is $6,000. There was $6,000 in revenue collected during the 2012-13 test year.

Bonneville Power Administration Parallel Capacity Support (-$10,096,000) – Avista and Bonneville executed a Parallel Operation Agreement on December 12, 2012, wherein

Avista provides Bonneville with parallel transmission capacity in support of Bonneville's integration of several wind resource projects. The agreement provided for an initial payment of $11,692,000 in February of 2013, which covered Bonneville's use of parallel capacity support prior to that point in time. Avista provides ongoing parallel capacity support under the agreement at a monthly charge of $266,000. Revenue for the test year was $13,288,000, which included the one-time payment and six months of monthly payments. Revenues for the 2015 rate year are $3,192,000.

Morgan Stanley – Point-to-Point Transmission Service ($300,000) – Morgan Stanley Capital Group has purchased 25MW of Long-Term Firm Point-to-Point Transmission Service from January 1, 2013, to December 31, 2017. The 2012-13 test year included revenues of $300,000 for six-months of service and the 2015 rate year reflects an amount of $600,000.

Kootenai Electric Cooperative (-$6,000) – The Company received a one-time payment of $6,000 from Kootenai Electric Cooperative (KEC) during the 2012-13 test year for reimbursement of costs associated with upgrades to relaying equipment to accommodate the integration of a new generation project on the KEC system. The 2015 rate year does not include any such payment.

IV. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS

Q. Please describe the Company's capital transmission projects that will be completed from June 30, 2013 through December 2015.

A. Avista continuously needs to invest in its transmission system to maintain reliable customer service and meet mandatory reliability standards. The capital transmission projects are being planned and constructed to meet either compliance requirements, improve system reliability, fix broken equipment, or replace aging equipment that is anticipated to fail.

Included in the compliance requirements are the North American Electric Reliability Corporation (NERC) standards, which are national standards that utilities must meet to ensure interconnected system reliability. Beginning June 2007, compliance with these standards was made mandatory and failure to meet the requirements could result in monetary penalties of up to $1 million per day per infraction. The majority of the reliability standards pertain to transmission planning, operation, and equipment maintenance. The standards require utilities to plan and operate their transmission systems in such a way as to avoid the loss of customers or impact to neighboring utility systems due to the loss of transmission facilities. The transmission system must be designed so that the loss of up to two facilities simultaneously will not impact the interconnected transmission system. These requirements drive the need for Avista to continually invest in its transmission system. Avista is required to perform system planning studies in both the near term (1-5 years) and long term (5-10 years). If a potential violation is observed in the future years, then Avista must develop a project plan to ensure that the violation is fixed prior to it becoming a real-time operating issue. Avista plans for the future projects and ensures that the design and construction of the required projects are completed prior to the time they are needed. Avista will continue to have a need to develop these compliance-related projects as system load grows, new generation is interconnected, and the system functionality and usage changes.

Avista capital transmission project requirements are developed through system planning studies, engineering analysis, or scheduled upgrades or replacements. The larger specific projects that are developed through the system planning study process typically go through a thorough internal review process that includes multiple stakeholder review to ensure all system needs are adequately addressed. For the smaller specific projects, Avista doesn't perform a traditional cost-benefit analysis. Projects are selected to meet specific system needs or equipment replacement. However, both project cost and system benefits are considered in the selection of the final projects.

Q. Did the Company consider any efficiency gains or offsets when evaluating the transmission projects to include in the Company's case?

A. Yes. The Company evaluated each project and determined that some of the 2013, 2014 and 2015 capital transmission projects will result in efficiency gains and potential offsets or savings, and the Company has included those where applicable. The primary offsets result in loss savings from reconductoring heavily-loaded transmission or distribution facilities. For these projects, an analysis was performed to determine the savings. The assumed avoided energy cost to determine the savings was $44 MWh, which is the 20 year life cycle cost calculated in Avista's 2013 Integrated Resource Plan (*see page iii*). However, not all projects will result in loss savings or other offsets. Avista has maintenance schedules for certain equipment. These maintenance cycles range from 5-15 years depending on the equipment. Unless the replacement of equipment occurs in the same year as the scheduled maintenance, there will not be any savings.

Although one might think that the replacement of equipment may reduce the failure rate of equipment and reduce after-hours labor costs, newly-installed equipment can get out of alignment, or require other adjustments. Significant system failures also occur during large weather-related events caused by wind, lightning, and snow. Furthermore, each year as we replace old equipment with new, the remainder of our system gets another year older, which continues to generate additional failures on our system.

Q. **Please describe each of the transmission projects planned for the period June 30, 2013 to December 31, 2015.**

A. The major capital transmission investment (on a system basis) for projects to be completed from June 30, 2013 to December 31, 2015 are shown in Table No. 3 and described below.

Table No. 3:

$ (000's)

Electric Transmission (System):	Jul-Dec 2013		2014		2015	
	System	O&M Offsets	System	O&M Offsets	System	O&M Offsets
I. Reliability Compliance:						
Substation - 115 kV Line Relay Upgrades	$ 350	$ -	$ 950	$ -	$ 900	$ -
Transmission - NERC High Priority Mitigation	1,350	-	1,900	-		-
Transmission - NERC Low Priority Mitigation	-	-	250	-	500	-
Transmission - NERC Medium Priority Mitigation	-	-	1,693	-	3,294	-
SCADA - SOO & BUCC	133	-	1,090	-	515	-
Total Reliability Compliance	**1,834**	**-**	**5,883**	**-**	**5,209**	**-**
II. Contractual Requirements:						
Colstrip Transmission	40	-	369	-	208	-
Tribal Permits and Settlements	103	-	495	-	1,430	-
Clearwater Sub Upgrades	-	-	2,700	-	500	-
Thornton 230 kV Switching Station	14	-	-	-	-	-
Total Contractual Requirements	**157**	**-**	**3,564**	**-**	**2,138**	**-**
III. Reliability Improvements:						
Substation - Distribution Station Rebuilds	6	-	500	-	-	-
Spokane Valley Transmission Reinforcement	845	-	1,900	-	600	-
Moscow 230 Substation Rebuild	6,686	-	5,853	-	-	-
Noxon Switchyard Rebuild	-	-	-	-	8,425	-
Westside property purchase	70	-	-	-	-	-
Total Reliability Improvements	**7,607**	**-**	**8,253**	**-**	**9,025**	**-**
IV. Reliability Replacement:						
Storms	1,096	-	1,100	-	1,100	-
Substation - Asset Mgmt. Capital Maintenance	1,689	-	2,600	-	2,600	-
Substation - Capital Spares	464	-	750	-	7,745	-
Transmission - Asset Management	546	-	1,315	-	1,370	-
Total Reliability Replacement:	**3,794**	**-**	**5,765**	**-**	**12,815**	**-**
V. Reliability Compliance and Improvements:						
Environmental Compliance	150	-	100	-	100	-
Reconductors and Rebuilds	4,271	-	9,297	12	18,888	10
Total Reliability Compliance and Improvements	**4,421**	**-**	**9,397**	**12**	**18,988**	**10**
	$ 17,813	**$ -**	**$ 32,863**	**$ 12**	**$ 48,175**	**$ 10**

I. Reliability Compliance Projects:

Substation – 115kV Line Relay Upgrades -2013: $350,000; 2014: $950,000; 2015: $900,000

This project involves the replacement of older protective 115 kV system relays with new micro-processor relays to increase system reliability by reducing the amount of time it takes to sense a system disturbance and isolate it from the system. This is a five to seven year project and is required to maintain compliance with mandatory reliability standards. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, and TPL-003-0a R1-R3. Positive offsets in reduced maintenance costs associated with this replacement effort are negatively offset by increased NERC testing requirements per standard PRC-005-1.

Transmission -NERC High Priority Mitigation - 2013: $1,350,000; 2014: $1,900,000

This program reconfigures insulator attachments, and/or rebuilds existing transmission line structures, or removes earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012 North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program (ER2560) covers mitigation work on Avista's "High Priority" 230kV transmission lines, including: Benewah-Pine Creek (BI CT203), Cabinet-Noxon (BI AT203), Cabinet-Rathdrum (BI CT202), Hatwai-North Lewiston (BI LT205), Lolo-Oxbow (BI LT202), and Noxon-Pine Creek (BI AT202). Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have been adopted into the State of Washington's Administrative Code (WAC).

Transmission –NERC Low Priority Mitigation - 2014: $250,000; 2015: $500,000

This program reconfigures insulator attachments, and/or rebuilds existing transmission line structures, or removes earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012 North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program (ER25xx) covers mitigation work on Avista's "Low Priority" 230kV and 115kV transmission lines. Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have been adopted into the State of Washington's Administrative Code (WAC).

Transmission -NERC Medium Priority Mitigation -2014: $1,693,000; 2014: $3,294,000

This program reconfigures insulator attachments, and/or rebuilds existing transmission line structures, or removes earth beneath transmission lines in order to mitigate ratings/sag discrepancies found between "design" and "field" conditions as determined by LiDAR survey data. This program was undertaken in response to the October 7, 2012 North American Electric Reliability Corporations (NERC) "NERC Alert" - Recommendation to Industry, "Consideration of Actual Field Conditions in Determination of Facility Ratings". This Capital Program (ER2581) covers mitigation work on Avista's "Medium Priority" 230kV and 115kV transmission lines, including North Lewiston-Shawnee 230kV, Beacon-Bell #4 230kV, Beacon-Bell #5 230kV, Noxon-Hot Springs #2 230kV, Beacon-Boulder #2 115kV, Beacon-Francis & Cedar 115kV, 9th & Central-Otis 115kV, Northwest-Westside 115kV, Dry Creek-Talbot 230kV, Walla Walla-Wanapum 230kV, Benewah-Moscow 230kV, Devils Gap-Stratford 115kV. Mitigation brings lines in compliance with the National Electric Safety Code (NESC) minimum clearances values. These code minimums have been adopted into the State of Washington's Administrative Code (WAC).

SCADA –SOO&BUCC - 2013: $133,000; 2014: $1,090,000; 2015: $515,000

This program replaces and/or upgrades existing electric and gas control center telecommunications and computing systems as they reach the end of their useful lives, require increased capacity, or cannot accommodate necessary equipment upgrades due to existing constraints. Included are hardware, software, and operating system upgrades, as well as deployment of capabilities to meet new operational standards and requirements. Some system upgrades may be initiated by other requirements, including NERC reliability standards, growth, and external projects (e.g. Smart Grid). Examples of upgrades to be completed under this program are Critical Infrastructure Protection version 5 (NERC requirement), Gas Control Room Management (PHMSA requirement), WECC RC Advanced Applications, and Technology Refresh (network and storage).

II. Contractual Requirements:

Colstrip Transmission - 2013: $40,000; 2014: $369,000; 2015: $208,000

As a joint owner of the Colstrip Transmission projects, Avista pays its ownership share of all capital improvements. Northwestern Energy either performs or contracts out the capital work associated with the joint owned facilities.

Tribal Permits - 2013: $103,000; 2014: $495,000; 2015: $1,430,000

The Company has approximately 300 right-of-way permits on tribal reservations that need to be renewed. The costs include labor, appraisals, field work, legal review, GIS information, negotiations, survey (as needed), and the actual fee for the permit.

Clearwater Substation Upgrade - 2014: $2,700,000; 2015: $500,000

This project includes a series of station upgrades to improve 115 kV system reliability in the Lewiston area. This part of the project will construct a new 115 kV line terminal in order to install a new bus sectionalizing breaker. In addition, the project replaces an older 115 kV oil circuit breaker and installs standard 115 kV air switches in place of the existing sliding link bus switches, which are dangerous to operate and a reliability concern.

Thornton 230 kV Switching Station - 2013: $14,000
The initial installation of this station is complete and involved the design and construction of the Thornton 230kV Switching Station in accordance with the LGIA with Palouse Wind, LLC. Per the Agreement, Avista will own, operate, and maintain this switching station and will be responsible for 2/3 of the overall cost while Palouse Wind will be responsible for 1/3 of the overall cost.

III. Reliability Improvements:

Substation – Distribution Station Rebuilds - 2013: $6,000; 2014: $500,000
This program replaces and/or rebuilds existing substations as they reach the end of their useful lives, require increased capacity, or cannot accommodate necessary equipment upgrades due to existing physical constraints. Included are Wood Substation rebuilds as well as upgrading stations to current design and construction standards. Some station rebuilds may be initiated by other requirements, including obligation to serve, growth, and external projects. Examples of substation rebuilds to be completed under this program in the next 5 years are Big Creek, Kamiah, and North Lewiston (Wood Substations), 9th & Central, 10th & Stewart, and Stratford (Life Cycle), Blue Creek (Productivity), and Lewiston Mill Road (Growth).

Spokane Valley Transmission Reinforcement - 2013: $845,000; 2014: $1,900,000; 2015: $600,000
The Spokane Valley Transmission Reinforcement Project includes rebuilding 4.4 miles of the Beacon - Boulder #2 115 kV Transmission Line, constructing the new Irvin Switching Station, rebuilding 1.75 miles of the Irvin - Opportunity 115 kV Tap, installing three 115kV circuit breakers at Opportunity Substation, and constructing a new 2.2 mile 115 kV transmission line from Irvin to Millwood/Inland Empire Paper. The completion of these projects is required to mitigate existing and future performance and reliability issues of the Transmission System in the Spokane Valley.

Moscow 230 Substation Rebuild - 2013: $6,686,000; 2014: $5,853,000
This project, which is presently under construction, completely rebuilds the Moscow 230 kV Substation. The new station will include gas circuit breakers for both the 230 kV and 115 kV yards, a new 250 MVA Autotransformer, two 115 kV Capacitor Banks, a new panel house, and a station configuration that allows for future additions. The primary driver for this project was the capacity of the existing 125 MVA Autotransformer. System planning studies showed an imminent thermal

overload of the 56 year old unit in the event we had a failure of the Shawnee Autotransformer. Considering these two units serve the entire Pullman-Moscow area, this project is critically important to Avista's ability to serve our customers. After revenue requirement was finalized, it was determined that offsets exist for this business case. The offsets for 2013 through 2015 were based on annual savings of 716.88MWh x $44/MWh to come to an annual savings of $31,543 system and $20,506 Washington. For 2013, six months of the offset was calculated ($15,772 system, $10,253 Washington), but no offset was included for 2013, 2014, or 2015.

Noxon Switchyard Rebuild - 2015: $8,425,000

The existing Noxon Rapids 230 kV Switchyard requires reconstruction due to the present age and condition of the equipment in the station. The existing bus is has suffered a number of recent failures and is configured as a single bus with a tiebreaker separating the East and West buses. The station is the interconnection point of the Noxon Rapids Hydroelectric development as well as a principal interconnection point between Avista and BPA, and as such is a significant asset in the reliable operation of the Western Montana Hydro Complex. Equipment outages within the Station (planned or unplanned) can cause significant curtailments of the local generation output. Due to the significance of the station, a complete rebuild will require coordination with Avista's Energy Resources Department and neighboring utilities, primarily BPA. The Noxon Switchyard Rebuild Project is proposed to be a Greenfield Double Bus Double Breaker 230 kV switching station to replace the existing Noxon Switchyard.

Westside property purchase - 2013: $70,000

The purchase was made for the anticipated reconstruction of 230/115 kV substation tentatively planned for 2017 or 2018.

IV. Reliability Replacements:

Storms - 2013: $1,096,000; 2014: $1,100,000; 2015: $1,100,000

This program will replace cross arms, poles and structures as required due to storms, and fires on distribution and transmission lines.

Substation Asset Management Capital Maintenance - 2013: $1,689,000; 2014: $2,600,000; 2015: $2,600,000

Avista has several different equipment replacement programs to improve reliability by replacing aged equipment that is beyond its useful life. These programs include transmission air switch upgrades, restoration of substation rock and fencing, recloser replacements, replacement of obsolete circuit switchers, substation battery replacement, meter replacements and upgrades, relay replacements, high voltage fuse upgrades, transformer replacements, breaker replacements, installation of diagnostic monitors, substation air switch replacements, and voltage regulator replacements. All of these individual projects improve system reliability and customer service. The equipment is replaced when useful life has been exceeded. The equipment under these replacement programs are usually not maintained on a set schedule so there aren't associated offsets.

Substation – Capital Spares - 2013: $464,000; 2014: $750,000; 2015: $7,745,000
This program maintains our fleet of Power Transformers and High Voltage Circuit Breakers. This fleet of critical apparatus is capitalized upon receipt and placed in service for both planned and emergency installations as required. The annual program expenditures may vary significantly in years when a transformer (230/115 kV) is purchased. In years without a transformer purchase, only minor variations will occur based on planned projects as well as replenishing apparatus fleet levels required for adequate capital spares. These are long lead time items so sufficient levels need to be maintained.

Transmission – Asset Management - 2013: $546,000; 2014: $1,315,000; 2015: $1,370,000
The Transmission Asset Management Business Case covers Transmission Minor Rebuilds in ER 2057, and Air Switch Replacements in ER 2254. Transmission Minor Rebuilds are developed using data received from the prior year's Wood Pole Inspection Program. Minor rebuilds may also use data received from annual Aerial Patrol Inspections. Both inspections programs are undertaken to maintain compliance with NERC Standard FAC-501-WECC-1. Air Switch Replacements are made based either on condition, capacity, or functionality issues. Prioritization of installations and replacements are made from information provided by Avista System Operations, Operations Offices, or Substation Engineering.

V. <u>Reliability Compliance and Improvements:</u>

Environmental Compliance - 2013: $150,000; 2014: $100,000; 2015: $100,000
Implementation of Forest Service Special Use Permits, waste oil disposal, including PCBs, and environmental compliance requirements related to storm water management, water quality protection, property cleanup and related issues, etc.

Reconductors and Rebuilds - 2013: $4,271,000; 2014: $9,297,000; 2015: $18,888,000
This program reconductors and/or rebuilds existing transmission lines as they reach the end of their useful lives, require increased capacity, or present a risk management issue. Projects include: ER 2310 - West Plains Transmission Reinforcement, ER 2550 - Pine Creek-Burke-Thompson, ER 2557 9CE-Sunset Rebuild, ER 2423 - System Condition Rebuild, ER 2457 Benton-Othello Rebuild, ER2556 CDA-Pine Creek Rebuild, ER 2564 Devils Gap-Lind Major Rebuild, ER 2574 - Chelan-Stratford River Crossing Rebuild, ER 2576a Addy-Devils Gap Reconductor, ER 2575 Garden Springs-Silver Lake Rebuild, ER 2582 BEA-BEL-F&C-WAI Reconfiguration, ER 2577 BEN-M23 Rebuild, ER 25xa - Out-Year Transmission Rebuild.

Q. Please describe each of the distribution projects planned for June 30, 2013 through 2015.

A. Distribution specific projects in Washington (including transformation) are necessary to meet capacity needs of the system, improve reliability, and rebuild aging distribution substations and feeders. The major capital distribution costs for projects to be completed from June 30, 2013 to December 31, 2015 are shown in Table No. 4 and described below.

Table No. 4:

$ (000's)									
Electric Distribution:	**Jul-Dec 2013**			**2014**			**2015**		
	System	**Washington**	**WA Offsets**	**System**	**Washington**	**WA Offsets**	**System**	**Washington**	**WA Offsets**
I. Distribution Projects:									
Distribution Grid Modernization	6,630	6,630	-	9,450	6,066	-	13,500	8,666	-
Distribution Wood Pole Management	4,436	2,799	-	14,680	9,121	-	15,873	9,862	56
Segment Reconductor and FDR Tie Program	1,473	1,473	-	2,653	2,431	-	3,074	2,859	-
Spokane Electric Network	1,413	1,413	-	2,300	2,300	-	2,300	2,300	-
Substation - Asset Mgmt. Capital Maintenance	97	62	-	1,500	963	-	1,500	963	-
Substation - Capital Spares	31	28	-	2,300	2,053	-	800	714	-
Substation - New Distribution Stations	373	373	-	379	379	-	2,045	2,045	-
Worst Feeders	500	321	-	1,500	963	-	2,000	1,284	-
Spokane Valley Transmission Reinforcement	151	151	-	-	-	-	-	-	-
Harrington 4 kV Cutover	-	-	-	1,000	1,000	-	2,000	2,000	-
Customer Prepay	-	-	-	-	-	-	1,997	1,282	-
Total Distribution Projects	**15,104**	**13,250**	**-**	**35,762**	**25,275**	**-**	**45,088**	**31,974**	**56**
II. Distribution Replacement Projects									
Distribution Line Protection	253	163	-	250	160	-	125	80	-
Distribution Minor Rebuild	4,792	2,959	-	8,300	5,124	-	8,300	5,124	-
Distribution Transformer Change-Out Program	813	643	-	4,700	3,718	-	6,900	5,459	-
Environmental Compliance	63	50	-	150	119	-	150	119	-
Electric Replacement/Relocation	1,279	845	-	2,300	1,380	-	2,400	1,439	-
Primary URD Cable Replacement	737	550	-	1,000	747	-	1,000	747	68
Reconductors and Rebuilds	-	-	-	2,500	1,605	-	2,500	1,605	-
Storms	1,888	1,046	-	2,200	1,219	-	2,300	1,274	-
Substation - Distribution Station Rebuilds	2,460	2,426	-	2,730	1,698	-	3,125	3,019	-
Franchising for WSDOT	42	42	-	265	265	-	195	195	-
Street Light Management	-	-	-	-	-	-	2,320	1,489	317
Total Distribution Replacement Projects	**12,326**	**8,723**	**-**	**24,395**	**16,034**	**-**	**29,315**	**20,550**	**385**
III. Smart Grid Projects									
Smart Grid Demonstration Project	360	360	-	525	525	-	-	-	-
Smart Grid Workforce Training Grant - DOE	360	360	-	-	-	-	-	-	-
Spokane Smart Circuit	1,104	1,104	-	-	-	-	-	-	-
Total Smart Grid Projects	**1,823**	**1,823**	**-**	**525**	**525**	**-**	**-**	**-**	**-**
Ram Rat 2 US 95 Widening*	816	524	-	-	-	-	-	-	-
Total Distribution Excluding Idaho	**30,069**	**24,320**	**-**	**60,682**	**41,835**	**-**	**74,403**	**52,524**	**441**
IV. Idaho Distribution Pojects (not included in this case)									
Lewiston Mill Road	-	-	-	1,950	-	-	-	-	-
Lucky Friday 115kV Rebuild	1,429	-	-		-	-	-	-	-
Appleway Increase Capacity	308	-	-		-	-	-	-	-
Pine Creek 230 Sub Switch and Relays	19	-	-		-	-	-	-	-
Substation-Distribuiton Station Rebuilds	376	-	-	4,020	-	-	1,974	-	-
Feeder Upgrades	48	-	-	250	-	-	2,500	-	-
Substation - New Distribution Stations	-	-	-	298	-	-		-	-
Segment Reconductor and FDR Tie Program	402	-	-	808	-	-	802	-	-
Total Idaho Distribution Projects	**2,582**	**-**	**-**	**7,326**	**-**	**-**	**5,276**	**-**	**-**
Total Distribution Including Idaho Direct	**$ 32,651**	**$ 24,320**	**$ -**	**$ 68,008**	**$ 41,835**	**$ -**	**$ 79,679**	**$ 52,524**	**$ 441**

* It was determined after finalizing the Pro Forma Cross Check Analysis, that this business case was inadvertently included in the Pro forma Cross Check calculation. Therefore, no description has been included.

I. Distribution Projects:

Distribution Grid Modernization - 2013: $6,630,000; 2014: $6,066,000; 2015: $8,666,000 Washington

In 2012, Avista began a program to upgrade distribution feeders to reduce energy losses, improve operation of the feeders and increase long-term reliability. The program will replace poles, transformers, conductors and other equipment on rural and urban feeders. As part of the work, elements of Avista's Smart Grid will be installed as appropriate on these feeders. O&M offsets associated with this project may occur in the future; however, they are not quantifiable at this time.

Distribution Wood Pole Management –2013: $2,799,000; 2014: $9,121,000; 2015: $9,862,000 Washington

The distribution wood pole management program evaluates wood pole strength of a certain percentage of the wood pole population each year such that the entire system is inspected every 20 years. Avista has over 240,000 distribution wood poles and 33,000 transmission wood poles in its electric system. Depending on the test results for a given pole, the pole is either considered satisfactory, needing to be reinforced with a steel stub, or needing to be replaced. As feeders are inspected as part of the wood pole management program, issues are identified unrelated to the condition of the pole. This project also funds the work required to resolve those issues (i.e. potentially leaking transformers, transformers containing more than or equal to 1 ppm polychlorinated biphenyls (PCBs), failed arresters, missing grounds, damaged cutouts, failed insulators and other visible issues. Transformers older than 1981 have the potential to have oil that contains polychlorinated biphenyls (PCBs). These older transformers present increased risk because of the potential to leak oil that contains PCBs. Poles installed during the pre-World War II buildup have reached the end of their useful life. Avista's Wood Pole Management program was put into place to prevent the Pole-Rotten events and Crossarm – Rotten events from increasing. The Company expects to achieve $86,000 in savings resulting from reduced call outs to fix problems during 2014. The Washington anticipated offsets in O&M spending is anticipated to be $56,000 in 2015.

Segment Reconductor and Feeder Tie program - 2013: $1,473,000; 2014: $2,431,000; 2015: $2,859,000 Washington

In 2014, Avista will invest $3.450 million dollars to improve the capacity and reliability of its distribution grid through targeted reconductoring/rebuild projects. In Washington State, $2.365 million dollars will be invested in fourteen (14) projects ranging from $25k (WSU Steam Plant Cable upgrade) to $320k (Sprague 761 – reconductor of CU wire). These projects are identified, prioritized, and coordinated through the combined effort of Avista's central system planning function together with the assistance of regional operating engineer analysis and study. This is an on-going effort to identify and mitigate the capacity constrained portions of Avista's 18,000 mile distribution grid. In addition to circuit capacity projects, Avista constructs several new feeder tie points annually in order to effect seasonal and or permanent load shifts from either heavily loaded circuits or to relieve substation transformer loading. O&M offsets associated with this business case may occur in the future; however, they are not quantifiable at this time.

Spokane Electric Network – 2013: $901,000; 2014: $2,300,000; 2015: $2,300,000 Washington

Avista owns and maintains an underground electric network that serves the core business district of downtown Spokane. The network is unique to Avista's electric distribution and requires specialized material, equipment, tooling, and training to perform maintenance repair, planned replacement, and capacity growth projects. The scope of annual capital replacements and additions includes: 10,000 feet of secondary cable, 5,000 feet of primary cable, 15 manholes, and 5 vaults/vault roofs.

Substation- Asset Management Capital Maintenance – 2013: $62,000; 2014: $963,000; 2015: $963,000 Washington

Avista has several different equipment replacement programs to improve reliability by replacing aged equipment that is beyond its useful life. These programs include transmission air switch upgrades, restoration of substation rock and fencing, recloser replacements, replacement of obsolete circuit switchers, substation battery replacement, meter replacements and upgrades, relay replacements, high voltage fuse upgrades, transformer replacements, breaker replacements, installation of diagnostic monitors, substation air switch replacements, and voltage regulator replacements. All of these individual projects improve system reliability and customer service. The equipment is replaced when useful life has been exceeded. The equipment under these replacement programs are usually not maintained on a set schedule so there aren't associated offsets.

Substation- Capital Spares – 2013: $28,000; 2014: $2,053,000; 2015: $714,000 Washington

This program maintains our fleet of Power Transformers and High Voltage Circuit Breakers. This fleet of critical apparatus is capitalized upon receipt and placed in service for both planned and emergency installations as required. The annual program expenditures may vary significantly in years when an Autotransformer (230/115 kV) is purchased. In years without an Autotransformer purchase, only minor variations will occur based on planned projects as well as replenishing apparatus fleet levels required for adequate capital spares. These are long lead time items so sufficient levels need to be maintained.

Substation – New Distribution Stations - 2013: $373,000; 2014: $379,000; 2015: $2,045,000 Washington

This program adds new distribution substations to the system in order to serve new and growing load as well as for increased system reliability and operational flexibility. New substations under this program will require planning and operational studies, justifications, and approved project diagrams prior to funding.

Planned new substation projects include Tamarack (NE Moscow), Greenacres and Irvin (Spokane Valley), and Lewiston Mill Road. Out years include construction for these and design and construction for one new substation per year on average depending on need and justifications.

Worst Feeders - 2013: $321,000; 2014: $963,000; 2015: $1,284,000 Washington
Initiating in 2009, ER 2414- "Worst Feeders" was proposed by Asset Management to improve the service reliability of the Company's worst performing electric distribution circuits. Many rural feeders significantly exceed the Company SAIFI target of 2.1. This program is coordinated through divisional Area Engineers to identify treatment of these feeders. Work plans may include, reconstruction, hardening, vegetation management, conversion from overhead to underground, enhanced protection, and relocation.

Spokane Valley Transmission Reinforcement - 2013: $151,000 Washington
The Spokane Valley Transmission Reinforcement Project includes rebuilding 4.4 miles of the Beacon - Boulder #2 115 kV Transmission Line, constructing the new Irvin Switching Station, rebuilding 1.75 miles of the Irvin - Opportunity 115 kV Tap, installing three 115kV circuit breakers at Opportunity Substation, and constructing a new 2.2 mile 115 kV transmission line from Irvin to Millwood/Inland Empire Paper. The completion of these projects are required to mitigate existing and future performance and reliability issues of the Transmission System in the Spokane Valley.

Harrington 4kV Cutover - 2014: $1,000,000; 2015: $2,000,000 Washington
The Harrington, WA area is the last area Avista serves at the legacy 4 kV voltage. This voltage is obsolete for serving utility distribution systems and we have very limited spare equipment to continue service at this voltage. The substation is very old and the transformer will be difficult and time consuming to replace if it fails. We do not have 4 kV on our mobile substations, so all the customers served by Harrington feeders will be out of service until the transformer is replaced. This could easily be up to 48 hours. There is no reason to delay this needed upgrade to our standard distribution class voltage and equipment. Minor system efficiencies also result.

Customer Prepay - 2015: $1,282,000 Washington
Customer Pre Pay- This project would update customer systems and the AMR interfaces to enable prepay programs. These systems need to be set up so that the customer's balance can trigger a disconnect when the customer's balance hits zero. The system also needs to alert customers to the low balance prior to disconnect. O&M reductions could occur based on the reduction of collection(s) activities.

II. Distribution Replacement Projects:

Distribution Line Protection - 2013: $163,000; 2014: $160,000; 2015: $80,000 Washington

Avista's Electric Distribution system is configured into a trunk and lateral system. Lateral circuits are protected via fuse-links and operate under fault conditions to isolate the lateral in order to minimize the number of affected customers in an outage. Engineering recommends treatment of the removal and replacement of Chance Cutouts, the removal and replacement of Durabute cutouts and the installation of cut-outs on un-fused lateral circuits. This is a targeted program to ensure adequate protection of lateral circuits and to replace known defective equipment.

Distribution Minor Rebuild- 2013: $2,959,000; 2014: $5,124,000; 2015: $5,124,000 Washington

This program is for distribution minor rebuild as requested by the customer or initiated by Avista. Examples of construction work includes replacing meters, services, transformers, primary overhead or underground lines, or devices. This also includes addressing trouble related jobs (i.e. replacing burnt or damaged poles).

Distribution Transformer Change Out Program 2013: $643,000; 2014: $3,718,000; 2015: $5,459,000 Washington

The Distribution Transformer Change-Out Program has three main drivers. First, the pre-1981 distribution transformers that are targeted for replacement average 42 years of age and are a minimum of 30 years old. Their replacement will increase the reliability and availability of the system. Secondly, the transformers to be replaced are inefficient compared to current standards. Thirdly, pre-1981 transformers have the potential to have PCB containing oil. The transformers to be removed early in the programs are those that are most likely to have PCB containing oil and their replacement will reduce the risk of PCB containing oil spills.

Environmental Compliance- 2013: $50,000; 2014: $119,000; 2015: $119,000 Washington

Implementation of Forest Service Special Use Permits, waste oil disposal, including PCBs, and environmental compliance requirements related to storm water management, water quality protection, property cleanup and related issues, etc.

Electric Replacement/Relocation - 2013: $832,000; 2014: $1,380,000; 2015: $1,439,000 Washington

This annual program will replace sections of existing infrastructure that require replacement due to relocation or improvement of streets or highways. Requirements may come from our franchise agreements, permits, or WA DOT. Avista installs many of its facilities in public right-of-way under established franchise agreements. Avista is required under the franchise agreements, in most cases, to relocate its facilities when they are in conflict with road or highway improvements.

Primary URD Cable Replacement- 2013: $550,000; 2014: $747,000; 2015: $747,000 Washington

This program involves replacing the first generation of Underground Residential District (URD) cable. This project has been ongoing for the past several years and focuses on replacing a vintage and type of cable that has reached its end of life and contributes significantly to URD cable failures. The Company estimates the cost of each underground outage to be $3,850. With the downward trend in underground outages, it is projected that 45 outages will occur in 2015, as compared to 72 in 2012. The outage savings are anticipated to be $163,950 System and $68,000 on a Washington Share basis.

Reconductors and Rebuilds - 2014: $1,605,000; 2015: $1,605,000 Washington

This program reconductors and/or rebuilds existing transmission or distribution lines as they reach the end of their useful lives, require increased capacity, or present a risk management issue. Projects include: ER 2310 - West Plains Transmission Reinforcement, ER 2550 - Pine Creek-Burke-Thompson, ER 2557 9CE-Sunset Rebuild, ER 2423 - System Condition Rebuild, ER 2457 Benton-Othello Rebuild, ER2556 CDA-Pine Creek Rebuild, ER 2564 Devils Gap-Lind Major Rebuild, ER 2574 - Chelan-Stratford River Crossing Rebuild, ER 2576a Addy-Devils Gap Reconductor, ER 2575 Garden Springs-Silver Lake Rebuild, ER 2582 BEA-BEL-F&C-WAI Reconfiguration, ER 2577 BEN-M23 Rebuild, ER 25xa - Out-Year Transmission Rebuild. After revenue requirements were finalized, it was determined that the savings included in the O&M adjustment should have included ERs for Burke-Pine Creek and Benton-Othello 115 based on reductions in line losses rather than Chelan-Strafford 115kV and Benton-Othello 115 based on estimated savings. The updated dollar amount of the O&M adjustment does not change due to this update. In addition, offsets were determined on the Bronx – Cabinet 115 kV rebuild/reconductor. The work involves several projects that have in service dates of November 2014 and November 2013. Therefore, we included two months worth of savings per project. For Burke-Thompson A&B 115kV Transmission Rebuild Project, the annual energy savings from reduced losses is 252 MWh in 2014 and 2013 MWh in 2015. Two months of which is 42MWh and 35.50 MWh respectively. The MWh are multiplied by the avoided energy cost of $44/MWh to arrive at $1,848 ($1,201 WA) and $1,562 ($1,015.46 WA) for 2014 and 2015. For Benton-Othello 115 kV Line Rebuild, the annual energy savings from reduced line losses is 962 MWh in 2014 and 1,388 MWh in 2015. Assuming two months of savings, the total loss savings are 160 MWh for 2014 and 231 MWh for 2015. Assuming an avoided energy cost of $44/MWH the 2014 savings is $7,040 ($4,577 WA) and $10,164 ($6,608 WA) for 2015. For Bronx – Cabinet 115 kV rebuild/reconductor, the annual energy savings from reduced line losses in 2014 is 572MWh annual or 95.34 MWh for two months. The associated offset is calculated by multiplying 95.34 by $44/MHh to arrive at $4,195 ($2,727 WA) in 2014. In 2015, the MWh were 1,144 annually or 190.67 for two months. The associated savings were $8,389 ($5,454 WA).

Storms - 2013: $1,046,000; 2014: $1,219,000; 2015: $1,274,000 Washington
Storm response involves a mixture of capital replacement and maintenance activities. Weather events associated with wind, lightning, rain, and snow create a number of outage situations. Program spend is based on historical averages.

Substation – Distribution Station Rebuilds - 2013: $1,199,000; 2014: $1,698,000; 2015: $3,019,000 Washington
This program replaces and/or rebuilds existing substations as they reach the end of their useful lives, require increased capacity, or cannot accommodate necessary equipment upgrades due to existing physical constraints. Included are Wood Substation rebuilds as well as upgrading stations to current design and construction standards. Some station rebuilds may be initiated by other requirements, including obligation to serve, growth, and external projects. Examples of substation rebuilds to be completed under this program in the next 5 years are Big Creek, Kamiah, and North Lewiston (Wood Substations), 9th & Central, 10th & Stewart, and Stratford (Life Cycle), Blue Creek (Productivity), and Lewiston Mill Road (Growth).

Franchising for Washington State Department of Transportation - 2013: $42,000; 2014: $265,000; 2015: $195,000 Washington
Avista is working closely with the Washington Department of Transportation to renew crossing and encroachment permits. As part of that process, we are realigning or modifying existing infrastructure to comply with State clear zone, conductor clearance, and other regulations regarding the location of poles, guy wires, padmounted equipment, and overhead conductors.

Street Light Management - 2015: $1,489,000 Washington
This program is a five year planned replacement of bulbs and 10 year planned replacement of photocells. This alternative has the starter boards running to failure. We anticipate there will be O&M savings in 2015 in the amount of $488,000 ($317,249 WA). The offsets occur due to converting 100 Watt street lights from High Pressure Sodium. The savings come from eliminating the labor, equipment, material, and overhead costs associated with repairing older lights.

III. <u>Smart Grid Projects</u>

Smart Grid Demonstration Project - 2013: $360,000; 2014: $525,000 Washington
This Smart grid project will bring smart grid technology to electric distribution facilities that serve nearly 13,000 customers in the City of Pullman. Avista expects to realize benefits from smart grid technologies in reduced system losses and lower operating costs. Customers should realize benefits from improved service reliability, improved energy data enabling efficient energy usage, and energy savings from conservation voltage reduction (CVR). For further discussion and description of this project please refer to Company witness Mr. Kopczynski at DFK-1T.

Smart Grid Workforce Training Grant – DOE- 2013: $360,000 Washington
Avista partnered with several utilities and colleges in the region to develop a smart grid workforce training program for a three year period. As a result of this partnership, Avista upgraded the Jack Stewart Training Center with a substation and distribution training facility to include smart grid technology, updated Avista training programs for apprentices, journeymen and pre-line school students to incorporate smart grid technology; and developed several online curriculum offerings that are shared by utilities and colleges in Washington, Oregon, Idaho, Montana and Utah. For further discussion and description of this project please refer to Company witness Mr. Kopczynski at DFK-1T.

Spokane Smart Circuit - 2013: $1,104,000 Washington
This project installed a Distribution Management System (DMS) that allows real time system information to be used to control the distribution system. Intelligent end devices such as capacitor banks, air switches and reclosers were installed that provide sensing and control of the distribution circuits. Substation control and communication equipment were upgraded to allow for the control and aggregation of field data. A wireless mesh network was installed to provide backhaul from end devices to the substations. The project automates distribution equipment on 58 feeders and in 14 substations. For further discussion and description of this project please refer to Company witness Mr. Kopczynski at DFK-1T.

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

A. Yes it does.