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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-12-08
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	SCOTT J. KINNEY
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Scott J. Kinney. I am employed by Avista Corporation as Director, Transmission Operations. My business address is 1411 East Mission, Spokane, Washington.

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

A. I graduated from Gonzaga University in 1991 with a B.S. in Electrical Engineering. I am a licensed Professional Engineer in the State of Washington. I joined the Company in 1999 after spending eight years with the Bonneville Power Administration. I have held several different positions in the Transmission Department. I started at Avista as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations Department as a supervisor and support engineer. In 2004, I was appointed as the Chief Engineer, System Operations. In June of 2008 I was selected to my current position as Director, Transmission Operations.

Q. What is the scope of your testimony?

A. My testimony describes Avista's pro forma period transmission revenues and expenses. I also discuss the Transmission and Distribution expenditures that are part of the capital additions testimony provided by Company witness Mr. DeFelice, as well as projects associated with the Company's Asset Management Program. Company witness Ms. Andrews incorporates the Idaho share of the net transmission expenses and investment

Q. Are you sponsoring any Exhibits?

A. Yes. Exhibit 9, Schedule 1 provides the transmission pro forma adjustments.

A table of contents for my testimony is as follows:

II. PRO FORMA TRANSMISSION EXPENSES

Q. Please describe the pro forma transmission expense revisions included in this filing.

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the July 2011 to June 2012 test year to the 2013 pro forma rate period. The changes in expenses and a description of each is summarized in Table 1 and are system costs with the exception of Grid West, which is a direct Idaho cost:

Table 1:

Transmission Expense Adjustments	
	***Pro Forma (System)**
Northwest Power Pool (NWPP)	$ 3,000
Colstrip Transmission	$ (43,000)
ColumbiaGrid RTO	$ 55,000
ColumbiaGrid Transmission Planning	$ 17,000
ColumbiaGrid OASIS	$ 4,000
Elect Sched & Acctg Srv (OATI)	$ 8,000
NERC CIP	$ 2,000
OASIS Expenses	$ 9,000
BPA Power Factor Penalty	$ (1,000)
WECC Total Dues - WECC Sys Secur & Admin- Net Oper Comm Sys	$ 67,000
WECC - Loop Flow	$ (14,000)
CNC Transmission Project	$ 126,000
Transmission Line Ratings Confirmation Plan (NERC Alert)	$ (189,000)
Total System Expense	**$ 44,000**
Grid West (ID Direct)	$ (35,000)
Total Expense	**$ 9,000**

*Representing the change in expense above or below the 2011 test period level.

<u>Northwest Power Pool (NWPP)</u> ($3,000) – Avista pays its share of the NWPP operating costs. The NWPP serves the electric utilities in the Northwest by supporting regional

transmission planning coordination, providing coordinated transmission operations including contingency generation reserve sharing, and Columbia River water coordination. Actual test period transmission related NWPP expenses were $51,000 and a $3,000 adjustment is being made to the pro forma period to reflect an approved 6.2% increase in the NWPP expenses allocated to the Company.

Colstrip Transmission (-$43,000) – Avista is required to pay its portion of the O&M costs associated with its share of the Colstrip transmission system pursuant to the joint Colstrip contract. In accordance with NorthWestern Energy’s (NWE) proposed Colstrip transmission plan provided to the Company, NWE will bill Avista $387,000 for Avista’s share of the Colstrip O&M expense during the pro forma period. This is a decrease of $43,000 from the actual expense of $430,000 incurred during the test year.

ColumbiaGrid ($55,000) – Avista became a member of the ColumbiaGrid regional 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 a general funding agreement and supports specific functional activities under the Planning and Expansion Functional Agreement and the OASIS Functional Agreement. The current general funding agreement for ColumbiaGrid expires December 31, 2012, however a follow-on contract will be developed to replace the expiring contract. Avista's ColumbiaGrid general funding expenses for the test year were $132,000 while 2013 general funding expenses provided by ColumbiaGrid at a Board meeting on August 14, 2012 are forecasted to be $187,000, an increase of $55,000.

<u>ColumbiaGrid Transmission Planning</u> ($17,000) – 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. Funding under the PEFA is on a two-year cycle with provisions to adjust for inflation. Actual PEFA expenses for the test year were $209,000. The Company's PEFA pro forma expenses are at the maximum total payment obligation of $226,000 as provided at the Board meeting on August 14, 2012. This cost reflects ColumbiaGrid's staffing levels to support the PEFA and the reallocation of a portion of ColumbiaGrid's administrative expenses (previously paid under the general funding agreement) to this functional agreement.

ColumbiaGrid Open Access Same-Time Information System (OASIS) ($4,000) – Avista entered into the ColumbiaGrid OASIS Functional Agreement in February 2008. This agreement provides for the development of a common OASIS which gives transmission customers the ability to purchase transmission capacity from multiple ColumbiaGrid members via a single common OASIS site instead of having to submit multiple transmission service requests to each member individually on each member's respective OASIS sites. Avista's test year expenses of $30,000 reflected initial developmental activities under this functional agreement. Avista's ColumbiaGrid OASIS pro forma expenses are $34,000, reflecting operational capability of the ColumbiaGrid OASIS and the reallocation of a portion of ColumbiaGrid's administrative expenses (previously paid under the general funding agreement) to this functional agreement.

Electric Scheduling and Accounting Services ($8,000) – The $8,000 increase in the pro forma period compared to test year expense for electric scheduling and accounting services is a result of annual increases and additional services purchased from our third party vendor. These services are required to assist in meeting the requirements of North American Electric Reliability Corporation (NERC) mandatory reliability standards. The pro forma scheduling and accounting costs are $179,000 compared to test year costs of $171,000.

NERC Critical Infrastructure Protection ($2,000) – The Company has purchased several software products to assist in protecting critical transmission system data from intrusion and to meet applicable NERC standards. The Company's pro forma expenses increase $2,000 from the actual test year expense of $31,000 due to annual application maintenance cost increases.

OASIS Expenses ($9,000) – These 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 pro forma period are $9,000 compared to $450 of actual expenses in the test year. In the test year employees associated with the OASIS function did not travel much nor attend training due to increased workload associated with several new projects and requirements.

<u>Power Factor Penalty</u> (-$1,000) – 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. Avista currently pays Bonneville a power factor penalty at several points of interconnection. Avista incurred $203,000 of power factory penalty charges during the test

year. The Company's pro forma 2013 expenses are expected to be $202,000 representing a continuation of the current 12 month ratchet set in June of 2012.

WECC – System Security Monitor and WECC Administration & Net Operating Committee Fees ($67,000) – The WECC Board of Directors approved a 12.5% increase in dues for 2013 at their Board meeting in June of 2012. The increase is primarily associated with labor and software additions to support additional reliability and compliance requirements for the WECC Reliability Coordinator function. WECC is also responsible for monitoring and measuring Avista's compliance with the standards and, therefore, continues to increase its staff and other resources to meet this FERC requirement. The Company paid its 2012 WECC assessments in January 2012: $205,000 for system security monitoring and $328,000 for operating and support fees, for a total WECC assessment of $533,000. The Company's total pro forma 2013 expenses have been increased by 12.5% to $600,000 ($231,000 for system security and $369,000 for operating and support) to reflect the WECC Board approved funding levels.

WECC - Loop Flow (-$14,000) – 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. Therefore a five-year average is used to determine future Loop Flow costs. Based upon the average WECC Loop Flow charges incurred by the Company during the five-year period from 2008 through 2012, pro forma Loop Flow expenses are $31,000. This is $14,000 less than actual test year charges of $45,000, which included payments for the 2011 and 2012 operating years.

Canada to Northern California (CNC) Transmission Project ($126,000) – The CNC transmission project was initially proposed by Pacific Gas and Electric Company ("PG&E"). As initially proposed, the CNC transmission project was an Extra High Voltage ("EHV") transmission project that, if developed, would include a 500kV transmission line that would run between British Columbia, Canada and Northern California. With PG&E as the primary sponsor, Avista, British Columbia Transmission Corporation, PacifiCorp and Transmission Agency of Northern California were also original sponsors of the CNC transmission project. The cost accrued by Avista for its participation in the CNC regional transmission project was $758,000. Of this amount, $537,000 is the amount Avista paid for its share of the initial sponsorship of the CNC transmission project pursuant to the Stage One Project Development Agreement, and $221,000 consisted of the direct transmission planning expenses incurred by Avista. Avista is amortizing these expenses over a three-year period beginning in 2012, resulting in an amortized expense of $253,000 ($88,000 Idaho share) in the pro forma period. A total of $127,000 (6 months) was amortized in the test year[1].

Transmission Line Ratings Confirmation Plan (NERC Alert) ($-189,000) – The Transmission Line Ratings Confirmation Plan was developed to address a "NERC Alert" issued on October 7, 2010. The 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

[1] The amortization of the Canada to Northern California (CNC) Transmission Line was proposed in the Company's last general rate case (AVU-E-11-01) that was resolved through a "black-box" settlement. The amortization period represents the method proposed in AVU-E-11-01.

to ensure system reliability. Avista initiated a three year program beginning in 2011 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 were to be evaluated at a projected total system cost of $2.945 million. The total project cost for this effort has been reduced to $2.260 million based on a reduction of miles required to evaluate. The remaining pro forma costs for this project are $0.323 million. The test year expenses associated with this project was $0.512 million.

Grid West (ID Direct) (-$35,000) - Avista signed an initial funding agreement in 2000, as did all other Pacific Northwest investor-owned electric utilities, to provide funding for the start-up phase of Grid West (then named "RTO West"). Grid West had planned to repay the loans to Avista and other funding utilities through surcharges to customers once it became operational. With the dissolution of Grid West, this repayment did not occur. As a result, Avista filed an application with the Commission to defer these costs. The Commission approved, on October 24, 2006, in Order No. 30151, the Company's request for an order authorizing deferred accounting treatment for loan amounts made to Grid West. In its Order the IPUC found these costs to be "prudent and in the public interest" and required the Company to begin amortization of the Idaho share of the loan principal ($422,000) beginning January 2007, for five years. With the completion of the amortization in December 2011 the Company will not incur costs associated with Grid West in the pro forma period. Avista did amortize a total of $35,000 in the test year.

III. PRO FORMA TRANSMISSION REVENUES

Q. Please describe the pro forma transmission revenue revisions included in this filing.

A. Adjustments have been made in this filing to incorporate updated information associated with known changes in transmission revenue for the 2013 pro forma period as compared to the 2011/12 test year. Each revenue item described below is at a system level and is included in Schedule 1 of Exhibit No. 9. Please see Table 2 and descriptions below for further detail on the revenue pro forma amounts.

Table 2:

Transmission Revenue Adjustments	
	***Pro Forma (System)**
Borderline Wheeling Transmission & Low Voltage	$ 40,000
Seattle/Tacoma Main Canal	$ (7,000)
Seattle/Tacoma Summer Falls	$ 0
OASIS, non-firm, & short-term firm (Other Wheeling)	$ (2,764,000)
Pacificorp- Dry Gulch	$ (4,000)
Spokane Waste to Energy Plant	$ (66,000)
Grand Coulee Project	$ 0
Palouse Wind	$ 0
Palouse Wind O&M	$ 70,000
Stimson Lumber	$ 3,000
Hydro Tech Systems - Meyers Falls	$ 3,000
BPA Parallel Operating Agreement Settlement	$ 3,192,000
Morgan Stanley Transmission Service	$ 600,000
Total Expense	**$ 1,067,000**

*Representing the change in revenue above or below the 2011 test period level.

<u>Borderline Wheeling Transmission and Low Voltage ($40,000)</u>

Total borderline wheeling revenues including Transmission ($7,169,000) and Low Voltage ($1,071,000) for the test year were $8,240,000. Total borderline wheeling revenue in the pro forma period has been set at $8,280,000 (Transmission, $7,209,000 and Low Voltage, $1,071,000), which reflects a slight increase over the 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 the new transmission rates 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, pro forma transmission revenue has been set equal to the average of actual revenue from 2010, 2011 and 2012 through June, or set per the actual charges in each specific contract. Each of the specific borderline contracts is further described below.

- Borderline Wheeling – Bonneville Power Administration – ($37,000) Actual test year revenue from borderline wheeling service provided to Bonneville was $7,994,000. The Bonneville borderline wheeling contracts are divided into transmission and low voltage service. These were accounted for separately beginning in October of 2010 as a result of the new transmission rates. The new transmission rates apply to transmission service, but not to low voltage service. The pro forma Bonneville borderline wheeling revenue is $8,031,000, which is the average of actual revenues from 2010, 2011, and 2012 through June.
- 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 pro forma revenue of $26,000, which was the same as the test year.
- 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. Revenue under this agreement for the test year was $60,000. Revenue for the 2013 pro forma period will remain the same at $60,000.

- Borderline Wheeling – Spokane Tribe of Indians – ($2,000) The Company provides borderline wheeling service over both transmission and low-voltage facilities to the Spokane Tribe of Indians. Total transmission and low-voltage wheeling revenue under this contract for the test year was $41,000. Revenue associated with the transmission component of this contract is adjusted annually per the contract. Accordingly, 2013 pro forma period revenue under this contract is set at $43,000.
- Borderline Wheeling – Consolidated Irrigation District – ($1,000) The Company provides borderline wheeling service over both transmission and low-voltage facilities to the Consolidated Irrigation District. Total transmission and low-voltage wheeling revenue under this contract for the 2011 test year was $118,000. A new contract signed with the Consolidated Irrigation District in October of 2011 resulted in a shift of charges between transmission and low-voltage services. Per the new contract, the total Consolidated Irrigation District revenue for the pro forma period is $119,000.

Seattle and Tacoma Revenues Associated with the Main Canal Project (-$7,000) – 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 $288,000 during the test year. Pro forma revenues are expected to be $281,000 based on a reduction in the ratchet demand.

<u>Seattle and Tacoma Revenues Associated with the Summer Falls Project</u> ($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 test year and will remain the same for the 2013 pro forma period.

OASIS Non-Firm and Short-Term Firm Transmission Service (-$2,764,000) - 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 pro forma 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 with an adjustment to 2011 revenues due to additional revenue received from Puget Sound Energy (PSE) as a result of a planned construction outage on BPA’s transmission system. The outage resulted in additional one time revenue of $1.6 million. The adjusted OASIS revenue for 2011 is $3.101 million. Using this adjusted revenue results in pro forma revenue of $2.946 million based on a three-year average from 2009 through 2011. The test year OASIS revenue was $5.710 million and includes the $1.6 million one-time collection from PSE resulting from the BPA construction outage.

PacifiCorp Dry Gulch (-$4,000) – Revenue under the Dry Gulch use-of-facilities agreement has been adjusted to $217,000 for the pro forma period, which is a $4,000 decrease from the test year actual revenue of $221,000. The Company is calculating its pro forma adjustments using a three-year average of actual revenue. 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. The three-year average of revenue was calculated using years 2009 through 2011.

Spokane Waste-to-Energy Plant (-$66,000) – This revenue has historically been associated with a long-term transmission service agreement with the City of Spokane that expired December 31, 2011. Upon the City of Spokane's decision to sell the output of the Spokane Waste to Energy facility to Avista beginning January 1, 2012, the City of Spokane no longer required transmission service to deliver the output to a third-party purchaser. Under this new arrangement, the City of Spokane compensates Avista for the use of certain transmission facilities directly related to the interconnection of the Spokane Waste to Energy project. The pro forma revenue associated with this use of facility charge is $28,000. The test year revenue, including six month's revenue from the expired transmission service contract, was $94,000.

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 test year and will remain the same for the 2013 pro forma period.

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, commencing January, 2012. Palouse Wind subsequently executed a power sales contract with Avista, rendering its signed transmission service contract unnecessary at this point in time. Under the terms of Avista's Open Access Transmission Tariff, Palouse Wind intends to delay use of its 100 MW of reserved transmission service for up to five years unless they are able to re-market the capacity. Accordingly, to obtain this deferral Palouse Wind must pay one month's transmission service reservation fee. Test year revenue associated with this deferred transmission service was $200,000 and the revenue for the 2013 pro forma period is expected to remain the same.

Palouse Wind O&M ($70,000) – Separate from any transmission service, Palouse Wind signed an interconnection agreement with the Company to integrate its wind project into the Avista system. Avista constructed a new 230kV switching station (Thornton) to integrate the output from the wind facility. A portion of the cost of the station was directly assigned to Palouse Wind. The interconnection agreement includes annual maintenance charges for equipment upkeep associated with those facilities directly assigned to Palouse Wind. Operating and Maintenance (O&M) charges under the interconnection agreement have not been finalized but preliminary calculations estimate the annual O&M charge to be about 3.5% of the overall asset costs. Based on this calculation Palouse Wind will pay the Company approximately $70,000 per year starting in 2013 for maintenance associated with directly assigned facilities at Thornton. The Thornton switching station was energized in August, 2012 so no O&M revenue was collected in the test year.

<u>Stimson Lumber Agreement</u> ($3,000) – The Company has identified a revenue stream associated with sole-use, or directly assigned, low-voltage facilities related to the integration of small generation resources. 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 test year revenue was $6,000.

<u>Hydro Tech Systems Agreement</u> ($3,000) – Low-voltage facilities in the Company's Greenwood Substation are dedicated for use by the Meyers Falls generation project

resulting in annual use-of-facilities revenue of $6,000, or $510 per month. The pro forma revenue from this agreement is $6,000 while there was $3,000 in revenue collected during the test year.

BPA Parallel Operation Agreement ($3,192,000) – The Company is negotiating a Parallel Operation Agreement with the Bonneville Power Administration regarding Bonneville's use of the Avista transmission system to support the integration of wind in southeastern Washington. Avista and Bonneville have reached tentative agreement on an ongoing settlement approach where Avista may provide Bonneville with up to 133 MW of parallel capacity support in return for a revenue stream roughly commensurate with Bonneville's cost to upgrade its own system to provide such capacity. The expected pro forma revenue associated with this agreement is $3,192,000. No such revenue was collected during the test year.

Morgan Stanley Transmission Service ($600,000) – Morgan Stanley Capital Group signed a five-year transmission service agreement with the Company for 25 MW of long-term firm transmission capacity. The agreement starts January 1, 2013, and will result in annual revenues of $600,000. No revenue was collected from this transmission agreement during the test year.

IV. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS

Q. Please describe the Company's capital transmission projects that will be completed in 2012?

A. Avista continuously needs to invest in its transmission system to maintain reliable customer service and meet mandatory reliability standards. The 2012 and 2013 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 develops future project plans to ensure that the design and construction of the required projects are completed prior to the time they are actually 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 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 2012 and 2013 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 $31.50 MWh, which is the average purchase and sale price appropriate for the rate period calculation of offsets.

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 a similar level of failures on our system. At the current funding levels, the Company's Asset Management program is designed to keep failure rates at current levels.

Q. Please describe each of the transmission projects planned for in 2012.

A. The major capital transmission costs (system) for projects to be completed in 2012 are $28.160 million and are shown in Table 3 and described below.

TABLE 3		
Transmission		
2012 Capital - Compliance, Contractual, and Replacement Projects		
	Pro Forma (System)	**O&M Offsets (System)**
Reliability Compliance		
Spokane/CDA Relay Upgrade	$900,000	
SCADA Replacement	$1,310,000	
System Replace/Install Capacitor Bank	$2,000,000	
Bronx-Cabinet 115 kV Rebuild/Reconductor	$2,500,000	$3,203
Power Transformers - Transmission	$952,000	
Total Reliability Compliance	**$7,662,000**	**$3,203**
Contractual Requirements		
Thornton 230 kV Switching Station	$4,350,000	
Colstrip Transmission	$410,000	
Tribal Permits	$325,000	
Total Contractual Requirements	**$5,085,000**	**$0**
Reliability Improvements		
Moscow City-N Lewiston 115 kV Reconductor	$2,500,000	
Burke-Thompson A&B 115 kV Reconductor	$2,500,000	
Millwood 115 kV Substation Rebuild	$2,000,000	
Noxon-Hot Springs 230 kV Line Re-Route	$500,000	
Total Reliability Improvements	**$7,500,000**	**$0**
Reliability Replacement		
Transmission Minor Rebuilds	$2,370,000	
Power Circuit Breakers	$1,200,000	
Hatwai 230 kV Breaker Replacement	$614,000	
Asset Management Replacement	$3,479,000	
Other Small Projects	$250,000	
Total Reliability Replacement	**$7,913,000**	**$0**
Total Transmission Projects	**$28,160,000**	**$3,203**

Reliability Compliance Projects ($7.662 million):

- **Spokane/Coeur d'Alene area relay upgrade ($0.900 million):** 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, 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.

- **SCADA Replacement ($1.310 million):** The System Control and Data Acquisition (SCADA) system is used by the system operators to monitor and control the Avista transmission system. An upgrade to the SCADA system to a new version provided by our SCADA vendor was completed in the first quarter of 2012. The previous application version was no longer supported by the vendor. The upgrade ensures Avista has adequate control and monitoring of its Transmission facilities. This portion of the project is required to meet Reliability Compliance under NERC Standards: TOP-001-1, TOP-002-2a R5-R10, R16, TOP-005-2 R2, TOP-006-2 R1-R7. Several Remote Terminal Units (RTUs) located at substations throughout Avista's service territory will also be replaced due to age. The RTUs are part of the transmission control system. There are no offsets or savings associated with this upgrade project because the Company already pays the application vendor a set annual maintenance fee for support.

- **System Replace/Install Capacitor Bank ($2.00 million):** This effort includes two projects. The first project is the replacement of the 115 kV capacitor bank at the Pine Creek 115 kV substations to support local area voltages during system outages. The second project is the addition of new shunt capacitors at Lind 115 kV substation to support system voltages during summer irrigation load conditions and system outages. These projects are required to meet reliability compliance with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3, and provide improved service to customers. The Lind project is scheduled to be completed in September of 2012 and the Pine Creek project is scheduled to be completed in the late fall of 2012. There are no loss savings or other offsets associated with these projects. The projects improve voltage support but don't reduce loss savings.

- **Bronx – Cabinet 115 kV rebuild/reconductor ($2.500 million):** In 2010 Avista's System Operations identified a thermal constraint on the 32-mile Bronx-Cabinet 115kV Transmission Line. This constraint was confirmed by the System Planning Group, and documented in the Transmission Line Design (TLD) Design Scoping Document (DSD) created on January 4, 2011, and modified on January 7, 2011. The reconductoring/rebuilding of this line with 795 kcmil ACSS conductor will provide a present-day 143 MVA line rating to match the Cabinet Switchyard Transformer, and a future 200 MVA line rating to match the parallel path Bonneville Power Authority (BPA) system. The 32 miles of line will be reconductored over a four year period, which began in 2011. Phase 2 of the project (addressed here) consists of the approximately 10-mile stretch between Hope, ID and Clarkfork Sub. The line upgrade will ensure compliance with requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Using 2010 actual loads, since the line was operated open in over half of 2011 for the first phase of the project, the new conductor will reduce line losses by 1220 MWh on an annual basis. This project will not be completed until December so offset savings of $38,430 will be observed in 2012 (based on a $31.50/MWh avoided energy cost).

- **Power Transformers – Transmission ($0.952 million):** The Moscow 230kV substation is currently being rebuilt. Construction started in 2011 and will continue through 2013. The rebuild includes the addition of a new 250 MVA 230/115 kV autotransformer. This autotransformer arrived on-site in late 2011 and was capitalized upon delivery per the company's accounting practices. The transformer was paid for in several installments. This $952,000 was the final installment (paid in 2012), which was paid after receiving warranty approval from the manufacturer to energize the autotransformer. This project is required to meet Reliability Compliance under NERC Planning and Operations Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Offsets for this project will not occur until the Moscow 230 kV Substation is complete in 2013, and therefore have been included in the 2013 project described later in my testimony.

<u>Contractual Requirements ($5.085 million):</u>

- **Thornton 230 kV switching Station ($4.350 million):** The Thornton 230kV Substation Project interconnects a Third Party Wind Farm Generation Project owned and operated by Palouse Wind to Avista's Benewah - Shawnee 230kV Transmission Line. The project includes the construction of the switching station and associated line work to connect the new station to Avista's existing 230 kV line. Palouse Wind will construct and pay for facilities to connect its Generation Collection Station to Thornton. Thornton is required to maintain Avista's 230 kV transmission service with or without the wind generation, so Avista's customers are not affected by any outages as a result of the interconnection. One third of the substation costs (not included here) will be paid for upfront by Palouse Wind as direct assigned facilities according to FERC Open Access Transmission Tariff requirements. There are no offsets with the construction of the new substation.

- **Colstrip Transmission ($0.410 million):** 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 ($0.325 million):** 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.

<u>Reliability Improvements ($7.500 million):</u>

- **Moscow City-North Lewiston 115 kV Transmission Rebuild ($2.500 million):** This project includes the reconductor/rebuild of the 22-mile line between Moscow City substation and North Lewiston due to the poor condition of the existing line. The project will be completed in three phases. The first phase in 2012 includes reconductoring the first seven miles out of Moscow City towards Leon Junction. The Moscow City-North Lewiston 115 kV line is normally operated in a radial configuration open at Moscow City to avoid the line being overloaded for area outages. If the line section between North Lewiston and Leon Junction is lost (normal source), then the breaker is closed at Moscow City to pick up load at Leon Junction. Since the 7 mile line section being rebuilt is normally not carrying load, there are no offsets associated with this project.

- **Burke-Thompson A&B 115 kV Transmission Rebuild ($2.500 million):** The Burke-Thompson falls 115 kV lines are jointly owned by Avista and Northwestern Energy. Avista owns and operates the 4-mile line section from Burke to the Montana border on both the A&B lines. These lines are part of the Montana to Northwest transmission path that moves generation from Montana to load centers in both Eastern and Western Washington and also serves mining load and residential customers in the Silver Valley area of Idaho. The current lines are in poor condition and are a significant safety concern. In the winter, the snow levels get high enough to reduce conductor clearance so the lines have to be removed from service to ensure safety. This project will rebuild both the A&B lines to improve reliability and eliminate the need to open the lines during the winter. The projects will reuse the existing conductor so there will be no loss savings or offsets associated with the rebuild.

- **Millwood Sub Rebuild ($2.00 million):** In 2012 the Company will begin to rebuild the existing 115 kV Millwood substation. Millwood serves local area Avista customers and Inland Empire Paper Company one of Avista's largest industrial customers. The current substation is old, approaching full capacity, and contains a significant amount of PCBs that are an environmental concern. Most of this project is considered a distribution effort, but the 115 kV lines that feed the substation need to be reconfigured to support the substation rebuild effort. The costs included here are associated with the 115 kV line reconfigurations. The existing conductor will be reused so there are no offsets associated with this project.

- **Noxon-Hot Springs #2 230 kV reroute ($0.500 million):** The Noxon-Hot Springs project is being driven by environmental issues that are impacting the reliability of the lines. Several h-frame structures are being undercut due to the meandering of Beaver Creek. The Company had hoped to reroute the line by moving all impacted structures away from the creek. However, the property owners didn’t support the new line route, so instead existing structures are being replaced with hybrid poles (concrete bottoms and steel tops) to eliminate the creeks impact on the poles. The new poles are being buried up to 25 feet to accommodate scouring. The project will reuse existing conductor so there are no offsets.

<u>Reliability Replacements ($7.913 million)</u>

- **Transmission Minor Rebuilds ($2.370 million):** These projects include minor transmission rebuilds as a result of age or damage caused by storms, wind, fire, and the public. These projects are required to operate the transmission system safely and reliably. The facilities will need to be replaced when damaged in order to maintain customer load service. In 2011 the Company spent $2.465 million on these minor rebuild projects as a result of damage caused by weather or the public through vandalism or accident. No offsets are expected for these projects. **Power Circuit Breakers ($1.200 million): Th**e Company transfers all circuit breakers to plant upon receiving them. The breakers purchased in 2012 are planned for installation at Moscow 230 and Lind 115 kV substations.

- **Hatwai Breaker and switch replacement ($0.614 million):** Avista currently owns the breaker terminal at BPA’s Hatwai substation associated with the Hatwai-North Lewiston 230 kV line. The Breaker and switches need to be replaced due to age. Avista has contracted with BPA to replace the breaker and three air switches in 2012 since BPA owns and operates the Hatwai substation.

- **Asset Management Replacement Programs ($3.479 million):** 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, arrestor upgrades, restoration of substation rock and fencing, recloser replacements, replacement of obsolete circuit switchers, substation battery replacement, interchange meter replacements, high voltage fuse upgrades, 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 any associated offsets.

- **Other Small Transmission Projects ($.250 million):** These maninly consist of reinforcement, rebuild, reconductoring and re-insulating projects.

Q. Please describe each of the distribution projects planned for in 2012.

A. The Company will spend approximately $65.123 million in Distribution projects at a system level, with $16.364 million specific to Idaho in 2012. A summary of the projects is shown in Table 4 and a brief description of each project impacting Idaho are given below.

TABLE 4

Distribution

2012 Capital - Distribution Projects

	Pro Forma (System)	Pro Forma (Idaho)	O&M Offsets Idaho
Distribution Projects			
Wood Pole Management	$13,025,000	$3,576,000	$5,600
PCB Related Distribution Rebuilds	$3,812,000	$2,057,000	
System Dist Reliability Improve Worst Feeders	$1,950,000	$722,000	
Power Transformers - Distribution	$1,450,000	$492,000	
Distribution - Pullman & Lewis Clark - ID	$650,000	$650,000	
Distribution - Cda East & North - ID	$855,000	$855,000	
10 & Stewart Dx Int - ID	$250,000	$250,000	
Total Distribution Projects	**$21,992,000**	**$8,602,000**	**$5,600**
Distribution Replacement Projects			
Elect Distribution Minor Blanket	$8,300,000	$3,235,000	
Failed Electric Plant	$2,200,000	$1,014,000	
Distribution Line Relocation	$1,900,000	$692,000	
Electric Underground Replacement	$1,792,000	$441,000	$25,000
Blue Creek 115 kV Rebuild - ID	$1,905,000	$1,905,000	
Other Small Projects	$887,000	$475,000	
Total Distribution Replacement Projects	**$16,984,000**	**$7,762,000**	**$25,000**
Washington Distribution Projects (not included in case)			
System Efficiency Feeder Rebuilds	$7,371,000	$0	
Distribution Spokane North and West	$1,910,000	$0	
Millwood Sub Rebuild	$1,000,000	$0	
Pullman (Turner) Substation Rebuild	$609,000	$0	
Metro Feeder Upgrade	$502,000	$0	
Wood Substation Rebuild - Orin	$300,000	$0	
Spokane Electric Network Increase Capacity	$1,650,000	$0	
Spokane Smart Circuit	$5,400,000	$0	
Pullman Smart Grid Demonstration Project	$6,300,000	$0	
Smart Grid Workforce Program	$1,105,000	$0	
Total Washington Distribution Projects	**$26,147,000**	**$0**	**$0**
Total Distribution Projects	**$65,123,000**	**$16,364,000**	**$30,600**

System distribution projects (including transformation) for 2012 total $21.992 million ($8.602

million Idaho Share). These projects are necessary to meet capacity needs of the system, improve reliability, and rebuild aging distribution substations and feeders. The following projects make up the $8.602 million.

- **Wood Pole Management ($13.025 million system / $3.576 million Idaho):** 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 arrestors, missing grounds, damaged cutouts, and dated high resistance conductor). 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 prior to World War II 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 $5,600 in savings resulting from reduced call outs to fix problems during 2012. The Company spent $15.961 million (system) on these efforts in 2011.

- **PCB Related Distribution Rebuilds ($3.812 million system / $2.057 million Idaho):** In 2011, Avista initiated a systematic replacement of distribution line transformers because their oil contains PCBs. In addition, replacement of the "pre-1981" transformers has benefits of improving the energy efficiency and long-term reliability of the distribution system. 2012 represents year-two of a six year effort to replace these distribution transformers. In 2012, the program is expected to replace approximately 750 line transformers in Idaho. The replacement work is scheduled to be completed throughout the entire year. Offsets associated with this project in have not been included in this case[2].

- **System Distribution Reliability Improve Worst Feeders ($1.950 million system / $0.722 million Idaho):** Based on a combination of reliability statistics, including CAIDI, SAIFI, and CEMI (Customers Experiencing Multiple Interruptions), feeders have been selected for reliability improvement work. This work is expected to improve the reliability of these electric primary feeders. This is an annually recurring program initiated in 2008 to address underperforming feeders on the electric distribution system. This work will improve the reliability of these feeders and overall service to customers in these areas. The projects were selected based on poor reliability performance not on cost savings. The treatment of feeder projects varies from conversion of overhead to underground facilities, installing additional mid-line protective devices, to hardening of existing facilities.

Power Transformer Distribution ($1.450 million system / $0.492 million Idaho): Transformers are transferred to plant upon receiving them. These transformers are being purchased to replace existing spares that will be installed in 2012 as either replacements or new installations. The purchased transformers will either remain as system spares or placed into service as part of the proposed 2013 projects. Offsets associated with this project have not been included in this case[2].

- **Distribution – Pullman & Lewis Clark ($.650 million Idaho): System analysis** of the distribution grid indicate a number of capacity constraints and locations where "switch ties" are needed to allow for

[2] Offsets for this project have been calculated and the Company will update these at a later date.

alternate service to customers in the case of planned or forced outages. In many cases, main trunk feeder conductor is replaced with higher capacity wire which reduces overall system losses, supports uniform voltage, and provides for capacity when reconfiguring the system during planned or forced outages.

- **Distribution – CDA East & North ($.855 million Idaho):** System analysis of the distribution grid indicate a number of capacity constraints and locations where "switch ties" are needed to allow for alternate service to customers in the case of planned or forced outages. In many cases, main trunk feeder conductor is replaced with higher capacity wire which reduces overall system losses, supports uniform voltage, and provides for capacity when reconfiguring the system during planned or forced outages.

- **10th & Stewart Dx Int ($.250 million Idaho):** This project involves increasing 115/13 kV transformation capacity at an existing substation in Lewiston, Idaho. This substation serves the Lewiston "Orchards" region including the newly developed commercial zone near 20th Avenue. Load demand requires additional distribution capacity.

The Company also will spend approximately $16.984 million (system) or $7.762 million (Idaho share) in Distribution equipment replacements and minor rebuilds associated with aging distribution equipment, underground cable with poor reliability performance, replacements from storm damage, or relocation of feeder sections resulting from road moves. A brief description of the projects included in these replacement efforts is given below.

- **Electric Distribution Minor Blanket Projects ($8.300 million system / $3.235 million Idaho):** This effort includes the replacement of poles and cross-arms on distribution lines in 2012 as required, due to storm damage, wind, fires, or obsolescence. The Company spent $8.270 million in 2011 for these projects. No offsets are expected for these projects.

- **Failed Electric Plant ($2.200 million system / $1.014 million Idaho):** Replacement of distribution equipment throughout the year as required due to equipment failure. The Company spent $1.384 million in 2011. The Company must replace the equipment to maintain customer load service. No offsets are expected from these projects.

- **Distribution Line Relocation ($1.900 million system / $0.692 million Idaho):** The relocation of distribution lines as required due to road moves requested by State, County or City governments. The Company spent $2.061 million (system) in 2011 on line relocations associated with road moves. No offsets or savings are expected for these projects.

- **Electric Underground Replacement ($1.792 million system / $0.441 million Idaho):** This effort involves replacing the first generation of Underground Residential District (URD) cable. This project has been ongoing for the past several years and will be completed in 2012. This program 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 spent $3.887 million (system) in 2011. The company anticipates that it will see approximately $82,000 (system) or $25,000 (in Idaho) in incremental savings as a result of reduced cable failures. This is being included as an offset for the Electric Underground Replacement project.

- **Blue Creek 115kV Rebuild ($1.905 million Idaho):** The Blue Creek 115-13 kV Substation, just east of Coeur d'Alene, needs to be rebuilt adjacent to the existing substation to accommodate new equipment, including a new control house, 115 kV bus and switches, and upgraded SCADA indication and control. The primary driver for this project is the need to replace the substation transformer, which would require excessive work in the existing station due to its design. An additional feeder will also be added for distribution system reliability and operational flexibility as well as future load service capability.

- **Other Small Projects ($ 0.887 million system / $0.475 million Idaho):** These mainly consist of capacity increases and minor replacements of equipment.

Q. Please describe the Company's capital transmission projects that will be completed in 2013?

A. The major capital transmission costs (system) for projects to be completed in 2013 are approximately $34.975 million and are shown in Table 5 and described below.

TABLE 5		
Transmission		
2013 Capital - Compliance, Contractual, and Replacement Projects		
	Pro Forma (System)	**O&M Offsets (System)**
Reliability Compliance		
Spokane/CDA Relay Upgrade	$1,450,000	
SCADA Replacement	$450,000	
System Replace/Install Capacitor Bank	$1,050,000	
Moscow 230 kV Substation Rebuild	$8,090,000	$3,780
Bronx-Cabinet 115 kV Rebuild/Reconductor	$2,500,000	$1,980
Power Transformers - Transmission	$2,065,000	
Irvin 115kV Switching Station	$1,150,000	
Opportunity 115 kV Switching Station	$1,550,000	
Opportunity 12F2	$400,000	
Total Reliability Compliance	**$18,705,000**	**$5,760**
Contractual Requirements		
Lancaster 230 kV Interconnection	$4,600,000	
Colstrip Transmission	$463,000	
Tribal Permits	$332,000	
Total Contractual Requirements	**$5,395,000**	**$0**
Reliability Improvements		
Moscow City-N Lewiston 115 kV Reconductor	$2,450,000	
Burke-Thompson A&B 115 kV Reconductor	$2,500,000	$660
Total Reliability Improvements	**$4,950,000**	**$660**
Reliability Replacement		
Transmission Minor Rebuilds	$2,200,000	
Power Circuit Breakers	$1,200,000	
Hatwai 230 kV Breaker Replacement	$215,000	
Asset Management Replacement	$2,310,000	
Total Reliability Replacement	**$5,925,000**	**$0**
Total Transmission Projects	**$34,975,000**	**$6,420**

Reliability Compliance Projects ($18.705 million):

- **Spokane/Coeur d'Alene area relay upgrade ($1.450 million):** 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, 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.

- **SCADA Replacement ($0.450 million):** The System Control and Data Acquisition (SCADA) system is used by the system operators to monitor and control the Avista transmission system. The SCADA system requires annual enhancements to improve performance, replace computer systems and networks, and integrate vendor provided improvements. This portion of the project is required to meet Reliability Compliance under NERC Standards: TOP-001-1, TOP-002-2a R5-R10, R16, TOP-005-2 R2, TOP-006-2 R1-R7. Several Remote Terminal Units (RTUs) located at substations throughout Avista's service territory will also be replaced due to age. The RTUs are part of the transmission control system. There are no offsets or savings associated with this upgrade project because the Company already pays the application vendor a set annual maintenance fee for support.

- **System Replace/Install Capacitor Bank ($1.050 million):** This effort includes the replacement of the 115 kV capacitor bank at the Odessa 115 kV substations to support local area voltages during system outages and summer irrigation load conditions. This project is required to meet reliability compliance with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3, and provide improved service to customers. The Odessa project is scheduled to be completed by June 2013. There are no loss savings or other offsets associated with these projects. The project improves voltage support but doesn't reduce loss savings.

- **Moscow 230 kV Sub - Rebuild 230 kV Yard ($8.090 million):** This project involves the rebuild of the existing Moscow 230 kV substation. The substation rebuild includes the replacement of the existing 125

MVA 230/115 kV autotransformer with a new 250 MVA autotransformer to meet compliance with NERC standards and ensure adequate load service. Currently the existing 230/115 kV autotransformer overloads for an outage of another autotransformer in the area during peak load conditions. The 230 kV portion of the substation will be constructed as a double breaker double bus configuration to maximize reliability and operational flexibility. The substation will be constructed over a three-year period with energization of the substation occurring in November of 2013. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Loss savings calculations indicate that the new transformer installation will result in an offset of $3,780 in the pro forma period (based on a $31.50/MWh avoided energy cost and an energization date of November, 2013).

- **Bronx – Cabinet 115 kV rebuild/reconductor ($2.500 million):** In 2010 Avista's System Operations identified a thermal constraint on the 32-mile Bronx-Cabinet 115kV Transmission Line. This constraint was confirmed by the System Planning Group, and documented in the Transmission Line Design (TLD) Design Scoping Document (DSD) created on January 4, 2011, and modified on January 7,2011. The reconductoring/rebuilding of this line with 795 kcmil ACSS conductor will provide a present-day 143 MVA line rating to match the Cabinet Switchyard Transformer, and a future 200 MVA line rating to match the parallel path Bonneville Power Authority (BPA) system. The 32 miles of line will be reconductored over a four year period, which began in 2011. Phase 3 of the project (addressed here) consists of reconductoring an 8-mile section of the line. The line upgrade will ensure compliance with requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Using 2010 actual loads, since the line was operated open in over half of 2011 for construction of the first phase of the project, the new conductor will reduce line losses by 755 MWh on an annual basis. This project will not be completed until December 2013 so the offset savings of $1,980 will be observed in 2013 (based on a $31.50/MWh avoided energy cost).

- **Power Transformers – Transmission ($2.065 million):** The Company will be rebuilding several 230 kV substations over the next 5 years. One of these stations is Westside in western Spokane and involves the replacement of two 230/115 kV autotransformers. The autotransformer purchased in 2013 may be part of the Westside project or included as a system spare. The transformer will be capitalized upon delivery per the Company's accounting practices. The Westside project is required to meet Reliability Compliance under NERC Planning and Operations Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3. Offsets for this project will not occur until the autotransformer is actually placed into service.

- **Irvin 115 kV Switching Station ($1.150 million):** A new 115 kV Switching Station will be constructed in the Spokane Valley to reinforce the transmission system. The Irvin 115kV Switching Station is the initial project in a series of projects intended to improve reliability of the 115kV transmission system and accompanying load service in the Spokane Valley. In 2013, $1,150,000 is scheduled to be spent for the construction of a new transmission line from the future Irvin station site to the existing Millwood Substation. Work will also be performed to relocate existing structures in and around the Irvin site to accommodate its integration. Since this is a new transmission line, no offsets will be observed.

- **Opportunity 115 kV Switching Station ($1.550 million):** This project involves adding three 115 kV breakers to the existing Opportunity substation. The project is part of a group of projects to support the reliability of the 115kV transmission system and accompanying load service in the Spokane Valley. The completion of the Opportunity switching station will allow for the connection of a 115 kV line from the new Irvin Substation as well as future construction of the Greenacres substation in 2014. This upgrade will ensure compliance with requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.

- **Opportunity 12F2 ($0.400 million):** In order to support the reliability of the Spokane Valley, a 115 kV transmission line needs to be added from the new Opportunity switching station to the new Irvin 115 kV switching substation. This project involves the under-build of a feeder on a 115 kV transmission line. The 115 kV line currently operates at Distribution voltage but will be reenergized at 115 kV with the completion of the feeder under-build. This will require the addition of a 115 kV line to the existing Opportunity 12F2 feeder poles. The transmission line upgrade will ensure compliance with requirements associated with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.

<u>Contractual Requirements ($5.395 million):</u>

- **Lancaster 230 kV Interconnection ($4.600 million):** Avista plans to interconnect to BPA’s existing 230 kV Lancaster substation by looping in its Boulder-Rathdrum 230 kV line. The interconnection improves the load service and system reliability in the Coeur d’Alene and Rathdrum Prairie areas of Avista’s service territory. The interconnection also reduces the loading on the heavily loaded Beacon-Bell transmission lines that serve the Spokane area. The interconnection will provide direct transmission access to output of the Lancaster natural gas combined cycle plant. BPA will perform the upgrade work, including the addition of 2 new breakers, required at Lancaster substation for a cost of $4.1 million and Avista will perform the necessary transmission line work to loop in its Boulder Rathdrum line for a cost of $0.500 million.

- **Colstrip Transmission ($0.463 million):** 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 jointly owned facilities.

- **Tribal Permits ($0.332 million):** The Company has approximately 300 right-of-way permits on tribal reservations that need to be renewed. The $322,000 listed above relates to permit costs in 2013. The costs include labor, appraisals, field work, legal review, GIS information, negotiations, survey (as needed), and the actual fee for the permit.

Reliability Improvements ($4.950 million):

- **Moscow City-North Lewiston 115 kV Transmission Rebuild ($2.450 million):** This project includes the reconductor/rebuild of the 22-mile line between Moscow City substation and North Lewiston due to the poor condition of the existing line. The project will be completed in three phases. The first phase will be completed in 2012 and the second phase in 2013. The 2013 effort includes reconductoring/rebuilding seven miles of line, completing the line section between Moscow city and Leon Junction. Phase 3 in 2015 will complete the 8-mile line section between Leon Junction and North Lewiston. The Moscow City-North Lewiston 115 kV line is normally operated in a radial configuration open at Moscow City to avoid the line being overloaded for area outages. If the line section between North Lewiston and Leon Junction is lost then the breaker is closed at Moscow City to pick up load at Leon Junction. Since the line section being rebuilt is normally not carrying load, there are no offsets associated with this project.

- **Burke-Thompson A&B 115 kV Transmission Rebuild ($2.500 million):** This project is the second phase of the Burke-Thompson A&B line rebuild effort that will begin in 2012. The 5-6 miles stretch on Burke-Pine Creek #4 115kV Line between Wallace and Burke Substation will be rebuilt. These lines are part of the Montana to Northwest transmission path that moves generation from Montana to load centers in both Eastern and Western Washington and also serves mining load and residential customers in the Silver Valley area of Idaho. The current lines are in poor condition. The projects will result in loss savings due to the replacement of the existing conductor with a larger conductor. The new conductor has less resistance resulting in savings of 251 MWh for an entire year. The project is scheduled to be energized in December 2013. Assuming an avoided cost of $31.50/MWh total 2013 Idaho savings is $660.

Reliability Replacements ($5.925 million)

- **Transmission Minor Rebuilds ($2.200 million):** These projects include minor transmission rebuilds as a result of age or damage caused by storms, wind, fire, and the public. These smaller projects are required to operate the transmission system safely and reliably. The facilities will need to be replaced when damaged in order to maintain customer load service. In 2011 the Company spent $2.465 million on these minor rebuild projects as a result of damage caused by weather or the public.

- **Power Circuit Breakers ($1.200 million):** The Company transfers all circuit breakers to plant upon receiving them. The breakers purchased in 2013 are planned for installation at Irvin and Odessa substations.

- **Hatwai Breaker and switch replacement ($0.215 million):** Avista currently owns the relays at BPA's Hatwai substation associated with the breaker terminal of Hatwai-North Lewiston 230 kV line. The relay and protection system needs to be upgraded along with the breaker and switches that are planned to be replaced in 2012. Avista has contracted with BPA to replace the relays and protection system since BPA owns and operates the Hatwai substation.

- **Asset Management Replacement Programs ($2.310 million):** 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, arrestor upgrades, restoration of substation rock and fencing, recloser replacements, replacement of obsolete circuit switchers, substation battery replacement, interchange meter replacements, high voltage fuse upgrades, 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 any associated offsets.

Q. Please describe each of the distribution projects planned for in 2013.

A. The Company will spend approximately $52.634 million in Distribution projects at a system level, with $21.155 million specific to Idaho in 2013. A summary of the projects is shown in Table 6 and a brief description of each project impacting Idaho are given below.

TABLE 6			
Distribution			
2013 Capital - Distribution Projects			
	Pro Forma (System)	**Pro Forma (Idaho)**	**O&M Offsets Idaho**
Distribution Projects			
Wood Pole Management	$12,016,000	$3,883,000	$5,600
System Efficiency Feeder Rebuilds	$8,001,000	$3,163,000	$4,980
PCB Related Distribution Rebuilds	$2,925,000	$899,000	$0
Power Transformers - Distribution	$2,100,000	$1,750,000	
ID	$500,000	$500,000	
Clark	$500,000	$500,000	
System Wood Substation Rebuild	$3,705,000	$3,705,000	
N. Moscow Increase Capacity - ID	$1,680,000	$1,680,000	
Total Distribution Projects	**$31,427,000**	**$16,080,000**	**$10,580**
Distribution Replacement Projects			
Elect Distribution Minor Blanket	$8,300,000	$3,235,000	
Failed Electric Plant	$2,250,000	$1,037,000	
Distribution Line Relocation	$2,200,000	$803,000	
Projects	**$12,750,000**	**$5,075,000**	**$0**
Washington Distribution Projects (not included in case)			
Feeder Automation Upgrades	$2,501,000	$0	
Distribution Spokane North and West	$500,000	$0	
Millwood Sub Rebuild	$3,000,000	$0	
Metro Feeder Upgrade	$498,000	$0	
Capacity	$1,763,000	$0	
Project	$195,000	$0	
Smart Grid Workforce Program	$0	$0	
Projects	**$8,457,000**	**$0**	**$0**
Total Distribution Projects	**$52,634,000**	**$21,155,000**	**$10,580**

Distribution projects related to Idaho (including transformers) for 2013 total $21.155 million. These projects are necessary to meet capacity needs of the system, improve reliability, and rebuild aging distribution substations and feeders. The following projects make up the $21.155 million.

- **Wood Pole Management ($12.016 million system / $3.883 million Idaho):** 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 older than 1981, failed arrestors, missing grounds, damaged cutouts, and dated high resistance conductor). 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 prior to World War II 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 $5,600 in savings resulting from reduced call outs to fix problems during 2013. The Company spent a total $15.961 million (system) on these efforts in 2011.

- **System Efficiency Feeder Rebuild ($8.001 million system / $3.163 Idaho):** Beginning in 2012, Avista began a program to rebuild distribution feeders to reduce energy losses, improve operation of the feeders and increase long-term reliability. The program will replace poles, transformers, conductor and other equipment on a rural feeder and two urban feeders in 2012. The work associated with this effort will be completed between June and December of 2013. The energy savings from reduced losses calculated using an average of three months of savings is 400 MWh. This equates to an offset of $12,600 system and $4,410 in Idaho using an avoided cost of $31.50/MWh.

- **PCB Related Distribution Rebuilds ($2.925 million system / $0.899 million Idaho):** In 2011, Avista initiated a systematic replacement of distribution line transformers because their oil contains PCBs. In addition, replacement of the "pre-1981" transformers has benefits of improving the energy efficiency and long-term reliability of the distribution system. 2013 represents year-three of a six year effort to replace these distribution transformers. In 2013, the program is expected to replace approximately 610 line transformers in Idaho. The replacement work is scheduled to be completed throughout the entire year. There are no energy savings from reduced losses in included in this case[3].

- **Power Transformer Distribution ($2.100 million system / $1.750 million Idaho):** Transformers are transferred to plant upon receiving them. These transformers are being purchased to replace existing spares that will be installed in 2013 as either replacements or new installations. The purchased transformers will either remain as system spares or placed into service as part of of proposed 2014 projects. There are no offsets associated with these transformers until they are placed into service.

- **Distribution-CDA East & North ($ 0.500 million Idaho):** System analysis of the distribution grid indicate a number of capacity constraints and locations where “switch ties” are needed to allow for alternate service to customers in the case of planned or forced

[3] Offsets for this project have been calculated and the Company will update these at a later date.

outages. In many cases, main trunk feeder conductor is replaced with higher capacity wire which reduces overall system losses, supports uniform voltage, and provides for capacity when reconfiguring the system during planned or forced outages.

- **Distribution – Pullman & Lewis Clark ($0.500 million Idaho):** System analysis of the distribution grid indicate a number of capacity constraints and locations where “switch ties” are needed to allow for alternate service to customers in the case of planned or forced outages. In many cases, main trunk feeder conductor is replaced with higher capacity wire which reduces overall system losses, supports uniform voltage, and provides for capacity when reconfiguring the system during planned or forced outages.

- **System Wood Substation Rebuild ($ 3.705 million Idaho):** The Big Creek 115-13 kV Substation near Kellogg, ID, will be rebuilt with steel structures and new equipment. The station was originally constructed in 1956 and needs to be rebuilt to today’s design and construction standards. In addition, the new station will have only one transformer rather than the two transformers it has today.

  The North Lewiston 115-13 kV Substation will be constructed to today’s design and construction standards inside the existing North Lewiston 230-115 kV Substation. The new station will be constructed while the existing 115-13 kV wood sub remains in service. The distribution feeders will be transferred to the new sub and the old sub will then be retired and salvaged. The primary driver for this project is the need to replace the substation transformer and the age of the wood substation, which was constructed in 1958.

- **N. Moscow Increase Capacity ($1.680 million Idaho):** The North Moscow 115 kV Substation will have a second transformer and new feeder added to the existing substation to meet increasing demand in the Moscow area, including the University of Idaho. This will require extension of the 115 kV bus, a new control house, a new 13 kV distribution structure, a 13 kV bus tie, and upgraded SCADA indication and control. The upgraded station will have greater operational reliability and flexibility and will have accommodations for future 13 kV distribution feeders.

The Company also will spend approximately $12.750 million (system) or $5.075 million (Idaho share) in Distribution equipment replacements and minor rebuilds associated with aging distribution equipment, underground cable with poor reliability performance, replacements from storm damage, or relocation of feeder sections resulting from road moves. A brief description of the projects included in these replacement efforts is given below.

- **Electric Distribution Minor Blanket Projects ($8.300 million system / $3.235 million Idaho):** This effort includes the replacement of poles and cross-arms on distribution lines in 2013 as required, due to storm damage, wind, fires, or obsolescence. The Company spent $8.270 million in 2011 for these projects. No offsets are expected.

- **Failed Electric Plant ($2.250 million system / $1.037 million Idaho):** Replacement of distribution equipment throughout the year as required due to equipment failure. The Company spent $1.384 million in 2011. No offsets or savings are expected for these projects. The Company must replace the equipment to maintain customer load service.

- **Distribution Line Relocation ($2.200 million system / $ 0.803 million Idaho):** The relocation of distribution lines as required due to road moves requested by State, County or City governments. The Company spent $2.061 million (system) in 2011 on line relocations associated with road moves. No offsets or savings are expected these projects.

V. Vegetation Management Program

Q. Please provide an update on the Company's vegetation management program?

A. "Avista's Vegetation Management Program" is still striving towards an average frequency of 4 years. Work performed as part of Avista's Performance Excellence Initiative suggested changes to the Company's contracting practices to increase efficiencies, allowing more work to be performed on an annual basis. For 2012, a new contract with provisions to transition from "time and material pricing" at the beginning of the year to a unit price structure by the end of the year was established. Avista will be measuring the results to quantify potential value and opportunities that would allow us to approach a four-year cycle within our current annual spending level for distribution feeders of $4.1 million. Accordingly, the Company has not made an adjustment for Vegetation Management.

While the number of "Tree Fell" events in our Outage Management Tool (OMT) shows a small trend upwards (Illustration 1), the number of "Tree Growth" events has declined over the past 4 years, except for a slight increase in 2011. The real improvement from Vegetation Management shows up in the number of outages (Illustration 2). The number of outages or partial outages due to "Tree Fell" and "Tree Growth" events has generally decreased.

Illustration 1 – Number of OMT Events

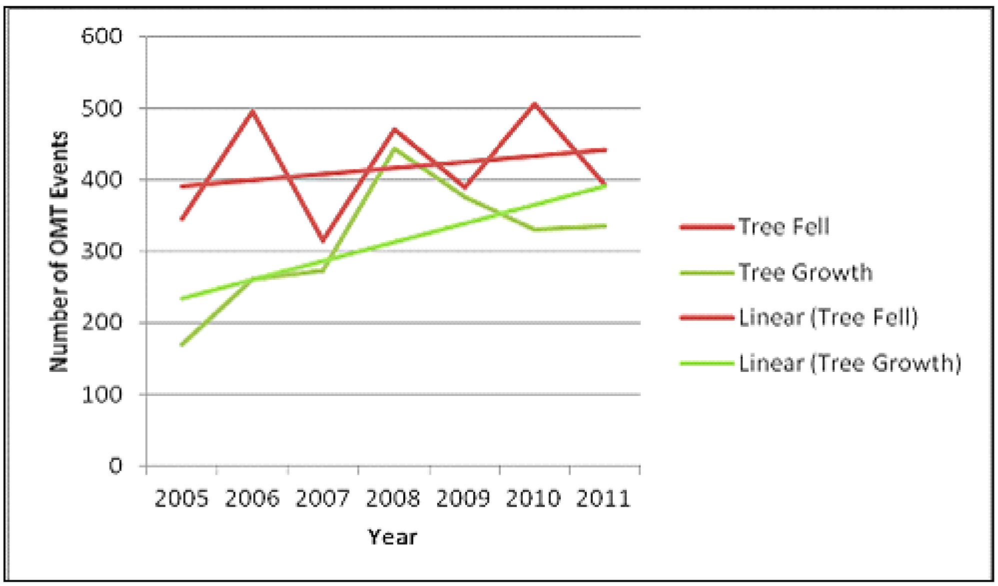
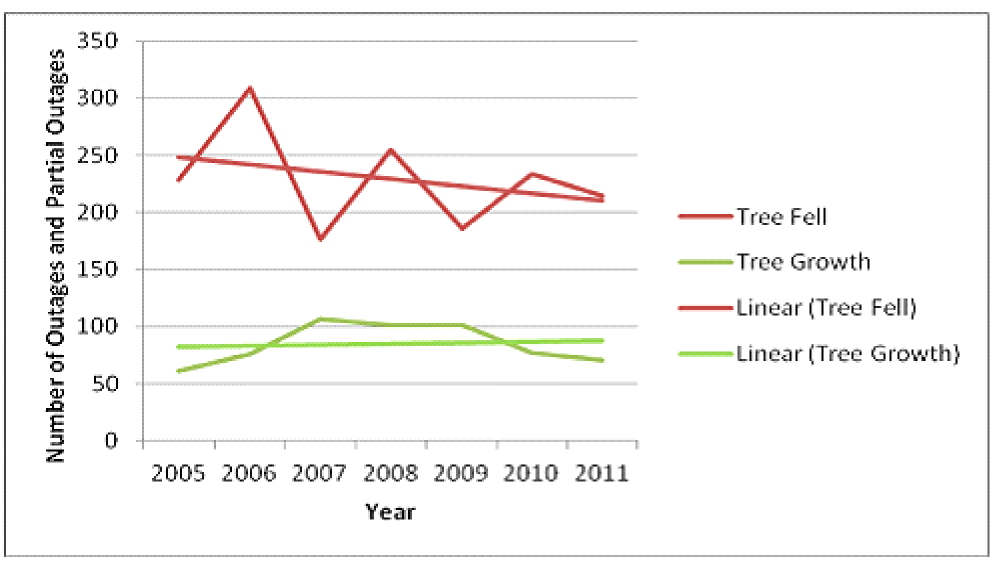


Illustration 2 – Number of Outages



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

A. Yes it does.