ATTACHMENT B

DOCKET NO. UE-100176

2010 DSM Business Plan

Avista Utilities

Energy Solutions Team

January 18, 2010

2010 Washington / Idaho DSM Business Plan

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Preface to the 2010 DSM Business Plan
Jon Powell

Avista is in the process of significantly redesigning and enhancing our approach to and reporting of our business planning, cost-effectiveness analysis and Evaluation, Measurement and Verification (EM&V) processes.

For example, one of the requests that we have received is for the establishment of a DSM "annual report" in some form. It is our belief that we can meet this expectation by combining (and revising as necessary) some of our existing reporting processes. By combining these reports into a comprehensive package we believe we will create a stand-alone document that will give us the opportunity to explain and document our DSM activities and results in a transparent manner without diverting significant staff time away from our critical ongoing operational requirement of gaining energy efficiency savings.

Below is a high-level summary of the documents that we produce, the timing and content of those documents and the changes we expect to undertake in 2009 and 2010.

- The DSM Business Plan
    - Produced in the 4th quarter for the following calendar year.
    - This business plan for the following year to includes budget, funding (balance and surcharge) projections, program plans, infrastructure plans, EM&V, summaries of major issues, a documentation of our implementation policy revisions and more.
        - *Please note that we will continue to regard this primarily as a working document*. It is our intent to focus our efforts upon the substance of the planning document. The document is intended to serve the purposes of communicating with key stakeholders, but the language and graphics are relatively plain.
    - This will allow the content of this report to be revised annually based upon our planning needs.
- The External Energy Efficiency (or "Triple-E") Report
    - We have made a commitment to completing this report by March 31st of every year. Each report summarizes the prior calendar year's DSM activity. In the past the reports have been completed at various times, at least once every twelve months but oftentimes more frequently to correspond to the timing of general rate cases.
        - It is our general intent in the future to request an annual finding of regulatory prudence of the DSM activity in the prior year shortly after the completion of the DSM Annual Report (which will include this Triple-E Report document).
    - In the past the report has summarized all elements leading towards the calculation of cost-effectiveness (including energy acquisition, expenses, customer costs and benefits, avoided energy costs and so on) plus a variety of other useful diagnostic statistics coming from or closely related to these calculations (levelized cost, cost per first year kWh/therm) and an annual summary of our tariff rider balance projections. Recent reports have had a minimum of verbiage explaining the document. We will expand the verbiage within the document to allow it to function as a stand-alone document.
    - We are undertaking substantial methodological changes to this report in 2009. These include the termination of our previous "derated" methodology (which recognized for cost-effectiveness and acquisition purposes the benefits and costs as a project progressed in pre-defined stages towards completion) to a

"completed only" methodology (which will recognize all project-related costs and benefits upon project completion only). Additionally we will be revising the means by which we disaggregate our DSM portfolio by jurisdiction, segment portfolio (residential, non-residential etc) and program. The Triple-E Report will include documentation of EM&V efforts substantiating the inputs into the calculations as well as plans for future measurement.

- Quarterly Triple-E Newsletters
    - Produced quarterly (with occasional omissions during quarters coinciding with a Triple-E meeting).
    - This document contains a report of our tariff rider balance and projections, our kWh and therm acquisition reporting (actual and budgeted), documentation of projects at Avista facilities and projects with a projected incentive of over $100,000 (with details modified as necessary for customer confidentiality) and any substantive updates for the Triple-E board.
    - There are no changes contemplated to the current process and document format.
- Monthly Triple-E Reporting
    - We have committed to producing a monthly calculation of the balance of each of our four tariff riders by the 15th day of the following month.
    - There are no changes contemplated for this document.
- Quarterly Tariff Rider Balance Projections
    - On a quarterly basis we provide a summary of each of the tariff rider balances and balance projections into the future.
- Annual Schedule 91 and Schedule 191 filings
    - We have committed to filing for revisions in our Schedule 91 (electric DSM surcharge) and Schedule 191 (natural gas DSM surcharge) by February 15th of every year. We have also committed to circulating to the Triple-E board for comment the proposed filing 30 days in advance of the filing. This commitment is formal within our Washington jurisdiction and is an informal commitment in our Idaho jurisdiction.
    - This is a new process for 2010. It is our intent to incorporate the filing into our DSM Annual Report since it contains the calculations and justification behind revisions to our surcharges that are a key component of business planning and reporting.

Additionally we convene two meetings of the Triple-E Board every year. These are generally one to two day meetings in the spring and fall of every year. Traditionally our spring meeting is west of the Cascades and the fall meeting is in Spokane. A variety of documents and presentations are prepared for this meeting and are made available to all external parties.

It is our intent to fulfill the request for a DSM "Annual Report" document by packaging all of the documents previously mentioned along with an introduction and guide that will allow the reader to access, understand and tie together all of these individual documents into a larger representation of Avista's past achievements, current status and planning for the future.

The best timing for the packaging of these documents would be at the time that the Triple-E Report is completed or shortly thereafter. Thus we would expect a March or April distribution time for what we will refer to as the "DSM Annual Report Package".

Considering the bulk of the documents within the package, we will distribute it electronically or by CD unless we receive specific requests for hardcopies.

Given the many revisions necessary for many of these documents and the new approach to packaging multiple documents into a single overview document, 2010 will undoubtedly be a learning year in many ways. We will solicit feedback from the Triple-E Board and others regarding the efficiency of our reporting process as well as on the substance of each of these documents to make possible the continuous improvement of this effort.

Executive Summary

Bruce Folsom

Quis est non tabellae est non tendo. That which is not written does not exist. Avista's 2010 DSM (Demand Side Management) Business Plan is lengthier than in previous years. This is because the DSM Team is, literally, doubling its efforts to explain how the Company plans, implements, and measures its contemplated energy efficiency savings. The 2010 Plan will highlight operational aspects of DSM acquisition; but it will also go into more detail about new initiatives (literally regarding Initiative 937) and figuratively (enhanced verification of savings). The detail expands on existing practices that will be better documented and the detail introduces new protocols for our 2010 energy efficiency programs.

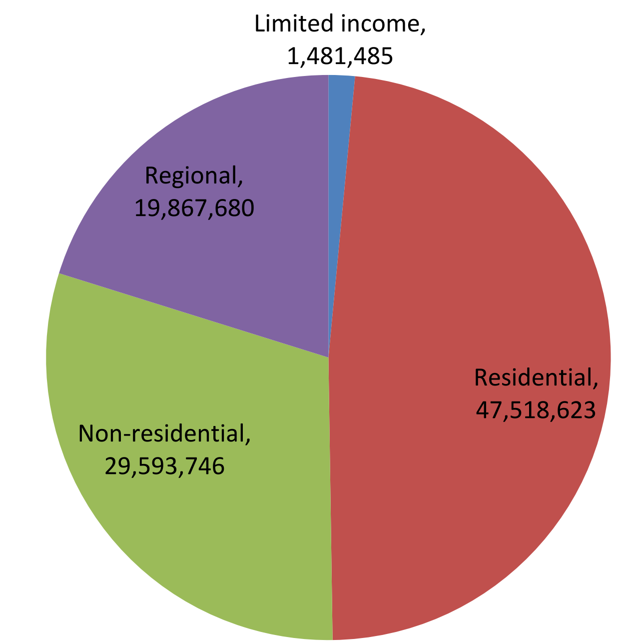
Length by itself does not equal transparency and, actually, length can hinder transparency. Thus, this Executive Summary intends to both highlight key portions of this plan and serve as a "reader's guide" to key aspects of the plan. This plan can be used as an overview of the Company's programs, it can be used by opinion leaders and the expert public to gain a more thorough understanding of the "how" and the "what" of Avista's programs, and it can be used by quantitative analysts to examine the Company's various methodologies.

Avista's energy efficiency services are entering into its fourth decade of operations. Over 140 aMW of load have been taken off Avista's system through energy efficiency. This represents about 10% of the Company's average load.

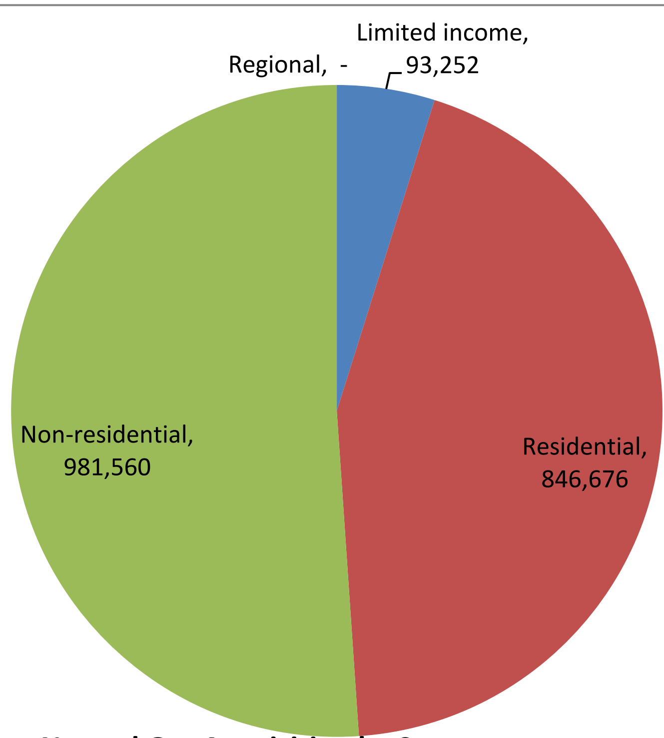
This Business Plan describes that:

- Avista's electric and natural gas energy efficiency programs are directed to six portfolios
  - Residential,
    - Residential programs are provided through prescriptive programs in which designated measures (high-efficiency appliances, water heaters and furnaces or weatherization measures such as insulation) are incentivized to customers through education and financial rebates
  - Low-income residential,
    - Low-income programs are delivered through community action programs (CAPs) because these agencies are eligible for matching Federal and state support and because they have the administrative systems in place to qualify customers by income levels
  - Commercial and industrial (described as "non-residential),
    - For Commercial and Industrial (C and I) customers, a financial rebate is available for any measure that saves electricity or natural gas and has a simple financial payback of over one year
      - C and I programs have historically been delivered on a custom (or "site-specific") basis,
      - In the past few years, the Company has been transitioning some of these programs to be standard offers (or "prescriptive") through forms specifying qualifying measures and associated conditions
  - Regional programs delivered locally
    - Approximately 20% of Avista's energy efficiency savings derive from regional programs provided by the Northwest Energy Efficiency Alliance (NEEA). Avista was one of 12 utility funding partners in 2009 and has committed to continued funding for the 2010-2014 funding cycle. NEEA uses economies of scale and the tools of market transformation to

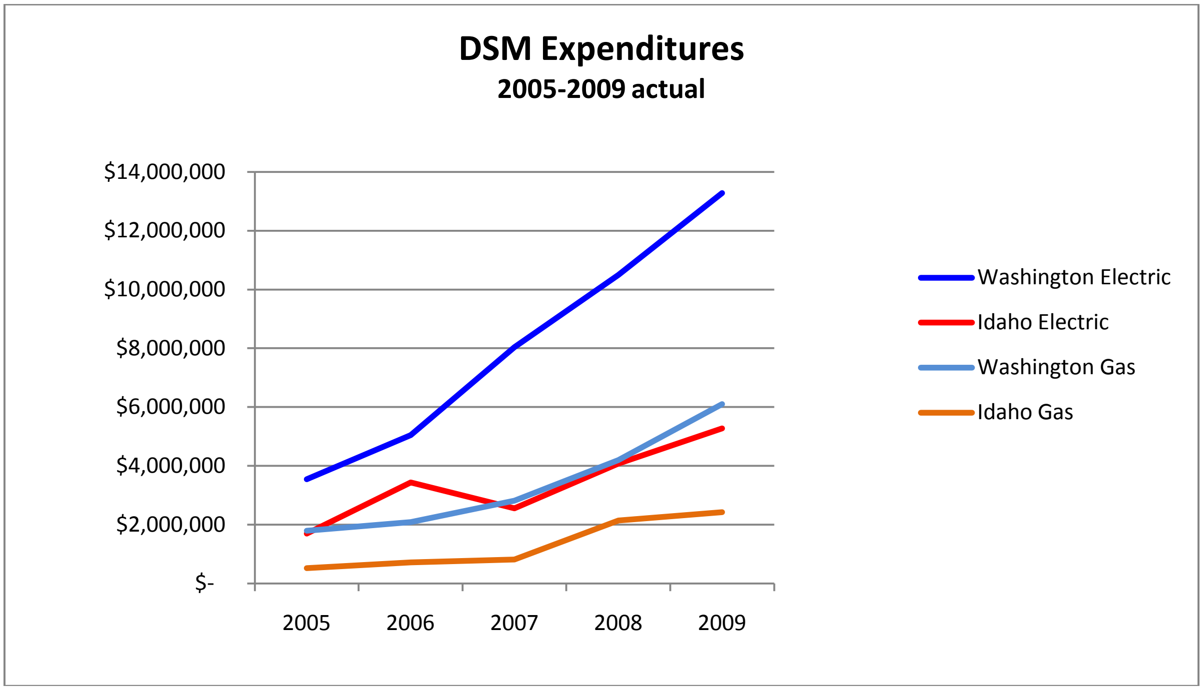
        - accelerate the adoption of cost-effective electric-efficiency products and practices.
    - Demand response programs
        - Avista has completed a two-year demand response pilot designed as a technology and customer acceptance
        - The results of Avista's demand response pilot have been incorporated within a larger exploration of the integrated benefits of demand response within Smart Grid technology in Pullman, Washington. This ARRA co-funded project is not funded through the DSM tariff rider but will be closely coordinated with the DSM resource planning functions
    - Renewable programs
        - Avista's involvement in distributed renewable generation has been primarily in the form of customer education and facilitating the integration of qualifying renewables into the grid. In 2010 the Company will be proposing a revision to Schedule 90, in both Idaho and Washington, to eliminate the incentive portion of this program while retaining the customer service function
- Over 470 measures and 36 individual energy acquisition programs are included in this business plan; this business plan is a working document and other measures and programs will be considered and added as appropriate
- For electric efficiency, Avista's 2010 Washington/Idaho targets are:
    - 90,104,000 kWh's based upon the most recent Integrated Resource Plan
    - 61,276,000 kWh's for our Washington I-937 target. This target is based upon the Northwest Power and Conservation Council's 6th Power Plan augmented with 1,285,000 kWh's of estimated direct-use (electric to natural gas) fuel-efficiencies.
        - Avista has opted to use the 6th Power Plan as a guide for I-937 compliance to due to potential methodological differences in the treatment of Avista's all-encompassing site-specific program within our IRP
- For natural gas efficiency, Avista's 2010 targets are:
    - 1,542,529 therms
    - Based on the Company's natural gas IRP
- Avista's energy efficiency programs are provided:
    - By 23 full-time equivalents spread over 34 individuals
        - This is an increase of 2.1 FTE over 2009 staffing levels
    - At a budgeted utility cost of $25.3 million
        - This is an increase of $2.1 over the 2009 budget but is $1.8 million less than the 2009 actual expenditures
- Evaluation, Measurement and Verification (EM&V)
    - In 2010, the Company's EM&V protocols will be enhanced to include greater:
        - Impact, process, market and net-to-gross analyses
        - This will be responsive to the IPUC Staff and multi-party MOU
    - All programs and measures will have an objective explanation to describe and document, in a transparent manner, how the savings were calculated and reported
- Messaging to customers will continue to have a strong focus
    - The EveryLittleBit (ELB) campaign will enter its third full year
        - The multi-channel approach will be continued and expanded through print, broadcast, web, and other approaches
        - Earned media will continue to be pursued in an integrated approach
- New projects provided in through economic stimulus or ARRA (American Recovery and Reinvestment Act) funding
    - In-home energy audits and revolving loan funds
    - The Pullman Smart Grid demonstration project for demand response
    - The potential for Resource Conservation Managers

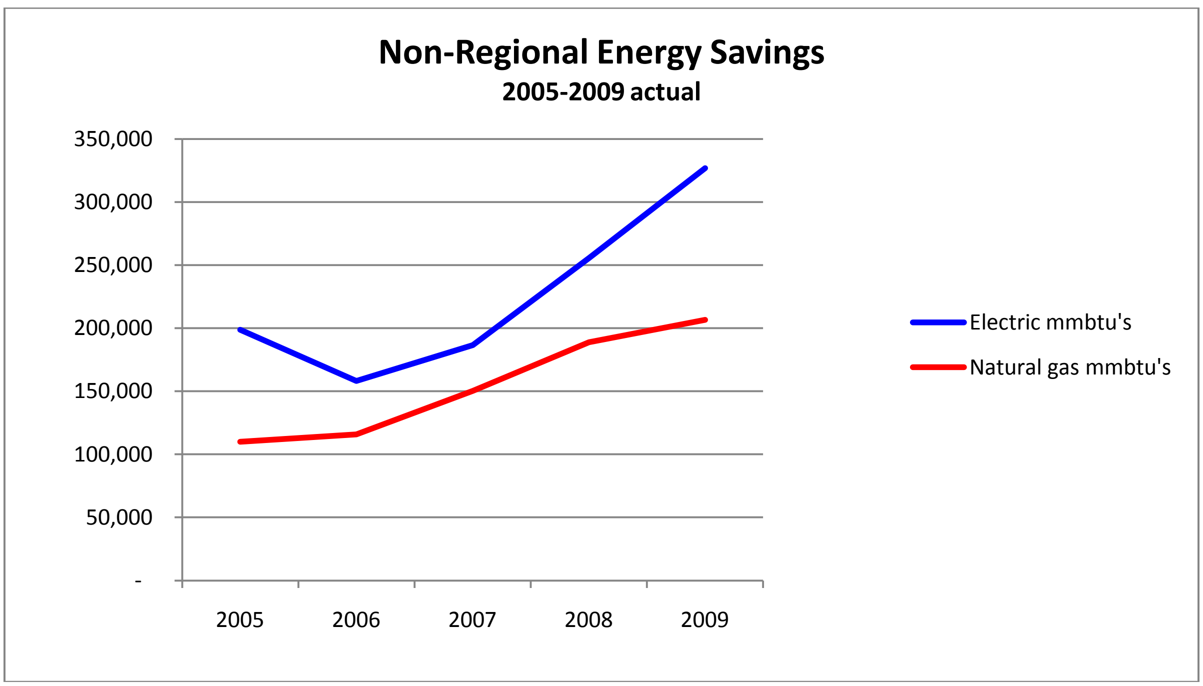


Electric Acquisition by Segment



Natural Gas Acquisition by Segment


DSM Expenditures
2005-2009 actual
$14,000,000
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$-
2005
2006
2007
2008
2009
Washington Electric
Idaho Electric
Washington Gas
Idaho Gas


Non-Regional Energy Savings
2005-2009 actual
350,000
300,000
250,000
200,000
150,000
100,000
50,000
-
2005
2006
2007
2008
2009
Electric mmbtu's
Natural gas mmbtu's

In 2010 the company is entering into its 7th era of energy efficiency. This era is the "Era of External Interest". The six previous eras include:

- 1978 to 1991 – "The Jimmy Carter Era"
- 1992-1994 – "The Energy Exchanger Era"
- 1995-2000 – "The Tariff Rider Era"
- 2001 – "The Year of the Western Energy Crisis"
- 2002-2005 – "The Financial Recovery Era"
- 2006 – 2009 – "The Era of Reinventing DSM"

The Era of External Interest is marked by several new approaches to DSM and associated issues. These issues are at the core of this DSM Business Plan.

- The first operational year of Washington Initiative 937 (aka renewable portfolio standards, RCW 19.285, and WAC 480-109)
- The first year of Washington natural gas decoupling (outside of a pilot)
- The first year of implementing the Idaho Public Utilities Commission Staff and multi-party Memorandum of Understanding on evaluation, measurement and verification (EM&V)
- The convening of a Collaborative to examine EM&V and low income issues
- New projects brought through economic stimulus or ARRA (American Recovery and Reinvestment Act) funding

Quis est non tabellae est non tendo. Over 500 data requests, many with multiple parts, were received in the Company's 2009 Washington natural gas decoupling case. Avista (and Idaho's two other investor-owned utilities) entered into a Memorandum of Understanding with the Idaho Public Utilities Commission Staff to better describe and report energy efficiency savings. Clearly, transparency and documentation will be highlighted in 2010 by Avista's DSM Team. Historically Avista has aspired to best practices in all facets of the delivery of energy efficiency service. This business plan is a commitment by the DSM Team to continue to do so and this business plan is an invitation to stakeholders to weigh in with observations.

Quick Reference Guide to Commonly Used Terms

The following common terms are used frequently throughout this business planning document. For the readers benefit these definitions and background are presented prior to their use.

CFL's (or Compact Fluorescent Lamps)
CFLs use between one fifth and one third of the power of equivalent incandescent lamps. While the purchase price of an integrated CFL is typically 3 to 10 times greater than that of an equivalent incandescent lamp, the extended lifetime and lower energy use will compensate for the higher initial cost.

Decoupling
In conventional utility regulation, utilities make money based on how much energy they sell. A utility's rates are set based largely on an estimation of costs of providing service over a certain set time period, with an allowed profit margin, divided by a forecasted amount of unit sales over the same time period. If the actual sales turn out to be as forecasted, the utility will recover all of its fixed costs and its set profit margin. If the actual sales exceeds the forecast, the utility will earn extra profit.

Demand Response
Mechanisms to manage the demand from customers in response to supply condition; for example, having electricity customers reduce their consumption at critical times or in response to market prices. Passive DR is employed to customers via pricing signals, such as inverted tier rates, time of use (TOU) or critical peak pricing (CPP).

DSM, Energy Efficiency, Conservation
Terms used interchangeably although conservation technically means using less while DSM (demand-side management) and energy efficiency means using less while still having the same useful output of function.

EM&V (Evaluation, Measurement and Verification)
This is composes of impact analysis (the measurement of the impact of the installation of an efficiency measure), process analysis (the evaluation of a process with the intent of developing superior approaches through obtaining a better understanding of the process itself), market analysis (evaluating the interaction between the market and measure to include the estimation of net-to-gross ratios, technical, economic and acquirable potentials) and cost analysis (the estimation of the cost characteristics of a measure with particular attention to incremental cost and the influence that a program may have upon those cost characteristics).

IPUC (Idaho Public Utilities Commission)
The IPUC regulates investor-owned utilities within the state of Idaho.

IRP (Integrated Resource Plan)
An IRP is a comprehensive evaluation of future electric or natural gas resource plans. The IRP must evaluate the full range of resource alternatives to provide adequate and reliable service to a customer's needs at the lowest possible risk-adjusted system cost. These plans are filed with the state public utility commissions on a periodic basis.

Measure
A measure is a energy-efficiency product or service that can be offered relatively independently of other similar products or services.

NEB (Non-Energy Benefits)
Benefits (or costs) resulting from the installation of an efficiency measure that are unrelated to the energy resource. This may any value or cost but is most commonly the impact of changes in water usage, sewage cost, reduced maintenance cost, etc. Values or costs which cannot be reasonably quantified (such as security, safety, productivity) are not included in Avista's measurement of non-energy benefits.

NPCC (Northwest Power and Conservation Council)
The Council was established by the Northwest Power Act in 1980 to provide the electric customers of Washington, Idaho, Oregon and Montana with regional electric power planning coordination.

Power Plan
The Northwest Power and Conservation Council is required to complete a regional Power Plan every five years. The Plan includes both supply-side (generation) and conservation resources. (Per the definition of "conservation" in the Northwest Power Act, electric-to-natural gas conversions are not considered to be "conservation" within the Plan). The Sixth Power Plan is currently nearing approval by the Council.

Prescriptive
A prescriptive program is a standard offer for incentives for the installation of an energy-efficiency measure. Prescriptive programs are generally applied when the measures are relatively low cost and are employed in relatively similar applications.

Program
A program is an aggregation of one or more energy-efficiency measures into a package that can be marketed to customers.

Schedules 90 and 190
These tariffs authorize Avista to operate electric-efficiency (Schedule 90) and natural gas-efficiency (Schedule 190) programs within Washington and Idaho. Electric to natural gas conversions are considered electric-efficiency programs, subject to achieving a specified net BTU efficiency.

Schedules 91 and 191
These tariffs establish a surcharge levied upon retail electric (Schedule 91) and natural gas (Schedule 191) sales to fund electric and natural gas-efficiency portfolios respectively.

Site-Specific
A non-residential program offering individualized calculations for incentives upon any electric or natural gas-efficiency measure not incorporated into a prescriptive program.

Tariff Rider
The surcharge on retail electric and natural gas sales that provides the funding for Avista's DSM programs. This surcharge is authorized under Schedule 91 (for electric programs) and Schedule 191 (for natural gas programs).

TRC (or Total Resource Cost test)
One of the four standard practice tests commonly used to evaluate that cost-effectiveness of DSM programs. The TRC test evaluates the cost-effectiveness from the viewpoint of all customers on the utility system. The primary benefits include the avoided cost of energy and non-energy benefits in comparison to the customer incremental cost and non-incentive utility expenditures. The California standard practice allows for tax credits to be considered offsets to

the customer incremental cost (though Avista calculates the TRC test with and without this offset).

UCT (or Utility Cost Test)
One of the four standard practice tests commonly used to evaluate that cost-effectiveness of DSM programs. The UCT evaluates the cost-effectiveness based upon a programs ability to minimize overall utility costs. The primary benefits are the avoided cost of energy in comparison to the incentive and non-incentive utility costs.

WUTC (or the Washington Utility and Transportation Commission)
The WUTC regulates investor-owned utilities within the state of Idaho.

Avista-Specific DSM Terminology and Methodologies

Jon Powell

Over the years, Avista's Demand-Side Management (DSM) portfolio has evolved through several phases and, during that time, certain Company-specific terminology, methodologies and issues have developed. As part of complying with the recent Idaho Public Utiilty Commission (IPUC) staff Memorandum of Understanding (MOU) on several DSM issues, we've refined several of these definitions for planning and evaluation purposes. In order to proceed with an improved degree of clarity, the following new and/or unique definitions are useful to state before proceeding into our planning process.

Measures, Programs and Portfolios

For purposes of disaggregating our energy-efficiency efforts into comprehensive packages, both for marketing them to customers as well as for analysis and planning, the Company has adopted general rules for the definitions of different levels of aggregation. From the bottom (most specific) up to the top (most aggregated) the general definitions are as follows:

- Sub-measure: A component of an efficiency measure that could not be offered without being packaged as part of other sub-measures.
- Measure: An efficiency alternative that can be independently offered (or not offered) to the customer.
- Program: One or more related (e.g. lighting, shell) measures that are aggregated into a program for purposes of evaluation or to better market them to customers.
- Portfolio: Aggregations of programs around a specific characteristic.
    - Market Segment Portfolio: An aggregation of programs within a specific market segment (residential, limited income, non-residential, regional etc).
    - Fuel Portfolio: All programs within a fuel (electric or natural gas).
    - Jurisdictional Portfolio: All programs within a jurisdiction (Washington or Idaho).
    - Local or Regional Portfolio: Distinguishing between Avista's local programs and our participation in regional programs.
    - Fuel/Jurisdictional Portfolio: A combination of the two aggregations above.
    - Overall Portfolio: A combination of all Avista DSM efforts.

The application of these definitions to the business planning analysis can occasionally be subjective. The distinction between sub-measures and measures can be somewhat indistinct, and the assignment of measures to programs may change over time. As the business planning process came towards a conclusion, it became apparent that there was the need for revisions in how some of these disaggregations should be applied in the next business plan.

"Sub-TRC" and "sub-UCT" tests

The IPUC staff MOU has formalized Avista's historical practice of evaluation the contribution of each individual measure to the portfolio Total Resource Cost (TRC) test and/or Utility Cost Test (UCT) as appropriate. Avista has committed, as part of the Idaho PUC staff MOU, to offering only those measures or programs that are expected to contribute to the overall cost-effectiveness of our overall DSM effort, absent reasonable and documented exceptions.

In the past, the Company has employed what we have termed a "sub-TRC" and "sub-UCT" test to evaluate the contributions of an individual measure or program to the TRC or UCT cost-effectiveness of the overall portfolio. These tests include the costs and benefits that a measure or program *incrementally* contributes to the portfolio. Generally it is the case that all of the benefits of a measure or program are incremental (e.g. if the measure were excluded the portfolio would not obtain the avoided cost or non-energy benefit value). But costs become progressively incremental as the degree of aggregation increases from measures progressing upwards to the overall portfolio. By utilizing this approach the Company includes those DSM elements that are cost-effective but avoids excluding incrementally cost-effective measures that can't bear the full weight of fixed infrastructure costs that could be assigned to them.

Customer incremental cost and direct incentives are always incremental costs even at the lowest levels of portfolio disaggregation. Non-incentive utility costs (labor, outreach etc) that are not materially changed by the exclusion of a particular measure are not considered incremental costs at the measure level. As measures are aggregated into programs it is generally true that more of these costs become incremental.

Avista has historically used this analytical approach, and most frequently the sub-TRC test, to evaluate the individual contributions of measures being considered for addition or termination from the portfolio. It is also used to target outreach efforts, to evaluate the value of the incremental throughput of outreach efforts and to establish 'break-even' levels of additional throughput necessary to make such efforts cost-effective.

The sub-UCT test is much less frequently used because it is nearly always the case that the sub-TRC test will be the more difficult test to pass and therefore will be the constraint upon the measure or programs contribution to the portfolio. This is generally the case because the customer incremental cost (incorporated within the TRC but not the UCT) is nearly always higher than the customer direct incentive (which is included in the UCT but not the TRC). Since nearly all of Avista's programs operate under an incentive that is capped at 50% of the customer incremental cost, this relationship nearly always applies. Significant non-energy benefits or disbenefits (influencing the TRC test but not the UCT test) may also impact the relationship between the two tests. When the utility incentive cost approaches or exceeds the customer incremental cost the sub-UCT test is employed as a means of determining the contribution of a DSM element to the overall portfolio.

In order to meaningfully incorporate the commitment to offering only TRC cost-effective programs (or justifiable exceptions) Avista has included within the analysis leading to this business plan an individual evaluation of the sub-TRC of over 470 measures and approximately 40 programs. The result of this analysis has been incorporated within the program plans presented within this document. References to the rigidities involved in measure or program termination (e.g. contractual obligations, program sunset dates, measure packaging etc.) are also included as necessary.

Prescriptive and Site-Specific

Avista's tariffs establish the criteria for eligible measures and incentives that Avista may grant for those measures. To establish a means by which the Company can consistently and efficiently implement the provisions of these tariffs, a series of written protocols and documented business practices has arisen over the years. One of these practices relate to the degree to which generalizations can and should be made in the implementation of efficiency measures.

The "prescriptive" term is applied to programs for which generalizations have been made as part of the program design. Programs that are "site-specific" are based upon project-specific information rather than references to typical or average applications of a measure.

Prescriptive programs allow for the program implementation to be streamlined, thus reducing cost and administrative burden. It also often improves the marketability of the program to customers and trade allies due to the ability to refer to fixed or easily calculated incentives rather than to the esoteric regulated formulas governing the site-specific program. Properly applied prescriptive approaches can lead to significant enhancements to program throughput and cost-effectiveness. Prescriptive programs also generally exempt a customer from the requirement of signing a contract prior to the installation of the measure, thus reducing the administrative burden upon the customer.

A downside of "prescriptivizing" a program is the loss of individual accuracy in the calculation of the customer incentive. This can to some degree be addressed by careful segmentation of the market to maximize the uniformity of each category within a prescriptive program.

As a general rule, prescriptive programs are only applied in circumstances where the benefit of enhanced marketability and implementation cost-efficiencies outweigh the loss of accuracy in individualized calculations. The best prospects for prescriptive treatments are for small measures that are used in the same manner in the majority of their applications.

The calculation of energy savings for purposes of establishing Avista's acquisition claim is unaffected by the prescriptive or site-specific treatment of a program. Through the EM&V process estimates of actual savings are made and incorporated into these claims without regard to the implementation approach used for the program.

The incentives offered for both prescriptive and site-specific programs are governed by Avista's Schedule 90 and 190 tariffs (attached as Appendix B to this plan). The results of these formulas may be rounded or adjusted to fit within a continuum of measures when applied to a prescriptive program. The incentive calculations are evaluated upon any noted significant change in incentive determinants (changes to incremental cost due to changes in base case, retail rates, changes in estimated energy savings etc). They are also periodically evaluated as part of the program manager responsibilities. Incentives for all measures were calculated as part of this business planning process and program managers are considering adjustments as necessary.

Measures which are incorporated into a prescriptive program may only be pursued through that prescriptive program. Non-residential customers installing an efficiency measure which is not included in these programs may apply for a site-specific contract. Contracts are necessary prior to the installation of the measure. Any non-residential efficiency measure not covered within the prescriptive programs qualifies for the site-specific program regardless of project size or cost-effectiveness. The Company does carefully target the program for cost-effective applications.

<u>"De-rating"</u>
Prior to 2009, Avista recognized the impact of site-specific projects as they moved through designated phases towards completion. Specifically, projects that had been contracted were assumed to be 75% complete, those under construction were 95% complete and those that had been post-verified were 100% complete. This was a reasonable representation of both the investment that Avista had in the project as well as the probability of full completion.

The de-rating methodology was useful at a time when Avista was producing multiple reports every year and when the sales cycle involved in site-specific projects potentially overlapped several of these reports. The process allowed for a better alignment in the timing of the incurrence of costs and benefits and resulted in more meaningful cost-benefit analysis.

Since that time Avista has moved to producing a single annual cost-effectiveness report, the share of site-specific projects within the overall portfolio has declined as more commercial measures have become "presciptivized", and there is an increasing need for transparency as a result of Washington natural gas decoupling and I-937 reporting requirements. Consequently, Avista will begin reporting on a completed-only basis for 2009 and beyond. Subject to time availability, we do plan on producing a cost-effectiveness evaluation using both de-rated and completed-only methodologies in the transitional year of 2009.

Business Plan Overview

Jon Powell

It is Avista's goal to acquire all cost-effective electric and natural gas efficiency resources that can be realistically achieved or facilitated by utility intervention and, in doing so, meeting our conservation acquisition requirements under the Washington Initiative 937 (I-937) and our electric and natural gas Integrated Resource Plan (IRP) targets (to include fully achieving the targets established by the Washington natural gas decoupling mechanism). This is a long-term goal requiring long-term strategies as well as the competent execution of ongoing DSM operations.

Towards that end the Company has identified several key issues which are addressed within this business plan. These issues, and a summary of our approach to those issues, are identified below and further elaborated upon in the body of this document:

- Maintain regulatory and stakeholder support for a flexible tariff structure governing Avista's DSM operations, use that flexibility as necessary to meet our DSM mission and continue support for the timely recovery of DSM investments.
    - Towards that end the Company intends to exceed expectations in terms of providing opportunities for meaningful external input and a high degree of transparency in our approach to fulfilling our DSM task.
        - The specific deliverables that Avista has committed to are detailed in the section entitled "Preface to the 2010 Business Plan" within this document.
- Continue to provide broad customer opportunities for direct participation in the DSM portfolio as well as a broad distribution of direct and indirect benefits from the DSM portfolio to Avista's customer base.
    - In 2009 Avista made significant inroads within the multifamily housing market through the UCONS program for the direct-installation of efficiency measures. This program was terminated in 2009 having achieved its original objectives. This market will be re-evaluated for new efficiency opportunities. The success of this effort will lead to an evaluation of similar efforts in other market segments that have been difficult to reach.
    - The Company currently has a rooftop HVAC maintenance pilot program underway. The results of this program will guide the potential development of a full-scale effort targeted for the small commercial market.
    - As a result of the Company's Washington natural gas decoupling order, we will be convening a stakeholder group to discuss new and improved means of penetrating the limited income market. We anticipate that this will be an ongoing process given the likelihood that we will need to identify and develop improved data upon which to base future program development. We will apply what we learn through this process to both our Washington and Idaho jurisdictions as appropriate.
    - The Company will be launching a two-year residential audit program using American Recovery and Reinvestment Act (ARRA) co-funding received from local jurisdictions. The budget includes sufficient funding for 2,000 audits in 2010 with the expectation of an additional 4,000 in 2011.
    - Washington and Idaho state ARRA funding for residential appliance rebates are being leveraged by the Company through a cooperative effort with both states. This is again a sunsetted program opportunity which the Company is leveraging during 2010 and 2011.

    - Washington state is offering ARRA co-funding for the exploration of multijurisdictional resource conservation manager programs. The RCM program is based upon a three-year effort within each jurisdiction.
- Maintain the cost-effectiveness of the DSM overall DSM portfolio, portfolio components and individual measures as appropriate while meeting our resource acquisition obligation.
    - The business planning effort includes a projection of total resource cost-effectiveness and utility cost-effectiveness tests. The contribution of individual measures and programs to these cost-effectiveness tests has also been calculated as part of an iterative planning process. Action plans have been developed to monitor in a timely manner and take appropriate management action within those areas that have been identified as critical during the upcoming year.
    - We have reached an agreement with the Idaho PUC staff, documented within an MOU (attached as Appendix F), regarding our commitment to performing sub-TRC or sub-UCT analysis of individual measures, programs and portfolios. Lacking reasonable causes for exception, the Company plans to offer only cost-effective measures and programs (as well as cost-effectiveness on a broader portfolio perspective). The Company has expanded pre-existing methodologies for sub-TRC cost-effectiveness evaluation and will document, on an annual or more frequent basis, the sub-TRC analysis and the role that it plays in management decision making.
    - Per our understanding with the Idaho PUC staff, Avista will incorporate consideration of the expected net-to-gross ratio within our future calculations of cost-effectiveness and program management with the intent of being TRC cost-effective on a net basis.
    - Avista's resource acquisition obligation is fundamentally to fulfill our role in the acquisition of all cost-effective efficiency measures that can be achieved through utility intervention. General numerical goals established within the integrated resource planning (IRP) process have been fine-tuned and updated at a more detailed level within the business plan.
- Advance the Company's desire to meet customer expectations in regards to our management of greenhouse gas emissions.
    - The DSM portfolio's obligation towards meeting this goal is largely based upon meeting our resource planning obligations.
- Continue to advance the cost-effective pursuit of direct-use of natural gas, as opposed to the indirect-use through the electric generation infrastructure, for our customers and within the region.
    - Avista has and will continue to field direct-use programs for our retail electric customers. We will enhance the outreach for these efforts to the extent that we can identify cost-effective opportunities to do so.
    - We will continue to be vocal in regional forums regarding the wisdom of direct-use based upon the cost-effectiveness, energy-efficiency and greenhouse gas emission minimization that can be achieved through these programs.
        - We will continue to advocate for the inclusion of natural gas resource acquisition into the mission of the Northwest Energy Efficiency Alliance when appropriate to do so.
    - Avista's proposed target under I-937 for 2010-2011 incorporates an additional amount above and beyond that specified within the Northwest Power and Conservation Council (NPCC) 6th Power Plan for acquisition of direct-use efficiencies.
- Maintain support for the level of utility effort and investment required to meet our obligations.

  - Towards this purpose and as part of our MOU with the Idaho PUC staff, the Company will be revising much of our reporting and external communication efforts during 2010. This will consist of a redesign of the annual Triple-E Report and the packaging of multiple documents into a DSM Annual Report package.
  - The Company has formally (in Washington) and informally (in Idaho) committed to maintaining a near-zero tariff rider balance on each of the four fuel and jurisdiction tariff riders. This will be achieved through ongoing management and annually scheduled revisions to the tariff rider. We do not anticipate that this will adversely impact our ability to fund the ongoing pursuit of cost-effective DSM acquisition.
    - It is particularly important to maintain support for revisions to the natural gas tariff rider during 2010. In order to move the expected natural gas tariff rider balances to zero by the close of 2010, a rather significantly negative current tariff rider balance must be offset with increased revenue generated by a revision to the tariff rider. Unfortunately between the time of the effective date of a revised tariff rider, approximately April 1st, and the end of the calendar year there is relatively little consumption within the highly seasonal natural gas annual load profile. This leads to a high volatility in the level of that tariff rider revision.
- Monitor and communicate the impact of the market and general business environment upon Avista's DSM programs and energy-efficiency in general
  - As avoided costs and retail rates generally increase, and as improvements in efficiency opportunities are realized, the acquisition potential and the expense of the DSM portfolio will continue to grow. It is the Company's obligation to communicate these expectations to ensure continued support for these efforts. To do so, it is also important that the Company continue the prudent management of our DSM portfolio, for example, from a cost-effectiveness perspective.
  - Within the near-term, achieving Avista's DSM acquisition goals is complicated by forecasted lower natural gas retail price signals which are inconsistent with forecasted long-term higher avoided cost trends. Specifically, the incorporation of expectations of future carbon costs within the forecasted avoided cost structure has increased the value of the stream of savings coming from an efficiency investment while simultaneously actual purchased gas adjustments to the retail rate have resulted in retail rate decreases. Thus the customer is receiving a price signal indicating that natural gas efficiency measures are relatively less valuable at the same time that the forecasted avoided cost stream upon which Avista bases natural gas DSM acquisition targets is indicating that these efficiency measures are becoming more valuable. This mismatch between the forecasted avoided cost and the customer's recent price signal will make achieving that efficiency target more challenging given that efficiency project funding comes primarily from customers with only a partial offset by utility incentives.
  - Current economic conditions and its influence upon the ability or willingness of customers to invest in efficiency measures has been incorporated within the projections of this business plan. The expectations were based upon December 2009 conditions and were less optimistic than those incorporated within earlier IRP planning processes. Thus meeting the acquisition goals established through those processes will become a more challenging feat.
- Support the cost-effective acquisition of efficiency resources through regional cooperative efforts.
  - Avista has found that the acquisition of efficiency measures, and in particular those found in segments characterized by large numbers of small customers, is often best achieved through cooperative regional market transformation efforts.

The continuation of a viable organization, such as the Northwest Energy Efficiency Alliance (NEEA), to perform this task is critical to meeting our DSM objectives as well as those of the northwest overall.

- NEEA's 13-year history has provided an example for regional market transformation that we believe can be achieved for natural gas utilities as well. Avista has supported an expansion of NEEA's mission to incorporate natural gas and will continue to do so in the future. Lacking the expansion of NEEA, Avista is supportive of either an ad hoc or permanent agreement among regional natural gas utilities to meet this common need.
- Avista has contractually committed to funding NEEA through the 2010-2014 funding cycle. The level of regional funding commitment has doubled (with expenditures subject to board approval) and Avista's share of that regional amount has increased from 4.0% to 5.4%. Increases but not necessarily proportionate levels of acquisition are expected in the long-term, but that increase in acquisition is subject to a lag effect as well as revisions to the allocation of regional savings to individual utilities and jurisdictions. Expectations for 2010 regional acquisition are only slightly higher than 2008 actual claims.

Each of these key issues and Avista's strategy for success will be further outlined within the appropriate portion(s) of the remainder of this business plan.

Washington Natural Gas Decoupling Issues

Jon Powell

Decoupling is a mechanism by which the link between the utility recovery of its revenue requirement and energy throughput is modified to some degree. As a consequence the reliance upon the utilities recovery of fixed costs becomes less dependent upon actual energy sales. From the DSM perspective, by breaking the link between energy sales and fixed cost recovery, the financial disincentive to successfully encouraging energy-efficiency is eliminated.

Avista completed a three-year natural gas decoupling pilot in Washington during 2009. Included in the pilot mechanism was a DSM acquisition trigger; the Company's recovery of tracked fixed margin was subject to achieving DSM acquisition targets identified in the prior IRP. The DSM trigger was based upon a tiered structure allowing for partial recovery for falling short of achieving 100% of the most recent natural gas IRP acquisition target. For purposes of the pilot mechanism, the DSM acquisition target was based upon both Washington and Idaho jurisdictions.

Following the completion of the pilot, the Company applied for and was granted a permanent decoupling mechanism. The terms of that mechanism differ in many ways from those involved in the pilot. In regards to DSM, a trigger mechanism has been retained but it is now based upon Washington-only acquisition in comparison to the Washington jurisdictional share of the most recent natural gas IRP DSM target. If the Company fully meets the DSM acquisition trigger and an earnings trigger, it will recover 45% of tracked fixed margin.

For purposes of the DSM business planning process, the decoupling order has created an increased sense of focus around achieving the acquisition target. As will be outlined later within this plan, the budget currently projects that Company will fall short of the Washington jurisdictional natural gas IRP target by 10.0% in the absence of management intervention over the course of the year. This projection is subject to a significant amount of uncertainty, and it is notable that actual local natural gas acquisition in 2009 exceeded the amount projected in the business plan by 36% as a result of the expansion of federal tax credits and other factors not anticipated during the business plan process. Thus natural gas acquisition should and will be subject to careful monitoring over the course of 2010.

The natural gas decoupling mechanism also comes with the requirement for an independent external review of Avista's acquisition claim. This includes not only a review of EM&V results but also the methodology for extrapolating those results into an acquisition claim for purposes of the decoupling mechanism. This has been incorporated into the EM&V planning process presented within this document.

Lastly, the order for the decoupling mechanism also calls for the establishment of a collaborative process to study improvements that can be made in achieving cost-effective energy-efficiency within the limited income customer segment. At present Avista anticipates that this will be an ongoing process during much of 2010 given the likely need to identify data requirements for future assessment and incorporation of that assessment into a final meaningful product. Ultimately the Company must deliver a report to the WUTC by September 1, 2010.

Washington Initiative 937 Issues

Jon Powell

In 2006 the voters of Washington passed Initiative 937 (I-937) requiring all utilities within the state of Washington with more than 25,000 retail customers to (1) meet 15% of their native load growth with qualifying renewable generation by 2020 with that percentage increasing in subsequent years and (2) acquire electric-efficiency resources equal to or exceeding either those identified in the Northwest Power and Conservation Council's (NPCC) Power Planning process or their own Integrated Resource Plan (IRP). These two requirements are entirely separable. For purposes of the DSM Business Plan we will be dealing with the second of these requirements only.

The utility electric acquisition requirements are evaluated biennially starting in 2010 (e.g. a 2010-2011 compliance period, a 2012-2013 compliance period and so on). The initiative establishes the expectation that the utility will acquire the conservation resources identified as cost-effective over a ten-year horizon. Failure to achieve these requirements will result in a $50 per mWh penalty.

I-937 gives utilities the option of using the NPCC Power Plan or their own IRP to establish the biennial I-937 acquisition goal. If they elect to use their IRP, they must demonstrate that the methodology is "consistent" with the Power Plan.

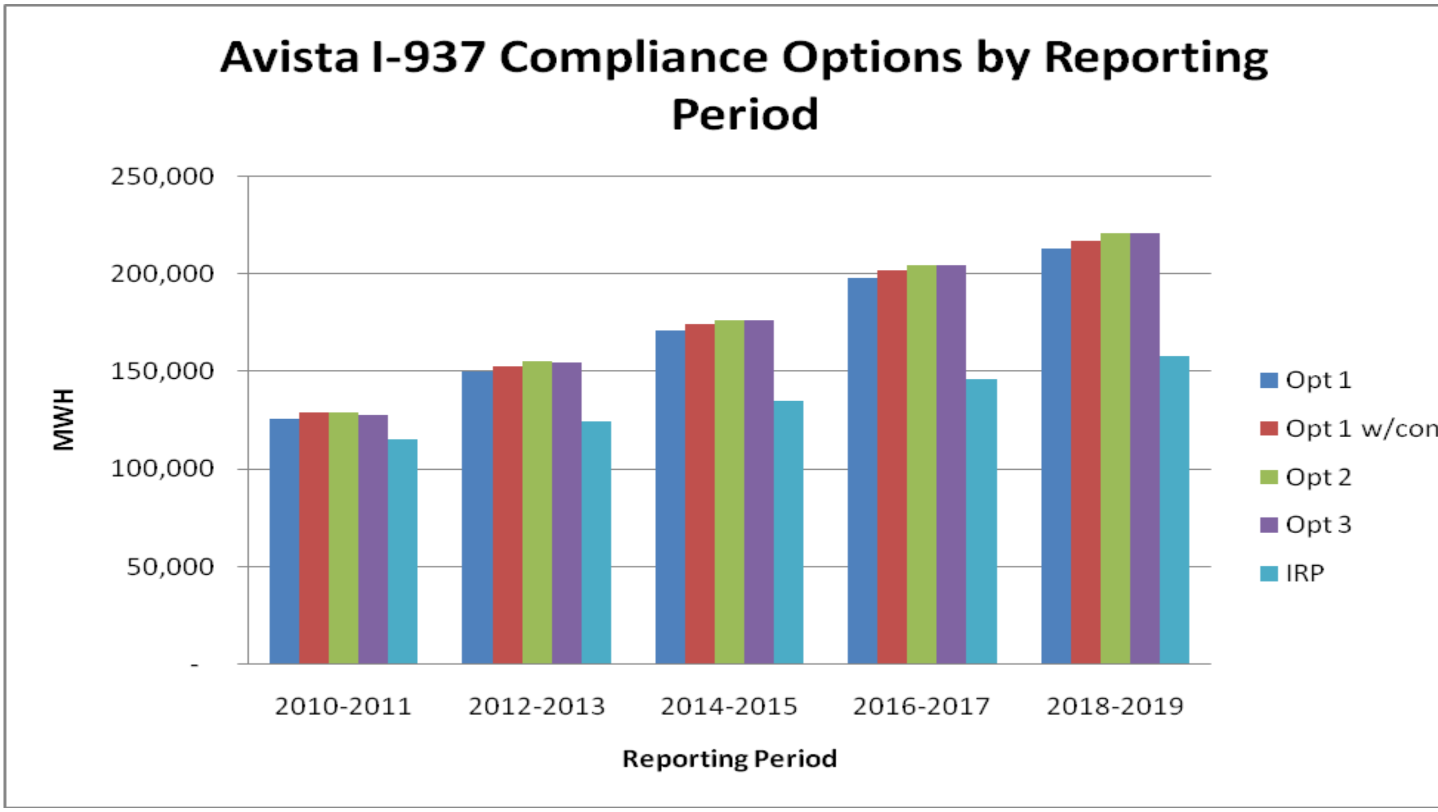
Avista has chosen to utilize the NPCC's 6th Power Plan results for the first 2010-2011 compliance period. The NPCC's allocation of 6th Power Plan conservation acquisition targets offer three options with different levels of aggregation of the regional target by customer segment (residential, commercial, industrial, irrigated agriculture etc). Avista has chosen to use the most aggregated of those options, option #1, which specifies an overall level of acquisition from all customer segments. This acquisition is divided, for Avista, into Washington and Idaho jurisdictions. For purposes of I-937 only the Washington jurisdictional requirement would be applied. The 2010 NPCC 6th Power Plan option #1 for Avista's Washington service territory is 59,991 mWh's, as of the time that this business plan was written. This amount ramps up by over 14% in 2011 creating a total acquisition requirement of 128,577 for the total 2010-2011 I-937 compliance period.

Avista has chosen to use the 6th Power Plan alternative in this first compliance period due to uncertainties over the requirement to demonstrate methodological consistency between the NPCC methodology and Avista's IRP methodology in the event that the IRP methodology was selected. Specifically, we are concerned about differences between our approach to the acquisition from our non-residential site-specific program versus that used in the 6th Power Plan. Under our non-residential site-specific program, all efficiency measures qualify for incentives. This allows us to pursue efficiency technologies that couldn't be anticipated within the biennial IRP process and certainly not within the 10 year or 20 year forecast of DSM acquisition. Consequently we project these unknown efficiency technologies by extrapolating from historic experience and adjusting for expected load growth, price elasticity and other factors. In completing the 6th Power Plan the NPCC has greater resources, a broader regional scope and longer five year cycle that allow for the evaluation of more individual measures in greater detail.

The WUTC's WAC 480-109 provides the flexibility to select a different option for future compliance periods based upon the circumstances prevailing at that time. Given the biennial IRP cycle, the five-year NPCC Power Plan process and the biennial and ten-year I-937 requirement, it may be necessary to reconsider the timeliness and applicability of these alternative plans differently in the future.

Another notable difference between the 6th Power Plan and Avista's electric DSM programs is the treatment of electric to natural gas conversions (also known as 'direct use of natural gas'). By law, the NPCC cannot incorporate these into the Power Plan as electric efficiency resources. Avista does, however, include them in our electric DSM portfolio. Consequently we are proposing to add the 2,595 mWh's of electric to natural gas conversions anticipated to the 2010-2011 acquisition target

Below is a graphical representation of the acquisition targets for three options offered under the 6th Power Plan for Avista's Washington service territory, including a variant of Option #1 with an additional acquisition target for electric-to-natural gas conversions, and Avista's IRP targets. These have been calculated for the next five two-year compliance periods.



Avista is proposing that the results of each two-year I-937 compliance period be treated on a cumulative basis as we move forward. In the first compliance period, 2010-2011, the cumulative treatment will be inconsequential. In later compliance periods, it is Avista's intent to measure the cumulative qualifying acquisition (or failure to acquire for which a penalty has been paid) against the cumulative goal for that same period of time using the target designated at the beginning of the prior compliance period (either the NPCC Power Plan or the IRP). This approach eliminates creating a disincentive for the utility to defer acquisition in excess of the target within any individual compliance period in order to preserve that conservation potential for later time periods. We believe this to be good public policy given the frequency in recent years of 'windows of opportunity' to cost-effectively exceed acquisition targets and accelerate conservation acquisition in general.

Qualifying acquisition that Avista intends to apply towards the conservation target can be categorized as follows:

- Traditional Avista electric-efficiency measures installed at the sites of our retail customers.

- The current draft of the 6th Power Plan includes energy savings resulting from non-specialty compact fluorescent lamps in all applications, at least for the 2010-2011 period.
- Quantifiable energy savings resulting from behavioral measures associated with Resource Conservation Manager activities.
- Quantifiable behavioral savings resulting from any informational campaigns that the utility may run to include, but not necessarily limited to, energy information displays available to the customer through in-home displays or the internet, billing inserts or other forms of energy consumption information sent to the customer with recommendations for efficiency measures and so on.
- Direct-use programs promoting the use of natural gas usage in place of electric usage where this results in an improvement of the BTU efficiency of the overall system. A symmetric appropriate adjustment to the acquisition target will be made as well.

- Avista's share of energy savings obtained through regional, cooperative utility or other market transformation efforts. At the moment this is limited to the Northwest Energy Efficiency Alliance. It is Avista's intent to apply the best estimate of the savings that has occurred within our Washington jurisdiction towards the conservation target. This amount will include non-specialty CFL acquisition tracked by NEEA during the 2010-2011 compliance period in the event that the final approved 6th Power Plan incorporates this as a qualifying measure for that time period.
  - Avista also intends to include any quantifiable market transformation impact resulting from our Multifamily Direct-Use Program towards the conservation target. Acquisition resulting from other as yet undefined non-regional market transformation efforts would also be considered as being eligible for I-937.
- Distribution efficiency measures including, but not limited to, voltage control, high-efficiency transformers and similar improvements. These conservation savings within this category will occur both on the customer and the utility side of the meter.
  - Distribution efficiency savings are a significant component of the conservation potential identified within the draft 6th Power Plan. Thus the inclusion of these savings within Avista's claim is appropriate.
- The Washington Administrative Code also allows the inclusion of "electricity savings from new high-efficiency cogeneration facilities" located at the site of our retail customers. At the moment, Avista does not expect any such installations within our service territory.

Since the 6th Power Plan identification of the conservation target includes natural adoption, it is Avista's intent to include not only all quantifiable programmatic energy savings, but also any quantifiable non-programmatic savings resulting from efficiency measures included in the Power Plan. At a minimum we will seek to quantify the sale of qualifying CFL's within Avista's service territory regardless of participation in utility programs.

In the event that there are improvements in energy codes or federal manufacturing standards within any individual two-year compliance period, it is Avista's intent to claim energy savings based upon the baseline that was in existence at the beginning of that time period. In subsequent compliance periods we would propose to symmetrically revise the conservation target and baseline as appropriate.

It is understood that an adequate quantification of claimed savings is required as part of this process. Plans for providing that quantification are detailed within the Evaluation, Measurement and Verification section of this document and a more specific planning timeline is included in Appendix D.

It is Avista's intent to meet the conservation acquisition requirement as opposed to the alternative of paying administrative penalties. Thus we regard the acquisition target established by I-937 as a floor for our Washington acquisition. Given our intent to treat the acquisition and target in future compliance periods on a cumulative basis, we will pursue any opportunities to exceed the acquisition level that may present itself during this period.

In planning for DSM activities within 2010 we have not found the acquisition floor to be a constraint. The budget expectation for 2010 acquisition exceeds that comparable I-937 goal (NPCC option #1 plus electric to natural gas conversions) by 11%. However, there is a significant increase in that target between 2010 and 2011. The expected 2010 acquisition is only 6% above the average acquisition necessary for the two-year (2010-2011) compliance period.

Since Avista is not expecting the need to initiate any additional DSM activities specifically designed to meet the I-937, we do not expect the need to study the issue of offering programs within our Washington requirements and not within our Idaho jurisdiction. Avista has long sought to keep any jurisdictional distinctions between programs to an absolute minimum given the nature of the communications across state lines.

Avista will seek the ongoing support from key stakeholders for revisions to the DSM tariff rider necessary to meet I-937 requirements and provide for timely cost-recovery of the related expenses.

Contemplated Revisions to DSM Operating (Schedule 90 and 190) Tariffs
Jon Powell

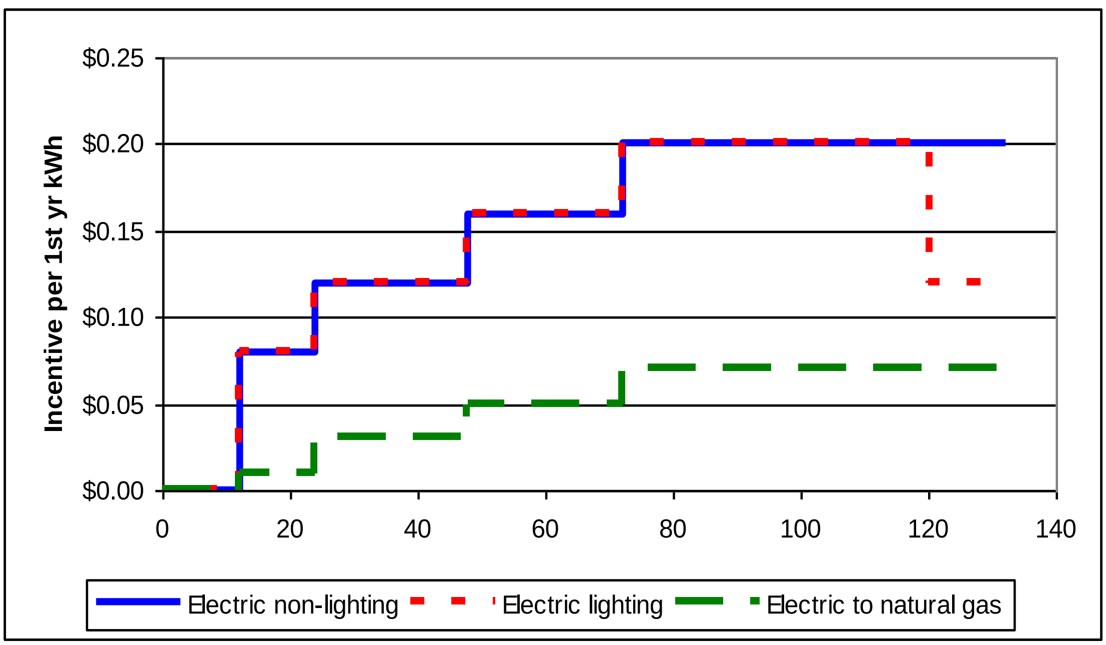
Avista's authorization to conduct and fund Washington and Idaho DSM activities is based upon tariffs establishing the DSM surcharge funding mechanism (Schedules 91 and 191 for electric and natural gas respectively) and tariffs governing how Avista implements our DSM programs (Schedules 90 and 190 for electric and natural gas respectively, plus Schedule 96 governing our Idaho demand-response pilot program). (The text of these tariffs are attached as Appedix B to this document).

Within this section we will project our plans for proposed revisions to these tariffs during 2010 and the reasoning behind them. We will use the periodic updates to the Triple-E Board and our Triple-E meetings to further discuss these revisions. Naturally all of these revisions are subject to regulatory approval, a process by which all stakeholders will have the opportunity to comment.

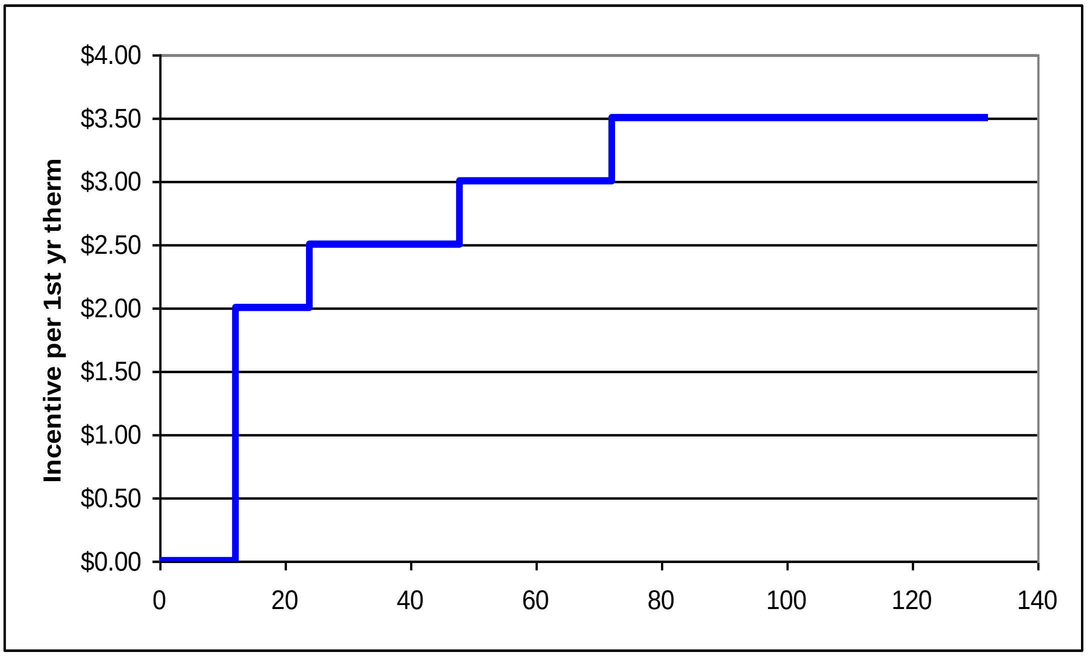
Schedules 90 and 190
Avista's Schedules 90 and 190 governs how the utility implements our electric and natural gas DSM programs. It specifies qualifying efficiency measures, establishes a tiered incentive structure guiding our rebate levels and establishes exceptions where the utility can substantially deviate from those levels. Avista's electric to natural gas conversion programs are considered an electric DSM measure and are therefore included within the scope of Schedule 90.

In early 2008 the Company was granted a revision in the Schedule 90 incentive levels to that represented within the chart below:

Avista' Electric DSM Incentive Schedule (Idaho and Washington)



Avista's Natural Gas DSM Incentive Schedule (Idaho and Washington)



As part of the business planning process program managers, and others, are tasked with the duty of developing the best approach to realize cost-effective efficiency opportunities. The approach to these opportunities is not constrained by current regulation; instead it is our intent to propose revisions to the tariffs if necessary to deliver our programs as effectively as possible. It was concluded during the business planning process that no revisions to the incentive tiers were considered necessary.

The only revision contemplated for Schedule 90 is the elimination of incentives for renewable generation in both jurisdictions. This issue has been under discussion with stakeholders over the past year including a dedicated discussion of the issue in the September 2009 meeting of the Triple-E Board. The consensus, both within the Company as well as among stakeholders, is that these technologies are not cost-effective under any of the standard practice tests nor are they likely to become cost-effective in the near future. Furthermore it is generally believed that the incentive is not a motivating factor in the customer adoption decision.
Consequently Avista is planning to propose a revision to Schedule 90, in both Washington and Idaho, to exclude the incentive support for this technology. At the same time, we do plan on continuing to offer technical support and customer education to assist the customer in reaching an informed decision.

<u>Schedule 96 (Idaho only)</u>

This tariff authorized Avista to complete a two-year demand-response pilot. The intent of the program was to improve our understanding of demand-response technology and customer acceptance. This effort, and how it will be transitioning into much larger efforts funded through other mechanisms, is outlined in the Demand Response Portfolio description contained within this document.

Summary of the 2010 DSM Acquisition Projections

Jon Powell

The core objective of the Avista DSM team is to field a portfolio of DSM measures that meets our obligation to acquire cost-effective efficiency resources. Since our acquisition targets are established through IRP processes and/or regional power planning processes based upon generally the same cost-effectiveness criteria as are applied in our program evaluations, the portfolio should also meet the acquisition targets established for purposes of Washington I-937 and natural gas decoupling compliance. Historically we have generally found that our business planning process generally leads to identifying a very slightly higher level of acquisition than the less detailed IRP and regional power planning processes; a consequence that we believe is the result of the optimization of programs that is possible when the efficiency portfolio is evaluated at a greater degree of detail.

The aforementioned process establishes a linkage between acquisition targets, realistically achievable acquisition and post-project cost-effectiveness analysis. Barring unforeseen events, timing issues or other unanticipated disconnects in the planning process there is an analytical consistency that lead to the creation of goals which are challenging yet achievable. Throughout the 2010 business planning process several factors have been identified which create an unusually high degree of slippage in these calculations. The most significant factors include:

- macroeconomic conditions that are less favorable to efficiency acquisition than were previously projected in the planning processes,
- significant downward retail rate adjustments from purchased gas adjustments (PGA) that reduce the participant cost-effectiveness of efficiency measures and consequently consumer willingness to participate in utility DSM programs,
- a general disconnect between retail price signals and the avoided cost forecast and
- the impact of the American Recovery and Reinvestment Act (ARRA).

The impact of general economic conditions has significantly impacted the quantity of new construction and the willingness of developers to undertake the incremental investment necessary for the installation of efficiency measures. The impact upon residential and non-residential retrofit efficiency opportunities are both adversely affected. Our current (December 2009) expectation of the local economic conditions in 2010 are less optimistic than those that were incorporated into the 2009 natural gas and electric IRP's forecast completed much earlier in the year. This will adversely impact our ability to reach electric and natural gas acquisition targets.

The two issues relating to retail rate impacts and their relationship to the avoided cost structure are relevant to natural gas acquisition only.

The purchased gas adjustments effective during 2010 do not impact the total resource cost-effectiveness or utility cost effectiveness of the portfolio, which are the two most frequently referenced cost-effectiveness perspectives. The PGA also does not impact long-term retail rate savings from an efficiency investment, thus the impact upon the long-term participant and non-participant cost-effectiveness tests is insignificant. However, customer perceptions of the return on their investment are very largely driven by the current rate, including short-term PGA adjustments. Since Avista's efficiency programs generally fund a maximum of 50% and an average of about 1/3rd of the incremental customer cost, we are heavily reliant upon the customers' willingness to fund the majority of the efficiency investment. The expectations relied upon within this business plan are based upon the most recent information regarding 2010 retail rates to establish estimates of 2010 acquisition.

The 2010 PGA adjustments are only one part of a disconnect between the avoided cost streams used for determining the cost-effectiveness of natural gas efficiency measures and the retail price signal being sent to our customers. The avoided cost stream includes a rather significant expected future carbon cost in the calculation of the benefits to be derived from investments in natural gas efficiency. This acts to increase the avoided cost and move the level of efficiency acquisition that is cost-effective up along the supply curve to a higher levels. However, the expectation of future carbon costs is not monetized within the current retail rate price signal that our customers are reacting to within the market. Thus we are faced with the prospect of pursuing a goal that is based upon the expectation of reducing future carbon costs, yet the majority of the funding for those investments must come from customers who have not and are not seeing any price signal related to that cost.

The factors adversely impact the Company's ability to meet targets listed above are partially offset by the 2010 availability of residential tax credits and a local jurisdiction co-funded (through Energy Efficiency Community Block Grants) residential audit program. Currently only three jurisdictions, all within Washington, are involved in the co-funding of the residential audit program.

The net result upon the most current outlook for DSM acquisition during 2010 is modestly favorable on the electric side but not as positive for natural gas DSM.

Note that the acquisition targets listed below include a 2010 I-937 target as well as a 2010-2011 average I-937 target. The I-937 target calculation chosen by Avista is based upon an NPCC estimate of cost-effective acquisition which contains a significant ramp up from 2010 to 2011. Thus it has been recommended that performance relative to this target be based upon the average acquisition necessary to meet this goal during the first two-year I-937 compliance period rather than the 2010-only target.

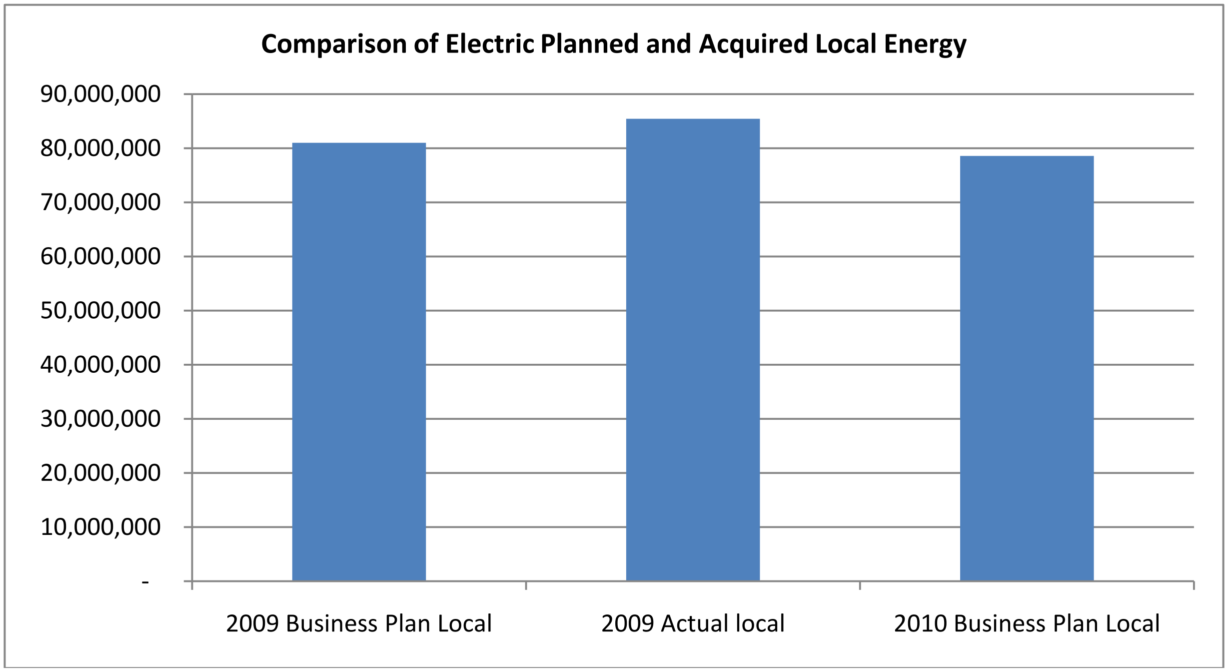
Summary of Acquisition Relative to Targets

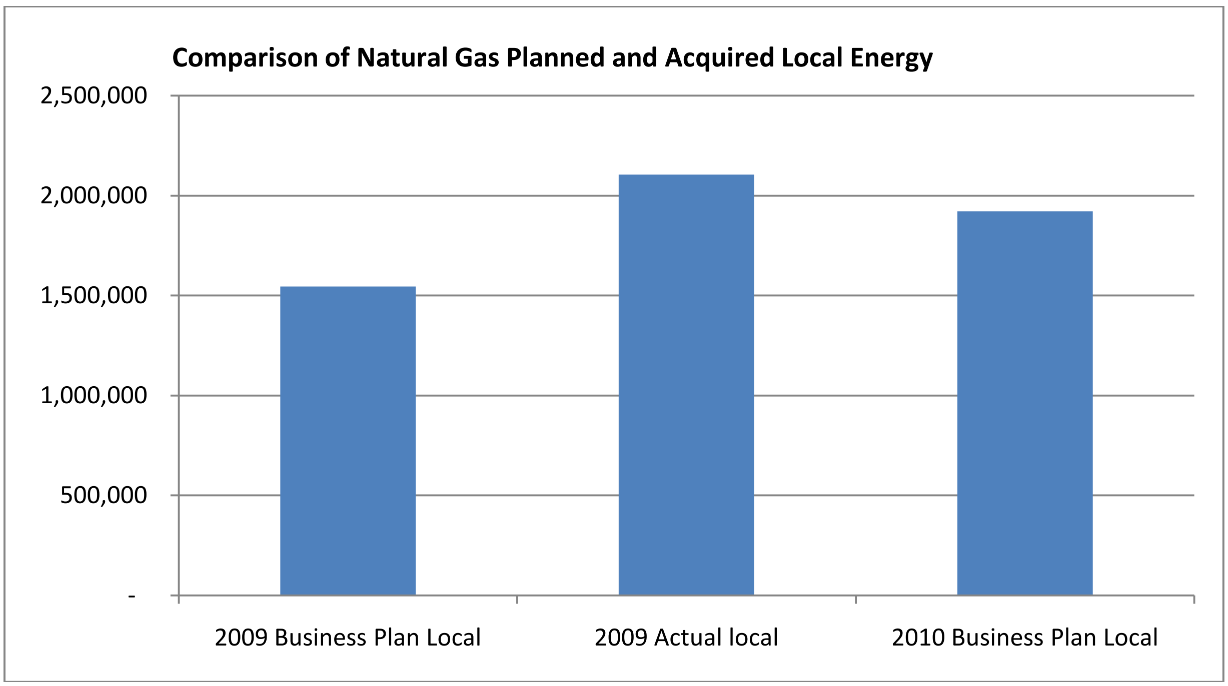
	kWh or therm target	Expected acquisition	over (under)	% over (under)
Electric IRP	91,104,000	98,461,533	7,357,533	8.1%
Washington I-937 2010	61,276,024	67,915,272	6,639,248	10.8%
WA I-937 2010-2011 avg	64,288,422	67,915,272	3,626,849	5.6%
Natural gas IRP	2,193,338	1,921,488	(271,850)	-12.4%
WA natural gas decoupling	1,542,529	1,385,606	(156,923)	-10.2%

The notable electric vs. natural gas differential relative to the target amounts is driven by the short-term impact of the PGA upon expected customer demand.

It is critical to note that energy-efficiency markets are in a period of flux for a variety of reasons, to include general economic trends as well as energy-industry specific issues, and a number of the factors identified as critical to 2010 performance are subject to significant uncertainty. Thus it should be understood that these estimates are subject to wide confidence intervals.

Comparing 2010 Business Plan local acquisition projections to tentative 2009 actual local acquisition, we are projecting an 8% reduction in electric acquisition and a 9% reduction in natural gas acquisition. We are forecasting that the Company will exceed the average electric acquisition necessary to meet the 2010-2011 I-937 compliance period but, lacking adjustments during the year, we will not fully meet the Washington decoupling natural gas acquisition target.





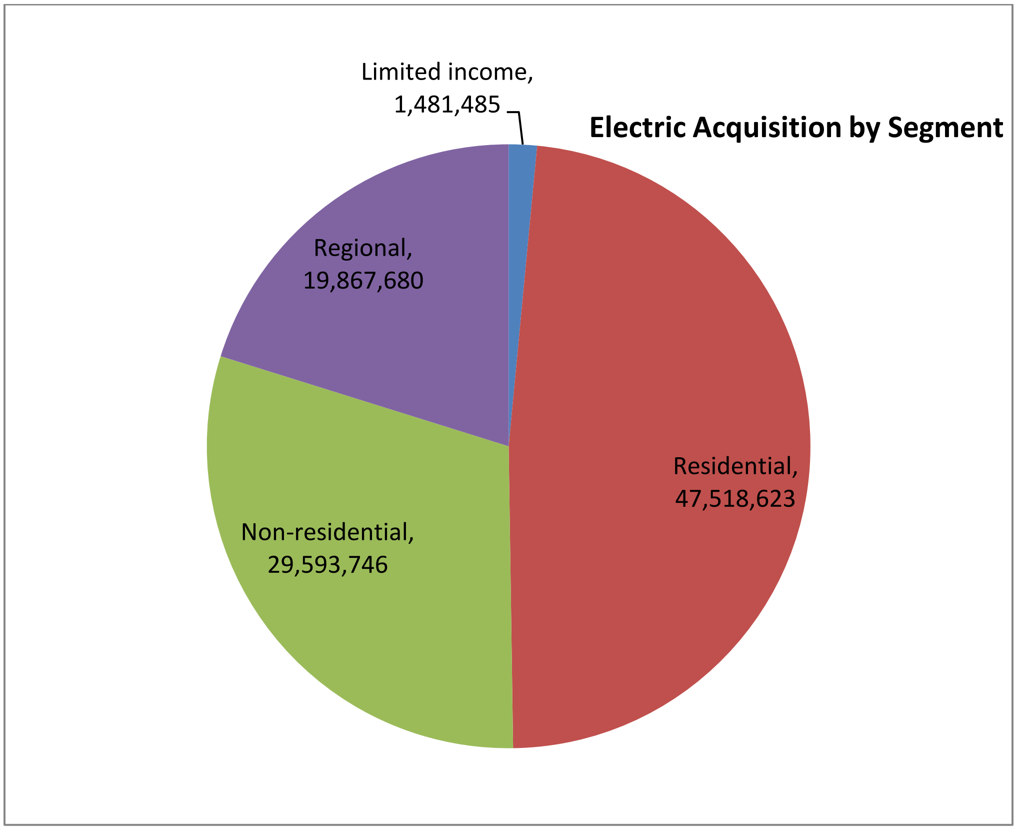
The estimates above do not include the impact of Northwest Energy Efficiency Alliance (NEEA) market transformation ventures within Avista's service territory. Though the funding for NEEA is doubling from $20 million per year to $40 million per year for the five year funding cycle commencing in 2010, Avista is not anticipating a significant increase in regional acquisition to occur during 2010 due to the inherent lag between investment and acquisition for market transformation ventures. Historically Avista's has claimed a 4.0% share of regional acquisition based upon our NEEA funding share in spite of the recognition that we are presently approximately 5½% of regional end use sales. Starting in 2010 NEEA will be performing a more detailed analysis of where energy savings actually occur by jurisdiction and utility service territory. The Company's business plan projects that 2.3 amW (19.9 million kWh's) will be credited to Avista during 2010.

The Company is also planning on continuing a discussion initiated in 2008 regarding the quantification and allocation of natural gas efficiency savings achieved from regional (NEEA) electric market transformation programs. Based upon these discussions an estimate of 50,000 therms of regional acquisition was included in the Company's 2009 DSM Business Plan. These savings are tracked by NEEA for the purpose of calculating cost-effectiveness, but they have historically not been attributed to individual service territories. Avista's intent is to quantify and claim an estimate of the natural gas savings resulting from projects such as residential windows, resource-efficient washing machines and the like. This may be a challenging proposition given the time that NEEA staff is devoting towards developing a new methodology for allocating electric savings for the 2010-2014 funding cycle.

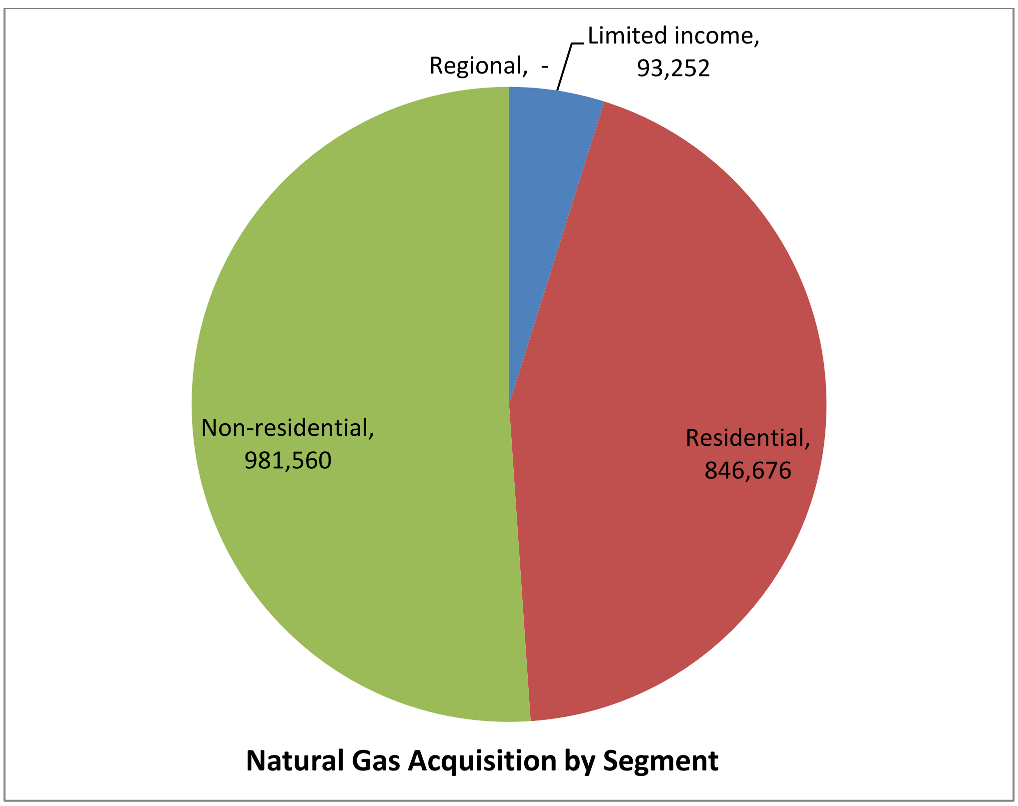
In addition to meeting overall acquisition targets in a cost-effective manner, the Company has long had the objective of ensuring that all customers contributing to the funding of DSM activities with the opportunity to obtain commensurate benefits. Preferably these benefits would come in the form of direct participation in programs with the customer benefiting from the receipt of incentives as well as, and more importantly, the realization of cost-effective energy efficiency savings. The opportunities for large benefits through direct participation is somewhat limited by the reality that major residential end-use appliances have a fairly long lifespan. Direct benefits through smaller and more frequently replaced measures effectively fill in many of those gaps. The realization of direct benefits by our customers has increased substantially as a result of both a general expansion of DSM efforts as well as a disproportionate increases in the residential component of the portfolio.

The realization of indirect benefits by individual customers through program participation by governmental agencies, employers or a general economic benefit is more uniformly distributed across both customer classes and over time. Given the strong historical and current participation of governmental, commercial and industrial customers in Avista's programs these indirect benefits are of significance in the Company's effort to provide broad coverage of the DSM portfolio.

The 2010 expectation of energy savings within the various customer segments is continuing the recent trend towards stronger residential participation. In 2010 the local portfolio, excluding NEEA acquisition, is expected to obtain 48% of the electric and 44% of the natural gas savings from the residential segment. This does not include electric savings of 2% and natural gas savings of 5% in the limited income segment. The expectations of NEEA performance is based upon the best current information available to us as at this point in the business planning process.



Electric Acquisition by Segment
Limited income, 1,481,485
Residential, 47,518,623
Non-residential, 29,593,746
Regional, 19,867,680



Regional, -
Limited income, 93,252
Residential, 846,676
Non-residential, 981,560
Natural Gas Acquisition by Segment

In 2010 the residential savings will be significantly influenced by the launch of the new residential audit program. This program is expected to complete 2,000 audits in 2010 and an additional 4,000 audits in 2011. The savings generated from this program include the results of behavioral actions and directly-installed efficiency measures, but a large percentage of the savings will come from recommendations leaded to participation in other Avista residential programs for shell, space and water heating appliances and ‘white goods’.
The JACO program for the removal and salvage of second refrigerators and freezers in residential homes will continue into 2010 (with a program extension to be evaluated as contract termination approaches based upon past and expected future program performance).

The UCONS contract for the direct-installation, at no customer cost, of efficiency measures in multifamily housing came to a termination at the end of 2009. The activity in 2010 will be limited to the completion of program commitments made in the prior year. This program has been extremely successful in reaching one of the Company’s most difficult to reach customer segments, the tenant population and particularly those of less than median income.
The Company is planning to continue the distribution of compact fluorescent lamps (CFL’s) during 2010 through our Geographic Saturation and Energy Conservation in Schools programs (participation in local community events with an educational message and physical CFL distribution) and a PECI contract for a more general residential distribution of CFL’s. As of the date of the completion of this business plan, it is expected that this measure will be incorporated into the NPCC 6^{th} Power Plan and will thus be an allowable measure for I-937 acquisition compliance for the 2010-2011 timeframe. Avista’s portfolio is not strongly reliant upon CFL acquisition, for 2010 local CFL programs are expected to account for only 5% of total acquisition and 7% of regional acquisition.

During 2010 the Company will also carry out a collaborative to examine concepts to evaluate and seek new approaches to improving the benefits provided through the limited income portfolio. This collaborative process will include the Triple-E Board and other stakeholders as appropriate. Though the collaborative was a WUTC-ordered requirement from the 2009 Washington general rate case, the Company will incorporate Washington and Idaho limited income issues into the process. A report on the results of the collaborative is due by September 1, 2010, the timing of which will allow the results to be included in the development of the 2011 DSM business plan.

Within the non-residential segment it is the small commercial customer market that has been the most persistently difficult segment to penetrate. The prescriptive lighting program is broadly applicable to small commercial customers and it will continue to be the largest opportunity for these customers to benefit from the DSM portfolio. Past attempts to leverage regional commercial HVAC maintenance programs into our service territory to augment the lighting program within this segment has proceeded through several phases. Many of these transitions related to changes or terminations of regional programs. During 2010 Avista will be performing an HVAC maintenance technical pilot project to determine the measures and energy savings that can be obtained from an entirely local program. Based upon these efforts a revised prescriptive HVAC program may be launched in 2011.

Summary of the 2010 DSM Cost-Effectiveness Projections

Jon Powell

Avista has historically evaluated the actual cost-effectiveness performance in the prior year within the annual Triple-E Report. This cost-effectiveness calculations from the total resource cost test (TRC), utility cost test (UCT), participant test and the non-participant test (also known as the rate impact measure test) perspectives are contained within that report. The analysis is applied to the total electric and natural gas portfolio, the electric and gas portfolio independently, and the regular-income and limited-income portfolios. Additional evaluations by market segment and technology are performed, but the small sample size at that level of disaggregation and the subjectivity of cost allocations usually render these results less informative.

Within the DSM business planning process the prospective cost-effectiveness of the future years programs are calculated. The emphasis within the business planning process is upon the TRC test, since it is nearly always more difficult than the UCT to pass. (The UCT is calculated for those programs where it is potentially the more challenging test to pass). The participant test and variants upon that test are used primarily as a means to developing intuition leading to estimates of customer response, throughput and target markets. DSM programs, unless they are very low in fixed cost and targeted for under-priced energy products (e.g. very heavily on-peak usage) are mathematically certain to fail the non-participant test. The objective of the non-participant test in determining the adverse rate impact upon the non-participating customer is largely rendered moot if the Company is successful in broad customer participation.

These cost-effectiveness calculations are performed on the electric, natural gas and combined fuel portfolios. Additional evaluations of "sub-TRC" cost-effectiveness are made by program or measure as necessary over the course of the year as well as within the business plan. The sub-TRC test determines if a measure contributes to the overall TRC cost-effectiveness of a program or portfolio. This evaluation is also performed annually as part of the evaluation of the incremental cost-effectiveness of outreach efforts and for the targeting of those efforts.

A summary of the calculation of the DSM standard practice cost-effectiveness tests is contained in Appendix G.

For the 2010 planning effort, and in response to agreements made as part of the MOU with the Idaho PUC staff (attached as Appendix F) the Company has substantially expanded the cost-effectiveness evaluation that is performed as part of the business planning process. The evaluation performed for this business plan includes an evaluation of sub-TRC tests by individual measure, by program and by fuel portfolio. At the measure and program level those costs which were considered incremental to the measure or program were incorporated into the evaluation. At the fuel portfolio and combined fuel portfolio level all TRC costs were included. Overall over 470 individual measures were evaluated. These measures were aggregated into 39 programs generating energy savings. Additional support and infrastructure programs were incorporated into the budget and aggregated into electric, natural gas and combined fuel portfolios.

The Idaho PUC staff MOU included the agreement to differentiate between the gross customer participation within the Company's DSM programs and net participation (those customers who would have not adopted the measure in the absence of the program). The completion of the discussion with the Idaho PUC staff did not permit Avista the opportunity to perform a net-to-gross study for this business planning process. In place of estimates of the net-to-gross ratio of individual measures and programs, Avista performed sensitivities of measures, programs and portfolios to various levels of net participation. This has provided important information on the sensitivity to net-to-gross ratio and confirmed the primary determinants of that sensitivity, information which will be used in program management during 2010.

The Company has long agreed to perform TRC cost-effectiveness with and without the inclusion of offsetting tax credits. In past years there have been very few such tax credits (or similar forms of governmentally funded support for the incremental cost of efficiency measures). This has changed markedly for 2010 due to the availability and widespread use of residential tax credits, support for the residential audit programs through Energy Efficiency Community Block Grants from cooperating local jurisdictions and Washington State support (obtained through the American Recovery and Reinvestment Act) for the planned multijurisdictional Resource Conservation Manager program. Thus, in 2010, there is expected to be a material difference between the TRC cost-effectiveness of programs with and without tax credits.

As a consequence of the measure-specific evaluation a significant number of measures were found to be cost-ineffective under the sub-TRC test (or, in a few cases, the sub-UCT test when appropriate). Generally the measures that failed the sub-TRC analysis had relatively low throughput and their immediate or planned termination didn't materially affect the overall portfolio cost-effectiveness. This correlation between poor sub-TRC performance and measure throughput is likely to be a persistent given that the TRC cost-effectiveness is moderately well correlated to participant cost-effectiveness and therefore the customer's willingness to adopt the measure.

The protocol established for the business planning process called for the termination of cost-ineffective measures at the earliest possible opportunity barring a compelling reason for retaining the measure in the portfolio. Few of the measures that failed the cost-effectiveness test are planned to be permanently retained within the portfolio. Those that are expected to be retained are usually the result of difficulties in separating a non-cost-effective measure from other closely related cost-effective measures. This may call for some degree of redefinition of these measures in the future.

The timing of the termination of those measures that have been found to be cost-ineffective was often dependent upon the requirement to provide notice of changes in the program, the need to revise collateral material and contractual or similar agreements. These considerations could delay termination for between two months or, in the case of contractual agreements, up to two years. The Company is committed to the termination of these programs at the first opportunity.

Avista does have one local market transformation program in process; a direct-fuel program intended to influence the choice of fuel in new multifamily construction. The first phase of that transformation effort involves the provision of incentives up to 100%, significantly beyond the 50% cap for most Avista progams. Since the TRC test does not consider transfer costs, such as incentives, this program does pass the sub-TRC test without the need to incorporate any transformation savings into the calculation. Since the average incentive cost is slightly less than the customer incremental cost the program also passes the sub-UCT test. In 2011 it may become necessary to consider these transformational benefits as the venture shifts to later phases that involve decreased per unit utility incentive expenditure and increased non-incentive (educational) utility support as part of a transition to an exit strategy.

Those measures within the limited income portfolio that were found to be non-cost-effective will be integrated into the new, for 2009, process of restricting the authority of limited income agencies to install measures to those that have been 'deemed'. The measures deemed under the program are those that are cost-effective in the majority of circumstances. Other measures not on the deemed list of measures can be completed upon request of the Community Action Agency, but only upon Avista's approval. Avista has established a tracking tool to evaluate the combined fuel cost-effectiveness of the limited income portfolio on a monthly basis over the course of the year to monitor this portfolio more closely. Consequently those limited income measures that were determined to be cost-ineffective will be incorporated within the more detailed cost-effectiveness analysis performed for that portfolio within 2010 and beyond.

As measures were aggregated into programs additional costs become incremental to the cost-effectiveness evaluation. Generally speaking, the inclusion of an additional measure is rarely significant enough to warrant the need for additional utility infrastructure, barring payments to administrators performing implementation tasks for the utility (such as with the UCONS multifamily program and the JACO refrigerator recycling program). However, at the program level the quantity of utility infrastructure support is large enough to require the recognition of those costs. These incremental costs were predominantly labor costs. In total 57% of labor costs were assigned to individual programs and incorporated into their cost-effectiveness evaluation, with the remainder of the labor costs being recognized only at the portfolio level.

The following tables summarize the cost-effectiveness of the overall electric, natural gas and combined portfolios using the TRC and UCT tests at various net-to-gross scenarios. The TRC test is calculated with and without the use of tax credits as offsets to customer incremental cost.

SUMMARY OF TRC COST-EFFECTIVENESS @ 100% net participation vs. gross participation

	Electric	Gas	Total
Electric avoided cost	$ 50,762,504	$ 125,945	$ 50,888,450
Natural gas avoided cost	$ (427,400)	$ 14,880,388	$ 14,452,989
Non-energy benefits	$ 4,311,458	$ 2,520,349	$ 6,831,807
Total TRC benefits	$ 54,646,563	$ 17,526,682	$ 72,173,245
Customer incremental cost	$ 25,539,581	$ 14,590,988	$ 40,130,569
Non-incentive local utility cost	$ 3,587,715	$ 2,568,193	$ 6,155,909
Offsetting tax credits	$ (1,028,018)	$ (1,814,730)	$ (2,842,748)
Total TRC costs	$ 28,099,279	$ 15,344,452	$ 43,443,730
Net TRC cost (with tax credits)	$ 26,547,284	$ 2,182,230	$ 28,729,515
TRC B/C (with tax credits)	1.94	1.14	1.66
Net TRC cost (without tax credits)	$ 25,519,267	$ 367,500	$ 25,886,767
TRC B/C (without tax credits)	1.88	1.02	1.56

SUMMARY OF UCT COST-EFFECTIVENESS @ 100% net participation vs. gross participation

	Electric	Gas	Total
Electric avoided cost	$ 50,762,504	$ 125,945	$ 50,888,450
Natural gas avoided cost	$ (427,400)	$ 14,880,388	$ 14,452,989
Total UCT benefits	$ 50,335,105	$ 15,006,333	$ 65,341,438
Incentive local utility cost	$ 11,242,882	$ 6,116,106	$ 17,358,988
Non-incentive local utility cost	$ 3,587,715	$ 2,568,193	$ 6,155,909
Total UCT costs	$ 14,830,598	$ 8,684,299	$ 23,514,897
Net UCT benefit	$ 35,504,507	$ 6,322,034	$ 41,826,542
UCT B/C ratio	3.39	1.73	2.78

The above table are based upon a presumption that the number of net customers adopting the measure equals total program participation. Thus it is assumed that "non-net" participants are offset by customers adopting the measure as a result of the program, but were not captured as program participants. (The potential for customers being influenced by a utility program but not becoming a documented program participant may occur through local transformational effects upon retail stocking patterns, trade ally awareness and similar program influences. A certain percentage of these customers will fail, for one reason or another, to submit an application for an incentive).

The calculations above indicate that all portfolios would pass both the UCT test and the TRC test, with and without the inclusion of tax credits, though the natural gas TRC's are marginally above 1.00.

SUMMARY OF TRC COST-EFFECTIVENESS @ 75% net participation vs. gross participation

	Electric	Gas	Total
Electric avoided cost	$ 38,071,878	$ 94,459	$ 38,166,337
Natural gas avoided cost	$ (320,550)	$ 11,160,291	$ 10,839,741
Non-energy benefits	$ 3,233,594	$ 1,890,261	$ 5,123,855
Total TRC benefits	$ 40,984,922	$ 13,145,011	$ 54,129,934
Customer incremental cost	$ 19,154,686	$ 10,943,241	$ 30,097,927
Non-incentive local utility cost	$ 3,587,715	$ 2,568,193	$ 6,155,909
Offsetting tax credits	$ (771,013)	$ (1,361,047)	$ (2,132,061)
Total TRC costs	$ 21,971,388	$ 12,150,387	$ 34,121,775
Net TRC cost (with tax credits)	$ 19,013,534	$ 994,624	$ 20,008,159
TRC B/C (with tax credits)	1.87	1.08	1.59
Net TRC cost (without tax credits)	$ 18,242,521	$ (366,423)	$ 17,876,098
TRC B/C (without tax credits)	1.80	0.97	1.49

SUMMARY OF UCT COST-EFFECTIVENESS @ 75% net participation vs. gross participation

	Electric	Gas	Total
Electric avoided cost	$ 38,071,878	$ 94,459	$ 38,166,337
Natural gas avoided cost	$ (320,550)	$ 11,160,291	$ 10,839,741
Total UCT benefits	$ 37,751,329	$ 11,254,750	$ 49,006,079
Incentive local utility cost	$ 11,242,882	$ 6,116,106	$ 17,358,988
Non-incentive local utility cost	$ 3,587,715	$ 2,568,193	$ 6,155,909
Total UCT costs	$ 14,830,598	$ 8,684,299	$ 23,514,897
Net UCT benefit	$ 22,920,731	$ 2,570,451	$ 25,491,182
UCT B/C ratio	2.55	1.30	2.08

The above table depicts that the cost-effectiveness of all portfolios are adversely impacted by the assumption that those influenced by the utility program to adopt the measure equal to only 75% of documented program participants. This net-to-gross ratio is sufficient to bring the natural gas portfolio TRC, without the inclusion of tax credits, to a slightly cost-ineffective level. The portfolios are cost-effective on all other measures.

SUMMARY OF TRC COST-EFFECTIVENESS @ 50% net participation vs. gross participation

	Electric	Gas	Total
Electric avoided cost	$ 25,381,252	$ 62,973	$ 25,444,225
Natural gas avoided cost	$ (213,700)	$ 7,440,194	$ 7,226,494
Non-energy benefits	$ 2,155,729	$ 1,260,174	$ 3,415,903
Total TRC benefits	$ 27,323,281	$ 8,763,341	$ 36,086,622
Customer incremental cost	$ 12,769,791	$ 7,295,494	$ 20,065,285
Non-incentive local utility cost	$ 3,587,715	$ 2,568,193	$ 6,155,909
Offsetting tax credits	$ (514,009)	$ (907,365)	$ (1,421,374)
Total TRC costs	$ 15,843,497	$ 8,956,322	$ 24,799,819
Net TRC cost (with tax credits)	$ 11,479,785	$ (192,982)	$ 11,286,803
TRC B/C (with tax credits)	1.72	0.98	1.46
Net TRC cost (without tax credits)	$ 10,965,776	$ (1,100,347)	$ 9,865,429
TRC B/C (without tax credits)	1.67	0.89	1.38

SUMMARY OF UCT COST-EFFECTIVENESS @ 50% net participation vs. gross participation

	Electric	Gas	Total
Electric avoided cost	$ 25,381,252	$ 62,973	$ 25,444,225
Natural gas avoided cost	$ (213,700)	$ 7,440,194	$ 7,226,494
Total UCT benefits	$ 25,167,552	$ 7,503,167	$ 32,670,719
Incentive local utility cost	$ 11,242,882	$ 6,116,106	$ 17,358,988
Non-incentive local utility cost	$ 3,587,715	$ 2,568,193	$ 6,155,909
Total UCT costs	$ 14,830,598	$ 8,684,299	$ 23,514,897
Net UCT benefit	$ 10,336,955	$ (1,181,132)	$ 9,155,823
UCT B/C ratio	1.70	0.86	1.39

At a net-to-gross ratio of 50%, as shown in the above tables, the natural gas portfolio becomes slightly cost-ineffective on the TRC test even with the inclusion of tax credits. Additionally, the natural gas UCT test also falls below 1.00.

It is notable that the higher sensitivity of the UCT test to variations in the net-to-gross ratio has caused a substantial reduction in the differential between the TRC and UCT tests. This is the result of the inclusion of the utility incentive for non-net participants within the UCT test (given that it is an actual utility cost regardless of the customer motivations) while the customer incremental cost is excluded from the TRC costs for “non-net” customers.

SUMMARY OF TRC COST-EFFECTIVENESS	@ 25% net participation vs. gross participation		
	Electric	Gas	Total
Electric avoided cost	$ 12,690,626	$ 31,486	$ 12,722,112
Natural gas avoided cost	$ (106,850)	$ 3,720,097	$ 3,613,247
Non-energy benefits	$ 1,077,865	$ 630,087	$ 1,707,952
Total TRC benefits	$ 13,661,641	$ 4,381,670	$ 18,043,311
Customer incremental cost	$ 6,384,895	$ 3,647,747	$ 10,032,642
Non-incentive local utility cost	$ 3,587,715	$ 2,568,193	$ 6,155,909
Offsetting tax credits	$ (257,004)	$ (453,682)	$ (710,687)
Total TRC costs	$ 9,715,606	$ 5,762,258	$ 15,477,864
Net TRC cost (with tax credits)	$ 3,946,035	$ (1,380,587)	$ 2,565,447
TRC B/C (with tax credits)	1.41	0.76	1.17
Net TRC cost (without tax credits)	$ 3,689,030	$ (1,834,270)	$ 1,854,760
TRC B/C (without tax credits)	1.37	0.70	1.11

SUMMARY OF UCT COST-EFFECTIVENESS	@ 25% net participation vs. gross participation		
	Electric	Gas	Total
Electric avoided cost	$ 12,690,626	$ 31,486	$ 12,722,112
Natural gas avoided cost	$ (106,850)	$ 3,720,097	$ 3,613,247
Total UCT benefits	$ 12,583,776	$ 3,751,583	$ 16,335,360
Incentive local utility cost	$ 11,242,882	$ 6,116,106	$ 17,358,988
Non-incentive local utility cost	$ 3,587,715	$ 2,568,193	$ 6,155,909
Total UCT costs	$ 14,830,598	$ 8,684,299	$ 23,514,897
Net UCT benefit	$ (2,246,821)	$ (4,932,716)	$ (7,179,537)
UCT B/C ratio	0.85	0.43	0.69

As shown in the above table, with only 25% of program participants being “net” for purposes of this evaluation, not only does the natural gas portfolio fail both the TRC and UCT tests by a substantial margin, but the electric and combined fuel portfolio also fail the UCT test. Note that at this level of net-to-gross ratio the typical relationship between the UCT and TRC test has reversed (the UCT B/C ratio is higher than the TRC B/C) for all portfolios.

The analysis of these net-to-gross scenarios is informative but, at a portfolio level, not particularly operational. The implementation strategies necessary to obtain healthy net-to-gross ratios are generally only meaningful at the program or measure level. All measures and programs were evaluated for the same four net-to-gross ratios indicated above. The 39 energy-acquiring programs for whom the net-to-gross ratio is meaningful are represented below, first in a table summarizing energy acquisition and cost to establish the relative size and importance of a program within the larger portfolios and then in a table summarizing their TRC B/C ratios (with and without tax credits) at varying net-to-gross ratios.

An analysis of individual line items aggregating to the overall budget, including those for which no energy acquisition is directly attributed, is contained below. This summary provides detail behind the budget levels and acquisition weighting of the individual components making up the overall portfolio.

	First-year kWh's	First-year therms	Customer direct incentives $	Non-labor / non-incentive $	Labor $	Total utility budget
LI appliances	24,360	-	$ 29,186	$ -	$ 801	$ 29,988
LI fuel conversion	1,324,316	-	$ 360,556	$ -	$ 43,566	$ 404,122
LI HVAC efficiency	-	861	$ 27,841	$ -	$ 28	$ 27,870
LI shell	131,869	92,281	$ 1,358,399	$ -	$ 7,374	$ 1,365,772
LI water heating efficiency	940	110	$ 19,138	$ -	$ 35	$ 19,172
HEALTH & HUMAN SAFETY	-	-	$ 105,170	$ -	$ -	$ 105,170
Energy Smart Grocer Program	6,000,000	-	$ 736,329	$ -	$ 95,643	$ 831,972
Nonres LEED	-	-	$ -	$ -	$ -	$ -
Nonres retrocommissioning	-	-	$ -	$ -	$ -	$ -
Nonres rooftop maintenance	-	-	$ -	$ -	$ -	$ -
Nonres traffic lights	67,035	-	$ 4,800	$ -	$ 1,069	$ 5,869
Nonres vending machines	9,000	-	$ 900	$ -	$ 143	$ 1,043
P food service	499,280	29,875	$ 89,600	$ -	$ 8,435	$ 98,035
P network computers	24,000	-	$ 2,000	$ -	$ 383	$ 2,383
P new equipment upgrades	-	-	$ -	$ -	$ -	$ -
P Non-res clotheswashers	31,013	850	$ 10,000	$ -	$ 508	$ 10,508
P Nonres lighting	11,550,000	-	$ 1,933,265	$ 300	$ 150,397	$ 2,083,962
P retrofit equipment upgrades	243,831	-	$ 21,600	$ -	$ 3,887	$ 25,487
P VFDs	2,053,264	-	$ 143,643	$ -	$ 50,613	$ 194,256
Steam Trap Replacement	-	9,151	$ 5,100	$ -	$ 146	$ 5,246
Green Motors	17,245	-	$ 2,250	$ -	$ 275	$ 2,525
Elec. to NG Water Heater Conversion	6,574	-	$ 300	$ -	$ 105	$ 405
Side Stream Filtration	381,000	-	$ 54,000	$ -	$ 6,073	$ 60,073
Demand Controlled Ventilation	7,892	608	$ 1,000	$ -	$ 135	$ 1,135
Site-Specific (electric)	26,000,000	-	$ 4,160,000	$ -	$ 677,584	$ 4,837,584
Site-Specific (gas)	-	785,000	$ 2,355,000	$ -	$ 31,704	$ 2,386,704
Resource Conservation Manager	353,488	21,193	$ -	$ 50,000	$ 41,704	$ 91,704
Premium Efficiency Motors	275,000	-	$ 42,842	$ -	$ -	$ 42,842
General C/I Forms, Brochures etc.	-	-	$ -	$ 7,000	$ -	$ 7,000
Multifamily	1,301,684	-	$ 300,908	$ -	$ 10,099	$ 311,007
Res appliances	1,062,600	26,800	$ 360,000	$ 4,600	$ 23,835	$ 388,435
Res Energy Star Home	368,650	16,548	$ 108,550	$ 209	$ 2,988	$ 111,747
Res fuel conversion	2,152,981	-	$ 113,250	$ 526	$ 16,703	$ 130,479
Res HVAC efficiency	8,016,338	358,914	$ 2,144,200	$ 4,531	$ 64,976	$ 2,213,707
Res lighting	4,800,000	-	$ 262,500	$ 60,000	$ 37,239	$ 359,739
Res refrig recycling	2,026,500	-	$ 105,000	$ 385,000	$ 27,834	$ 517,834
Res shell	5,032,707	477,834	$ 1,981,325	$ 4,653	$ 42,751	$ 2,028,730
Res water heating efficiency	118,910	7,182	$ 47,000	$ 81	$ 978	$ 48,059
Solar	-	-	$ -	$ -	$ -	$ -
UCONS contract	429,330	-	$ -	$ -	$ 3,331	$ 3,331
Wind	-	-	$ -	$ -	$ -	$ -
Trees	2,088	-	$ 1,800	$ 400	$ 16	$ 2,216
Residential Audit (electric)	3,897,958	-	$ 226,746	$ 117,634	$ 266,412	$ 610,792
Residential Audit (winter gas)	-	89,247	$ 215,881	$ 78,914	$ 6,100	$ 300,894
Residential Audit (annual gas)	-	5,035	$ 7,909	$ 4,452	$ 344	$ 12,705
Energy Conservation Schools Program	64,000	-	$ 3,500	$ 10,000	$ 13,064	$ 26,564
Geographic saturation	320,000	-	$ 17,500	$ 20,000	$ 39,739	$ 77,239
Positive Energy-type program	-	-	$ -	$ -	$ -	$ -
On-Bill Financing	-	-	$ -	$ -	$ -	$ -
Northwest Energy Efficiency Alliance	19,867,680	-	$ -	$ 2,160,000	$ -	$ 2,160,000
Demand Response - DCUs (pilot)	-	-	$ -	$ 5,000	$ -	$ 5,000
RTF funding	-	-	$ -	$ 73,000	$ -	$ 73,000
DSM Outreach	-	-	$ -	$ 644,000	$ -	$ 644,000
EPRI	-	-	$ -	$ 52,000	$ -	$ 52,000
E-Source	-	-	$ -	$ 45,000	$ -	$ 45,000
CEE	-	-	$ -	$ 6,800	$ -	$ 6,800
Travel & training	-	-	$ -	$ 50,000	$ -	$ 50,000
Other expenses (Triple-E mtgs etc)	-	-	$ -	$ 9,190	$ -	$ 9,190
M&E	-	-	$ -	$ 1,000,000	$ -	$ 1,000,000
Nexus	-	-	$ -	$ 64,000	$ -	$ 64,000
IRP Technical Potential Study	-	-	$ -	$ 100,000	$ -	$ 100,000
Labor	-	-	$ -	$ -	$ 1,280,662	$ 1,280,662
TOTAL	98,461,533	1,921,488	$ 17,358,988	$ 4,957,290	$ 2,957,679	$25,273,957

Of the 62 individual budget line items listed above, 39 of the line items refer to 36 programs which directly generate 2010 energy savings (the site-specific and residential audit program are broken out into two and three individual components respectively). Residential audits are split amount three line items and site-specific is split into two line items for evaluation purposes. There are two budget line items not included in the count of energy acquisition program, the Washington Department of General Administration and Quantum Engineering RFP contract payments, that are payments for past energy acquisition programs. These 36 programs compose $19.7 million (78%). The remaining $5.6 million (22%) of the 2010 budget funds the infrastructure and support for those programs.

Based upon the costs and energy savings above the sub-TRC, cost-effectiveness of the 2010 energy acquisition programs were calculated, as summarized in the table below. The calculations include 100%, 75%, 50% and 25% net-to-gross ratio scenarios as well as calculations with and without the use of tax credits as offsets to customer incremental cost.

In reviewing the less cost-effective programs contained in the table below several issues were identified that may mitigate how the future of these programs are addressed during 2010.

- It should be noted that the limited income portfolio has a mechanism in place for both deemed and individually approved projects. Thus the program cost-effectiveness within that portfolio is subject to improvement without discontinuance of an entire program. While some of these improvements could be made during the year, the deemed measures are revised on an annual basis only.
- The Resource Conservation Manager program is a minimum two year effort. Calendar year 2010 will contain less than twelve months of that effort. The energy savings realized in the second year of the program is likely to be higher. Much of the first year will be focused upon preparing the database and identifying ‘hardwired’ projects and behavioral savings programs. Thus the cost-effectiveness presented within this table is less than that of the a longer-term vision of the program.
- There is a degree of uncertainty within premium efficiency motor program in the timing, nature and impact of code revisions. This uncertainty does significantly impact the cost-effectiveness evaluation.
- Note that the three line items composing the residential audit would generally be aggregated, though there is some potential for fine-tuning the individual components of that program. The two line items of the site-specific program are much more separable but are functionally designed into a single program.

Energy acquiring programs only	100% net TRC w/o tax credits	100% net TRC w tax credits	75% net TRC w/o tax credits	75% net TRC w tax credits	50% net TRC w/o tax credits	50% net TRC w tax credits	25% net TRC w/o tax credits	25% net TRC w tax credits
LI appliances	0.86	0.86	0.85	0.85	0.82	0.82	0.75	0.75
LI fuel conversion	2.84	2.84	2.71	2.71	2.50	2.50	2.01	2.01
LI HVAC efficiency	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
LI shell	1.31	1.31	1.30	1.30	1.29	1.29	1.27	1.27
LI water heating efficiency	1.95	1.95	1.92	1.92	1.86	1.86	1.71	1.71
Energy Smart Grocer Program	1.37	1.37	1.24	1.24	1.06	1.06	0.73	0.73
Nonres traffic lights	18.14	18.14	17.68	17.68	16.82	16.82	14.68	14.68
Nonres vending machines	1.98	1.98	1.93	1.93	1.84	1.84	1.62	1.62
P food service	1.44	1.44	1.43	1.43	1.40	1.40	1.32	1.32
P network computers	2.14	2.14	2.07	2.07	1.95	1.95	1.66	1.66
P Non-res clotheswashers	5.81	5.81	5.76	5.76	5.66	5.66	5.38	5.38
P Nonres lighting	1.06	1.06	1.05	1.05	1.03	1.03	0.97	0.97
P retrofit equipment upgrades	2.68	2.68	2.62	2.62	2.49	2.49	2.17	2.17
P VFDs	3.20	3.20	3.06	3.06	2.83	2.83	2.29	2.29
Steam Trap Replacement	2.00	2.00	1.99	1.99	1.98	1.98	1.93	1.93
Green Motors	1.70	1.70	1.66	1.66	1.60	1.60	1.43	1.43
El. to NG Water Heater Conversion	18.90	18.90	16.17	16.17	12.55	12.55	7.50	7.50
Side Stream Filtration	0.99	0.99	0.98	0.98	0.97	0.97	0.93	0.93
Demand Controlled Ventilation	1.95	1.95	1.91	1.91	1.83	1.83	1.64	1.64
Site-Specific (electric)	3.63	3.63	3.51	3.51	3.30	3.30	2.79	2.79
Site-Specific (gas)	1.56	1.56	1.56	1.56	1.55	1.55	1.53	1.53
Resource Conservation Manager	0.86	0.86	0.64	0.64	0.43	0.43	0.21	0.21
Premium Efficiency Motors	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
Multifamily	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77
Res appliances	0.71	0.92	0.70	0.92	0.70	0.91	0.69	0.90
Res Energy Star Home	1.56	1.97	1.56	1.96	1.55	1.95	1.52	1.91
Res fuel conversion	2.84	2.84	2.81	2.81	2.75	2.75	2.59	2.59
Res HVAC efficiency	1.53	1.57	1.52	1.56	1.50	1.54	1.46	1.49
Res lighting	5.99	5.99	5.44	5.44	4.59	4.59	3.12	3.12
Res refrig recycling	1.10	1.10	0.82	0.82	0.55	0.55	0.27	0.27
Res shell	0.94	1.21	0.94	1.21	0.94	1.20	0.93	1.19
Res water heating efficiency	2.05	2.05	2.04	2.04	2.01	2.01	1.93	1.93
UCONS contract	2.17	2.17	2.15	2.15	2.12	2.12	2.02	2.02
Trees	0.86	0.86	0.86	0.86	0.85	0.85	0.84	0.84
Residential Audit (electric)	1.61	1.74	1.43	1.54	1.18	1.25	0.77	0.79
Residential Audit (winter gas)	1.02	1.15	0.94	1.04	0.81	0.88	0.57	0.60
Residential Audit (annual gas)	0.62	0.67	0.58	0.63	0.53	0.56	0.40	0.42
Energy Cons. Schools Program	1.61	1.61	1.27	1.27	0.89	0.89	0.47	0.47
Geographic saturation	2.36	2.36	1.90	1.90	1.37	1.37	0.74	0.74

The table above illustrates the differences in sensitivity of the various programs to the net-to-gross ratio. Those programs with very low utility fixed program cost are relatively insensitive to the net-to-gross ratio; customers who are excluded from the TRC calculation as “non-net” remove not only all of their TRC benefits but, if there is no fixed non-incentive utility cost, all of their TRC costs as well. Thus these programs aren’t impacted by changes in the net-to-gross ratio.

It’s important to realize that only 57% of the labor costs and very little other infrastructure costs were considered incremental to the incorporation of any particular program within the portfolio.

Thus the cost-effectiveness calculations above reflect the ability of individual programs to contribute to the cost-effectiveness of the larger portfolio. The net cost-effectiveness from this set of programs must fully offset the additional costs that are non-incremental to the individual programs for the overall portfolio to be cost-effective. Avista's practice of minimizing fixed program cost and maximizing the proportion of utility expenses that are returned to customers in the form of direct incentives have *historically* led to a relative insensitivity to the net-to-gross ratio at both the program and portfolio level. Changes in this trend carry with it both the opportunity for increased acquisition as well as several forms of cost-effectiveness risk; all of which calls for careful management during 2010.

Not specifically included within this document is the sub-TRC calculation of the 470 measures within these 39 line items covering 36 individual programs. These evaluations included the same net-to-gross ratio and tax credit sensitivities presented above for the overall programs. Several of the measures that did not pass the sub-TRC evaluation are planned for termination, but the Company's ability to terminate such programs is subject to practical timing rigidities such as customer notice, implementation strategy and contractual and other agreements for those measures. Some such measures have been committed to for as long as two years and others scheduled for near-immediate termination. Thus the beneficial impact of the measure-by-measure analysis will be phased in over a longer period of time that the above 2010 cost-effectiveness analysis.

Measures that are being considered for addition to the portfolio are traditionally subjected to a sub-TRC evaluation as part of the discussion of the measure and/or program. Inputs to the cost-effectiveness calculation are often revised as the program matures, and this can lead to a program that was anticipated to be cost-effective becoming cost-ineffective upon later evaluation. The most frequent unknown is the level of actual energy savings acquired from the application of an efficiency measure based upon improved engineering estimates and/or impact EM&V. An additional very significant uncertainty for purposes of the calculations above is the net-to-gross ratios that the programs and portfolios will be evaluated at the end of the year. The impact of the uncertainties, and particularly those arising from impact evaluations, will be addressed during the year. Specifically, program managers have committed to triggering a cost-effectiveness re-evaluation when improved information affecting the cost-effectiveness analysis becomes available.

Summary of the 2010 DSM Budget Projections

Jon Powell

Establishing an expenditure budget for 2010 is necessary for corporate budgeting purposes, use in projecting tariff rider surcharge requirements, cost-effectiveness and general infrastructure planning. Expenditures relative to the budget are tracked on a monthly basis over the course of the year, but this does not prohibit the potential for exceeding the budget for prudent DSM investments presuming reasonable cost-recovery.

Customer response and opportunities for prudent DSM resource investments have in recent years contributed to a tendency to exceed the budgets established within the business planning process. The high profile of energy-efficiency and ever increasing customer response has created what has become a fairly persistent tendency for unexpected opportunities to arise during the year. This has led to the $11.9 million negative (customer owes shareholder) aggregate tariff rider balance at the close of 2009 for the Company's two fuels and two jurisdictions. (Expectations for revisions to Schedule 91 and 191 are further discussed in the Contemplated Revisions to DSM Tariffs and the Tariff Balance & Tariff Surcharge Projections sections of this document). For 2010 the Company is planning upon proposing a $2 million contingency fund to be included in the Washington electric tariff rider revisions to be filed on February 15th, 2010. This budget does not reflect that contingency fund nor how (or if) it would be expended during the year. The funding is simply a placeholder that would allow for the pursuit of unanticipated opportunities while simultaneously meeting the commitment to return the tariff rider balance to zero by December 31st, 2010.

An overall Washington / Idaho (electric and natural gas) DSM budget of $25.3 million has been developed based upon the business planning effort. Relative to 2009 actual expenditures this is a 7% ($1.8 million) decrease in the overall budget. However, the aforementioned persistent unanticipated opportunities for cost-effective investment resulted in actual expenditures exceeding the budgeted expenditures by 17% during that year. Thus the inclusion of a $2 million contingency fund would bring the 2010 budget to only $0.2 million (1%) above the 2009 actual expenditure level, as illustrated in the table below:

	WA E	ID E	WA G	ID G	Total
2009 actual expenditures	$ 13,544,504	$ 4,997,387	$ 6,109,174	$ 2,417,327	$ 27,068,392
2010 budgeted expenditures	$ 12,385,350	$ 5,574,777	$ 5,236,202	$ 2,077,627	$ 25,273,957
2010 budget less 2009 actual expenditures ($)	$ (1,159,154)	$ 577,390	$ (872,972)	$ (339,700)	$ (1,794,435)
2010 budget less 2009 actual expenditures (%)	-9%	12%	-14%	-14%	-7%
2009 budgeted expenditures	$ 12,822,057	$ 5,172,502	$ 3,620,219	$ 1,586,624	$ 23,201,401
2009 favorable (unfavorable) variance	$ (722,447)	$ 175,115	$ (2,488,955)	$ (830,703)	$ (3,866,991)
2009 favorable (unfavorable) variance	-6%	3%	-69%	-52%	-17%
				Contingency budget line item	$ 2,000,000
				2010 budget with contingency vs. 2009 actual $	$ 205,565
				2010 budget with contingency vs. 2009 actual %	1%

Note that the degree of uncertainty reflected in the 2009 expenditure variance is significantly greater for natural gas programs than they are for electric programs. It has been determined that there is a preference for managing to reach the natural gas IRP and decoupling acquisition targets through tightly targeting for more cost-effective programs and projects rather than addressing the shortfall through a general ramp-up of programs. This decision is based upon the need for simultaneously managing the tariff rider balance towards zero over a short period of time coinciding with a seasonable low usage period and the need to improve the cost-effectiveness of the natural gas portfolio.

The Company is projecting that we will achieve the 2010 IRP acquisition target as well as the 2010-2011 I-937 acquisition levels while returning the tariff riders towards zero without an excessive revision in the tariff rider surcharge. Thus contingency funds will be employed only if there is the prospect for cost-effective electric resource acquisition, and particularly if these prospects are of a lost opportunity nature.

Avista has traditionally evaluated the budget at the beginning and during the year based upon several standardized disaggregations. The categorization is designed to provide the necessary information for managing the key issues mentioned throughout this document. The usual categorizations are as follows:

- By fuel and jurisdiction, creating four separate budgets for Washington electric, Washington natural gas, Idaho electric and Idaho natural gas. This categorization is primarily used for tariff rider balance projections.
- By functional category, traditionally consisting of three categories; (1) incentives, (2) non-incentives and (3) non-incentive/non-labor.

- By portfolio segment; non-residential, residential, limited income, demand response, distributed generation, regional efforts and common expenses.

Using those tools Avista's 2010 DSM budget can be summarized in the following tables.

The overall DSM budget expenditures are broken out by individual tariff rider and functional category as follows:

2010 Aggregate DSM Budget

	Electric		Gas		
	WA electric	Idaho electric	Washington gas	Idaho gas	Total
Incentives	$ 7,656,119	$ 3,586,763	$ 4,356,614	$ 1,759,491	$ 17,358,988
Non-incentive, non-labor	$ 2,969,609	$ 1,307,321	$ 504,817	$ 175,542	$ 4,957,290
Labor	$ 1,759,623	$ 680,693	$ 374,770	$ 142,593	$ 2,957,679
Total	$ 12,385,350	$ 5,574,777	$ 5,236,202	$ 2,077,627	$ 25,273,957

For comparison purposes, the 2009 actual DSM expenditures and the 2009 budgeted expenditures are contained in the tables below:

2009 Aggregate DSM Actuals

	Electric		Gas		
	WA electric	Idaho electric	Washington gas	Idaho gas	Total
Incentives	$9,649,940	$3,362,318	$5,078,846	$1,929,139	$20,020,243
Non inc / Non Labor	$2,686,315	$1,095,286	$329,615	$150,517	$4,261,733
Labor	$1,208,249	$539,783	$700,713	$337,671	$2,786,416
Total	$13,544,504	$4,997,387	$6,109,174	$2,417,327	$27,068,392

2009 Aggregate DSM Budget

	Electric		Gas		
	WA electric	Idaho electric	Washington gas	Idaho gas	Total
Incentives	$ 9,972,639	$ 3,939,974	$ 3,104,460	$ 1,364,041	$ 18,381,115
Non inc / Non Labor	$ 1,732,232	$ 753,734	$ 236,462	$ 102,884	$ 2,825,312
Labor	$ 1,117,186	$ 478,794	$ 279,297	$ 119,699	$ 1,994,975
Total	$ 12,822,057	$ 5,172,502	$ 3,620,219	$ 1,586,624	$ 23,201,401

The 2010 budget for each of the three functional categories by portfolio is shown below. Notably the regional portfolio non-labor cost has increased by $1.36 million between 2009 and 2010 reflecting the increased level of NEEA funding and revisions in the allocation of that funding responsibility throughout the region for the 2010-2014 funding cycle.

2010 Direct Customer Incentives

	Electric		Gas		
	WA electric	Idaho electric	Washington gas	Idaho gas	Total
Non-residential	$ 4,832,969	$ 2,318,886	$ 1,695,448	$ 715,327	$ 9,562,630
Residential	$ 2,127,260	$ 911,877	$ 2,075,623	$ 781,308	$ 5,896,068
Limited Income	$ 695,890	$ 356,001	$ 585,544	$ 262,855	$ 1,900,290
Demand Response	$ -	$ -	$ -	$ -	$ -
Distributed Gen	$ -	$ -	$ -	$ -	$ -
Regional	$ -	$ -	$ -	$ -	$ -

Common	$ -	$ -	$ -	$ -	$ -
Total	$ 7,656,119	$ 3,586,763	$ 4,356,614	$ 1,759,491	$ 17,358,988

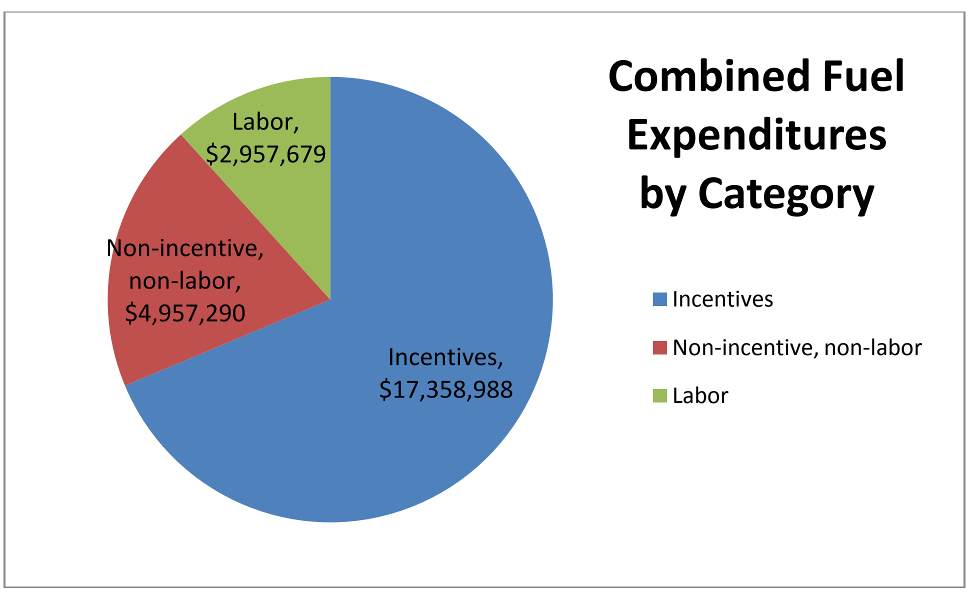
2010 Non-Labor, Non-Incentive Funding

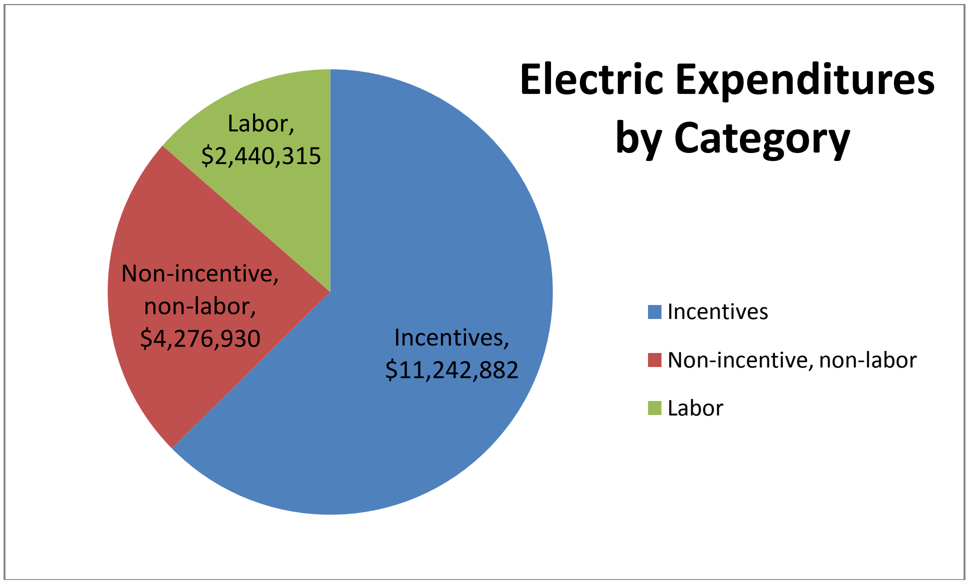
	Electric		Gas		
	WA electric	Idaho electric	Washington gas	Idaho gas	Total
Non-residential	$ 43,582	$ 1,718	$ 11,407	$ 593	$ 57,300
Residential	$ 440,821	$ 154,049	$ 92,201	$ 3,929	$ 691,000
Limited Income	$ -	$ -	$ -	$ -	$ -
Demand Response	$ -	$ 5,000	$ -	$ -	$ 5,000
Distributed Gen	$ -	$ -	$ -	$ -	$ -
Regional	$ 1,459,651	$ 700,349	$ -	$ -	$ 2,160,000
Common	$ 1,025,555	$ 446,205	$ 401,210	$ 171,020	$ 2,043,990
Total	$ 2,969,609	$ 1,307,321	$ 504,817	$ 175,542	$ 4,957,290

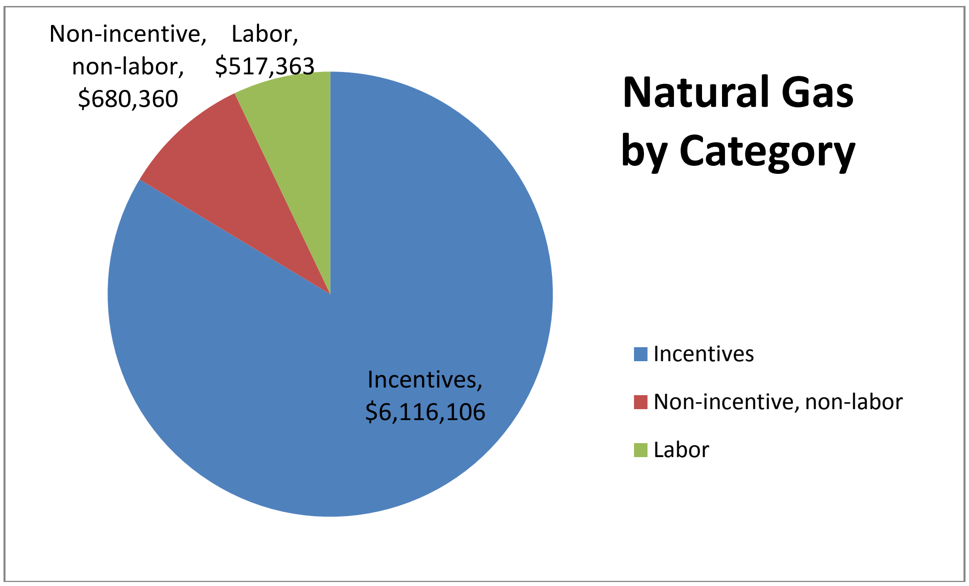
2010 Labor Funding

	Electric		Gas		
	WA electric	Idaho electric	Washington gas	Idaho gas	Total
Non-residential	$ 711,562	$ 322,533	$ 25,110	$ 9,599	$ 1,068,803
Residential	$ 453,120	$ 89,584	$ 11,551	$ 2,155	$ 556,410
Limited Income	$ 32,934	$ 15,802	$ 2,157	$ 910	$ 51,804
Demand Response	$ -	$ -	$ -	$ -	$ -
Distributed Gen	$ -	$ -	$ -	$ -	$ -
Regional	$ -	$ -	$ -	$ -	$ -
Common	$ 562,007	$ 252,774	$ 335,952	$ 129,929	$ 1,280,662
Total	$ 1,759,623	$ 680,693	$ 374,770	$ 142,593	$ 2,957,679

The distribution of utility expenditures across the various categories used for the ongoing management of programs is represented in the charts below with breakouts for electric and natural gas as well as the combined fuel portfolio.







The allocation of expenditures across these three categories is a result of the business strategies and tactics that are being planned for 2010 and have significant implications upon cost-effectiveness and acquisition risk.

As outlined in previous sections of this document, Avista has committed to the Idaho PUC staff to more formally evaluate DSM portfolios, programs and measures on a net rather than a gross basis. Part of the past net-to-gross strategy has been to maintain a high percentage of customer direct incentive expenditures as a proportion of total utility expenditures. This approach to managing portfolio net-to-gross risk is being gradually eroded as a necessary consequence of pursuing opportunities for significant increases in energy acquisition that require increased non-incentive investments. The degree to which these relationships are changing between 2009 and 2010 as well as the unexpected changes during 2009 are illustrated in the table below reflecting incentive expenditures in comparison to overall utility expenditures.

Incentive Expenditures as a % of Total Utility Expenditures				
		2009 budget	2009 actual	2010 budget
Incentives as a % of total budget	Electric	77%	70%	63%
	Natural gas	86%	82%	86%
	Total	79%	74%	79%

The continuation of this trend does not necessarily call for actions geared towards increasing the proportion of utility expenditures going towards incentives, but given the known increase in net-to-gross sensitivity that comes as a result of this trend there is call to increase the attention given to managing the net-to-gross ratio of individual programs and the overall portfolio.

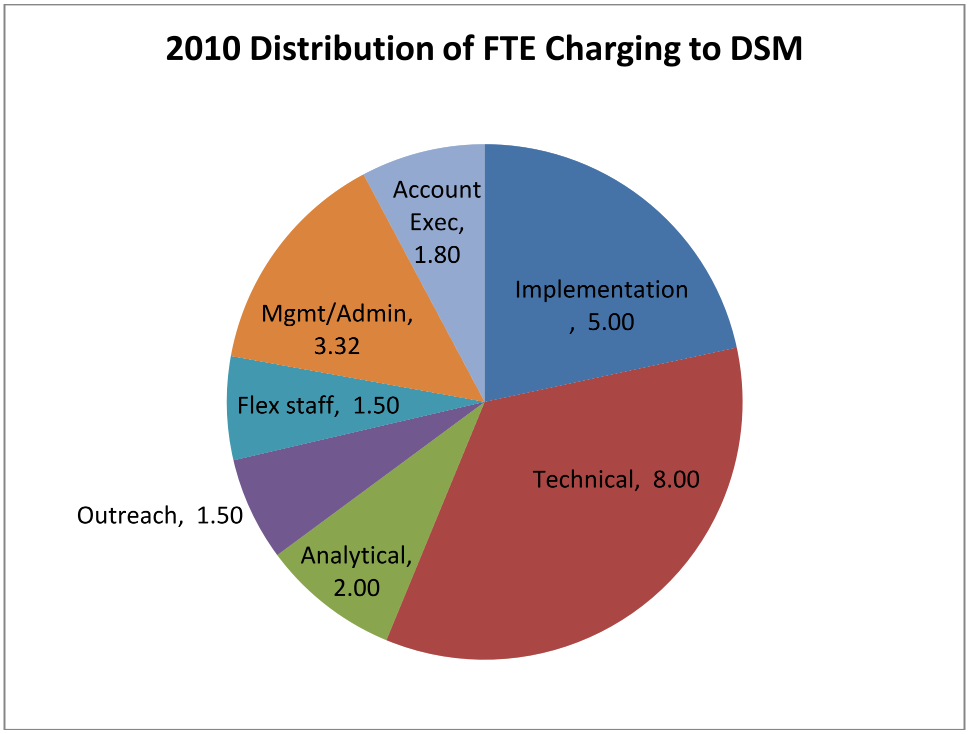
DSM infrastructure costs continue to grow, though at a lesser pace than energy acquisition. The 2010 budget includes a 10% (2.1 FTE) increase in overall labor complement. This is a 23.1 FTE labor expense spread over 40 individual expected to charge to the DSM budget in 2010. The majority of the growth is in the technical area (2.0 FTE's as a direct result of increased throughput and increased emphasis on EM&V) with additional growth contributions from the management / administrative area (driven by residential rebate processing requirements) of 1.8 FTE. There is an expected reduction in implementation staff of 2.0 FTE due to shifts in program responsibility and efficiencies resulting from transference of some rebate processing functions to the administrative staff. Other labor areas show relative little growth or declines from 2009 to 2010.

The processing of residential rebates will be a continued item of concern in 2010. The substantially increased residential customer response and the need for high data quality has resulted in a review of this process in late 2009 which will continue into 2010. This may well result in shifts in the type of labor employed for DSM operations but is unlikely to change the total labor requirement of the portfolio.

The growth in DSM FTE over the past several business plans is illustrated in the table below:

	2008 budget	2009 budget	2010 budget	2009 to 2010 % growth	2009 to 2010 FTE growth
Management/administrative	1.5	1.5	3.3	122%	1.8
Analysis	2.1	2.1	2.0	-5%	-0.1
Technical	4.0	6.0	8.0	33%	2.0
Student & flex staff	0.0	1.0	1.5	50%	0.5
Account Executive	2.6	2.6	1.8	-31%	-0.8
Implementation	6.0	7.0	5.0	-29%	-2.0
Outreach	0.8	0.8	1.5	88%	0.7
	17.0	21.0	23.1	10%	2.1

The 2010 budgeted distribution of labor by functional category is represented in the following chart:



The ability to attract and retain qualified DSM professionals is a concern both within Avista and throughout the region. To date Avista has been relatively able to meet the demands for increasing staff, but this is and will be a concern in the future. Internal and external solutions for short- and long-term staffing needs have been explored on an ad hoc basis as vacancies are created, and these are building towards an understanding of process changes and the local labor market that will point towards longer term strategies in 2010.

Tariff Rider Balance & Surcharge Projections
Lori Hermanson

Funding Mechanism

The Company's energy efficiency programs are funded through electric (Schedule 91) and natural gas (Schedule 191) tariff riders for both Washington and Idaho. These tariff riders are applicable to all retail customers for energy sold and to the flat rate charges for customer- and company-owned street and area lights and are used to recover costs incurred by energy efficiency programs in an effort to acquire least cost resources.

For Idaho (effective August 1, 2009) and Washington (effective February 1, 2009) the current electric DSM rates applicable are:

	Idaho DSM Rate	Washington DSM Rate
Schedule 1	$0.00258 per kWh	$0.00317 per kWh
Schedule 11 & 12	$0.00303 per kWh	$0.00449 per kWh
Schedule 21 & 22	$0.00232 per kWh	$0.00331 per kWh
Schedule 25	$0.00166 per kWh	$0.00217 per kWh
Schedule 25P	$0.00146 per kWh	n/a
Schedule 31 & 32	$0.00242 per kWh	$0.00295 per kWh
Schedules 41-48	3.98% of base rates	4.79% of base rates

For Idaho (effective August 1, 2009) and Washington (effective February 1, 2009) the current natural gas DSM rates applicable are:

	Idaho DSM Rate	Washington DSM Rate
Schedule 101	$0.03458 per therm	$0.03344 per therm
Schedule 111 & 112	$0.03045 per therm	$0.02944 per therm
Schedule 121 & 122	n/a	$0.02756 per therm
Schedule 131 & 132	$0.02552 per therm	$0.02663 per therm

All tariff rider collections are cumulated in four separate balancing accounts for each fuel and jurisdiction. Direct and allocated energy efficiency expenditures are charged against these balancing accounts. The current electric and natural gas tariff rider balances are:

	Idaho	Washington
Electric balance as of 11/31/09	$2,406,978	$2,789,558
Natural gas balance as of 11/31/09	$1,618,420	$4,150,390
Total balance as of 11/31/09	$4,025,398	$6,939,948

*The amounts above represent the amount that ratepayers owe shareholders for the net difference between collections through Schedules 91 and 191 surcharges and DSM program expenditures.

Company Commitments on DSM

In 2009, the Company committed to the Idaho Public Utilities Commission (IPUC) and Washington Utilities and Transportation Commission (WUTC) to file revisions to the DSM portions of Schedules 91 and 191 on or before February 15 of each year to establish sufficient funding levels for the following twelve months as well as amortize any tariff rider imbalance. In addition, the Company will circulate drafts of any tariff rider revision affecting the Company's DSM portfolio to our Triple-E Board at least 30 days prior to the filing.

The Company provides quarterly reporting on the Schedule 91 and 191 tariff rider balances to the Triple-E Board. The Triple-E Board also receives email alerts if or when tariff rider balances exceed +/- 20% of the forecasted annual revenue at any month end. In addition, the Company will complete and circulate analysis of the previous year's DSM activities to the Triple-E Board by March 31 of each year.

Level of Surcharge Anticipated for February 2010 Filing

Several components affect the outcome of efforts to reduce and maintain the tariff rider balancing accounts as close to zero as possible. All estimates begin with the Company's revenue forecast which can be impacted by several variables such as weather, economy, and power cost adjustments to name a few. Historically, we tend to see a decrease in DSM participation when customers see a decrease in energy prices. When weather differs from the forecast, the amount of revenue collected for energy efficiency programs can be affected either positively or negatively while program costs continue to accumulate in spite of weather impacts. At the same time, customers may need or want to make energy efficiency improvements to their homes or businesses, however, the effects of a declining economy may make it impossible for customers to participate in DSM in spite of the availability of resources such as federal tax credits.

On the expense side, the most uncertain and difficult variable to predict is customer participation. Customer participation also tends to influence the tariff rider balance the most since generally over 70 percent of total expenditures are attributable to incentives paid to customers. In 2008, the Company's incentive tiers were increased. An increase to participation was anticipated, however, it was difficult to determine the level of participation that might be expected from this tariff change. Also, there is generally a lag in response to tariff changes in this nature. So while we began to see increases in participation levels in 2008, the full impact from the change in incentive levels did not actually occur until 2009.

All of these components in addition to legislation such as I-937, changes in program implementation, and other various factors contribute to either excesses or shortfalls in the tariff rider balancing accounts. When this results in an excess balance where shareholders owe ratepayers, then the Company would respond by decreasing the DSM surcharge in Schedules 91 and 191. Conversely, when this results in a shortfall where ratepayers owe shareholders, the Company responds by increasing the DSM surcharge in Schedules 91 and 191. In anticipation for the February 2010 filing, the Company projects what the tariff rider balancing accounts will be by the end of 2010 and by what amount the Schedule 91 and 191 surcharges should be adjusted by.

The 2010 end of year projection of the electric tariff rider balancing accounts are shown below as well as the percent change in the surcharge in order to maintain a near zero balance by end of year 2010. Note that credit ending balances in the tariff rider accounts indicate that shareholders owe ratepayers. For purposes of the calculations below, it is assumed that the current tariff rider will remain in place through March 31st, 2010 and the proposed tariff rider would be in effect on April 1, 2010.

	Idaho	Washington
Electric balance as of 11/30/09	$2,406,978	$ 2,789,558
Dec 09 Forecasted Revenue	$714,000	$1,575,000
Dec 09 Estimated Expense	$585,000	$2,300,000
Projected EOY 2009 Balance	($2,277,978)	($3,514,558)
Budgeted 2010 Expense	$6,013,164	$12,017,668
2010 Revenue Req'd to zero balance	$8,291,142	$15,532,226
Jan '10 to Mar '10 Revenue	$2,105,766	$4,709,864
Revenue Req'd Apr '10 to Dec '10	$6,185,375	$10,822,362
Rider Req'd to deliver above revenue	3.31%	3.34%
Current Tariff Rider	2.97%	3.96%

% Change in Tariff Rider	+11.4%	-15.6%

The 2010 end of year projection of the natural gas tariff rider balancing accounts are shown below along with the projected percentage change in the Schedule 191 surcharge in order to maintain a near zero balance by end of year 2010. Again, credit ending balances in the tariff rider accounts indicate that shareholders owe ratepayers. For purposes of the calculations below, it is assumed that the current tariff rider will remain in place through March 31st, 2010 and the proposed tariff rider would be in effect on April 1, 2010.

	Idaho	Washington
Natural Gas balance as of 11/30/09	($1,618,420)	($ 4,150,390)
Dec 09 Forecasted Revenue	$458,000	$946,000
Dec 09 Estimated Expense	$309,000	$529,000
Projected EOY 2009 Balance	($1,469,420)	($3,733,390)
Budgeted 2010 Expense	$2,014,852	$4,707,039
2010 Revenue Req'd to zero balance	$3,484,272	$8,440,429
Jan '10 to Mar '10 Revenue	$1,028,443	$704,546
Revenue Req'd Apr '10 to Dec '10	$2,455,829	$7,735,883
Rider Req'd to deliver above revenue	5.73%	8.28%
Current Tariff Rider	3.77%	3.69%
% Change in Tariff Rider	+51.9%	+124.6%

Applying these adjustments mentioned above to the current surcharges in Idaho and Washington Schedules 91 and 191 would result in the following tariff rider surcharges for electric and natural gas customers.

Electric Schedules	Idaho DSM Rate	Washington DSM Rate
Schedule 1	$0.00281 per kWh	$0.00266 per kWh
Schedule 11	$0.00331 per kWh	$0.00375 per kWh
Schedule 12	$0.00362 per kWh	$0.00394 per kWh
Schedule 21	$0.00259 per kWh	$0.00282 per kWh
Schedule 22	$0.00245 per kWh	$0.00270 per kWh
Schedule 25	$0.00183 per kWh	$0.00186 per kWh
Schedule 25P	$0.00169 per kWh	
Schedule 31	$0.00273 per kWh	$0.00247 per kWh
Schedule 32	$0.00288 per kWh	$0.00260 per kWh
Street and Area Lights		
Natural Gas Schedules		
Schedule 101	$0.05347 per therm	$0.07693 per therm
Schedule 111	$0.04406 per therm	$0.06327 per therm
Schedule 121		$0.05747 per therm
Schedule 131	$0.04081 per therm	$0.06070 per therm

Electric and Natural Gas Rate Impact on DSM Revenue

As electric and natural gas rates increase, customers tend to respond by reducing their consumption with simple behavior changes such as turning down the thermostat and dressing warmer during winter. This works to a point but eventually, higher energy costs drive more customers to participate in the Company's energy efficiency programs. Since DSM tariff rider collections are tied to consumption, as consumption decreases so does funding available for the energy efficiency programs. By the time energy prices drive large increases in program participants, energy efficiency funding is already being collected at lower levels due to the decreases in consumption. The tariff rider surcharges can be increased to mitigate these imbalances, however, there's often a timing lag between the uptake in participation and the catch up from increased surcharges. In addition, due to seasonality the Company may not see the benefit of the adjustments until nearly a year later which only adds to the initial imbalance.

Consistency with Integrated Resource Planning (IRP)
Lori Hermanson

Electric IRP
Every two years the Company considers the future needs of its customers and analyzes and outlines a strategy to meet that projected demand through energy efficiency and a mix of new renewable and traditional resources. The Company's most recent electric IRP was filed in 2009 and included the evaluation of approximately 3,000 energy efficiency measures. These 3,000 measures were significantly drawn from the Northwest Power and Conservation Council's 5th Power Plan since the 6th Power Plan was still in process of being drafted. Therefore, there could be mismatches between our 2009 IRP and the final draft of the 6th Power Plan.

The evaluation of those measures resulted in the following energy efficiency targets for 2010 and 2011.

Segment	2010	2011
Low Income	1,977	2,056
Residential	20,519	21,339
Prescriptive Non-Residential	18,211	18,940
Site-Specific Non-Residential	24,937	25,934
Total Local Acquisition (MW)	65,644	68,269

Natural Gas IRP
Every two years the Company considers the future needs of its customers and analyzes and identifies a strategic natural gas resource portfolio that includes a component of energy efficiency. The Company's most recent natural gas IRP was completed in 2009 and included the evaluation of over 300 energy efficiency measures. The evaluation of those measures to provide a least cost option for our customers resulted in energy efficiency targets of 312,884 and 307,224 dekatherms for 2010 and 2011, respectively.

This 2010 goal of 312,884 dekatherms represents an increase of 98 percent, or 175,583 dekatherms, from the 2007 natural gas IRP energy efficiency target for 2010. This large increase in the natural gas energy efficiency target is the result of a steep carbon mitigation cost adder which reflects the price impact of anticipated climate change legislation in our natural gas price forecast that is modeled to take effect in 2015. This sizeable increase in natural gas prices significantly increases our avoided costs over the planning horizon.

At a time when customers are seeing reductions in natural gas prices, the Company IRP has resulted in a greatly increased DSM target. Historically, the Company has seen that when energy prices decline so does the level of DSM participation. So a challenge and a concern is how to influence customers to implement natural gas efficiency upgrades at a time when prices are declining based on a priced modeled to increase in 2015. In addition, a 98 percent ramp up from one year to the next is difficult to implement from one year to the next.

The Company proposed to resolve these challenges by meeting all cumulative potential identified in the 2009 IRP over the 20-year planning cycle but will do so at a more gradual ramping of program activity. It was determined that a 6.5 percent constraint on the annual increase over the first 10 years was necessary while simultaneously achieving the same objective by the end of the 20 year period. This annual growth constraint resulted in the following DSM natural gas targets of 219,334 and 233,654 dekatherms for 2010 and 2011, respectively.

DSM Avoided Costs (Electric and Natural Gas)

Lori Hermanson

Avoided Cost Enhancement

In 2007, during the Heritage Project (a comprehensive review of the Company's energy-efficiency and load management programs) the avoided costs for evaluating DSM projects were analyzed to ensure that energy-efficient measures were evaluated consistently and transparently against supply side resources. A team of analysts quantified seven resource value components: avoided cost of energy, avoided carbon emission costs, reduction in cost volatility, value of avoided transmission and distribution losses, the value of deferred generation capacity and the value of deferred transmission and distribution capital investments.

Avoided cost of Energy

The avoided cost of energy was calculated using the electric price forecast from the 2009 Integrated Resource Plan. This market cost was calculated with AURORA^{XMP} using 300 iterations of varying load, hydro, wind, forced outages, emissions, and natural gas prices in the Western Interconnect for the period from 2010 to 2029. Renewable portfolio standards and potential emissions costs are included in the market prices. The model chooses the most economic resources available to satisfy projected load obligations plus a planning margin. The values presented here are those that the Company could avoid paying for new resources if energy efficiency, load management, distribution improvement, and distributed generation projects through the Heritage Project were undertaken.

Avoided Carbon Emissions Cost

New thermal resources produce a variety of emissions that have associated costs through taxes or cap and trade programs. The four main emissions with costs included in the base case market forecast are carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxide (NO_x), and mercury (Hg). There are some caveats to consider concerning emissions because of the inherent uncertainty in emissions markets and legislation. SO_2 costs are the most predictable because a national market-based cap and trade system already exists for SO_2. The NO_x prices are less certain because the national cap-and-trade program does not begin until 2010, but the forecasted costs are generally well accepted. Mercury costs are more problematic than the first two emissions categories because several western states have decided to opt out of the federal mercury standards so they can apply more stringent mercury standards. The avoided mercury costs are based on the active and proposed mercury guidelines for each state using blended price forecasts from a variety of sources.

CO_2 costs are the most problematic category of emissions to model because of the fragmented nature of CO_2 legislation in the US. There are many state level and regional initiatives that are competing with a multitude of cap and trade proposals at the national level. The 2009 IRP includes CO_2 costs based on a probability distribution that uses the National Commission on Energy Policy (NCEP) as the mean value starting in 2015. The NCEP case is a comprehensive climate change risk reduction program that was released in December 2004. There are many unknown factors regarding projected costs of CO_2 emissions because there is considerable state and federal legislative activity with a wide range of potential costs. The NCEP case is at the low end of the projected costs when compared to recent federal proposals. Carbon emissions costs may differ significantly from this analysis depending on which, if any, of the federal or state laws are passed. The start date of the legislation will also play an important role in emissions costs.

Avoided Generation Capacity

Another component of Heritage Project value is avoided generation capacity. The value of avoided generation capacity is coincident with system peaks in December, January, and

February. Avoided generation capacity is valued by the difference in resource cost versus the market, not considering any portfolio risk reduction. This is the value of meeting your capacity needs at the least overall cost, which is calculated as the premium paid above market costs to obtain a mix of Company-owned resources.

Reduction in Energy Cost Volatility

The next component of avoided cost is the risk premium. Risk, in this analysis, refers to the volatility in the electric market forecast. The types of conservation measures being considered by the Heritage Project avoid the intrinsic market volatility because they do not rely upon any of the variable components.

Several different methodologies to compute risk have been considered. Originally, the risk portion of the analysis assumed that ratepayers would be willing to pay a premium that was quantified by the difference between the expected value of the 300 AURORA^{XMP} iterations and the 95% confidence interval of those iterations. The analytics team decided that this methodology was not robust enough for the Heritage Project analytics exercise. The second methodology used the intrinsic value of a price cap using the Black-Scholes model. There were concerns with this methodology because of its theoretical nature and because it was not tied in with the IRP methodology. Continued discussions resulted in a third and final approach to the valuation of a risk premium that relies on the PRiSM model used in the 2009 IRP. This method separated the value of avoided winter peak generation capacity from the volatility value, which is covered in the next section. All three methodologies resulted in similar values, but the PRiSM model method was deemed to be most consistent with the IRP, appropriate, and defendable.

The risk premium over market value is based on results from the PRiSM model developed for the IRP process. The PRiSM model uses a linear programming model routine to determine the optimal amount and timing of future resource acquisitions and their associated costs. There is a capacity value, which was discussed in the previous section, and a risk reduction component. After our capacity needs have been met, there are ways to lower power cost volatility. The volatility reduction strategy generally involves adding resources with high capital and low variable costs. These resources increase expected costs, but decrease expected risk.

Reduction in Transmission and Distribution Energy Losses

A precise estimate of transmission and distribution (T&D) system impacts is difficult to quantify for Heritage Projects. Geography, season, time-of–day, and other considerations can impact these calculations in a manner that is not easily translated into assumptions regarding a specific resource option. Nevertheless, a generalized estimate of the impact of a reduction in end-use demand upon T&D losses is required for any resource analysis. Presently the analyst team applies a 6.5% average loss factor for T&D projects.

Discussions are underway to improve the quality of the analysis by incorporating separate estimates of T&D losses for a summer peak (based upon a space cooling-driven peak scenario) and a winter peak (based upon a space heating-driven peak). This will incorporate assumptions of both demand and ambient temperatures into the analysis of evaluated resource options.

Based upon the estimates of the avoided cost of energy, emissions and risk reduction valuation above (using the flat load assumptions) an adder of $3.98 per MW is incorporated into the energy avoided cost, as illustrated in the table below.

Deferred Generation Capacity

The pure capacity value of $300 per kilowatt is the remaining capital cost of a combustion turbine that is not offset by the value of the energy produced by the turbine and that is sold into the short-term energy market. The value is calculated by subtracting the present value of the energy sales over the turbine's economic life from the present value of the revenue requirements associated with the installed capital cost of the turbine. Table 6 illustrates how the pure capacity value (no energy value) is derived. The initial installed capacity cost of the turbine is $450 per kilowatt. When the turbine is dispatched against the short-term electricity market it generates margins (electric revenue less fuel and O&M costs) to offset $150 per kilowatt of the initial installed cost. The remaining $300 per kilowatt of capacity cost not offset by the value of energy sales is the pure capacity cost.

DSM Portfolio and Program Overview

Jon Powell

As part of meeting the expectations of the Idaho Staff MOU, Avista has more tightly defined and applied our past definitions of measure, program and portfolio. Based upon these definitions a total of over 470 individual measures have been aggregated into 36 individual energy-acquiring programs. Additional “umbrella” programs supporting energy acquisition through enhancing the throughput of other programs are also partially incorporated into these calculations. Examples of these programs include the Leadership in Energy and Environmental Design (LEED) and non-residential retro-commissioning programs, which identify cost-effective measures for acquisition through other programs.

During the business planning process several improvements to better align the cost and energy acquisition of programs through redefining measures and programs were identified. These will likely be implemented during 2010 and incorporated into the 2011 DSM business plan to improve the usefulness of this model for planning and evaluation purposes.

For the 2010 business plan, the overall DSM portfolio has been subdivided into the three main local components (residential, limited income and non-residential). The regional portfolio, consisting exclusively of the Northwest Energy Efficiency Alliance activities, is treated separately though there is an increasing tendency for local and regional overlap of program efforts.

Two additional portfolios contain little or no energy acquisition; the renewable generation portfolio and the demand-response portfolio. Avista is proposing a Schedule 90 tariff modification to exclude the granting of incentives for renewable generation, but the portfolio will continue as a customer educational and support program. The demand-response program is authorized through Idaho’s Schedule 96 and is a pilot effort to be terminated in 2010 and transitioned to an expansion of demand-response beyond the scope of DSM or DSM funding.

The individual portfolios will be described in more depth individually, followed by overviews of the program plans contained within that portfolio.

The Non-Residential Portfolio Overview

Jon Powell

The tariffs authorizing Avista's DSM programs are sufficiently broad to allow for the inclusion of any measure saving electric or natural gas energy. Within the non-residential portfolio the implementation of this authority is achieved through a combination of prescriptive programs geared towards relatively common and uniform measures and a site-specific program for all other efficiency measures.

In the past Avista has sought to use prescriptive programs to streamline the implementation process and reduce expenses as well as to simplify the communications to trade allies and customers. Though the general intent is to only use prescriptive programs for measures with significant throughput, the cost of fielding and implementing a prescriptive program is very minimal relative to serving the same customer demand through the site-specific program. Consequently there has been little reluctance to design and field prescriptive programs with the intent to stimulate customer demand, even with the knowledge that not all of these programs will succeed. Thus the reader will note that there are prescriptive programs with relatively little throughput. These programs are candidates for termination, with the measures associated with that program to be acquired through the site-specific program in the future.

Efficiency measures that do not qualify for the Company's prescriptive programs can be incentivized through the site-specific program. This program does require a pre-project contractual agreement but is available to projects of any size. There is not a cost-effectiveness requirement, but project targeting is generally sufficient to minimize the number of projects and degree to which these projects are not cost-effective. When cost-ineffective projects are incorporated into the program the incentive, which is based upon therm throughput, will result in them being a disproportionately low percentage of total utility expenditures. However, regardless of the small size of the incentives received, the customers full measure incremental cost is incorporated into the program regardless of how small the incentive they received was, and thus these projects can have a significant adverse impact upon program TRC. An increased level of project targeting by account executives and the technical staff is planned during 2010 to address this issue.

A total of 48% of electric and 44% of natural gas acquisition are expected to come from the non-residential segment. This is comparable to an actual 2009 acquisition of 32% and 51%, respectively. There is a general trend for the growth of the residential portfolio acquisition to be significantly above that of the non-residential portfolio.

Program: Prescriptive Non-Residential Clothes Washer Program

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included:
- Energy Star Rated Commercial Clothes Washers
- CEE Tier 1 Rated Commercial Clothes Washers
- CEE Tier 2 Rated Commercial Clothes Washers
- CEE Tier 3 Rated Commercial Clothes Washers

Expected 2010 acquisition: 31,013 kWh and 850 therms
Expected customer participation: Laundromats and Multifamily dwellings
Expected 2010 incentive cost: $10,000
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $10,508
TRC benefit/cost ratio:
- 0% net-to-gross scenario: 5.81 with tax credits, 5.81 without tax credits
- 25% net-to-gross scenario: 5.76 with tax credits, 5.76 without tax credits
- 50% net-to-gross scenario: 5.66 with tax credits, 5.66 without tax credits
- 75% net-to-gross scenario: 5.38 with tax credits, 5.38 without tax credits

Program Description:
In October 2008 we launched a prescriptive clothes washer program. Commercial clothes washers that are certified Energy Star or CEE are eligible for a rebate upon installation. Savings and rebate amounts were determined based on information from Energy Star and CEE regarding savings over standard models. Having a streamlined prescriptive approach will allow us to target laundromats and multi-family laundry areas which are typically difficult to handle through our site specific program. We have budgeted $5,730 in electric incentives and $4,270 in natural gas incentives. This program is marketed through account executives, vendors, contractors and other outreach material. There is an NEB of $364 associated with these measures for water savings and detergent costs.

Summary of Opportunities and Threats:
It has been difficult to catch commercial clothes washer upgrades through our site specific program. A streamlined prescriptive approach will enable us to reach these markets before decisions are made and influence customers to choose higher efficiency clothes washer models. We have estimated 31,013 kWh and 850 therms in savings for 2010.

Key 2010 Program Issues and Actions:
We are considering adjusting the incentives for this program in 2010 to a single incentive level in place of the current tiered incentive structure. Before making that decision, we will be looking at the regional programs and incentives being offered as well as updating costs.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Non-Res Demand Controlled Ventilation

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Mike Dillon
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Ventilation controls paid at .25 per square foot
Expected 2010 acquisition: 7,892 kWh and 608 therms
Expected customer participation:
Expected 2010 incentive cost: $1,000
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $1,135
TRC benefit/cost ratio:

- 0% net-to-gross scenario: 1.95 without tax credits, 1.95 with tax credits
- 25% net-to-gross scenario: 1.91 without tax credits, 1.91 with tax credits
- 50% net-to-gross scenario: 1.83 without tax credits, 1.83 with tax credits
- 75% net-to-gross scenario: 1.64 without tax credits, 1.64 with tax credits

Program Description:
Avista offers incentives for installing ventilation controls on existing buildings that use carbon dioxide levels to measure occupancy and modify the percentage of outside air based on variable levels. Rather than setting intake rates for maximum occupancy levels at all times, demand-controlled ventilation measures the approximate number of people occupying a space and resets the intake rates based on that measurement. In order to be eligible for incentives, conditioned spaces must be kept between 65 and 75 degrees during operating hours. Incentives are based on the total square footage of the controlled conditioned space with a 2,000 square feet minimum. Incentives will be paid at a rate of $.25 per square foot with a cap of 2,500 square foot per sensor. If the space has portable walls, each room must be controlled separately. Controlled space must meet a minimum of ASHREA 62 standards.

Summary of Opportunities and Threats:
This program was developed to encourage the control of existing building temperatures of conditioned spaces.

Key 2010 Program Issues and Actions:
No changes are being planned for this program in 2010.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Non-Residential Direct-Use Water Heater Program

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Converting an existing electric water heater 80 gallons or smaller to a natural gas water heater 80 gallons or smaller.
Expected 2010 acquisition: 6,574 kWh
Expected customer participation: Smaller Commercial Customers
Expected 2010 incentive cost: $300
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $405
TRC benefit/cost ratio:
0% net-to-gross scenario: 18.90 without tax credits, 18.90 with tax credits
25% net-to-gross scenario: 18.90 without tax credits, 18.90 with tax credits
50% net-to-gross scenario: 18.90 without tax credits, 18.90 with tax credits
75% net-to-gross scenario: 18.90 without tax credits, 18.90 with tax credits

Program Description:
$150 for a conversion of an existing electric water heater 80 gallons or smaller to a natural gas water heater 80 gallons or smaller with an Efficiency Factor ≥ .60 or an AFUE ≥ 90%. Building square footage must be 4,000 or less (larger buildings can apply for a site specific rebate through your Avista Account Executive). Customer must be an Avista commercial electric and natural gas customer to be eligible. Rebate offer is effective May 1, 2007. This program was initiated for our smaller commercial customers.

Summary of Opportunities and Threats:
None critical to program implementation in 2010.

Key 2010 Program Issues and Actions:
No program changes are anticipated for 2010.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Non-Residential EnergySmart Grocer

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Anti-Sweat Heat Controls, ECMs, Case Lighting, Night Curtains, CFLs and Cooler misers, floating head pressure controls, gaskets, strip curtains, VFDs for condensers, and walk-in evap. motors.
Expected 2010 acquisition: 6,000,000 kWh.
Expected customer participation: Approximately 100 individual customers.
Expected 2010 incentive cost: $736,329
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $831,972
TRC benefit/cost ratio:

0% net-to-gross scenario: 1.37 without tax credits, 1.37 with tax credits
25% net-to-gross scenario: 1.24 without tax credits, 1.24 with tax credits
50% net-to-gross scenario: 1.06 without tax credits, 1.06 with tax credits
75% net-to-gross scenario: 0.73 without tax credits, 0.73 with tax credits

Program Description:
The EnergySmart Program was selected as the preferred bid through the 2006/2007 commercial refrigeration RFI/RFP process. The program was launched in late 2007 and is facilitated through PECI. A Field Energy Analyst with expertise in commercial refrigeration provides customers with a no cost audit of the refrigeration in their facility. The customer receives a detailed energy savings report regarding potential savings and is guided through the process from inception through the payment of incentives for qualifying equipment. PECI utilizes a modeling program called Grocer Smart to determine savings. PECI is handling the outreach effort through industry contacts, cold calling and contractor relationships. The account executives are also providing customer referrals with permission from the customers. This program is available to all non-residential retail electric customers with refrigeration facilities. PECI has also contracted with BPA and PSE to provide this program so overlapping customers with other electric utilities may also benefit. Administrative fees are paid to PECI on a pay for performance of $0.0801 per kWh and $0.6000 per therm.

Summary of Opportunities and Threats:
We have contracted with PECI for the EnergySmart program to run for 3 years. It is estimated that over 14,000,000 kWh will be saved in the 3 year period. The estimated savings for 2010 is 6 million kWh. In addition to the potential savings that will be achieved through the measures implemented, customers receive technical assistance and comprehensive audits at no charge. Refrigeration often represents the primary electricity expense in a grocery store or supermarket. Although the potential for savings is high, it is often overlooked because of the technical aspect of the equipment. This program provides a concentrated effort to assist customers through the technical aspects of their refrigeration systems while providing a clear view of what savings can be achieved.

Key 2010 Program Issues and Actions:
This program contract has an end date of December 31, 2010. We will be evaluating this program during the course of the next year to determine next steps for this market sector.

Evaluation, Measurement and Verification Plan:

This program is on the 2010 schedule for impact evaluation. PECI has an evaluation under contract with Summit Blue to perform impact evaluation for their EnergySmart Grocer Program. The final report has yet to be written. When results are final we will determine if this evaluation will replace an internal evaluation.

Program: Prescriptive LED Traffic Signals

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included:
Replacement of Incandescent signals with LED signals for the following:

- Pedestrian Signals 9”
- Pedestrian Signals 12”
- Traffic Signals 8” Green
- Traffic Signals 8” Red
- Traffic Signals 8” Yellow
- Traffic Signals 12” Green
- Traffic Signals 12” Red
- Traffic Signals 12” Yellow
- Traffic Arrows 8” Green
- Traffic Arrows 8” Red
- Traffic Arrows 8” Yellow
- Traffic Arrows 12” Green
- Traffic Arrows 12” Red
- Traffic Arrows 12” Yellow

Expected 2010 acquisition: 67,035 kWh
Expected customer participation: City and County Municipalities
Expected 2010 incentive cost: $4,800
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $5,869
TRC benefit/cost ratio:

0% net-to-gross scenario: 18.14 without tax credits, 18.14 with tax credits
25% net-to-gross scenario: 17.68 without tax credits, 17.68 with tax credits
50% net-to-gross scenario: 16.82 without tax credits, 16.82 with tax credits
75% net-to-gross scenario: 14.68 without tax credits, 14.68 with tax credits

Program Description:
This program provides customers with a prescriptive incentive amount when they retrofit existing incandescent traffic signals with new LED signals. Incentives are paid for pedestrian signals, red, yellow and green traffic signals and traffic arrows. Savings and incentives are based on BPA C&RD information. As budgets allow customers are converting existing signals to LED. Our incentives help them to move the projects up in times of budget constraints. This program is available to traffic signal owners which are primarily cities. This program is marketed through account executives that have contacts with the appropriate traffic engineers within the various city organizations.

Summary of Opportunities and Threats:
LED (light-emitting diode) traffic signals use 80% to 90% less energy than traditional incandescent traffic signals. Their energy use is 8 - 25 watts, depending on size and color, compared to a range of approximately 67 - 150 watts for incandescent lamps. LED lights also look brighter than incandescent lights. Equally important is how long they last. LED traffic signals can last as long as ten years compared to roughly two years for incandescent lamps. This translates to lower maintenance costs.

Key 2010 Program Issues and Actions:
This program in the past had used a dollar amount of $360 for NEBs for labor savings and rolling a truck out to change a bulb. We cut that amount in half to $180 for 2010 and this program is being evaluated to ensure we have the current costs in our analysis. The acquisition forecasted for this program is down from years past; as we feel we may be reaching market saturation. We will be monitoring program utilization in 2010 to see if adjustments should be made in future offerings.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Non-Residential Leadership in Energy and Environmental (LEED) Certification Program

Key Individuals:
Program Manager: Renee Coelho and Greta Zink
Program Technical Resource: Mike Dillon
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included:
Expected 2010 acquisition: None. This is an 'umbrella' program that contributes to acquisition in other programs
Expected customer participation: Unknown
Expected 2010 incentive cost: None expected
Expected 2010 non-incentive/non-labor cost: None expected
Expected 2010 total utility cost: None expected
TRC benefit/cost ratio: Inapplicable for 'umbrella' programs.

Program Description:
In 2004 we developed and launched a program to provide incentives for customers that achieve LEED certification on new construction projects. At the time we identified several market barriers for achieving LEED certification. They included:

- An emerging design and construction process.
- Industry focus on lowest first cost options
- Little or no attention given to long term operating costs
- Low market awareness of the benefits of LEED facilities

We also identified several reasons why it would be appropriate for us to provide incentives. They included:

- Currently there are not LEED certified buildings in our service territory
- 20% minimum energy use reduction vs. conventional design and construction
- Improved productivity
- Improved site development and reduced irrigation requirements
- Reduced mechanical equipment size

This rationale for providing incentives is still valid in 2010. Although the market is moving the market barriers are still there. In 2010 we will pay $.25 per conditioned square feet. This incentive was revised from the original offering of $1.25 per conditioned square feet from the beginning of the program. We also added an incentive of .50 cents per conditioned square feet for customers that achieve LEED-EB (existing buildings). The incentive is intended to help cover the costs of the certification with a requirement that 4 points are achieved in the Energy Optimization section of the LEED checklist (20% better than WSEC). Projects with potential LEED certification incentives, along with the other incentives we pay on the project, are contracted through the site specific process. Renee Coelho handles those contracts. Greta Zink and Renee Coelho work with Mike Dillon on incentive amounts and outreach. This program is marketed through account executives, vendors, contractors, architects and other outreach material. This program is available to all non-residential retail electric and natural gas customers that achieve LEED-NC or LEED-EB.

Summary of Opportunities and Threats:
The LEED incentive program is intended to help customers overcome the barriers associated with achieving LEED certification while achieving a higher level of electric and natural gas energy savings.

Key 2010 Program Issues and Actions:
LEED NC Incentive Analysis:
The LEED NC incentive program originally established by Avista was used as a market transformation program to speed the delivery of LEED buildings to our service territory. In this time period the Avista service territory has had 8 projects that at a minimum have received a LEED certified rating with 6 additional projects in the contractual phase. This program needed to be reevaluated given the change in the new construction market conditions, the acceptability of LEED for new construction projects and a decrease in overall project costs due to USGBC streamlining of the process and increased experience of green building practices by the local design community. United States Green Building Council (USGBC) has come out with a new LEED version 3 that is now current in effect with revised energy performance levels and the new E&A credit 1 threshold level should be increased to 10 points which corresponds to a 30% reduction under a code level new construction or 26% improved performance of a major retrofit. So with all these conditions in mind in addition to tariff balance levels we will reduce our LEED incentive to $.25/sf starting January 1st, 2010 with the new LEED point requirements for any project that must go under LEED 2009 (Version 3).

The assumptions and reasoning behind the analysis are as follows:

- The energy savings associated with the new construction projects will still fall under our normal site specific programs and because of a lack of quantifiable kWh/therm savings associated with the soft savings of the intergraded design process.
- An increase in the demand of LEED certification incentives in our service territory shows that the initial market barrier removal effort has been successful.
- The new requirements for E&A Credit 1 will be 10 points.
- LEED-EB should be left at the 4 points and $.50/sf because we currently have not received any projects, have a basis for claiming savings and the energy requirements with the newest version of LEED have stayed largely the same.

This program is part of a long-term market transformation effort and is closely coordinated with similar efforts in this market by the Northwest Energy Efficiency Alliance, the US Department of Energy and many other entities.

LEED Incentive Comparisons

Incentive based on $0.08 per kwH and $3.00 per therm

Office Bldg. 10,000 sq ft, 1-Floor

	Baseline	LEED 25% Reduction	Savings	New Tech Incentive
kWh	102,481	76,861	25,620	$2,050
Therms	2,282	1,712	571	$1,712
EUI	58	43		$3,761
		LEED Incentive per sq ft		**$0.38**

Office Bldg. 20,000 sq ft, 2-Floors

	Baseline	LEED 25% Reduction	Savings	New Tech Incentive
kWh	205,614	154,211	51,404	$4,112
Therms	4,248	3,186	1,062	$3,186
EUI	56	42		$7,298
		LEED Incentive per sq ft		**$0.73**

Office Bldg. 30,000 sq ft, 3-Floors

	Baseline	LEED 25% Reduction	Savings	New Tech Incentive
kWh	308,798	231,599	77,200	$6,176
Therms	6,221	4,666	1,555	$4,666
EUI	56	42		$10,842
		LEED Incentive per sq ft		**$1.08**

Office Bldg. 50,000 sq ft, 3-Floors

	Baseline	LEED 25% Reduction	Savings	New Tech Incentive
kWh	516,674	387,506	129,169	$10,333
Therms	9,744	7,308	2,436	$7,308
EUI	55	41		$17,641
		LEED Incentive per sq ft		**$1.76**

Office Bldg. 100,000 sq ft, 4-Floors

	Baseline	LEED 25% Reduction	Savings	New Tech Incentive
kWh	1,036,834	777,626	259,209	$20,737
Therms	18,515	13,886	4,629	$13,886
EUI	108	81		$34,623
		LEED Incentive per sq ft		**$3.46**

Average Incentive	**$1.48**

Evaluation, Measurement and Verification Plan:
There is no M & V for this program, as there is no savings claimed. This program will be evaluated on an annual basis for implementation efficiencies.

Program: Prescriptive Food Service

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Andy Paul
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Over 25 equipment measures including ovens, fryers, griddles, ice machines, holding cabinets, refrigerators, freezers and dishwashers.
Expected 2010 acquisition: 499,280 kWh and 29,875 Therms
Expected customer participation: Approximately 218 customers
Expected 2010 incentive cost: $89,600
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $98,035
TRC benefit/cost ratio:

- 0% net-to-gross scenario: 1.44 without tax credits, 1.44 with tax credits
- 25% net-to-gross scenario: 1.43 without tax credits, 1.43 with tax credits
- 50% net-to-gross scenario: 1.40 without tax credits, 1.40 with tax credits
- 75% net-to-gross scenario: 1.32 without tax credits, 1.32 with tax credits

Program Description:
The Prescriptive Food Service Program was launched in October 2006 and re-evaluated and enhanced in March 2008. There are over 25 high efficiency equipment measures offered on this program. Our goal with this program is to provide an easy path for customers to make choices for high efficiency equipment in commercial kitchens. This has been a difficult market to reach with our site specific program and is ideal for a prescriptive approach because savings are similar between applications because they are not generally weather dependent.
This program is available to all non-residential retail electric and natural gas customers.
The program is budgeted to pay $43,888 in electric incentives and $45,712 in natural gas incentives. This program is marketed through account executives, vendors, contractors and other outreach material. It is also marketed through our Energy Star partnership. In 2008 we began advertising in appropriate trade magazines and we did a direct mail piece

Summary of Opportunities and Threats:
Historically, we have had a relatively low level of throughput for commercial food service equipment. The prescriptive program has seen a relatively higher level of increased participation.

Key 2010 Program Issues and Actions:
Changes planned for 2010 are to eliminate the HE Gas Hot Water Heaters and Hot Water Circulating Pump Time clocks and HE Gas Char Broiler. We will review the incentives on the Ice Makers and Gas Steam Cookers. We reviewed the dishwasher incentives and kept them at the current levels to be able to market them in a consistent offering. The Energy Star and CEE Tier 2 Solid Door Refrigerator incentives will be lowered. Energy Star and CEE Tier 2 Solid Door Freezers will all be offered at the same incentive level regardless of how many doors and we will not be making any changes to the glass door freezer incentives. Vent hood variable speed control, electric space heat + Vent hood dedicated makeup air unit (MAU) variable speed control were combined to make one measure instead of having the makeup air unit variable speed control a standalone to make this measure more cost effective.

Evaluation, Measurement and Verification Plan:
This program is on the 2012 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Prescriptive Power Management for PC Networks

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Installation of Network Power Management Software
Expected 2010 acquisition: 24,000 kWh
Expected customer participation: 5 Customers at 40 units per customer
Expected 2010 incentive cost: $2,000 in electric incentives.
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $2,383
TRC benefit/cost ratio:

0% net-to-gross scenario: 2.14 without tax credits, 2.14 with tax credits
25% net-to-gross scenario: 2.07 without tax credits, 2.07 with tax credits
50% net-to-gross scenario: 1.95 without tax credits, 1.95 with tax credits
75% net-to-gross scenario: 1.66 without tax credits, 1.66 with tax credits

Program Description:
In 2005 we developed a prescriptive approach to providing incentives to customers that install a network based power management software solution. Despite the fact that most personal computers (PCs) have the capability to shift to a low-power operating state after a specified period of inactivity, only a small fraction of those PCs actually do so. For companies that have numerous PCs, the wasted energy from computers that remain in the full-power “on” state even when they are idle can be significant. Software products that can simplify the process of implementing power management in large numbers of networked PCs are now available. We offer a $10 incentive per controlled PC for solutions that fit our criteria. The criteria includes:

- ability to provide regular energy use reports,
- the ability to control every available level of power management offered by the PC,
- the ability to reset user over-ride capabilities, a minimum average savings of 120 annual kWh per PC,
- the ability to provide usage data prior to the controls being installed (baseline setting) and the software must remain in operation for a minimum of 3 years.

This type of product seems to have two main barriers to installation. The first one being the resistance from IS/IT departments to install this type of product and the amount of time that vendors are willing to spend in this service territory (versus a larger market somewhere else). This program is available to all non-residential retail electric customers with multiple PC’s. This program is marketed through account executives, vendors, contractors and other outreach material. Because there are a limited number of suppliers of qualifying products and the sales cycle for this product is long, it is heavily dependent on the vendor to sell the product to Avista eligible customers. It is not an easy product for us to market because of the vendor accountability.

Summary of Opportunities and Threats:
Customers with multiple PC’s that remain in the “on” mode while not in use have the potential to save kWh with the installation of products of this type. Products that control usage at a network level have the chance of being the most effective because they remove the manual aspect that often does not provide consistency.

Key 2010 Program Issues and Actions:
No changes are currently planned for this program.

Evaluation, Measurement and Verification Plan:
This program is on the 2010 schedule for impact evaluation. Currently we have measured data for one education segment. This evaluation will extend that data to the commercial office building segment.

Program: Prescriptive Premium Efficiency Motors

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Andy Paul
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included:
Expected 2010 acquisition: 275,000 kWh
Expected customer participation:
Expected 2010 incentive cost: $42,842
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $42,842
TRC benefit/cost ratio:

0% net-to-gross scenario: 0.80 without tax credits, 0.80 with tax credits
25% net-to-gross scenario: 0.80 without tax credits, 0.80 with tax credits
50% net-to-gross scenario: 0.80 without tax credits, 0.80 with tax credits
75% net-to-gross scenario: 0.80 without tax credits, 0.80 with tax credits

Program Description:
The premium efficiency motors program was developed several years ago in an effort to change the buying patterns for customers who use motors in their facilities. This program provides an incentive for customers who purchase premium efficiency motors over standard motors for stock. The incentives are intended to pay approximately 50% of the incremental costs of buying a premium efficiency motor. This is our only prescriptive program that allows incentives to be paid upon purchase rather than upon installation. This is an intentional piece of this program since we are trying to get customers to keep premium efficiency motors in stock. In 2008 we had a significant increase to participation levels in this program. This is due to the change that customers are now making in their purchasing practices and it is also due to vendor involvement. In order to qualify for incentives, motors must meet our listed NEMA Premium™ efficiency standards. This program was re-evaluated in March, 2008 and incremental cost information was updated to reflect actual costs and updated market information. This resulted in some rebates going up and some going down on individual motors. This program will be re-evaluated in 2010 because NEMA Premium will be the new standard. This program is available to all non-residential retail electric customers. This program is marketed through account executives, vendors, contractors and other outreach material.

Summary of Opportunities and Threats:
This program provides electric energy savings. Premium efficiency motors provide customers with reduced downtime and lower maintenance and operating costs. This program has also provided a market transformation element because purchasing practices have been altered as a result of our incentives.

Key 2010 Program Issues and Actions:
This program will be re-evaluated in December of 2010 because NEMA Premium will be the new standard.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Prescriptive Refrigerated Warehouse Program
(AKA Retrofit Equipment Upgrade Program)

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Efficiency improvements in fast acting doors, door seals, VFD's, fan motors, freezer and cooler lighting.
Expected 2010 acquisition: 243,831 kWh
Expected customer participation: Small segment of customers
Expected 2010 incentive cost: $21,600
Expected 2010 non-incentive/non-labor cost:
Expected 2010 total utility cost: $25,487
TRC benefit/cost ratio:
- 0% net-to-gross scenario: 2.68 without tax credits, 2.68 with tax credits
- 25% net-to-gross scenario: 2.62 without tax credits, 2.62 with tax credits
- 50% net-to-gross scenario: 2.49 without tax credits, 2.49 with tax credits
- 75% net-to-gross scenario: 2.17 without tax credits, 2.17 with tax credits

Program Description:
In the summer of 2006, Avista launched a prescriptive program that had measures applicable to refrigerated warehouses. Although there are a relatively small number of these customers in the Avista service territory, there are significant opportunities for energy savings. The program provides the opportunity for customers to receive a prescriptive incentive for efficiency improvements in fast acting doors, door seals, VFD's, fan motors, freezer and cooler lighting. This program is marketed through account executives, vendors, contractors and other outreach material. This program is available to all refrigerated warehouse retail electric customers.
The program is budgeted to pay $21,600 in electric incentives. No expenses are directly related to this program.

Summary of Opportunities and Threats:
The prescriptive refrigerated warehouse program provides this segment of customers the opportunity to receive incentives through a streamlined approach. Customers can complete the listed measures, submit copies of their invoices and receive their incentive directly within 4-6 weeks.

Key 2010 Program Issues and Actions:
We will be looking at possibly combining the cooler lighting part of this program into the Prescriptive Lighting Program in 2010. We will be evaluating if this should be kept as a prescriptive program or possibly be offered as a site specific only.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Non-Residential Retro-Commissioning

Key Individuals:
Program Manager: Renee Coelho and Greta Zink
Program Technical Resource: Mike Dillon
Program Evaluation, Measurement and Verification Resource: Damon Fisher
Expected 2010 acquisition: None. This is an 'umbrella' program supporting acquisition in other programs.
Expected customer participation: Small segment of customers
Expected 2010 incentive cost: None expected
Expected 2010 non-incentive/non-labor cost: None expected
Expected 2010 total utility cost: None expected
TRC benefit/cost ratio: Inapplicable given the lack of activity and 'umbrella' program status of the program

Program Description:
This program provides an opportunity for eligible customers to receive an incentive towards a qualified retro-commissioning study. This program was developed for commercial buildings that have never gone through any type of commissioning or quality assurance process and are performing below their potential. Retro-commissioning is a systematic process for investigating, analyzing and optimizing the performance of building systems that have never (or at least within the last 5 years) been commissioned. Building commissioning is increasingly recognized as a cost-effective process to improve building performance, reduce energy use, increase equipment life, improve indoor air quality and improve occupant comfort and productivity. Although the savings that are achievable through retro-commissioning can be significant, market penetration still seems to be relatively low. Our program will try to overcome these barriers with education, incentives and a streamlined approach to implementation. Currently the program parameters include a .10 per square foot incentive for RCx studies done by a qualified commissioning agent, an incentive for contractors to make eligible "quick fixes" and the opportunity for customers to receive schedule 90/190 incentives for qualifying projects.

This program will be available to customers that meet the following criteria:

- Avista electric or electric and natural gas
- Building must have 50,000 square feet or more of conditioned space
- Building must be controlled by an energy management system
- Energy Use Index (EUI) of >100% of normal
- Building must be 5 years or older
- Minimum average occupancy of 50% over last 2 year period

This program was launched in the first quarter of 2009. We are estimating that 5 buildings will receive studies in 2010 and 1 building will complete.

Summary of Opportunities and Threats:
Some of the major barriers that have been identified include: lack of awareness, first cost too high to be funded through tight capital budgets, lack of resource time and knowledge, inconsistent approaches and the need for a significant time investment. Eligible customers would receive an incentive toward the submission of a qualified study. This will provide the opportunity for customers to identify and correct problems within the facilities that are causing an above normal EUI.

Evaluation, Measurement and Verification Plan:

Due to the low participation in this program there is not an evaluation planned at this time.

Program: Side Stream Filtration

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: $18 per ton for Side Stream Filtration System
Expected 2010 acquisition: 381,000 kWh
Expected customer participation: Approximately 3,000 tons
Expected 2010 incentive cost: $54,000
Expected 2010 non-incentive/non-labor cost:
Expected 2010 total utility cost: $60,073
TRC benefit/cost ratio:

0% net-to-gross scenario: 0.99 without tax credits, 0.99 with tax credits
25% net-to-gross scenario: 0.98 without tax credits, 0.98 with tax credits
50% net-to-gross scenario: 0.97 without tax credits, 0.97 with tax credits
75% net-to-gross scenario: 0.93 without tax credits, 0.93 with tax credits

Program Description:
Avista offers incentives for the installation of permanent side-stream filtration systems on open loop chiller/cooling tower systems. Side-stream filtration systems are easily installed on new or existing system. Side-Stream filtration does not replace normal maintenance, but helps the equipment operate more efficiently between normal cleaning and inspections.
Some of the benefits of a side-stream filtration system include:

- Reduction in corrosion & erosion
- Easily installed on new or existing systems
- Improves plant efficiency
- Extends equipment life

Summary of Opportunities and Threats:
This program helps keep the exterior water loop cleaner and therefore makes the exchange of heat or cooling more efficient.

Key 2010 Program Issues and Actions:
Check-in with past participants to make sure they are adhering to their annual tear down, inspection and maintenance of the chiller.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Steam Trap Replacement/Repair Program

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Steam Trap Replacement for the following pipe sizes:
1/2 inch, 3/4 inch, 1 inch, 1-1/4 inch, 1-1/2 inch, 2 inch
Expected 2010 acquisition: 9,151 Therms
Expected customer participation: Approximately 20 steam trap replacements
Expected 2010 incentive cost: $5,100
Expected 2010 non-incentive/non-labor cost:
Expected 2010 total utility cost: $5,246
TRC benefit/cost ratio:

0% net-to-gross scenario: 2.00 without tax credits, 2.00 with tax credits
25% net-to-gross scenario: 1.99 without tax credits, 1.99 with tax credits
50% net-to-gross scenario: 1.98 without tax credits, 1.98 with tax credits
75% net-to-gross scenario: 1.93 without tax credits, 1.93 with tax credits

Program Description:
Repair or replacement of failed steam traps. Where steam traps are to be replaced, only new working valve traps are eligible and traps must have a strainer. A minimum of 95 percent of the steam generation must be provided by Avista retail natural gas.

Summary of Opportunities and Threats:
Steam systems with faulty steam traps can waste significant amounts of energy. Maintenance on steam traps is often ignored. The steam trap incentive program is intended to increase awareness and incentivize customers and vendors to take action that previously had not been taken.

Key 2010 Program Issues and Actions:
This program is in process of being re-evaluated for current applicability to the market and tools to identify savings.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Prescriptive Vending Machine Control Program

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Installation of vending machine controls
Expected 2010 acquisition: 9,000 kWh
Expected customer participation: Various commercial businesses
Expected 2010 incentive cost: $900
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $1,043
TRC benefit/cost ratio:

- 0% net-to-gross scenario: 1.98 without tax credits, 1.98 with tax credits
- 25% net-to-gross scenario: 1.93 without tax credits, 1.93 with tax credits
- 50% net-to-gross scenario: 1.84 without tax credits, 1.84 with tax credits
- 75% net-to-gross scenario: 1.62 without tax credits, 1.62 with tax credits

Program Description:
A $90 rebate is available for the installation of vending machine controls on cold drink vending machines dispensing non-perishable drinks that do not have pre-existing vending machine controls. Rebates are available for the replacement of existing vending machine controls. Electric service to the vending machines must be provided by Avista Utilities.

Summary of Opportunities and Threats:
None critical to program implementation in 2010.

Key 2010 Program Issues and Actions:
No changes are being planned for this program at this time.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Prescriptive Commercial HVAC Variable Frequency Drive

Key Individuals:
Program Manager: Renee Coelho
Program Technical Resource: Mike Dillon and Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures include: Variable Frequency Drives (VFD) to be installed on commercial HVAC applications for one or more of the following equipment: Supply and/or Return Fans, Building Exhaust Fans, Boiler Feed Water Pump, Cooling Tower Pump, Chilled Water Pump and Condensing Water Pump. A total of 3 types of variable frequency drives are offered a rebate through this prescriptive method of program delivery: VFD for Fans; VFD for Cooling Pump Only; or VFD for Heating Pump or a Combined Heating and Cooling Pump.
Expected 2010 acquisition: 2,053,264 kWh's.
Expected customer participation: Approximately 20 individual customers. Many customers install more than one VFD at a time.
Expected 2010 incentive cost: $143,643
Expected 2010 non-incentive/non-labor cost: $0 –
Expected 2010 total utility cost: $194,256
TRC benefit/cost ratio:
0% net-to-gross scenario: 3.20 without tax credits, 3.20 with tax credits
25% net-to-gross scenario: 3.06 without tax credits, 3.06 with tax credits
50% net-to-gross scenario: 2.83 without tax credits, 2.83 with tax credits
75% net-to-gross scenario: 2.29 without tax credits, 2.29 with tax credits

Program Description:
The Commercial HVAC Variable Frequency Drive (VFD) Program serves the customer who would benefit from a variable frequency drive on their heating and cooling equipment. Large office buildings, school districts, universities, hospitals, manufacturing and production facilities are the primary participants of this program. The program was originally conceived in 1995 to offer customers a "prescriptive" way to participate in DSM program by installing a device that would be a benefit in most large commercial HVAC applications. An outside consulting firm was hired to analyze and develop the savings and initial incentives. These parameters are evaluated periodically or as changes are made to codes, DSM incentive levels or other issues that come along with program implementation. Vfd's are a gray area in the construction industry. In some cases they are required while in others they are one of many efficiency choices a customer can make. Avista's participants usually install VFD's in a retrofit situation but we are seeing them considered as part of new construction upgrades. Avista's program allows multiple VFD's to be submitted for a rebate at one time and often the customer will install anywhere from 2 – 10 vfd's on their HVAC equipment system with sizing from 2hp to 100 hp. The incentive that is paid for each vfd is based on the horsepower installed and varies based on the type of HVAC application (i.e. fan or pump).

Summary of Opportunities and Threats:
Avista continues to review the savings analysis associated with VFD installation and the role it plays in the new construction arena. A new building code standard is expected in July 2010. At that time Avista will re-evaluate if VFD's should be incentivized for new construction and determine if they are indeed industry standard for new buildings

Key 2010 Program Issues and Actions

Avista will continue to offer the Commercial HVAC Variable Frequency Drive program for both new construction and retrofits. A new building code standard is expected in July 2010. At that time Avista will determine if VFD's will be considered industry standard per the new code requirements.

Evaluation, Measurement and Verification Plan:

Since the energy efficiency incentive is based on the horsepower installed, Avista inspects each VFD unit to confirm that matches with what the customer has submitted on their application form and invoices. The Evaluation, Measurement and Verification Engineer will work in conjunction with the Program Manager in 2010 to incorporate measurement and verification of the Commercial HVAC Variable Frequency Drive in upcoming years.

Program: Shared Resource Conservation Manager (RCM) Program

Key Individuals:
Program Manager: Camille Martin
Program Technical Resource: Mike Dillon and others
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Site Specific
Expected 2010 acquisition: 353,488 kWh's and 21,193 therms
Expected customer participation: 4-16 commercial customers.
Expected 2010 incentive cost: None. Incentives for 'hardwired' program savings will accrue to the site-specific program.
Expected 2010 non-incentive/non-labor cost: $50,000
Expected 2010 total utility cost: $91,704
TRC benefit/cost ratio:

Note that this cost-effectiveness evaluation is based only upon the first year of the RCM program. A larger proportion of the energy savings will occur in year two of this minimum two-year program. In the event that a third year is funded yet additional savings will occur. Preliminary expectations as the program was being developed led to expectations that the two- and three-year gross cost-effectiveness is favorable. The three year cost-effectiveness with expected low non-net participation was projected to be favorable as well. The program remains under development and these estimates are preliminary.

0% net-to-gross scenario: 0.86 without tax credits, 0.86 with tax credits
25% net-to-gross scenario: 0.64 without tax credits, 0.64 with tax credits
50% net-to-gross scenario: 0.43 without tax credits, 0.43 with tax credits
75% net-to-gross scenario: 0.21 without tax credits, 0.21 with tax credits

Program Description:
This program creates a partnership between Washington State Energy Program (SEP), *Avista Utilities* and shared geographically organized counties, cities and school districts. *Avista Utilities* will structure, market and manage this program. SEP will provide the specialized training (Data management & Assessment) needed by prospective Resource Conservation Manager(s) (RCM). SEP and Avista would provide partial financial support plus the support of 10% by each participant. The proposed program has the potential to achieve very substantial, long-term energy and natural resource cost savings.

Past Experience
Avista Utilities has past experience promoting the use of RCM that was limited to K-12 schools. Avista was unable to expand this program to larger campuses, campuses with more complex ownership structures or energy usage patterns, or privately-owned corporate campuses – campuses that arguably present greater EE savings opportunities than those found at the typical K-12 school setting. With the new resources provided by the American Recovery and Reinvestment Act of 2009 (ARRA), Avista Utilities believes that it can now execute this larger RCM program in its territory in the state of Washington.

As part of Avista's energy efficiency strategy, we will be providing partnerships with Cities, Counties and School districts to develop a resource conservation management program:

- This program would motivate certain large-scale utility customers in Washington to employ dedicated resource conservation managers at sites of concentrated (and currently largely unmanaged) energy usage of government facilities.
- Avista will structure, market and manage this program, and arrange for the specialized training needed by prospective resource conservation managers.

- Avista will continue to provide a commercial and industrial energy audit and incentives programs.
- Avista believes that the deployment of trained resource conservation managers at these kinds of facilities has the potential to achieve substantial and measurable energy efficiency ("EE") cost savings.
- Avista will operate this program in partnership with the Washington State Energy Program ("SEP"):
    - Avista Utilities contributes in the first year following the appointment of a trained RCM; the measured energy cost savings realized from his efforts will more than offset the fully-loaded employment costs of the new position.
    - Our goal is to deliver more value to our customers for their energy dollar, while continuing to meet our customers' energy needs in a reliable and low-cost way.
    - This program will help create sustainable green jobs.

<u>Goals</u>

RCM Program goals include:

- Reduce the energy use in counties, cities and school district buildings and facilities.
- Increase the ability for counties, cities and school districts to manage their expenses for energy and other utilities.
- Establish a shared RCM program that supports small counties, cities and school districts.
- Create a sustainable RCM program.
- Create RCM employment opportunities.
- Provide energy and resource conservation education outreach to staff, students and community.
- Deliver more value to our customers for their energy dollar, while continuing to meet our customers' energy needs in a reliable and low-cost way.
- Evaluate and measure the RCM Program's success.
- Provide suggestions so that the program continuously improves.
- Report results of the program's execution and reduction in use of kilowatts and therms.

<u>Summary of Opportunities and Threats</u>:

<u>Opportunities</u>

- Reduce the energy use in counties, cities and school district buildings and facilities.
- Increase the ability for counties, cities and school districts to manage their expenses for energy and other utilities.
- Establish a shared RCM program that supports small counties, cities and school districts.
- Create a sustainable RCM program.
- Create RCM employment opportunities.
- Provide energy and resource conservation education outreach to staff, students and community.
- Cash incentives programs for specific actions by occupants and staff in individual facilities that reduce energy consumption.
- Community efforts to create green sustainable jobs.

<u>Challenges</u>

- Getting a cooperative commitment of a shared RCM may be difficult.
- Obtaining budget approval to allocate a portion of the salary for the RCM and energy efficient capital improvements. Dwindling county and city budgets may not afford 10% of RCM salary and capital improvements.
- Receiving the support needed from the campuses top management and staff under them.
- Convincing occupants to change behavioral practices.

- Convincing custodial and maintenance staff that their involvement is vital for the program to succeed.
- A shared RCM may be stretched too far to complete all tasks.

Key 2010 Program Issues and Actions:
This program has not been planned and executed. This is a place holder, as this may be a 2010 energy efficiency program that Avista offers.

Evaluation, Measurement and Verification Plan:
Quantifying savings as a result behavioral changes is challenging. As the scope of the position develops a measurement and verification plan will be developed. If the positions are created a formal process evaluation is scheduled for 2011.

Program: Non-Residential Site Specific Programs
(Combined gas and electric programs unless otherwise specified)

Key Individuals:
Program Manager: Renee Coelho and Greta Zink
Program Technical Resource: Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included:
Expected 2010 acquisition: 26,000,000 kWh and 785,000 therms
Expected customer participation: Various commercial and industrial customers
Expected 2010 incentive cost: $4,160,000 in electric and $2,355,000 in gas incentives
Expected 2010 non-incentive/non-labor cost: None assigned to the program
Expected 2010 total utility cost: $7,224,280
TRC benefit/cost ratio (electric):
- 0% net-to-gross scenario: 3.63 with tax credits, 3.63 without tax credits
- 25% net-to-gross scenario: 3.51 with tax credits, 3.51 without tax credits
- 50% net-to-gross scenario: 3.30 with tax credits, 3.30 without tax credits
- 75% net-to-gross scenario: 2.79 with tax credits, 2.79 without tax credits

TRC benefit/cost ratio (natural gas):
- 0% net-to-gross scenario: 1.56 with tax credits, 1.56 without tax credits
- 25% net-to-gross scenario: 1.56 with tax credits, 1.56 without tax credits
- 50% net-to-gross scenario: 1.55 with tax credits, 1.55 without tax credits
- 75% net-to-gross scenario: 1.53 with tax credits, 1.53 without tax credits

Program Description:
The site specific program is a major component in our commercial/industrial portfolio. Customers receive technical assistance and incentives in accordance with Schedules 90/190. Our program approach allows us to have a very flexible response to any energy efficiency project that has demonstrable kWh and/or therm savings. The majority of site specific kWh and therm savings are comprised of appliances, compressed air, HVAC, industrial process, motors (non-prescriptive), shell measures and some custom lighting projects that don't fit the prescriptive path. This program is available to all non-residential retail electric and natural gas customers. It is estimated that customers who participate in the 2010 site specific program will realize energy savings of over 26 million kWh and 685,000 therms. The site specific program brings in the largest portion of savings to the overall energy efficiency portfolio.

Summary of Opportunities and Threats:
Renee Coelho manages the contract process for the site specific program. The engineering group calculates savings based on the individual project and incentive calculations are made through the standardized dual-fuel incentive calculator (DFIC) based on the parameters of schedule 90/190. The account executives are responsible for outreach and management of customer projects. The outreach effort for this program is primarily through the account executives. The account executives are designated as the one point of contact for commercial and industrial customers. Program outreach also occurs through the engineering group and industry trade allies. The commercial energy efficiency programs, including site specific, are also marketed through the website, at tradeshows, through industry groups and through other appropriate trade publications.

Evaluation, Measurement and Verification Plan:
In the 2010 plan, HVAC site-specific measures including high efficient rooftop units, boilers, and furnaces are scheduled for impact analysis. Targeted measurement and verification will be performed as necessary for non HVAC site-specific measures.

Program: Non-Residential Rooftop HVAC Maintenance Pilot Program

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Levi Westra
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: None at this time
Expected 2010 acquisition: Pilot Program will not be completed until the end of 2010
Expected customer participation: Pilot customers only, currently 2.
Expected 2010 incentive cost: No incentive dollars were applied to 2010.
Expected 2010 non-incentive/non-labor cost: No significant incremental funding in 2010 for pilot costs.
Expected 2010 total utility cost: No material costs.
TRC benefit/cost ratio: Inapplicable. This is a pilot program only. Based upon the results of the pilot program the cost-effectiveness of a generally available program will be estimated.

Program Description:
The HVAC Rooftop Maintenance Pilot Program is being run to determine the savings that can occur when performing regular maintenance on an HVAC Rooftop Unit compared to units that have no maintenance done regularly. This pilot program is replacing the AirCare Plus Program that ran for five years. AirCare Plus started as a NEEA venture to attempt market transformation for the rooftop HVAC industry. The premise of the program was that very little, if any, maintenance was done on a regular basis for these units. NEEA decided to no longer fund the project when it was determined not to be a reasonable market transformation effort. We decided to fund the program at a local level and make changes to the protocol to fit our needs. The program was run in our Idaho service territory for 2 years and then was expanded service territory wide for 2006, 2007 and 2008. During external audits, this program was flagged as one to be re-evaluated for savings. We are in that re-evaluating process now.

Summary of Opportunities and Threats:
In our external audits we had been asked to look at the savings being identified with this program. In order to accommodate that request, we did not renew our contract with PECI in order to initiate a pilot program. This pilot is to compare like rooftop units, on one rooftop, performing maintenance on one and not the other and log the data on both units to better identify the energy savings of regularly maintaining those units.

Key 2010 Program Issues and Actions:
The outcome of the pilot program will determine our next steps in what type of offering we may have for this market sector.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Non-Res Demand Controlled Ventilation

Key Individuals:
Program Manager: Greta Zink
Program Technical Resource: Mike Dillon
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Ventilation controls paid at .25 per square foot
Expected 2010 acquisition: 7,892 kWh and 608 therms
Expected customer participation:
Expected 2010 incentive cost: $1,000
Expected 2010 non-incentive/non-labor cost:
Expected 2010 total utility cost: $1,135
TRC benefit/cost ratio:

> 0% net-to-gross scenario: 1.95 without tax credits, 1.95 with tax credits
> 25% net-to-gross scenario: 1.91 without tax credits, 1.91 with tax credits
> 50% net-to-gross scenario: 1.83 without tax credits, 1.83 with tax credits
> 75% net-to-gross scenario: 1.64 without tax credits, 1.64 with tax credits

Program Description:
Avista offers incentives for installing ventilation controls on existing buildings that use carbon dioxide levels to measure occupancy and modify the percentage of outside air based on variable levels. Rather than setting intake rates for maximum occupancy levels at all times, demand-controlled ventilation measures the approximate number of people occupying a space and resets the intake rates based on that measurement. In order to be eligible for incentives, conditioned spaces must be kept between 65 and 75 degrees during operating hours. Incentives are based on the total square footage of the controlled conditioned space with a 2,000 square feet minimum. Incentives will be paid at a rate of $.25 per square foot with a cap of 2,500 square foot per sensor. If the space has portable walls, each room must be controlled separately. Controlled space must meet a minimum of ASHREA 62 standards.

Summary of Opportunities and Threats:
This program was developed to encourage the control of existing building temperatures of conditioned spaces.

Key 2010 Program Issues and Actions:
No changes are being planned for this program in 2010.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: Prescriptive Lighting

Key Individuals:
Program Manager: Leona Doege
Program Technical Resource: Tom Lienhard and others
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: A total of 20 individual measures (and additional sub-measures). These include T12, HID incandescent retrofits to more energy efficient light sources including, T8, T5, induction LED, cold cathode and a variety of compact fluorescent lamps.
Expected 2010 acquisition: 11,550,000 kWh. There will be an interactive impact upon the fuel used for space heating, including natural gas.
Expected customer participation: Approximately 2,000 individual customers.
Expected 2010 incentive cost: $1,933,265
Expected 2010 non-incentive/non-labor cost: $300 primarily for collateral material
Expected 2010 total utility cost: $2,083,962
TRC benefit/cost ratio:
- 0% net-to-gross scenario: 1.06 without tax credits, 1.06 with tax credits
- 25% net-to-gross scenario: 1.05 without tax credits, 1.05 with tax credits
- 50% net-to-gross scenario: 1.03 without tax credits, 1.03 with tax credits
- 75% net-to-gross scenario: 0.97 without tax credits, 0.97 with tax credits

Program Description:
There is significant opportunity for lighting improvements in commercial facilities. Avista has been offering site specific incentives for qualified lighting projects for many years. In an effort to streamline the process and make it easier for customers and vendors to participate in the program we developed a prescriptive approach several years ago. This program provides for many common retrofits to receive a pre-determined incentive amount. Incentive amounts were calculated using a baseline average for existing wattages and replacement wattages. Actual savings are calculated based on customer run times using the averages as calculated for incentive amounts.

This program is available to all non-residential retail electric customers in Washington and Idaho.

The prescriptive lighting program makes it easier for customers, especially smaller customers and vendors to participate in the program. We have seen a substantial increase in the number of projects that have been completed since this approach was instituted.

Summary of Opportunities and Threats:
Code changes and future bans on existing light sources are a concern regarding establishing a phase-out period for incentives for certain measures. For example, T12 retrofits are expected to be phased out by July 2012. LED lighting is advancing in performance and coming down in price. Opportunities to help customers change out outdoor area lighting and some street lighting may increase as a result over the next two years.

Key 2010 Program Issues and Actions:
Some changes to the measures offered and incentive levels are expected to take place in early 2010. Those changes are still under review at the time of this business plan. The changes are to better streamline our efforts towards providing incentives to only cost effective measures and to provide market barrier removal. For example, two-foot U-lamps are expensive, making a T12 to T8 U-tube retrofit a non-cost effective measure. It is expected to be replaced with T12 U-lamp to T8 linear retrofit in the two-foot section of our Commercial Lighting Incentive Agreement

form. Some incentives are expected to be lower due to lower product and installation costs we are seeing.

Evaluation, Measurement and Verification Plan:
It is imperative we continue to do our due diligence to make sure we are properly accounting for energy savings. Once a specific lighting measure is added to the prescriptive lighting program the verification continues in several ways.

- Random verification of savings through installation pre and post metering on a sample of devices in retrofit isolation.
- Verification of installation of a sampling of individual prescriptive projects.
- Verification of equipment costs for review of incentive amounts.
- Substantiation of equipment / materials and quantities proposed vs. installed via supplier invoices and on-site Post Verification inspections
- Verification of changes in building code requirements and changing expectations for incentives.
- Verification of the appropriateness of average runtime hours used in the prescriptive lighting savings calculator done by studying prior installations.

Spring of 2009, a study was conducted on 2008 prescriptive lighting projects. Verification of program deemed savings and confirmation of the program's predicted energy savings were the primary study goals. Specifically the study targeted actual runtime hours of installed measures. These runtimes were compared to the customer provided values, and statistically evaluated.

The study measured actual runtime hours from a sample of 44 projects. The projects were randomly selected, from a pool of nearly 500 prescriptive lighting projects, using a random number generator. This sample size provided a confidence level of 90% with an initially estimated confidence interval of 15%. That is, there is 90% confidence that the sample results will be within a range of ±15% of the average result. Based on this statistical sample model, lighting loggers were installed at each of the sample sites, and logged operation for 7 continuous days.

Initial results indicate that the average customer under reports hours of operation by 2% (3067 hrs reported versus 3133 hrs measured). The primary metric evaluated in this study is the ratio of measured hours to reported hours (Tmeas/Treport), using a metric based on a ratio normalizes the data. The average of this metric for the 44 samples is 1.13. This indicates that on average each project measured 13% more hours than they reported. As a result, for the projects sampled, the analysis predicted 19% under estimate in program energy savings, specifically, 692,588kW-h/yr of energy savings estimated based on customer information, and 828,279kW-h/yr of energy savings based on actual measured operation. The higher percentage of energy savings is a result of several large projects under reporting hours of operation, thereby weighting energy savings. Also, evaluation of the data indicates that the initial estimate of a 15% confidence interval was not far from reality with the data revealing a confidence interval of 17.7%.

In summary, it can be said with 90% confidence that the program will result in hourly operation between 95% and 131% of the customer provided value. Also, the sample indicates that the customers participating with relatively large projects may be more likely to under-estimate hours of operation.

For 2010, each measure within the program will be monitored on its percentage of throughput. We do see changes in throughput per measure from year to year. However, monitoring throughput per measure will help direct our efforts for 2011 and 2012 program planning and changes we expect to make according to code changes.

The Residential Portfolio Overview

Chris Drake

The Company's residential portfolio is composed almost entirely of prescriptive programs. The only efficiency measures that are not prescriptive are for multifamily residential customers or distributed generation. In these unique cases the projects are treated site-specifically. Otherwise, efficiency measures not incorporated within one of the prescriptive programs are not available for residential customers. This is necessitated by the large number of small projects that characterize the residential customer segment.

The residential market is expected to acquire 30% of electric and 51% of the natural gas savings achieved by Avista during 2010. This amount, and particularly the natural gas acquisition, is subject to a significant amount of uncertainty due to the continuation of federal tax credits, the launch of the residential audit program and the impact of the Price of Gas Adjustment (PGA) revisions upon customer decision-making.

The measure-by-measure sub-TRC analysis will lead to the termination of several significant residential efficiency measures during 2010, specifically tankless water heaters, ground-source heat pumps and high-efficiency air conditioning. The timing of those terminations is dependent upon the need for customer and trade ally notice.

Program: Multifamily Direct Use

Key Individuals:
Program Manager: Chris Drake (Overall effort led by Ken Boni and Sue Baldwin)
Program Technical Resource: Jon Powell, Tom Lienhard, Renee Coelho, Sue Baldwin, Ken Boni, Pat Lynch, Bruce Folsom, Bryan Cox, Debbie Simock, Colette Bottinelli
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: The program incents developers to install natural gas space and water heating as opposed to the default electric choices in new construction multifamily projects.
Expected 2010 acquisition: 1,301,684 kWh
Expected customer participation: 300 customers
Expected 2010 incentive cost: $ 300,908
Expected 2010 non-incentive/non-labor cost: $ 0
Expected 2010 total utility cost: $311,008
TRC benefit/cost ratio:
0% net-to-gross scenario: 3.77 without tax credits, 3.77 with tax credits
25% net-to-gross scenario: 3.77 without tax credits, 3.77 with tax credits
50% net-to-gross scenario: 3.77 without tax credits, 3.77 with tax credits
75% net-to-gross scenario: 3.77 without tax credits, 3.77 with tax credits

Program Description:
The multifamily direct use program attempts to avoid the loss opportunity associated with space and water heating systems in multifamily. Historically the developers are concerned with first costs and therefore install electric straight resistance space and water heating in the majority of multifamily properties. Unlike single family and forced air heating systems, retrofitting electric baseboard in multifamily or venting water heaters after the fact is extremely cost-prohibitive.

There is a strong market transformation effort that intends to obtain a meaningful share of the multifamily market and hopefully increase knowledge with developers of natural gas options as well as solidify new designs and installation expertise.

The following is the current customer description of the program with primary program requirements.

Multifamily Development Incentives
Incentives are available to multifamily developers who install natural gas space and water heating measures rather than electric. An incentive of $2,000 per unit is available for installation of natural gas space heat and natural gas water heat. Multifamily is defined as 4 or more units per building for this incentive. Incentives are available for new construction only. Supplemental electric heat is allowable in the units as long as 75% of the unit is heated with natural gas. Qualifying water heating applications can either be individual natural gas hot water heaters in each unit or a central natural gas hot water system.

Summary of Opportunities and Threats:
The program attempts to cover full incremental costs and we are monitoring for a shift in the market. The long term plan is to reduce incentives to just the value of the avoided electric costs. The challenge is getting in front of developers and having them to commit before the design phase which can have over a year lag until construction. We want to sunset the program appropriately but not prematurely so we need to balance getting developers into the program, getting projects completed, obtaining a share of the market and then moving towards the lower incentives.

One of the biggest challenges is the issue of split incentives. Investments in energy efficiency by the developer create benefits that directly accrue to the tenant. A long term view would suggest that a multifamily property with lower utilities has greater value and higher occupancy rates but first cost remains a significant hurdle. Ideally the market transformation effort will reduce the incremental cost of installing natural gas by growing the natural gas multifamily designs and installation expertise in the region.

Key 2010 Program Issues and Actions:
Due to the economic downturn, the multifamily starts have been reduced and the opportunity to contract developers in the program has been diminished. Many starts in 2010 may have been designed over 2 years ago so 2010 should be a good indicator but it is unlikely that we will make changes in 2010. If the program is successful in 2010, it would certainly position it for evaluation in 2011 and potential changes. Again, it’s a delicate balance to cement developers into using the societal preference of direct use and not pull the rug out from under them by eliminating the program before the market is transformed. Of course, at some point it will have to be determined if the split incentive is too much of a barrier and developers remain focused on short term and first costs.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary. This program is scheduled for an impact analysis in 2012

Program: Multifamily Energy Efficiency Direct Install

<u>Key Individuals</u>:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Mike Dillon, Greta Zink, UCONS
Program Evaluation, Measurement and Verification Resource: Damon Fisher

<u>Program Overview</u>:
Measures included: The multifamily direct install program ended at the end of 2009 after a 2 ½ year effort. There are no plans to continue it at this time.
Expected 2010 acquisition: 429,330 kWh's
Expected customer participation: No new customers. The contract has reached the end of its term and only follow-up installations are being completed.
Expected 2010 incentive cost: No new incentives
Expected 2010 non-incentive/non-labor cost: No new non-labor costs
Expected 2010 total utility cost: $3,331 in labor costs to wrap-up the last few jobs and contract
TRC benefit/cost ratio:

0% net-to-gross scenario: 2.17 without tax credits, 2.17 with tax credits
25% net-to-gross scenario: 2.15 without tax credits, 2.15 with tax credits
50% net-to-gross scenario: 2.12 without tax credits, 2.12 with tax credits
75% net-to-gross scenario: 2.02 without tax credits, 2.02 with tax credits

<u>Program Description</u>:
Direct installation of small efficiency devices (CFL's, low-flow showerheads etc) in multifamily units. UCONS has been contracted to perform the program recruitment and implementation. The contract ended in 2009, absent the completion of the installation of a few of the late contacts made under the program.

<u>Summary of Opportunities and Threats</u>:
This program serves as a template for the possible future use of direct-installation programs, particularly in difficult to reach market segments. This experience will be incorporated into the discussion of other similar residential and non-residential segments as well as the limited income collaborative discussions.

<u>Key 2010 Program Issues and Actions</u>:
The program termination should proceed without any major issues. UCONS has saturated the eligible and interested market. Customer requests have fallen off significantly during the last months of the program.

<u>Evaluation, Measurement and Verification Plan</u>:
To be determined.

Program: Energy Star Homes

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Rachelle Humphrey, Mike Dillon
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Incentives are available for customers who purchase an Energy Star certified, new construction home. The program covers both stick-built and manufactured homes.
Expected 2010 acquisition: 368,650 kWh 16,548 therms
Expected customer participation: 122 customers.
Expected 2010 incentive cost: $ 108,550
Expected 2010 non-incentive/non-labor cost: $ 209
Expected 2010 total utility cost: $114,747
TRC benefit/cost ratio:

- 0% net-to-gross scenario: 1.56 without tax credits, 1.97 with tax credits
- 25% net-to-gross scenario: 1.56 without tax credits, 1.96 with tax credits
- 50% net-to-gross scenario: 1.55 without tax credits, 1.95 with tax credits
- 75% net-to-gross scenario: 1.52 without tax credits, 1.91 with tax credits

Program Description:
This program leverages the regional and national effort surrounding Energy Star homes. The Northwest Energy Efficiency Alliance has committed significant resources to develop and implement a program that sets standards, trains contractors and provides 3rd party verification of qualifying homes. NEEA in effect administers the program and Avista pays the incentive for homes that successfully make it through the process and certified. Additionally, after the launch of NEEA's regional effort, the manufactured homes industry established manufacturing standards and a labeling program to obtain Energy Star certified homes. While the two approaches are unique, they both offer 15-25% savings versus the baseline and offer comparable savings.

The following is the current customer description of the program with primary program requirements.

Energy Star Homes
A $900 incentive is available for new construction homes using Avista electric or Avista electric and natural gas that meet the ENERGY STAR Homes criteria and are verified as an ENERGY STAR Home. Homes must use Avista electric or natural gas to heat their homes and their hot water. This incentive may not be combined with any other incentive.
A $650 incentive is available for homes that have Avista natural gas but electric is not provided by Avista (both the hot water and space heat must be natural gas). This incentive may not be combined with any other incentive. For more information on ENERGY STAR Homes visit www.northwestenergystar.com

Summary of Opportunities and Threats:
Fortunately this is a regional effort that is closely involved in codes and standards as the changing baseline for new construction creates a challenge to ensure Energy Star standards achieve adequate savings. NEEA continues to work this issue to ensure they stay ahead of the minimum with requirements for Energy Star homes.

Key 2010 Program Issues and Actions:

No changes are contemplated by Avista unless guidance from NEEA, due to code changes, requires program changes.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary. This program is scheduled for impact evaluation in 2011.

Program: Residential Direct-Use Efficiency
(AKA Residential Fuel-Efficiency or Residential Conversions)

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Rachelle Humphrey, Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Conversion from electric straight resistance space and water heating. For space heating measures specifically include customers converting primary electric heat such as electric baseboard and electric forced air furnaces to natural gas heat. Measures include ducted and non-ducted natural gas heating solutions. For water heat, measures include converting electric water heaters to natural gas. In all cases, measures require customer to be Avista electric. As a note, electric to heat pump energy efficiency upgrades are described to customers as conversions, however, their costs and savings are included in the HVAC program.
Expected 2010 acquisition: 2,152,981 kWh
Expected customer participation: Approximately 167 customers
Expected 2010 incentive cost: $ 113,250
Expected 2010 non-incentive/non-labor cost: $ 526
Expected 2010 total utility cost: $130,479
TRC benefit/cost ratio:
0% net-to-gross scenario: 2.84 without tax credits, 2.84 with tax credits
25% net-to-gross scenario: 2.81 without tax credits, 2.81 with tax credits
50% net-to-gross scenario: 2.75 without tax credits, 2.75 with tax credits
75% net-to-gross scenario: 2.59 without tax credits, 2.59 with tax credits

Program Description:
Program is targeted to Avista electric customers using electric straight resistance as their primary space heat or electric for water heat. While residential measure do not lend themselves to site-specific approaches due to large number of customers, there is an opportunity to make assumptions for an average residential home and thus implement a prescriptive offering. Electric shares a smaller portion of the space and water heat market, however, where those customers exist and natural gas is available, significant electric savings are present. This is a retrofit program only since the majority of new construction single family home already install natural gas.

The following is the current customer description of the program with primary program requirements.

CONVERSIONS FROM ELECTRIC STRAIGHT RESISTANCE
Electric to Natural Gas Heat
A $1,000 incentive is available to Avista electric customers who replace electric as their primary heat (i.e. electric forced air furnace or electric baseboard heat) with a central natural gas heating system. This incentive may be claimed in addition to the high-efficient natural gas furnace incentive. A $500 incentive is available to replace Avista electric heat with a natural gas wall heater.

Electric to Natural Gas Water
A $250 incentive is available to Avista electric customers who replace an electric water heater with a new natural gas water heater. This incentive may be claimed in addition to the high-efficient natural gas water heater incentive.

Summary of Opportunities and Threats:
As we continue to offer conversion incentives and potentially “move further up the tree” beyond the low hanging fruit of easy to convert or very short payback projects, we will want to verify prescriptive saving estimates. In other words, as the market shrinks and we convert hard to reach customers, do these customers have a smaller heat load requirement, longer payback, etc. Intuitively, increased incentives in March of 2008 started to reach hold outs to conversion perhaps due to large capital costs but relatively smaller heating load. This may or may not be significantly different than prescriptive assumptions but it has been highlighted for impact evaluation.

Key 2010 Program Issues and Actions:
Impact evaluations will be monitored closely in case results demonstrate a need to reduce prescriptive savings estimates and/or incentive levels.

Evaluation, Measurement and Verification Plan:
This program is on the 2010 schedule for impact evaluation. As of this writing, the data for resistance heat to natural gas is being collected. The evaluation will provide a reasonable savings per unit from a statistically significant sample. In addition, we should gain an understanding of our underlying assumptions.

Program: Residential HVAC Efficiency

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Rachelle Humphrey, Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Increase customer space heating from standard efficient natural gas furnaces and boilers to high efficiency. Increase customer space heating from standard efficient heat pumps and electric straight resistance to high efficiency electric heat pumps.
Expected 2010 acquisition: 8,016,338 kWh 358,914 therms
Expected customer participation: Approximately 6,210 customers
Expected 2010 incentive cost: $ 2,144,200
Expected 2010 non-incentive/non-labor cost: $ 4,531
Expected 2010 total utility cost: $2,148,731
TRC benefit/cost ratio:
0% net-to-gross scenario: 1.53 without tax credits, 1.57 with tax credits
25% net-to-gross scenario: 1.52 without tax credits, 1.56 with tax credits
50% net-to-gross scenario: 1.50 without tax credits, 1.54 with tax credits
75% net-to-gross scenario: 1.46 without tax credits, 1.49 with tax credits

Program Description:
This program is quite versatile as it is able to reach new construction and existing homes as well as existing and new natural gas customers. The basic premise is customers are replacing upon burnout (or new construction) and are planning to buy at least a code heat pump or natural gas furnace. So whether it's a new home or a home with an older furnace, even if the older furnace is another fuel, a customer is encouraged to upgrade from the standard efficient heat pump or natural gas furnace to a high efficient model.

This program lends itself well to a prescriptive offering similar to most residential applications that involve a large number of customers in similar single family home settings. Savings are estimated based on the difference between heating an average home with a high efficient system versus the code minimum. Certainly some homes are bigger and some homes are smaller, some have higher heat settings, some have lower, etc. Estimates are intended to be conservative and while some may be less than estimated and equal or larger amount will be greater.

The following is the current customer description of the program with primary program requirements.

HIGH EFFICIENCY EQUIPMENT INCENTIVES
Natural Gas Furnace/Boiler
A $400 incentive is available for installation of a high efficiency natural gas furnace of 90% AFUE (heating efficiency) or greater, or a natural gas boiler of 90% AFUE or greater.

Air Source Heat Pump
A $400 incentive is available for installation of a high efficiency central heat pump of 8.5 HSPF (heating efficiency) or greater (7.7 HSPF and 13.0 SEER for manufactured homes. Please make a note on rebate form to indicate manufactured home.) HSPF verification requires an ARI certificate. Ductless Heat Pumps are being evaluated through a separate pilot and do not qualify for this incentive at this time.

Ground Source Heat Pump
A $1500 incentive is available for installation of a high efficiency ground source heat pump of 13.6 HSPF (heating efficiency) or higher. A comparable Coefficient of Perfomance rating would be a 3.5 COP or higher. This may not be combined with any other high efficiency incentives.

Variable Speed Motor
A $100 incentive is available for installation of a primary heating system that incorporates a variable speed motor. This incentive may be combined with a high efficiency incentive.

Central Air Conditioner
A $350 incentive is available for replacing an old but functioning central air conditioning system with a new high efficient model of 14.0 SEER or better. Central air conditioning in this case is defined as a ducted air conditioning system of 1.5 tons (18,000 BTUs) cooling or higher, conditioning at least 75% of the home. This incentive may not be combined with heat pump or variable speed motor incentives. SEER verification requires an ARI Certificate.

Summary of Opportunities and Threats:
While the program requires minimum requirements for participation, it should be noted that we have surveyed actual efficiency levels to better estimate savings. For example, the program requires a 90% AFUE natural gas furnace which is significantly higher than the federal minimum 78% AFUE requirement. There are federal tax credits currently available that require 95% AFUE and so we are currently experiencing a large percentage of installations that are materially more efficient than our minimum requirement for participation.

The presence of the federal tax credit also contributes to throughput and we should anticipate continued high or even increased throughput as long as the tax credits remain. Currently, the applicable credit expires at the end of 2010.

Key 2010 Program Issues and Actions:
Space heating (and cooling) represent the largest energy loads for residential and thus offer significant energy saving opportunities. Some of the measures currently available, however, either come at too large a premium to be cost-effective and/or have federal standards that are fairly high efficient already. Ground Source Heat Pump and retro-fit Air Conditioning measures did not pass sub-TRC evaluations and therefore will be discontinued in 2010.

Evaluation, Measurement and Verification Plan:
This program is on the 2010 schedule for impact evaluation. In addition to verifying savings we will gain a better understanding of the underlying assumption used in residential calculations. Those assumptions are used in several programs.

Program: Residential Shade Tree Program

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Garth Davis
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Installation of shade tree to include pre-qualification call to/from Spokane County Conservation District (SCCD), site-visit and tree-siting by SCCD master gardener, tree planting by SCCD designated volunteer.
Expected 2010 acquisition: 2,088 kWh (based upon average annual savings over measure (tree) life. First year savings are virtually zero with a significant annual increase over time.
Expected customer participation: Approximately 100 customers
Expected 2010 incentive cost: $1,800
Expected 2010 non-incentive/non-labor cost: $400 for collateral materials
Expected 2010 total utility cost: $2,216
TRC benefit/cost ratio:
- 0% net-to-gross scenario: 0.86 without tax credits, 0.86 with tax credits
- 25% net-to-gross scenario: 0.86 without tax credits, 0.86 with tax credits
- 50% net-to-gross scenario: 0.85 without tax credits, 0.85 with tax credits
- 75% net-to-gross scenario: 0.84 without tax credits, 0.84 with tax credits

Program Description:
While this program is designed to be replicable throughout our electric service territory, it relies heavily on 3rd party involvement. In this case Avista has partnered with the Spokane County Conservation District (SCCD) who has offered to deliver the program to customers.

The program offers an $18 incentive per tree to SCCD for installation of qualifying shade trees. SCCD will work with customers to identify via the phone potential sites. SCCD will then conduct a site-visit to the customer's home to site the right tree in the right location for energy savings. The siting is 15-30 feet to the south of the home and avoiding overhead electrical and other utility lines. SCCD has selected shade trees that are recommended for this region and it's growing conditions as well as potential of large canopy at maturity.

While Avista may support a larger effort, SCCD has proposed a targeted approach in the city of Spokane with a planned installation of 50 trees in the spring and 50 in the fall.

The goal is that the shade tree will offset existing or potential air conditioning load in the future. The savings increase over the life of the tree and the first year savings are an average year savings over the life of the tree.

The following is the current customer description of the program with primary program requirements.

SHADE TREE PROGRAM City of Spokane-Avista Electric
Avista is partnering with Spokane County Conservation District (SCCD) in an effort to reduce the cooling demand in homes and increase the urban tree canopy. A properly placed deciduous tree can reduce your summer cooling cost by up to 40 percent.
For program eligibility and guidelines please contact Garth Davis at SCCD by e-mail garth-davis@sccd.org or call SCCD at 509-535-7274.

The cost of the program is underwritten by Avista and SCCD, the homeowner is responsible for the care and maintenance of the tree.

To be eligible for the Shade Tree program you must be a homeowner in the City of Spokane, Washington and an Avista electric customer. The sight will be inspected by SCCD personnel to ensure you have the space available for a mature tree on the west side of your home. You will receive a site visit that will determine the exact location and proper tree for your needs. To maintain the health of the tree it will be planted by SCCD in the spring or fall. The home owner is responsible for the ongoing care and maintenance of the tree as directed.
If you are interested in the Shade Tree Program please contact: Garth Davis at the SCCD by e-mail garth-davis@sccd.org or call SCCD at 509-535-7274.

Program Eligibility and Guidelines
The Shade Tree Program is available to Avista electric customers in the city of Spokane, Washington.

SCCD will conduct a pre-screening meeting to help identify qualifying homes.
Minimum program requirements include:
Owners of existing single and multi-family, primary living residences (including manufactured and modular homes) are eligible to participate in the Program.
Owners are responsible for complying with all applicable codes and regulations.
Owners must submit a signed copy of this Agreement to Avista, prior to the shade tree being planted.

Avista reserves the right to verify that a shade tree has been planted and/or inspect such shade tree after planting. Avista will coordinate inspection with Owners, as applicable.

Summary of Opportunities and Threats:
As mentioned above, the program was designed with the ability to replicate it to other parts of the electric service territory. Avista will continue to respond to proposals from regional arborists and make them aware of the potential shade tree incentive.

Key 2010 Program Issues and Actions:
The program was successfully launched in 2009 with an initial pilot of approximately 30 homes/trees. While the full implementation is only 100 per year we are open to additional expansions by SCCD or new partners.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation; however, targeted installation (planting) verification will be performed as necessary.

Program: Residential Shell

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Rachelle Humphrey, Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Improve weatherization or shell of customer homes by increasing R-values in attic/ceiling, wall and floor as well as replacement of existing windows to new energy star windows.
Expected 2010 acquisition: 5,032,707 kWh 477,834 therms
Expected customer participation: Approximately 6,210 rebates
Expected 2010 incentive cost: $ 1,981,325
Expected 2010 non-incentive/non-labor cost: $ 4,653
Expected 2010 total utility cost: $2,028,739
TRC benefit/cost ratio:
- 0% net-to-gross scenario: 0.94 without tax credits, 1.21 with tax credits
- 25% net-to-gross scenario: 0.94 without tax credits, 1.21 with tax credits
- 50% net-to-gross scenario: 0.94 without tax credits, 1.20 with tax credits
- 75% net-to-gross scenario: 0.93 without tax credits, 1.19 with tax credits

Program Description:
This program targets customers with under-insulated homes and older, inefficient windows. For customers with less than R-19 in the attic or less than R-5 in the wall or floor, this program incents customers to complete measures that increase the existing R-Value by R-10 or greater. In many cases, the average R-Value increase is closer to R-19 than R-10, however, the minimum is R-10 to allow for the greatest number of installations and savings are based on an average R-15 added.

For windows, the greatest opportunity is for single pane or double-pane with aluminum frame windows. The savings are based on the increased U-Factor rating and therefore the conductive heat losses (the lower the U-Factor number, the more efficient the window). It should be noted and as applicable added to the impact analysis that infiltration is not easily incorporated into this prescriptive analysis. Therefore the savings estimates are conservative assuming that many homes benefit from an increased insulation value in the new windows as well as decreased infiltration.

The following is the current customer description of the program with primary program requirements.

WEATHERIZATION FOR AVISTA ELECTRIC / NATURAL GAS HEATED HOMES
Ceiling and Attic Insulation
Ceiling/Attic (both fitted/batt type and blown-in):
A 25 cents per square foot incentive is available for the addition of new insulation that increases the R-Value by R-10 or greater. Homes are eligible if the existing insulation is less than R-19 for attics. Insulation must be installed only where such cavities separate conditioned from unconditioned areas of the residence. (Any insulation installed outside the cavity, such as siding applications, does not meet incentive requirements.)

Floor and Wall Insulation
Floor and Wall Insulation (both fitted/batt type and blown-in):
A 50 cent per square foot incentive is available for the addition of new insulation that increases the R-Value by R-10 or greater. Homes are eligible if the existing insulation is less than R-5 for

walls and R-5 in floors. Insulation must be installed only where such cavities separate conditioned from unconditioned areas of the residence. (Any insulation installed outside the cavity, such as siding applications, does not meet incentive requirements.)

Windows**
A $3.00 incentive, per square foot of qualifying windows installed, is available to customers who heat primarily with Avista electric or natural gas for the upgrade of windows with a u-factor of .35 or lower (the lower the u-factor, the more efficient the window). Windows must be rated by a recognized organization such as the National Fenestration Rating Council (NFRC) or Department of Energy (DOE).
**Both the invoice and incentive form(s) must show square footage,
u-factor, and costs.

Summary of Opportunities and Threats:
There are some additional opportunities in 2010. Previously the program required windows with a U-Factor of .35 or better. While Energy Star windows were not specifically cited as the requirement, the U-Factor was in line with Energy Star requirements. At the current level a sub-TRC evaluation showed the window portion of residential shell measures lacking. At the same time, Energy Star requirements have now improved to .30 U-Factor or better. This presents an opportunity to improve the TRC and clear customer communications.

Key 2010 Program Issues and Actions:
In 2010 we would like to implement changes to the window requirement to specify .30 U-Factor or Energy Star qualified.

Evaluation, Measurement and Verification Plan:
This program is on the 2010 schedule for impact and net to gross evaluation. The net to gross evaluation will provide the free ridership and spillover data needed to calculate cost effectiveness. This data will also be valuable in understanding NTG for other residential programs and potentially shape future NTG evaluations. The impact evaluation will be a bill analysis.

Program: Residential Water Heating Efficiency

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Rachelle Humphrey, Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Increase efficiency of residential customer's water heating from standard efficient natural gas and electric systems to high efficient models.
Expected 2010 acquisition: 118,910 kWh 7,182 therms
Expected customer participation: Approximately 940 customers
Expected 2010 incentive cost: $ 47,000
Expected 2010 non-incentive/non-labor cost: $ 81
Expected 2010 total utility cost: $48,059
TRC benefit/cost ratio:

0% net-to-gross scenario: 2.05 without tax credits, 2.05 with tax credits
25% net-to-gross scenario: 2.04 without tax credits, 2.04 with tax credits
50% net-to-gross scenario: 2.01 without tax credits, 2.01 with tax credits
75% net-to-gross scenario: 1.93 without tax credits, 1.93 with tax credits

Program Description:
With the increase in sub-TRC evaluation, water heaters were identified as having lower TRCs. Water heaters certainly have some unique challenges. Federal standards have improved for water heating to the point where there are limited cost-effective opportunities. This is good for customers since the baseline models are much better than just a few years ago, however, there is quite a premium in some cases to go beyond the standard. For example, while natural gas tankless water heaters nearly eliminate standby losses, the current incremental costs make these cost-ineffective. For tank type systems, there are still some opportunities; however, these will have to be re-evaluated as new federal standards once again improve in late 2010.

The following is the current customer description of the program with primary program requirements.

Water Heater
A $50 incentive is available for installation of an electric water heater (tank type) of 0.93 EF (efficiency) or greater; a natural gas water heater (tank type) of 0.60 EF or greater for 50-gallon, 0.62 EF or greater for 40-gallon. A $200 incentive is available for installation of a natural gas instantaneous model (tankless) of 0.82 EF or greater.

Summary of Opportunities and Threats:
Again, the threat to this program is that there are higher efficient models but the incremental costs to achieve the savings may outweigh the avoided costs or benefits. Currently tank type models continue to enjoy cost-effective options for high efficiency options but that could change. Incremental costs for high efficient systems needs to decrease as federal standards improve. If not, there may not be cost-effective options for water heating incentives.

On the electric side, there are new technology opportunities in the promise of cost-effective and adequately performing heat pump water heaters. Currently the incremental cost is prohibitive and whether they perform properly in cold climates is questionable. A regional task force is working with manufacturers to limit the heat penalty of heat pump water heaters installed inside the conditioned space and/or performance issues of systems installed in non-conditioned space. The regional effort on the northern climate specs should help guide our efforts related to heat pump water heater options.

Key 2010 Program Issues and Actions:
New federal standards go into effect later in September of 2010 for water heater efficiencies. At that time a re-evaluation of costs and benefits will be needed to determine if there are cost-effective measures available to move customers beyond code systems.

Tankless water heaters do not pass the sub-TRC test and will be discontinued in 2010.

Evaluation, Measurement and Verification Plan:
To be determined.

Program: Residential CFL Distribution Program

Key Individuals:
Program Manager: Camille Martin
Program Technical Resource: Mike Dillon and others
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: 32 kWh average savings per CFL
Expected 2010 acquisition: 4,800,000 kWh's through all components of the program, measure and market segment.
Expected customer participation: Approximately 75,000 customers if each customer received two CFL's
Expected 2010 incentive cost: $262,500
Expected 2010 non-incentive/non-labor cost: $60,000
Expected 2010 total utility cost: $359,735
TRC benefit/cost ratio:
- 0% net-to-gross scenario: 5.99 without tax credits, 5.99 with tax credits
- 25% net-to-gross scenario: 5.44 without tax credits, 5.44 with tax credits
- 50% net-to-gross scenario: 4.59 without tax credits, 4.59 with tax credits
- 75% net-to-gross scenario: 3.12 without tax credits, 3.12 with tax credits

Program Description (Policy):
Organizations with customer contacts are one means of educating customers regarding energy efficiency and our programs, and to distribute inexpensive energy efficiency products, such as CFLs, that acquire energy savings and reinforce our message.

- Organizational Types and Tiers:
  - Non-Profit Organizations/Government/Public Academic Institutions
    - 200 CFLs on average will be provided, capped at 200 organizations in total.
    - If the product(s) is resold (e.g., as a fundraiser), Avista must provide written approval to the organization to do so.
  - For-profit Businesses
    - Provide up to 200 CFLs (direct shipped or from Avista storage), again, capped at 200 organizations in total.
    - The product(s) must not be sold.
- General Criteria:
  - The organization's distribution base must be at least 80% Avista electric or natural gas customers.
  - Avista energy conservation educational materials must be available for distribution by the organization to recipients of the product(s). An Avista representative may participate in the demonstration, perhaps making educational presentations, being available to respond to energy-efficiency questions, etc.
  - These policies will remain in effect through the remainder of calendar year 2010, unless we choose to terminate or modify them prior to that time. Avista retains the right to modify or terminate these policies at any time, without notice.

Summary of Opportunities and Threats:
Opportunities

- Large target audience to target within the outreach program.
- Easy to obtain and implement in Avista customer households.
- Using giveaways as a tool for promoting customer energy conservation awareness.

Challenges

- Even though CFLs have improved significantly, getting past attitudes that CFLs perform poorly, such as light output, life and color.

Key 2010 Program Issues and Actions:
This program will be ending in 2011 since CFL twists will be phased in as the standard lighting source, starting 2012. The phased incandescent ban will begin 2012 through 2014.

Evaluation, Measurement and Verification Plan:
Regional Technical Forum (RTF) figures are used to determine the kWh savings. An inventory of CFLs distributed is kept to track the amount distribution completed.

In order to get an understanding of the installation rate of the bulbs, a post card will be attached to each bulb that the customer will mail back free of charge. The card will contain an ID number that indicates when and where the bulb was given out. The customer will be instructed to return the card when the bulb is installed.

The following companion program is incorporated within the overall residential CFL program above.

PECI CFL Specialty Bulb Promotion (buy down) Program

Key Individuals:
Program Manager: Camille Martin
Program Technical Resource: Mike Dillon and others
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Programs Description:
Currently, Avista has a specialty CFL buy down program contracted through Portland Energy Conservation Inc., (PECI) on behalf of NEEA. Avista has select retailers of ENERGY STAR CFLs offering energy-saving bulbs, such as globes, high-heat reflectors, 3-way twists, candelabras, daylights and A-lamps ,available at reduced prices.

Summary of Opportunities and Threats:

Opportunities

- Large target audience to target within the CFL promotion program.
- Easy to obtain and implement in Avista customer households.

Challenges

- Even though CFLs have improved significantly, getting past attitudes that CFLs perform poorly, such as light output, life and color.

Key 2010 Program Issues and Actions:
This program will be ending in 2010 since CFLs will be phased in as the standard lighting source, starting 2012. The phased incandescent ban will begin 2012 through 2014.

Evaluation, Measurement and Verification Plan:
Regional Technical Forum (RTF) figures are used to determine the kWh savings.

Program: Residential Refrigerator Recycling Program

Key Individuals:
Program Manager: Camille Martin
Program Technical Resource: Mike Dillon and others
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Retirement of second refrigerators and freezers in residential homes.
Expected 2010 acquisition: 2.03 million kWh savings (3000 units recycled).
Expected customer participation: Approximately 2,700 individual customers.
Expected 2010 incentive cost: $105,000
Expected 2010 non-incentive/non-labor cost: $385,000
Expected 2010 total utility cost: $490,000
TRC benefit/cost ratio:

0% net-to-gross scenario: 1.10 without tax credits, 1.10 with tax credits
25% net-to-gross scenario: 0.82 without tax credits, 0.82 with tax credits
50% net-to-gross scenario: 0.55 without tax credits, 0.55 with tax credits
75% net-to-gross scenario: 0.27 without tax credits, 0.27 with tax credits

JACO Second Refrigerator and Freezer Recycling Program Description:
JACO Environmental Inc. (JACO) picks up to two Refrigerators and/or Freezers (units) from an Avista electric residential customer's home when they request a pick-up. The pick-up service is free to the customer. A $30 rebate is provided for each operational refrigerator and/or freezer, up to two per household. The old refrigerators or freezers are delivered to a recycling facility operated by JACO. JACO recycles nearly 95 percent of each refrigerator, and safely disposes of the toxins and chlorofluorocarbon gases from foam insulation. JACO works with local businesses to recycle glass, plastic and metal.
To have a refrigerator or freezer picked up and recycled:

- The refrigerator or freezer needs to be in working condition and between 10 to 27 cubic feet in size. Units also must be 1995 models or older.
- The program is for Avista Electric or Electric/Gas customers only.
- Customers must own the unit(s) being recycled, with a limit of two units per account.
- The $30 rebate check will be mailed to the customer within 4 to 6 weeks after the appliance collection.

Outreach Tactics
JACO is contracted to run a turn-key program that delivers most of the marketing outreach. Avista has done a limited amount of marketing and communications designed to support the program's goals and enlist participation:

- Employee notification: general audience and training to call centers
- Bill insert and e-bill postcard advertisement of the appliance recycling
- Web tie-in and information
- Community Events Outreach

Program Goal
The goal is to have 3000 units recycled per year.

Summary of Opportunities and Threats:
This program is contracted through mid-2010. No contract extension has been signed as of January 2010. Continuation of this program will partly depend on the terms and conditions of proposed extension.

The following situational analysis outlines both the opportunities and challenges this program presents:
Opportunities

- Large target audience and ways to get the word out about the program (bill inserts, contact center and other employees, website and the "Something for Everyone" outreach program).
- Easy to obtain and implement with Avista residential customers.
- There is an environmental and substantial energy efficiency benefit to recycling second refrigerators and freezers.

Challenges

- In 2009 there was a decline in units being recycled.
- Getting the program message to all customers.

Key 2010 Program Issues and Actions:

In 2010 JACO and Avista marketing will focus on the following concepts to increase units being recycled:

- ✓ JACO will participate in the "New Power to Conserve" promotion.
- ✓ JACO will increase marketing outreach.
- ✓ Avista will continue doing bill inserts in 2010.

Evaluation, Measurement and Verification Plan:
The program assumptions and metrics come from JACO's analysis that uses Regional Technical Forum (RTF) figures. The kWh savings are based on 905 kWh for refrigerators and 925 kWh for freezers. JACO is currently doing some additional analysis of the units recycled to determine the average kWh savings for our customers.

Program: Energy Star® rated Appliance Rebates

Key Individuals:
Program Manager: Camille Martin
Program Technical Resource: Mike Dillon and others
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: A total of 5 individual measures. These include measures for Energy Star® rated Refrigerators, Clothes Washers and Dishwashers.
Expected 2010 acquisition: 1,062,600 kWh's and 26,800 therms
Expected customer participation: Approximately 10,000 individual customers.
Expected 2010 incentive cost: $360,000
Expected 2010 non-incentive/non-labor cost: $4,600, primarily for collateral material
Expected 2010 total utility cost: $388,435
TRC benefit/cost ratio:

0% net-to-gross scenario: 0.71 without tax credits, 0.92 with tax credits
25% net-to-gross scenario: 0.70 without tax credits, 0.92 with tax credits
50% net-to-gross scenario: 0.70 without tax credits, 0.91 with tax credits
75% net-to-gross scenario: 0.69 without tax credits, 0.90 with tax credits

Program Description:
Energy Star® rated appliance rebates have been available to Avista residential customers since 2008. We will be expanding our marketing of rebates to include ARRA appliance rebates offered by the state's of Idaho and Washington; and the City and County of Spokane on Energy Star® qualified appliances. Increased use of these appliances is valuable to Avista for reducing the energy demand and helping our customers reduce their energy usage. Our goal for these rebates is primarily to increase the number of customers purchasing and using Energy Star® rated appliances.

In 2010, with the addition of the state rebates, redemption rates may substantially increase.

Summary of Opportunities and Threats:
The following situational analysis outlines both the opportunities and challenges this program presents:
Opportunities

- Upgrading to energy star appliances is one way consumers can cut down energy use.
- Increase sales for ENERGY STAR® appliance retailers in our service area.

Challenges

- The value of the rebate may not be enough incentive for customers to buy the considerably more expensive Energy Star® rated appliance models.

Key 2010 Program Issues and Actions:
Freezer rebates will be eliminated for 2010. Freezers didn't pass sub-TRC and are non-cost effective.

Evaluation, Measurement and Verification Plan:
Avista will be continuing these rebates (refrigerators, dishwashers and clothes washers) until the state ARRA appliance rebate program ends. Avista will be reevaluating these rebates mid 2010.

Regional Technical Forum (RTF) savings figures are used to calculate kilowatt and therm savings for each Energy Star® rated appliance rebated.

In 2010 a net-to-gross evaluation is planned to determine Avista's influence in purchasing decisions.

Program: Energy Conservation in Schools Program (Dollars for Change)

Key Individuals:
Program Manager: Camille Martin
Program Technical Resource: Mike Dillon and others
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: 54 kWh average savings per CFL
Expected 2010 acquisition: 64,000 kWh savings.
Expected customer participation: Approximately 5000 customers.
Expected 2010 incentive cost: $3,500
Expected 2010 non-incentive/non-labor cost: $10,000
Expected 2010 total utility cost: $26,564
TRC benefit/cost ratio:

0% net-to-gross scenario: 1.61 without tax credits, 1.61 with tax credits
25% net-to-gross scenario: 1.27 without tax credits, 1.27 with tax credits
50% net-to-gross scenario: 0.89 without tax credits, 0.89 with tax credits
75% net-to-gross scenario: 0.47 without tax credits, 0.47 with tax credits

Program Description:
As part of our "Geographic Saturation" programs, we are designing an educational energy conservation offerings within Avista's service territory at primary and secondary academic facilities. This Educational Facilities Energy Conservation Program includes but is not limited to:

- Energy conservation outreach education directed to connect with students and staff.
- CFL fundraisers to implement energy efficiency projects at academic facilities.

Summary of Opportunities and Threats:

Opportunities

- Fundraising with Compact Fluorescent Light Bulbs is educational
- Kids are impressionable. If conservation becomes a habit at an early age, they are much more likely to retain those habits when they get older.
- Fundraising with compact fluorescent light bulbs empowers young people by showing that they can make a difference in protecting the environment and fighting global warming.

Challenges

- Kids would have little or no idea what they were selling or why. This program will need an educational component (Wattson).

Key 2010 Program Issues and Actions:

In 2009, this program was piloted in four schools. In 2010, the program will be expanded to ten schools.

Evaluation, Measurement and Verification Plan:
EM&V may include continuing runtime measurement from 2009, measurement of kW of selected lighting systems, going back on a sample of old projects to measure persistence and measure life, review of the literature on emerging technologies etc.

Program: Residential Distributed Renewable Generation

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Renee Coelho, Rachelle Humphrey, Dan Knutson, Tom Lienhard
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Incentives for energy generated from qualifying renewable distributed generation that reduces customer load.
Expected 2010 acquisition: Program proposed for termination in 2010
Expected customer participation: It is estimated that 50 customers will be involved in the educational / informational portion of the program.
Expected 2010 incentive cost: Program proposed for termination in 2010
Expected 2010 non-incentive/non-labor cost: None
Expected 2010 total utility cost: None. Labor costs are considered non-incremental due to the utilities required involvement in the project.
TRC benefit/cost ratio: None calculated given the proposal for program termination. Measure cost-effectiveness is very low.

Program Description:
This program provides technical resources and incentives for customers interested in generating energy with qualified renewables to offset their own load. The program utilizes a site-specific approach with customers individually contracted for their projects.

Here is the tariff language from schedule 90 that covers the program:

> "Incentives for distributed renewable energy measures will be limited to net-metering facilities operating under Avista Utilities Idaho/Washington Rate Schedule 63 Net Metering rules. Incentives will be limited to energy production not to exceed 100% of the average annual energy use of the facility for the preceding three years or if new, a similar facility's annual use as calculated by the Company. Incentives will be limited to 50% of the total cost of the installation. This market transformation effort supports renewable energy measures in the residential and small commercial segments".

Summary of Opportunities and Threats:
The measures falling under this classification are non-cost-effective.   Avista's rebates are a very small percentage of the measure cost and are unlikely to be a significant influence upon the customers purchase decision.

Key 2010 Program Issues and Actions:
The distributed generation measures have received considerable attention from the IPUC staff. Jon Powell has been the primary Avista representative on this issue and is working to respond and resolve staff concerns. While technical support for distributed generation will continue to be offered, the incentive will most likely be discontinued. Since it is currently included in the tariff, necessary procedural steps are being planned by Jon Powell.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation, however, targeted measurement and verification will be performed as necessary.

Program: “Something for Everyone” and “Geographic Saturation

Key Individuals:
Program Manager: Camille Martin
Program Technical Resource: Mike Dillon and others
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: 32 kWh average savings per CFL. Other efficiency measures (caulking, showerheads) are distributed but savings but not incorporated into acquisition claim or cost-effectiveness pending EM&V.
Expected 2010 acquisition: 320,000 kWh savings from CFL savings.
Expected customer participation: Approximately 15,000 individual customers.
Expected 2010 incentive cost: $17,500
Expected 2010 non-incentive/non-labor cost: $20,000
Expected 2010 total utility cost: $77,239
TRC benefit/cost ratio:
0% net-to-gross scenario: 2.36 without tax credits, 2.36 with tax credits
25% net-to-gross scenario: 1.90 without tax credits, 1.90 with tax credits
50% net-to-gross scenario: 1.37 without tax credits, 1.37 with tax credits
75% net-to-gross scenario: 0.74 without tax credits, 0.74 with tax credits

Program Description:
The "Something for Everyone" DSM project will assist in acquiring more cost effective kWhs and therms as identified by the Electric and Gas IRPs through increased penetration, program design and outreach; and an aggressive marketing plan to achieve these goals. The “Something for Everyone” program will promote energy efficiency measures in residential customer homes. They include:

- CFL Recycling Program
- CFL Distribution Programs (Events, bulb exchanges, neighborhood councils, civic organizations, city programs, fundraisers)

Impacted Markets
This program is available to all Avista residential customers in Washington and Idaho

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Anticipated Observable Program Benefits
The program should achieve savings of 650,000 kWh over two years. The program has already been well-received by residential customers. The program should successfully reach 50,000 customers over the two year period and make a significant contribution in a difficult to reach customers.

Summary of Opportunities:
Opportunities
- A great opportunity to tell Avista’s story about energy efficiency programs.
- Outreach at local events provides an opportunity to interact positively with customers.
- Events provide a chance to educate and answer our customers questions.
- Using giveaways as a tool for promoting customer energy conservation awareness.

Key 2010 Program Issues and Actions:
Changes, contemplated changes or plans that need to be made in 2010 include the potential for the elimination of some measures, addition of other measures, incentive changes due to changes in cost or base case, changes in leveraging of regional efforts, etc.

Evaluation, Measurement and Verification Plan:
EM&V protocols may include continuing runtime measurement from 2009, measurement of kW of selected lighting systems, going back on a sample of old projects to measure persistence and measure life, review of the literature on emerging technologies, etc.

Program: Residential In-Home Energy Audits

Key Individuals:
Program Manager: Joe Brabeck
Program Technical Resource: Bryce Eschenbacher and others
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: A residential energy audit complete with air flow diagnostic and the installation of compact fluorescent lamps, weather stripping and low flow showerheads
Expected 2010 acquisition: 3,897,958 million kWh's. 94,282 therms
Expected customer participation: Approximately 2,000 individual customers.
Expected 2010 incentive cost: $450,536
Expected 2010 non-incentive/non-labor cost: $201,000
Expected 2010 total utility cost: $924,380
TRC benefit/cost ratio (electric measures only):
- 0% net-to-gross scenario: 1.61 without tax credits, 1.74 with tax credits
- 25% net-to-gross scenario: 1.43 without tax credits, 1.54 with tax credits
- 50% net-to-gross scenario: 1.18 without tax credits, 1.25 with tax credits
- 75% net-to-gross scenario: 0.77 without tax credits, 0.79 with tax credits

TRC benefit/cost ratio (winter-impact natural gas measures only):
- 0% net-to-gross scenario: 1.02 without tax credits, 1.15 with tax credits
- 25% net-to-gross scenario: 0.94 without tax credits, 1.04 with tax credits
- 50% net-to-gross scenario: 0.81 without tax credits, 0.88 with tax credits
- 75% net-to-gross scenario: 0.57 without tax credits, 0.60 with tax credits

TRC benefit/cost ratio (annual-impact natural gas measures only):
- 0% net-to-gross scenario: 0.62 without tax credits, 0.67 with tax credits
- 25% net-to-gross scenario: 0.58 without tax credits, 0.63 with tax credits
- 50% net-to-gross scenario: 0.53 without tax credits, 0.56 with tax credits
- 75% net-to-gross scenario: 0.40 without tax credits, 0.42 with tax credits

Program Description:
Avista Utilities will provide in-home energy audits to residential customers in Spokane County. The audit will include both internal and external inspections as well as diagnostic tests including a blower door test to detect outside air infiltration, pressure pan test for heating system duct leakage and a combustion zone test for natural gas fired furnaces, water heaters and ovens. Some minor energy efficiency measure will be installed and a energy efficiency kit with addition energy saving items will be left with the homeowner.

Summary of Opportunities and Threats:
Opportunities include savings through immediately installed items, those left behind with customer and possible behavior modification (setting back thermostats, turning off computers, etc). Also combining the results of our audit and Avista Home Improvement rebates may result in larger savings due to the upgrades of insulation, furnaces and hot water tanks, major appliances ,and window replacements. Threats may include liability issues resulting from testing furnaces and hot water tanks and being in attics and crawl spaces.

Key 2010 Program Issues and Actions:
Since this is a brand new program the demand for the "for fee" audit service is unknown. In addition there are several barriers to entry for prospective auditors that must be overcome. Training costs, relatively high equipment costs licensing and insurance cost coupled with a below market payment for the audit are challenges. Plus since this only a two year program the prospective auditors aren't sure of the market potential for their services after the subsidies cease to exist.

Evaluation, Measurement and Verification Plan:
An EM&V plan will be developed for the quantification of the energy savings of this program. The detailed development of the methodology will be deferred until the program has been in operation for a moderate (e.g. three to six month) period of time. This will allow for an assessment of the most significant measures contributing to the overall energy savings and for a more knowledgeable approach for incorporating interactive impacts within the final methodology.

The Limited Income Portfolio Overview
Chris Drake

The Company's residential limited income portfolio is composed primarily of site-specific programs delivered by local Community Action Partner (CAP) agencies. Avista contracts with up to six CAP agencies to deliver energy efficiency programs to limited income customers. CAP agencies are uniquely qualified for customer intake processes due to complimentary energy assistance and other income-qualified programs.

Limited income efficiency measures are typically similar to measures offered under residential prescriptive programs due to cost-effective guidelines. Limited income efficiency measures do include some measures, like infiltration, that have not been included in the residential programs but are well-suited to a site-specific approach. A list of approved measures with a high predictability of adequate cost-effectiveness is provided to CAP agencies. Other measures may be submitted for approval if cost-effectiveness is in question. Health and human safety measures that are necessary to ensure the habitability of the home as well as energy saving investments are allowed under these programs. CAP agencies complete installation of efficiency measures at no cost to qualified customer through this Avista funding. Administrative fees are paid to the CAP agencies for delivery of these programs.

The approval process mentioned above is supported by limited income programs tracking cost-effectiveness in a near real-time basis. Even measures that are less than cost-effective may be approved based on the overall portfolio performance.

The residential limited income market is expected to acquire 2% of electric and 5% of the natural gas savings achieved by Avista during 2010.

Program: LI Appliance

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Renee Coelho, Rachelle Humphrey, Tom Lienhard, CAPs
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Installation of Energy Star refrigerators
Expected 2010 acquisition: 24,360 kWh
Expected customer participation: Approximately 49 customers
Expected 2010 incentive cost: $29,186
Expected 2010 non-incentive/non-labor cost: None
Expected 2010 total utility cost: $29,987
TRC benefit/cost ratio:

0% net-to-gross scenario: 0.86 without tax credits, 0.86 with tax credits
25% net-to-gross scenario: 0.85 without tax credits, 0.85 with tax credits
50% net-to-gross scenario: 0.82 without tax credits, 0.82 with tax credits
75% net-to-gross scenario: 0.75 without tax credits, 0.75 with tax credits

Program Description:
This program covers the installation of Energy Star refrigerators prescriptively for replace before burn out situations where the refrigerator is older than 1992 vintage. There is also an option to install Energy Star refrigerators in replace upon or immediately before burn out situations with prior written approval. Determination is made based on total resource cost-effectiveness analysis that the measure passes or it may also be approved if the overall limited income portfolio performance is high enough. Limited income total resource cost-effectiveness is tracked in a "calculator" that is updated monthly to reflect portfolio performance. If specific energy usage of existing refrigerator is unknown or if it is a replace upon burn out, then the new Energy Star refrigerator is compared to a standard efficient system to estimate savings.

Summary of Opportunities and Threats:
The CAP agencies are uniquely positioned to identify qualifying customers as a result of the energy assistance programs offered by the same agencies. Customers who may benefit from cost-effective energy efficiency improvements are referred to the weatherization department to begin the process.

Key 2010 Program Issues and Actions:
In 2009 a new process was implemented to more closely manage TRC performance for the limited income portfolio. Additionally, certain measures that are typically cost-effective are encouraged and allowed without prior approval. All other measures require written permission to complete. The process evaluates measures not specifically on the list and if they are cost-effective they are approved. Some measures may also be approved even if they are less than cost-effective if the portfolio as a whole has a high enough TRC.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation; however, targeted measurement and verification will be performed as necessary.

Program: LI Fuel Conversion

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Renee Coelho, Rachelle Humphrey, Tom Lienhard, CAPs
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Conversion of electric straight resistance space and water heat systems to natural gas.
Expected 2010 acquisition: 1,324,316 kWh
Expected customer participation: Approximately 40 customers
Expected 2010 incentive cost: $360,556
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $404,122
TRC benefit/cost ratio:
- 0% net-to-gross scenario: 2.84 without tax credits, 2.84 with tax credits
- 25% net-to-gross scenario: 2.71 without tax credits, 2.71 with tax credits
- 50% net-to-gross scenario: 2.50 without tax credits, 2.50 with tax credits
- 75% net-to-gross scenario: 2.01 without tax credits, 2.01 with tax credits

Program Description:
This program involves two measures that replace existing electric straight resistance heat with natural gas, for both space and water heating needs. The measure's include necessary piping and venting to convert the existing home and in some cases the addition of duct-work as well. For customers to qualify for a conversion project they must demonstrate they heat primarily with electric heat. A bill analysis is completed that estimates the electric usage devoted to space heating to arrive at what is called an R-number. A customer must have a minimum R-number of 4,000 to qualify for a conversion to natural gas.

Summary of Opportunities and Threats:
The CAP agencies are uniquely positioned to identify qualifying customers as a result of the energy assistance programs offered by the same agencies. Customers who may benefit from cost-effective energy efficiency improvements are referred to the weatherization department to begin the process.

Key 2010 Program Issues and Actions:
In 2009 a new process was implemented to more closely manage TRC performance for the limited income portfolio. Additionally, certain measures that are typically cost-effective are encouraged and allowed without prior approval. All other measures require written permission to complete. The process evaluates measures not specifically on the list and if they are cost-effective they are approved. Some measures may also be approved even if they are less than cost-effective if the portfolio as a whole has a high enough TRC.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation; however, targeted measurement and verification will be performed as necessary. It is tentatively scheduled for an impact evaluation in 2012.

Program: LI HVAC Efficiency

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Renee Coelho, Rachelle Humphrey, Tom Lienhard, CAPs
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Upgrade of space heating systems, typically standard natural gas furnaces to high efficiency systems. Also possible would be electric straight resistance systems to heat pumps if natural gas is not available for a conversion project. In both cases written approval would be required prior to beginning these measures as they are not specifically included in the “pre-approved” list of measures.
Expected 2010 acquisition: 861 therms
Expected customer participation: Approximately 7 customers
Expected 2010 incentive cost: $27,841
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $27,879
TRC benefit/cost ratio:
    0% net-to-gross scenario: 0.47 without tax credits, 0.47 with tax credits
    25% net-to-gross scenario: 0.47 without tax credits, 0.47 with tax credits
    50% net-to-gross scenario: 0.47 without tax credits, 0.47 with tax credits
    75% net-to-gross scenario: 0.47 without tax credits, 0.47 with tax credits

Program Description:
Typically this program covers situations where the CAP determines that the customer has very inefficient natural gas furnace and recommends installing a new, high efficient system. The savings is based on the existing system vs. the proposed system. In some cases, if the customer’s existing system is no long functioning or very close to the end of its life, then the savings would be based on the difference between a new standard code system and the proposed high efficiency model.

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Key 2010 Program Issues and Actions:
In 2009 a new process was implemented to more closely manage TRC performance for the limited income portfolio. Additionally, certain measures that are typically cost-effective are encouraged and allowed without prior approval. All other measures require written permission to complete. The process evaluates measures not specifically on the list and if they are cost-effective they are approved. Some measures may also be approved even if they are less than cost-effective if the portfolio as a whole has a high enough TRC.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation; however, targeted measurement and verification will be performed as necessary. This program is scheduled for impact evaluation in 2011.

Program: LI Shell

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Renee Coelho, Rachelle Humphrey, Tom Lienhard, CAPs
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Measures include attic, wall, floor and duct insulation, infiltration and Energy Star windows.
Expected 2010 acquisition: 131,869 kWh 92,281 therms
Expected customer participation: Approximately 192 customers
Expected 2010 incentive cost: $1,358,399
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $1,365,770
TRC benefit/cost ratio:

0% net-to-gross scenario: 1.31 without tax credits, 1.31 with tax credits
25% net-to-gross scenario: 1.30 without tax credits, 1.30 with tax credits
50% net-to-gross scenario: 1.29 without tax credits, 1.29 with tax credits
75% net-to-gross scenario: 1.27 without tax credits, 1.27 with tax credits

Program Description:
The limited income CAP agencies focus primarily on shell measures and improvements. They offer ceiling/attic, wall, floor and duct insulation. The complete blower door tests to assess infiltration opportunities and complete extensive infiltration measures as applicable. When infiltration measures are completed a post-blower door test is also completed to estimate savings. Energy Star windows measures are also completed for single pane or broken windows.

CAP agencies complete a site-specific home energy audit to determine which shell measures will be completed.

Summary of Opportunities and Threats:
The CAP agencies are uniquely positioned to identify qualifying customers as a result of the energy assistance programs offered by the same agencies. Customers who may benefit from cost-effective energy efficiency improvements are referred to the weatherization department to begin the process.

Key 2010 Program Issues and Actions:
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Evaluation, Measurement and Verification Plan
This program is not on the 2010 schedule for impact evaluation; however, targeted measurement and verification will be performed as necessary. This program is scheduled for an impact evaluation in 2011.

Program: LI Water Heating

Key Individuals:
Program Manager: Chris Drake
Program Technical Resource: Jon Powell, Lori Hermanson, Renee Coelho, Rachelle Humphrey, Tom Lienhard, CAPs
Program Evaluation, Measurement and Verification Resource: Damon Fisher

Program Overview:
Measures included: Conversion of electric straight resistance space and water heat systems to natural gas.
Expected 2010 acquisition: 940 kWh 110 therms
Expected customer participation: Approximately 14 customers
Expected 2010 incentive cost: $19,138
Expected 2010 non-incentive/non-labor cost: $0
Expected 2010 total utility cost: $19,175
TRC benefit/cost ratio:

0% net-to-gross scenario: 1.95 without tax credits, 1.95 with tax credits
25% net-to-gross scenario: 1.92 without tax credits, 1.92 with tax credits
50% net-to-gross scenario: 1.86 without tax credits, 1.86 with tax credits
75% net-to-gross scenario: 1.71 without tax credits, 1.71 with tax credits

Program Description:
This program covers the upgrade of water heaters, prescriptively electric water heaters and with prior approval, natural gas models as well. Limited income energy efficiency equipment upgrades such as water heating are challenging from a cost-effective perspective. In a regular income situation, the customer is in need of a water heater and would have to pay at least for a code minimum system. Therefore the cost of the upgrade is the incremental cost. For limited income, since we pay 100% of the project, the entire system cost is currently compared to the incremental energy benefits and it is a difficult hurdle to overcome.

Summary of Opportunities and Threats:
The CAP agencies are uniquely positioned to identify qualifying customers as a result of the energy assistance programs offered by the same agencies. Customers who may benefit from cost-effective energy efficiency improvements are referred to the weatherization department to begin the process.

Key 2010 Program Issues and Actions:
In 2009 a new process was implemented to more closely manage TRC performance for the limited income portfolio. Additionally, certain measures that are typically cost-effective are encouraged and allowed without prior approval. All other measures require written permission to complete. The process evaluates measures not specifically on the list and if they are cost-effective they are approved. Some measures may also be approved even if they are less than cost-effective if the portfolio as a whole has a high enough TRC.

Evaluation, Measurement and Verification Plan:
This program is not on the 2010 schedule for impact evaluation; however, targeted measurement and verification will be performed as necessary.

The Regional Portfolio Overview

Jon Powell

Regional Market Transformation - Electric

Market transformation has come to be defined as an approach for influencing markets to accelerate and/or enhance the ultimate saturation of cost-effective energy-efficient practices. Experience within the northwest has indicated that market transformation is a tool best applied as part of a regional cooperative effort. The regional approach favorably applies a greater economy of scale and addresses cross-utility 'leakage' issues prevalent in local programs. The result is a higher probability of success and enhanced cost-effectiveness.

Avista has been an active and funding partner in the application of the tools of market transformation to energy-efficiency since the Northwest Energy Efficiency Alliance (NEEA) was founded in 1996 to serve that purpose within the region. The 2010-2014 NEEA funding cycle, which Avista has contractually committed to, is the fourth such series of funding contracts since the creation of the organization. Avista's participation has been based upon the finding that (1) NEEA has proven to be both a cost-effective means of acquiring resources that Avista, acting alone, could either not acquire or not acquire as cost-effectively and (2) that where NEEA's efforts and local efforts overlap, NEEA is a cost-effective enhancement to a purely local effort.

Historically NEEA has acquired electric efficiency resources at a TRC cost of approximately 10 mills (1 cent) per kWh. Even taking into account alternative base case scenarios less favorable to venture cost-effectiveness, we are quite confident that the acquisition is occurring at a cost of 25 mills or less even recognizing the high degree of sensitivity that these calculations have to alternative base case scenarios. Avista does not expect that NEEA will continue to acquire efficiency resources at this cost given that the annual funding, subject to board approval of expenditures, has doubled from $20 million to $40 million for the 2010-2014 funding cycle and the benefits of the residential lighting market transformation are waning. However, we do believe that NEEA will be the most cost-effective approach to many efficiency opportunities.

The funding shares originally calculated in 1996 and used with little modification through 2009 have been updated for the 2010-2014 funding cycle. For Avista this has meant in increase from 4.0% of the regional funding to 5.4% of regional funding, reflecting our relative growth of regional end-use load. Through 2009 Avista has chosen to use the 4.0% funding share as a means of claiming our 'share' of regional acquisition despite our increasing share of regional load in order to maintain a regional symmetry between funding and distribution of claimed benefits. This has likely resulted in Avista underestimating acquisition falling within our service territory and underestimating the cost-effectiveness of the funding effort to Avista customers in the past. For the 2010-2014 funding cycle NEEA has committed to establishing a more rigorous accounting of market transformation acquisition by utility service territory and jurisdiction. Though this is very likely to result in an increase of Avista's claimed benefit beyond the historic 4.0% claim, it is uncertain if it will reach or exceed the 5.4% share of funding provided by Avista.

During 2010 the Company will need to track closely the following NEEA issues:

- We continue to share the concern of many within the region over the high reliance of NEEA upon residential lighting measures. This issue has been and continues to be addressed through a variety of forums within the region. We believe that there is no single measure that can replace the CFL as the cornerstone of regional market transformation cost-effectiveness, but success within multiple markets is plausible and will support the ongoing high cost-effectiveness of the organization.

- As regional and local programs overlap, largely due to the success of the regional programs and the laudable leveraging of these opportunities by local utilities, the current approach to attributing all savings in overlapping programs to the local utility has and will continue to result in an underestimate of the cost-effectiveness of the regional efforts. This ‘attribution’ issue demands a solution before it results in erroneous policy decision regarding the continued viability of the maintenance of a regional market transformation organization.

Based on NEEA’s current business plan, Avista expects to claim only 2.3 amW’s during 2010 based upon the impact of NEEA ventures and regional allocation of savings. This savings is only slightly above the level of savings claimed in the past despite the large 2010 budget increase due to the delay between the funding availability to NEEA and the demonstrated acquisition within Avista’s service territory. It is fully expected that an evaluation of Avista’s measured energy savings in comparison to the costs borne by Avista and Avista customers will lead to a finding that the effort is cost-effective within our jurisdiction.

Additionally, Avista will continue to work with NEEA to develop the quantifications necessary to allow for the estimation of the natural gas therm acquisition resulting from NEEA programs within Avista’s service territory. This will generally be based upon a conversion of the non-energy benefits associated with natural gas usage reduction in the major therm-producing programs (e.g. WashWise and residential fenestration) and a regional allocation of those savings. It is hoped that a consistent means of reporting savings and allocating them throughout the region can be achieved. This business plan does not include any estimate of therm savings from NEEA programs due to the uncertainty regarding the likelihood that such estimates can be generated in time to meet Washington decoupling filing deadlines.

Demand-Response Portfolio

Leona Doege

Avista (the Company) completed a two-year Energy Load Management pilot program on December 31st, 2009. The purpose of the pilot was to gain experience with customer acceptance, program design, operational components and cost effectiveness. Direct Load Control (DLC) devices were installed in volunteer households in portions of Sandpoint and Moscow, Idaho. A separate group within those communities participated in an In-Home-Display (IHD) device study as part of this pilot.

Control technology in each DLC participant's home enabled the Company to initiate curtailment signals to electric furnaces, air-conditioning units, heat-pumps and water heaters at times of high peak demand. The Company provided notification of these events to participants 24-hours prior. Customers were allowed to opt-out at anytime.

For participating in the pilot, the DLC volunteer households were given either a $10 per month bill credit for the months their appliance qualified for an event or a state-of-the art thermostat. The IHD group received a Blue Line Power Cost Monitor.

As a product test, the pilot proved Energy Load Management could be feasible and reliable. Avista initiated 10 successful events by either cycling heating or air-conditioning units or shutting off water heater units for a period of two to four hours at a time across a range of morning and evening peak demand time slots.

As a market test, the pilot indicated a strong willingness to participate. The override rate (or customer opt-out) averaged less than 2% overall and were concentrated among a few. Participants showed willingness to invest their time, forego privacy, re-arrange schedules, and receive either less heat or less air-conditioning.

The Energy Load Management program demonstrated conditions under which residential customers would accept load curtailment of home heating, air-conditioning or water heating. Also demonstrated is a method to which an active relationship between residential customers and their utility can be established.

A full program report will be filed with the Idaho Public Utilities Commission on or before March 1, 2010.

DSM Outreach

Bruce Folsom

In the past three years, Avista has increased its promotion of energy efficiency through the "Every Little Bit" campaign. This multi-media effort was initiated with a general communication campaign to inform customers of both general efficiency program availability as well as providing educational energy-efficiency messages to customers in the first year with the intent of driving increased participation. The genesis of this campaign came from market research which indicated that customers had three concerns about increasing their energy efficiency. These concerns were "it costs too much," "I've done all I can," and "it doesn't make much difference." The Every Little Bit theme was chosen as a vehicle to address these concerns.

The ELB effort is designed to use multiple outreach channels, including website, web banners, print and broadcast outreach, print material (brochures, signage, etc.), participation in community events and other methods to reach customers. The intent is to educate and encourage customers to install energy efficient measures with the "call to action" being a visit to the Company's website (www.everylittlebit.com or www.avistautilities.com). During the second and subsequent years the program was designed to become progressively more specific. Decisions regarding target programs are based upon the program sub-TRC (the TRC cost-effectiveness calculation less any utility costs that are fixed in the short-run) and the additional participation that we believe can be driven by investments in outreach as well as overall portfolio cost-effectiveness. The additional throughput that can be obtained from our outreach investments also takes into consideration the opportunity to leverage the growing efficiency messages in the general media and partnerships with utility and non-utility organizations. The Every Little Bit campaign is integrated into earned media opportunities through Avista's Corporate Communications Department.

In 2009, we added an "Efficiency Avenue" tool (to complement the residential "House of Rebates") on the website which guides customers to our commercial rebate programs. The website also maintains a number of low-cost / no-cost efficiency measures that customers can take to manage their energy use.

The outreach effort is coordinated with ongoing updates to sub-TRC analysis and integrated into the long-term program management planning process. Efficiency messages that are not associated with individual programs come out of a collaborative process incorporating input from efficiency engineer staff, program managers and program outreach specialists. The intent is to maintain a fresh and informative appeal to the overall outreach effort.

The Every Little Bit campaign will be continued into 2010 as a primary means to reach customers with low-cost/no-cost opportunities for saving energy as well as increasing customer usage of our efficiency rebates, and to underscore the value of saving energy.

Triple-E Reporting and Cost-effectiveness

Lori Hermanson

Since 1999 the Company has summarized the cost-effectiveness evaluation, energy acquisition claim and related analysis in a document known as the "Triple-E" Report for delivery to the External Energy Efficiency ("Triple-E") Board.

In the past this report has been based upon a combination of actual completed jobs and the application of a "derating" methodology to site-specific projects. The derating methodology incorporated a percentage of project characteristics (energy acquisition, incremental cost, incentive costs, etc.) into the calculations as the project hit pre-designated milestones towards completion. These milestones included the "contracted" phase (at which point a 75% credit for the project was taken), "construction" (at which point 95% cumulative credit for the project was taken) and "completed" (when the full cumulative credit for the project was recognized). Additionally there are other phases ("scope", "study", "inactive", etc.) that classified project status for the account executive, engineer and program implementer information and program tracking.

This approach improved the meaningfulness of cost-effectiveness calculations at a time when a significant portion of the Company's DSM throughput was derived from site-specific projects with a long sales cycle and when the frequency of reporting was once every four months rather than once every year. The methodology more closely aligned the recognition of costs and benefits for purposes of the analysis.

During the establishment of the 2006-2009 Washington natural gas decoupling pilot mechanism the criteria for recovery included a DSM acquisition trigger. For purposes of external clarity it was determined that this should be calculated upon completed projects only. For this period Avista continued to use the derated methodologies on Triple-E Reports up to and including 2008, but reported completed-only therms for use in the decoupling pilot calculations.

For 2009 and beyond a decision has been reached to base the cost-effectiveness evaluation upon completed-only projects. The longer period of time covered by the Triple-E Reports and the reduced reliance upon long sales cycle projects diminish the value of the methodology. At the same time, supporting the permanent Washington natural gas decoupling mechanism and complying with Washington I-937 requirements place greater value upon transparency in the calculations.

Time permitting, there may be some additional calculations of 2009 upon a derated basis to permit some evaluation continuity used for management of the portfolio, but generally speaking the Company will terminate the derated methodology and, beginning with the 2009 Triple-E Report, initiate a completed-only methodology.

<u>Monthly & Quarterly Reporting</u>

The Company has committed to providing monthly reports to the Triple-E Board if and when the Tariff Rider balances exceed +/- 20% of the forecasted annual revenue at any month end. In addition, the Company provides quarterly reports to the Triple-E Board that reports on beginning tariff rider account balances for that quarter by state and fuel, tariff rider collections and expenditures for that quarter, ending balances, and projected ending balances for end of year 2010.

<u>Internal Reporting</u>

The Company has more frequent, detailed reporting that it does for on-going operations. This includes such things as monthly savings, periodic cost-effectiveness checks to ensure that we're maintaining a cost-effective portfolio, engineering calculations based on updated market details (i.e. costs of efficiency products declining, updated savings based on measurement, etc.), and post-verifications on site-specific projects and recalculations of incentives.

Standard Practice Tests

The California Public Utilities Commission (CPUC) has promoted conservation and load management since the 1970s as an alternative to power plant construction and gas supply options. However, no official guidelines existed for utility-sponsored programs until 1983 when the California Energy Commission (CEC) published the *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs.* The Standard Practice Manual identifies the cost and benefit components and cost-effectiveness calculation procedures from four perspectives: Participant, Ratepayer Impact Measure (RIM) formerly regarded as the Non-Participant Test, Utility Cost Test (UCT) or Program Administrator Cost (PAC) and Total Resource Cost Test (TRC). There is a fifth perspective, the Societal Test, which is a variant of the TRC Test. The Company, however, only calculates the four main tests.

Participant Test			**Ratepayer Impact Measure**	
Numerator	Denominator		Numerator	Denominator
Bill reduction	Customer cost		Avoided cost savings	Lost revenue
Non-energy benefits	Incentives			Non-incentive utility cost
				Incentives

Utility Cost Test			**Total Resource Cost Test**	
Numerator	Denominator		Numerator	Denominator
Avoided cost savings	Non-incentive utility cost		Avoided costs savings	Non-incentive utility cost
	Incentives		Non-energy benefits	Customer cost

The participant test is a good first look at the benefit or desirability of the program to customers. However, a limitation is that it doesn't accurately capture the complexities and diversity of customer decision-making processes for demand-side management investments. Many customers choose to participate for non-quantifiable benefits not captured by this test.
The RIM test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. A weakness of this test is that the results are less certain than those of other tests since the test is sensitive to the differences between long-term projections or marginal costs and long-term projections of rates. Both are difficult to quantify with certainty.

The Total Resource Cost test measures the net costs of a demand-side management program as a resource option based on the total costs of the program. This includes both the participants' and the utility's costs. The costs of DSM resources in the TRC test are based on total costs while supply-side resources typically are based only on costs incurred by power suppliers. This could be a downside of this test when trying to align demand-side with supply-side options.

The Utility Cost test measures the next costs of a demand-side management program as a resource option based on the costs incurred by the Utility. This excludes any net costs incurred by the participant. Since this test only reflects a portion of the full cost of the resource, the test cannot be used to evaluate load building programs.

Sub-TRC Test
When evaluating new measures or programs, it is generally considered that one more measure or one more program will not incrementally increase utility non-incentive costs. Therefore, during the early evaluation process, these new measures or programs are evaluated using the TRC test without the inclusion of the non-incentive utility cost. If measures or programs pass this sub-TRC test with a benefit-cost ratio of greater than 1.0, then the Company will pursue these demand-side options.

Net to Gross
The net-to-gross adjustment accounts for impacts not attributable to the DSM program. One example of this is the impact of “non-net” program participants. Non-net participants are those customers adopting the measure and captured in program participation tracking that would have implemented the efficiency measures in the absence of the program. Another example of this is the impact from spillover or free drivers. Spillover is a percentage of participants who implement the measure due to the program but never collect the incentive so they’re not counted as a participant. Therefore, in order to calculate the true impact of the Company’s DSM programs, the gross impacts need to be adjusted for the impacts from “non-net” participants and spillover.

Historically, the Company has always reported savings and cost-effectiveness on a gross basis. However, the IPUC has requested that the Company try to incorporate the impacts of the net-to-gross ratio and spillover into future cost-effectiveness calculations. The Company’s EM&V program has not yet generated usable estimates of the net-to-gross ratio, and consequently the 2010 DSM business plan was based upon an analysis of the sensitivity of the TRC (and UCT as applicable) cost-effectiveness to various levels of net-to-gross ratios. This assists in identifying the sensitivity and determinants of the cost-effectiveness calculation to various net-to-gross scenarios. The Company will be reviewing these findings and seeking improved approaches to manage the net-to-gross ratio during 2010.

Generally the Company feels that the incentive tiers incorporated into our Schedule 90 and 190 tariffs appropriately target incentive dollars for projects where they would have the highest net impact. The effectiveness of the tiers in achieving this objective will be a specific subject of review within the Company.

Evaluation, Measurement and Verification
Damon Fisher

Overview
For the 2010 budget year Avista is updating, documenting and creating procedures related to the evaluation of programs in terms of savings, cost effectiveness and program efficiency. This effort is to make what we do more transparent to Avista's stakeholders and provide data that meets the needs of I-937 and decoupling.

Additionally independent third-party evaluators may be retained to either perform formal evaluations or to review evaluations performed by Avista personnel. It is believed that this effort will provide stakeholders reasonable confidence that evaluation results are independent. It is our intention to provide results that stakeholders can be confident in.

Avista wants these efforts to follow industry best practices. Consequently, we have adopted the *Model Energy Efficiency Program Impact Evaluation Guide*, by Steven R. Schiller as the method by which programs will be evaluated. Additional references are:

- *International Performance Measurement and Verification Protocol* (IPMVP).
- *ASHREA Guideline 14-2002.*

These documents are well-respected in the industry and commonly used.

Significant Changes for 2010

Implementation of Project Tracker:
This is an application that allows us to track site specific projects from beginning to end without paper and human memories.

- From an implementer perspective: It requires that a project is always assigned to a lead. This increases "ownership" and improves customer service.
- From a management perspective: it provides metrics that facilitate the most efficient allocation of work. This, in turn, increases throughput.
- From an EM&V perspective: For non-random sampling, it allows for the easier identification of projects that are good candidates for evaluation. This establishes a common repository for new projects and will ease the search process and increase timeliness of EM&V.
- From an Account Executive perspective: It gives them up-to-date project information that they can pass on to customers.

We are currently using this application. We are mapping the process flow and determining the needed interface changes. Early returns are positive. It has adjusted workload and improved communications between the engineering team and the Account Executives.

Program Management Process:
A major part of our transparency effort is capturing the heretofore seemingly insignificant program changes, considerations, validations etc. that we currently don't log in a formal manner. Historically our program managers have made immediate changes to processes, as needed. This can be weekly, monthly, or yearly. We've heard from our stakeholders that these should be formally identified in the form of "process evaluations." In order to do so, the program managers will be using Project Tracker for each program. When they have a requirement of technical assistance they can assign it to an engineer who will answer the question, perform an analysis, etc., then send it back. This process will document the program changes as the program is being tracked. An annual "process evaluation" report can then be compiled for each program.

In order to document that every program gets a regular review each year (possibly every six months) the program manager will perform a checklist review of their program(s). The primary elements of the checklist will include checking for code changes, incremental costs, and a review of savings assumptions (deemed or otherwise). These reviews are currently done but not formalized. It is the formalization that will provide the transparency.

Protocols:
We have written drafts of protocols that will be used in the evaluation of programs, Appendix D. These are "living drafts" that will be improved on an ongoing basis. They spell out the process by which evaluations are done, the format of evaluation plans and reports.

Decoupling
Avista has just been granted a permanent natural gas decoupling mechanism that will require independent M&V efforts. Those efforts will take a similar form as during the decoupling pilot which consisted of a random sample of projects being evaluated by a third party. However, for the next decoupling determination we will have significantly more information due to the planned impact evaluations. Approximately 40% of the prescriptively-acquired therms and 60% of site-specific therms will undergo a formal evaluation in 2010.

I-937
2010 will be the first year of compliance with I-937 efficiency goals. Avista will industry best practices for savings verification.

EM&V Collaborative
Avista was ordered by the Washington Utilities and Transportation Commission in our recently concluded natural gas decoupling case to convene a collaborative to examine evaluation, measurement and verification (EM&V) items and low-income issues specified in the order. We were asked to submit the results of this collaborative to the Commission by September 1, 2010.

2010 EM&V Activities Schedule
As a matter of course, Avista performs EM&V activities on a daily basis. Those efforts will continue and be more transparent. For the upcoming year we will supplement those activities with formal evaluations some of which will be performed by third parties.

The 2010 budget for EM&V activities is $1.0 million or about 4% of the DSM budget. These activities include the following:

- Project Measurement and Verification
  - Site specific measures may be unique enough that they require individual measurement and verification that is not part of a program evaluation.
- Project Installation Verification
  - All site specific commercial and industrial projects are visually inspected as a prerequisite to incentive payment.
- Program Evaluations
  - Formal and informal program evaluations are used to verify program savings and to improve the performance of programs.
- Pilot/Evaluation Programs
  - Roof Top Maintenance: Avista is currently running a yearlong study on the potential savings from proper maintenance of RTUs.
  - Solar Water Heaters: Avista is in the middle of a several year study of solar domestic hot water heaters.
- Decoupling
  - Independent evaluation of our therm savings will be implemented.

Avista has implemented a three year evaluation plan that is found in appendix D. The activities scheduled for 2010 are-

Program Name	Description	Evaluation Type	Base Year
Nonres site specific - HVAC	HE RTU's, Boilers, Furnaces	Impact	2008
Res shell	Insulation, Windows	Impact-Net/Gross	2009/2010
Res HVAC	HE Furnaces, HP, GSHP	Impact	2008
Res fuel conversion	Electric to gas, Electric to HP	Impact	2008
Res water heating efficiency	HE waterheaters gas, electric, tankless	Impact	2010
Energy Smart Grocer Program	Door seals, LED lighting,	Impact	2009/2010
P network computers	Computer shutdown by software	Impact	2010
Res appliances	Energy star and CEE appliance	Net/Gross	2009/2010

In general, the list includes larger programs that are a significant portion of portfolio savings (a key component of cost effectiveness, I-937 and decoupling requirements). In addition to savings analysis, there is going to be an increased effort to quantify net/gross ratios over the next few years. To date we have been doing sensitivity analysis to identify potential net/gross issues.

In January we will start sending out RFPs for program evaluations. The Net/Gross evaluations will be first. It is yet to be determined which of the remaining evaluations will be done by a third party. However, all internal evaluations will be reviewed and commented on by a third party.

Implementation Policies
Renee Coelho

Written Policy

Incentives for energy efficiency projects are calculated using the same methodology as outlined in Tariff Schedules 90 and 190 in both Washington and Idaho. To maintain consistency with how the final incentive is determined the "Dual-Fuel Incentive Calculator" is used for all pre-project and post-project analysis. This tool takes into account the energy savings associated with both fuels, with the appropriate rate schedule in the designated state. There are four types of incentives the customer could be eligible for: electric efficiency improvement, natural gas efficiency improvement, electric to natural gas improvement and a dual-fuel efficiency improvement. The first three improvements use one-to-one fuel calculation to determine the projects simple-payback and applied to the corresponding incentive tier level outlined in Schedule 90 or 190. The dual-fuel incentive calculation, takes into account both kilowatt-hour and therm savings, converted to BTU's in order to determine the appropriate allocation of incentive dollars by fuel, as well as the simple-payback and is again applied to the corresponding tier level as mentioned above.

The calculator includes a policy outline that outlines how costs are captured for the purpose of an incentive analysis and cost-effective analysis. The policy also lists the types of projects that are considered eligible for incentive consideration. The policy and the calculator itself are updated whenever there is a change in rates or a change in the incentive tiers; otherwise, a yearly review is conducted. Prescriptive programs (both in the residential and commercial/industrial portfolios) each have an associated dual-fuel incentive calculator as part of the program development.

For Oregon, incentive calculation is based on the description outlined in Schedule 492 and an Oregon specific incentive calculator has also been developed to maintain consistency in evaluation.

Policy Guidelines

For energy efficiency programs, policy is established whenever there is a modification to the tariff language, or change to a program/service offering. Tariff pages serve as the documentation for past and present incentive levels and program/service offerings. Currently, changes to the day-to-day implementation are kept in a "Captain's Log" that is housed on a common drive that is exclusive to the Energy Solutions Department. This log contains email documentation or final write-ups about decisions that affect the beginning or termination of a service/program, updates about requirements for eligibility, etc. Before the information is incorporated into the Captain's Log – discussion occurs among the DSM Manager, Analysts, Program Managers, Engineers and Account Executives to determine the best course of action to take for the issue at hand. In 2010, there will be an updated method to the Captain's Log. It may include a combination of an on-line tracking database system as well as hard copy documentation. Information about how to proceed with updates to policies for programs and other requirements is still being gathered at the time of this publication.

Implementation and customer focus are just a few of the many components considered when evaluating a new or existing policy. Final communication of the policy is presented in the weekly Department Staff meeting with a subsequent email. In some cases, the policy also appears as part of the Dual-Fuel incentive calculator mentioned above, or is housed in the department's SalesLogix database that tracks primarily commercial/industrial efficiency projects. Whenever contact with the customer is necessary as a result in a change in policy, a variety of communication tactics are implemented to provide updated information. They may include but are not limited to a combination of the following: direct contact from the customer's Account Executive in the form of a visit, email, phone call, or letter advising of the change; article in the bi-monthly Energy Solutions newsletter distributed by Questline; bonus Questline coverage highlighting the specific change; refreshed information on the Avista Utilities website; meetings and/or collateral information provided to the Company's Call Center and Construction Representatives in both local and outlying areas; letters or phone calls to appropriate vendors and other trade allies that might benefit or be affected by the change in program/service.

Issues Identified for Management Focus

Jon Powell

Throughout the business planning process there were issues identified that indicated a particular need for management during 2010. These elements have been collected and summarized within this section to ensure clarity and focus upon those issues over the course of the year. In no particular order, these items include:

- Acquisition tracking
  - The business plan indicates that we will be 10% short of our natural gas decoupling target and 12% short of our Washington/Idaho IRP target. There is considerable uncertainty regarding the 2010 status of a number of issues to which acquisition will be highly sensitive to, e.g. customer response given the economy, PGA impacts upon retail rates, continuation of tax credits and the response to ARRA co-funded programs such as Avista's prospective residential audit and resource conservation manager programs. The projection that we will not meet targets, the uncertainty over critical issues relevant to acquisition and the short period of time upon which to react to observed trends calls for close monitoring and management throughout the entire year.
  - Projections are that the DSM contribution to the electric acquisition required under the I-937 target will exceed the target by 6% of the average acquisition needed during the 2010-2011 I-937 compliance cycle even before considering any distribution efficiency acquisition. Though this prospect appears to be very favorable, it is also recognized that the distribution efficiency investment is significantly dependent on ARRA funding that may not be fully certain, and it may be somewhat premature to project how those funds will ultimately be used. Thus an overall management of progress towards the I-937 targets will need to be carefully monitored based upon all I-937 qualifying acquisition during the course of 2010-2011.
  - It is estimated that we will exceed the 2010 electric IRP target by 8%. Tracking this acquisition independently of I-937 tracking is necessary since it is a 2010 goal only and distribution efficiency savings would not apply towards this target.
- Limited income portfolio implementation
  - Avista will convene a collaborative to discuss potential improvements in the acquisition level and cost-effectiveness of our Washington and Idaho limited income portfolio. The planning process for this effort has been initiated and will lead towards a September 2010 report to the WUTC.
- EM&V
  - Avista will convene a collaborative to discuss EM&V issues with particular attention to meeting the requirements and expectations established in the IPUC staff MOU, Washington natural gas decoupling and I-937 discussions.
  - Implement the three-year EM&V plan described within this business plan during 2010. This will include meeting the requirements of the natural gas decoupling pilot for independent external verification of Washington natural gas acquisition.
    - Though the greatest external focus is upon impact EM&V, there is currently action underway to establish a means of identifying needs for process EM&V as well as assigning accountabilities.
    - Incorporate within those requirements a measurement of the net-to-gross ratio with sufficient disaggregation to be useful in both performing cost-effectiveness analysis on a net basis and for supporting efforts to manage the net-to-gross ratio through changes in implementation strategy. This should include a survey of the literature on the net-to-gross ratios

estimated by others as well as the methodologies for estimating the ratios.

- Regulatory filings
    - File for revisions to the tariff riders within Schedules 91 and 191 in both jurisdictions that are sufficient to eliminate the existing negative balances by the end of 2010. Within Washington, the filing must be made by February 15th, 2010 with a distribution to the Triple-E Board for comment no later than January 15th, 2010. This will permit an update of the calculations using actual end-of-year 2009 results.
    - File for revisions to Schedule 90 in both jurisdictions to eliminate the incentives granted (but not DSM involvement in technical assistance and customer education) for renewable energy generation.
- Cost-effectiveness
    - Meet our commitments for fielding only those measures and programs that contribute to portfolio TRC and UCT cost-effectiveness (whichever test is the more constraining). Do so by:
        - Following through on program planner commitments for terminating those measures determined to be non-cost-effective per the sub-TRC analysis performed as part of the business plan.
        - Continue to evaluate the sub-TRC of prospective measures and programs as part of the decision-making process on the status of those programs.
        - Following through on commitments for program planners to consider and document exceptions to the above requirement. Potential exceptions identified to date may be market transformation programs (where there is plausible evidence that the program or measure would be cost-effective when the full market transformation costs and benefits are taken into consideration), impact upon other cost-effective programs and measures and possible considerations of impact upon the limited income portfolio.
        - Incorporate the cost-effectiveness commitments made through the IPUC staff MOU and previous commitments for combined electric and natural gas limited income cost-effectiveness into an ongoing update to the approach taken to the limited income portfolio implementation. The tools readily available in 2010 are the "LITRC-squared" model tracking the cost-effectiveness of the overall portfolio, including the impact of individually-approved measures for Community Action Program installation.
        - Management of the net-to-gross ratio as it pertains to cost-effectiveness
            - Given the expectation for increasing proportions of non-incentive expenditures within the overall DSM utility cost and the awareness of the sensitivity of the TRC and UCT cost-effectiveness ratios to that percentage, it is necessary to expend particular focus upon the net-to-gross issue in general throughout the year.
            - It has been suggested that all involved in the DSM task, particularly the program planners, convene a series of meetings to discuss how the Company can manage net-to-gross ratios to maximize the net cost-effectiveness of the portfolio. This may include revisions to Schedules 90 or 190 if deemed appropriate.
    - Review the methods used for assigned fixed infrastructure cost to individual programs as part of the cost-effective analysis. This analysis will become increasing important given the sub-TRC cost-effectiveness criteria and net-to-gross ratio issues.
- Management of the DSM tariff rider balances.

  - Based upon the expected 2010 expenditures, the proposed revision to Schedules 91 and 191 and the expected billing determinants over the course of the year, we are projecting that we will end the year with a zero balance on each of the four Avista tariff riders. (This is not including consideration of the $2 million contingency funding for the Washington electric DSM rider). However, there is no reason to believe that the historical trend for unanticipated opportunities for cost-effective DSM investment will not continue in 2010. The decision to pursue those opportunities will need to be made with knowledge of the tariff rider balance status and the impact of these decisions upon that balance.
- Improve the degree of rigor and consistency in the application of the sub-measure, measure, program and portfolio definitions. The application of these definitions are critical to supporting cost-effectiveness analysis and using that cost-effectiveness analysis in the decision to continue, terminate or offer new measures or programs.
- Meet or exceed the expectations and commitments that have been made for external communication. Formalized commitments have been made as part of the most recent Washington revisions to Schedules 91 and 191 as well as the 2009 signing of a multiparty MOU with the Idaho PUC staff.
- Continue to evaluate the short-term and long-term needs for DSM staffing in a manner that balances cost-minimization and quality control. The residential rebate processing function is in the most critical need of review due to recent promotions.
- A review of the options for improved targeting of the site-specific program towards the most cost-effective projects will be considered as part of an overall effort to increase project and portfolio cost-effectiveness as well as to minimize the adverse impact of the minority of cost-ineffective projects on the overall performance.
- Review the methods used for assigned fixed infrastructure cost to individual programs as part of the cost-effective analysis. This analysis will become increasing important given the sub-TRC cost-effectiveness criteria and net-to-gross ratio issues.

Appendix A – Summary of Written Implementation Policies

Renee Coelho

Avista's Schedule 90 and 190 govern the DSM operations that the Company can (and must) offer. These tariffs were designed to provide the utility with sufficient flexibility to be responsive to market conditions and opportunities, but at the same time impose upon the utility a greater responsibility for ensuring that the flexible tariff is implemented without undue discrimination and within the letter and spirit of the tariff itself.

As a consequence, the Company has developed a "Dual-Fuel Incentive Calculator" (DFIC) spreadsheet model. This model ensures a consistency in the calculation of incentives for our customers. The model is most frequently applied to our site-specific program, given that each project will require a customized incentive calculation, but is also applied to "typical" projects to determine prescriptive incentive amounts. This tool also provides engineers, account executives and program managers with key diagnostic statistics regarding the projects to improve our understanding of how the program is being applied for use in future program design and redesign.

One element that is incorporated into the DFIC model is a series of policy statements. These policies have been established to improve the consistency of the application of our programs. These policies have been copied in below in their entirety. The DFIC model is not included in this business plan but is available upon request.

<u>Policy Guidelines from the DFIC Model</u>

<u>Policy Rules for the Calculation of Customer Incentives</u>
(if in doubt about the interpretation of these rules, consult Renee Coelho or Jon Powell prior to representing any incentive to the customer)

<u>Definition of Fields within SalesLogix</u>

- KW - Customer coincident demand
- kWh – direct or primary savings for an electric or dual fuel project
- Therms – direct or primary savings for a natural gas or dual fuel project
- Secondary kWh – incidental savings or increased usage due to a natural gas or dual fuel project; does not count for or against goal. Increased usage is entered as a negative.
- Secondary therms – incidental savings or increased usage due to an electric or dual fuel project; does not count for or against goal. Increased usage is entered as a negative.
- Measure life – is the measure life for the individual project or the standard measure life when no better estimate is available. This provides a cross-check to verify whether or not standard measure lives used in reporting should be adjusted.
- Cost – entire cost of the project
- Cost for CE Calcs – the incremental cost of the project to be used in the cost-effectiveness calculations
- Recurring non-energy benefits – an annual recurring non-energy benefits entered in nominal dollars
- One time non-energy benefits – a non-recurring non-energy benefit (i.e. maintenance savings the year the windows were installed or the difference between regular windows and historical windows)
- Schedule 99/199 – pseudo rate schedule for projects with a special contract
- Schedule 90 – pseudo rate schedule for dual fuel projects where there are electric savings but the customer is not an electric customer of the Company

- Schedule 190 – pseudo rate schedule for dual fuel projects where there are natural gas savings but the customer is not a natural gas customer of the Company

Treatment of Non-Energy Benefits

- Data regarding non-energy benefits is to be collected by technical project lead and by account executive; entry of one time and/or recurring non-energy benefits into SalesLogix being account executive responsibility
- Non-energy benefit data must be incorporated into cost-effectiveness calculations
- Non-energy benefits are not to be included in the calculation of simple payback for purposes of determining the customer's incentive
- Non-quantifiable non-energy benefits should be documented within the DFIC. This is important for times when the portfolio may not be cost-effective.
- Demand response for our purposes is defined as utility dispatchable and is entered in a separate demand response part of SalesLogix.

Calculation of Simple Payback (used for Direct Incentives)

- Simple payback is the customer cost, as defined within this policy, divided by the first year own-fuel bill savings accruing to the customer. The incentive level will then be determined by applying that simple payback to the tier structure defined in Schedule 90 and 190.
- Data collection will be the joint responsibility of the technical lead and the account executive. Coordination and entry of the data into SalesLogix will be the account executive's responsibility
- The account executive is responsible for submitting the data for calculation of simple payback before evaluation is submitted to customer.
- Data is to be submitted for calculation of simple payback before evaluation is submitted to customer (when report is handed from technical lead to segment manager)
- The final results of the DFIC calculation will be communicated to the account executive prior to being presented to the customer, unless the account executive approves alternate arrangements.
- Capital cost estimates can be arrived at in many ways (e.g., Means Mechnical Estimating, contractor bids, industry standards, and in-house spreadsheets)
- Simple payback calculation are not to include values for non-energy benefits
- The simple payback calculation will **not** include adjustments for **secondary** energy effects that are not "own-fuel". Thus secondary electric savings are considered in electric efficiency (and dual-fuel and fuel-switching) calculations and secondary natural gas savings are considered in natural gas efficiency (or dual-fuel or fuel-switching) calculations. But non-electric savings are not incorporated into electric SPB calculations nor are non-natural gas savings incorporated into natural gas efficiency SPB's.
- The calculation will include adjustments for direct non-electric energy effects (e.g., therm penalty as a result of a fuel switch project).
- The calculation will include the bill savings resulting from kWh, kW, kVAR impacts of the project, plus any associated electric bill, tax or fee impacts.
- Calculation is to include adjustments for secondary electric energy effects (e.g., heating increase or cooling savings resulting in kWh change)
- **Similar measures (e.g., lighting and lighting controls or HVAC and HVAC controls) *will* be bundled for calculations, but dissimilar measures (e.g., lighting and VFDs) *will not be combined.***
- Projects which are served under different rate schedules are never, under any circumstances, combined into a single project.
- Projects which are at different locations are never, under any circumstances, combined into a single project. For purposes of this policy, different locations mean that the projects involved could not feasibly be served by a single meter. If the projects could be

served by a single meter, the projects will be combined if they are of a similar measure and on the same rate schedule if the customer benefits from combining the multiple projects. The intent is to avoid uneconomic manipulation of metering in order to allow the combination of projects.

- Sales tax paid by the customer and associated with the energy efficiency portion of the project will be included as a cost for the simple payback calculation.
- Energy savings should be valued based upon the actual savings that the customer receives. Generally this will mean that the highest tier of usage on each individual rate should be used, which is the methodology embedded in the DFIC model. However, when using this tier would not properly value customer energy savings, the model rate inputs should be modified by using the hypothetical rate schedules "99" and "199" to represent the project-specific inputs.

<u>Calculation of Customer Cost (used for Direct Incentives)</u>

- The customer costs to be included in the simple payback calculation will be only those associated with the energy efficiency portion of the project relative to a defined baseline. Energy savings will be calculated based upon the same definition of the baseline and high efficiency project.
- The calculation of customer costs will not include any deductions for non-energy benefits, but the baseline and high efficiency projects will be defined to exclude these costs and benefits to the extent possible.
- Calculation is not to include adjustments for secondary non-electric energy effects (e.g., heating increase or cooling savings in therm change)
- Calculation is to include all values for electric energy savings; kWh, kW, kVAR
- Calculation is to include adjustments for secondary electric energy effects (e.g., heating increase or cooling savings resulting in kWh change)
- Any direct or indirect incentive received by the customer will not be used to reduce the customer cost for purposes of the calculation of simple payback
- The installation of used equipment does qualify for direct incentives, assuming that the equipment meets the manufacturer's code minimum or industry standards. Disposal of the old equipment is not included in the customer cost for purposes of calculating simple payback, but is considered as a customer cost for cost-effectiveness purposes
- Appropriate base case for projects where existing equipment is in imminent failure is the manufacturer's code minimum or industry standard, whichever is more energy efficient.
- Appropriate base case for projects involving new construction or substantial renovation is the equivalent code minimum or industry standard, whichever is more energy efficient.
- Base case for calculation of savings will be the same base case used in calculation of customer incentives (i.e. A/C upgrade from 8 SEER to 12 SEER when code minimum is 13 SEER—if A/C was functioning fine with measure life still remaianing savings would be claimed for the upgrade and incentive paid even though code minimum wasn't met. However, if failure was imminent, meeting code minimum would be necessary to claim savings and pay incentive).

<u>Calculation of Customer Cost (used for Cost-Effectiveness)</u>

- Calculation is to include only costs associated with the energy efficiency component of a customer project
- Calculation is to be adjusted for significant differences between remaining life of existing equipment and expected life of recommended equipment
- Calculation is not to include adjustments for non-energy benefits, although non-energy benefits are to be tracked for inclusion in cost-effectiveness calculations
- Calculation is to be performed by the project engineer
- Calculation is not to include adjustments for direct incentives

Qualifying Projects

- Projects that are characterized by having a significant degradation of end-use quality do not qualify for either customer incentives or credit toward energy savings calculations. Degradation of savings is defined as a significant reduction to the value, comfort, convenience or other attributes of an end use. Any non-trivial reduction in the safety of any end-use will disqualify the project. This will apply to both residential and non-residential projects.

  For example, degradation of end use would disqualify projects such as: (1) a lighting retrofit that reduces the lighting level below industry standards, (2) changes in HVAC temperature settings which are not associated with any other efficiency project, (3) reductions in lighting levels which are deemed to adversely affect safety, (4) the closure or destruction of a facility.

  Examples of projects which are not disqualified due to degradation of end-use include: (1) reductions in lighting levels which do not adversely effect comfort, safety or any other end use attribute, (2) changes in HVAC temperatures when facilities are unoccupied or changes in a manner which do not adversely effect comfort or any other end use attribute, (3) changes in an industrial process which reduces the energy use without effecting the quantity or quality of the product, (4) changes in facility operating hours which do not materially effect the business value of the facility.
- Maintenance measures in general do not qualify for incentivization, nor do we take credit for the efficiency gains from maintenance measures alone. This does not preclude the development of market transformation programs intended to improve maintenance practice on a sustained basis. Maintenance measures are defined as measures which bring end-use equipment back to (or towards) their original level of efficiency or measures which are necessary for the continued operation of the unit as it was designed to function. Examples of maintenance measures would include filter changes, lamp replacements, periodic lubrications, replacement of components with an expected life less than the equipment that it is a part of (e.g. fluorescent tubes). This definition does not preclude providing incentives for improvements to existing equipment that take it to an efficiency beyond that which it was originally designed for (e.g. additional of a variable frequency drive to an existing motor). In the case of an efficiency upgrade the appropriate standard efficiency base case would be the existing equipment, properly maintained and operating as it was designed to operate.

Capturing of “Soft Savings”

- Behavioral savings from community outreach and education that are difficult to quantify will not be included with our primary electric and natural gas savings and counted toward meeting goal.

Appendix B – Tariffs Governing Avista DSM Programs
Jon Powell

The regulation permitting Avista to offer and fund DSM programs within our Washington and Idaho service territory are governed by the nine tariffs. These tariffs are:

- Schedule 90 (Washington tariff and Idaho tariff): Specifies the conditions under which Avista operates electric DSM programs.
- Schedule 190 (Washington tariff and Idaho tariff): Specifies the conditions under which Avista operates natural gas DSM programs.
- Schedule 91 (Washington tariff and Idaho tariff): Establishes the tariff rider surcharge funding electric DSM and (in Washington only) LIRAP programs.
- Schedule 191 (Washington tariff and Idaho tariff): Establishes the tariff rider surcharge funding natural gas DSM and (in Washington only) LIRAP programs.
- Schedule 96 (Idaho only): Governs Avista's two-year demand-response pilot.

Avista has long sought to offer identical programs to our Washington and Idaho customers to avoid the need for distinguishing between our Washington and Idaho programs within the marketplace. This is of high importance given that the two jurisdictions are inextricably joined for purposes of program outreach and implementation. Thus you will note an extremely high degree of similarity between the tariffs of the two jurisdictions.

The text of the most recent versions of each of the nine tariffs are contained below. These tariffs are also available on the Company's website at www.avistautlities.com.

SCHEDULE 90
ELECTRIC ENERGY EFFICIENCY PROGRAMS
WASHINGTON

1. AVAILABILITY

The services described herein are available to specified residential, commercial, and industrial, retail electric distribution customers of Avista for the purpose of promoting the efficient use of electricity. Customers receiving electric distribution service provided under special contract and/or customers receiving electric services not specified under Tariff Schedule 91 (Energy Efficiency Rider Adjustment) are not eligible for services contained in this schedule unless specifically stated in such contract or other service agreement. The Company may provide partial funding for the installation of electric efficiency measures and may provide other services to customers for the purpose of identification and implementation of cost effective electric efficiency measures as described in this schedule. These services are available to owners of facilities, and also may be provided to tenants who have obtained appropriate owner consent.
Assistance provided under this schedule is limited to end uses where electricity is the primary energy source. Assistance may take the form of monetary incentives or nonmonetary support, as further defined within this tariff. The Company shall strive to develop a portfolio of programs that is cost-effective on an aggregate basis. Customer participation under this schedule shall be based on eligibility requirements contained herein.

2. ELIGIBLE CUSTOMER SEGMENTS

All customers in all customer segments to whom this tariff is available are eligible for participation in electric efficiency programs developed in compliance with this tariff. The broad availability of this tariff does not preclude the Company from targeting measures, markets and customer segments as part of an overall effort to increase the costeffectiveness and access to the benefits of electric efficiency.

3. MEASURES

Only electric efficiency measures with verifiable energy savings are eligible for assistance. Measure eligibility may not necessarily apply to all customer segments.
Final determination of applicable measures will be made by the Company. Eligible technologies may include, but are not limited to, energy-efficient appliances, assistive technologies, controls, distributed renewable energy, motors, heating, ventilation and airconditioning
(HVAC) systems, lighting, maintenance, monitoring, new technologies, and shell.
Incentives for distributed renewable energy measures will be limited to net-metering facilities operating under Avista Utilities Idaho/Washington Rate Schedule 63 Net Metering rules. Incentives will be limited to energy production not to exceed 100% of the average annual energy use of the facility for the preceding three years or if new, a similar facility's annual use as calculated by the Company. Incentives will be limited to 50% of the total cost of the installation. This market transformation effort supports renewable energy measures in the residential and small commercial segments.
Market transformation ventures will be considered eligible for funding to the extent that they improve the adoption of electric efficiency measures that are not fully accepted in the marketplace. These market transformation efforts may include efforts funded through regional alliances or other similar opportunities.

4. FUNDING AND NONMONETARY ASSISTANCE

4.1 Funding

The incentive to be provided by the Company for electric or fuel-conversion efficiency measure(s) is based upon the simple payback of the measure prior to the application of an incentive, as calculated by Company staff and based upon standardized measure cost(s). These incentive tiers apply to measures with energy savings lasting 10 years or longer that meet or exceed the higher of the current energy code or industry practice that are applicable to the project. Simple payback is defined as the capital cost of the project divided by the energy savings per year. Fuel-conversion incentives are available only for conversion to natural gas with an end-use efficiency of 44% or greater. The incentives shall be as follows:

Incentive Level
(cents per first year kWh saved)
Measures
Simple Pay-Back
Period *(Minimum measure life of 10 years*)*

Electric Efficiency 1 to under 2 years 8 cents
2 to under 4 years 12 cents
4 to under 6 years 16 cents
6 to under 10 years 20 cents
Over 10 years ** 20 cents
Over 10 years *** 12 cents
Fuel-Conversion 1 to under 2 years 1 cents
2 to under 4 years 3 cents
4 to under 6 years 5 cents
Over 6 years 7 cents

** Measures with an energy savings life less than 10 years may receive an incentive amount not to exceed the full incremental cost of the measure.*
*** Applicable only to non-lighting measures.*
**** Applicable only to lighting measures .*

Incentives in which the tier structure applies will be capped at 50% percent of the incremental project cost with the exception of the following that may be capped at a maximum of 100% of the measure cost:

4.1.1 DSM programs delivered by community action agencies contracted by the Company to serve Limited Income or vulnerable customer segments including agency administrative fees and health and human safety measures;

4.1.2 Low-cost electric efficiency measures with demonstrable energy savings (e.g. compact fluorescent lamps);

4.1.3 Programs or services supporting or enhancing local, regional or national electric efficiency market transformation efforts.

The Company will actively pursue electric efficiency opportunities that may not fit within the prescribed services and simple pay-back periods described in this tariff. In these circumstances the customer and the Company will enter into a site specific services agreement.

4.2 Non-Monetary Assistance

Assistance without the granting of direct monetary incentives to the customer is available across all applicable segments and may be provided in various ways, that include, but are not limited to, the following:

4.2.1. Educational, training or informational activities that enhance electric efficiency. This may include technology or customer-segment specific seminars, literature, trade-show or community events, advertising or other approaches to increasing the awareness and adoption of resource efficient measures and behaviors.

4.2.2. Financial activities intended to reduce or eliminate the financial barriers to the adoption of electric efficiency measures. This may include programs intended to reduce the payment rate for resource efficiency measures, direct provision of leased or loaned funds or other approaches to financial issues with better than existing market terms and conditions.

4.2.3. Product samples may be provided directly to the customer when energy efficiency products may be available to the utility at significantly reduced cost as a result of cooperative buying or similar opportunities.

<u>Text of Washington Schedule 91 (establishing the tariff rider surcharge funding Avista's electric DSM programs)</u>

SCHEDULE 91
PUBLIC PURPOSES RIDER ADJUSTMENT - WASHINGTON
APPLICABLE:
To Customers in the State of Washington where the Company has electric service available. This Public Purposes Rider or Rate Adjustment shall be applicable to all retail customers for charges for electric energy sold and to the flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service. This Rate Adjustment is designed to recover costs incurred by the Company associated with providing Demand Side Management services and programs and Low Income Rate Assistance (LIRAP) to customers.
MONTHLY RATE:
The energy charges of the individual rate schedules are to be increased by the following amounts:
DSM Rate LIRAP Rate
Schedule 1 $0.00317 per kWh $0.00058 per kWh(I)
Schedule 11 & 12 $0.00449 per kWh $0.00081 per kWh(I)
Schedule 21 & 22 $0.00331 per kWh $0.00060 per kWh(I)
Schedule 25 $0.00217 per kWh $0.00039 per kWh(I)
Schedule 31 & 32 $0.00295 per kWh $0.00052 per kWh(I)
Schedules 41-48 4.65% of base rates (R) 0.84% of base rates (I)
SPECIAL TERMS AND CONDITIONS:
Service under this schedule is subject to the Rules and Regulations contained in this tariff.
The above Rate is subject to increases as set forth in Tax Adjustment Schedule 58.

Text of Washington Schedule 190 (governing the conduct of Avista's gas DSM programs)

SCHEDULE 190
NATURAL GAS EFFICIENCY PROGRAMS
WASHINGTON

1. AVAILABILITY

The services described herein are available to qualifying residential, commercial, and industrial, retail natural gas distribution customers of Avista Corporation for the purpose of promoting the efficient use of natural gas. Customers receiving natural gas distribution service provided under special contract and/or customers receiving natural gas services not specified under Tariff Schedule 191 (Natural Gas Efficiency Rider Adjustment) are not eligible for services contained in this schedule unless specifically stated in such contract or other service agreement. The Company may provide partial funding for the installation of natural gas efficiency measures and may provide other services to customers for the purpose of identification and implementation of cost effective natural gas efficiency measures as described in this schedule. Facilities-based services are available to owners of facilities, and also may be provided to tenants who have obtained appropriate owner consent.

Assistance provided under this schedule is limited to end uses where natural gas is or would be the energy source and to measures which increase the efficient use of natural gas. Assistance may take the form of monetary incentives or non-monetary incentives, as further defined within this tariff. The acquisition of resources is costeffective as defined by a Total Resource Cost test (TRC) as a portfolio. Customer participation under this schedule shall be based on eligibility requirements contained herein.

2. ELIGIBLE CUSTOMER SEGMENTS

All customers in all customer segments to whom this tariff is available are eligible for participation in natural gas efficiency programs developed in compliance with this tariff. The broad availability of this tariff does not preclude the Company from targeting measures, markets and customer segments as part of an overall effort to increase the cost-effectiveness and access to the benefits of natural gas efficiency.

3. MEASURES

Only natural gas efficiency measures with verifiable energy savings are eligible for assistance. Measure eligibility may not necessarily apply to all customer segments. Final determination of applicable measures will be made by the Company.

Market transformation ventures will be considered eligible for funding to the extent that they improve the adoption of natural gas efficiency measures that are not fully accepted in the marketplace. These market transformation efforts may include efforts funded through regional alliances or other similar opportunities.

4. FUNDING AND NONMONETARY ASSISTANCE

4.1 Funding

The incentive level provided by the Company to a customer for natural gas efficiency measure(s) is based upon the simple payback of the measure prior to the application of an incentive, as calculated by Company staff and based upon standardized measure cost(s). Simple payback is defined as the capital cost of the project divided by the energy savings per year. The incentives shall be as follows:

Measures Simple Pay-Back Period Incentive Level
(dollars/first year therm saved)
(Minimum measure life of 10
years*)
I to 2 years 2.00
2 to 4 years 2.50
Natural Gas Efficiency
4 to 6 years 3.00

Over 6 years 3.50

*Measures with an energy savings life less than 10 years may receive an incentive amount not to exceed the full incremental cost of the measure.

Incentives in which the tier structure applies will be capped at 50% of the incremental project cost with the exception of the following that may be capped at a maximum of 100% of the measure cost:

4.1.1 Energy efficiency programs delivered by community action agencies contracted by the Company to serve Limited Income or vulnerable customer segments including agency administrative fees and health and human safety measures;

4.1.2 Low-cost natural gas efficiency measures with demonstrable energy savings (e.g. rooftop unit service);

4.1.3 Programs or services supporting or enhancing local, regional or national natural gas efficiency market transformation efforts.

Avista Corporation will actively pursue natural gas efficiency opportunities that may not fit within the prescribed services and simple pay-back periods described in this tariff. In these circumstances the customer and Avista Corporation will enter into a site specific services agreement.

4.2 Non-Monetary Assistance

Non-monetary assistance is service that does not involve the granting of direct monetary incentives to the customer. This type of assistance is available across all applicable segments. This assistance may be provided in various ways that include, but are not limited to, the following:

4.2.1. Educational, training or informational activities that enhance resource efficiency. This may include technology or customer-segment specific seminars, literature, trade-show booths, advertising or other approaches to increasing the awareness and adoption of resource efficient measures and behaviors.

4.2.2. Financial activities intended to reduce or eliminate the financial barriers to the adoption of resource efficiency measures. This may include programs intended to reduce the payment rate for resource efficiency measures, direct provision of leased or loaned funds or other approaches to financial issues by better than existing market terms and conditions.

4.2.3. Product samples may be provided directly to the customer when resource efficient products may be available to the utility at significantly reduced cost as a result of cooperative buying or similar opportunities.

4.2.4. Technical Assistance may consist of engineering, financial or other analysis provided to the customer by or under the direction of, Avista Corporation staff. This may take the form of design reviews, product demonstrations, third-party bid evaluations, facility audits, measurement and evaluation analysis or other forms of technical assistance that addresses the costeffectiveness, technical applicability or end-use characteristics of customer alternatives.

5. BUDGET & REPORTING

The natural gas efficiency programs defined within this tariff will be funded by surcharges levied within Schedule 191. The Company will manage these programs to obtain resources that are cost-effective from a Total Resource Cost perspective and achievable through utility intervention. Schedule 191 will be reviewed periodically and revised as necessary to provide adequate funding for natural gas efficiency efforts.

Text of Washington Schedule 191 (establishing the tariff rider surcharge funding Avista's natural gas DSM programs)

SCHEDULE 191
PUBLIC PURPOSES RIDER ADJUSTMENT - WASHINGTON
APPLICABLE:
To Customers in the State of Washington where the Company has natural gas service available. This Public Purposes Rider or Rate Adjustment shall be applicable to all retail customers taking service under Schedules 101, 111, 112, 121, 122, 131, and 132. This Rate Adjustment is designed to recover costs incurred by the Company associated with providing Demand Side Management services and programs, and Low Income Rate Assistance (LIRAP) to customers.
MONTHLY RATE:
The energy charges of the individual rate schedules are to be increased by the following amounts:
DSM Rate LIRAP Rate
Schedule 101 $0.03344 per Therm $0.00979 per Therm(I)
Schedule 111 & 112 $0.02944 per Therm $0.00846 per Therm(I)
Schedule 121 & 122 $0.02756 per Therm $0.00781 per Therm(I)
Schedule 131 & 132 $0.02663 per Therm $0.00756 per Therm(I)
SPECIAL TERMS AND CONDITIONS:
Service under this schedule is subject to the Rules and Regulations contained in this tariff.
The above Rate is subject to increases as set forth in Tax Adjustment Schedule 158.

Text of Idaho Schedule 90 (governing the conduct of Avista's electric DSM programs)

SCHEDULE 90
ELECTRIC ENERGY EFFICIENCY PROGRAMS
IDAHO

1. Availability

The services described herein are available to specified residential, commercial, and industrial, retail electric distribution customers of Avista Corporation for the purpose of promoting the efficient use of electricity. Customers receiving electric distribution service provided under special contract and/or customers receiving electric services not specified under Tariff Schedule 91 (Energy Efficiency Rider Adjustment) are not eligible for services contained in this schedule unless specifically stated in such contract or other service agreement. The Company may provide partial funding for the installation of electric efficiency measures and may provide other services to customers for the purpose of identification and implementation of cost effective electric efficiency measures as described in this schedule. Facilities-based services are available to owners of facilities, and also may be provided to tenants who have obtained appropriate owner consent.

Assistance provided under this schedule is limited to end uses where electricity is the energy source. Assistance may take the form of monetary incentives or non-monetary incentives, as further defined within this tariff. The acquisition of resources is cost-effective as defined by a Total Resource Cost test (TRC) as a portfolio. Customer participation under this schedule shall be based on eligibility requirements contained herein.

2. ELIGIBLE CUSTOMER SEGMENTS

All customers in all customer segments to whom this tariff is available are eligible for participation in electric efficiency programs developed in compliance with this tariff. The broad availability of this tariff does not preclude the Company from targeting measures, markets and customer segments as part of an overall effort to increase the cost-effectiveness and access to the benefits of electric efficiency.

3. MEASURES

Only electric efficiency measures with verifiable energy savings are eligible for assistance. Measure eligibility may not necessarily apply to all customer segments. Final determination of applicable measures will be made by the Company. Eligible technologies may include, but are not limited to, energy-efficient appliances, assistive technologies, controls, distributed renewable energy, motors, heating, ventilation and air-conditioning (HVAC) systems, lighting, maintenance, monitoring, new technologies, and shell.

Incentives for distributed renewable energy measures will be limited to net-metering facilities operating under Avista Utilities Idaho/Washington Rate Schedule 63 Net Metering rules. Incentives will be limited to energy production not to exceed 100% of the average annual energy use of the facility for the preceding three years or if new, a similar facility's annual use as calculated by the Company. Incentives will be limited to 50% of the total cost of the installation. This market transformation effort supports renewable energy measures in the residential and small commercial segments.

Market transformation ventures will be considered eligible for funding to the extent that they improve the adoption of electric efficiency measures that are not fully accepted in the marketplace. These market transformation efforts may include efforts funded through regional alliances or other similar opportunities.

4. FUNDING AND NONMONETARY ASSISTANCE

4.1 Funding

The incentive to be provided by the Company for electric or fuel-conversion efficiency measure(s) is based upon the simple payback of the measure prior to the application of an incentive, as calculated by Company staff and based upon standardized measure cost(s). These incentive tiers apply to measures with energy savings lasting 10 years or longer that meet or exceed the higher of the current energy code or industry practice that are applicable to the project. Simple payback is defined as the capital cost of the project divided by the energy savings per year. Fuel-conversion incentives are available only for conversion to natural gas with an end-use efficiency of 44% or greater. The incentives shall be as follows:

Incentive Level
(cents per first year kWh saved)
Measures
Simple Pay-Back
Period ***(Minimum measure life of 10 years*)***

Electric Efficiency 1 to under 2 years 8 cents
2 to under 4 years 12 cents
4 to under 6 years 16 cents
6 to under 10 years 20 cents
Over 10 years ** 20 cents
Over 10 years *** 12 cents
Fuel-Conversion 1 to under 2 years 1 cents
2 to under 4 years 3 cents
4 to under 6 years 5 cents
Over 6 years 7 cents

** Measures with an energy savings life less than 10 years may receive an incentive amount not to exceed the full incremental cost of the measure.*
*** Applicable only to non-lighting measures.*
**** Applicable only to lighting measures .*

Incentives in which the tier structure applies will be capped at 50% percent of the incremental project cost with the exception of the following that may be capped at a maximum of 100% of the incremental cost:

4.1.1 Limited Income or vulnerable customer segments and the agencies serving those customers;

4.1.2 Low-cost electric efficiency measures with demonstrable energy savings (e.g. compact fluorescent lamps);

4.1.3 Programs or services supporting or enhancing local, regional or national electric efficiency market transformation efforts.

4.2 Non-Monetary Assistance

Non-monetary assistance is service that does not involve the granting of direct monetary incentives to the customer. This type of assistance is available across all applicable segments. This assistance may be provided in various ways that include, but are not limited to, the following:

4.2.1. Educational, training or informational activities that enhance resource efficiency. This may include technology or customer-segment specific seminars, literature, trade-show booths, advertising or other approaches to increasing the awareness and adoption of resource efficient measures and behaviors.

4.2.2. Financial activities intended to reduce or eliminate the financial barriers to the adoption of resource efficiency measures. This may include programs intended to reduce the payment rate for resource efficiency measures, direct provision of leased or loaned funds or other approaches to financial issues by better than existing market terms and conditions.

4.2.3. Product samples may be provided directly to the customer when resource efficient products may be available to the utility at significantly reduced cost as a result of cooperative buying or similar opportunities.

4.2.4. Technical Assistance may consist of engineering, financial or other analysis provided to the customer by or under the direction of, Avista Corporation staff. This may take the form of design reviews, product demonstrations, third-party bid evaluations, facility audits, measurement and evaluation analysis, project management or other forms of technical assistance that addresses the cost-effectiveness, technical applicability or end-use characteristics of customer alternatives.

Text of Idaho Schedule 91 (establishing the tariff rider surcharge funding Avista's electric DSM programs)

SCHEDULE 91
ENERGY EFFICIENCY RIDER ADJUSTMENT - IDAHO
APPLICABLE:
To Customers in the State of Idaho where the Company has electric service available. This Energy Efficiency Rider or Rate Adjustment shall be applicable to all retail customers for charges for electric energy sold and to the flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service. This Rate Adjustment is designed to recover costs incurred by the Company associated with providing energy efficiency services and programs to customers.
MONTHLY RATE:
The energy charges of the individual rate schedules are to be increased by the following amounts:
Schedule 1 - .258 ¢ per kWh Schedule 25 - .166 ¢ per kWh
Schedule 11 & 12 - .303 ¢ per kWh Schedule 25P - .146 ¢ per kWh
Schedule 21 & 22 - .232 ¢per kWh Schedule 31 & 32 - .242 ¢ per kWh
Flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Services (Schedules 41, 42, 43, 44, 45, 46, 47, 48 & 49) are to be increased by 3.98%.
SPECIAL TERMS AND CONDITIONS:
Service under this schedule is subject to the Rules and Regulations contained in this tariff.
The above Rate is subject to increases as set forth in Tax Adjustment

Text of Idaho Schedule 96 (governing Avista's demand-response pilot program)

SCHEDULE 96

ENERGY LOAD MANAGEMENT PROGRAMS - PILOT

PURPOSE:

To provide residential and commercial demand response programs for a two-year period. Internet protocol thermostats, direct control units and related technology may be installed to test reduction in energy usage at peak times of the year.

AVAILABLE

To Rate Schedule 1, 11, and 21 Customers in the State of Idaho where the Company provides electric service in selected areas of Sandpoint and Moscow.

APPLICABLE

To all customers receiving electric service who agree to participate under this schedule.

INCENTIVE

Participating customers with demand response switches will receive an audit on all equipment controlled via the switch plus a $10 a month credit for the months of July, August, December, January and February.

SPECIAL TERMS AND CONDITIONS

Qualifying participants must be homeowners or business owners occupying the premises for at least one year on a full-time basis.

Customers can have an alternate non-electric back-up heat source (an alternate heat source will be required if demand response units are to be installed on baseboard electric load).

Participating customers will have no incremental costs.

This program will provide load use controls for some of the following appliances:

- Air – Conditioning
- Complete HVAC system (electric heat-pump w/air conditioning)
- Water Heater
- Pool Pump
- Electric Forced Air Heating System
- Electric Base Board Heating System
- Irrigation pump (if any)

Customers may apply for or terminate from this schedule anytime during the pilot.

Issued by Avista Corporation By Kelly Norwood, Vice President State and Federal Regulation

Text of Idaho Schedule 190 (governing the conduct of Avista's natural gas DSM programs)

SCHEDULE 190
NATURAL GAS EFFICIENCY PROGRAMS
IDAHO

1. AVAILABILITY

The services described herein are available to qualifying residential, commercial, and industrial, retail natural gas distribution customers of Avista Corporation for the purpose of promoting the efficient use of natural gas. Customers receiving natural gas distribution service provided under special contract and/or customers receiving natural gas services not specified under Tariff Schedule 191 (Natural Gas Efficiency Rider Adjustment) are not eligible for services contained in this schedule unless specifically stated in such contract or other service agreement. The Company may provide partial funding for the installation of natural gas efficiency measures and may provide other services to customers for the purpose of identification and implementation of cost effective natural gas efficiency measures as described in this schedule. Facilities-based services are available to owners of facilities, and also may be provided to tenants who have obtained appropriate owner consent.

Assistance provided under this schedule is limited to end uses where natural gas is or would be the energy source and to measures which increase the efficient use of natural gas. Assistance may take the form of monetary incentives or non-monetary incentives, as further defined within this tariff. The acquisition of resources is costeffective as defined by a Total Resource Cost test (TRC) as a portfolio. Customer participation under this schedule shall be based on eligibility requirements contained herein.

2. ELIGIBLE CUSTOMER SEGMENTS

All customers in all customer segments to whom this tariff is available are eligible for participation in natural gas efficiency programs developed in compliance with this tariff. The broad availability of this tariff does not preclude the Company from targeting measures, markets and customer segments as part of an overall effort to increase the cost-effectiveness and access to the benefits of natural gas efficiency.

3. MEASURES

Only natural gas efficiency measures with verifiable energy savings are eligible for assistance. Measure eligibility may not necessarily apply to all customer segments. Final determination of applicable measures will be made by the Company.

Market transformation ventures will be considered eligible for funding to the extent that they improve the adoption of natural gas efficiency measures that are not fully accepted in the marketplace. These market transformation efforts may include efforts funded through regional alliances or other similar opportunities.

4. FUNDING AND NONMONETARY ASSISTANCE

4.1 Funding

The incentives specified below are provided by the Company to promote the best use of natural gas resources. Incentives are based upon the simple payback of the measure prior to the application of an incentive, as calculated by Company staff and based upon standardized measure cost(s). These incentive tiers apply to measures with energy savings lasting 10 years or longer that meet or exceed current manufacturing and energy codes and/or industry standard practices that are applicable to the project. Simple payback is defined as the capital cost of the project divided by the energy savings per year. The incentives shall be as follows:

Measures Simple Pay-Back Period Incentive Level
(dollars/first year therm saved)
(Minimum measure life of 10
years*)

1 to 2 years 2.00
2 to 4 years 2.50
Natural Gas Efficiency
4 to 6 years 3.00
Over 6 years 3.50

*Measures with an energy savings life less than 10 years may receive an incentive amount not to exceed the full incremental cost of the measure.

Incentives in which the tier structure applies will be capped at 50% of the incremental project cost with the exception of the following that may be capped at a maximum of 100% of the measure cost:

4.1.1 Energy efficiency programs delivered by community action agencies contracted by the Company to serve Limited Income or vulnerable customer segments including agency administrative fees and health and human safety measures;

4.1.2 Low-cost natural gas efficiency measures with demonstrable energy savings (e.g. rooftop unit service);

4.1.3 Programs or services supporting or enhancing local, regional or national natural gas efficiency market transformation efforts.

Avista Corporation will actively pursue natural gas efficiency opportunities that may not fit within the prescribed services and simple pay-back periods described in this tariff. In these circumstances the customer and Avista Corporation will enter into a site specific services agreement.

4.2 Non-Monetary Assistance

Non-monetary assistance is service that does not involve the granting of direct monetary incentives to the customer. This type of assistance is available across all applicable segments. This assistance may be provided in various ways, that include, but are not limited to, the following:

4.2.1. Educational, training or informational activities that enhance resource efficiency. This may include technology or customer-segment specific seminars, literature, trade-show booths, advertising or other approaches to increasing the awareness and adoption of resource efficient measures and behaviors.

4.2.2. Financial activities intended to reduce or eliminate the financial barriers to the adoption of resource efficiency measures. This may include programs intended to reduce the payment rate for resource efficiency measures, direct provision of leased or loaned funds or other approaches to financial issues by better than existing market terms and conditions.

4.2.3. Product samples may be provided directly to the customer when resource efficient products may be available to the utility at significantly reduced cost as a result of cooperative buying or similar opportunities.

4.2.4. Technical Assistance may consist of engineering, financial or other analysis provided to the customer by or under the direction of, Avista Corporation staff. This may take the form of design reviews, product demonstrations, third-party bid evaluations, facility audits, measurement and evaluation analysis or other forms of technical assistance that addresses the costeffectiveness, technical applicability or end-use characteristics of customer alternatives.

5. BUDGET & REPORTING

The natural gas efficiency programs defined within this tariff will be funded by surcharges levied within Schedule 191. The Company will manage these programs to obtain resources that are cost-effective from a Total Resource Cost perspective and achievable through utility intervention. Schedule 191 will be reviewed annually and revised as necessary to provide adequate funding for natural gas efficiency efforts.

6. OPTIONAL HIGH ANNUAL LOAD FACTOR LARGE GENERAL SERVICE PROGRAM

Customers receiving natural gas service under Schedules 131 and 132 with costeffective natural gas efficiency projects are eligible to respond to the Company's Request for Proposals (RFP). The RFP will be developed jointly with representative Customers and the Northwest Industrial Gas Users (NWIGU). The RFP will be available for release no later than April 1, 2001 and annually thereafter.
Natural gas savings are to be calculated using standard engineering practices, and with operations schedules documented by the Customer. The Company will review natural gas savings calculations, and reserves the right to modify energy savings estimates. Actual savings may be trued up based on post-installation energy use monitoring. Further details will be provided in the RFP.
Funding is available directly to the Customer upon receipt of customer verification of completed installation. The Company will fund cost-effective projects, using the costeffectiveness
standards to determine the value of natural gas savings, such that the Company's incentive satisfies the Total Resource Cost test (TRC) as a portfolio. Project funding will be up to the amount of conservation revenues collected from the Schedule 131 and 132 Customers under Schedule 191 of this Tariff over the period for which this Schedule is in effect, minus the Company's cost to administer this program. Annual incentive amounts for this program will be subject to the Company's annual budget for energy efficiency programs. Further provisions will be provided in the RFP. The Company, at its option, may inspect installations prior to payments of the funding.

Text of Idaho Schedule 191 (establishing the tariff rider surcharge funding Avista's natural gas DSM programs)

SCHEDULE 191
ENERGY EFFICIENCY RIDER ADJUSTMENT - IDAHO
APPLICABLE:
To Customers in the State of Idaho where the Company has natural gas service available. This Energy Efficiency Rider or Rate Adjustment shall be applicable to all retail customers taking service under Schedules 101, 111, 112, 131, and 132. This Rate Adjustment, is designed to recover costs incurred by the Company associated with providing energy efficiency services and programs to customers. The Company may, at its discretion to match revenue under this schedule with demand for services under Schedule 190, reduce or increase this charge on an annual basis. Any change in this charge is subject to Commission approval and its review of the previous year expenditures under Schedule 190 and determinations with regard to any revenue carry forward, and prospective budget on an annual basis. Any annual expenditures exceeding annual collections when combined with any carry forward budget surplus shall be at the Company's risk of future recovery.
MONTHLY RATE:
The energy charges of the individual rate schedules are to be increased by the following amounts:
Schedule 101 $0.03458 per Therm
Schedule 111 & 112 $0.03045 per Therm
Schedule 131 & 132 $0.02552 per Therm
SPECIAL TERMS AND CONDITIONS:
Service under this schedule is subject to the Rules and Regulations contained in this tariff.
The above Rate is subject to increases as set forth in Tax Adjustment

Appendix C – Heritage Plan Analytical Roadmap

Jon Powell

Attached below is a copy of the Heritage Plan “Analytical Roadmap” that was used in 2007 to develop a methodology for developing an electric avoided cost price signal that is more specific and useful for purposes of evaluating electric efficiency measures. As a result of this effort Avista was able to better isolate the cost associated with capacity vs. energy and to incorporate a risk valuation premium within the avoided cost structure.

This methodology has been used for the development of the avoided cost streams used for DSM analysis since that date.

Avista Heritage Project

Analytics Task Force

Road Map

Date: October 4, 2007
Presented by: Dave DeFelice, Bruce Folsom, Lori Hermanson, Bill Johnson, John Lyons, Jon Powell

Task Force Road Map

Introduction

Avista established a new demand response initiative, called the Heritage Project, in 2006. The goals of the Heritage Project are to increase the acquisition of sustainable and cost-effective energy and demand savings through comprehensively examining and implementing expanded energy efficiency programs, peak shaving/shifting programs, and other options (e.g., distribution system efficiencies). This project continues the Company's legacy of conservation innovation and education on our customers' behalf.

The identification of cost-effective resources and appropriate cost-recovery depends upon a technically sound and transparent analytical approach. Representatives of several departments developed the analytical process and the estimates necessary to proceed with the Heritage Project. Updates to this analytical process will be done as circumstances change, such as the underlying avoided cost of energy and carbon legislation.

Resource valuation for Heritage Project concepts has centered around six categories of resource value. Four of these values are part of a total avoided cost of energy usage and the remaining two values represent reductions in system-coincident demand.

The resource value of energy includes:

- Commodity cost of energy
- Avoiding carbon emissions
- Reducing retail rate volatility
- Reducing transmission and distribution system losses

The value of system-coincident capacity includes deferring future investments in:

- Generation capacity
- Transmission and distribution

Calculation of Resource Value Components

The calculation of resource value begins with the commodity cost of energy. To this are added costs to reflect avoided carbon emissions, retail rate volatility, and transmission and distribution system losses. Each is described, in turn, below.

1. Commodity Cost of Energy

The base, or commodity, cost of electricity was calculated in Avista's 2007 Integrated Resource Plan (IRP). Wholesale electric prices were estimated based upon 300 iterations of the AURORA^{XMP} market forecasting model under varying load, hydro, wind, forced outages, emissions, and natural gas prices in the Western Interconnect for the period 2008 to 2028. Renewable portfolio standards and projected carbon emissions costs are included in the base case market prices. The model chooses the most economic resources available to satisfy projected load obligations, including reserves for system reliability (i.e., planning margin). The IRP modeling results include a cost for carbon and other regulated emissions. Of these emission costs, the carbon emissions value was subtracted from the avoided energy cost calculations for separate treatment (in Section 2, below) because of the unique risks associated with this component.

Table 1 shows estimated avoided energy costs for 10-, 20- and 40-year periods (excluding carbon costs emission values).

TABLE 1: Annual Average Avoided Cost ($/MWH)

	10-Year Levelized	20-Year Levelized	40-Year Levelized
Flat	49.60	55.84	69.41
On-Peak	53.59	60.47	75.47
Off-Peak	44.23	49.60	61.25

2. Avoided Carbon Emissions Cost

New thermal resources produce emissions that have costs from taxes or cap and trade programs. Four emissions types are included in the IRP base case market forecast: carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury (Hg). A more detailed discussion of how emissions costs are calculated may be found in the Environmental Issues section of Avista's 2007 IRP.

Carbon emissions are separated from other pollutants because of uncertainty over how such emissions will be regulated. Many state and regional initiatives now compete with a multitude of cap and trade proposals at the national level. Avista's 2007 IRP reflects CO_2 costs as a probability distribution using the National Commission on Energy Policy (NCEP) for its mean value starting in 2015. The NCEP case is a comprehensive climate change risk reduction program study that was released in December 2004. The NCEP case is conservative compared to recent federal proposals. Carbon emissions costs may differ significantly from this analysis depending on which, if any, of the federal or state laws are passed. Carbon emission costs will be updated as the legislative process develops.

Table 2 provides estimates for levelized CO_2 emission costs. The 10-year costs are significantly lower than 20-years costs because the CO_2 market is modeled to begin in 2015. Avoided CO_2 emission costs will increase significantly if legislation more stringent than the NCEP is adopted, or if a cap and trade program begins prior to 2015.

TABLE 2: Annual Average Avoided CO_2 Emissions Cost ($/MWH)

	10-Year Levelized	20-Year Levelized	40-Year Levelized
Flat	1.96	4.29	5.83
On-Peak	2.02	4.38	6.10
Off-	1.89	4.18	5.48

Peak			

3. Energy Cost Volatility

Energy consumers are presumed to be adverse to volatility and willing to pay a premium for rate stability. In this analysis, volatility in the electricity market forecast is referred to as “risk.” Fixed cost resources, such as Heritage Project measures avoid market volatility, or risk, because they do not rely upon any of the price drivers persistent in the marketplace, such as the cost of natural gas used to fuel a plant. An example of societies’ preference for rate stability can be illustrated by its willingness to pay for reserve margins, normally covered by the construction and operation of peaking plants. These plants have very high operating costs on a per-MWh basis because they run sparingly; however, they mitigate the risk of buying higher priced power in tight market situations.

Several different risk quantification methodologies were applied to this analysis. The first considered various confidence intervals around the mean value of the 300 AURORA^{XMP} Monte Carlo iterations. The analytics team found that this methodology could not sufficiently establish a relationship between a ratepayer’s willingness to pay for less risk and any particular confidence interval. The Black-Scholes model was also evaluated to determine the risk premium. This model calculates the intrinsic value of a price cap to limit ratepayer risk. Ultimately, a third approach to the risk premium valuation using PRiSM was selected to remain consistent with the IRP.

PRiSM uses a linear programming model routine to determine the optimal amount and timing of future resource acquisitions and their associated costs. PRiSM is able to separate capacity and risk reduction values. Once capacity needs are met, PRiSM looks for cost-effective ways to lower power cost volatility. The volatility reduction strategy generally involves adding resources with high capital and low variable costs. These types of resources, such as wind generation, increase expected costs through the higher capital component and decrease expected risk through lower variable costs. Table 3 shows the premium that would be paid above the “short-term” market price to obtain resources that would reduce risk to the same levels as those resources that would be acquired through the Heritage Project. Incorporating this value into the avoided costs facilitates the comparison of alternative resource costs on a risk-adjusted basis.

TABLE 3: Annual Average Avoided Risk Cost ($/MWH)

	10-Year Levelized	20-Year Levelized	40-Year Levelized
Flat	10.09	10.63	9.41

4. Reduction in Transmission and Distribution Energy Losses

The analytics team used a 6.5% average loss factor for transmission and distribution (T&D) projects. A precise estimate of T&D system impacts is difficult to quantify for Heritage Projects. Geography, season, time-of–day and other considerations can impact these calculations in a manner that is not easily translated into assumptions regarding specific resource options. Nevertheless, an estimate of the impact of a reduction in end-use demand upon T&D losses is required for resource analysis.

Discussions are underway to improve the quality of efficiency analyses by separating T&D losses between summer (space cooling) and winter peak (space heating) peaks. The improvements will incorporate both demand and ambient temperatures into the analysis of evaluated resource options.

Based upon the estimates of the avoided cost of energy, emissions and risk reduction valuation above (using the flat load assumptions), an adder of $4.01 per MW is incorporated into the energy avoided cost, as illustrated in Table 4.

TABLE 4: Estimate of Value of Reduced T&D Losses (using flat load assumption over a 10-year horizon)

	$/MWh
Avoided cost of energy	49.60
Value CO_2 emissions	1.96
Value of risk reduction	10.09
Total of above energy values	**61.65**
Application of 6.5% T&D losses to above	4.01
Resulting total value of energy	65.66

5. Value of Avoided Generation Capacity

Some Heritage Project programs have disproportionate (relative to system) impacts on peak summer loads where market prices are high. There are opportunities including dispatchable programs that yield little or no energy savings, but offer the region the opportunity to avoid or postpone the construction of generation capacity. As these programs are dispatchable, their values are not properly reflected in market price forecasts derived by the AURORA^{XMP} model. It is necessary to evaluate these opportunities as "naked" capacity (capacity without any energy). The value of capacity estimated in this section is applicable to resources possessing virtually no energy content, which essentially limits this value to demand-response programs.

A pure capacity value of $300 per kilowatt is based upon the remaining capital cost of a combustion turbine not offset by energy revenues. Table 5 illustrates how the pure capacity value is derived. The initial installed capacity cost of the turbine is $450 per kilowatt. When the turbine is dispatched against the short-term electricity market it generates margins (electric revenue less fuel and O&M costs) to offset $150 per kilowatt of the initial installed cost. The remaining $300 per kilowatt of capacity cost that is not offset by the value of energy sales is the pure capacity cost.

TABLE 5: Derivation of Pure Capacity Cost Based On a Simple Cycle Combustion Turbine

Total Installed Cost of Simple Cycle Combustion Turbine	$54,000,000	
Turbine Capacity	120	MW
Installed Cost of Simple Cycle Combustion Turbine	$450	/kW
Present Value of Revenue Requirement / Installed Cost	137%	
Present Value of Total Installed Cost Revenue Requirement	$73,980,000	
Present Value of Net Energy Margin (Revenue - Fuel and O&M)	$24,660,000	
Present Value of Capacity Net of Energy Value	$49,320,000	
Initial Installed Cost of Capacity Net of Energy Value	$36,000,000	
Naked Capacity Cost Net of Energy Value	$300	/kW

Northwest electricity markets witness higher prices during summer space cooling-driven regional peaks. Price excursions with very high prices are typically short, but reducing energy purchases during these periods can significantly reduce power supply costs. There are opportunities for Avista to implement demand-response and energy efficiency measures that would reduce native loads during these peak periods. The derived generation capacity value is applied to determine the cost-effectiveness of these opportunities.

6. Value of Avoided Transmission and Distribution Capital Investments

Decreasing electrical consumption reduces T&D infrastructure needs. Certain Heritage Project opportunities have a disproportionate impact on T&D, so it is necessary to treat them as a separate component of resource value.

The most recent estimate (2003) of avoided transmission and distribution capacity is $81 per kilowatt, based on the Edison Electric Institute methodology for calculating distribution transformer specifications. Costs have escalated by 30% since 2003, which increases the 2006 value of avoided T&D capacity to $105 per kW. There is an ongoing discussion regarding significant escalations to this value based upon recent T&D costs and future expectations and, therefore, the estimate of $105/kW is viewed as a low, conservative estimate of value for analytical study purposes. The avoided T&D cost will be modified based upon the outcome of this ongoing evaluation.

7. Application of Generation and Transmission and Distribution Capacity

Avista is using values of $300/kW for generation capacity and $105/kW for transmission and distribution (T&D) capacity in its analytics. These values are installed cost values. In order to utilize these values for demand initiative evaluation the installed costs are amortized over the useful life of the demand initiative. This creates a stream of annual capacity values that can then be applied to the capacity reduction contribution of the demand initiative.

For example, a demand initiative that removes load during peak hours will be credited with capacity savings by multiplying the capacity reduction of the demand initiative by the annual capacity value for the year (both generation and T&D). In addition, the demand initiative also receives credit for its annual energy savings. Demand initiatives that do not provide any on-peak capacity reduction will not receive the capacity credit and will only be credited with energy savings.

Summary

The six components of resource value outlined above are summarized in Table 6.[1]

TABLE 6: Resource Value Component Summary
(All calculations assume a flat load)

Component	10-yr Energy ($/MWh)	20-yr Energy ($/MWh)	40-yr Energy ($/MWh)	Capacity[5] ($/kW)
Avoided cost of energy	$50[1]	$56[1]	$69[1]	
Avoided cost of CO_2 emissions	$2[2]	$4[2]	$6[2]	
Reduction in energy cost volatility	$10[3]	$11[3]	$9[3]	
Reduction in T&D losses	$4[4]	$5[4]	$6[4]	
Value deferred generating capacity				$300[6]
Value of deferred T&D capacity				$105
TOTAL COST	**$66**	**$76**	**$90**	**$405**

1 The flat load assumption is a simplification of a calculation that will be based upon a full 8760-hour stream of avoided energy costs.

2 This fixed CO_2 emissions cost adder will be applied until definitive legislative impacts can be more accurately modeled and included in the avoided cost of energy.

3 This adder reflects the difference between the expected value of the avoided cost stream and the value of resources obtained to reduce exposure to high market prices.

4 Based upon a 6.5% T&D loss assumption. In practice this will be applied to each individual hour of the 8760-hour avoided energy cost stream.

5 Capacity value is based upon the contributions of a resource to system-coincident peak load reduction. Presently this is based upon a winter space heating-driven system peak assumption.

6 This capacity value is applicable only to programs with virtually no energy but significant capacity value.

Consistent with the company's 2007 IRP, these energy and capacity value estimates will be used to evaluate Heritage Project opportunities, resulting in an optimal selection of generation and non-generation resources. This optimal level includes a valuation of the reduction in power supply cost as well as energy cost volatility.

[1] These calculations are applicable to energy efficiency, load management, and transmission and distribution projects.

These summary values make it possible to evaluate non-utility generation resources by applying 8760-hour resource load shape and system-coincident peak contributions to develop an estimate of total resource value. This price becomes the cost cap for Heritage Project programs. By evaluating and sorting the collection of options, it is possible to build a resource supply-curve and estimate the resources that can be cost-effectively acquired.

Appendix D – Detailed Evaluation, Measurement and Verification Plan
Damon Fisher

Attached, below, is a summary of the current expectations regarding Avista's three-year EM&V plans. The efforts summarized within this table will be completed in a manner consistent with the summary of the EM&V methodology presented within the body of this business plan.

Three Year Evaluation Schedule Updated Annually or as Necessary

	Program Name	Description	Evaluation Type	Base Year	Internal or External	Evaluator	External Review	Objective
2010	Nonres site specific - HVAC	HE RTU's, Boilers, Furnaces	Impact	2008/2009	Internal	TBD	TBD	Determine how closely our modeling methods determine savings
	Res shell	Insulation, Windows	Impact-Net/Gross	2009/2010	External	TBD	NA	Determine free ridership and savings
	Res HVAC	HE Furnaces, HP, GSHP	Impact	2008/2009	External	TBD	NA	Determine the overall savings of the program.
	Res fuel conversion	Electric to gas, Electric to HP	Impact	2008/2009	Internal	Damon Fisher	TBD	Determine the overall savings of the program.
	Res water heating efficiency	HE water heaters gas, electric, tankless	Impact	2010	Internal	Damon Fisher	TBD	Determine if assumptions in energy calcs are appropriate.
	Energy Smart Grocer Program	Door seals, LED lighting,	Impact	2009/2010	Internal	Damon Fisher	TBD	Determine if calculation used by IPUC are appropriate.
	P network computers	Computer shutdown by software	Impact	2010	Internal	Tom Lienhard	TBD	Verify Software manufacture's energy use assumptions in an office environment
	Res appliances	Energy star and CEE appliance	Net/Gross	2009/2010	External	TBD	NA	Determine free ridership
2011	P nonres lighting	Prescriptive lighting	Impact-Net/Gross	2010	Internal	Engineering Team	Yes	Determine unit power consumption meets assumptions and free ridership
	Res refrig recycling	Used Refrig recycling	Process	N/A	TBD	TBD	TBD	Verify refrigerators are being handled/recycled per the contract
	LI Shell	Insulation, Infiltration, windows	Impact/Process	2009	TBD	TBD	TBD	Determine savings and evaluate program delivery for improvements
	RCM	Resource Conservation Manager	Process	N/A	TBD	TBD	TBD	New program. Evaluate the process.
	LI HVAC efficiency	HE Furnace	Impact/Process	2009	TBD	TBD	TBD	Determine savings and evaluate program delivery for improvements
	P Non-res clothes washers	Commercial clothes washers	Impact-Net/Gross	2010	TBD	TBD	TBD	Determine free ridership and savings
	Res Energy Star Home	New Construction, Certified Homes	Impact	2009	TBD	TBD	TBD	Determine the overall savings of the program.
2012	P food service	Dish Washer, Freezer, Ovens	Impact	2011	TBD	TBD	TBD	Determine the overall savings of the program.
	LI fuel conversion	Electric to gas, furnace & WH	Impact/Process	2010	TBD	TBD	TBD	Determine savings and evaluate program delivery for improvements

	Multifamily	Direct use, heat, water	Impact	2011	TBD	TBD	TBD	Determine the overall savings of the program.
	Site Specific: Lighting	Non Prescriptive Lights	Impact	2011	TBD	TBD	TBD	Determine the overall savings of the program.
TBD	P VFDs	HVAC motor VFDs						
	LI appliances	Energy Star Refrigerator						
	LI water heating efficiency	HE Electric and Gas H2O heater						
	Solar	Generation						
	Wind	Generation						
	Res lighting	PECI CFL Program						
	Nonres traffic lights	Retrofit LEDs						
	Nonres vending machines	Vending Miser						
	P new equipment upgrades	Refrigerated Warehouse						
	P retrofit equipment upgrades	Refrigerated Warehouse						
	Steam Trap Replacement	Steam trap w/ strainer						
	Green Motors	Green Motor rewind contract						
	Side Stream Filtration	Evaporative cooler water treatment						
	Demand Controlled Ventilation	HVAC IAQ						
	Trees	Shade trees						

Appendix E – I-937 Compliance Filing

Linda Gervais

In Compliance with WAC 480-109-010(2), Avista Utilities is required to submit the attached "Conservation Resource Report" to the Washington Utilities and Transportation Commission on January 29, 2010.

BEFORE THE WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of Avista's Ten-year Achievable Conservation Potential and Biennial Conservation Target Report in Compliance with RCW 19.285 and WAC 480-109	)	DOCKET NO. UE-091983 COMPLIANCE REPORTING OF AVISTA CORPORATION

In compliance with WAC 480-109-010, Avista Corporation (hereinafter "Avista," the "Utility," or "Company"), respectfully submits this Ten-year Achievable Conservation Potential and Biennial Conservation Target Report ("Conservation Resource Report") in the above-captioned matter. The term "conservation" will be used interchangeably with energy efficiency and demand-side management ("DSM") throughout this filing.

I. BACKGROUND

Washington voters on November 7, 2006 approved Initiative Measure No. 937 ("I-937"), titled the Energy Independence Act ("Act"). The Act, now codified at chapter 19.285 RCW, concerns requirements for new electrical energy resources. Large utility companies are required to obtain 15 percent of their electricity from new renewable resources such as solar and wind by 2020 and to undertake cost-effective energy conservation. The new law provides that the Commission "may adopt rules to ensure the proper implementation and enforcement of this chapter as it applies to investor-owned utilities." *RCW 19.285.080.*

On November 27, 2007, the Commission filed with the Office of the Code Reviser an Order Adopting Rules Permanently in WAC 480-109, related to Electric Companies—Acquisition of Minimum Quantities of Conservation and Renewable Energy as Required by the Energy Independence Act (Chapter 19.285 RCW). The effective date for the adoption of the rules was December 28, 2007.

The conservation provisions of RCW 19.285 became effective on January 1, 2010 and WAC 480-109-010 requires the filing of this Conservation Resource Report on or before January 31, 2010. (References to I-937 and WAC 480-109 are used interchangeably in this filing.)

II. INTRODUCTION

This filing describes public involvement efforts by Avista in developing its targets, how the Company establishes its ten-year achievable conservation potential and biennial conservation target, what measures will qualify towards that target, how acquisition will be measured, and how Avista will work with stakeholders during the initial (2010-2011) compliance period, as well as the Company's expectations for future compliance periods.

Avista has chosen to use the Northwest Power Planning Council's Option #1 of the 6th Power Plan to establish the Company's acquisition target, adjusted to include electric-to-natural-gas fuel conversions. The resulting targets are greater than the Company's Integrated Resource Plan's energy efficiency targets for the same period. Avista intends to acquire 128,603 mWh's of energy efficiency as described in this filing in 2010 and 2011, the first I-937 two-year compliance period. Avista's projection of the acquisition over a ten-year period, assuming that this same option is selected in future compliance periods, is 873,302 mWh's.

III. PROCESS AND PUBLIC INVOLVEMENT

Avista's energy efficiency targets have been determined through its Integrated Resource Planning ("IRP") process, pursuant to WAC 480-100-238. Substantial public involvement opportunity was presented to interested parties as the IRP process convened six meetings of the Technical Advisory Committee (TAC) in 2008 and 2009. The Company's Integrated Resource Plan was filed with the Commission on August 31, 2009. Chapter 3 of the IRP describes Avista's analysis of conservation potential under then-current protocols.

The Northwest Power and Conservation Council ("Council") convened several meetings of its Conservation Resource Advisory Committee ("CRAC") to describe how the Council staff was determining the regional conservation targets for inclusion in the Council's 6th Power Plan. Significant public involvement, between April and August of 2009, was provided given the attention to increases in proposed energy efficiency targets.

In July, Avista discussed with Commission Staff the public involvement components of WAC 480-109. The Company and Commission Staff agreed to move up the External Energy Efficiency Board (Triple E) meeting from November to September, for the purpose of accelerating the Company's Compliance Plan, and to provide opportunity for public involvement, per the requirements of WAC 480-109. (The Triple E is Avista's stakeholder advisory committee for its energy efficiency planning and programs[2].)

[2] Triple E is Avista's non-binding oversight and technical advisory group for energy efficiency. The Triple E is currently composed of twenty organizations including Commission staffs, customer representatives, and stakeholders with an interest in energy efficiency service delivery.

Commission Staff suggested broadening the notification list to include the Company's IRP Technical Advisory Committee[3] and others, which the Company did. Avista consulted with Commission Staff regarding the type of notification (e.g., newspaper notice, etc.) for the planned September Triple E meeting and followed Commission Staff suggestions regarding e-mail notification to specific interested party lists and posting the meeting notice to the Company's website.

On September 4th, 2009 the Commission Staff hosted a Conservation Potential Methodology Meeting that included jurisdictional electric utilities and interested parties. Commission Staff provided an overview of the "Energy Conservation Requirements of the Energy Independence Act." The Northwest Power and Conservation Council Staff presented the 6th Power Plan draft targets, the public involvement process leading to these targets, and the "Utility Target Calculator" for determination of any utility's share of the Council Staff's proposed regional targets.

Commission Staff participated in Avista's September 30, 2009 I-937 Compliance Plan meeting. The Company later inquired of Commission Staff regarding the need for more meetings, and Commission Staff suggested that Avista continue the process that had been implemented, specifically to request e-mail responses to a draft Compliance Plan and to keep responses for purposes of appending them to the Company's compliance filing.

On November 11, 2009, Avista distributed to the Triple E and TAC members a draft compliance filing via electronic mail reiterating that "…public involvement is essential to this process and consequently, seeking input as an interested stakeholder." Avista received comments from parties and hosted a conference call on December 16, 2009. The Company's Evaluation, Measurement and Verification

[3] Technical Advisory Committee (TAC) includes Commission staffs, customers, academics, government agencies, consultants, utilities and other interested parties.

(EM&V) draft plan was distributed to the Triple E on November 24, 2009 with a follow up progress report on December 29, 2009 in response to a Staff inquiry.

On December 31, 2009, the Company provided its “Informal Compliance with WAC 480-109-010(1)” projecting Avista’s cumulative ten-year electric conservation potential in the state of Washington and two-year targets. Presentations from Avista’s meetings and responses to the draft compliance plan, the EM&V draft, and the informal filing are provided in Attachment A.

IV. CONSERVATION PROGRAMS

Avista’s energy efficiency programs provide a wide range of conservation programs and education for residential, commercial, industrial and low income customers. Programs fall into standard offer (or “prescriptive”) and customized (or “site-specific”) classifications. Prescriptive programs offer cash incentives for standardized products, such as weatherization measures and high efficiency appliances. These programs are primarily directed towards residential and small commercial customers. Site-specific programs provide cash incentives to commercial and industrial customers for any cost-effective energy savings measure with a simple payback greater than one year. These site-specific programs require customized services for commercial and industrial customers because many applications need to be tailored to the unique characteristics of customers’ premises and processes. Provided as Attachment B is the Company’s 2010 DSM Business Plan, a XXX page document that provides substantial details about Avista’s energy efficiency programs.

Avista has used the results of its IRP process to establish a budget for conservation measures, determine the size and skill sets necessary for future conservation operations, and identify general target markets for programs. The results of the IRP analysis establish baseline goals for continued development and enhancement of Avista’s conservation programs and an operational conservation business plan however, for purposes of this compliance period, Avista is using the Council’s 6th Power Plan. The near-term conservation business planning is summarized by portfolio in the following sections:

Residential Portfolio

A review of residential program concepts and their sensitivity to key assumptions included in the IRP process indicate that more detailed assumptions based upon actual program plans and target markets may improve the cost-effectiveness of many of the residential concepts. Thus, all concepts with Total Resource Cost (TRC) benefit-to-cost ratios of 0.75 or better are evaluated as part of the business planning process. See additional details in Attachment B.

Limited Income Residential Portfolio

Avista is committed to maintaining stable funding and maintaining program flexibility for limited income conservation programs. There are six local community action partner (CAP) agencies—five in Washington—that the Company funds for the delivery of limited income weatherization and energy efficiency programs. CAP funding is currently set at $1,482,000 million per year for the State of Washington. Limited income programs include insulation and ENERGY STAR® approved windows, doors and refrigerators, space and water heating upgrades, and electric to natural gas space and water heating conversions. CAP agencies can offer other cost-effective programs with Avista's approval. These programs require periodic updates because of changes in fuel focus and target measures.

Non-Residential Portfolio

All electric-efficiency measures with a simple payback exceeding one year automatically qualify for Avista's non-residential portfolio. The Business Plan provides Avista's account executives, program managers and end-use engineers with guidance regarding potentially cost-effective target markets. However, the unique and specific characteristics of a customer's facility override any high-level program prioritization. More details related to the site-specific conservation are provided in Attachment B starting on page X.

Avista does not have a sizable agricultural (or "pumping") load relative to other utilities. Therefore, energy efficiency projects directed towards this market segment are included as program offerings under the site-specific options available to commercial and industrial customers.

V. ESTABLISHING THE CONSERVATION TARGET

WAC 480-109 permits the utility to establish electric energy efficiency acquisition targets based upon either the most recent Northwest Power and Conservation Council power plan or its most recent integrated resource plan (IRP), provided that the methodology used in that IRP is consistent with the Council's power plan methodology.[4]

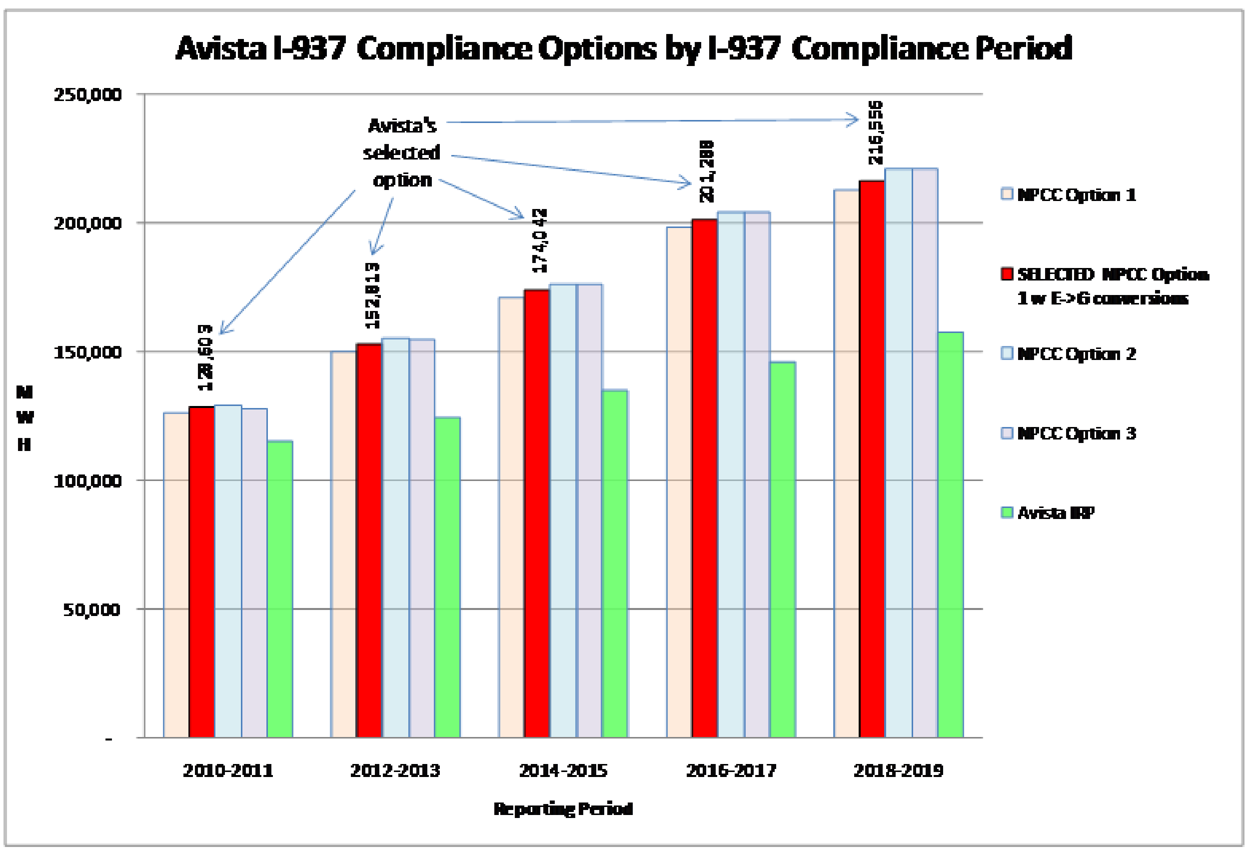
The 6^{th} Power Plan establishes three options for determining the target of a particular utility and jurisdiction. The options are distinguished by the degree of market segment disaggregation (i.e., energy efficiency measures available to specific customer type) contained within the estimate. Option #1 is the least disaggregated and contains an acquisition target for the entire utility and jurisdiction, option #2 disaggregates the acquisition into four market segments and option #3 disaggregates acquisition into five market segments.

Avista has chosen to use option #1 of the 6^{th} Power Plan to reflect its specific share of the regional target, based upon overall acquisition without regard to segment. This is because Avista's DSM programs are somewhat unique in that any efficiency measure is deemed eligible for the non-residential site-specific program. As previously described, the Company will provide a financial rebate to commercial and industrial customers through site-specific programs for any electric energy saving measure with a simple financial payback of one-year or over, pursuant to Tariff Schedule 90. For purposes of the IRP, Avista does attempt to identify efficiency opportunities to develop an estimate of future cost-effectiveness and acquirable potential. However, a significant quantity of acquisition results from measures that are extremely unique and therefore not amenable to generic analysis or from measures that could be reasonably

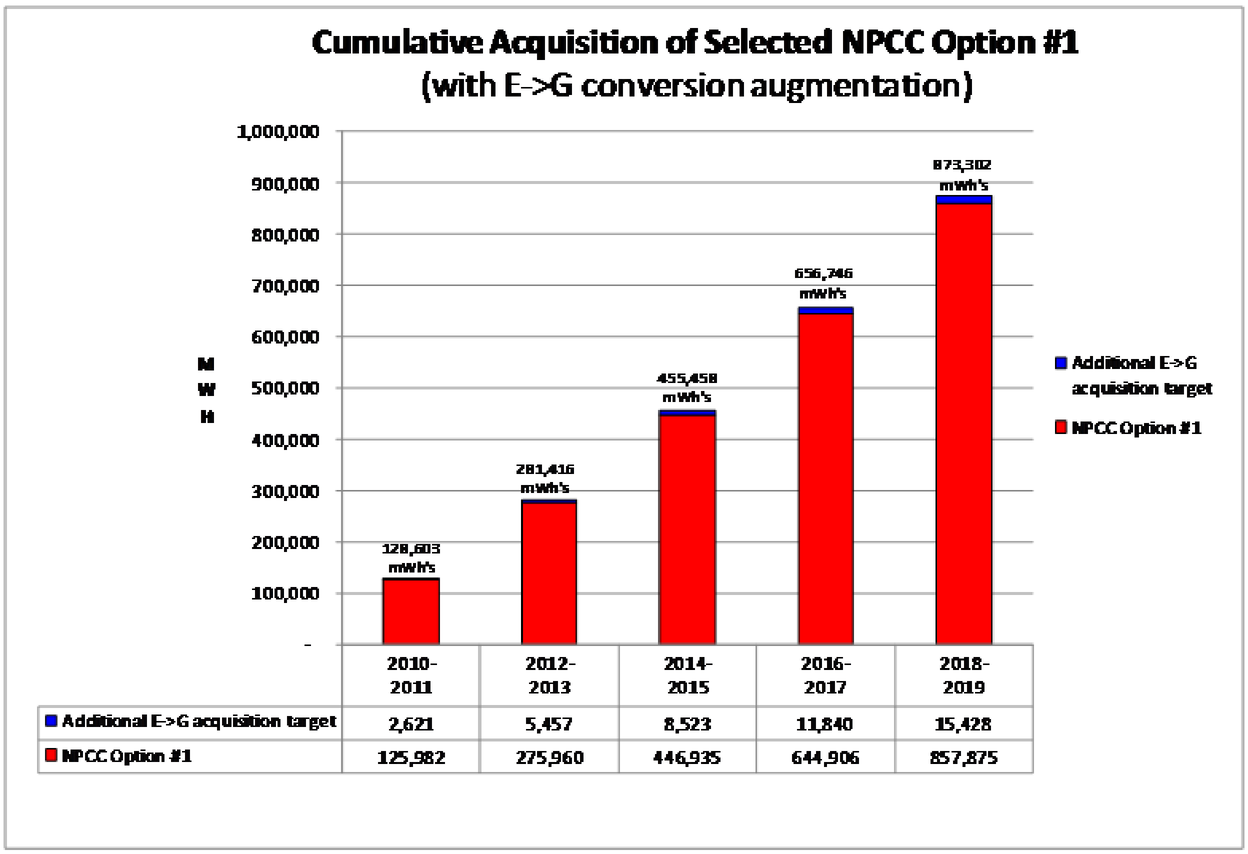
[4] While RCW 19.285 states the most recent Council Power Plan is to be used, Avista understands that the Washington Legislature must initiate legislation to specifically validate the most recent plan's targets for proper effect of law. Avista further understands that the proposed 6^{th} Power Plan is scheduled for adoption by the Council at its scheduled Feb. 9-11, 2010 meeting. Avista anticipates that the DSM targets contained in the 6^{th} Power Plan will be adopted in the near future and, therefore, uses these targets as if adopted. Thus, Avista considers this to be an immaterial timing difference that will be resolved by the time the Commission addresses the Company's filing herein.

anticipated during the IRP process. Consequently, Avista performs an estimate of the future acquisition of these measures primarily based upon historical acquisition with modifications for customer load growth, price elasticity and other expected events that would improve this estimate. Acquirable potential for the site-specific program, and all other programs, are derived from results driven by program planners and technical staff based upon the specific characteristics of that program and expected market conditions. While historically Avista has used its IRP targets for conservation acquisition, due in part to the difficulty in estimating savings from site-specific measures, the Company has chosen to use its share of the Council's targets be for the 2010-2011 biennial period.

The table below shows that Avista's elected targets based on option #1, under the Council's 6th Power Plan, exceeds those of the Company's IRP targets.



The Northwest Power Act, establishing the requirement for the Council's power plan process, contains a specific definition of "conservation" that excludes electric-to-natural gas conversions. However, these conversions are eligible for incentives under Avista's electric efficiency programs, and these measures are often the most cost-effective alternative for both the customer and the utility. (3 sentences why?) Consequently, Avista has chosen to increase the NPCC option #1 target in the amount of the acquisition incorporated into our corporate budget submittal. By increasing the target by the amount of acquisition expected from these programs during 2010-2011 we also are proposing that these conversions will become an eligible measure for meeting that target.



Based upon the selection of this option, it is Avista's intent to acquire 128,603 mWh's of energy efficiency qualifying under our proposal in the first 2010-2011 I-937 compliance period. Avista's projection of the acquisition over a ten-year period, assuming that this same option is selected in future compliance periods, is 873,302 mWh's. This acquisition will include traditional local electric efficiency measures, as well as electric to natural gas conversions, quantifiable behavioral efficiencies, distribution system efficiencies on both the customer and utility side of the meter, quantifiable adoption of efficiency measures contained within the scope of the 6th Power Plan beyond utility program intervention and Avista's share of acquisition achieved by the Northwest Energy Efficiency Alliance (NEEA).[5] Only Washington jurisdictional acquisition will be credited towards achieving the I-937 target. Avista is not committing to any predetermined allocation of the target acquisition across customer segments or efficiency technologies.

For this first compliance period, Avista is electing to establish a target based upon a single acquisition target rather than a range of target acquisition. It is also our intent to treat the acquisition target in the 2nd (2012-2013) compliance period and beyond as a cumulative target. The cumulative 2010-2013 acquisition target applied to the second (2012-2013) I-937 compliance period would include all acquisition achieved in 2010-2011 or acquisition for which penalties, if any, have been paid during that period. This approach better aligns utility and shareholder interest by eliminating the tendency to limit acquisition in excess of a compliance period in order to preserve market potential in subsequent compliance periods. RCW 19.285

[5] Quantifiable adoption of efficiency measures contained within the scope of the 6th Power Plan beyond utility program intervention means the documented installation of cost-effective electric-efficiency measures.

provides only for penalties but no "rewards." Avista currently has no ratemaking incentive mechanism to provide for rewards to recognize DSM acquisition in excess of targets.

VI. QUALIFYING CONSERVATION MEASURES

Acquisition from all conservation measures qualifying under the Northwest Power Planning Act plus electric to natural gas conversion acquisition will qualify towards meeting the conservation target. This includes measures that may not have been identified during the prior Power Plan due to insufficient information or analysis, and measures that were evaluated and may not have been cost-effective at the time they were evaluated for the Power Plan. The American Recovery and Reinvestment Act ("ARRA" and also known as "economic stimulus") has provided funding to Avista for some aspects of energy efficiency programs, to customers for use on energy efficiency projects, and to potential community partners who may expand energy efficiency opportunities. Energy efficiency measures from ARRA-supported projects are included as qualifying measures.

This Conservation Resource Report presumes that no significant structural changes to DSM acquisition, beyond the Company's control, will occur during the compliance period that would affect target determination. If changes occur that would materially affect Avista's DSM targets, the Company will file appropriate amendments and will be reflected in the Biennial Reports.

If, during the course of any two year compliance period, energy codes or federal manufacturing standards are revised, the baseline for purposes of measuring conservation acquisition will be based upon the codes and standards in effect at the beginning of that compliance period. In subsequent compliance periods the acquisition target will be modified to account for the higher code or standard and an adjustment will be made to the measurement of acquisition applicable towards that target. This convention prevents providing utilities with an incentive to oppose cost-effective codes and standards in order to enhance their acquisition relative to the conservation target.

Avista will claim a share of acquisition resulting from its investment and involvement in the Northwest Energy Efficiency Alliance (NEEA) based upon the best available disaggregation of savings for Avista's Washington jurisdiction.

Distribution Efficiency

Avista's distribution engineering staff has developed a process to evaluate the quantity and type of losses across its existing distribution infrastructure. As part of the process, Avista approximated losses across the following components of each distribution feeder: conductors, transformers, secondary districts and Voltage Amps Reactive (VAR) compensation. In order to rank each feeder as a possible efficiency project, an economic analysis was performed to determine opportunity and priority.

Recognizing the challenge in approximating energy savings for specific load varying feeders, the Avista distribution engineering staff developed a program to improve the measurement of power flow across the feeders. Currently, the measurement of load is limited to drag meters or Supervisory Control and Data Acquisition (SCADA) points located back at the substation bus.

The measurement program referred to as “Distribution Reliability Energy Efficiency” (DREE) identified meters and communication infrastructure necessary to measure voltage and current at points along the length of a feeder. The DREE program approach will provide calibration for the engineering models used to approximate energy savings.

Avista has been selected to receive grant awards in each of the Smart Grid categories “Smart Grid Investment Grid” (SGIG) and “Smart Grid Demonstration Project” (SGDP) funded by the American Reinvestment and Recovery Act (ARRA). Prior to these grant awards, Avista had evaluated a set of feeder upgrade programs independent of, but not exclusive of, smart grid concepts as previously discussed. With the opportunity afforded by the grant funding, elements of the feeder upgrade program combined with smart grid concepts were deemed appropriate. Both smart grid projects have energy efficiency targets identified.

In addition to specific efficiency programs, Avista revised existing distribution standards that were based on a life-cycle cost model versus an initial first cost model. The life-cycle cost model takes into consideration the cost of energy loss over the life of the equipment. As a result of the revised standards, distribution infrastructure which requires rebuilding or replacement as part of normal business practices will utilize more efficient equipment. The incremental energy savings resulting from the replacement of old equipment with new equipment will be counted towards conservation targets.

VII. MEASUREMENT OF ACQUISITION

Avista is in its 30^{th} year of providing energy efficiency services. Its current methodology for evaluation of savings was established in 1995. The Company has received findings of prudence for its energy efficiency expenditures, under this methodology, from both the Washington and Idaho Commission for every period requested through 2007.

Avista is in the process of enhancing its Evaluation, Measurement and Verification protocols. The Company circulated an EM&V draft plan for review by the Triple-E board in November, 2009. The Commission ordered, in Docket Nos. UE 090134, UG 090135 and UG 060518 (consolidated), Avista to initiate a collaborative to review EM&V issues and to provide a report to the Commission on or before September 1, 2010. That report will describe Avista's enhanced EM&V protocols.

As described in its draft plans, EM&V is intended to reflect all of the analyses necessary to supply information to stakeholders to adequately determine the prudence of Avista's DSM Programs. EM&V includes "impact," "process," "market," and "cost test" test analyses. These are described below (and taken as a whole are synonymous with other terms such as "Portfolio Evaluation" or "Program Evaluation").

> <u>Impact Analysis</u> – Impact analysis provides the documentation necessary to prove that the savings estimated within a particular program are equal to the savings realized by all of the customers participating in that program. Impact analysis subcomponents include:

- Measure Verification applies principles of the International Performance Measurement & Verification Protocol (IPMVP). Only a single measure may be verified using this technique or protocol. The verification of a statistically significant number of projects using IPMVP techniques is often extrapolated to verify and perform impact analysis on whole programs. The following parameters are necessary for the verification of a measure.

    - Process for calculating the savings;
    - Incremental cost of a measure;
    - Installation date;
    - Measure life;
    - Claimed savings;
    - Rate schedule for DFIC Calculation; and
    - Other

Process Analysis – Process analysis is the documentation of the continuous changes necessary to create, implement, modify and possibly terminate programs. The following items are included in process analysis.

- Contact information;
- Changes to programs over time;
- Rules for customer qualification;
- Project Cost data; and
- Other

Market Analysis – Market analysis determines the effect of the marketplace on customer implementation of energy efficiency including customer costs. This analysis is under development and will be included in the Company's EM&V collaborative with interested parties as previously discussed.

Cost Test Analysis – Cost test analysis combines several industry terms relative to the evaluation of energy efficiency cost-effectiveness including among others, Net to Gross analysis, Total Resource Cost (TRC) analysis, Free Riders or Free Drivers.

Revisions to reported annual savings may occur due to the results of these EM&V protocols. These modifications of savings will be documented with supporting analyses and may yield increases or decreases in final reported savings.

VIII. ONGOING PUBLIC INVOLVEMENT REGARDING TARGETS

The status of target achievement and associated updates will be provided to interested parties in several ways over the compliance period, beginning with planning. Several meetings with the Triple E will be held in 2010 specific to evaluation, measurement and verification protocols described in Section VII.

Avista provides an annual DSM Business Plan, provided herein as Attachment B. This process guides the business operations for the following year. The annual plan is publicly distributed to the Triple-E Board. Included in the plan are details regarding budget, labor, programs, outreach, measurement and evaluation and other details necessary to achieving the conservation target. Additionally, the Triple E meets twice a year, providing for ongoing review of Avista's DSM activities. Currently, the Company provides monthly tariff rider balances, quarterly reports, and provides periodic newsletters with programmatic and statistical updates.

Avista augmented its 2010 DSM Business Plan with an assessment of distribution efficiency improvements planned or contemplated in the following year.

Issues that may be addressed for future compliance periods will be solicited from interested parties through the Company's Triple E Board. For example, based on experience gained in this process, the segmentation of site-specific market penetration for use in the Company's next IRP may be further pursued. Further, while not an issue until 2015, better alignment of the Company's IRP with the Council's planning for future power plans would increase the quantification of each. The Company's DSM planning, as part of its current IRP, was several months ahead of the Council's DSM planning for its 6th Power Plan. Therefore, there was not much opportunity for the two planning efforts to converge as has occurred in past planning cycles.

IX. CONCLUSION

Avista has chosen to use the Northwest Power Planning Council's Option #1 of the 6th Power Plan to establish the Company's acquisition target, adjusted to include electric-to-natural-gas fuel conversions. The resulting targets are greater than the Company's Integrated Resource Plan's energy efficiency targets for the same period. Avista intends to acquire 128,603 mWh's of energy efficiency as described in this filing in 2010 and 2011, the first I-937 two-year compliance period. Avista's projection of the acquisition over a ten-year period, assuming that this same option is selected in future compliance periods, is 873,302 mWh's.

All distribution efficiency programs which are implemented to replace existing infrastructure will qualify towards meeting the conservation target. In addition to infrastructure upgrades, smart grid related programs will also qualify towards conservation targets.

Avista will provide updates to the Triple-E Board regarding its progress towards meeting the I-937 conservation goal and any significant issues arising regarding acquisition, measurement or planning that may affect compliance. This will include as part of the Company's current DSM quarterly report, an estimate of qualifying DSM and distribution efficiency acquisition within each compliance period in comparison to estimated progress towards the acquisition target.

RESPECTFULLY SUBMITTED this 29th day of January, 2010.

AVISTA CORPORATION

By: ________________________________

Kelly O. Norwood
Vice President, State and Federal Regulation

Appendix F – Memorandum of Understanding with the IPUC Staff

Jon Powell

In late 2009 policy discussions between the IPUC staff, Avista, Idaho Power and Rocky Mountain Power concerning EM&V and related cost-effectiveness as well as reporting issues led to the attached Memorandum of Understanding (MOU). The MOU to follow has led to many of the revisions discussed throughout the business plan document, most particularly a renewed commitment to EM&V, integration of net-to-gross within the Company's cost-effectiveness analysis and revisions to the packaging of externals reports.

It is the responsibility of each utility to plan for and implement the requirements of the MOU as appropriate for their individual DSM portfolio.

MEMORANDUM OF UNDERSTANDING
FOR PRUDENCY DETERMINATION OF DSM EXPENDITURES

This Memorandum of Understanding ("MOU") is entered into on this ___ day of December 2009 between Idaho Power Company ("Idaho Power"), Avista Utilities, PacifiCorp (d/b/a Rocky Mountain Power) (collectively "the Utilities" and individually as "the utility"), and the Staff of the Idaho Public Utilities Commission ("Staff"). All of the above-named entities are hereinafter sometimes referred to collectively as "Parties" or individually as "Party."

WITNESSETH:

A. The Parties agree that there exists a need for the Utilities and Staff to develop a common understanding of the basis upon which prudency of demand-side management ("DSM") expenditures can be determined for purposes of cost recovery.

B. The Parties attended a workshop on October 5, 2009, to discuss the contents of a more comprehensive utility annual DSM report that would demonstrate a commitment to, and accomplishment of, objective and transparent evaluation of DSM efforts. The agreed-upon principles ("guidelines") stemming from that workshop are set out below.

C. A copy of Staff's expectations for DSM prudency review is included as Attachment No. 1. Although Utilities will make a good faith effort to address Staff's expectations in following these guidelines, Staff expectations are informational and the Utilities will not be bound by them in the context of this Memorandum of Understanding.

D. The Parties recognize that implementation of the DSM prudency guidelines and evaluation framework described below will not automatically result in

DSM prudency findings. Instead, even with their implementation, future DSM prudency findings will require the preparation of a formal filing with the Commission.

NOW, THEREFORE, in consideration of the foregoing, the parties agree as follows:

Utility DSM Annual Report Requirements

1. Template. Idaho Power's *2008 Demand-Side Management Annual Report* will be used as a starting point template for enhanced reports beginning with reports for 2009 DSM operations and results. Elements like those found in Idaho Power's 2008 report will be included in each Utility's annual report for Idaho programs that reporting year, clearly identifying Idaho-specific data and narratives. The DSM annual reports may be filed as stand-alone documents or as a combination of documents (e.g., combined with a DSM business plan) that together fulfill the agreements in this MOU.

2. Table of Contents. Each annual DSM report will contain a table of contents that references all items specified below, including the appendix where the Cost-Effectiveness and Evaluation Table can be found.

3. Highlights or Introduction Section. Each annual DSM Report will include an initial overview of:

a. Process evaluations begun or completed during the previous year, modifications to DSM processes that resulted from those evaluations, and planned process evaluations and modifications for the coming year.

b. Impact evaluations begun or completed during the previous year, modifications to DSM programs that resulted from those evaluations, and planned impact evaluations for the coming year. This section will also highlight updates of assumptions or reference reports used in assessing cost-effectiveness during the past year and those expected to be reviewed in the coming year.

4. Cost-Effectiveness Section. Each DSM annual report will include a Cost-Effectiveness section and table listing individual programs/measures and the basis for estimates of their cost-effectiveness, i.e., formulas, data inputs and assumptions, and source/rationale for each datum and assumption, including the date of the source.

5. Evaluation Section. Each DSM annual report will include an Evaluation section and table showing the schedule for evaluations, including impact assessment, assumptions, source review, the schedule for field impact measurement, and completion date. If this schedule is not included, a reasonable explanation for why such a schedule, in whole or in part, is not necessary will be included.

a. It is anticipated that over a reasonable frequency cycle (e.g., 2 to 3 years), all substantial programs will have undergone process and impact evaluations. However, Staff agrees that the initial evaluation cycles may be longer for 2008 and 2009 programs until these guidelines are fully implemented.

b. A copy of each DSM evaluation completed since filing the previous DSM annual report will be included as an appendix to the annual DSM report, as well as any confidential cost information that are not included. The utility will supplement its DSM report with any confidential cost information once the Staff has signed a protective agreement with the utility.

6. Program Specific Section. Program-specific sections of the annual DSM Report will be reported by sector or by customer class, with a description of each

individual program offered in the sector or customer class, and will include a list of measures within each program.

a. Process Evaluation. Each program-specific section will have a process evaluation description that includes:

i. Program implementation modifications undertaken during the course of the year and the rationale behind the change(s).

ii. Other process issues identified during the course of the year.

iii. Any formal process evaluation undertaken during the year.

iv. Total process evaluation cost, inclusive of both utility-provided and contract-provided services, and names of primary outside evaluators conducting process evaluations and titles of internal evaluators. The DSM Report will indicate which cost information is considered confidential; each utility will supplement its DSM report with any program evaluations containing confidential proprietary information once the Staff has signed a protective agreement with the utility.

v. Process changes completed or planned during the upcoming year, if any.

b. Impact and Cost-effectiveness Evaluation. Each program-specific section will include an impact and cost-effectiveness evaluation description including:

i. Primary assumptions and source (with year source was produced) used in the initial determination of cost-effectiveness.

ii. Primary assumptions and source (with year source was produced) used to determine post implementation impact and cost-effectiveness.

iii. Any changes from initial determination (or last evaluation) used for current cost-effectiveness evaluation and the reason for the change (such as updated assumptions, sources or field measurement).

iv. Planned cycle for reassessment of cost-effectiveness assumptions or measurement.

v. Total impact evaluation cost, inclusive of both utility-provided and contract-provided services, and names of primary outside evaluators and titles of inside evaluators. The DSM Report will indicate which cost information is considered confidential; each utility will supplement its DSM report with any program evaluations containing confidential proprietary information once the Staff has signed a protective agreement with the utility.

vi. Changes in program due to evaluation results.

c. Market Effects Evaluations. Each program-specific section will describe any market effects evaluations that have been planned or completed by or for the utility, including those planned or completed by the Northwest Energy Efficiency Alliance that are pertinent to any programs for which the utility is claiming electricity savings or other impacts.

7. Expenses Without Direct Energy Savings. As discussed in the October 5 workshop, the Utilities have expenses associated with DSM-related activities for which they do not claim energy savings. Expenses associated with non-quantifiable energy saving programs and initiatives, including but not limited to, infrastructure, education, outreach, and research, will be identified in the DSM annual reports and may be considered reasonable and necessary expenses for a broad based DSM portfolio.

Reasonable evaluations of such programs and efforts, commensurate with their costs, will be accomplished and reported. The Utilities will include these expenses in the calculations which determine a cost-effective DSM portfolio.

Prudency Determination

8. A utility may request a DSM prudency review at any time.

9. The Parties recognize that planning, implementing, and evaluating DSM programs are not a precise science; they require the application of judgment and experience. Utilities are encouraged to continually review these programs and make appropriate program improvements.

10. Within that context, review of utility demand-side management expenses for prudency shall take into consideration utility compliance with the planning, evaluation, and reporting guidelines listed above. A showing by the utility that it made a good faith effort to reasonably perform within these guidelines will constitute *prima facie* evidence that the utility's DSM expenses were prudently incurred for cost recovery purposes. By its performing within these guidelines, assuming there is no evidence of imprudent actions or expenses, the utility can reasonably expect that in the ordinary course of business Staff will support full cost recovery of its DSM program expenses.

Treatment of 2008 and 2009 Expenditures

11. Recognizing that their 2008 DSM reports have already been filed, the Utilities need not amend those reports, but instead will combine evaluation reporting for 2008 with 2009 in their 2009 reports to be filed in 2010. Because it is not possible to comply exactly with the requirements listed above for the historical expenses of 2008 and 2009, Parties agree to include as many components as possible in the 2010 Annual

DSM Report. Staff agrees to provide reasonable and necessary leeway for the implementation of the guidelines described in this MOU for the 2010 DSM reports.

12. Staff agrees that Avista Utilities may re-file its 2008 DSM prudency requests that were deferred in AVU-E-09-01 and AVU-G-09-01 as full-year prudency requests that will not be opposed by Staff.

Commission Not Bound by This Memorandum of Understanding

13. The parties to this Memorandum of Understanding acknowledge that the Commission Staff binds only itself and has no explicit or implicit authority to bind the Idaho Public Utilities Commission.

IN WITNESS WHEREOF, the Parties hereto have caused this Memorandum to be executed in their respective names on the dates set forth below.

Dated this ____ day of December 2009.

IDAHO PUBLIC UTILITIES COMMISSION STAFF

By:________________________________
Randy Lobb
Representing the Idaho Public Utilities Commission Staff

Dated this ____ day of December 2009.

IDAHO POWER COMPANY

By:________________________________
Representing Idaho Power Company

Dated this ____ day of December 2009.

AVISTA UTILITIES

By:________________________________
David J. Meyer
Representing Avista Utilities

Dated this ____ day of December 2009.

ROCKY MOUNTAIN POWER

By:___________________________________
Representing Rocky Mountain Power

ATTACHMENT NO. 1

Staff Expectations for Cost-Effectiveness Tests, Methods and Evaluations

1. Cost Effectiveness Measurements. As stated at the October 5, 2009, DSM evaluation workshop, Staff believes that prudent DSM management requires that cost-effectiveness be analyzed from a wide variety of perspectives, including the ratepayer impact perspective, and that all programs and individual measures should have the goal of cost-effectiveness from the total resource, utility, and participant perspectives. (See IPUC Order No. 22299 issued January 27, 1989, and Order No. 28894 issued November 21, 2001.) If a particular measure or program is pursued in spite of the expectation that it will not, itself, be cost-effective from each of those three perspectives, then the annual DSM report should explain why the measure or program was implemented or continued.

2. Net-to-Gross Adjustments. The net-to-gross issue was also discussed at the evaluation workshop. Some of the references that the utilities assert that they use, such as the *California Standard Practice Manual*, actually require that all tests be done on a net savings basis. Staff continues to assert that most programs and measures have a significant number of participants who would have installed the measure or changed their behavior in the absence of the utility program. Absent new evaluation research to provide a basis for the net-to-gross adjustments used by each utility, the utility has the burden of explaining the source of its net savings adjustments or lack thereof. Staff will continue to assess whether utility cost-effectiveness estimates sufficiently and prudently include net-to-gross adjustments.

3. Third-Party Evaluators. Independence of evaluators from program and portfolio management is another important issue that was discussed at the evaluation workshop. While it was generally agreed that not all evaluations need to be performed by third-party evaluators, Staff believes such evaluations tend to be perceived as being more objective and transparent, and thus more credible, than evaluations performed by utility staff, all other factors being equal. While Staff will review all evaluations and may

review any evaluation in depth, utilities should expect that their self-evaluations may be scrutinized more closely than third-party evaluations, as may the programs themselves.

4. Estimating Non-Energy Benefits. Non-energy benefits are important and prudent factors to assess in analyzing cost-effectiveness and determining incentive levels, but Staff cautions against creating confusion by subtracting the estimated value of non-energy benefits from program and measure costs when reporting DSM costs on a cents per kWh basis.

5. Contractor Costs. After DSM reports are filed in 2010, Staff may reconsider whether to require inclusion of specific contract amounts paid to contractors in subsequent DSM reports.

6. Suggested Resources. In addition to the several evaluation, measurement, and cost-effectiveness manuals that were discussed at the workshop, Staff suggests it may be useful for utilities to generally follow the guidelines in the National Action Plan for Energy Efficiency's *Model Energy Efficiency Program Impact Evaluation Guide*, released November 2007. Another of NAPEE's reports titled *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers* may also be useful.

Appendix G – Cost-Effectiveness Primer

Jon Powell

The following summary of Avista's application of the standard practice cost-effectiveness test appeared as "Appendix B" in the 2007 Triple-E Report and is reproduced below as a guide for this business plan.

Avista has also committed to performing variants upon these calculations upon request whenever possible, including the calculation of the TRC test without tax subsidies and based upon net and gross participation scenarios. This analysis will generally add to and not be a substitute for other evaluation and calculation of descriptive statistics.

These calculations will be incorporated into our reporting and planning documents as appropriate.

Appendix B
Introduction to Avista's Analytical Methodology

The analytical evaluation of Avista's programs can largely be divided into two general approaches; the standard practice cost-effectiveness tests and descriptive statistics. Each approach and each calculation within the two different approaches provide a different perspective on the status of a program. When viewed as a whole they are intended to provide a meaningful insight into the program for purposes of making informed decisions for the management of individual programs as well as the overall portfolio.

The descriptive statistics, such as direct incentive per kWh saved, general costs per kWh saved and so on are easily understood and calculated. Over the course of designing, implementing and evaluating these programs these descriptive calculations are made and modified as necessary.

The cost-effectiveness tests are a more standardized and, in many ways, a more rigorous analytical tool. In consideration of their value as a management tool we wrote a brief summary of calculation, meaning and interpretation of these tests for our implementation staff. This summary has been periodically modified and redistributed internally and externally for use in introducing the methodology for calculating and interpreting the standard practice tests.

Cost-Effectiveness Primer

The four 'standard practice tests' were developed in California as a means to evaluate the cost-effectiveness of demand-side management programs from the perspectives of different participants. These four tests are:

Total Resource Cost (TRC) test: This is a societal benefit-cost analysis and indicates the cost-effectiveness of a project is to the whole of society. In recent years the inclusion of non-energy benefits in this test has become more acceptable (and even expected). These costs include reductions in customer maintenance, reduced insurance and potentially even the value of reduced emissions and other societal costs of energy generation, transmission and delivery.

Utility Cost Test (UCT): This test indicates whether the utility cost of serving all customers goes up or down as a result of the program. This is not the customer 'energy' cost, which would include end-use equipment and similar costs, it is only the costs incurred by the utility to serve the customer.

Participant test: This is the cost-effectiveness for the participating customer. It includes the value of the energy savings (and other savings) from the project vs. the customer project costs.

Rate Impact Measure (RIM) test (also known as the non-participant test): This indicates if the program will result in a rate increase or decrease. It is also known as the 'non-participant test' because programs that fail the RIM test result in an increase in rates and disadvantage a non-participating customer. The 'non-participating customer' bears the cost of the rate increase without obtaining any program benefits.

What is and isn't included in the four standard practice tests can be shown in the illustrative table:

	TRC	UCT	PART	RIM
Electric avoided cost value (utility discount rate)	$ 4,330,973	$ 4,330,973		$ 4,330,973
Gas avoided cost value (utility discount rate)	$ 131,242	$ 131,242		$ 131,242
Customer value of kWh savings			$ 5,066,599	
Customer value of kW savings			$ 619,317	
Customer value of gas savings			$ 102,216	
Customer electric incentive received			$ 1,276,582	
Customer gas incentive received			$ 0	
Customer value of customer Non-Energy Benefits	$ 0		$ 0	