Section 1:
Technical Advisory Committee Meeting Presentation Materials

Section 2:
Portfolio Results Comparison for the Climate Stewardship Act Future, Volatile Gas Future, and the No Carbon Legislation Future

Section 3:
Demand Side Management Measures Cost Effectiveness Summary

Section 4:
Resource Integration Costs (Transmission Estimates)
# Avista Utilities 2007 Integrated Resource Plan
## Technical Advisory Committee Meeting No. 1 Agenda
### February 24, 2006

<table>
<thead>
<tr>
<th>Topic</th>
<th>Time</th>
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<tbody>
<tr>
<td>1. Introductions</td>
<td>10:00</td>
<td>Barcus</td>
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<td>3. Work Plan Discussion</td>
<td>10:20</td>
<td>Gall</td>
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<tr>
<td>4. Transmission Planning</td>
<td>10:45</td>
<td>Folsom</td>
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<td>5. 2005 IRP and TAC Comments</td>
<td>11:15</td>
<td>Lyons</td>
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<td>6. Lunch</td>
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<td>7. 2007 IRP Topic Discussions</td>
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<td>• Resource Planning</td>
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<td>• Conservation</td>
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<td>• Analytical Process</td>
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<td>• Capacity Planning</td>
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<td>• Other</td>
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<tr>
<td>8. Adjourn</td>
<td>2:00</td>
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Integrated Resource Planning

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

John Lyons
Integrated Resource Planning

- Investor owned utilities are required by Washington and Idaho state law to submit a comprehensive integrated resource plan (IRP) every two years.
- The plan includes a long-term forecast for a variety of topics including:
  - Loads and resources
  - Conservation
  - Transmission planning
  - Potential resource evaluations
  - Base and scenario driven price forecasts
  - Preferred Resource Strategy
  - Emissions and Environmental Analyses
  - Special studies
New Developments for the 2007 IRP

- Washington House Bill 2351 filed December 2005
  - Encourage the construction of renewable generation through a renewable portfolio standard (RPS)
  - Require investor and community owned utilities to file IRPs
  - IRP “must include demand forecasts, assessment of technically feasible improvements, assessment of technically feasible generating technologies, resource evaluation, and specific actions to be taken by the utility …the plan must also include a progress report that relates the new plan to the previous plan.”

- Updated IRP Rules: “Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.” (WAC 480-100-238 (4))
More Participation for the 2007 IRP

• Increased the size and scope of the invitation list
• Sought feedback on 2005 IRP TAC process
• NPCC – Specific invitations made to technical staff with focus on topic areas
• Environmental Community – Invitations to NWEC/NRDC
• Peer Utilities – personal invitations made to IRP technical staff from NW utilities
• Academic Community – invitations to WSU, OSU and Gonzaga
2007 IRP Work Plan Discussion

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

James Gall
The Work Plan is provided in response to WAC 480-100-238 in the state of Washington.

Outlines the process that we will take to develop the 2007 Integrated Resource Plan.

Will use a process similar to the previous two plans.

Improvements to the 2007 IRP include more detailed site-specific resource assumptions, wind integration costs, sustained peaking capacity, a cost of service study, and a detailed analysis of conservation programs.
Work Plan Details

Proposed TAC meetings

- February 24, 2006
- September 2006
- December 2006
- February 2007
- April 2007
- May 2007
- July 2007 – tentative IRP draft review
2007 IRP Tasks

- Resource options
- Update AURORA\textsuperscript{XMP} database
- Develop Avista load forecast
- Cost of service study
- Develop deterministic base case
- Simulate market scenarios
- Create data sets and statistics for risk studies
- Conservation study
- Simulate base case risk study
- Simulate risk study “futures”
- Enhance PRS LP model
- Develop efficient frontier for PRS with LP Model
2007 IRP Report Tasks

- Prepare IRP report and appendix outline
- Prepare text drafts
- Prepare charts and tables
- Internal draft release and review
- External draft release and review
- Final editing and printing
- Final report distribution and submission
- Technical Advisory Committee survey and comments
Transmission Planning

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

Bruce Folsom
FERC’s Standards of Conduct and IRPs

- FERC revised its Standards of Conduct for Transmission Providers Rule – effective on September 22, 2004
- Orders 2004, et.al., require a separation of transmission system operation employees from merchant employees to prevent the energy marketing branch of a company from having more information than publicly available. “The purpose of the prohibition is to prevent transmission providers from unduly favoring their affiliates with transmission information that is not disclosed to non-affiliates thereby disadvantaging the non-affiliates.”
- Shared employees, who operate in both realms cannot be a conduit to pass transmission information between the transmission and merchant groups
- This presents unique issues for utilities that house integrated resource planning in its merchant function
FERC Response to Planning Constraints

In a November 2005 letter to the Oregon PUC, FERC acknowledged that:

- “… integrated resource planning is important in fulfilling the mandate of Section 1233 of the Energy Policy Act of 2005 to encourage the planning and expansion of transmission facilities.”
- “… resource planning can be accomplished, in many instances, within the guidelines established by Order No. 2004.”
- Case-by-case waivers for the standards can be applied for specific situations
- “I feel confident that we can find creative ways in which to facilitate integrated resource planning while maintaining allegiance to the non-discrimination goals of the Standards of Conduct.”
FERC and Transmission Planning

• Meetings between transmission employees and merchant employees that may address proprietary transmission information must be posted to OASIS (Open Access Same-time Information System). Therefore all TAC meetings involving transmission personnel or inviting transmission personnel will be posted to OASIS.

• Meeting notes will be taken

• Questions about transmission studies conducted by the Transmission Department can be asked provided that answers will not consist of prohibited information

• Transmission studies and any supporting data must be posted to OASIS on a “same-time” basis when provided to merchant employees.

• Responses and results of transmission studies will be posted to OASIS at http://www.oatioasis.com/avat/index.html
Current IRP Transmission Planning

- Meet with Transmission Planners to identify transmission system opportunities
- Consider new transmission lines and upgrades
  - Specifics of opportunities may need to be “generic” to prevent transfer of information (i.e., from Avista Merchant)
- Discuss potential locations of new resources and the transmission upgrades necessary for integration
2005 IRP and TAC Comments

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

John Lyons
## 2005 TAC Survey

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<td>Have many TAC meetings did you attend?</td>
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<td>7.9</td>
<td>1 – 10</td>
<td>Rank the number and length of TAC meetings.</td>
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<td>8.4</td>
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<td>Rank of content of the meetings.</td>
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<tr>
<td>8.2</td>
<td>1 – 10</td>
<td>Rank of overall TAC process.</td>
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</table>
2005 TAC - Areas Performed Well

- Content of the material
- Description of modeling approaches and results
- Reporting a complex subject in summary fashion
- Thorough analysis
- Meetings were well planned and conducted
- Presentations were well done
- Policy issue discussions
- Financial impact of planning and discussion of financial-economic environment
- Encouraging interaction/involvement
- Information sharing
2005 TAC - Areas for Improvement

- Increase attendance and TAC member diversity
- More details on the mathematical methodologies used
- More discussion on transmission constraints and FERC policy
- Focus on DSM earlier in the process
- Present Avista-specific plans earlier in the process
- Improve opportunities for participation by phone

- Do not assume qualifications of the TAC members
- Continue to improve modeling
- Improve communication of expectations and results
- Provide information prior to the meetings
- Leave more time for comments, refinement, and additional analysis at the end of the process
2005 TAC - Possible Meeting Sites

- Spokane – at Avista headquarters
- Conference call – possibly with West, East and Boise locations
- Olympia
- Boise
- Seattle
- PNNL
- Large customer sites
- At generation projects – such as CS2 or a potential site
- Pullman
Topics for the 2007 IRP

- Most surveys had no additional topics for consideration
- Would like to see additional work on the integration of DSM and energy efficiency
- Provide a more robust consideration of nuclear power
- Include more customer based cogeneration
2007 IRP Topic Brainstorm

2007 Integrated Resource Plan
First Technical Advisory Committee Meeting
February 24, 2006

Clint Kalich
Resource Planning

- Supply-Side Resource Assumptions
  - Generic (e.g., NPCC) vs. site-specific data
  - Pros and cons
- Modeling Emissions
- WA RPS Initiative
Conservation

• Should 2007 IRP diverge from 2005 methodology
• CVR load control study update
• Transmission efficiency upgrades
  – How do we get the data?
  – 10% market adder was used for the 2005 IRP for all conservation
    • i.e., traditional DSM, plant upgrades
Capacity Planning

• Sustained peaking capacity analysis
  – Can we reach consensus in 2007 IRP timeframe
  – Wind vs. other resources
• Wind integration studies
  – 2002 work and 2006 consultant study findings
• Wind contribution to peak demand
  – Does wind add to system peaking capability?
Analytical Process

• Monte Carlo Analyses
  – 2005 IRP varied gas, load, hydro, and wind
  – More/Less for 2007

• Hydro Issues
  – 70-year hydro study is now available
  – Breaking out the Northwest is in progress

• Scenarios and futures
  – What would the TAC like to see for 2007?
Other Areas

• Peak capacity credit method for cost of service
Avista Utilities 2007 Integrated Resource Plan
Technical Advisory Committee Meeting No. 2 Agenda
August 31 & September 1, 2006

8/31/06
- Introductions 9:30 Barcus
- Review of TAC-1 Meeting 9:35 Lyons
  - Review 2005 Action Plan
- IRP Modeling Overview 10:00 Lyons
  - Emissions
  - Fuel Price Forecasts Gall
  - Other Modeling Assumptions Gall
  - Preliminary Transmission Costs & Paths Heath
  - Resource Options & Cost Assumptions Lyons
  - Futures and Scenarios Lyons
- Lunch – Presentation on 2006 Renewables RFP 12:00 Silkworth
- IRP Modeling Overview, Continued 1:00 Lyons
- Future Resource Requirements (L&R) 2:00 Heath
- Review of Futures & Scenarios Market Results 2:30 Gall
- Preview of Preliminary Preferred Resource Strategy 4:00 Kalich
- Adjourn 4:30

9/01/06
- Review of First Day/Discussion/TAC Input 8:30 Lyons
- Preliminary PRS Discussion 10:00 Gall/Kalich
  - Portfolio Selection Criteria
  - Futures & Scenarios
  - PRS Selection Model
  - Results
- Lunch – Alternative Energy Future Discussion 12:00 Lyons
- Preliminary PRS Discussion, Continued 1:00 Gall/Kalich
- Adjourn 2:30
Review of First TAC Meeting & 2005 IRP Action Plan Review

2007 Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

John Lyons
Review of First TAC Meeting

The First Technical Advisory Committee Meeting was on February 24, 2006:

- New and potential rules and laws for integrated resource planning
- Work plan discussion – what will be presented to the TAC
- Transmission planning – FERC guidelines
- Reviewed comments on the 2005 IRP and TAC
- Started 2007 IRP topic discussions including resource planning, conservation, analytical process, capacity planning, and ideas from TAC members
2005 IRP Action Plan

The Action Plan for 2005 includes activities planned to support the PRS from the 2005 IRP, enhance the process, and research areas of interest not included in the 2005 IRP

The 2005 Action Plan covered four major areas:
1. Renewable Energy and Emissions
2. Modeling Enhancements
3. Transmission Modeling and Research
4. Conservation
Renewable Energy and Emissions

1. Commission a study to assess wind potential in Avista’s service territory
   • Wind map survey of our service territory has been completed
   • An aerial survey for wind flagging has been completed on the more promising sites
   • Several promising areas have been located and are being researched

2. Continue to monitor emissions legislation and its potential effects on markets and the Company
   • Ongoing review at state, regional, and national levels
   • Have formed a committee on climate change
Renewable Energy and Emissions

3. Research clean coal technology and carbon sequestration
   • There will be a lunch presentation at the next TAC meeting

4. Assess biomass potential within and outside Avista’s service territory

5. Continue to study the availability of various renewable energy technologies, including local sites
   • RFP for renewable energy – lunch presentation today
   • Open to reviewing any projects that are brought to us
Modeling Enhancements

1. Evaluate 70-year water record for inclusion in 2007 IRP studies
   • This has been included – will provide more details in the modeling presentation later today

2. Add more functionality to the Avista Linear Programming Model
   • Direct consideration of cash flow and rate impacts versus after-the-fact reviews
   • We will be working on this for the final PRS
Transmission Modeling and Research

1. Work to maintain/retain existing transmission rights on the Company’s transmission system

2. Continue involvement in BPA transmission business practice processes and rate proceedings

3. Continue participation in regional and sub-regional efforts to establish new regional transmission structures
   • Avista is participating in ColumbiaGrid

4. Evaluate costs to integrate new resources across Avista’s service territory and from regions outside of the Northwest
   • Internal cost studies are being done by the transmission group and we are reviewing outside studies as they become available
Conservation

1. Review the potential for cost-effective load shifting programs using hourly market prices

2. Complete the conservation control project currently underway as part of the Northwest Energy Efficiency Initiative
2006 Renewables
Request for Proposals

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

Steve Silkworth
2006 Renewables RFP

• The 2005 Integrated Resource Plan indicates that Avista has a need for additional energy resources by 2016. These additional resources include:
  – 400 MW of wind power (approximately 135 average MW of energy)
  – 80 MW of other renewables (bio fuels, geothermal, etc)
  – 250 MW of coal
  – 52 MW of plant upgrades
  – 69 MW of conservation

• Avista’s 2005 IRP Integrated Resource Plan will meet Washington State’s proposed Renewable Portfolio Standard requirement.
2005 IRP Implementation
2006 Renewables RFP

- A Request for Proposal for up to 35 average MW of renewable energy was issued to the public on January 4, 2006
- Bids were opened February 1, 2006
- 14 wind power bids received, 1190 MW of capability, 430 aMW energy
- Eight other bids received including: Geothermal power, land fill gas, wood biomass, wood gasification, small hydro, and bio-solids (waste wood and sludge) totaling 43 MW of capability and 40 aMW of energy
2006 Renewables RFP

• Currently negotiating with one project to purchase up to 100 MW of wind power
  – Online date is projected to be December 2007
  – 50 MW with an option for an additional 50 MW
  – Power purchase agreement for 10 to 15 years with an option to own the project
  – Transmission availability has recently become an issue
Wind Acquisition -- Next Steps

• Complete contract negotiations
• Solve transmission problems
• Management approval and enter into the agreement
• Continue researching potential wind development sites within Avista’s service territory
• Continue the implementation of the 2005 IRP
Alternative Energy Future

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
September 1, 2006

John Lyons
Alternative Energy Future

Covering some of the more interesting alternative energy information that we have studied, but was not quite ready for resource planning for a variety of reasons, including:

- Cost effectiveness
- Scalability
- Commercial availability
- Unproven technology
Energy Storage Technologies

• Vanadium batteries – basically a large battery system that is charged in off-peak hours and discharged to shave peak load
  – Advantages
    • Less toxic and more efficient than traditional battery technologies
    • Useful in special circumstances to prevent or at least delay additional transmission or generation acquisitions
  – Disadvantages
    • High cost – Capital cost of $5,200 per kW
    • Size limitations – 25 kW up to 10 MW for several hours
Energy Storage Technologies cont.

• Other storage technologies exist and are in development, particularly for wind projects
  – Compressed air energy storage – off peak energy is used to compress air in a sealed chamber (cavern, mine, well, etc) and then released during peak hours with some natural gas and burned in a gas turbine
    • Two major operating sites: 110 MW plant in McIntosh, Alabama and a 230 MW facility in Huntdorf, Germany
    • Manufacturers claim to be able to construct facilities from 5 MW to 350 MW
  – Advantages – overcome some of the variability and capability problems with wind
  – Disadvantages – losses of up to 80% when removing compressed air and cost of constructing facility
Wave or Tidal Power

• Conversion of the inherent energy in waves or tides into electricity from a variety of different methods
• Completed and proposed sites are in the North Sea, New Jersey, Hawaii, Scotland, England, Western Australia, and off the coast of Washington
• Advantages:
  – No fuel costs
  – No emissions impact
• Disadvantages:
  – Site issues concerning sea life
  – Unproven technology, long-term reliability concerns
• Costs estimates range from $400 to $1,700 per kW
Alternative Wind Technologies

There are several wind issues and technologies we are studying

• Marine based turbines – larger sizes, GE developing 5 MW plant
• New blade designs – shapes, sizes, and materials
  – Owens Corning E-Glass – 6% longer blades, 12% more power, and 20% less cost available in late 2006
• Flying wind turbines – placed into the jet stream up to 30,000 feet
• These issues will probably not result in a radical change in the wind industry, but will most likely improve efficiencies
Biomass Technologies

• Wood waste, landfill gas, and manure digesters are already included in the IRP, but wanted to cover some of the technology that is being developed

• Includes any crops that are converted into liquid fuels, such as biodiesel and ethanol

• Advantages:
  – Local economic benefits because of the distributed nature of production
  – Lower dependence on outside sources

• Disadvantages:
  – High costs due to the state of the technology and size of the industry
  – Substantial federal subsidies
  – Issues with removing crops from the food supply, especially with corn
  – Less energy dense than petroleum derived fuels – net energy benefits
Solar Energy

Photovoltaic resources are included in the IRP:

- Problems with using PV on a large scale due to high capital costs in excess of $7,000 per kW and capacity constraints
- Current manufacturing technologies have an energy payback of about 3 years, new technologies are projected to reduce this to 2 years
- PV has averaged 35% growth over the past 35 years, but still only provides about 0.1% of worldwide electric supply
- Benefits are free fuel and reductions in CO₂ – 1 kW of solar energy reduces CO₂ by 2,600 pounds per year
- New manufacturing technologies are aimed at lowering capital costs and boosting production capacity – 430 MW of solar cell production being developed in Silicon Valley
- GE is building a 150-acre solar project in Portugal
  - 52,000 PV cells for 11 MW at a price of $75 million
  - Portugal has a law requiring utilities to pay 0.31 Euros per kWh or about $0.40 per kWh in the US
Other Forms of Solar Energy

Solar Tower
- The tower works by concentrating heating the air which will move up the chimney at speeds of up to 35 miles per hour where wind turbines are stationed
- Originally planned for 200 MW on a 25,000 acre site with a 3,280 feet tall at a price of about $1 billion
- Recently scaled back to 50 MW with a 1,600 foot tall tower for $250 million ($5,000 per kW)
- A successful 50 kW prototype was constructed in Spain in 1982 and it operated until 1989

Solar Trough
- Uses parabolic mirrors to concentrate the sun’s energy to heat tubes of mineral oil to 250 to 550 degrees, which is run through a heat exchanger and then a turbine
- APS has a 1 MW plant in Arizona completed this year for $6 million
Modeling Overview: Emissions

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

John Lyons
Emissions in the IRP

Several emissions costs are being included in the Base Case for the 2007 IRP

- \( \text{CO}_2 \) – carbon dioxide, the primary greenhouse gas
- \( \text{SO}_2 \) – sulfur dioxide, causes acid rain, the Clean Air Act of 1990 capped at 8.9 million tons per year starting in 2008
- \( \text{NO}_x \) – nitrogen oxide, causes acid rain, the Clean Air Act of 1990 capped emissions at 2.0 million tons per year starting in 2008
- \( \text{Hg} \) – mercury; highly toxic; planned regulation by the federal government under a cap and trade program but many states are opting out of that program
Base Case – Greenhouse Gas Costs

Stochastic CO₂ Tax (Base Case)

- Average
- Min
- Max

$ per Ton

80% CI High
80% CI low

Years:
Base Case - SO₂ Emissions Costs

![Graph showing SO₂ emissions costs from 2008 to 2027. The graph includes data points for average, minimum, maximum, 80% CI high, and 80% CI low.](image-url)
Base Case – Stochastic NO\textsubscript{x} Costs

![Stochastic NO\textsubscript{x} Tax (Base Case) chart]

- **Average**
- **Min**
- **Max**
- **80% CI High**
- **80% CI low**

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Base Case – Stochastic Hg Tax

![Stochastic Hg Tax (Base Case)](chart)
Emission Costs - Nominal Dollars
IRP Modeling Overview: Resource Options and Cost Assumptions

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

John Lyons
Supply Side Options Included in Model

- Natural Gas Combined Cycle (CCCT)
- Natural Gas-Fired Simple Cycle (SCCT)
- Wind Turbine
- Coal Pulverized Subcritical
- Coal – Supercritical
- Coal – Ultracritical
- Coal – IGCC
- Coal – IGCC with Sequestration
- Geothermal
- Biomass
- Alberta Oil Sands
- Nuclear
- Co-Generation, Conservation, and Photovoltaics will be included in the final PRS
Natural Gas Combined Cycle (CCCT)

- **Type:** 2x1 Natural Gas-Fired Combined Cycle F Class Gas Turbine with Duct Burner
- **Size (MW):** 610
- **Heat Rate (Btu/kWh):** 6,790 (duct burner at 9,300)
- **Fuel Source:** Pipeline natural gas
- **Availability:** 2008
- **Capacity Factor:** 90.1%
- **Capital Cost ($/kW):** $744
- **Variable O&M ($/MWh):** $3.23
- **Fixed O&M (kW/Year):** $9.16
- **Emissions (lbs/mmbtu):** $SO_2 = 0.0001$ $NO_X = 0.011$ $CO_2 = 117$ $Hg = 0.000001$
- **Location Options:** Northwest
- **Production Tax Credit:** No
Natural Gas Simple Cycle (SCCT) Option 1

- **Type:** Two General Electric LM6000 Aero-Derivatives
- **Size (MW):** 94
- **Heat Rate (Btu/kWh):** 9,000
- **Fuel Source:** Pipeline natural gas
- **Availability:** 2008
- **Capacity Factor:** 93.7%
- **Capital Cost ($/kW):** $790
- **Variable O&M ($/MWh):** $9.25
- **Fixed O&M (kW/Year):** $9.16
- **Emissions (lbs/mmbtu):** \( \text{SO}_2 = 0.0001 \quad \text{NO}_x = 0.011 \quad \text{CO}_2 = 117 \quad \text{Hg} = 0.000001 \)
- **Location Options:** Northwest
- **Production Tax Credit:** No
Natural Gas Single Cycle (SCCT) Option 2

- **Type:** Industrial Frame Unit, Generic NPCC Industrial Machine
- **Size (MW):** 94
- **Heat Rate (Btu/kWh):** 10,500
- **Fuel Source:** Pipeline natural gas
- **Availability:** 2008
- **Capacity Factor:** 93.7%
- **Capital Cost ($/kW):** $494
- **Variable O&M ($/MWh):** $4.63
- **Fixed O&M (kW/Year):** $6.87
- **Emissions (lbs/mmbtu):** $SO_2= 0.0001$ $NO_X= 0.011$ $CO_2= 117$ $Hg= 0.000001$
- **Location Options:** Northwest
- **Production Tax Credit:** No
Wind Turbine

- **Type**: Central station wind power project
- **Size (MW)**: 100 (40 turbines)
- **Heat Rate (Btu/kWh)**: N/A
- **Fuel Source**: Wind
- **Availability**: 2008
- **Capacity Factor**: 22.2% - 35.9%
- **Capital Cost ($/kW)**: $1,600
- **Variable O&M ($/MWh)**: $6.00 - $10.00 (includes royalties and integration)
- **Fixed O&M (kW/Year)**: $17.50
- **Emissions (lbs/mmbtu)**: N/A
- **Location Options**: Northwest and Montana
- **Production Tax Credit**: Yes through 2014
Coal – Pulverized Subcritical

- **Type:** Pulverized Coal-Fired Subcritical Steam-Electric Plant
- **Potential Sizes (MW):** 180 – 1,000
- **Heat Rate (Btu/kWh):** 9,371
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2013
- **Capacity Factor:** 83.4%
- **Capital Cost ($/kW):** $1,758
- **Variable O&M ($/MWh):** $3.54
- **Fixed O&M (kW/Year):** $44.57
- **Emissions (lbs/mmbtu):** \( \text{SO}_2 = 0.12 \) \( \text{NO}_x = 0.07 \) \( \text{CO}_2 = 205 \) \( \text{Hg} = 0.00002 \)
- **Location Options:** Montana and Wyoming
- **Production Tax Credit:** No
Coal – Pulverized Supercritical

- **Type**: Pulverized Coal-Fired Supercritical Steam-Electric Plant
- **Size (MW)**: 350 – 1,000
- **Heat Rate (Btu/kWh)**: 8,955
- **Fuel Source**: Western Low-Sulfur Sub-Bituminous Coal
- **Availability**: 2013
- **Capacity Factor**: 83.4%
- **Capital Cost ($/kW)**: $1,848
- **Variable O&M ($/MWh)**: $3.50
- **Fixed O&M (kW/Year)**: $45.50
- **Emissions (lbs/mmbtu)**: $\text{SO}_2 = 0.12 \quad \text{NO}_X = 0.07 \quad \text{CO}_2 = 205 \quad \text{Hg} = 0.00002$
- **Location Options**: Montana and Wyoming
- **Production Tax Credit**: No
Coal – Pulverized Ultracritical

- **Type:** Pulverized Coal-Fired Ultracritical Steam-Electric Plant
- **Potential Sizes (MW):** 600 – 1,000
- **Heat Rate (Btu/kWh):** 8,825
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- ** Availability:** 2013
- **Capacity Factor:** 83.4%
- **Capital Cost ($/kW):** $1,854
- **Variable O&M ($/MWh):** $3.53
- **Fixed O&M (kW/Year):** $46.55
- **Emissions (lbs/mmbtu):** SO₂ = 0.12  NOₓ = 0.07  CO₂ = 205  Hg = 0.00002
- **Location Options:** Montana and Wyoming
- **Production Tax Credit:** No
Coal – Circulating Fluidized Bed

- **Type:** Coal-Fired Circulating Fluidized Bed Steam-Electric Plant
- **Potential Sizes (MW):** 50 - 450
- **Heat Rate (Btu/kWh):** 9,300
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2013
- **Capacity Factor:** 83.4%
- **Capital Cost ($/kW):** $1,758 - $1,854
- **Variable O&M ($/MWh):** $3.50 - $5.57
- **Fixed O&M (kW/Year):** $44.57 - $48.43
- **Emissions (lbs/mmbtu):** $O_2 = 0.55 \ NO_X = 0.18 \ CO_2 = 205 \ Hg = 0.00033$
- **Location Options:** Northwest, Montana, and Wyoming
- **Production Tax Credit:** No
Coal – IGCC

- **Type:** Coal-Fired Integrated Gasification Combined-Cycle with H-Class Turbine
- **Potential Sizes (MW):** 401 - 600
- **Heat Rate (Btu/kWh):** 8,131
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2013
- **Capacity Factor:** 82.3% - 85.3%
- **Capital Cost ($/kW):** $2,198 - $2,333
- **Variable O&M ($/MWh):** $2.83 - $2.91
- **Fixed O&M (kW/Year):** $53.57 - $54.98
- **Emissions (lbs/mmbtu):** \( \text{SO}_2 = 0.03 \) \( \text{NO}_x = 0.15 \) \( \text{CO}_2 = 205 \) \( \text{Hg} = 0.00000022 \)
- **Location Options:** Northwest, Montana, and Wyoming
- **Production Tax Credit:** No
Coal – IGCC with Sequestration

- **Type:** Coal-Fired Integrated Gasification Combined-Cycle with H-Class Turbine
- **Size (MW):** 490 gross and 401 net
- **Heat Rate (Btu/kWh):** 9,595
- **Fuel Source:** Western Low-Sulfur Sub-Bituminous Coal
- **Availability:** 2015
- **Capacity Factor:** 82.3% - 85.3%
- **Capital Cost ($/kW):** $2,814 - $2,987
- **Variable O&M ($/MWh):** $3.02 - $3.12
- **Fixed O&M ($/Year):** $63.21 - $64.87
- **Emissions (lbs/mmbtu):** SO₂ = 0.003  NOₓ = .015  CO₂ = 20.5  Hg = .000000022
- **Location Options:** Northwest, Montana, and Wyoming
- **Production Tax Credit:** No
Geothermal

- **Type:** Generic NPCC Unit
- **Size (MW):** 20
- **Heat Rate (Btu/kWh):** 15,000
- **Fuel Source:** Geological Steam
- **Availability:** 2008
- **Capacity Factor:** 92.3%
- **Capital Cost ($/kW):** $4,000
- **Variable O&M ($/MWh):** $2.00
- **Fixed O&M (kW/Year):** $70.00
- **Emissions (lbs/mmbtu):** N/A
- **Location Options:** Southern Idaho
- **Production Tax Credit:** Yes through 2014
Biomass

- **Type:** Wood Residue, Landfill, and Manure (Open Loop)
- **Size (MW):** 1 - 25
- **Heat Rate (Btu/kWh):** 12,000
- **Fuel Source:** Wood, Refuse, and Manure
- **Availability:** 2008
- **Capacity Factor:** 92.3%
- **Capital Cost ($/kW):** $3,500
- **Variable O&M ($/MWh):** $16.00
- **Fixed O&M (kW/Year):** $35.00
- **Emissions (lbs/mmbtu):** $\text{SO}_2 = \text{N/A} \quad $\text{NO}_x = \text{N/A} \quad $\text{CO}_2 = 720 – 1,116 \quad \text{Hg} = \text{N/A}$
- **Location Options:** Northwest
- **Production Tax Credit:** Yes through 2014
Alberta Oil Sands

- **Type:** Natural gas-fired 7F-class simple-cycle gas turbine plant
- **Size (MW):** 180
- **Heat Rate (Btu/kWh):** 6,500
- **Fuel Source:** Pipeline natural gas or Syngas
- **Availability:** 2013
- **Capacity Factor:** 90.1%
- **Capital Cost ($/kW):** $722 excluding transmission
- **Variable O&M ($/MWh):** $3.23
- **Fixed O&M (kW/Year):** $9.16
- **Emissions (lbs/mmbtu):** $SO_2 = 0.0001$  $NO_x = 0.011$  $CO_2 = 117$  $Hg = 0.000001$
- **Location Options:** Alberta
- **Production Tax Credit:** No
Nuclear

• **Type:** Advanced Nuclear Power Plant
• **Size (MW):** 1,100
• **Heat Rate (Btu/kWh):** 9,600
• **Fuel Source:** Natural uranium
• **Availability:** 2020
• **Capacity Factor:** 88.0%
• **Capital Cost ($/kW):** $1,992
• **Variable O&M ($/MWh):** $1.16
• **Fixed O&M (kW/Year):** $54.95
• **Emissions (lbs/mmbtu):** N/A
• **Location Options:** Northwest
• **Production Tax Credit:** No
Other Modeling Assumptions

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

James Gall
Modeling Overview

AURORAxmp

• North American electric market forecasting tool, it uses fundamental drivers to forecast electric prices
• Tracks value of existing Avista portfolio, as well as potential new portfolios of resources
• The AURORA database is updated to reflect proprietary company data and to reflect regional data not available to the vendor

What’s Best®

• Linear Program that is an Excel Add-in, used to optimize models. For this IRP, What’s Best is the engine used to solve for the Preferred Resource Strategy Model

@Risk

• Monte-Carlo/Stochastic Excel Add-in that allows for certain variables to be a distribution rather than a single point estimate, used to feed Emissions and Wind data into AURORA
New AURORA Features Utilized for this IRP

• New topology that separates the Northwest Region into eight separate areas with transmission limitations between each area

• Expanded use of Computational Datasets- Allows to run multiple user input iterations, with AURORA built in risk logic

• Operational Pools- Adds the ability for areas to share reserves (e.g. NWPP, CAISO)

• Hydro shaping is shaped to load net of wind generation.

• Transmission losses for individual generators are tracked

• Ability to build regional capacity to a planning margin (not used for draft)
Changes to Market Modeling Techniques

- Model random forced outages
- Use daily natural gas prices
- Modeling of emissions CO\textsubscript{2}, SO\textsubscript{2}, NO\textsubscript{x}, and Hg prices “taxes” stochastically
- Not modeling wind stochastically, but using hourly generation
- Use of AURORA risk functionality for load and natural gas prices
- Use market hub for pricing/resource evaluation (Mid Columbia/ area 92)
- Focus on resources that change market fundamental for price forecasting (i.e. CCCT, SCCT, coal, wind)
- 70-year median hydro generation is used for capacity expansion, and deterministic studies
AURORA Topology
Regional Hydro Modeling

• Uses 04/05 NWPP Headwater Study, with modifications for Canadian Hydro generation and lack of data from Montana.

• Although the data from NWPP study is large, still not all hydro generation is available and updated
  – Hydro capacity available from NWPP study:
    • NW: 99%
    • BC: 47%
    • Idaho: 85%
    • Montana: 79%

• What about the rest of the plants?
  – For BC, total BC hydro generation was available for part of the study, this data was correlated with available generation from NWPP study and generalized for all of the regions hydro
  – For Montana additional generations was available from Yellowtail to increase percent of accounted generation
  – According to NWPP some data within the model has not been updated recently- these are plants not part of the Columbia River or its tributaries these plants were not modified.
Hydro Capacity Factors

- All hydro units within an area share the same generation pattern.
- The bars are the median hydro generation levels used for the capacity expansion and deterministic studies.
- 10, 25, 75, and 90th percentiles are shown for a range in hydro generation used in stochastic studies.
Avista Hydro Generation

70-Year Hydro Generation for 2008 available generation

- Clark Fork: 325 MW
- Spokane: 129 MW
- Mid Columbia: ~93 MW
Stochastic Hydro

- Each hydro year is randomly drawn for each study year (2008-2027) and each of the 300 iterations
- This methodology attempts to create a uniform distribution of used hydro years of the available 70-year hydro study
Regional Load Growth
(Annualized Percent Growth)
Load Variability

- All areas modeled have variability component
  - Based on mean and standard deviations of monthly load
  - Uses 2002 to 2004 loads from FERC Form 714
- Each area is correlated to the Spokane area
  - Only areas with statistically significant correlations were included
  - Looked at each weekday separately to eliminate weekly trends
  - Averaged weekday results to obtain final values

![Western Interconnect Weighted Average Load](image)
Renewable Portfolio Standards

- Western States with Renewable Portfolio Standards (RPS)
  - California
  - Nevada
  - Arizona
  - New Mexico
  - Colorado
  - Montana
- Western States with pending RPS Regulation
  - Washington
  - Oregon
  - Arizona (higher standards)

Base Case includes current and proposed RPS regulations

Northwest Assumptions:
Oregon RPS is same as WA standard,
RPS affects only 90% of WA/OR Load

WA/OR RPS assumptions to be re-evaluated for final study
Wind Modeling

- Wind is modeled similar to that of the 2005 IRP, and uses for the most part the same data.
- Each wind region is modeled hourly.
- A wind model was created using @Risk to create hourly wind patterns using monthly capacity factors and standard deviations, with hourly correlations.
- Wind was not varied stochasticly for the draft study. The final study will use stochastic wind data for potential Avista projects.
  - This draft study assumption overstates wind’s ability to hedge our portfolio
Modeling Overview: Futures & Scenarios

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

John Lyons
Futures

- A future is stochastically or randomly modeled
- Avista’s IRP process models 21 years into the future with 300 Monte Carlo draws of hydro, load, natural gas prices, emissions, and thermal forced outage values
- The benefits of using futures lies in their ability to quantitatively assess market risks
- The disadvantages to using futures include the large amount of computational power needed for the exercise, as well as the difficulty of understanding the results of the exercise
- Each future takes about 2,700 hours of computing time and generates nearly 62 GB of data
Scenarios

- Scenarios are modeled by using average levels of hydro, load, gas prices, wind, emissions, and forced outages
- One or more variable is then changed
- Advantages for scenarios include quicker solution times and more understandable results due to the limited number of changes to underlying model assumptions
Uses of Futures and Scenarios

- Scenarios and futures are used to help understand the impacts and size of the impacts on a variety of different assumptions about the future on such things as:
  - Wholesale electric market
  - Different resource options
  - Avista’s current load & resource portfolio
  - The Preferred Resource Strategy
2007 IRP Market Futures (Stochastic)

- **Base Case** – assumes average hydro, gas, and load conditions
- **Zero Carbon Tax** – assumes no carbon tax is enacted
- **McCain/Lieberman Carbon Tax** – based on Climate Stewardship Act
- **More Volatile Natural Gas** – doubles the price volatility of gas
- **Shift in Gas (high) 50% up** – increases gas price escalation by 50%
- **Shift in Gas (low) 50% down** – decreases gas prices escalation by 50%
- **Increase WECC load escalation 50%** – WECC loads increase 50% faster than in the Base Case
- **Decrease WECC load escalation 50%** – WECC loads increase 50% slower than in the Base Case
2007 IRP Market Scenarios (Deterministic)

- **Unlimited Nuclear begin 2015** – model is allowed to build as much cost-effective nuclear power as possible
- **Electric Car** – assumes a surge in the number of plug-in cars and light trucks amounting to 10% penetration per year
- **Gas & Wind Build** – only gas and wind resource allowed to be constructed
- **Global Warming** – shifted weather conditions cause changes in the timing of the hydro run off
- **No Gas Plants after 2013** – does not allow the construction of new gas-fired plants after 2013
- **No WA/OR RPS** – assumes that the RPS is not passed in Oregon or Washington
Base Case vs. McCain & Lieberman CO\textsubscript{2} Tax

*Graph showing the comparison between Base Case Taxation and M&L Taxation from 2008 to 2027. The graph indicates a significant increase in taxation cost under the M&L Taxation scenario compared to the Base Case Taxation.*
Load Growth: Eastern Washington Energy

- **Base Case**
- **50% Higher Escalation**
- **50% Lower Escalation**
- **Electric Car**
Global Warming Scenario - NW Hydro CF

![Graph showing capacity factor with a label for +3.5% Energy]
Fuel Price Forecasts

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

James Gall
## Levelized Natural Gas and Coal Costs

<table>
<thead>
<tr>
<th></th>
<th>Nominal Price per Dthm</th>
<th>Real Price per Dthm</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Henry Hub NG</strong></td>
<td>$7.47</td>
<td>$6.31</td>
</tr>
<tr>
<td><strong>AECO NG</strong></td>
<td>$6.58</td>
<td>$5.56</td>
</tr>
<tr>
<td><strong>Sumas NG</strong></td>
<td>$6.73</td>
<td>$5.68</td>
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<tr>
<td><strong>Mine Mouth PRB Coal</strong></td>
<td>$0.38</td>
<td>$0.32</td>
</tr>
<tr>
<td><strong>Short Haul PRB Coal</strong></td>
<td>$0.76</td>
<td>$0.64</td>
</tr>
<tr>
<td><strong>Long Haul PRB Coal</strong></td>
<td>$1.42</td>
<td>$1.20</td>
</tr>
</tbody>
</table>

20-Year Levelized (2008 to 2027) shown in 2006 dollars
Methodology

- NYMEX forwards (6/15/2006)
- Long-term fundamentals based forecast (consultant)
- Prices after 2020 grow at 2019/20 growth rate
Intra Year Gas Prices

<table>
<thead>
<tr>
<th>Month</th>
<th>Percent of Annual</th>
<th>Month</th>
<th>Percent of Annual</th>
</tr>
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<tbody>
<tr>
<td>Jan</td>
<td>111%</td>
<td>Jul</td>
<td>95%</td>
</tr>
<tr>
<td>Feb</td>
<td>111%</td>
<td>Aug</td>
<td>96%</td>
</tr>
<tr>
<td>Mar</td>
<td>109%</td>
<td>Sep</td>
<td>95%</td>
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<td>Apr</td>
<td>96%</td>
<td>Oct</td>
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<td>May</td>
<td>94%</td>
<td>Nov</td>
<td>100%</td>
</tr>
<tr>
<td>Jun</td>
<td>95%</td>
<td>Dec</td>
<td>104%</td>
</tr>
</tbody>
</table>

Monthly Gas Shape: Consistent with 2006 Gas IRP, average of monthly forward prices available on July 1, 2005 (these prices were used to avoid hurricane related price skews). All gas prices use this monthly shape.

Daily Gas Shape: Average daily percent change from the monthly average price from 2003 to 2006 at AECO
Nominal Fuel Costs

- AECO
- Uranium
- Henry Hub
- Long Haul Coal
- Mine Mouth Coal
- Short Haul Coal

$ per mmBTU

$ per Ton


$0 $4 $8 $12 $16 $20 $24 $28 $32 $36 $40

$0 $4 $8 $12 $16 $20 $24 $28 $32 $36 $40
Basin Differentials/Gas Transportation

- Differentials are based on long-term forecast by a Consultant between 2008 and 2020, shown as a delta from Henry Hub
- Prices shown are a nominal levelized cost between 2008 & 2027, values are shown in 2006 dollars
- Differentials after 2020 use the rate of growth from 2019/20 for all time periods thereafter
Stochastic Gas

- How do we model uncertainty
- 300 independent monthly draws of a lognormal distribution using the gas forecast as the mean and a standard deviation of 50% of the mean.
- The example below is for January 2007
Historical Daily Sumas NG Prices
Historical Volatility (forward prices)

AECO Jan 2006 Forwards

Mean: $7.26
Stdev: $2.22

$9.23
Historical Volatility (forward prices)

AECO July 2006 Forwards

Mean: $6.03
Stdev: $1.59

$4.99

Supplemental - Section 1
Historical Volatility (forward prices)

Mean: $8.64  
Stdev: $1.51
Historical Volatility (forward prices)

AECO July 2007 Forwards

Mean: $6.99
Stdev: $1.14
IRP Modeling Overview: Preliminary Transmission Costs & Paths

2007 Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

Heidi Heath
Avista currently owns:

- 623 miles of 230 kV line
- 1537 miles of 115 kV line
- 11% interest in 495 miles of a 500 kV line coming from Colstrip
Miles of High-Voltage Transmission Lines

<table>
<thead>
<tr>
<th>Company</th>
<th>Miles</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pacifi Corp</td>
<td>15530</td>
</tr>
<tr>
<td>BPA</td>
<td>15342</td>
</tr>
<tr>
<td>Alberta</td>
<td>13132</td>
</tr>
<tr>
<td>BC Hydro</td>
<td>11185</td>
</tr>
<tr>
<td>Northwestern</td>
<td>7000</td>
</tr>
<tr>
<td>Idaho Power</td>
<td>4671</td>
</tr>
<tr>
<td>Sierra Pacific</td>
<td>2446</td>
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<tr>
<td>Avista</td>
<td>2169</td>
</tr>
<tr>
<td>PGE</td>
<td>815</td>
</tr>
<tr>
<td>SCL</td>
<td>657</td>
</tr>
</tbody>
</table>
Current and Planned Upgrades

- Reconstructed 230 kV line from Rathdrum to Spokane
- Constructed 230 kV Dry Creek substation near Clarkston, Washington
- Added 230-115 kV transformer bank at Boulder Substation for Spokane Valley Reinforcement
- Reconstructed Pinecreek 230 kV Substation
- Constructing 60 miles of 230 kV transmission line between Benewah and Shawnee substations to relieve congestion (Oct 2007)
- Increasing capacity of two 230 kV lines from Beacon substation to Bell substation (March 2007)
Other Upgrades in Avista’s Service Territory

- Bonneville recently upgraded the Coulee-Bell line, replacing the 115 kV line with a 500 kV line
- Bonneville recently relocated Bell lines running along Highway 395 in preparation for a new freeway in Spokane
- Bonneville is reconductoring and replacing poles on the Franklin-Walla Walla 115 kV line
Regional Transmission Issues

- Coordinated transmission planning
- RTO development and funding
- Cost allocation
- Wind integration issues
ColumbiaGrid RTO

• FERC Order 2000 requires transmission owners to develop and submit a proposal to establish an RTO, or to explain why such an organization cannot be developed.

• ColumbiaGrid formed March 31, 2006

• Avista is one of six founding members of ColumbiaGrid, with Puget Sound Energy, Seattle City Light, Grant County PUD, Chelan County PUD, and Bonneville Power Administration. Tacoma Power is also a member.
Transmission Modeling in the IRP

• Various locations for potential resources were studied by the transmission department
• Cost estimates currently use 2005 IRP data
• There are several issues and uncertainties regarding expansion of the transmission system:
  – Firm transmission capacity is scarce in many areas so integrating large-scale resources will be difficult
  – No comprehensive regional planning process for transmission expansion issues
  – BPA is unable to finance new transmission construction due to restrictions on federal borrowing authority
  – Multi-jurisdictional siting and permitting issues exist for new large-scale transmission expansion
Generation Integration Cost Estimates

• Transmission data from the 2005 IRP used for this study

• Updated estimates will be provided for the final 2007 IRP
Eastern Montana

350 MW – probably not available
- 500 kV series capacitors and other upgrades
- $100 million

750 MW
- 500 kV series capacitors, 230 kV upgrade in eastern Washington
- $400 million

1000 MW
- Major 500 kV facilities
- $1.5 billion
Mid-C Projects

Includes all projects delivering power at Mid-C (wind, nuclear, oil sands, etc.)

350 MW
  • $100 million

750 MW
  • $150 million

1000 MW
  • $800 million
Southern Washington

Currently 115 kV, planned upgrade to 230 kV in 2007

350 MW
  • Little new transmission required, $10 million

750 MW
  • 230 kV reinforcement, $80 million

1000 MW
  • Major 500 kV facilities required, $1.5 billion
Northern Idaho

Currently 230 kV line

350 MW
- Little new transmission required, $10 million

750 MW
- 230 kV reinforcement, $70 million

1000 MW
- Major new 500 kV facilities required, $1.5 billion
West of Spokane

Currently 115 kV line, suitable for integration of 40-50 MW

350 MW
• New 230 kV double circuit line required, $50 million

750 MW
• Additional upgrades required, $100 million

1000 MW
• Major new 500 kV facilities required, $1.5 billion
Alberta Oil Sands

Several options: AC or DC lines, delivery at Bell or Mid-C

Courtesy of NTAC
Alberta Oil Sands

• For current study $2.445 billion was the assumed cost of the line to bring power from Fort McMurray to the Northwest

• The Northwest Transmission Assessment Committee recently studied several transmission options. Prices are estimated to be between ~1 billion to ~2 billion. Consideration will be given to these prices in the final report.
Future Resource Requirements

2007 Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

Heidi Heath
Future Resource Requirements

- New resource requirements are determined by the net balance of expected loads and resources.
- Energy and capacity values for expected loads and resources are calculated twenty years into the future and are included in Planning L&R’s.
- First deficit expected for energy and capacity in 2011
## Energy Loads and Resources

### REQUIREMENTS

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<td>System Load</td>
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<td>1,161</td>
<td>1,194</td>
<td>1,226</td>
<td>1,252</td>
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<td>1,302</td>
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<td>Contract Obligations</td>
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<td>60</td>
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<td>Total Requirements</td>
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<td>1,254</td>
<td>1,286</td>
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<td>1,361</td>
<td>1,380</td>
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### RESOURCES

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<td>Base Load Thermals</td>
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<td>242</td>
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<td>Gas Dispatch Units</td>
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<td>294</td>
<td>284</td>
<td>294</td>
<td>279</td>
<td>294</td>
<td>284</td>
<td>295</td>
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<tr>
<td>Total Resources</td>
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<td>1,266</td>
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<td>1,219</td>
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<td>1,194</td>
<td>1,173</td>
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### POSITION

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<td>(20)</td>
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### CONTINGENCY PLANNING

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<td>44</td>
<td>(70)</td>
<td>(152)</td>
<td>(158)</td>
<td>(191)</td>
<td>(215)</td>
<td>(268)</td>
<td>(259)</td>
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Energy L&R – Annual Resource Capability

![Graph showing resource capability over years with various categories like Hydro, Base Thermal, Contracts, Gas Dispatch, Peakers, and Load w/ CI.](image-url)
# Energy L&R – Annual Resource Capability

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<th>2009</th>
<th>2010</th>
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<th>2027</th>
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<td><strong>Load w/ CI</strong></td>
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<td>1,444</td>
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<td>-380</td>
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Energy L&R – First Quarter Resource Capability

![Graph showing resource capability from 2008 to 2017 for Hydro, Base Thermal, Contracts, Gas Dispatch, Peakers, and Load w/ CI.](image-url)
Energy L&R – Second Quarter Resource Capability
Energy L&R – Third Quarter Resource Capability
Energy L&R – Fourth Quarter Resource Capability
Energy L&R – Annual Capability Without Q2

- Hydro
- Base Thermal
- Contracts
- Gas Dispatch
- Peakers
- Load w/ CI

Years: 2008 to 2018
### Energy L&R – Annual Capability Without Q2

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# Capacity Loads and Resources

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Capacity L&R – Annual Resource Capability

- Peakers
- Gas Dispatch
- Contracts
- Base Thermal
- Hydro
- Load w/ Planning Reserve

Years: 2008 to 2018
## Capacity L&R – Annual Resource Capability

<table>
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<tr>
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<th>2009</th>
<th>2010</th>
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<th>2012</th>
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<th>2027</th>
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<tr>
<td><strong>Hydro</strong></td>
<td>1,142</td>
<td>1,154</td>
<td>1,121</td>
<td>1,128</td>
<td>1,084</td>
<td>1,098</td>
<td>1,056</td>
<td>1,070</td>
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<tr>
<td><strong>Base Thermal</strong></td>
<td>280</td>
<td>280</td>
<td>280</td>
<td>280</td>
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<td>280</td>
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<tr>
<td><strong>Gas Dispatch</strong></td>
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<td>308</td>
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<td>308</td>
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<tr>
<td><strong>Peakers</strong></td>
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<td>243</td>
<td>243</td>
<td>243</td>
<td>243</td>
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<td><strong>Total Resources</strong></td>
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<td>-109</td>
<td>-213</td>
<td>-375</td>
<td>-586</td>
<td>-794</td>
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</table>
Adjustments

- L&R adjustments from 2005 IRP:
  - Load forecast – updated in July
  - Confidence interval updated
  - Hydro upgrades
  - Updated contracts (small power, wind, Upriver)
  - Added Thompson River Co-Gen project
  - Hydro forecast changed, going from a 60-year historical model to a 70-year historical model
Fundamental Modeling
Futures and Scenarios

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 31, 2006

James Gall
Base Case: Mid-C Annual Average Prices

- Deterministic
- Mean
- 80% CI Low
- 80% CI Low
- Min
- Max

Years: 2008 to 2027
Prices: $150 to $-
No CO₂ Tax Future: Mid-C Annual Average Prices

The graph shows the projected annual average prices for CO₂ without a tax in the Mid-C region from 2008 to 2027. The lines represent different scenarios:

- Red line: Deterministic
- Blue line: Mean
- Black line: 80% CI Low
- Gray line: Min
- Green line: Max

The y-axis represents the price range from $0 to $150, while the x-axis represents the years from 2008 to 2027.
Cost of CO₂ Taxation to Market (~$4.50)

Mid Columbia Market Prices

$ per MWh

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</tbody>
</table>

- Base Case
- No CO2
Mid Columbia Market Volatility

**CO₂ Taxes Reduce Volatility?**

- **Coefficient of Variation**
- **Base Case**
- **No CO₂**

Year: 2008 to 2027
Western Interconnect Total Fuel Cost in Billions
(Does Not Include Emission Taxes)

Note: Electric Car Scenario reduces gasoline and diesel costs by approximately $850 billion NPV, resulting in a net societal benefit of ~$550 billion.
Mid C Electric Prices For All Studies

- No CO2 Tax
- No Gas after 2013
- No Coal
- No RPS
- ML/EIA CO2 Tax
- Global Warming
- Nuclear Okay
- Electric Car
- High Gas Prices
- Low Gas Prices
- Base Case
- Low Load Growth
- High Load Growth

$/MWh

We answer to you.

Electric Car Scenario does not include offsets from reduced gasoline/diesel consumption.
Western Interconnect Resource Selection: Base Case

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT

The chart shows the projected resource selection for Western Interconnect, specifically in the Base Case scenario. Key resources such as nuclear, wind, and various types of IGCC (Integrating Gasification Combined Cycle) plants are visualized over a period from 2008 to 2027. The graph indicates a gradual increase in the generation capacity attributed to these resources, highlighting the evolving energy landscape and strategic planning for future energy demands.
Western Interconnect Resource Selection: M&L CO2 Tax

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT

aMW

Western Interconnect Resource Selection: No Gas Build after 2013

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT
Western Interconnect Resource Selection: No NW RPS

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT

Year:
- 2008
- 2009
- 2010
- 2011
- 2012
- 2013
- 2014
- 2015
- 2016
- 2017
- 2018
- 2019
- 2020
- 2021
- 2022
- 2023
- 2024
- 2025
- 2026
- 2027

aMW:
- 0
- 10,000
- 20,000
- 30,000
- 40,000
- 50,000
- 60,000
- 70,000
- 80,000
- 90,000
- 100,000
Western Interconnect Resource Selection: Global Warming Begin 2008

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT

aMW

Western Interconnect Resource Selection: No Coal Build

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT

0 10,000 20,000 30,000 40,000 50,000 60,000 70,000 80,000 90,000 100,000

aMW

Western Interconnect Resource Selection: Low Gas Price Escalation

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT

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Western Interconnect Resource Selection: High Gas Price Escalation

- **Nuclear**
- **Wind**
- **IGCC Seq**
- **IGCC**
- **Pulverized**
- **SCCT**
- **CCCT**

The graph shows the projected available megawatts (aMW) for various energy resources from 2008 to 2027, with a high gas price escalation scenario.
Western Interconnect Resource Selection: Low Load Growth (50% Lower)

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT

aMW

0  10,000  20,000  30,000  40,000  50,000  60,000  70,000  80,000  90,000  100,000

Western Interconnect Resource Selection: High Load Growth (50% Higher)

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT
Western Interconnect Resource Selection: Electric Car Shift

- Nuclear
- Wind
- IGCC Seq
- IGCC
- Pulverized
- SCCT
- CCCT

Chart showing the projected increase in electric car shift in aMW from 2008 to 2027.
Preliminary PRS Discussion

2007 Electric Integrated Resource Plan
Second Technical Advisory Committee Meeting
September 1, 2006

James Gall & Clint Kalich
## Prior Preferred Resource Strategies

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Preferred Resource Strategy (PRS) Model

- Linear program that optimizes cost and risk of Avista’s current electric portfolio of resources with potential resources to meet the Company’s expected load growth
- Developed internally by Avista using MS Excel and an Add-in What’s Best® to perform the solving function
- Mark to market resource values from AURORA are uploaded into the model for each potential resource and for all 300 iterations
- The model’s objective function is to optimize net position deficits given resource constraints such as availability, time to construct, G & T capital costs, fixed and variable O&M, emissions, renewable certificates, tax credits, other transmission costs, market value and fuel costs
Constraints

Resource

– Coal
  • Available after 2013
  • no NW pulverized
– Alberta Oil Sands
  • Available after 2013-no minimum constraint
– Wind
  • Columbia Basin: 200MW Tier 1, 100 MW Tier 2
  • Montana: No Constraints
  • Avista Service Territory Area: 200MW Tier 1, 200 MW Tier 2
  • 100MW limitation per year, 650 MW Total (including 100 MW RFP)
  • Capacity Contribution is 10%
– Other Renewables
  • Limited to 80MW first 10 Years and 160MW over 20-year horizon
– Nuclear available after 2025

Other Constraints

– Model builds to no more than 25 MW over capacity need
– Energy constraint is a minimum, therefore Avista will be energy long
– DSM will be updated for final study, uses 2005 IRP assumptions
Resource Needs and Build-Out

- Energy Need
- Capacity Need
- Energy Built
- Capacity Built

megawatts (average)

- 2008
- 2009
- 2010
- 2011
- 2012
- 2013
- 2014
- 2015
- 2016
- 2017
- 2018
- 2019
- 2020
- 2021
- 2022
- 2023
- 2024
- 2025
- 2026
- 2027
DRAFT Resource Selection

- Avista is seeking guidance on the development of a 2007 Integrated Resource Plan (IRP) to forecast resource needs for the next twenty years.
- Resources shown on the following slides are a “DRAFT” set of resources that were found economic in the preliminary studies of the IRP to meet future load deficits, the final resource selection for the 2007 IRP will be available the summer of 2007.
- Avista is NOT actively pursuing any of the resources at this time, with exception of 100MW of wind identified in the 2005 IRP
- The final Preferred Resource Strategy may or may not include the resource on the following pages
# Prior Preferred Resource Strategies (Energy)

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* Includes 100MW of RFP Wind
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## Base Case: PRS Model Details

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New Resource Mix (2017 & 2027)

Resource Mix 2017, Nameplate
(MW)

- Wind, 200
- CCCT, 124
- Coal, 66
- Oil Sands, 20
- Other Renew., 80

Resource Mix 2027, Nameplate
(MW)

- Wind, 200
- CCCT, 124
- Coal, 66
- Nuclear, 114
- Oil Sands, 322
- Other Renew., 160
We answer to you.

50% Cost/ 50% Risk Resource Strategy (Capacity)

- Market
- Wind (10%)
- Other Renew
- SCCT
- CCCT
- Nuclear
- Oil Sands
- Seq Coal
- IGCC Coal
- Traditional Coal
- RFP Wind (10%)
- DSM
We answer to you.

50% Cost/ 50% Risk Resource Strategy (Energy)

- Market
- Wind
- Other Renew
- SCCT
- CCCT
- Nuclear
- Oil Sands
- Seq Coal
- IGCC Coal
- Traditional Coal
- RFP Wind
- DSM
Efficient Frontier

- No Additions
- 25% Risk, 75% Cost
- All CCCT
- 50% Coal, 50% CCCT
- 50% Risk, 50% Cost
- No CO2 Tax
- 75% Risk, 25% Cost
- 75% Risk, 25% Cost
- All Renewables

2008-17 Net Present Value

2017 Standard Devation

No Additions
Efficient Frontier Comparison
40% to 60% NPV Weighting

NPV Weighting

0%
5%
10%
15%
20%

0%
5%
10%
15%
20%

0%
5%
10%
15%
20%

Wind Nameplate (MW)

0
50
100
150
200
250
300
350

Supplemental- Section 1
# No CO2 Taxation: PRS Model Details

## Summary Stats for Scenario

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# Wind Capital Cost Sensitivities

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## Avista Utilities 2007 Integrated Resource Plan
### Technical Advisory Committee Meeting No. 3 Agenda
#### Wednesday January 10, 2007

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2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting

January 10, 2007

**Topic**
- Review & Feedback of 2nd TAC
- Draft PRS Review
- Fuel Price Forecast
- Clean Coal Technologies
- Emissions Update
- Load Forecast
- Conservation

**Presenter**
- Lyons
- Gall/Lyons
- Christie/Gall
- Lyons
- Lyons
- Barcus
- Folsom & Powell
Review & Feedback: Second TAC Meeting

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

John Lyons
TAC Meeting #2 – August 31, 2006 & September 1, 2006

- All of the past TAC meeting notes are available on the Avista web site
- Reviewed 2005 Action Plan
- IRP Modeling Overview
- Lunch presentations on the 2006 Renewables RFP and Alternative Energy Future
- Future resource requirements
- Review of preliminary futures and scenarios market results
- Review of the preliminary Preferred Resource Strategy
Questions from TAC Meeting #2

- Editorial updates to several slides for clarification – done on web site
- Gas basin differentials – covered in the Fuel Price Forecast later today
- Continue to work on increasing attendance – additional phone calls and emails

The following will be included in the final 2007 IRP:

- Highlight the efficient frontier model in the 2007 IRP
- Determine the amount of conservation needed to defer new coal or a CT
- Verify that Northwest utilities are not going after the same wind supply curve
- Determine how much of a resource cushion is needed or is acceptable
- Regional wind resource adequacy
- Address the free rider problem associated with not adding resources
- Include a thorough discussion of our definition of risk
- Utilizing a probability distribution for CO₂ in the Base Case
Draft Preferred Resource Strategy Review

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

James Gall & John Lyons
Resource Needs and Build-Out

- Energy Need
- Capacity Need
- Energy Built
- Capacity Built

megawatts (average)

### DRAFT Preferred Resource Strategies (Energy)

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* Includes 100 MW of RFP Wind
DRAFT New Resource Mix (2017 & 2027)

Resource Mix 2017, Nameplate (MW)
- Wind, 200
- CCCT, 124
- Coal, 66
- Other Renew., 80
- Oil Sands, 20

Resource Mix 2027, Nameplate (MW)
- Wind, 200
- CCCT, 124
- Coal, 66
- Nuclear, 114
- Other Renew., 160
- Oil Sands, 322

* Does not include the 100 MW of RFP wind
We answer to you.

50% Cost/ 50% Risk Resource Strategy (Energy)

- Market
- Wind
- Other Renew
- SCCT
- CCCT
- Nuclear
- Oil Sands
- Seq Coal
- IGCC Coal
- Traditional Coal
- RFP Wind
- DSM

average megawatts

0 100 200 300 400 500 600 700 800 900 1,000

# Base Case: DRAFT PRS Model Details

## Summary Stats for Scenario

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Incremental Avg $/MWh over Market for Resource Portfolios

- 100/0 Cost Risk
- 75/25 Cost Risk
- 50/50 Cost/Risk
- 25/75 Cost Risk
- 0/100 Cost Risk

Levelized Cost

$/MWh


Incremental Avg $/MWh over Market for Resource Portfolios
Fuel Price Forecast

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

Kevin Christie & James Gall
## Levelized Natural Gas and Coal Costs

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## Forecast Assumptions

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<td>$ 6.39</td>
<td>$ 5.29</td>
<td>$ 5.33</td>
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<td>US Economic Growth (% GDP)</td>
<td>3.50%</td>
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<td>3.20%</td>
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<tr>
<td>US Gas Demand (bcf/d)</td>
<td>60.52</td>
<td>65.86</td>
<td>68.27</td>
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<tr>
<td>EG Demand (bcf/d)</td>
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<td>WTI Oil Price (2005$)</td>
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<td>$ 50.52</td>
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<tr>
<td>US Gas Prod. (bcf/d)</td>
<td>51.53</td>
<td>52.45</td>
<td>49.77</td>
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<td>LNG Imports (bcf/d)</td>
<td>1.61</td>
<td>5.82</td>
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<td>Net Imports (bcf/d)</td>
<td>8.25</td>
<td>7.60</td>
<td>8.22</td>
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<td>Mackenzie Delta Pipeline</td>
<td>In service 2014</td>
<td>In service 2012</td>
<td></td>
</tr>
<tr>
<td>Alaska Pipeline</td>
<td>In service 2020</td>
<td>In service 2017</td>
<td>In service 2018</td>
</tr>
</tbody>
</table>
Methodology

- NYMEX forwards (1/03/2007)
- Long-term fundamentals based forecast (consultant)
- Prices after 2020 grow at the last 5 years average growth rate
## Intra Year Gas Prices

**Daily Gas Shape:** Average daily percent change from the monthly average price from 2003 to 2006 at AECO

<table>
<thead>
<tr>
<th>Month</th>
<th>Percent of Annual</th>
<th>Month</th>
<th>Percent of Annual</th>
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<tr>
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<td>Jul</td>
<td>93%</td>
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<td>Feb</td>
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<td>96%</td>
</tr>
<tr>
<td>May</td>
<td>92%</td>
<td>Nov</td>
<td>101%</td>
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<tr>
<td>Jun</td>
<td>92%</td>
<td>Dec</td>
<td>106%</td>
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</tbody>
</table>

**Monthly Gas Shape:** Consistent with 2006 Gas IRP methodology where the monthly shape is calculated by the average of monthly forward prices available on January 3, 2007. All gas prices use this monthly shape.
Basin Differentials/Gas Transportation

- Differentials are percent of Henry Hub, based on the average basin differential from a historical perspective.
Draft IRP Gas Price Forecast vs Final Gas Price Forecast (levelized price increased from $7.47 to $7.83)
Other NW Utilities IRP Gas Price Methodology

- **Avista (2005):** Blend of Forward Prices and Global Insights
- **Avista Natural Gas (2006):** Multiple scenarios utilizing forward prices and various consultants
- **Avista (2007):** Blend of Forward Prices and Consultant Forecast
- **Puget Sound Energy (2007):** Forward Prices and Global Insights
- **PacifiCorp (2006/07):** Forward Prices and PIRA
- **Idaho Power (2006):** weighted average of NYMEX, PIRA, EIA, NWPCC, and US Power Outlook
- **Portland General Electric (2006/07):** Forward Prices and PIRA
Stochastic Natural Gas- Modeling Uncertainty

- 300 iterations, lognormal distribution drawn monthly with serial correlation (78%). The mean is the gas price forecast and the standard deviation is 50% of the mean.
- Another study will be performed using a higher/lower standard deviation
Coal Prices

![Graph showing coal prices from 2008 to 2027. The graph includes three categories: Mine Mouth (PRB), Short Haul (250 Miles), and Long Haul (1000+ Miles). The prices are depicted in dollars per ton. The Mine Mouth price remains relatively constant, while the Short Haul and Long Haul prices show an increasing trend over the years.](image)
Clean Coal Technologies

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

John Lyons
What is clean coal?

• “Clean coal technology describes a new generation of energy processes that sharply reduce air emissions and other pollutants from coal-burning power plants.” – US DOE

• Clean coal technologies are aimed at increasing efficiencies and reducing sulfur dioxide (SO$_2$), nitrogen oxides (NOx), particulates, and greenhouse gases (mainly CO$_2$)

• There are four classes of clean coal technologies:
  – Precombustion technologies
  – Advanced combustion technologies
  – Postcombustion technologies
  – Conversion technologies

• Clean coal technologies come from several different disciplines and often result in multiple revenue stream possibilities, so more than electric generation needs to be considered
Classes of Clean Coal Technologies

• Precombustion Technologies
  – Coal washing to remove ash, sulfur, and other impurities
  – Lowers costs of reducing SO₂ emissions as a combination technology

• Advanced Combustion Technologies
  – New technologies to retrofit or construct new pulverized coal plants
  – Atmospheric and pressurized fluidized bed combustion – reduce SO₂ 95%
  – Higher pressures result in lower operating temperatures, smaller boilers, and higher generating efficiencies

• Postcombustion Technologies
  – Retrofits to the stacks of existing plants to remove SO₂ and NOx
  – Greatest potential for plants that have few current environmental controls

• Conversion Technologies
  – Technologies to convert coal into a gas or liquid fuel
  – Integrated Gasification Combined Cycle or IGCC
Categories or Ranks of Coal

1. Lignite – soft with a high moisture content
   • 25 – 35% carbon and 4,000 – 8,300 btu/lb

2. Subbituminous – medium-soft with less moisture than lignite
   • 35 – 45% carbon and 8,300 – 13,000 btu/lb

3. Bituminous – medium-hard, low moisture and high heat value
   • 45 – 86% carbon and 10,500 – 15,500 btu/lb

4. Anthracite – hard coal, high carbon, low moisture & ash
   • 86 – 98% carbon and 15,000 btu/lb
IGCC

- IGCC removes pollutants before they go up the stack
  - SO₂ and NOx is reduced by over 95%
  - Generating efficiencies increase 40 – 45%, which reduces CO₂ emissions
  - There are four operational plants, but the technology is still developing
  - IGCC has higher capital and O&M costs, which are partially offset by operating efficiencies
  - Can use petroleum residues, coal, or even biomass as a feedstock
- FutureGen is the $1 billion initiative to construct “the world's first zero-emissions fossil fuel plant”
  - 275 MW prototype to produce hydrogen and electricity with zero emissions
  - Will be first plant to capture and sequester CO₂
  - Selected sites in Illinois and Texas as the finalists for the project
Carbon Capture and Sequestration

• Carbon capture refers to the technologies to keep CO₂ emissions from fossil fuel generation from being released into the atmosphere. Sequestration is the long-term or permanent storage of the CO₂.

• DOE programs are looking for technologies that are:
  – Effective and cost-competitive,
  – Stable and long term
  – Environmentally benign

• Sequestration is divided into geologic, ocean, terrestrial, and other categories
Geologic Sequestration

- Geologic sequestration involves pumping compressed CO₂ into the earth
- Several different types of geologic forms are well suited for geologic sequestration
- Oil and Gas Reservoirs
  - Can help recover oil or natural gas – which makes it a revenue stream
  - US uses about 32 million tons of CO₂ per year for enhanced oil recovery
  - Well understood, studied, and highly stable form of sequestration
- Coal Bed Methane
  - Inject CO₂ instead of pumping water out to depressurize the coal bed
  - Has been successfully field tested, but not commercially utilized yet
- Saline Formations
  - Pump CO₂ into deep saline formations which may store up to 500 billion tons of CO₂
  - Statoil is injecting approximately one million tons of recovered CO₂ into an underwater saline formation – equals the output of a 150 MW coal plant
Ocean Sequestration

- Ocean sequestration uses the CO$_2$ absorbing power of the ocean
- Oceans can absorb 80 – 90% of atmospheric CO$_2$ but it takes a long time to transfer to the ocean depths
- Research into trying to speed this process in one of two ways:
  - Enhancement of the natural carbon sequestration of the ocean
    - 64 sq km region added trace iron and increased CO$_2$ levels
  - Direct Injection of CO$_2$ into the deep ocean
Terrestrial Sequestration

- Terrestrial sequestration occurs when atmospheric CO₂ is stored in biomass or the soil
- Sequestration in soil or vegetation can handle about 1/3 of all human generated CO₂ or 2 billion tons of carbon annually
- Three general means of reducing GHG with terrestrial sequestration
  1. Maintain existing carbon storage in trees and soils
  2. Increase carbon storage by increased planting and improving tillage practices
  3. Substituting bio-based fuels and products for fossil fuels
Other Sequestration Technologies

- Advanced Chemical and Biological Approaches
- Recycling CO₂ with chemical or biological conversion
- May help eliminate the need to purify or compress the CO₂ for geologic sequestration, which uses more energy
- Genetic manipulation of plants and trees to enhance carbon sequestration potential
- Use of tubes of algae as a filter for CO₂ – algae is eventually turned into biodiesel
- Jupiter Oxygen is testing its Oxy-fuel technology on a $34 million retrofit of a small coal plant
  - Initial reports show a 95% CO₂ capture rate, 90% removal of all mercury, 99+% sulfur removal, 99+% particulate capture, more than 80% of the PM 2.5 particulate, and .088 Lbs/ MMBtu of NOₓ
Emissions Update

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

John Lyons
Emissions Modeling in the IRP

Emissions cost included in the 2007 IRP Base Case:

- CO₂ – utilizing a distribution of NCEP, Climate Stewardship Act, and no legislation for each of the 300 draws

- SO₂ – $812/ton in 2007 and $2,717/ton in 2030 (nominal)

- NOx – $2,237 in 2010 and $4,127/ton in 2030 (nominal)

- Hg – $1,748/ounce in 2010 and $5,158/ounce in 2030 (nominal)
Emissions Modeling

- Hg, SO$_2$, and NOx are being modeled using a log normal distribution

- CO$_2$ is being modeled based on a probability distribution for each of the 300 iterations:
  - 50% probability of NCEP
  - 15% probability of 25% below the NCEP
  - 15% probability of 25% above the NCEP
  - 10% probability of no CO$_2$ legislation
  - 5% probability of 50% of EIA/Climate Stewardship Act
  - 2% probability of 80% below the NCEP
  - 2% probability of 80% higher than the NCEP
  - 1% probability EIA/Climate Stewardship Act
Emission Costs – Nominal Dollars

- SO2 per Ton
- NOx per Ton
- Hg per Ounce
- CO2 per 100 Tons
National Emissions Developments

• Mercury Legislation
  – Clean Air Mercury Rule (CAMR) set permanent caps reduced and mercury reduction goals from coal-fired power plant emissions
  – CAMR allows for optional state participation in a national mercury trading allowance program
  – States are allowed to determine if allocations are granted or auctioned

• Proposed National Greenhouse Gas Legislation
  – Senator Reid has introduced S. 6, the National Energy and Environment Security Act of 2007
  – Promoting multiple energy ideas including risk reduction for global warming
Other Emissions Developments

• Joint Action Framework on Climate Change
  – Signed 12/1/06 by California, New Mexico, Oregon, and Washington
  – Provides for state PUC collaboration on energy efficiency, carbon capture & sequestration, and renewable energy

• Boulder, Colorado
  – First US tax specifically on carbon emitting fossil fuels
  – Adds approximately $1.33 to $3.80 to monthly electric bills
  – Funds are earmarked for investments in renewable energy, and efficiency improvements for buildings and transportation
  – Estimated to reduce GHG 7% below 1990 levels by 2012

• Northeastern Regional Greenhouse Gas Initiative
  – Develop a regional cap-and-trade program with a market-based emissions trading system
  – Will require electric power generators to reduce CO₂ emissions
Washington Emissions Developments

• Mercury Legislation – Proposed
  – 0.0087 lb/GWh all sources in 2013
  – All plants must be compliant by 2017
  – Possible trading for the first 3 years
  – 70% to existing source, 5% new source, 25% supplemental

• Proposed Greenhouse Gas Legislation
  – Establish a greenhouse gas performance standard for base load fossil-fueled electric generation facilities before 7/1/08
  – 2004 CO₂ mitigation requirement for new generation is still in effect
Idaho Emissions Developments

• Mercury Legislation
  – Has no state budget for mercury under CAMR
  – Has decided not to participate in the cap-and-trade program.
  – Has reserved the right to opt in to the cap-and-trade program at a later date after assessing energy needs.

• Greenhouse Gas Legislation
  – Has no active GHG legislation
Montana Emissions Developments

• Mercury Legislation
  – Montana Board of Environmental Review approved final adoption of the Montana Mercury Rule on 10/16/06
  – Established an emission limit of 0.9 lbs/TBtu for facilities using sub bituminous coal, and 1.5 lbs/TBtu for plants firing lignite, both on a rolling 12-month average
  – Temporary alternate emission limits can be applied for, but decrease in 2018
  – Requires a review of each plant every decade
  – Proposed new unit set-aside of 75% until 2018 and 30% thereafter.

• Greenhouse Gas Legislation - Pending
  – Montana Global Warming Solutions Act
  – 1/1/10 – identify, report, verify all sources of GHG emissions
  – 1/1/10 – determine 1990 emissions levels and set limit to be achieved by 2020
  – Set new recommendations before 1/1/19 for 2020 and beyond
  – 1/1/11 – identify “maximum technologically feasible and cost-effective reductions from sources or categories of source of greenhouse gases by 2020”
Oregon Emissions Developments

• Mercury Legislation - Proposed
  – 90% or 0.60 lbs/TBtu by July 1, 2012 with possible one-year extension
  – Allowing for compliance alternative if targets are not met with best available controls
  – Four possible trading options under consideration

• Greenhouse Gas Legislation – in development
  – Developing a detailed report by the end of 2007
  – Stabilize by 2010 – all GHG, not just CO₂
  – 10% below 1990 levels by 2020
  – 75% below 1990 levels by 2050
California Emissions Developments

- Mercury Legislations
  - Considering a more stringent rule than CAMR

- Greenhouse Gas Legislation
  - AB32 – Global Warming Solutions Act: caps state CO₂ at 1990 levels by 2020 with enforceable penalties (~ 25% reduction)
  - SB1368 – CEC directed to set GHG standards for electricity produced within the state and purchases from outside of the state
  - SB107 – Investor owned utilities mandated to obtain 20% of power from renewables
Avista Emissions Developments

• The core group of the Avista Climate Change Committee has been meeting on a consistent basis
  – Reviewing other organizations climate change policies
  – Writing a draft climate change statement
  – Designing a climate change section for our web site
  – Providing educational pieces to all employees in company newsletters
Avista’s 2007 Load Forecast

2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007

Randy Barcus
randy.barcus@avistacorp.com
(509) 495-4160
We answer to you.

**Net Native Load**

- **Growth rates**
  - 5 yr = 2.8%, 10 yr = 2.4%

- **Forecast 2007-2017**

- **Actual 1997-2005**

- **2006 is 10 months actual, 2 months forecast**

- **Average MW including losses**

```
Average MW including losses
900 1,000 1,100 1,200 1,300 1,400 1,500
```

**Legend:**
- F2007Nov
- F2006
- F2005
- F2004
Supplemental- Section 1

We answer to you.
Native Load Forecast
Load (MW)
BOLD Actual

1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030

F2007
Annual Avg
929
954
988
1,012
964
994
1,013
1,021
1,045
1,060
1,091
1,124
1,163
1,196
1,229
1,255
1,274
1,306
1,325
1,358
1,379
1,399
1,426
1,449
1,477
1,497
1,518
1,556
1,582
1,606
1,626
1,646
1,674
1,699

2007-2012 growth rate
2007-2017 growth rate
2007-2027 growth rate
Thursday, January 11, 2007

Avista Corp

2.8%
2.4%
2.0%

744

672

744

720

Jan
1,098
1,065
1,076
1,153
1,147
1,095
1,087
1,194
1,188
1,159
1,266
1,307
1,354
1,396
1,438
1,471
1,493
1,534
1,558
1,599
1,625
1,650
1,684
1,713
1,748
1,773
1,799
1,846
1,879
1,909
1,934
1,959
1,994
2,025

Feb
1,035
994
1,075
1,114
1,110
1,072
1,076
1,108
1,111
1,199
1,198
1,238
1,280
1,317
1,354
1,383
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1,439
1,460
1,496
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1,542
1,572
1,598
1,629
1,652
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Mar
952
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1,582
1,605
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1,798

Apr
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950
921
905
929
926
925
976
966
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1,214
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1,331
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1,380
1,400
1,420
1,456
1,481
1,505
1,525
1,544
1,571
1,595

3.0%
2.5%
2.1%

2.9%
2.4%
2.0%

2.9%
2.4%
2.0%

3.0%
2.5%
2.1%

744

May
832
941
917
889
862
898
900
900
927
962
970
999
1,034
1,064
1,093
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1,268
1,289
1,313
1,332
1,350
1,383
1,406
1,428
1,446
1,464
1,489
1,511
2.8%
2.4%
2.0%

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2007 Electric IRP

720

744

740

720

744

720

744

Jun
786
845
933
924
868
950
968
963
963
987
987
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1,558
1,584
1,608
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1,702

Sep
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904
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864
891
934
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2.8%
2.3%
2.0%

2.6%
2.2%
1.9%

2.9%
2.4%
2.0%

3.0%
2.5%
2.1%

2.8%
2.3%
2.0%

2.6%
2.2%
1.9%
50

2.8%
2.3%
2.0%

231


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<th>Native Peak Demand</th>
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2007-2012 growth rate 2.9%  2007-2017 growth rate 2.4%  2007-2027 growth rate 2.1%
Assumptions

• People, Jobs and Customers
  – Global Insight, Inc. Economic Forecasts
  – Spokane County and Kootenai County Trends
  – Customer Growth Projections

• Prices, Price Elasticity and Use per Customer
  – Electric and Natural Gas Price Forecasts
  – Own-Price, Cross-Price and Income Elasticity
  – Use per Customer Projections

• Sales Forecast
  – Small Customer Projections—Residential, Commercial and Industrial
  – Large Customer Projections—Manufacturing, Medical, Hospitality, Education and Governmental

• Conservation

• Weather Forecasts
  – NWS 1971-2000 Normal
  – Heating and Cooling Degree Days

• Scenarios
National Economy

- U.S. Gross Domestic Product
- Consumer Price Index
- West Texas Intermediate Oil Price
- 10-year Treasury’s Interest Rates
- U.S. Unemployment Rate
- U.S. Housing Starts
- U.S. Job Growth
- U.S. Productivity (Output per Worker)
- University of Michigan Consumer Sentiment
Real GDP
(percent change)
We answer to you.

Consumer Price Index
(percent change)

Oil Prices
(West Texas Intermediate)
Interest Rates
(10 year Treasury's)

Unemployment Rate
(percent)
U.S. Housing Starts
(million)

U.S. Job Growth
(percent change)
Productivity
Output per Worker

Consumer Sentiment
University of Michigan

We answer to you.
Regional Economy

- Global Insight County Forecasts
- Methodology
- Addressing acknowledgement shortcoming

- Both Idaho and Washington use Global Insight forecasts for various governmental planning efforts
Concept Coverage & Frequency

- 42 concepts & all 3111 Counties
- 2x a year (Spring/Jun & Fall/Dec)
- forecast: 30-yr of Annual data; most history: 1975

- Employment: 10 NAICS Supersectors
- Income: Average annual wage, total wage disbursements, & non-wage income (real & nominal)
- Demographics: Population, Households, and 10-year age categories for both
Historical Data

- Employment – Global Insight creation off BLS Data
  - Monthly ES202, from BLS, with missing values filled-in
  - Data constrained to the monthly metro/states CES data, which is of higher quality
  - Lag: 9-12 months
- Income
  - Annual, from BEA
  - Lag: 1-2 yrs (currently thru 2004)
- Total Pop
  - Annual, from Census
  - Lag: 1-2 yrs (currently thru 2005q2)
- Households & Cohorts
  - Mostly from Census years
Features/Goals of County Forecast

– All Counties Must Constrain to Metro Forecast (including non-metro portions of each state)
  • Ensures consistency with Metro/State forecasts
  • Takes advantage of higher-quality Metro/State forecasts, which have better, more reliable data and more advanced models
  • Cuts down on complexity of task
Forecast Methodology Overview

- Export Base Theory
  - Emp in Export/Base sectors → Emp in Nonbase/Service Sectors → Income → Population → Demogs
- Mfg grown based on Cty’s detailed sectoral composition (& corresponding state outlook)
- Most other sectors grown like state or a ratio of (concept/Pop or other concept) to state ratio
- Then, all constrained to MSA
- Pop Cohorts: Growth rates in cty cohort shares approach St growth rates in cohort shr over time
- HH Cohorts: Δ in Cty Headship rates by cohort moves like Δ in State headship rate
Methodology: Details

- **Base Emp**: Mfg, Mining, Fed Govt, S&L Govt (if capital)
  - Mfg: \( EEMFG = EEMFG.1 \times (\text{generated ratio})^k \).
  - Other Base sectors: Grow like State

- **Nonbase Emp**
  - \( \Delta \text{Cty NB} = \Delta \text{Cty Base} \times (\Delta \text{State Base}/\Delta \text{State NB}) \)

- **Income**:
  - Average Annual Wage: Grow like State
  - \((\text{Nonwage Income}/\text{WD})\) for Cty grown like same for St

- **Population**:
  - \( \Delta \text{Cty Pop} = \Delta \text{Cty Emp} \times (\Delta \text{State Pop}/\Delta \text{State Emp}) \)

- Lastly, Constrained to Metro
Methodology: Details

- Pop Cohorts:
  - Use cohort shares of total population
  - $\text{Ctyshr/Ctyshr.1} = (\text{Stshr/Stshr.1}) \times (\text{Growth in CtyShr between Census Pts})^{[1/N]} / (\text{Growth in StShr between Census Pts})$
    where $N$ runs from 10 to 0 over 75 yrs

- HH Cohorts:
  - Headship rates by Cohort & Cty (HH Coh / Pop Coh)
  - $\Delta$ Headship for Cty Coh moves like $\Delta$ Headship for St Coh
  - Headship Rates * Pop $\rightarrow$ HH Cohort $\rightarrow$ Sum to Total HH
Kootenai and Spokane County Forecasts

• Population Change
  • Population Total
    – Service Area Population estimated at 875,000 in 2006
    – Kootenai and Spokane County Population 582,000 in 2006
    – Represents 66.5 percent of area served

• Employment Change

• Employment Total
  – Service Area Employment estimated at 359,000 in 2006
  – Kootenai and Spokane County Population 267,000 in 2006
  – Represents 74.4 percent of area served

• Recently subscribed to Global Insight forecasts for Gas IRP
  – Boundary, Shoshone, Latah, Nez Perce in Idaho
  – Stevens, Whitman, Asotin in Washington
Kootenai and Spokane County Population Trends

Kootenai and Spokane Resident Population Change

Year-over-Year Population Change

Spokane Population  Kootenai Population
Kootenai and Spokane Population Total

1990-2006 Spokane Growth Rate 1.3%
Kootenai Growth Rate 4.1%

2006-2036 Spokane Growth Rate 1.2%
Kootenai Growth Rate 2.6%
Kootenai and Spokane Non-Farm Employment Change

Year-over-Year Job Change

Spokane Employment  Kootenai Employment
Kootenai and Spokane Job Total

1990-2006 Spokane Growth Rate 2.1%
Kootenai Growth Rate 5.2%

2006-2036 Spokane Growth Rate 1.5%
Kootenai Growth Rate 3.3%
Electric Customer Forecast—Base Case

- **Average during the Year**
  - Residential
  - Commercial
  - Industrial
  - Street Lights

- **1997-2007 Growth Rate** 1.7%
- **2007-2027 Growth Rate** 1.8%
Residential Customers—Index of Persons per Unit

- Year: 1997
- Value: 1.02
- Year: 2002
- Value: 1.01
- Year: 2007
- Value: 1.00
- Year: 2012
- Value: 0.99
- Year: 2017
- Value: 0.98
- Year: 2022
- Value: 0.97
- Year: 2027
- Value: 0.96
Prices, Price Elasticity, and Use per Customer

- **Personal Consumption Deflator**
  - 1997-2007 average compounded at 2.14 percent
  - 2007-2027 average compounded at 2.60 percent

- **Electricity Prices (PRS from 2005 IRP)**
  - 2007-2027 average compounded at 3.50 percent
  - Assume mid-year 17.5 percent rate increases every five years
  - Impact is 5 percent above the rate of inflation

- **Elasticity**
  - -0.15 Electricity Price Elasticity (a 17.5 percent price increase is a real price increase of 14.9 percent, causing a 2.2 percent use decline, ceteris paribus)
  - +0.05 Cross Price Elasticity for Natural Gas
  - +0.75 Income Elasticity (makes electricity more affordable over time)
Residential kWh Use Per Customer

- Residential kWh Use Per Customer over the years from 1997 to 2027.
- The graph shows a general increase in residential kWh use over the years.
- The data is presented in two categories: Residential and Commercial.
Sales Forecasts

• Methodology
  – Bottom up forecast of customers and use per customer
  – By rate schedule for each State (Washington and Idaho)
  – Monthly for five years, annually thereafter

• Schedules
  – Schedule 1 – Small Residential
  – Schedule 11 – Small Commercial and Industrial
  – Schedule 12 – Medium Residential
  – Schedule 21 – Large Commercial and Industrial
  – Schedule 25 – Very Large Commercial and Industrial
  – Schedule 28 – Large Government Facilities
  – Schedule 30, 31, 32 – Residential, Commercial and Industrial Pumping
  – Schedule 41, 42, 43, 44, 45, 46, 47, 48, 49 Residential, Commercial and Industrial Area or Street Lights

• Roll Up Sales Forecast

• Results
Monthly Historical and Forecast Sales

Last Actual October 2006

kWh

Residential  Commercial  Industrial  Street Lights
Annual Historical and Forecast Sales

Last Actual October 2006

Residential  Commercial  Industrial  Street Lights
• Conservation
  – Codes and existing programs are included in the forecast
  – New programs are treated as “load serving” resources

• Weather Forecasts
  – The forecast uses normal temperatures from the 1971-2000 time period
  – Attempts to capture global warming impacts are not addressed

• Other Issues
  – Electric Cars
  – Natural Gas Retail Sales Interaction with Generation Cost Scenarios
Scenarios

• **Avista’s Natural Gas IRP Approach**
  – Vary customer growth for firm customers by plus or minus 50% from the base case
  – Considered the Medium High and Medium Low forecast in the context of the Northwest Power and Conservation Council’s Plan
  – Large natural gas customers do not receive firm gas (only transportation) from Avista, and plan for their own supplies and deliveries

• **Prior Approaches for Avista’s Electric IRP**
  – The 20-year growth rate of 2.0 percent was increased/decreased by 50%, resulting in a medium high growth rate of 3.0 percent, medium low of 1.0 percent
  – Optimistic and pessimistic economic long range economic forecasts were developed and used to produce alternative forecasts, although defining optimistic and pessimistic economic outlooks is controversial
  – Superimposing the Northwest Power and Conservation Council’s Plan range of growth rates onto the base case sales forecast

• Avista is soliciting specific feedback from the TAC on a satisfactory approach
Avista, DSM and the 2007 Electric IRP

Bruce Folsom & Jon Powell
2007 Electric Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 10, 2007
Overview of the DSM Presentation

- The Past and Present of DSM within Avista  (*Jon Powell*)
- The Reinvention of DSM  (*Bruce Folsom*)
- Integrating Future DSM into the 2007 Electric IRP  (*Jon Powell*)
A Historical Context for Avista DSM

- Electric DSM first offered in 1978
- 1995 approval of electric (and natural gas) DSM tariff rider
- 2001 Western Energy Crisis response
- 2002-2005 “lean and mean” business plan
- 2006 Reinvention of DSM
Avista DSM Achievements

Electric DSM Acquisition

- Actual aMW
- aMW goal
- W regional

Months

Years:
- 1999
- 2000
- 2001
- 2002
- 2003
- 2004
- 2005
- 2006

aMW
Avista DSM Achievements

Gas DSM Acquisition

- Actual therms
- Retail only
- Therm goal

Month

Therms

2001
2002
2003
2004
2005
2006
Avista DSM Achievements

Combined Gas and Electric DSM Acquisition

- Actual local mmbtu
- mmbtu goal

Month

mmbtu

1999 2000 2001 2002 2003 2004 2005 2006

100,000 200,000 300,000 400,000 500,000 600,000 700,000
Current DSM Funding

- Funding
  - DSM Tariff Riders (WA & ID, electric & natural gas)
    - Estimated 2007 WA revenue = $4.5 million
      - Residential $0.00127 / kWh, proportionate to other schedules
    - Estimated 2007 ID revenue = $2.1 million
      - Residential $0.00081 / kWh, proportionate to other schedules
    - 2007 WA/ID electric budget $9.1 million
      - $2.5 million in excess of revenue
    - Projected 2007 tariff rider balances
      - WA negative $1.6 million to negative $3.8 million
      - ID positive $0.3 million to positive $0.0 million
    - Direct financial incentives to customers account for 78% of 2007 utility budget
  - Asymmetric interest provisions
    - BPA C&RD / CRC program
    - C&RD program $394k per year
Current Organization of DSM Operations

• Three local portfolios + regional cooperative efforts
  – Non-Residential Portfolio
    • Site-Specific program
      – ANY EFFICIENCY MEASURE QUALIFIES
      – Incentive based upon a tiered incentive structure
        » For projects with simple paybacks > 1 year
        » 6, 10, 12, 14 and 4 cent / 1st year kWh for electric-efficiency
        » 1 to 4 cents / 1st year kWh for fuel-efficiency
  – Prescriptive programs
    – Lighting, VFD’s etc.
  – Limited Income Residential portfolio
    • Implemented through annual contracts with six CAP agencies
    • ANY EFFICIENCY MEASURE QUALIFIES
    • Additional provisions for health & human safety measures
Current Organization of DSM Operations

- Residential portfolio
  - Exclusively prescriptive programs
    - Weatherization, heat pumps etc.
  - Avista Request for Information / Request for Proposals
    - Business planning effort growing out of previous electric IRP
    - → Early 2006 RFI
    - → Early 2007 RFP’s
      - Enhancements to commercial refrigeration efficiency programs (predominately electric)
      - Enhancements to multifamily housing efficiency programs (electric and gas)
Current Organization of DSM Operations

- Regional portfolio
  - Northwest Energy Efficiency Alliance funding utility
    - Acquisition of electric-efficiency through market transformation
    - Funded by five IOU’s, ETO, generating publics + BPA
      » Avista funding = 4.0% of Northwest
    - Past acquisition at a TRC levelized cost of about 10 mills
      » Not necessarily representative of future costs
    - Funding from DSM tariff rider for 1st ten years
      » Currently funding NEEA through BPA CRC dollars
  - Significant and increasing overlap with local programs
    » Local leveraging opportunities
Oversight and Regulation

• External Energy Efficiency ("Triple-E") board
  – A response to increased tariff flexibility in 1999
  – Composed of regulators, customers, CAP agency representatives
    and other major stakeholders
  – Quarterly updates, spring & fall meetings, annual report

• Cost-recovery of DSM expenses
  – Prudence of DSM expenditures is incorporated into each GRC
Reinventing DSM

• Continuation of meeting traditional DSM challenges
  – Achieve the substantial increase in gas DSM acquisition goal
  – Establish the infrastructure necessary for long-term operations
  – Obtain sufficient funding to maintain near-zero balances on each of the four individual tariff riders.
• Participate in the Northwest response to changes in electric markets and how they effect the viability of regional programs
• Expand the horizons of “DSM” to include all approaches to non-generation resource management
Starting Point for Expanded Initiative

- Track record of innovation
- Energy efficiency programs among best in the country
  - 2001 – “The Year of the Western Energy Crisis”
- A Demand Response Team that has…
  - Strong technical skills
  - Excellent people-to-people attributes
- Company-wide experience and expertise in utility operations
Demand Response Is…

- Energy efficiency

AND...

- Critical peak pricing (i.e., peak shaving)
- Peak shifting
- Time-of-use pricing
- Credits for large customers who have pre-established contracts
- Seasonal pricing
- Voltage control
- Distributed generation and cogeneration
- Transmission and distribution (T&D) efficiencies
- All other
Benefits

- Customer benefits
- More information for large resource acquisition decisions
  - National and state policy: emission requirements
  - Technology: pulverized coal, IGCC, nuclear
- Reduced pressure on, or alternatives for, capital budget
- Potential cost savings
Alignment of “Processing” and Analyses

• Power supply analysis starts with a resource and its portfolio fit:
  – Hydro
  – Baseload thermal
  – Renewables
  – Peaking facilities

• Demand response also starts with a resource and portfolio fit:
  – Energy efficiency
  – T&D efficiencies
  – Time-of-use pricing (daily and seasonal)
  – Peak shaving (critical peak pricing & bilateral customer contracts)
  – Real-time pricing
Alignment… (continued)

• Enterprise-wide
  – Most departments will have potential to contribute
  – Three states – two fuels
• Not bounded by all-or-nothing…break into pieces
  – Schedule 25
  – Scalable and learning from examples (ours and others)
• Full examination of all ideas
  – Scrutinize recognizing that we have paid $250/mwh at times
• Timing will differ for varying assessments and roll-outs
  – Peak-shaving in place for next summer
Demand Response Initiative:

• Maintain focus on targets and existing DSM programs while
  – assessing best practices status
  – surveying and implementing expanded options

• Continue the Company’s legacy:
  – resource acquisition through least-cost demand response programs
  – innovate on customers’ behalf
Demand Response Initiative (continued):

- Acquire sufficient energy and demand savings to delay a thermal plant as long as cost-effective
  - through a comprehensive, state-of-the-art demand response initiative
  - by examining and implementing:
    - expanded energy efficiency programs,
    - peak shaving programs,
    - consideration of time-of-use schedules,
    - and all other options (e.g., T&D efficiency),
  - in a manner that is sustainable and fiscally credible

...pursue the most efficient portfolio (supply and demand response) that we can possibly deliver
Potential Change in Regulatory Treatment

- Washington Electric General Rate Case, consider:
  -- Capitalizing (may also need Accounting Order, in advance)
  -- Allowance for Funds Used Conserving Energy
  -- One-way Balancing Account
  -- In the alternative, increase Schedule 91 and 191

- Has the effect of increasing budget, as appropriate

- Request finding of prudence per Schedule 91 requirement
Coordination and Iteration

Figure 1

1 – Councils; Consultant
2 – Total Company
3 -- External
4 – Examine Strategy re Margin Enhancement
5 – Increased Energy Effic
6 – Peak Shaving
7 – TOU Analysis re AMR
8 – Other (e.g., T&D)
Some Key Activities

• Assessments
  – Review all potential energy efficiency programs and delivery options
  – Survey industry best practices
  – Survey all demand response programs with segmentation by typ

• Communication and coordination

• Milestone establishment and monitoring
Integration of DSM into the 2007 IRP

Objective:

• This should not be a purely academic effort or merely to meet regulatory requirements – it should be part of our resource and business planning process
  – Identify potential non-residential technologies and applications to target
    • “Acceptance” or “rejection” within the IRP will not remove any technology or application from potentially being included in our non-residential portfolio
  – Re-evaluate residential measures in our current portfolio and evaluate the introduction of additional measures
    • The IRP evaluation will lead to a process that could change our menu of qualifying residential measures
  – Establish an acquisition goal that will assist us in
    • Budget projections & tariff rider revenue planning
    • Infrastructure needs to include labor complement
Integration of DSM into the 2007 IRP

- Avista’s approach to incorporating DSM into the IRP:

Integration by Price Signal

1. **AURORA Resource Stacks**
2. **Deferrable Resource Avoided Cost**
3. **DSM Department Acquires**

   - **WECC Supply-Side Resources**
   - **Decrement Deferrable Resource by Amount of DSM**
Why this works … and when it doesn’t

• DSM is acquired in small annual amounts relative to the size of the overall load requirement
  – This does not preclude having a large amount of DSM online through the ‘snowballing’ effect over time

• DSM is non-dispatchable (historically)
  – Evaluation of potential exceptions to this approach will be evaluated as appropriate

• The non-interactive nature allows the Company to continually modify and test new opportunities between IRP’s in a manner consistent with the most recent IRP.
Challenges of Integrating DSM

- Our much richer avoided cost stream (8760-hour detail as opposed to a single annual avoided cost) is more demanding of our load research capabilities

- The lack of a demand-response component to our Schedule 90 (DSM) tariffs limit our ability to either
  - Pursue cost-effective peak-shifting opportunities
  - More aggressively incentivize efficiency measures with a disproportionate coincident system peak impact
  - Are we interpreting our tariffs correctly?
Proposed 2007 methodology

Business Planning process:
Incentive format and levels, target markets, tariff revisions, regional cooperative efforts, interactions with gas DSM programs
The Post-IRP Business Planning Process

- This is where the DSM results of the IRP are operationalized
- Includes a more detailed assessment of those measures that “passed” the IRP
  - Incorporates consideration of more detailed measure applicability, especially within the non-residential markets
  - Would include additional consideration of residential and non-residential measures that were deemed marginally non-cost-effective in the IRP
- Incorporation into a 2008 DSM Business Plan
  - Establishment of new acquisition goals
    - External goals as well as by portfolio, by Account Executive, by engineer etc.
  - Appropriate budgeting
  - Potential revisions to tariff rider levels
  - Review of infrastructure capabilities
  - Revise target markets and measures
  - Review residential and non-residential prescriptive programs
    - Addition or deletion of measures
    - Revise incentives
  - Establish a plan to pursue measures which may be outside the scope of our current Schedule 90 (DSM) tariff authority
# Avista Utilities 2007 Integrated Resource Plan
## Technical Advisory Committee Meeting No. 4 Agenda
### Wednesday March 28, 2007

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<th>Time</th>
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<td>Review of 3\textsuperscript{rd} TAC Meeting</td>
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<td>Market Analysis</td>
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<td>Gall</td>
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<td>Load Forecast – Global Warming</td>
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<td>Conservation Program Update</td>
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<td>Lunch – DSM Presentation</td>
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<td>Portfolio Selection Criteria</td>
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Review of TAC 3 Meeting

2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

John Lyons
TAC Meeting #3 – January 10, 2007

- Draft PRS Review
- Fuel Price Forecast
- Clean Coal Presentation
- Emission Update
- Load Forecast
- Conservation
Comments/Questions from TAC Meeting #3

• What is Plan B if the PRS is not feasible? Why? – Final IRP
• Are we maintaining or increasing our level of risk? – Final IRP
• Chart Net Power Supply Expenses PRS vs. No Additions – Final IRP
• Should a gas hedge be included in the model – net cost or benefit of a hedging premium – Yes
• Adding a premium over market price for avoided cost – Final IRP
• Petroleum coke as a feedstock – Discussion, not modeled
• Correct errors on slides from the last meeting – Done
• Include chart comparing summer vs. winter peak – Final IRP
Market Analyses

2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

James Gall
Base Case Market Analysis

- This is the anchor of the IRP analysis
- Mean of 300 potential outcomes
- Assumes average conditions and expectations
- Includes risk measurement
- Some methodology changes since 2005 IRP and 2007 “draft” IRP
Methodology Changes From Prior IRP Analysis

Key Changes

- Regional resource selection must meet planning margin targets
- Uses four Northwest areas rather than one or eight
- Updated fuel prices and capital costs
- Focus on market drivers rather than regional resource speculation
- Added stochastic abilities, methodologies, and iterations
- Carbon “taxes” included in Base Case analysis
- Additional renewables assumed from increased RPS legislation
Stochastic Study Requirements

- Develop deterministic AURORA study using average and expected conditions for the given change
- Develop stochastic (Monte Carlo) models to create data using historical and expected statistics, these are inputted in AURORA
- 300 hourly AURORA simulations between 2008 and 2027 for the entire Western Interconnect
- Requires 2,160 computing hours on 25 CPUs and a large data server that stores 124 GB per study
- Each study takes four days, excluding the time to build the deterministic study
Stochastic Analysis Components

AVA Wind
- Single Site: U-shaped with serial correlation

Hydro
- Random draw of 70yr historical record

Natural Gas
- Lognormal differential from the mean

Load
- Normal with regional correlation

CO₂
- Probability Model

NOₓ
- Lognormal

SO₂
- Lognormal

Hg
- Lognormal

Thermal Outages
- Random - Mean Time to Repair

Potential Correlation
# Base Case Key Assumptions

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<td>(Real)</td>
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<tr>
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<td>(AAGR)</td>
<td></td>
<td>(AAGR)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Northwest Non-Coincident Peak Demand (MW), (WA, OR, N. Idaho)</strong></td>
<td></td>
<td>1.38%</td>
<td>25,749</td>
<td>29,311</td>
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<tr>
<td>(AAGR)</td>
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<td>(AAGR)</td>
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<tr>
<td><strong>Western Interconnect Non-Coincident Peak Demand (MW)</strong></td>
<td></td>
<td>2.37%</td>
<td>162,672</td>
<td>202,388</td>
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<td>(AAGR)</td>
<td></td>
<td>(AAGR)</td>
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<tr>
<td><strong>Hydro Energy (aMW)</strong></td>
<td></td>
<td>14,152</td>
<td>14,067</td>
<td>14,162</td>
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<td><strong>CO₂ Tax ($/Ton)</strong></td>
<td></td>
<td>$4.35</td>
<td>$0.00</td>
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<tr>
<td>(Real)</td>
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<td>(Real)</td>
<td>(Nominal)</td>
<td>(Nominal)</td>
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<td>(Nominal)</td>
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## Base Case: New Resource Selection Western Interconnect *(Cumulative Nameplate MW)*

<table>
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<th>2015</th>
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<th>2027</th>
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<tbody>
<tr>
<td>CCCT</td>
<td>5,280</td>
<td>15,360</td>
<td>23,040</td>
<td>46,080</td>
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<tr>
<td>SCCT</td>
<td>17,002</td>
<td>31,793</td>
<td>46,661</td>
<td>52,761</td>
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<td>0</td>
<td>2,800</td>
<td>3,600</td>
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<td>IGCC coal</td>
<td>0</td>
<td>0</td>
<td>2,550</td>
<td>11,900</td>
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<td>IGCC coal w/ sequestration</td>
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<td>Wind (economic)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>RPS wind</td>
<td>2,016</td>
<td>9,499</td>
<td>20,046</td>
<td>29,086</td>
</tr>
<tr>
<td>RPS other</td>
<td>638</td>
<td>2,177</td>
<td>4,331</td>
<td>6,457</td>
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<tr>
<td><strong>Total Excluding Wind</strong></td>
<td>22,920</td>
<td>52,130</td>
<td>80,182</td>
<td>122,398</td>
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<tr>
<td><strong>Total With Wind @ 33%</strong></td>
<td>23,585</td>
<td>55,265</td>
<td>86,797</td>
<td>131,966</td>
</tr>
</tbody>
</table>
Base Case: Northwest Resource Need
25% Planning Margin, 15% Wind Contribution

NW Winter Peak Demand

1 Hr Peak Capacity
Planning Margin

MW

- 5,000
10,000
15,000
20,000
25,000
30,000
35,000
40,000
45,000
50,000


Avista Corp 2007 Electric IRP
## Base Case: New Resource Selection in Northwest (*Cumulative Nameplate MW*)

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2015</th>
<th>2020</th>
<th>2027</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCCT</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,920</td>
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<tr>
<td>SCCT</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>540</td>
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<tr>
<td>Pulverized coal</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>IGCC coal</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>IGCC coal w/ sequestration</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wind (economic)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0</td>
<td>0</td>
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<tr>
<td>RPS wind</td>
<td>0</td>
<td>44</td>
<td>2,832</td>
<td>5,835</td>
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<td>RPS other</td>
<td>150</td>
<td>261</td>
<td>1,017</td>
<td>1,871</td>
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<tr>
<td>Total Excluding Wind</td>
<td>150</td>
<td>261</td>
<td>1,017</td>
<td>4,331</td>
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<tr>
<td>Total With Wind @ 33%</td>
<td>150</td>
<td>276</td>
<td>1,952</td>
<td>6,257</td>
</tr>
</tbody>
</table>
Base Case Annual Average Mid-C Prices
Nominal Dollars

Levelized Prices:
Nominal 2008$: $60.13
Real 2007$: $49.59
Market Implied Heat Rate - Not Adjusted for CO₂ Tax (Mid-C Electric Price/Sumas NG Price)
Western Interconnect Resource Contribution
(% of Total Energy)

- Gas Fired
- Coal Fired
- Hydro
- Renewable
- Other

Year:
- 2008
- 2009
- 2010
- 2011
- 2012
- 2013
- 2014
- 2015
- 2016
- 2017
- 2018
- 2019
- 2020
- 2021
- 2022
- 2023
- 2024
- 2025
- 2026
- 2027
Western Interconnect Total Fuel Costs in Millions
Average Annual Growth Rate ~4.9%
Futures

- These studies are stochastic
- Represent potential macro economic changes
- What are we modeling as futures?
  - No CO$_2$ taxes
  - Climate Stewardship Act of 2003 (C.S.A.) [modified]
  - More volatile natural gas markets
  - No relaxation in gas markets *(still in process, deterministic presented)*
## No CO₂ Taxes: New Resource Selection Western Interconnect (Cumulative Nameplate)

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2015</th>
<th>2020</th>
<th>2027</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCCT</td>
<td>2,400</td>
<td>15,360</td>
<td>23,040</td>
<td>48,000</td>
</tr>
<tr>
<td>SCCT</td>
<td>19,860</td>
<td>31,693</td>
<td>45,299</td>
<td>49,031</td>
</tr>
<tr>
<td>Pulverized coal</td>
<td>0</td>
<td>3,600</td>
<td>4,400</td>
<td>6,800</td>
</tr>
<tr>
<td>IGCC coal</td>
<td>0</td>
<td>425</td>
<td>6,375</td>
<td>11,900</td>
</tr>
<tr>
<td>IGCC coal w/ sequestration</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wind (economic)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>RPS wind</td>
<td>2,016</td>
<td>9,499</td>
<td>20,046</td>
<td>29,086</td>
</tr>
<tr>
<td>RPS other</td>
<td>638</td>
<td>2,177</td>
<td>4,331</td>
<td>6,457</td>
</tr>
<tr>
<td>Total Excluding Wind</td>
<td>22,898</td>
<td>53,255</td>
<td>83,445</td>
<td>122,188</td>
</tr>
<tr>
<td>Total With Wind @ 33%</td>
<td>23,563</td>
<td>56,390</td>
<td>90,060</td>
<td>131,786</td>
</tr>
</tbody>
</table>
No CO₂ Tax: Annual Average Mid-C Prices
Nominal Dollars

Levelized Prices:
Nominal 2008$: $55.84
Real 2007$: $46.05

Avista Corp
2007 Electric IRP
No CO₂ Tax: Market Implied Heat Rate
(Mid-C Electric Price/Sumas NG Price)
No CO$_2$ Tax: Western Interconnect Resource Contribution (% of Total Energy)
Carbon Tax Assumptions for High Carbon Tax Future (Climate Stewardship Act of 2003)

The graph shows the carbon tax assumptions from 2008 to 2027, with the x-axis representing years and the y-axis representing the tax per ton of CO2 in dollars. The graph includes two lines:

- **Base Case (NCEP)**: A line starting at a tax of $10 in 2008 and increasing steadily to $60 by 2027.
- **Climate Stewardship Act**: A line starting at $10 in 2008 and increasing sharply from 2015 onwards, reaching $60 by 2027.
## C.S.A. CO₂ Taxes: New Resource Selection Western Interconnect *(Cumulative Nameplate MW)*

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2015</th>
<th>2020</th>
<th>2027</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCCT</td>
<td>6,240</td>
<td>12,000</td>
<td>23,520</td>
<td>46,560</td>
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<td>SCCT</td>
<td>15,176</td>
<td>33,206</td>
<td>44,010</td>
<td>50,573</td>
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<td>0</td>
<td>1,200</td>
<td>1,200</td>
<td>1,600</td>
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<tr>
<td>IGCC coal</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>2,975</td>
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<td>IGCC coal w/ sequestration</td>
<td>0</td>
<td>0</td>
<td>1,203</td>
<td>5,213</td>
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<tr>
<td>Wind (economic)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>RPS wind</td>
<td>2,016</td>
<td>9,499</td>
<td>20,046</td>
<td>29,086</td>
</tr>
<tr>
<td>RPS other</td>
<td>638</td>
<td>2,177</td>
<td>4,331</td>
<td>6,457</td>
</tr>
<tr>
<td><strong>Total Excluding Wind</strong></td>
<td>22,054</td>
<td>48,583</td>
<td>74,264</td>
<td>113,378</td>
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<tr>
<td><strong>Total With Wind @ 33%</strong></td>
<td>22,719</td>
<td>51,718</td>
<td>80,879</td>
<td>122,976</td>
</tr>
</tbody>
</table>
C.S.A. CO₂ Taxes: Annual Average Mid-C Prices Nominal Dollars

Levelized Prices:
Nominal 2008$: $69.07
Real 2007$: $56.96
C.S.A. CO$_2$ Taxes: Market Implied Heat Rate
(Mid-C Electric Price/Sumas NG Price)
C.S.A. CO₂ Taxes: Western Interconnect Resource Contribution (% of Total Energy)
Volatile Gas: Annual Average Mid-C Prices
Nominal Dollars

<table>
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<td>2008</td>
</tr>
<tr>
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<tr>
<td>2025</td>
</tr>
<tr>
<td>2026</td>
</tr>
<tr>
<td>2027</td>
</tr>
</tbody>
</table>

- Deterministic
- Mean
- Max
- Min
- 80% Confidence Level Low
- 80% Confidence Level High
Mid-C Electric Forecast Comparison

- BaseCase
- VolGas
- NoCO2
- C.S.A.
- 2007 Draft
- 2005 IRP

Years: 2008 to 2027
Price Range: $40 to $120
Mid-C Electric Forecast Comparison of Volatility (Mid-C Annual Avg/ Mid-C Annual Stdev)

- NoCO2
- BaseCase
- C.S.A.
- 2007 Draft
- 2005 IRP
- VolGas

Year: 2008 to 2027
Market Scenarios

- These studies are deterministic
- Represent specific macro changes
- What are we modeling has scenarios?
  - 20% higher & lower natural gas prices
  - 50% higher & lower regional load growth
  - Nuclear available in 2015
  - High electric car penetration
  - No new coal resources
  - Global Warming (hydro and load changes)
  - No new natural gas plants after 2015

Not Completed Yet!
Gas Price Scenarios

- **Base Case**
- **High Gas**
- **Low Gas**
- **Constant Gas Growth**

2008 Levelized Costs:
- $8.22
- $8.19
- $6.85
- $5.48
Scenarios Electric Price Forecasts... So Far
## Mid-C Electric Comparison (Nominal $/MWh)

<table>
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</thead>
<tbody>
<tr>
<td>Base Case/Volatile Gas</td>
<td>49.59</td>
<td>60.13</td>
<td>52.58</td>
<td>50.79</td>
<td>55.91</td>
<td>70.69</td>
<td>94.86</td>
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<td>No CO₂</td>
<td>46.05</td>
<td>55.84</td>
<td>52.65</td>
<td>50.27</td>
<td>49.35</td>
<td>62.98</td>
<td>85.11</td>
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<td>C.S.A.</td>
<td>56.96</td>
<td>69.96</td>
<td>51.92</td>
<td>49.42</td>
<td>68.90</td>
<td>92.29</td>
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<td>Constant Gas Growth</td>
<td>58.46</td>
<td>68.82</td>
<td>52.76</td>
<td>59.18</td>
<td>69.12</td>
<td>78.45</td>
<td>94.07</td>
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<tr>
<td>High Gas (20%)</td>
<td>58.32</td>
<td>68.59</td>
<td>61.77</td>
<td>58.93</td>
<td>61.76</td>
<td>80.57</td>
<td>105.35</td>
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<td>Low Gas (-20%)</td>
<td>43.43</td>
<td>51.03</td>
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<td>41.68</td>
<td>47.62</td>
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<td>High Regional Load Growth</td>
<td>51.57</td>
<td>60.65</td>
<td>53.72</td>
<td>50.63</td>
<td>57.37</td>
<td>71.76</td>
<td>92.84</td>
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<td>Low Regional Load Growth</td>
<td>50.22</td>
<td>59.05</td>
<td>51.94</td>
<td>49.45</td>
<td>54.47</td>
<td>69.76</td>
<td>94.39</td>
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<td>Nuclear available 2015</td>
<td>50.43</td>
<td>59.29</td>
<td>52.27</td>
<td>49.38</td>
<td>54.89</td>
<td>69.42</td>
<td>93.87</td>
</tr>
</tbody>
</table>
All Market Studies Mid-C Price % Change from Base Case
All Market Studies Total Fuel Costs (Nominal)
Global Warming Degree Day Trend Scenario

2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

Randy Barcus
GLOBAL TEMPERATURES (2500 B.C. TO 2007 A.D.)

1100 B.C. VERY WARM

Hebrew Exodus From Egypt

Only Scattered Volcanic Eruptions

5680 B.C.

2200 B.C.

WARM

2400

2000

800

400

800

400

200

1200

600

1200

600

0 A.D.

200

Roman Empire

Viking Explorations (Reached NE Canada)

79 A.D. Vesuvius Erupts Pompeii Destroyed in Italy

4 B.C. Birth of Christ

Vesuvius Etna Italy

Grecian Empire COLD

250 B.C.

35 Volcanic Eruptions

535-550

Krakatoa, Indonesia and at least 10 other eruptions

135-1360

24 Eruptions (Italy, Pacific, Alaska and Iceland)

55 Eruptions

AT LEAST 75 MAJOR TEMPERATURE SWINGS IN THE LAST 4,500 YEARS!

Whenver SOLAR RADIATION has DECREASED and VOLCANIC ACTIVITY has INCREASED, global temperatures SUDDENLY PLUMMET, often within weeks or months.

2500 B.C. To 0 A.D. 0 A.D. To 2007

57°F Normal

1998

58.3°F

1991 Mount Pinatubo Philippines

1883 Krakatoa Indonesia

1851 Pelee Martinique

1845 Nevado del Ruiz Columbia

1815 Mt. Tambora Indonesia

1792 Unzen Japan

1783 Lakagigar Iceland

1772 Papadanyan Indonesia

1741 Vesuvius Italy

Supplemental- Section 1
GLOBAL MEAN TEMPERATURE GRAPH SINCE 1880
Prepared by Cliff Harris and Randy Mann

58°F
57.5°F
57°F
56.5°F
56°F

Normal


56.3°F 1888 (Lowest)

58.3°F 1998 (Highest)

58.0°F 2007

Mount Pinatubo 1991

For Discussion Purposes Only
Annual Heating Degree Days, Percent of Normal - Spokane, WA

\[ y = 0.00000000038x^5 - 0.00000011814x^4 + 0.00001215496x^3 - 0.00046405582x^2 + 0.00507029510x + 0.95457034192 \]
1971-2006 Spokane HDD Trend

$y = -18.894x + 7168.311$

1971-2000 NOAA Normal is 6,820

For Discussion Purposes Only
For Discussion Purposes Only

AVISTA

Avista Corp

2007 Electric IRP
1971-2006 Spokane HDD Trend

\[ y = -18.894x + 7168.311 \]

1971-2000 NOAA Normal is 6,820
Global Warming Degree Day Trends (2007-2037)

- Heating Degree Days
- Cooling Degree Days

For Discussion Purposes Only
Avista Corp
2007 Electric IRP
# Preliminary Load Forecast Impacts

## Electric Load (semi-rough estimates)

- **July/August**
  - 2007: +10 aMW, ~0.9%
  - 2017: +18 aMW, ~1.3%
  - 2027: +26 aMW, ~1.6%
  - 2037: +34 aMW, ~1.7%

- **December/January**
  - 2007/8: -18 aMW, ~(1.4%)
  - 2017/8: -29 aMW, ~(1.8%)
  - 2027/8: -40 aMW, ~(2.1%)
  - 2037/8: -51 aMW, ~(2.1%)

## Natural Gas Firm Load (very rough estimates)

- **Calendar**
  - 2007: -3%
  - 2017: -5%
  - 2027: -7%
  - 2037: -9%
The purpose of this presentation was designed to answer one simple question: If temperatures rise during the long-range forecast horizon consistent with the science on global warming, how much would Avista's loads shift?

At this time, Avista's regulatory requirements indicate use of the National Oceanic and Atmospheric Administration's official 30-year normal. Were that regulatory requirement to change, Avista would produce consistent regulatory filings based on the modified rules.
Heritage Project Update

2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

Bruce Folsom
Heritage Project – Demand Response Initiative

Maintain focus on targets and existing DSM programs while

- assessing best practices status
- surveying and implementing:
  - expanded options and
  - expanded delivery mechanisms

Continue the Company’s legacy:

- resource acquisition through least-cost demand response programs
- innovate, educate and communicate on customers’ behalf
Heritage Project (Continued)

Acquire sufficient energy and demand savings to delay a thermal plant as long as financially possible

- through a comprehensive, state-of-the-art demand response initiative
- by examining and implementing:
  - expanded energy efficiency programs,
  - peak shaving programs,
  - consideration of time-of-use schedules and other pricing options,
  - and all other options (e.g., T&D efficiency),
- in a manner that is sustainable and fiscally credible

...pursue the most efficient portfolio (supply and demand response) that we can possibly deliver
Heritage Project Status

Road Maps completed:

- Energy Efficiency Task Force
- Load Management Task Force
- Transmission and Distribution Task Force
- Each has very different flavor

Next Steps:

- Bring on additional staff
- Design and implement 2007 enhanced and new programs
- Continue Analytics
- Plan for 2008 capital needs…”Blueprint for the Future”
- Implement outreach and communication program
Energy Efficiency Road Map

- Started with a very strong platform of energy efficiency services
- Inventoried macro-list
- Enhanced programs and new programs to be launched in 2007
- Focus on education and outreach supported by new programs
- Oregon Achievement Plan
- Avista Model Plan
Load Management Road Map

- Avista faces high peak costs, but different than other parts of country
- Technology costs continue to fall and technology can now be integrated
- Decisions are how best to apply which technology—“prices to devices”
  - Infrastructure needs
  - Defining system and hardware requirements
  - Assessing costs/benefits
  - Testing and experimenting with customer acceptance
- Five projects identified for 2007, after options were scrutinized
- Framework for 2008+ activities
Transmission & Distribution Road Map

- Focus to be on internal rates of return
- Nine projects identified for review
- Three specific improvements are underway or in the analysis stage
# Analytics Road Map—Representative Example

## Resource Value Component Summary
(All calculations assuming an illustrative flat load)

<table>
<thead>
<tr>
<th>Component</th>
<th>10 yr Energy $(/MW)$</th>
<th>20 year Energy $(/MW)$</th>
<th>Capacity $(/kW)$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avoided cost of energy</td>
<td>$49^1</td>
<td>$57^1</td>
<td></td>
</tr>
<tr>
<td>Avoided emissions cost</td>
<td>$2^2</td>
<td>$4^2</td>
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<tr>
<td>Reduction in energy cost volatility</td>
<td>$16^3</td>
<td>$18^3</td>
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<tr>
<td>Reduction in T&amp;D losses</td>
<td>$4^4</td>
<td>$5^4</td>
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<tr>
<td>Value of deferred gen capacity</td>
<td></td>
<td></td>
<td>$300</td>
</tr>
<tr>
<td>Value of deferred T&amp;D capacity</td>
<td></td>
<td></td>
<td>$105</td>
</tr>
<tr>
<td><strong>TOTAL COST</strong></td>
<td><strong>$71</strong></td>
<td><strong>$84</strong></td>
<td><strong>$405</strong></td>
</tr>
</tbody>
</table>

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. It is likely that this fixed emissions cost adder will be applied until the impact of pending or likely legislative impacts can be modeled.
3. This is an adder to reflect the difference between the expected value of the avoided cost stream and the 95% confidence interval.
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 we are moving forward based upon a winter space heating-driven system peak assumption.
Communications Planning

Sustained (3-5 year) outreach campaign

- Stage new roll-outs
- To each program, its best tool
  - Media release?
  - Paid media?
  - Other

Communications to all Company employees

Employee training in specific areas that have direct customer contact

- prepare employees to continue to inform customers about
  - energy conservation, and
  - available programs and rebates.
## Current Avista Energy Efficiency Programs

<table>
<thead>
<tr>
<th>Residential/Limited Income</th>
<th>Commercial/Industrial/Institutional</th>
</tr>
</thead>
<tbody>
<tr>
<td>High-efficiency natural gas furnaces/boilers</td>
<td>Site Specific (any measure)$^1$</td>
</tr>
<tr>
<td>High-efficiency heat pumps</td>
<td>Efficient lighting and occupancy sensors</td>
</tr>
<tr>
<td>High-efficiency variable speed motors</td>
<td>Food service equipment</td>
</tr>
<tr>
<td>High-efficiency water heaters</td>
<td>Rooftop HVAC maintenance (AirCare Plus)</td>
</tr>
<tr>
<td>Electric to natural gas heat</td>
<td>Variable frequency drives</td>
</tr>
<tr>
<td>Electric to heat pump</td>
<td>LEED certification</td>
</tr>
<tr>
<td>Electric to natural gas water heaters</td>
<td>Multi-family, replace electric DHW with gas</td>
</tr>
<tr>
<td>Ceiling/attic, floor and wall insulation</td>
<td>Premium efficiency motors</td>
</tr>
<tr>
<td>Windows</td>
<td>Supermarket and grocery store refrigeration</td>
</tr>
<tr>
<td>Limited income measures including health/safety</td>
<td>Power management for computer networks</td>
</tr>
<tr>
<td></td>
<td>LED traffic signals</td>
</tr>
<tr>
<td></td>
<td>Refrigerated warehouses</td>
</tr>
<tr>
<td></td>
<td>Efficient spray head installation</td>
</tr>
</tbody>
</table>

$^1$The Site Specific program is an all-encompassing offer to provide incentives on any cost-effective commercial and industrial energy efficiency measure. This is implemented through site analyses, customized diagnoses, and incentives determined for savings generated specific to customers’ premise or process.
## Proposed New Energy Efficiency Programs

<table>
<thead>
<tr>
<th>Start Time</th>
<th>Residential &amp; Small Commercial/Industrial</th>
<th>Commercial/Industrial/Institutional</th>
</tr>
</thead>
</table>
| 1Q07       | • Res & Small C&I Quick Hits Program<br>  
             - Something For Everyone Measures<br>  
             - Fireplace Dampers | • C&I Quick Hits Program<br>  
                      - Side-Stream Filtration<br>  
                      - Energy/Heat Recovery Ventilation (ERV/HRV)<br>  
                      - Demand Control Ventilation (DCV)<br>  
                      - Steam Traps |
| 2Q07       | • Super Efficient Habitat for Humanity (HFH) Homes | |
| 3Q07       | • Geographic Saturation Program | • Retro-Commissioning Program<br>  
                      • Behavioral Program |
| 4Q07       | • Regional Natural Gas Market Transformation Program | • Facilities Model Program (ongoing) |
Proposed 2007 Load Management Projects

- Residential Demand Response Pilot
- Small Commercial Demand Response Pilot
- Large Commercial/Industrial Interruptibility
- Avista Facilities Demonstration Project
- Large Commercial/Industrial Distributed Generation
Proposed 2008 Load Management Projects

- Support for Accelerated AMR Build-Out in Washington and AMI in Idaho
- Rate Design
- Demand Response
- Distributed Generation
Transmission and Distribution Road Map

- Secondary Districts
- Substations
  - Substation Size and Location
  - Substation Transformers
  - Substation Lighting and Parasitic Loads
- Feeders and Conductors
  - Feeder Balance
  - Economic conductor analysis
- Distribution Transformers
  - High Efficiency
  - Right Sizing
- Conservation Voltage Reduction (CVR)
T&D Continued

Three specific projects are under way or under consideration:

- Rockford/Latah
- Priest River
- Colville12F2 Recondutor
Customer Benefits

- Lower bills for participating customers
- Reduced costs for general body of customers
- Take some control of the bill in a period of increasing costs
- Interact with the utility; learn of other programs
  - Average monthly billing
  - Low-income rate assistance
  - Consumer programs, *et cetera*
- Helps address a re-awakened environmental focus due to “daily” GHG reports
- Customers like knowing they have options, even if they don’t avail themselves of programs
- Satisfaction that their utility is “socially responsible”
- Conservation is a root value in our society with strong support
Company Benefits

- Implement IRP
  - Documents technical and achievable savings
  - Stakeholder involvement…meet with the expert public, the opinion leaders
- Acquire lower cost resources
- Potential for cost savings
- Customer touches
  - Customers and the community like good news
  - Provides for proactive customer assistance
  - Increases satisfaction ratings
- More information for large resource acquisition decisions
  - National and state policy (e.g., emission requirements)
  - Technology
- Reduced pressure on, or alternatives for, the capital budget?
2007 Implementation Items

- **Energy Efficiency**
  - To existing 21 programs, several enhanced and new programs/measures

- **Load Management**
  - Two pilots (res and com) at Liberty Lake and Sandpoint
  - Large customer interruptibility and distributed generation

- **Transmission and Distribution**
  - Examining nine potential projects and 3 are work in progress

- **Costs are based on each set of unique circumstances—**
  - Energy efficiency, the avoided cost of a base load plant or purchase
  - Load management, the cost of peaking resources (e.g., gas turbines)
  - T&D, the internal rate of return (IRR) compared to other capital projects

- **Communications**
  - External and internal
Overall Key Points

- Focus on existing DSM targets while assessing best practices…
- Continue the Company’s legacy: innovation/education on customers behalf
- Acquire sufficient energy and demand savings through a comprehensive, state-of-the-art demand response initiative
  - by examining and implementing:
    - expanded energy efficiency programs,
    - peak shaving/shifting programs,
    - and all other options (e.g., T&D efficiency),
  - in a manner that is sustainable and fiscally credible
Preferred Resource Strategy Criteria & Analysis

2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

James Gall
Linear Programming Decision Support Systems (LP DSS)

- Used outside of utility industry for decades
  - Power utilities are “behind the times” in adopting LP DSS
- Support highly complex decision-making with single- and multiple-objective functions
- Utility portfolio development is complicated & expensive
- Requires advanced portfolio and market analyses
- Avista used LP DSS starting with 2003 IRP
  - The PRS Model
  - Enhancements added in each IRP cycle
Preferred Resource Strategy (PRS) Methodology

- Linear program that solves for the optimal resource strategy to meet resource deficits over planning horizon.
- Model selects its resources to reduce cost and risk.

Minimize:

\[(X_1 \times \text{NPV of Total Cost}_{2008-2017} + X_2 \times \text{Absolute Deviation Power Supply Costs}_{2017} \times F) + (X_1 \times (10\% \times \text{NPV of Total Cost}_{2018-2027} + X_2 \times 10\% \times \text{Absolute Deviation Power Supply Costs}_{2027} \times F))\]

Subject to:
- Capacity Need +/- deviation
- Energy Need +/- deviation
- Wash St. Renewable Portfolio Standard
- Resource Limitations and Timing
- Capital Spending

Where:
- \(X_1\) = Weight of cost reduction (between 0 and 1)
- \(X_2\) = Weight of risk reduction (1 - \(X_1\))
- \(F\) = Factor to equate Risk and Cost at 50/50 study
Requirements for PRS Model (Inputs)

- Expected load & resource balance for next 20 years
- 20 year by 300 iteration matrix of resource values
  - Avista’s current resource portfolio cost
  - Each new resource alternatives market value (electric price less fuel costs, variable O&M, and emissions offsets “taxes”)
- Conservation estimates
- Generation capital costs, fixed operating costs, transmission costs, revenue requirements
- Availability assumptions (how much and when)
What Does The PRS Model Tell Us?

- Specific quantity of resource selection and timing
- Expected power supply cost for each year
- Expected risk or volatility in expected power supply costs for each year
- Expected power supply-related rate impacts
- Capital requirements and cash flow expectations
- Cost ($/MWh) in excess to market to meet capacity needs
- Illustrates the trade off between risk and cost of different portfolios

The PRS Model Does Not Make the Decision
PRS Model Assumptions

- No non-sequestered coal or nuclear are permitted (Base Case)
- No more than 400 MW of wind between 2008 and 2017
- No more than 600 MW of wind between 2008 and 2027
- Must meet WA RPS by building resources or buying green tags at the 4% revenue requirement cap
- No capital spending constraints (Base Case)
- May purchase fixed-price gas contract for CCCT plants
- May purchase/sell in short-term market for annual balancing
- Must approximate (i.e., not over-/under-build) needs
Short List Resource Options (Levelized $2007 “real”/MWh)

- CCCT 2008
- Co-Gen
- Geothermal
- Biomass
- Nuclear
- MT- Sub 2013
- MT- IGCC spare 2013
- Columbia Basin Wind
- Montana Wind
- NW- Sub 2013
- Aero Peaker 2008
- Avista Wind
- NW- IGCC spare 2013
- Frame Peaker 2008
- MT- IGCC spare seq 2018
- NW- IGCC spare seq 2018
- Alberta Oil Sands

Legend:
- Gen Capital & Overheads
- Trans Capital & Overheads
- Fixed VOM
- Trans (non Capital)
- Losses
- Fuel Costs
- VOM
- Emissions
# Resource Capital Costs
*(Excludes Transmission)*

<table>
<thead>
<tr>
<th>Resource Option</th>
<th>2007$/kW</th>
<th>Resource Option</th>
<th>2007$/kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCCT</td>
<td>786</td>
<td>Coal – Subcritical</td>
<td>1,906</td>
</tr>
<tr>
<td>SCCT-Aero</td>
<td>628</td>
<td>Coal – Supercritical</td>
<td>2,004</td>
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<tr>
<td>SCCT-Frame</td>
<td>419</td>
<td>Coal – Ultracritical</td>
<td>2,010</td>
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<tr>
<td>Wind</td>
<td>1,884</td>
<td>Coal – CFB</td>
<td>2,155</td>
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<tr>
<td>Geothermal</td>
<td>4,000</td>
<td>IGCC</td>
<td>2,378</td>
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<tr>
<td>Biomass</td>
<td>3,500</td>
<td>IGCC - w/Spare Gasifier</td>
<td>2,524</td>
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<tr>
<td>Oil Sands</td>
<td>3,963</td>
<td>IGCC – Sequestered</td>
<td>3,045</td>
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<tr>
<td>Nuclear</td>
<td>3,100</td>
<td>IGCC - Sequestered w/Spare Gasifier</td>
<td>3,232</td>
</tr>
<tr>
<td>Small Co-Gen</td>
<td>2,100</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Gas-Fired Combined Cycle With Fixed Gas

- Medium- to long-term fixed-price gas contract, or
- Could be coal gasified into pipeline-quality gas
  - Provide a significant new source of gas supply
  - Create a sequestered IGCC plant w/o operational trade-offs
    - Remote locations, altitude penalties, gasifier reliability
- Model is flexible in modeling any type of fixed gas price
- Fixed versus spot gas price assumptions

<table>
<thead>
<tr>
<th>Year</th>
<th>Fixed</th>
<th>Spot</th>
<th>Year</th>
<th>Fixed</th>
<th>Spot</th>
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<tbody>
<tr>
<td>2012</td>
<td>6.75</td>
<td>5.35</td>
<td>2022</td>
<td>9.52</td>
<td>8.93</td>
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<td>2018</td>
<td>8.3</td>
<td>7.14</td>
<td>2027</td>
<td>11.31</td>
<td>11.28</td>
</tr>
</tbody>
</table>

- Intent of this resource is to illustrate the ability to reduce power cost risk without building a coal resource directly
Avista’s Annual Average Resource Need

Excludes Additional Conservation
Avista’s Annual Average Resource Need (excluding Q2)

Excludes Additional Conservation
Current Portfolio Costs and Risk

- 99th Confidence Level Power Supply Cost
- Expected Power Supply Cost (minus 1 Stdev)
- Expected Power Supply Cost (plus 1 Stdev)
- Expected Power Supply Cost

Annual Power Supply Expense

2008 - 2027
What is the Efficient Frontier?

- Demonstrates the trade off of cost and risk
- Difficulty: how much additional cost are we willing to pay to reduce risk
Efficient Frontiers
Efficient Frontiers (Incremental $/MWh & Percent Change)

2008-17 Levelized Cost ($/MWh)

Cost

Risk

$20.65 $21.72 $22.79 $23.86 $24.93 $26.00 $27.07 $28.14

$10.00 $8.75 $7.50 $6.25 $5.00 $3.75 $2.50

-60% -40% -20% 0% 20% 40% 60%

Base Case
No CO2 Taxes
C.S.A.
Vol Gas

Avista Corp 2007 Electric IRP
Base Case Options & Portfolios
Efficient Frontiers (Incremental $/MWh)

Incremental Levelized $/MWh between 2008-2017
## Summary Table: Base Case

<table>
<thead>
<tr>
<th>#</th>
<th>Item</th>
<th>100/0</th>
<th>90/10</th>
<th>75/25</th>
<th>60/40</th>
<th>50/50</th>
<th>40/60</th>
<th>25/75</th>
<th>10/90</th>
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<td>1</td>
<td>NPV Total Power Cost to 2017</td>
<td>1,656</td>
<td>1,692</td>
<td>1,814</td>
<td>1,859</td>
<td>1,859</td>
<td>1,862</td>
<td>1,862</td>
<td>1,862</td>
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<td>NPV Total Power Cost to 2027</td>
<td>4,613</td>
<td>4,735</td>
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<td>5,586</td>
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<td>5,651</td>
<td>5,872</td>
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<td>Power Cost in 2017</td>
<td>392</td>
<td>430</td>
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<td>491</td>
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<td>Power Cost in 2027</td>
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<td>995</td>
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<td>1,014</td>
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<td>Power Cost Stdev in 2017</td>
<td>76</td>
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<td>Power Cost Stdev in 2027</td>
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<td>Power Cost ABSDEV in 2017</td>
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<td>Power Cost ABSDEV in 2027</td>
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<td>124</td>
<td>81</td>
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<td>68</td>
<td>67</td>
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<td>9</td>
<td>C. of V. 2016</td>
<td>19.3%</td>
<td>13.9%</td>
<td>9.1%</td>
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<td>10</td>
<td>C. of V. 2027</td>
<td>20.8%</td>
<td>17.4%</td>
<td>13.6%</td>
<td>7.1%</td>
<td>6.0%</td>
<td>5.8%</td>
<td>5.7%</td>
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<td>12</td>
<td>Acc. Capital Cost 2027</td>
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<td>13</td>
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<td>6.9%</td>
<td>6.9%</td>
<td>6.9%</td>
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<td>6.9%</td>
<td>6.7%</td>
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<tr>
<td>14</td>
<td>Rate AARG 2027</td>
<td>4.7%</td>
<td>4.7%</td>
<td>4.8%</td>
<td>5.3%</td>
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<td>5.5%</td>
<td>5.5%</td>
<td>5.8%</td>
<td>5.8%</td>
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<td>15</td>
<td>Rate Max Year</td>
<td>9.3%</td>
<td>9.6%</td>
<td>9.5%</td>
<td>9.5%</td>
<td>9.5%</td>
<td>9.9%</td>
<td>9.8%</td>
<td>11.9%</td>
<td>12.6%</td>
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<tr>
<td>16</td>
<td>2017 95th% Diff</td>
<td>144.9</td>
<td>116.6</td>
<td>81.5</td>
<td>72.9</td>
<td>72.9</td>
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<tr>
<td>17</td>
<td>DSM Reduction to Capacity by 2017</td>
<td>-</td>
<td>-</td>
<td>-</td>
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<td>-</td>
<td>-</td>
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<tr>
<td>18</td>
<td>Coal Capacity by 2017</td>
<td>-</td>
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<td>-</td>
<td>-</td>
<td>-</td>
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<td>-</td>
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<tr>
<td>19</td>
<td>CCCT Capacity by 2017</td>
<td>-</td>
<td>16</td>
<td>117</td>
<td>117</td>
<td>117</td>
<td>106</td>
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<td>20</td>
<td>CT Capacity by 2017</td>
<td>394</td>
<td>233</td>
<td>-</td>
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<td>-</td>
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<tr>
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<td>Wind Nameplate by 2017</td>
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<td>Oil Sands Capacity by 2017</td>
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<td>OtherRenew Capacity by 2017</td>
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<td>26</td>
<td>Coal Capacity by 2027</td>
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<td>-</td>
<td>238</td>
<td>349</td>
<td>377</td>
<td>377</td>
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<td>27</td>
<td>CCCT Capacity by 2027</td>
<td>-</td>
<td>16</td>
<td>249</td>
<td>226</td>
<td>145</td>
<td>106</td>
<td>106</td>
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<td>28</td>
<td>CT Capacity by 2027</td>
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<tr>
<td>30</td>
<td>Oil Sands Capacity by 2027</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>211</td>
<td>226</td>
</tr>
<tr>
<td>31</td>
<td>OtherRenew Capacity by 2027</td>
<td>20</td>
<td>59</td>
<td>78</td>
<td>78</td>
<td>78</td>
<td>78</td>
<td>78</td>
<td>59</td>
<td>59</td>
</tr>
<tr>
<td>32</td>
<td>Other Resources Capacity by 2027</td>
<td>-</td>
<td>160</td>
<td>292</td>
<td>292</td>
<td>292</td>
<td>303</td>
<td>303</td>
<td>303</td>
<td>303</td>
</tr>
</tbody>
</table>
Power Supply Risk Comparison

![Graph showing Power Supply Risk Comparison from 2008 to 2027. The graph compares 'No Resource Additions' and '50/50 Cost/Risk Resource Mix.' The percentages range from 0% to 35% on the y-axis, and the years from 2008 to 2027 on the x-axis. The graph indicates a general decrease in risk from 2008 to 2013, with fluctuations from 2014 onwards.](image)

- **No Resource Additions**
- **50/50 Cost/Risk Resource Mix**

Avista Corp 2007 Electric IRP
Resource Mix (50/50) Energy

New Resource Contribution to Energy Needs

- Seq. Coal
- Other Renewables
- Wind
- CCCT-Fixed Gas
- CCCT
- SCCT
- Short-term Purchase
- Short-term Sale
- Energy Need

MW of Capacity/Energy

Resource Mix (75/25) Capacity

New Resource Contribution to Capacity Needs

- Seq. Coal
- Other Renewables
- Wind
- CCCT-Fixed Gas
- CCCT
- SCCT
- Short-term Purchase
- Short-term Sale
- Capacity Need

MW of Capacity/Energy

- 2008
- 2009
- 2010
- 2011
- 2012
- 2013
- 2014
- 2015
- 2016
- 2017
- 2018
- 2019
- 2020
- 2021
- 2022
- 2023
- 2024
- 2025
- 2026
- 2027
Resource Mix (75/25) Energy

New Resource Contribution to Energy Needs

MW of Capacity/Energy:
- 0
- 100
- 200
- 300
- 400
- 500
- 600
- 700
- 800
- 900
- 1,000

Year:
- 2008
- 2009
- 2010
- 2011
- 2012
- 2013
- 2014
- 2015
- 2016
- 2017
- 2018
- 2019
- 2020
- 2021
- 2022
- 2023
- 2024
- 2025
- 2026
- 2027

Colors:
- Seq. Coal
- Other Renewables
- Wind
- CCCT-Fixed Gas
- CCCT
- SCCT
- Short-term Purchase
- Short-term Sale
- Energy Need
Next Steps

- Finalize Preferred Resource Strategy and add “lumpiness”
- Conduct additional portfolio analysis
- Test Preferred Resource Strategy against all futures & scenarios
Cost of Service

2007 Electric Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
March 28, 2007

Tara Knox
Cost of Service Background

Cost of Service Process (See handout)
- Purpose is to determine the share of total cost each customer group should pay based on usage characteristics
Production and Transmission Costs are classified as energy-related and demand-related components
  - Energy is total annual consumption
  - Demand is simultaneous consumption (peak)
Over the past 20 years, Washington has used “peak credit” to classify Production and Transmission Costs, Avista has also used “peak credit” in Idaho over the same period
Avista’s Current Cost of Service Calculation

- Replacement Cost Comparison (See handout)
- All Avista resources represented
- Thermal segregated from Hydro, with their own peak credit factors
  - CS2 as intermediate plant included with thermal base load
  - Brings down the average thermal cost which raises the demand proportion
- Transmission ratio is 50/50 weighting of thermal and hydro ratios
Puget Sound Energy – Cost of Service

• PSE uses a levelized cost comparison
  ▪ Compares hypothetical CT with a hypothetical CCCT
  ▪ Peaking unit hours of operation and fuel choices are derived from the Puget IRP
Cost of Service Questions

- Can we incorporate IRP information into Avista’s Demand/Energy classification?
- From an operating prospective, what is the appropriate cost split between demand and energy?
- Looking for suggestions
ELECTRIC COST OF SERVICE STUDY FLOWCHART

Pro Forma Results of Operations

Functionalization

Production
Transmission
Distribution and Customer Relations
Common

Classification

Energy / Commodity Related
Demand / Capacity Related
Customer Related

Allocation

Direct Assignment Generation Level mWh's
Customer Level mWh's
Direct Assignment Coincident Peak
Non-Coincident Peak
Direct Assignment Number of Customers
Weighted Number of Customers

Residential
Small General
Large General
Extra Large General
Pumping
Street & Area Lights

Pro Forma Results of Operations by Customer Group
<table>
<thead>
<tr>
<th>Thermal and Coyote Springs</th>
<th>Replacement Cost $ (1)</th>
<th>Installed Capacity KW (2)</th>
<th>Cost per KW $</th>
<th>%</th>
<th>Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kettle Falls (212)</td>
<td>169,066,749</td>
<td>50,700</td>
<td>3,335</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Colstrip (410)</td>
<td>282,403,948</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Colstrip (411)</td>
<td>211,270,898</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Colstrip</td>
<td>503,674,846</td>
<td>233,400</td>
<td>2,158</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coyote Springs II (610)</td>
<td>162,220,875</td>
<td>267,000</td>
<td>566</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Thermal</td>
<td>835,062,570</td>
<td>571,100</td>
<td>1,462</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Peaking Units</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Kettle Falls CT (211)</td>
<td>9,16,018</td>
<td>7,200</td>
<td>1,273</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northeast Spokane CT (213)</td>
<td>27,081,245</td>
<td>61,800</td>
<td>428</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boulder Park CT (216)</td>
<td>31,567,782</td>
<td>24,600</td>
<td>1,283</td>
<td></td>
<td></td>
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<tr>
<td>Rathdrum CT (310)</td>
<td>50,872,834</td>
<td>165,500</td>
<td>386</td>
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<td></td>
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<tr>
<td>Total Peaking Units</td>
<td>127,685,880</td>
<td>260,100</td>
<td>491</td>
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</table>

<table>
<thead>
<tr>
<th>Hydro Plant</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Monroe Street (201)</td>
<td>46,947,839</td>
<td>14,800</td>
<td>3,172</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Little Falls (202)</td>
<td>104,086,383</td>
<td>32,000</td>
<td>3,253</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Long Lake (203)</td>
<td>271,004,114</td>
<td>70,000</td>
<td>3,381</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Upper Falls (204)</td>
<td>58,288,767</td>
<td>10,000</td>
<td>5,829</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nine Mile (205)</td>
<td>82,084,830</td>
<td>26,400</td>
<td>3,109</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Post Falls (300)</td>
<td>79,262,577</td>
<td>14,800</td>
<td>5,356</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cabinet Gorge (304)</td>
<td>433,446,050</td>
<td>265,000</td>
<td>1,636</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Noxon Rapids (401)</td>
<td>584,184,717</td>
<td>473,400</td>
<td>1,234</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Hydro</td>
<td>1,059,306,177</td>
<td>906,400</td>
<td>1,831</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Thermal Plant Average Replacement Cost per KW Capacity | $1,462 | 100.00% |
| Peaking Units Average Replacement Cost per KW Capacity | $491 | 33.57% Demand |
| Remainder | $971 | 66.43% Energy |

**Thermal Peak Credit**

| Hydro Plant Average Replacement Cost per KW Capacity | $1,831 | 100.00% |
| Peaking Units Average Replacement Cost per KW Capacity | $491 | 26.82% Demand |
| Remainder | $1,340 | 73.18% Energy |

**Hydro Peak Credit**

| Transmission | 50/50 Weighting Thermal and Hydro Demand Percentages | 30.19% Demand |
| Transmission | 50/50 Weighting Thermal and Hydro Energy Percentages | 69.81% Energy |

**Transmission Peak Credit**


(2) From 2005/Q4 FERC Form 1, Pages 402, 403, 406, 407, and 410, line 5 for each plant.
Estimated Resource Integration Costs

Randy Gnaedinger
System Planning Engineer
Topics

Study Work Performed

Avista’s Transmission System vs. Other Utilities System

Regional Concerns

Resource Integration Report
Study Work Outline

• Generation Size
  – 50 to 400+ MW
  – At 23 total different locations

• Indifferent of Fuel Type
  – Wind vs. Natural Gas

• Timeframe – 2015

• Powerflow
  – 3 seasons
Outside vs. Inside Avista’s Transmission System

• Knowledge of One's Own System

• Future Projects

• Special Circumstances
  – Western Montana Hydro Agreement
Regional Concerns

Transmission Paths

- West of Hatwai
- Idaho to Northwest
- Montana to Northwest

Regional Process and Other Utility Assessment
2007 IRP Integration Report

2015 Timeframe
Smaller Project Integration
Larger Project Integration
Cost Estimates
## Estimated Integration Costs Inside Avista’s System

<table>
<thead>
<tr>
<th>MW Size</th>
<th>Location</th>
<th>50 MW</th>
<th>100 MW</th>
<th>250 MW</th>
<th>400+ MW</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Sprague, WA</td>
<td>NA</td>
<td>NA</td>
<td>$58M</td>
<td>$80+M</td>
</tr>
<tr>
<td></td>
<td>Spokane/ Cœur d’Alene</td>
<td>$3M</td>
<td>$7M</td>
<td>$32M</td>
<td>$32M-$500M</td>
</tr>
<tr>
<td></td>
<td>Mica Peak</td>
<td>$4M</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Clark Fork Hydro</td>
<td>$0</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Dayton, WA</td>
<td>$32M</td>
<td>$32M</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Reardan, WA</td>
<td>$2M</td>
<td>$13M</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Lind, WA</td>
<td>$1.5M</td>
<td>$6M</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Othello, WA</td>
<td>$1.5M</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td></td>
<td>Colfax, WA</td>
<td>$1.5M</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>
Questions?

2007 IRP Estimated Resource Integration Costs Document is posted on Avista’s OASIS
## Avista Utilities 2007 Integrated Resource Plan
### Technical Advisory Committee Meeting No. 5 Agenda
#### Wednesday April 25, 2007

<table>
<thead>
<tr>
<th>Topic</th>
<th>Time</th>
<th>Staff</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Introductions</td>
<td>9:30</td>
<td>Barcus</td>
</tr>
<tr>
<td>2. Review of 4&lt;sup&gt;th&lt;/sup&gt; TAC Meeting</td>
<td>9:40</td>
<td>Lyons</td>
</tr>
<tr>
<td>3. Presentation of PRS for 2007 IRP</td>
<td>9:45</td>
<td>Kalich/Gall</td>
</tr>
<tr>
<td>4. Lunch</td>
<td>12:00</td>
<td></td>
</tr>
<tr>
<td>5. PRS continued</td>
<td>12:45</td>
<td>Kalich/Gall</td>
</tr>
<tr>
<td>6. Action Items</td>
<td>3:00</td>
<td>Lyons</td>
</tr>
<tr>
<td>7. Adjourn</td>
<td>3:30</td>
<td></td>
</tr>
</tbody>
</table>
Review of the Fourth Technical Advisory Committee Meeting

2007 Electric Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
April 25, 2007

John Lyons
Fourth Technical Advisory Committee Meeting

- Market Analysis
- Load Forecast Scenario on Global Warming
- Conservation Program Update
- DSM at Avista Facilities
- Portfolio Selection Criteria
- Cost of Service
- Transmission Cost Estimates for the 2007 IRP
Preferred Resource Strategy Analysis

2007 Electric Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
April 25, 2007

Clint Kalich
James Gall
Short List Resource Options

(“Levelized $2007 “real”$/MWh)

- CCCT 2008
- Co-Gen
- Geothermal
- Biomass
- Nuclear
- MT- Sub 2013
- MT- IGCC spare 2013
- Columbia Basin Wind
- Montana Wind
- NW- Sub 2013
- Aero Peaker 2008
- Avista Wind
- NW- IGCC spare 2013
- Frame Peaker 2008
- MT- IGCC spare seq 2018
- NW- IGCC spare seq 2018
- Alberta Oil Sands

- Gen Capital & Overheads
- Trans Capital & Overheads
- Fixed VOM
- Trans (non Capital)
- Losses
- Fuel Costs
- VOM
- Emissions
## Resource Capital Costs *(Excludes Transmission)*

<table>
<thead>
<tr>
<th>Resource Option</th>
<th>2007$/kW</th>
<th>Resource Option</th>
<th>2007$/kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCCT</td>
<td>786</td>
<td>Coal – Subcritical</td>
<td>1,906</td>
</tr>
<tr>
<td>SCCT-Aero</td>
<td>628</td>
<td>Coal – Supercritical</td>
<td>2,004</td>
</tr>
<tr>
<td>SCCT-Frame</td>
<td>419</td>
<td>Coal – Ultracritical</td>
<td>2,010</td>
</tr>
<tr>
<td>Wind</td>
<td>1,884</td>
<td>Coal – CFB</td>
<td>2,155</td>
</tr>
<tr>
<td>Geothermal</td>
<td>4,000</td>
<td>IGCC</td>
<td>2,378</td>
</tr>
<tr>
<td>Biomass</td>
<td>3,500</td>
<td>IGCC - w/Spare Gasifier</td>
<td>2,524</td>
</tr>
<tr>
<td>Oil Sands</td>
<td>3,963</td>
<td>IGCC – Sequestered</td>
<td>3,045</td>
</tr>
<tr>
<td>Nuclear</td>
<td>3,100</td>
<td>IGCC - Sequestered w/Spare Gasifier</td>
<td>3,232</td>
</tr>
<tr>
<td>Small Co-Gen</td>
<td>2,100</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Company cannot construct options highlighted in red
Avista’s Annual Average Resource Need
Preferred Resource Strategy - Capacity

- Short-term Sale
- CCCT
- Other Renewables
- DSM
- Hydro Upgrades
- Capacity Shortage

MW

Preferred Resource Strategy - Energy

- Short-term Sale
- CCCT
- Wind
- Other Renewables
- DSM
- Hydro Upgrades
- Energy Shortage
What is the Efficient Frontier?

- Demonstrates the trade off of cost and risk
- Difficulty: how much additional cost are we willing to pay to reduce risk
Efficient Frontiers

2008 to 2017 Total Cost Percent Change from 75% Cost/25% Risk
Efficient Frontier- Base Case

No RPS and Corporate RPS to be included in final document
Efficient Frontier - Carbon “Okay” Future

2008 to 2017 Total Cost Percent Change from 75% Cost/25% Risk

- No Additions
- SCCT & Green Tags
- CCGT & Green Tags
- PRS - No Fixed Gas
- Renewables & CT
- Wind 20%
- Cont. to PMPRS
- 25% Risk
- 50% Risk
- 100% Risk
- 2005 PRS
Portfolio Comparison- Total Cost
Power Supply Expense and New Resource Costs

No Additions
100/0 Cost/Risk
CT
CCCT
PRS- No Fixed Gas
Wind with 20% CC
75/25 Cost/Risk
PRS
50/50 Cost/Risk
25/75 Cost/Risk
Wind & CT
2005 IRP
0/100 Cost/Risk

2008 Total Cost [Million$ NPV]

2008-2017 NPV
2018-2027 NPV
Portfolio Comparison- 2017 Total Cost
Total of existing portfolio and new resources

2017 Power Supply Expense and New Resource Costs (Millions)
Portfolio Comparison- 2017 Risk

Coefficient of variation (standard deviation divided by total expected cost)

0/100 Cost/Risk
25/75 Cost/Risk
50/50 Cost/Risk
75/25 Cost/Risk
PRS
2005 IRP
Wind with 20% CC
Wind & CT
PRS- No Fixed Gas
CCCT
100/0 Cost/Risk
CT
No Additions

2017 Total Cost Stdev / 2017 Expected Total Cost
Portfolio Comparison- Max Annual Increase

Power supply-related costs ONLY (2008-2018 timeframe)

- 100/0 Cost/Risk
- CT
- CCCT
- No Additions
- 25/75 Cost/Risk
- 50/50 Cost/Risk
- 75/25 Cost/Risk
- Wind with 20% CC
- Wind & CT
- PRS- No Fixed Gas
- 0/100 Cost/Risk
- PRS
- 2005 IRP

Increase to Power Supply Related Rates
Portfolio Comparison - Avg Increase

Power Supply Related Costs ONLY (2008-2018 timeframe)

- No Additions
- 100/0 Cost/Risk
- CT
- CCCT
- Wind with 20% CC
- PRS - No Fixed Gas
- 2005 IRP
- PRS
- 75/25 Cost/Risk
- 25/75 Cost/Risk
- 50/50 Cost/Risk
- 0/100 Cost/Risk
- Wind & CT

Portfolio Comparison- Capital Costs
Net Present Value of 2008-2017 Capital Expenditures

PRS may require capital or debt equivalents to stabilize the price of natural gas
Portfolio Comparison - Renewables

Nameplate Renewable Resources

Renewables Capacity (MW Nameplate)
Gas-Fired Combined Cycle With Fixed Gas

- Medium- to long-term fixed-price gas contract, or
- Could be coal gasified into pipeline-quality gas
  - Provide a significant new source of gas supply
  - Create a sequestered IGCC plant w/o operational trade-offs
    - Remote locations, altitude penalties, gasifier reliability
- Model is flexible in modeling any type of fixed gas price
- Intent of this resource is to illustrate the ability to reduce power cost risk without building a coal resource directly
Base Case/PRS Fixed Gas Assumptions

- Can select resource in any year
- Pay $2 premium above expected gas price
- Purchase 75% of the fuel as fixed
- All combined cycle plants have fixed gas component
- What if:
  - Pay $3.50 gas price premium
  - Pay $5.00 gas price premium
  - All spot market purchases
  - Purchase 25% of fuel as fixed
  - Purchase 100% of fuel as fixed

May need to create new tool to optimize the amount of fuel to be purchased at a fixed price
Efficient Frontier - Fixed NG Gas Price Sensitivity

2008 to 2017 Total Cost Percent Change from PRS

2017 Percent Change of Power Supply Cost Risk

Base Case
Base Case - No Fixed Priced Gas
75% Cost 25% Risk
PRS
## Fixed Gas Selection Impacts (MW)

### 75% Cost/25% Risk Portfolio Criteria (2008-2017)

<table>
<thead>
<tr>
<th>Fueling Type</th>
<th>CCCT</th>
<th>CCCT Fixed</th>
<th>Wind</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>PRS (75% fixed gas fueling @ $2/dth premium)</td>
<td>0</td>
<td>350</td>
<td>300</td>
<td>35</td>
</tr>
<tr>
<td>$3.50 Gas Price Premium (75% fixed gas)</td>
<td>129</td>
<td>221</td>
<td>322</td>
<td>35</td>
</tr>
<tr>
<td>$5.00 Gas Price Premium (75% fixed gas)</td>
<td>211</td>
<td>139</td>
<td>400</td>
<td>35</td>
</tr>
<tr>
<td>0% Fixed Price Fueling</td>
<td>340</td>
<td>0</td>
<td>300</td>
<td>40</td>
</tr>
<tr>
<td>25% Fixed Price Fueling @ $2/dth premium</td>
<td>0</td>
<td>350</td>
<td>300</td>
<td>35</td>
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<tr>
<td>100% Fixed Price Fueling @ $2/dth premium</td>
<td>31</td>
<td>319</td>
<td>257</td>
<td>35</td>
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</table>
Impacts of Varying Capital Costs
Applied to 25% Risk Reduction Portfolio Criteria

Assumptions: $/kW

<table>
<thead>
<tr>
<th>Resource</th>
<th>Low</th>
<th>Base Case</th>
<th>High</th>
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<tbody>
<tr>
<td>Wind</td>
<td>1,300</td>
<td>1,884</td>
<td>2,500</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>600</td>
<td>786</td>
<td>1,000</td>
</tr>
<tr>
<td>IGCC Coal w/ Sequestration</td>
<td>2,500</td>
<td>3,232</td>
<td>N/A</td>
</tr>
<tr>
<td>Alberta Oil Sands</td>
<td>2,000</td>
<td>3,963</td>
<td>N/A</td>
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</tbody>
</table>

Sensitivity did not change the amount of resource selection

Wind Results

<table>
<thead>
<tr>
<th></th>
<th>2008-2017</th>
<th>2017-2027</th>
</tr>
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<tbody>
<tr>
<td>Base Case</td>
<td>300</td>
<td>0</td>
</tr>
<tr>
<td>Low</td>
<td>400</td>
<td>200</td>
</tr>
<tr>
<td>High</td>
<td>143</td>
<td>0</td>
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</tbody>
</table>

Limit Reached
## Impacts of Varying Capital Costs (MW)

*Quantifies Low Risk Portfolios Changes to Capital Intensive Resources*

<table>
<thead>
<tr>
<th></th>
<th>50/50</th>
<th>40/60</th>
<th>25/75</th>
<th>0/100</th>
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</thead>
<tbody>
<tr>
<td><strong>Base Case</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IGCC w/ Seq</td>
<td>0</td>
<td>0</td>
<td>130</td>
<td>101</td>
</tr>
<tr>
<td>Alberta Oil Sands</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>226</td>
</tr>
<tr>
<td><strong>IGCC @ 2,500</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IGCC w/ Seq</td>
<td>0</td>
<td>66</td>
<td>299</td>
<td>101</td>
</tr>
<tr>
<td>Alberta Oil Sands</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>226</td>
</tr>
<tr>
<td><strong>Oil Sands @ 2,000</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IGCC w/ Seq</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>101</td>
</tr>
<tr>
<td>Alberta Oil Sands</td>
<td>210</td>
<td>226</td>
<td>226</td>
<td>226</td>
</tr>
</tbody>
</table>
Key PRS Message Points

- Meets requirements of I-937 & SB6001
- Conservation up 100% from 2003 IRP, 50% from 2003
- No coal-fired generation, but sequestration possible in outer years
- Higher capital costs reduced renewables contribution by half
- A return to gas-fired resources
- Fixed gas contracts provide significant portfolio benefits, allowing emulation of coal plant characteristics (stable rates)
- Plan guided by linear programming PRSiM model
- Ignoring Q2 surpluses in L&R tabulation increases costs without reducing risk
- Resource acquisition allows approximately a 15% planning margin
Action Items for the 2007 IRP

2007 Electric Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
April 25, 2007

John Lyons
2005 IRP Action Plan

1. Renewable energy and emissions
   - Wind potential study, monitor legislation, research clean coal and sequestration, and assess biomass potential

2. Modeling enhancements
   - 70-year water record and improve Avista Linear Programming Model

3. Transmission modeling and research
   - Maintain existing rights, collaborate with BPA, regional participation, and cost study

4. Conservation
   - Load shifting programs and complete conservation control project

Renewable Energy

- Continue to study potential wind sites within service territory
- Study Montana wind resources and transmission issues
- Learn more about non-wind renewables to satisfy RPS requirements
2007 IRP Action Plan – Conservation

- Reevaluate the process of integrating conservation into the IRP
- Study and quantify transmission and distribution efficiency concepts
- Determine potential impacts and costs of load management options currently being reviewed by the Heritage Project
- Develop and quantify the long-term impacts of the recently signed contractual relationship with the Northwest Sustainable Energy for Economic Development organization
2007 IRP Action Plan – Emissions

- Continue to monitor local, state, and federal level rules and regulations concerning power plant emissions. Most notably greenhouse gases.
- Continue to study emissions markets and costs/benefits of participating in an active market like the Chicago Climate Exchange
2007 IRP Action Plan – Modeling and Forecasting Enhancements

- Study potential for fixed gas through financial arrangements or gasified coal
- Continue to study the impact of global warming on the load forecast
- Monitor the following conditions for the load forecast: large load additions, Shoshone county mining developments, and the market penetration of electric cars
2007 IRP Action Plan – Transmission Issues

- Maintain existing transmission rights
- Continue to work with BPA on transmission issues
- Participate in regional and sub-regional transmission planning efforts
- Continue to evaluate the cost of integrating new resources into our system
2007 IRP Action Plan – Other Areas of Interest

Suggestions for Action Items to be developed for the 2009 IRP?
Next Steps

2007 Electric Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
April 25, 2007

Clint Kalich
Next Steps

- Management Review Draft Released on Tuesday, May 1
  - Comments back on or before June 1
- Draft IRP Released to TAC Members on Friday, June 15
  - Comments back on or before Friday, July 13
  - Does TAC want to reconvene prior to or on July 13?
- Final 2007 IRP Released August 31
- On to the 2009 IRP!!!
Climate Stewardship Act Future

Net Present Value of New Resource Cost and Power Supply Costs by Portfolio
(2007 $Millions)

2017 Total Power Supply Expenses ($Millions)

Maximum Annual Cost Change for Power Supply (%)
No Carbon Legislation Future

Net Present Value of New Resource Cost and Power Supply Costs by Portfolio
(2007 $Millions)

2017 Total Power Supply Expenses ($Millions)

Maximum Annual Cost Change for Power Supply (%)

Avista Corp 2007 Electric IRP
Supplemental - Section 2

Average Annual Power Cost Component Change 2008-2017 (%)

Volatility (Coefficient of Variation) of 2017 Power Supply Expenses

Volatile Gas Future

Net Present Value of New Resource Cost and Power Supply Costs by Portfolio

(2007 $Millions)

2017 Total Power Supply Expenses ($Millions)

Maximum Annual Cost Change for Power Supply (%)

Avista Corp 2007 Electric IRP
Average Annual Power Cost Component Change 2008-2017 (%)

Volatility (Coefficient of Variation) of 2017 Power Supply Expenses

Summary of the Cost-Effectiveness of Demand-Side Management Measures

The following provide summary statistics for the DSM measures analyzed for the final integrated (demand and supply) resource portfolio.

The files contain a disaggregation of the various components of the avoided cost structure used within the analysis to include the avoided cost of energy as well as transmission, distribution and generation capacity costs. Additional adjustments to the avoided cost for risk and emissions have been included to facilitate direct comparison of demand and supply-side resource options.

The measure’s cost, expected life, and energy savings are included in the calculation of the Total Resource Cost (TRC). The TRC has been expressed as a ratio between costs and benefits within the summary sheets as a means of determining the cost-effectiveness of each measure.

Additional graphics indicate the components of each measure’s total avoided cost.

The 8760-hour load shape of each measure has not been included in the summary sheets due to the sheer volume of data, but an indication of the manner in which the load shape has been applied to derive peak transmission, distribution and generation credits has been included. These three categories are based upon measures that are very likely to peak coincident with system loads (“driver” load profiles, such as air conditioning loads), those whose load shapes are independent of the primary drivers of system load (“non-drivers”, such as lighting loads) and those measures that are very likely to be at a zero load during system peak (“non-drivers,” such as space heating loads).
Residential Measures
## Energy efficient split AC (SEER 12 to 14)

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>$</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.548</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>53%</td>
<td></td>
</tr>
<tr>
<td>$0.036</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>3%</td>
<td></td>
</tr>
<tr>
<td>$281.00</td>
<td>0.369 PV of avoided cost of generation capacity</td>
<td>35%</td>
<td></td>
</tr>
<tr>
<td>$68.42</td>
<td>0.090 PV of avoided cost of T&amp;D capacity</td>
<td>9%</td>
<td></td>
</tr>
<tr>
<td>$1.042</td>
<td></td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

**driver**, "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- **7.41% Discount rate**
- **18 Measure life**
- **232 Annual kWh savings per unit**
- **0.1312% Percent of annual energy in maximum hour (use for "driver" measures)**
- **0.0561% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)**

| $ | 127.03 PV of avoided cost of energy (energy + emissions + risk) | 53% | |
| $ | 8.26 PV of avoided cost of energy (T&D losses) | 3% | |
| $ | 85.53 PV of avoided cost of generation capacity | 35% | |
| $ | 20.82 PV of avoided cost of T&D capacity | 9% | |
| $ | - PV of avoided cost of natural gas | | |
| $ | - PV of non-energy benefits | | |
| $241.64 | Total Resource Cost test benefits | | |
| $518.00 | Incremental customer cost | | |
| $ | - Incremental non-incentive utility cost | | |
| $518.00 | Total Resource Cost test costs | | |

*($276) Net TRC $ amount

**0.47 TRC benefit / cost ratio**

Energy efficient split AC (SEER 12 to 14)
Central air conditioning efficiency tune-up

Summarization of AC benefits and comparison to TRC costs

| Measure life | 5
| Annual kWh savings per unit | 125
| Percent of annual energy in maximum hour (use for "driver" measures) | 0.1312%
| Percent of annual energy in average hour of designated system peak (use for "non-driver" measures) | 0.0561%

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>T&amp;D capacity</th>
<th>Generation capacity</th>
<th>Energy, emissions, risk</th>
<th>T&amp;D losses</th>
<th>Natural gas</th>
<th>Non-energy benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.192 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.012 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.032 PV of avoided cost of T&amp;D capacity</td>
<td>$0.371</td>
<td>$0.52 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.032 PV of avoided cost of T&amp;D capacity</td>
<td>$0.371</td>
</tr>
</tbody>
</table>

$102.97 | $0.135 PV of avoided cost of generation capacity | 52%
$24.42 | $0.032 PV of avoided cost of T&D capacity | 9%
$0.371 | $0.032 PV of avoided cost of T&D capacity | 9%

7.41% Discount rate
5Measure life
125Annual kWh savings per unit
0.1312% Percent of annual energy in maximum hour (use for "driver" measures)
0.0561% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

50.0503 Levelized cost/kWh of four energy components of AC
$0.0412 Levelized cost/kWh of two capacity components of AC

$23.94 PV of avoided cost of energy (energy + emissions + risk)
$16.89 PV of avoided cost of generation capacity
$4.00 PV of avoided cost of T&D capacity
$0.00 PV of avoided cost of natural gas
$0.00 PV of non-energy benefits

$46.39 Total Resource Cost test benefits

$123.00 Incremental customer cost
$123.00 Total Resource Cost test costs

$123.00 Incremental non-incentive utility cost

$(77) Net TRC $ amount

0.38 TRC benefit / cost ratio

Central air conditioning efficiency tune-up
**Energy efficient window AC (SEER 12 to 14)**

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Description</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.338 PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
<td>51%</td>
</tr>
<tr>
<td>$0.022 PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
<td>3%</td>
</tr>
<tr>
<td>$184.47 $0.242 PV of avoided cost of generation capacity</td>
<td></td>
<td>37%</td>
</tr>
<tr>
<td>$44.23 $0.058 PV of avoided cost of T&amp;D capacity</td>
<td></td>
<td>9%</td>
</tr>
<tr>
<td>$0.660</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

**Driver, "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)**

- 7.41% Discount rate
- 10 Measure life
- 127 Annual kWh savings per unit
- 0.1312% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0561% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

<table>
<thead>
<tr>
<th>Description</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$42.95 PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$2.79 PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$30.73 PV of avoided cost of generation capacity</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$7.37 PV of avoided cost of T&amp;D capacity</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- PV of avoided cost of natural gas</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- PV of non-energy benefits</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$83.84 Total Resource Cost test benefits</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$106.00 Incremental customer cost</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$- Incremental non-incentive utility cost</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$106.00 Total Resource Cost test costs</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**($22) Net TRC $ amount**

**0.79 TRC benefit / cost ratio**

**Total Resource Cost test benefits**

**Avoided Cost Value**

- T&D capacity
- Generation capacity
- Energy, emissions, risk
- T&D losses

**Avista Corp 2007 Electric IRP**
## Buy back inefficient appliances (to avoid reuse)

**Summary of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.233</td>
<td>$0.267</td>
<td>87%</td>
</tr>
<tr>
<td>$0.015</td>
<td>$0.016</td>
<td>6%</td>
</tr>
<tr>
<td>$0.004</td>
<td>$0.004</td>
<td>1%</td>
</tr>
<tr>
<td>$0.267</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

**Per first year kWh**

$120.83 $0.016 $0.016 PV of avoided cost of generation capacity 6%

$28.72 $0.004 $0.004 PV of avoided cost of T&D capacity 1%

**Non-driver**

"Driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

<table>
<thead>
<tr>
<th>Discount rate</th>
<th>Measure life</th>
<th>Annual kWh savings per unit</th>
<th>Percent of annual energy in maximum hour (use for &quot;driver&quot; measures)</th>
<th>Percent of annual energy in average hour of designated system peak (use for &quot;non-driver&quot; measures)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.41%</td>
<td>6</td>
<td>625</td>
<td>0.0148%</td>
<td>0.0129%</td>
</tr>
</tbody>
</table>

**Avoided Cost Value**

- **Energy, emissions, risk**: $166.90 Total Resource Cost test benefits
- **Generation capacity**: $9.74 PV of avoided cost of generation capacity
- **T&D losses**: $9.45 PV of avoided cost of T&D losses
- **T&D capacity**: $2.32 PV of avoided cost of T&D capacity
- **Natural gas**: $0 PV of avoided cost of natural gas
- **Non-energy benefits**: $0 PV of non-energy benefits

**Additional Costs**

- **Incremental customer cost**: $100.00
- **Incremental non-incentive utility cost**: $0
- **Total Resource Cost test costs**: $100.00

**Net TRC $ amount**: $67

**TRC benefit / cost ratio**: 1.67
Caulking and weatherstripping (single family, resistance)

<table>
<thead>
<tr>
<th>Summary of AC benefits and comparison to TRC costs</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Per first year kW</td>
<td>Per first year kWh</td>
</tr>
<tr>
<td>$0.371</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
</tr>
<tr>
<td>$0.024</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
</tr>
<tr>
<td>$184.47</td>
<td>-</td>
</tr>
<tr>
<td>$44.23</td>
<td>-</td>
</tr>
<tr>
<td>$0.395</td>
<td></td>
</tr>
<tr>
<td>$296.14</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
</tr>
<tr>
<td>$19.25</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
</tr>
<tr>
<td>$</td>
<td>PV of avoided cost of generation capacity</td>
</tr>
<tr>
<td>$</td>
<td>PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$</td>
<td>PV of avoided cost of natural gas</td>
</tr>
<tr>
<td>$</td>
<td>PV of non-energy benefits</td>
</tr>
<tr>
<td>$315.39</td>
<td>Total Resource Cost test benefits</td>
</tr>
<tr>
<td>$650.00</td>
<td>Incremental customer cost</td>
</tr>
<tr>
<td>$</td>
<td>Incremental non-incentive utility cost</td>
</tr>
<tr>
<td>$650.00</td>
<td>Total Resource Cost test costs</td>
</tr>
</tbody>
</table>

Discount rate: 7.41%
Measure life: 10 years
Annual kWh savings per unit: 798
Percent of annual energy in maximum hour (use for "driver" measures): 0.0019%
Percent of annual energy in average hour of designated system peak (use for "non-driver" measures): 0.0000%

Avoided Cost Value

[Diagram showing the distribution of costs]
## Central heat pump efficiency tune-up

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.245</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>94%</td>
</tr>
<tr>
<td>$0.016</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$120.83</td>
<td>$- PV of avoided cost of generation capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$28.72</td>
<td>$- PV of avoided cost of T&amp;D capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$2.60</td>
<td>PV of avoided cost of generation capacity</td>
<td>0%</td>
</tr>
<tr>
<td></td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$124.51</td>
<td>Total Resource Cost test benefits</td>
<td>100%</td>
</tr>
</tbody>
</table>

- **Measure type**: "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- **Discount rate**: 7.41%
- **Annual kWh savings per unit**: 6
- **Percent of annual energy in maximum hour (use for "driver" measures)**: 0.0019%
- **Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)**: 0.0000%

### Avoided Cost Value

- **T&D losses**
- **Generation capacity**
- **Energy, emissions, risk**

### Other values:

- **Levelized cost/kWh of four energy components of AC**: $0.0553
- **Levelized cost/kWh of two capacity components of AC**: $0.0000
- **Net TRC $ amount**: $2
- **TRC benefit / cost ratio**: 1.01

---

**Avista Corp 2007 Electric IRP**
Duct insulation retrofit (R3-R8, single family, resistance)

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Benefit Description</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.836 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>94%</td>
<td></td>
</tr>
<tr>
<td>$0.054 PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>$372.36 $</td>
<td>0%</td>
<td></td>
</tr>
<tr>
<td>$92.43 $</td>
<td>0%</td>
<td></td>
</tr>
<tr>
<td>$0.890</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

Note:
- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 1,134 Annual kWh savings per unit
- 0.0019% Percent of annual energy in maximum hour
- 0.0000% Percent of annual energy in average hour of designated system peak

Avoided Cost Value

<table>
<thead>
<tr>
<th>Component</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation capacity</td>
<td>$0.0747</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>$0.0000</td>
</tr>
<tr>
<td>Energy, emissions, risk</td>
<td></td>
</tr>
<tr>
<td>Risk</td>
<td></td>
</tr>
<tr>
<td>Total energy</td>
<td>$1,009.13</td>
</tr>
<tr>
<td>Total capacity</td>
<td>0%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Incremental Costs</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer cost</td>
<td>$518.00</td>
</tr>
<tr>
<td>Non-incentive utility cost</td>
<td></td>
</tr>
<tr>
<td>Total Resource Cost test costs</td>
<td>$491</td>
</tr>
</tbody>
</table>

TRC benefit / cost ratio: 1.95

Avista Corp

2007 Electric IRP
## Duct sealing (single family, resistance)

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.642</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>94%</td>
</tr>
<tr>
<td>$0.042</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$300.00</td>
<td>PV of avoided cost of generation capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$73.31</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$0.683</td>
<td>Total energy</td>
<td>100%</td>
</tr>
<tr>
<td></td>
<td>Total capacity</td>
<td>100%</td>
</tr>
</tbody>
</table>

**Measure life**

- 7.41% Discount rate
- 1,007 Annual kWh savings per unit
- 0.0019% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0000% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

| $646.19           | PV of avoided cost of energy (energy + emissions + risk) |
| $42.00            | PV of avoided cost of energy (T&D losses) |
| $ -               | PV of avoided cost of generation capacity |
| $ -               | PV of avoided cost of T&D capacity |
| $ -               | PV of avoided cost of natural gas |
| $ -               | PV of non-energy benefits |
| $688.19           | Total Resource Cost test benefits |

| $750.00           | Incremental customer cost |
| $ -               | Incremental non-incentive utility cost |
| $750.00           | Total Resource Cost test costs |

**($62) Net TRC $ amount**

**0.92 TRC benefit / cost ratio**

**Avoided Cost Value**

- Energy, emissions, risk
- T&D losses
- T&D capacity
- Generation capacity

---

Avista Corp 2007 Electric IRP 10
## Electric vs gas clothes dryer

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.478</td>
<td>87%</td>
<td></td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.031</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$0.030</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$0.007</td>
<td>1%</td>
<td></td>
</tr>
<tr>
<td>Total energy</td>
<td>$0.547</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

###非驱动 ("驱动", "非驱动" or "零") 测量类型（基于与管理系统峰值期的相符合）

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Per unit kWh savings</th>
<th>% of total capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.41% Discount rate</td>
<td>$229</td>
<td>93% Total energy</td>
</tr>
<tr>
<td>14 Measure life</td>
<td>$15</td>
<td>7% Total capacity</td>
</tr>
<tr>
<td>479 Annual kWh savings per unit</td>
<td>$0.0155%</td>
<td></td>
</tr>
<tr>
<td>0.0127% Percent of annual energy in average hour of designated system peak (use for &quot;非驱动&quot; measures)</td>
<td>$0.0127%</td>
<td></td>
</tr>
</tbody>
</table>

### Avoided Cost Value

- **Energy, emissions, risk**
- **T&D losses**
- **T&D capacity**
- **Generation capacity**

### Other Costs

- **Total Resource Cost test benefits**: $262
- **Incremental customer cost**: $200.00
- **Incremental non-incentive utility cost**: $0
- **Total Resource Cost test costs**: $200
- **Net TRC $ amount**: $62

**TRC benefit / cost ratio**: 1.31

---

Avista Corp 2007 Electric IRP
### Electric vs HE gas water heater

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Benefit Description</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.513</td>
<td>88%</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.033</td>
<td>6%</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$0.028</td>
<td>5%</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$0.007</td>
<td>1%</td>
</tr>
<tr>
<td>Total energy</td>
<td>$0.581</td>
<td>100%</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>$0.028</td>
<td>6%</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>$0.007</td>
<td>5%</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>$0.007</td>
<td>1%</td>
</tr>
<tr>
<td>Energy, emissions, risk</td>
<td>$0.0160%</td>
<td>6%</td>
</tr>
<tr>
<td>% of annual energy in maximum hour (use for &quot;driver&quot; measures)</td>
<td>7.41%</td>
<td>94%</td>
</tr>
<tr>
<td>Annual kWh savings per unit</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>Annual kWh savings per unit</td>
<td>5,131</td>
<td></td>
</tr>
<tr>
<td>Total Resource Cost test benefits</td>
<td>$2,981.20</td>
<td></td>
</tr>
<tr>
<td>Incremental customer cost</td>
<td>$512.00</td>
<td></td>
</tr>
<tr>
<td>Incremental non-incentive utility cost</td>
<td>$512.00</td>
<td></td>
</tr>
<tr>
<td>Net TRC $ amount</td>
<td>$2,469</td>
<td></td>
</tr>
</tbody>
</table>

**TRC benefit / cost ratio**: 5.82

---

**Supplemental- Section 3**

---

**Avista Corp 2007 Electric IRP**
More efficient pumps for domestic water systems

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.496</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>88%</td>
</tr>
<tr>
<td>$0.032</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$ 248.96</td>
<td>$ 0.028 PV of avoided cost of generation capacity</td>
<td>5%</td>
</tr>
<tr>
<td>$ 60.28</td>
<td>$ 0.007 PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
</tbody>
</table>

| $0.564 | PV of avoided cost of energy (energy + emissions + risk) |

| $0.007 | PV of avoided cost of T&D capacity |

| $248.96 | $ 0.028 PV of avoided cost of generation capacity |

| $60.28 | $ 0.007 PV of avoided cost of T&D capacity |

| 94% Total energy | 100% Total capacity |

| 7.41% Discount rate | 15 Measure life |

| 250 Annual kWh savings per unit | 0.0125% Percent of annual energy in maximum hour (use for "driver" measures) |

| 0.0114% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures) | $ 124.03 PV of avoided cost of energy (energy + emissions + risk) |

| $ 8.06 PV of avoided cost of energy (T&D losses) | $ 7.09 PV of avoided cost of generation capacity |

| $ 1.72 PV of avoided cost of T&D capacity | - PV of avoided cost of natural gas |

| - PV of non-energy benefits | $ 140.90 Total Resource Cost test benefits |

| $ 200.00 Incremental customer cost | - Incremental non-incentive utility cost |

| $ 200.00 Total Resource Cost test costs | ($59) Net TRC $ amount |

| 0.79 TRC benefit / cost ratio | More efficient pumps for domestic water systems |

Avoided Cost Value

- Energy, emissions, risk
- T&D capacity
- T&D losses
- Generation capacity

Avista Corp 2007 Electric IRP 13
**Energy Star Home**

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.496</td>
<td>88%</td>
<td></td>
</tr>
<tr>
<td>$0.032</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>$0.028</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>$0.007</td>
<td>1%</td>
<td></td>
</tr>
<tr>
<td>$0.564</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>non-driver</th>
<th>&quot;driver&quot;, &quot;non-driver&quot; or &quot;zero&quot; measure type (based upon coincidence with managed system peak period)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.41%</td>
<td>Discount rate</td>
</tr>
<tr>
<td>1.800</td>
<td>Annual kWh savings per unit</td>
</tr>
<tr>
<td>0.0125%</td>
<td>Percent of annual energy in maximum hour (use for &quot;driver&quot; measures)</td>
</tr>
<tr>
<td>0.0114%</td>
<td>Percent of annual energy in average hour of designated system peak (use for &quot;non-driver&quot; measures)</td>
</tr>
</tbody>
</table>

- $ 893.01 PV of avoided cost of energy (energy + emissions + risk)
- $ 58.05 PV of avoided cost of energy (T&D losses)
- $ 51.05 PV of avoided cost of generation capacity
- $ 12.36 PV of avoided cost of T&D capacity
- PV of avoided cost of natural gas
- PV of non-energy benefits

$ 1,014.47 Total Resource Cost test benefits

$ 3,500.00 Incremental customer cost

$ 3,500.00 Total Resource Cost test costs

($2,486) Net TRC $ amount

**Avoided Cost Value**

- Generation capacity
- T&D capacity
- T&D losses
- Energy, emissions, risk

**TRC benefit / cost ratio**: 0.29
### Exterior doors (retrofit)

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th></th>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.516</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
<td>94%</td>
</tr>
<tr>
<td>$0.034</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>$248.96$</td>
<td>-</td>
<td>PV of avoided cost of generation capacity</td>
<td></td>
</tr>
<tr>
<td>$60.28$</td>
<td>-</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td></td>
</tr>
<tr>
<td>$0.550</td>
<td></td>
<td></td>
<td>100%</td>
</tr>
<tr>
<td>$0.0619</td>
<td>Levelized cost/kWh of four energy components of AC</td>
<td></td>
<td>0% Total energy</td>
</tr>
<tr>
<td>$0.0000</td>
<td>Levelized cost/kWh of two capacity components of AC</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Zero** "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 15 Measure life
- 300 Annual kWh savings per unit
- 0.0019% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0000% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$154.88 PV of avoided cost of energy (energy + emissions + risk)

$10.07 PV of avoided cost of energy (T&D losses)

$ - PV of avoided cost of generation capacity

$ - PV of avoided cost of T&D capacity

$ - PV of avoided cost of natural gas

$ - PV of non-energy benefits

$164.94 Total Resource Cost test benefits

$250.00 Incremental customer cost

$ - Incremental non-incentive utility cost

$250.00 Total Resource Cost test costs

($85) Net TRC $ amount

0.66 TRC benefit / cost ratio

---

**Avoided Cost Value**

- Generation capacity
- T&D losses
- T&D capacity
- Energy, emissions, risk

---

Avista Corp

2007 Electric IRP
**Faucet aerator (single and multi-family)**

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Per first year</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy, emissions, risk</td>
<td>$0.337</td>
<td>88%</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>$0.022</td>
<td>6%</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>$0.019</td>
<td>5%</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>$0.005</td>
<td>1%</td>
</tr>
<tr>
<td>Total energy</td>
<td>$0.383</td>
<td>100%</td>
</tr>
</tbody>
</table>

**Non-driver measure type**

- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 9 Measure life
- 76 Annual kWh savings per unit
- 0.0160% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0113% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Per first year</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy, emissions, risk</td>
<td>$169.66</td>
<td>94%</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>$0.01</td>
<td>6%</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>$40.59</td>
<td>5%</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>$0.01</td>
<td>1%</td>
</tr>
</tbody>
</table>

- 76% Total energy
- 6% Total capacity

**Levelized cost/kWh of four energy components of AC**

- $0.0561

**Levelized cost/kWh of two capacity components of AC**

- $0.0037

**Avoided Cost Value**

- Generation capacity
- T&D capacity
- Energy, emissions, risk

**Net TRC $ amount**

- $16

**TRC benefit / cost ratio**

- 2.29
Fireplace dampers (WA/ID) (chimney-top, electric heat)

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.516</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>94%</td>
</tr>
<tr>
<td>$0.034</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$248.96</td>
<td>- PV of avoided cost of generation capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$60.28</td>
<td>- PV of avoided cost of T&amp;D capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$0.550</td>
<td>PV of avoided cost of generation capacity</td>
<td>100%</td>
</tr>
<tr>
<td>$</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>100%</td>
</tr>
<tr>
<td>$</td>
<td>Total energy</td>
<td>100%</td>
</tr>
<tr>
<td>$</td>
<td>Total capacity</td>
<td>0%</td>
</tr>
</tbody>
</table>

| $1,233.84       | PV of avoided cost of energy (energy + emissions + risk) |
| $80.20          | PV of avoided cost of energy (T&D losses) |
| $               | PV of avoided cost of generation capacity |
| $               | PV of avoided cost of T&D capacity |
| $               | PV of avoided cost of natural gas |
| $               | PV of non-energy benefits |
| $1,314.04       | Total Resource Cost test benefits |
| $500.00         | Incremental customer cost |
| $               | Incremental non-incentive utility cost |
| $500.00         | Total Resource Cost test costs |
| 2.63            | TRC benefit / cost ratio |

### Avoided Cost Value

- **Generation capacity**
- **T&D losses**
- **T&D capacity**
- **Energy, emissions, risk**

**Fireplace dampers (WA/ID) (chimney-top, electric heat)**

**Supplemental- Section 3**

Avista Corp 2007 Electric IRP
### Electric furnace vs condensing gas space heat conversion

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Per first year kWh</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.836</td>
<td></td>
<td>94%</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.054</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$372.36</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$92.43</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PV of avoided cost of natural gas</td>
<td>$</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PV of non-energy benefits</td>
<td>$</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total energy</strong></td>
<td><strong>$0.890</strong></td>
<td></td>
<td><strong>100%</strong></td>
</tr>
<tr>
<td><strong>Total capacity</strong></td>
<td><strong>0%</strong></td>
<td></td>
<td><strong>0%</strong></td>
</tr>
<tr>
<td><strong>Total cost</strong></td>
<td><strong>$17,291.80</strong></td>
<td></td>
<td><strong>100%</strong></td>
</tr>
</tbody>
</table>

#### Measure details

- **Zero** "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- **7.41%** Discount rate
- **30** Measure life
- **10,699** Annual kWh savings per unit
- **0.0019%** Percent of annual energy in maximum hour (use for "driver" measures)
- **0.0000%** Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

#### Avoided Cost Value

- **Generation capacity**
- **T&D losses**
- **T&D capacity**
- **Energy, emissions, risk**

#### Cost breakdown

- **$8,939.80** PV of avoided cost of energy (energy + emissions + risk)
- **$581.09** PV of avoided cost of energy (T&D losses)
- **$** PV of avoided cost of generation capacity
- **$** PV of avoided cost of T&D capacity
- **$** PV of avoided cost of natural gas
- **$** PV of non-energy benefits
- **$9,520.88** Total Resource Cost test benefits
- **$2,278.00** Incremental customer cost
- **$** Incremental non-incentive utility cost
- **$2,278.00** Total Resource Cost test costs
- **$7,243** Net TRC $ amount

#### TRC benefit / cost ratio

- **4.18** TRC benefit / cost ratio
## High efficiency clothes washer (electric DHW, dryer)

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.478</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>87%</td>
</tr>
<tr>
<td>$0.031</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$237.24</td>
<td>$0.030 PV of avoided cost of generation capacity</td>
<td>6%</td>
</tr>
<tr>
<td>$57.34</td>
<td>$0.007 PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.547</td>
<td>$</td>
<td>100%</td>
</tr>
</tbody>
</table>

**non-driver**

- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 14 Measure life
- 381 Annual kWh savings per unit
- 0.0155% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0127% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

- $182.28 PV of avoided cost of energy (energy + emissions + risk)
- $11.85 PV of avoided cost of energy (T&D losses)
- $11.51 PV of avoided cost of generation capacity
- $2.78 PV of avoided cost of T&D capacity
- $- PV of avoided cost of natural gas
- $- PV of non-energy benefits
- $208.42 Total Resource Cost test benefits

- $484.00 Incremental customer cost
- $- Incremental non-incentive utility cost
- $484.00 Total Resource Cost test costs

($276) Net TRC $ amount

**0.43 TRC benefit / cost ratio**
### Home electronics and office equipment

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.496</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>88%</td>
</tr>
<tr>
<td>$0.032</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$248.96</td>
<td>PV of avoided cost of generation capacity</td>
<td>5%</td>
</tr>
<tr>
<td>$60.28</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.564</td>
<td>Total energy</td>
<td>100%</td>
</tr>
<tr>
<td>7.41%</td>
<td>Discount rate</td>
<td>6% Total capacity</td>
</tr>
<tr>
<td>15</td>
<td>Measure life</td>
<td></td>
</tr>
<tr>
<td>677</td>
<td>Annual kWh savings per unit</td>
<td></td>
</tr>
<tr>
<td>0.0125%</td>
<td>Percent of annual energy in maximum hour (use for &quot;driver&quot; measures)</td>
<td></td>
</tr>
<tr>
<td>0.0114%</td>
<td>Percent of annual energy in average hour of designated system peak (use for &quot;non-driver&quot; measures)</td>
<td></td>
</tr>
<tr>
<td>$335.87</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
</tr>
<tr>
<td>$21.83</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
</tr>
<tr>
<td>$19.20</td>
<td>PV of avoided cost of generation capacity</td>
<td></td>
</tr>
<tr>
<td>$4.65</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td></td>
</tr>
<tr>
<td>-</td>
<td>PV of avoided cost of natural gas</td>
<td></td>
</tr>
<tr>
<td>-</td>
<td>PV of non-energy benefits</td>
<td></td>
</tr>
<tr>
<td>$381.55</td>
<td>Total Resource Cost test benefits</td>
<td></td>
</tr>
<tr>
<td>$382</td>
<td>Net TRC $ amount</td>
<td></td>
</tr>
</tbody>
</table>

#### Avoided Cost Value

- **Generation capacity**
- **T&D capacity**
- **T&D losses**
- **Energy, emissions, risk**

---

*Avista Corp 2007 Electric IRP*
## Hot tub and swimming pool covers

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.295</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>88%</td>
</tr>
<tr>
<td>$0.019</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$154.14</td>
<td>0.018 PV of avoided cost of generation capacity</td>
<td>5%</td>
</tr>
<tr>
<td>$36.80</td>
<td>0.004 PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.336</td>
<td>PV of avoided cost of generation capacity</td>
<td>100%</td>
</tr>
</tbody>
</table>

#### non-driver
- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 250 Annual kWh savings per unit
- 0.0125% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0114% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

<table>
<thead>
<tr>
<th>$73.66</th>
<th>PV of avoided cost of energy (energy + emissions + risk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$4.79</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
</tr>
<tr>
<td>$4.39</td>
<td>PV of avoided cost of generation capacity</td>
</tr>
<tr>
<td>$1.05</td>
<td>PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$-</td>
<td>PV of avoided cost of natural gas</td>
</tr>
<tr>
<td>$-</td>
<td>PV of non-energy benefits</td>
</tr>
<tr>
<td>$83.89</td>
<td>Total Resource Cost test benefits</td>
</tr>
<tr>
<td>$300.00</td>
<td>Incremental customer cost</td>
</tr>
<tr>
<td>$300.00</td>
<td>Total Resource Cost test costs</td>
</tr>
</tbody>
</table>

($216) Net TRC $ amount

### Avoided Cost Value

- Generation capacity
- T&D capacity
- T&D losses
- Energy, emissions, risk

<table>
<thead>
<tr>
<th>TRC benefit / cost ratio</th>
<th>0.28</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hot tub and swimming pool covers</td>
<td></td>
</tr>
</tbody>
</table>
# Heat pump water heater (single and multi-family)

## Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kWh</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.368</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>88%</td>
</tr>
<tr>
<td>$0.024</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$184.47</td>
<td>$0.021 PV of avoided cost of generation capacity</td>
<td>5%</td>
</tr>
<tr>
<td>$44.23</td>
<td>$0.005 PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.418</td>
<td>PV of avoided cost of generation capacity</td>
<td>5%</td>
</tr>
<tr>
<td>$42.21</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$36.95</td>
<td>PV of avoided cost of natural gas</td>
<td>6%</td>
</tr>
<tr>
<td>$8.86</td>
<td>PV of non-energy benefits</td>
<td>6%</td>
</tr>
<tr>
<td>$737.46</td>
<td>Total Resource Cost test benefits</td>
<td>100%</td>
</tr>
</tbody>
</table>

### "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- **7.41%** Discount rate
- **10** Measure life
- **1,766** Annual kWh savings per unit
- **0.0160%** Percent of annual energy in maximum hour (use for "driver" measures)
- **0.0113%** Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

### Avoided Cost Value

- **Generation capacity**
- **T&D capacity**
- **T&D losses**
- **Energy, emissions, risk**

| $1,661.96 | Incremental customer cost |
| $1,661.96 | Total Resource Cost test costs |

### $0.44 TRC benefit / cost ratio

| (S925) Net TRC $ amount | $925 |

Avista Corp 2007 Electric IRP 22
Proper HVAC sizing

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.595</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>94%</td>
</tr>
<tr>
<td>$0.039</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$281.00</td>
<td>PV of avoided cost of generation capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$68.42</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$0.633</td>
<td>PV of avoided cost of generation capacity</td>
<td>100%</td>
</tr>
<tr>
<td></td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>100%</td>
</tr>
</tbody>
</table>

"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

7.41% Discount rate

18 Measure life

705 Annual kWh savings per unit

0.0019% Percent of annual energy in maximum hour (use for "driver" measures)

0.0000% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$419.19 PV of avoided cost of energy (energy + emissions + risk)

$27.25 PV of avoided cost of energy (T&D losses)

$ - PV of avoided cost of generation capacity

$ - PV of avoided cost of T&D capacity

$ - PV of avoided cost of natural gas

$ - PV of non-energy benefits

$446.44 Total Resource Cost test benefits

$ - Incremental customer cost

$ - Incremental non-incentive utility cost

$ - Total Resource Cost test costs

$446 Net TRC $ amount

Avoided Cost Value
### Induction cooktop

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Value $</th>
<th>kWh</th>
<th>% of Total Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>0.356</td>
<td></td>
<td>88%</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>0.023</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>0.021</td>
<td></td>
<td>5%</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>0.005</td>
<td></td>
<td>1%</td>
</tr>
<tr>
<td>Total</td>
<td>0.405</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

**Measure Type**
- *driver*, *non-driver* or *zero* measure type
  - *driver*: measure that coincides with managed system peak period
  - *non-driver*: measure that is not coincident with managed system peak period

**Other Parameters**
- Discount rate: 7.41%
- Measure life: 10 years
- Annual kWh savings per unit: 27
- Percent of annual energy in maximum hour: 0.0125%
- Percent of annual energy in average hour of designated system peak period: 0.0114%
- Total Resource Cost test benefits: 9.60 $0.62 $0.57 $0.14 $0.57 $0.14 $0.57 $0.14
- Total Resource Cost test costs: 264.42 $264.42
- Net TRC $ amount: ($253) 0.04 TRC benefit / cost ratio

---

**Avoided Cost Value**
Insulation (R19-R38, single family, resistance)

Summary of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th></th>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.836 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$372.36</td>
<td>$94%</td>
<td></td>
</tr>
<tr>
<td>$0.054 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$92.43</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>- PV of avoided cost of generation capacity</td>
<td>-</td>
<td>0%</td>
<td></td>
</tr>
<tr>
<td>- PV of avoided cost of T&amp;D capacity</td>
<td>-</td>
<td>0%</td>
<td></td>
</tr>
<tr>
<td>$0.890</td>
<td>$372.36</td>
<td>$94%</td>
<td></td>
</tr>
</tbody>
</table>

- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 30 Measure life
- 1.074 Annual kWh savings per unit
- 0.0019% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0000% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

<table>
<thead>
<tr>
<th></th>
<th>897.41 PV of avoided cost of energy (energy + emissions + risk)</th>
<th>58.33 PV of avoided cost of energy (T&amp;D losses)</th>
<th>- PV of avoided cost of generation capacity</th>
<th>- PV of avoided cost of T&amp;D capacity</th>
<th>- PV of avoided cost of natural gas</th>
<th>- PV of non-energy benefits</th>
<th>955.74 Total Resource Cost test benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$812.70 Incremental customer cost</td>
<td>- Incremental non-incentive utility cost</td>
<td>$812.70 Total Resource Cost test costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

$143 Net TRC $ amount

$1.18 TRC benefit / cost ratio
### Low flow showerhead

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>First Year kW Cost</th>
<th>First Year kWh Cost</th>
<th>% of Total Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy + Emissions + Risk</td>
<td>$0.368</td>
<td>$0.021</td>
<td>88%</td>
</tr>
<tr>
<td>T&amp;D Losses</td>
<td>$0.024</td>
<td>$0.005</td>
<td>6%</td>
</tr>
<tr>
<td>Generation Capacity</td>
<td>$0.418</td>
<td></td>
<td></td>
</tr>
<tr>
<td>T&amp;D Capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Energy</td>
<td>$37.14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>T&amp;D Losses</td>
<td>$2.41</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generation Capacity</td>
<td>$2.11</td>
<td></td>
<td></td>
</tr>
<tr>
<td>T&amp;D Capacity</td>
<td>$0.51</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non-energy Benefits</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Resource Cost Test Benefits</td>
<td>$42.18</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Incremental Customer Cost</td>
<td>$37.95</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Incremental Non-Incentive Utility Cost</td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Resource Cost Test Costs</td>
<td>$37.95</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Non-driver**
- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 10 Measure life
- 0.0160% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0113% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

**Avoided Cost Value**

- Generation capacity
- T&D capacity
- T&D losses
- Energy, emissions, risk

**Net TRC $ amount**

1.11 TRC benefit / cost ratio

---

*Avista Corp 2007 Electric IRP*
### Pipe insulation (single family, per foot installed)

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.513 PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
<td>248.96</td>
<td>88%</td>
</tr>
<tr>
<td>$0.033 PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
<td>60.28</td>
<td>6%</td>
</tr>
<tr>
<td>$0.028 PV of avoided cost of generation capacity</td>
<td></td>
<td>0.007</td>
<td>5%</td>
</tr>
<tr>
<td>$0.007 PV of avoided cost of T&amp;D capacity</td>
<td></td>
<td></td>
<td>1%</td>
</tr>
<tr>
<td>$0.581</td>
<td></td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

#### Additional Information

- **Discount rate**: 7.41%
- **Measure life**: 15 years
- **Annual kWh savings per unit**: 133
- **Percent of annual energy in maximum hour**: 0.0160%
- **Percent of annual energy in average hour of designated system peak**: 0.0113%

#### Avoided Cost Value

- **Generation capacity**: $3.76
- **T&D losses**: $0.91
- **Energy, emissions, risk**: $4.43
- **Total Resource Cost test benefits**: $77.28
- **Incremental customer cost**: $2.81
- **Incremental non-incentive utility cost**: $2.81
- **Total Resource Cost test costs**: $2.81

#### TRC benefit / cost ratio: 27.50

#### Net TRC amount: $74
Smart programmable thermostats

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.431</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>94%</td>
</tr>
<tr>
<td>$0.028</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$212.09</td>
<td>PV of avoided cost of generation capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$51.06</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$0.460</td>
<td>Total energy</td>
<td>100%</td>
</tr>
<tr>
<td></td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>100% Total capacity</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>7.41% Discount rate</th>
<th>Measure life</th>
<th>12</th>
<th>Annual kWh savings per unit</th>
<th>755</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.0019% Percent of annual energy in maximum hour (use for &quot;driver&quot; measures)</td>
<td></td>
<td>0.0000% Percent of annual energy in average hour of designated system peak (use for &quot;non-driver&quot; measures)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| $325.78            | PV of avoided cost of energy (energy + emissions + risk) | $0.0591 Levelized cost/kWh of four energy components of AC |
| $21.18             | PV of avoided cost of energy (T&D losses) | $0.0000 Levelized cost/kWh of two capacity components of AC |
| $                    | PV of avoided cost of generation capacity | |
| $                    | PV of avoided cost of T&D capacity | |
| $                    | PV of avoided cost of natural gas | |
| $                    | PV of non-energy benefits | |
| $346.95            | Total Resource Cost test benefits | |

| $100.00            | Incremental customer cost | |
| $                    | Incremental non-incentive utility cost | |
| $100.00            | Total Resource Cost test costs | |

| $247 Net TRC $ amount |

3.47 TRC benefit / cost ratio

Avoided Cost Value

Smart programmable thermostats
## CFL 20W screw-in for incandescent 75W

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kWh</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.332 PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
<td>91%</td>
</tr>
<tr>
<td>$0.022 PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>$169.66 $0.010 PV of avoided cost of generation capacity</td>
<td></td>
<td>3%</td>
</tr>
<tr>
<td>$40.59 $0.002 PV of avoided cost of T&amp;D capacity</td>
<td></td>
<td>1%</td>
</tr>
<tr>
<td>$0.366</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

### Non-driver

*driver*, "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- **7.41% Discount rate**
- **9.4 Measure life**
- **42 Annual kWh savings per unit**
- **0.0127% Percent of annual energy in maximum hour (use for "driver" measures)**
- **0.0059% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)**

<table>
<thead>
<tr>
<th>$</th>
<th>PV of avoided cost of energy (energy + emissions + risk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$13.94</td>
<td></td>
</tr>
<tr>
<td>$0.91</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
</tr>
<tr>
<td>$0.42</td>
<td>PV of avoided cost of generation capacity</td>
</tr>
<tr>
<td>$0.10</td>
<td>PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$</td>
<td>PV of avoided cost of natural gas</td>
</tr>
<tr>
<td>$</td>
<td>PV of non-energy benefits</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>$</th>
<th>Total Resource Cost test benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>$15.37</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>$</th>
<th>Incremental customer cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>$6.47</td>
<td>Incremental non-incentive utility cost</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>$</th>
<th>Total Resource Cost test costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>$6.47</td>
<td></td>
</tr>
</tbody>
</table>

**2.38 TRC benefit / cost ratio**

### Avoided Cost Value

- **Energy, emissions, risk**
- **T&D capacity**
- **Generation capacity**

**$90 Net TRC $ amount**
Remove second refrigerator

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.615 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>87%</td>
</tr>
<tr>
<td>$0.040 PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$ 300.00 $</td>
<td>0.039 $</td>
</tr>
<tr>
<td>$ 73.31 $</td>
<td>0.009 $</td>
</tr>
<tr>
<td>$0.704</td>
<td>100%</td>
</tr>
</tbody>
</table>

non-driver: "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- 7.41% Discount rate
- 20 Measure life
- 1,946 Annual kWh savings per unit
- 0.0148% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0129% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$ 1,197.54 PV of avoided cost of energy (energy + emissions + risk)
$ 77.84 PV of avoided cost of energy (T&D losses)
$ 75.31 PV of avoided cost of generation capacity
$ 18.40 PV of avoided cost of T&D capacity
$ - PV of avoided cost of natural gas
$ - PV of non-energy benefits
$ 1,369.10 Total Resource Cost test benefits

$ - Incremental customer cost
$ - Incremental non-incentive utility cost
$ - Total Resource Cost test costs

$1,369 Net TRC $ amount

TRC benefit / cost ratio

Avista Corp 2007 Electric IRP
### Energy efficient windows (retrofit, single family, resistance)

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Description</th>
<th>Per first year kWh</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.836</td>
<td></td>
<td>94%</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.054</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$ -</td>
<td></td>
<td>0%</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$ -</td>
<td></td>
<td>0%</td>
</tr>
<tr>
<td>$0.890</td>
<td></td>
<td></td>
<td>100%</td>
</tr>
<tr>
<td>&quot;driver&quot;, &quot;non-driver&quot; or &quot;zero&quot; measure type (based upon coincidence with managed system peak period)</td>
<td>$ -</td>
<td>$ 372.36</td>
<td>0%</td>
</tr>
<tr>
<td>7.41% Discount rate</td>
<td></td>
<td></td>
<td>0%</td>
</tr>
<tr>
<td>2.127 Annual kWh savings per unit</td>
<td></td>
<td></td>
<td>0%</td>
</tr>
<tr>
<td>0.0019% Percent of annual energy in maximum hour (use for &quot;driver&quot; measures)</td>
<td>$ -</td>
<td>$ 92.43</td>
<td>0%</td>
</tr>
<tr>
<td>0.00000% Percent of annual energy in average hour of designated system peak (use for &quot;non-driver&quot; measures)</td>
<td>$ -</td>
<td></td>
<td>0%</td>
</tr>
<tr>
<td>$ 1,777.26 PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ 115.52 PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ - PV of avoided cost of generation capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ - PV of avoided cost of T&amp;D capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ - PV of avoided cost of natural gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ - PV of non-energy benefits</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ 1,892.79 Total Resource Cost test benefits</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ 3,100.69 Incremental customer cost</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ - Incremental non-incentive utility cost</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$ 3,100.69 Total Resource Cost test costs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>($1,208) Net TRC $ amount</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>0.61 TRC benefit / cost ratio</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Avoided Cost Value**

- **Energy, emissions, risk**
- **Generation capacity**
- **T&D capacity**
- **T&D losses**
Electric furnace vs heat pump conversion

**Summary of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.595</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>94%</td>
</tr>
<tr>
<td>$0.039</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$281.00</td>
<td>PV of avoided cost of generation capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$68.42</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$0.633</td>
<td>Total energy</td>
<td>100%</td>
</tr>
</tbody>
</table>

- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 18 Measure life
- 5,538 Annual kWh savings per unit
- 0.0019% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0000% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

| $3,292.86 | PV of avoided cost of energy (energy + emissions + risk) |
| $214.04   | PV of avoided cost of energy (T&D losses) |
| $ -       | PV of avoided cost of generation capacity |
| $ -       | PV of avoided cost of T&D capacity |
| $ -       | PV of avoided cost of natural gas |
| $ -       | PV of non-energy benefits |
| $3,506.90 | Total Resource Cost test benefits |
| $1,395.00 | Incremental customer cost |
| $ -       | Incremental non-incentive utility cost |
| $1,395.00 | Total Resource Cost test costs |

- $2,112 Net TRC $ amount
- 2.51 TRC benefit / cost ratio

---

**Avoided Cost Value**

- Generation capacity
- T&D losses
- T&D capacity
- Energy, emissions, risk

---

Avista Corp

2007 Electric IRP
Smart/energy efficient appliance rebate program

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.570</td>
<td>$0.036</td>
<td>87%</td>
</tr>
<tr>
<td>$0.037</td>
<td>$0.009</td>
<td>6%</td>
</tr>
<tr>
<td>$0.652</td>
<td></td>
<td>1%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>non-driver</th>
<th>&quot;driver&quot;, &quot;non-driver&quot; or &quot;zero&quot; measure type (based upon coincidence with managed system peak period)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.41%</td>
<td>Discount rate</td>
</tr>
<tr>
<td>18</td>
<td>Measure life</td>
</tr>
<tr>
<td>58</td>
<td>Annual kWh savings per unit</td>
</tr>
<tr>
<td>0.0148%</td>
<td>Percent of annual energy in maximum hour (use for &quot;driver&quot; measures)</td>
</tr>
<tr>
<td>0.0129%</td>
<td>Percent of annual energy in average hour of designated system peak (use for &quot;non-driver&quot; measures)</td>
</tr>
</tbody>
</table>

| $33.05     | PV of avoided cost of energy (energy + emissions + risk)                                             |
| $2.15      | PV of avoided cost of energy (T&D losses)                                                           |
| $2.10      | PV of avoided cost of generation capacity                                                           |
| $0.51      | PV of avoided cost of T&D capacity                                                                   |
| -          | PV of avoided cost of natural gas                                                                   |
| -          | PV of non-energy benefits                                                                            |
| $37.81     | Total Resource Cost test benefits                                                                   |

$201.55 Incremental customer cost
- Incremental non-incentive utility cost
$201.55 Total Resource Cost test costs

($164) Net TRC $ amount

0.19 TRC benefit / cost ratio

Avoided Cost Value

- Energy, emissions, risk
- T&D capacity
- Generation capacity
- T&D losses

Avista Corp 2007 Electric IRP 33
### Solar water heating

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.513</td>
<td>88%</td>
<td></td>
</tr>
<tr>
<td>$0.033</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>$0.028</td>
<td>5%</td>
<td></td>
</tr>
<tr>
<td>$0.007</td>
<td>1%</td>
<td></td>
</tr>
<tr>
<td>$0.581</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

**Subtotal**

<table>
<thead>
<tr>
<th></th>
<th>94% Total energy</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>6% Total capacity</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>non-driver</th>
<th>&quot;driver&quot;, &quot;non-driver&quot; or &quot;zero&quot; measure type (based upon coincidence with managed system peak period)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$1,315.38</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
</tr>
<tr>
<td>$85.50</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
</tr>
<tr>
<td>$72.46</td>
<td>PV of avoided cost of generation capacity</td>
</tr>
<tr>
<td>$17.55</td>
<td>PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$-</td>
<td>PV of avoided cost of natural gas</td>
</tr>
<tr>
<td>$-</td>
<td>PV of non-energy benefits</td>
</tr>
<tr>
<td>$1,490.89</td>
<td>Total Resource Cost test benefits</td>
</tr>
<tr>
<td>$5,310.00</td>
<td>Incremental customer cost</td>
</tr>
<tr>
<td>$-</td>
<td>Incremental non-incentive utility cost</td>
</tr>
<tr>
<td>$5,310.00</td>
<td>Total Resource Cost test costs</td>
</tr>
</tbody>
</table>

| ($3,819)   | Net TRC $ amount                                                                                |

| 0.28       | TRC benefit / cost ratio                                                                       |

**Avoided Cost Value**

- **Energy, emissions, risk**: 74%
- **T&D losses**
- **Generation capacity**
- **T&D capacity**

---

Avista Corp 2007 Electric IRP 34
## Tankless water heater (single family)

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy, emissions, risk</td>
<td>88%</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>6%</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>5%</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>1%</td>
</tr>
</tbody>
</table>

### $0.581 100%

- **Per first year kW**: $0.513 PV of avoided cost of energy (energy + emissions + risk)
- **Per first year kWh**: $0.033 PV of avoided cost of energy (T&D losses)
- **Per first year kWh**: $0.028 PV of avoided cost of generation capacity
- **Per first year kWh**: $0.007 PV of avoided cost of T&D capacity

### Non-driver

- *"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)*
- Discount rate: 7.41%
- Measure life: 15 years
- Annual kWh savings per unit: 682
- Percent of annual energy in maximum hour (use for "driver" measures): 0.0160%
- Percent of annual energy in average hour of designated system peak (use for "non-driver" measures): 0.0113%

### $396.25

- **Total Resource Cost test benefits**: $396.25
- **Incremental customer cost**: $1,010.00
- **Incremental non-incentive utility cost**: $1,010.00

### $0.0615

- Levelized cost/kWh of four energy components of AC

### $0.0040

- Levelized cost/kWh of two capacity components of AC

### Net TRC $ amount

- **0.39 TRC benefit / cost ratio**
### HE Variable High Speed Motor

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>$0.642 PV of avoided cost of energy (energy + emissions + risk)</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$</td>
<td></td>
<td>$0.042 PV of avoided cost of energy (T&amp;D losses)</td>
<td>94%</td>
</tr>
<tr>
<td>$</td>
<td></td>
<td>$0.000 PV of avoided cost of generation capacity</td>
<td>6%</td>
</tr>
<tr>
<td>$</td>
<td></td>
<td>$0.000 PV of avoided cost of T&amp;D capacity</td>
<td>0%</td>
</tr>
<tr>
<td>$0.684</td>
<td></td>
<td>$0.000 PV of avoided cost of natural gas</td>
<td>0%</td>
</tr>
<tr>
<td>$0.684</td>
<td></td>
<td>$0.000 PV of avoided cost of non-energy benefits</td>
<td>100%</td>
</tr>
</tbody>
</table>

*non-driver* "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- **7.41%** Discount rate
- **20** Measure life
- **250** Annual kWh savings per unit
- **0.0019%** Percent of annual energy in maximum hour (use for "driver" measures)
- **0.0000%** Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

<table>
<thead>
<tr>
<th>$</th>
<th>PV of avoided cost of energy (energy + emissions + risk)</th>
<th>$0.642</th>
</tr>
</thead>
<tbody>
<tr>
<td>$160.42</td>
<td></td>
<td>$0.642</td>
</tr>
<tr>
<td>$10.43</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.042</td>
</tr>
<tr>
<td>$0.03</td>
<td>PV of avoided cost of generation capacity</td>
<td>$0.000</td>
</tr>
<tr>
<td>$0.01</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$0.000</td>
</tr>
<tr>
<td>$0.01</td>
<td>PV of avoided cost of natural gas</td>
<td>$0.000</td>
</tr>
<tr>
<td>$0.01</td>
<td>PV of non-energy benefits</td>
<td>$0.000</td>
</tr>
<tr>
<td>$170.89</td>
<td>Total Resource Cost test benefits</td>
<td>$0.684</td>
</tr>
</tbody>
</table>

- **$200.00** Incremental customer cost
- **$0.000** Incremental non-incentive utility cost
- **$200.00** Total Resource Cost test costs

### Avoided Cost Value

- **Generation capacity**
- **T&D losses**
- **T&D capacity**
- **Energy, emissions, risk**

### TRC benefit / cost ratio

- **0.85** TRC benefit / cost ratio

- **($29)** Net TRC $ amount

---

**Avista Corp 2007 Electric IRP**
### Water heater controller

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.513</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>88%</td>
</tr>
<tr>
<td>$0.033</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$248.96</td>
<td>0.028 PV of avoided cost of generation capacity</td>
<td>5%</td>
</tr>
<tr>
<td>$60.28</td>
<td>0.007 PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.581</td>
<td>Total value</td>
<td>100%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>non-driver</th>
<th><em>driver</em>, &quot;non-driver&quot; or &quot;zero&quot; measure type (based upon coincidence with managed system peak period)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.41%</td>
<td>Discount rate</td>
</tr>
<tr>
<td>15</td>
<td>Measure life</td>
</tr>
<tr>
<td>224</td>
<td>Annual kWh savings per unit</td>
</tr>
<tr>
<td>0.0160%</td>
<td>Percent of annual energy in maximum hour (use for &quot;driver&quot; measures)</td>
</tr>
<tr>
<td>0.0113%</td>
<td>Percent of annual energy in average hour of designated system peak (use for &quot;non-driver&quot; measures)</td>
</tr>
</tbody>
</table>

| $114.83    | PV of avoided cost of energy (energy + emissions + risk)                                         |
| $7.46      | PV of avoided cost of energy (T&D losses)                                                        |
| $6.33      | PV of avoided cost of generation capacity                                                       |
| $1.53      | PV of avoided cost of T&D capacity                                                              |
| $0.0040    | Levelized cost/kWh of two capacity components of AC                                              |
| $115       | Net TRC $ amount                                                                                 |
| $8.68      | TRC benefit / cost ratio                                                                        |

**Avoided Cost Value**

- **Energy, emissions, risk**
- **T&D losses**
- **Generation capacity**
- **T&D capacity**

**Supplemental- Section 3**

Avista Corp 2007 Electric IRP
## Water heater tank wraps, pads, closet insulation

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.513</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>88%</td>
</tr>
<tr>
<td>$0.033</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$248.96</td>
<td>0.028 PV of avoided cost of generation capacity</td>
<td>5%</td>
</tr>
<tr>
<td>$60.28</td>
<td>0.007 PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.581</td>
<td>$0.028 $0.007</td>
<td>100%</td>
</tr>
</tbody>
</table>

*non-driver* "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- 7.41% Discount rate
- 15 Measure life
- 364 Annual kWh savings per unit
- 0.0160% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0113% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

<table>
<thead>
<tr>
<th>$186.59</th>
<th>PV of avoided cost of energy (energy + emissions + risk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$12.13</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
</tr>
<tr>
<td>$10.28</td>
<td>PV of avoided cost of generation capacity</td>
</tr>
<tr>
<td>$2.49</td>
<td>PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$-</td>
<td>PV of avoided cost of natural gas</td>
</tr>
<tr>
<td>$-</td>
<td>PV of non-energy benefits</td>
</tr>
<tr>
<td>$211.49</td>
<td>Total Resource Cost test benefits</td>
</tr>
</tbody>
</table>

| $17.00  | Incremental customer cost                               |
| $-      | Incremental non-incentive utility cost                  |
| $17.00  | Total Resource Cost test costs                          |

$194 Net TRC $ amount

12.44 TRC benefit / cost ratio

---

**Avoided Cost Value**

- **Generation capacity**
- T&D capacity
- **T&D losses**
- **Energy, emissions, risk**
Commercial Measures
Light fixture reconfiguration

Summary of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.535</td>
<td>$0.035 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>86%</td>
</tr>
<tr>
<td>$0.040</td>
<td>PV of avoided cost of generation capacity</td>
<td>6%</td>
</tr>
<tr>
<td>$0.010</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>2%</td>
</tr>
<tr>
<td>$0.619</td>
<td>$260.14 $63.11</td>
<td>100%</td>
</tr>
</tbody>
</table>

- **Non-driver**: "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- **7.41% Discount rate**
- **16 Measure life**
- **0.0207% Percent of annual energy in maximum hour (use for "driver" measures)**
- **0.0153% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)**

Avoided Cost Value

- **$0.38 PV of avoided cost of energy (energy + emissions + risk)**
- **$0.02 PV of avoided cost of energy (T&D losses)**
- **$0.03 PV of avoided cost of generation capacity**
- **$0.01 PV of avoided cost of T&D capacity**
- **$0.00 PV of avoided cost of natural gas**
- **$0.00 PV of non-energy benefits**
- **$0.44 Total Resource Cost test benefits**

**Incremental**
- **$0.50 Incremental customer cost**
- **$0.00 Incremental non-incentive utility cost**
- **$0.50 Total Resource Cost test costs**

**Net TRC $ amount**: ($0.06)

**0.89 TRC benefit / cost ratio**

Light fixture reconfiguration

AURORA, etc.

- **$0.02 PV of avoided cost of energy (T&D losses)**
- **$0.03 PV of avoided cost of generation capacity**
- **$0.01 PV of avoided cost of T&D capacity**
- **$0.00 PV of non-energy benefits**

**Total Resource Cost test benefits**: $0.44

**Levelized cost/kWh of four energy components of AC**: $0.0620

**Levelized cost/kWh of two capacity components of AC**: $0.0054

**92% Total energy**

**8% Total capacity**

**Energy, emissions, risk**
Energy efficient case fans (grocery, per sq. ft.)

Summary of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.522 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>87%</td>
<td></td>
</tr>
<tr>
<td>$0.034 PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>$260.14</td>
<td>$0.036 PV of avoided cost of generation capacity</td>
<td>6%</td>
</tr>
<tr>
<td>$63.11</td>
<td>$0.009 PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.601</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

- Non-driver: "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- 7.41% Discount rate

- 16 Measure life

- 2.887 Annual kWh savings per unit

- 0.0152% Percent of annual energy in maximum hour (use for "driver" measures)

- 0.0139% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

- $1.51 PV of avoided cost of energy (energy + emissions + risk)

- $0.10 PV of avoided cost of energy (T&D losses)

- $0.10 PV of avoided cost of generation capacity

- $0.03 PV of avoided cost of T&D capacity

- $0.00 PV of avoided cost of natural gas

- $0.00 PV of non-energy benefits

- $1.74 Total Resource Cost test benefits

- $1.16 Incremental customer cost

- $0.00 Incremental non-incentive utility cost

- $1.16 Total Resource Cost test costs

- $0.58 Net TRC $ amount

- 1.50 TRC benefit / cost ratio

Energy efficient case fans (grocery, per sq. ft.)
CFL 20W fixture for incandescent 75W (retrofit)

Summary of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.425</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>86%</td>
</tr>
<tr>
<td>$0.028</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$0.032</td>
<td>PV of avoided cost of generation capacity</td>
<td>7%</td>
</tr>
<tr>
<td>$0.008</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>2%</td>
</tr>
<tr>
<td>$0.493</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

92% Total energy
8% Total capacity

non-driver, "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

7.41% Discount rate

12 Measure life

260 Annual kWh savings per unit

0.0207% Percent of annual energy in maximum hour (use for "driver" measures)

0.0153% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$110.54 PV of avoided cost of energy (energy + emissions + risk)
$7.18 PV of avoided cost of energy (T&D losses)
$8.41 PV of avoided cost of generation capacity
$2.03 PV of avoided cost of T&D capacity
$0.00 PV of avoided cost of natural gas
$0.00 PV of non-energy benefits

$128.16 Total Resource Cost test benefits

$48.50 Incremental customer cost
$0.00 Incremental non-incentive utility cost
$48.50 Total Resource Cost test costs

$79.66 Net TRC $ amount

2.64 TRC benefit / cost ratio

Avoided Cost Value

- Generation capacity
- T&D capacity
- T&D losses
- Energy, emissions, risk
### Commissioning/retro-commissioning

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Value</th>
<th>% of Total Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.207</td>
<td>86%</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.013</td>
<td>6%</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$0.016</td>
<td>7%</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$0.004</td>
<td>2%</td>
</tr>
<tr>
<td>Total energy</td>
<td>$0.240</td>
<td>100%</td>
</tr>
</tbody>
</table>

**Non-driver"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)**

- **7.41%** Discount rate
- **5** Measure life
- **4,000** Annual kWh savings per unit
- **0.0205%** Percent of annual energy in maximum hour (use for "driver" measures)
- **0.0154%** Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

- **$0.83** PV of avoided cost of energy (energy + emissions + risk)
- **$0.05** PV of avoided cost of energy (T&D losses)
- **$0.06** PV of avoided cost of generation capacity
- **$0.02** PV of avoided cost of T&D capacity
- **$0.00** PV of avoided cost of natural gas
- **$0.00** PV of non-energy benefits
- **$0.96** Total Resource Cost test benefits

- **$0.27** Incremental customer cost
- **$0.00** Incremental non-incentive utility cost
- **$0.27** Total Resource Cost test costs

- **$0.69** Net TRC $ amount

- **3.56** TRC benefit / cost ratio

---

**Avoided Cost Value**

- **Generation capacity**
- **T&D capacity**
- **Energy, emissions, risk**

---

Avista Corp 2007 Electric IRP
Demand defrost (grocery, per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

Per first year kW  Per first year kWh  % of total value

$0.356  PV of avoided cost of energy (energy + emissions + risk)  87%
$0.023  PV of avoided cost of energy (T&D losses)  6%

$0.026  PV of avoided cost of generation capacity  6%
$0.006  PV of avoided cost of T&D capacity  1%

$0.411  100%

92% Total energy  8% Total capacity

Measure life  10
Annual kWh savings per unit  1.876
Percent of annual energy in maximum hour (use for "driver" measures)  0.0152%
Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)  0.0139%

$0.67  PV of avoided cost of energy (energy + emissions + risk)
$0.04  PV of avoided cost of energy (T&D losses)
$0.05  PV of avoided cost of generation capacity
$0.01  PV of avoided cost of T&D capacity
$0.00  PV of avoided cost of natural gas
$0.00  PV of non-energy benefits

Total Resource Cost test benefits  $0.77

Incremental customer cost  $0.04
Incremental non-incentive utility cost  $0.00
Total Resource Cost test costs  $0.04

Net TRC $ amount  $0.73

19.26  TRC benefit / cost ratio

Demand defrost (grocery, per sq. ft.)
Energy efficient ice makers (grocery)

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.356 PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
<td>87%</td>
</tr>
<tr>
<td>$0.023 PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>$0.026 PV of avoided cost of generation capacity</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>$0.006 PV of avoided cost of T&amp;D capacity</td>
<td></td>
<td>1%</td>
</tr>
<tr>
<td>$0.411</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

92% Total energy

8% Total capacity

Avoided Cost Value

- Energy, emissions, risk
- Generation capacity
- T&D capacity
- T&D losses

- $583.20 PV of avoided cost of energy (energy + emissions + risk)
- $37.91 PV of avoided cost of energy (T&D losses)
- $41.99 PV of avoided cost of generation capacity
- $10.07 PV of avoided cost of T&D capacity
- $0.00 PV of avoided cost of natural gas
- $0.00 PV of non-energy benefits

$673.16 Total Resource Cost test benefits

- $2,507.00 Incremental customer cost
- $0.00 Incremental non-incentive utility cost
- $2,507.00 Total Resource Cost test costs

($1,833.84) Net TRC $ amount

0.27 TRC benefit / cost ratio

Energy efficient ice makers (grocery)
Exit sign replacement (electroluminescent)

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.616</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>88%</td>
</tr>
<tr>
<td>$0.040</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$0.034</td>
<td>PV of avoided cost of generation capacity</td>
<td>5%</td>
</tr>
<tr>
<td>$0.008</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.699</td>
<td>Total cost</td>
<td>100%</td>
</tr>
</tbody>
</table>

94% Total energy
6% Total capacity

- **non-driver**: "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 7.41% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

**Avoided Cost Value**

- $234.72 PV of avoided cost of energy (energy + emissions + risk)
- $15.26 PV of avoided cost of energy (T&D losses)
- $13.05 PV of avoided cost of generation capacity
- $3.19 PV of avoided cost of T&D capacity
- $0.00 PV of avoided cost of natural gas
- $0.00 PV of non-energy benefits

$266.21 Total Resource Cost test benefits

- $107.34 Incremental customer cost
- $0.00 Incremental non-incentive utility cost
- $107.34 Total Resource Cost test costs

$158.87 Net TRC $ amount

2.48 TRC benefit / cost ratio

Exit sign replacement (electroluminescent)
## Prescriptive Energy Recovery Ventilation (ERV)

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Per first year kWh</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.506</td>
<td></td>
<td>90%</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.033</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$248.96</td>
<td>$0.021</td>
<td>4%</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$60.28</td>
<td>$0.005</td>
<td>1%</td>
</tr>
<tr>
<td>Total energy</td>
<td>$0.564</td>
<td></td>
<td>100%</td>
</tr>
<tr>
<td>% of total energy</td>
<td>95%</td>
<td></td>
<td>5%</td>
</tr>
</tbody>
</table>

**Measure life**: 15 years

**Annual kWh savings per unit**: $20,000,000

**Percent of annual energy in maximum hour (use for "driver" measures)**: 0.0104%

**Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)**: 0.0082%

### Avoided Cost Value

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$10,119.42</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$657.76</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$410.54</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$99.41</td>
</tr>
<tr>
<td>PV of avoided cost of natural gas</td>
<td>$0.00</td>
</tr>
<tr>
<td>PV of non-energy benefits</td>
<td>$0.00</td>
</tr>
<tr>
<td>Total Resource Cost test benefits</td>
<td>$11,287.13</td>
</tr>
<tr>
<td>Incremental customer cost</td>
<td>$14,000.00</td>
</tr>
<tr>
<td>Incremental non-incentive utility cost</td>
<td>$0.00</td>
</tr>
<tr>
<td>Total Resource Cost test costs</td>
<td>$14,000.00</td>
</tr>
<tr>
<td>Net TRC $ amount</td>
<td>($2,712.87)</td>
</tr>
</tbody>
</table>

**TRC benefit / cost ratio**: 0.81
### Evaporator fan cycling (grocery)

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Description</th>
<th>Per first year kWh</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.203 PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
<td></td>
<td>87%</td>
</tr>
<tr>
<td>$0.013 PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>$0.014 PV of avoided cost of generation capacity</td>
<td>102.97 $</td>
<td>0.014 $</td>
<td>6%</td>
</tr>
<tr>
<td>$0.003 PV of avoided cost of T&amp;D capacity</td>
<td>24.42 $</td>
<td>0.003 $</td>
<td>1%</td>
</tr>
<tr>
<td>$0.234</td>
<td></td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>Measure life</th>
<th>Measure cycle</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.41% Discount rate</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>0.0152% Percent of annual energy in maximum hour (use for &quot;driver&quot; measures)</td>
<td>0.0139% Percent of annual energy in average hour of designated system peak (use for &quot;non-driver&quot; measures)</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.03 PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
</tr>
<tr>
<td>$0.00 PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
</tr>
<tr>
<td>$0.00 PV of avoided cost of generation capacity</td>
<td></td>
</tr>
<tr>
<td>$0.00 PV of avoided cost of T&amp;D capacity</td>
<td></td>
</tr>
<tr>
<td>$0.00 PV of avoided cost of natural gas</td>
<td></td>
</tr>
<tr>
<td>$0.00 PV of non-energy benefits</td>
<td></td>
</tr>
<tr>
<td>$0.03 Total Resource Cost test benefits</td>
<td></td>
</tr>
<tr>
<td>$0.09 Incremental customer cost</td>
<td></td>
</tr>
<tr>
<td>$0.00 Incremental non-incentive utility cost</td>
<td></td>
</tr>
<tr>
<td>$0.09 Total Resource Cost test costs</td>
<td></td>
</tr>
<tr>
<td>($0.06) Net TRC $ amount</td>
<td></td>
</tr>
<tr>
<td><strong>0.35 TRC benefit / cost ratio</strong></td>
<td></td>
</tr>
</tbody>
</table>

### Avoided Cost Value

- **Generation capacity**
- **T&D capacity**
- **T&D losses**
- **Energy, emissions, risk**

---

Avista Corp  
2007 Electric IRP  
48
Fast-acting loading dock doors and seals

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.423 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.423</td>
<td>86%</td>
<td></td>
</tr>
<tr>
<td>$0.027 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.027</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>$0.033 PV of avoided cost of generation capacity</td>
<td>$0.033</td>
<td>7%</td>
<td></td>
</tr>
<tr>
<td>$0.008 PV of avoided cost of T&amp;D capacity</td>
<td>$0.008</td>
<td>2%</td>
<td></td>
</tr>
<tr>
<td>$0.491</td>
<td>$0.491</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

- **non-driver**: "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 12 Measure life
- 48,013,000 Annual kWh savings per unit
- 0.0205% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0154% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)
- $20,303.84 PV of avoided cost of energy (energy + emissions + risk)
- $1,319.75 PV of avoided cost of energy (T&D losses)
- $1,568.89 PV of avoided cost of generation capacity
- $377.67 PV of avoided cost of T&D capacity
- $0.00 PV of avoided cost of natural gas
- $0.00 PV of non-energy benefits
- $23,570.15 Total Resource Cost test benefits
- $14,197.00 Incremental customer cost
- $0.00 Incremental non-incentive utility cost
- $14,197.00 Total Resource Cost test costs
- $9,373.15 Net TRC $ amount
- 1.66 TRC benefit / cost ratio

Avoided Cost Value

![Avoided Cost Value Diagram](image_url)

- Energy, emissions, risk
  - Generation capacity
  - T&D losses
  - T&D capacity

Supplemental- Section 3
## HE Chiller, 0.51 kW/ton, 300 Tons (per sq. ft.)

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Benefit Description</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.503</td>
<td>59%</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.033</td>
<td>4%</td>
</tr>
<tr>
<td>Total energy driver &quot;driver&quot;, &quot;non-driver&quot; or &quot;zero&quot; measure type</td>
<td>$248.96</td>
<td>63%</td>
</tr>
<tr>
<td>Total capacity driver &quot;driver&quot;, &quot;non-driver&quot; or &quot;zero&quot; measure type</td>
<td>$60.28</td>
<td>37%</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$0.257</td>
<td></td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$0.062</td>
<td></td>
</tr>
<tr>
<td>Total Resource Cost test benefits</td>
<td>$0.854</td>
<td>100%</td>
</tr>
</tbody>
</table>

#### Additional values:

- **Discount rate**: 7.417%
- **Measure life**: 15 years
- **Annual kWh savings per unit**: $0.728
- **Percent of annual energy in maximum hour (use for "driver" measures)**: 0.1031%
- **Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)**: 0.0547%
- **Levelized cost/kWh of four energy components of AC**: $0.0603
- **Levelized cost/kWh of two capacity components of AC**: $0.0359

### Avoided Cost Value

![Avoided Cost Value Chart]

**Chart Description:**

- **Energy, emissions, risk**: Largest component.
- **T&D losses**: Second largest component.
- **Generation capacity**: Third largest component.
- **T&D capacity**: Smallest component.

### Calculation:

- **PV of avoided cost of energy (energy + emissions + risk)**: $0.503
- **PV of avoided cost of energy (T&D losses)**: $0.033
- **PV of avoided cost of generation capacity**: $0.257
- **PV of avoided cost of T&D capacity**: $0.062
- **Total Resource Cost test benefits**: $0.62
- **Incremental customer cost**: $0.18
- **Incremental non-incentive utility cost**: $0.00
- **Total Resource Cost test costs**: $0.18
- **Net TRC $ amount**: $0.44

### Benefit / Cost Ratio:

**3.45**

---

**Avista Corp**

2007 Electric IRP
HE DX, 10 tons, EER=11.3 (per sq. ft.)

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Benefit</th>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.503</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$248.96</td>
<td>59%</td>
</tr>
<tr>
<td>$0.033</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$60.28</td>
<td>4%</td>
</tr>
<tr>
<td>$0.854</td>
<td></td>
<td></td>
<td>100%</td>
</tr>
<tr>
<td>248.96</td>
<td>$0.257 PV of avoided cost of generation capacity</td>
<td></td>
<td>30%</td>
</tr>
<tr>
<td>60.28</td>
<td>$0.062 PV of avoided cost of T&amp;D capacity</td>
<td></td>
<td>7%</td>
</tr>
<tr>
<td>$0.854</td>
<td></td>
<td></td>
<td>63% Total energy</td>
</tr>
</tbody>
</table>

- **driver** "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- **7.41%** Discount rate
- **15** Measure life
- **0.498** Annual kWh savings per unit
- **0.1031%** Percent of annual energy in maximum hour (use for "driver" measures)
- **0.0547%** Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

<table>
<thead>
<tr>
<th>Benefit</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.25 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.02 PV of avoided cost of energy (T&amp;D losses)</td>
<td>7.41% Discount rate</td>
</tr>
<tr>
<td>$0.13 PV of avoided cost of generation capacity</td>
<td>$0.03 PV of avoided cost of T&amp;D capacity</td>
<td>30% Total capacity</td>
</tr>
<tr>
<td>$0.00 PV of avoided cost of natural gas</td>
<td>$0.00 PV of non-energy benefits</td>
<td>37% Total capacity</td>
</tr>
<tr>
<td>$0.43 Total Resource Cost test benefits</td>
<td>$0.29 Incremental customer cost</td>
<td>1.47 TRC $ amount</td>
</tr>
<tr>
<td>$0.00 Incremental non-incentive utility cost</td>
<td>$0.29 Total Resource Cost test costs</td>
<td>1.47 TRC benefit / cost ratio</td>
</tr>
<tr>
<td>$0.10 Net TRC $ amount</td>
<td>$0.0603 Levelized cost/kWh of four energy components of AC</td>
<td>2007 Electric IRP</td>
</tr>
</tbody>
</table>
**Electric vs gas water, 40 gal., EF=.95 (per sq. ft.)**

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.509</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>87%</td>
</tr>
<tr>
<td>$0.033</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$248.96</td>
<td>$0.033 PV of avoided cost of generation capacity</td>
<td>6%</td>
</tr>
<tr>
<td>$60.28</td>
<td>$0.008 PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.582</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

**Total energy non-driver**

- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 15 Measure life
- 3.050 Annual kWh savings per unit
- 0.0212% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0131% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

| $1.55            | PV of avoided cost of energy (energy + emissions + risk) | 93% Total energy |
| $0.10            | PV of avoided cost of energy (T&D losses) | 7% Total capacity |
| $0.10            | PV of avoided cost of generation capacity |
| $0.02            | PV of avoided cost of T&D capacity |
| $0.00            | PV of avoided cost of natural gas |
| $0.00            | PV of non-energy benefits |
| $1.78            | Total Resource Cost test benefits |
| $0.68            | Incremental customer cost |
| $0.00            | Incremental non-incentive utility cost |
| $0.68            | Total Resource Cost test costs |
| $1.10            | Net TRC $ amount |

**TRC benefit / cost ratio**

- 2.61

**Avoided Cost Value**

Generation capacity — T&D capacity — T&D losses — Energy, emissions, risk

---

Avista Corp 2007 Electric IRP 52
Humidistat controls (grocery, per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy, emissions, risk</td>
<td>87%</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>6%</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>6%</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>Total energy</td>
<td>92%</td>
</tr>
<tr>
<td>Total capacity</td>
<td>8%</td>
</tr>
</tbody>
</table>

Per first year kW Per first year kWh

- $0.414 PV of avoided cost of energy (energy + emissions + risk)
- $0.027 PV of avoided cost of energy (T&D losses)
- $0.029 PV of avoided cost of generation capacity
- $0.007 PV of avoided cost of T&D capacity
- $0.478

Non-driver, "driver", or "zero" measure type (based upon coincidence with managed system peak period)

- 7.41% Discount rate
- 12 Measure life
- 1.207 Annual kWh savings per unit
- 0.0152% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0139% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

- $0.50 PV of avoided cost of energy (energy + emissions + risk)
- $0.03 PV of avoided cost of energy (T&D losses)
- $0.04 PV of avoided cost of generation capacity
- $0.01 PV of avoided cost of T&D capacity
- $0.00 PV of avoided cost of natural gas
- $0.00 PV of non-energy benefits

- $0.58 Total Resource Cost test benefits

- $0.02 Incremental customer cost
- $0.00 Incremental non-incentive utility cost

- $0.02 Total Resource Cost test costs

- $0.56 Net TRC $ amount

28.83 TRC benefit / cost ratio

Avista Corp 2007 Electric IRP 53
## Exit sign replacement (LED)

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost Value</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.616</td>
<td>88%</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.040</td>
<td>6%</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$0.034</td>
<td>5%</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$0.008</td>
<td>1%</td>
</tr>
<tr>
<td>Total</td>
<td>$0.699</td>
<td>100%</td>
</tr>
</tbody>
</table>

### Additional Details
- **Discount rate**: 7.41%
- **Measure life**: 20 years
- **Annual kWh savings per unit**: 351,000
- **Percent of annual energy in maximum hour (use for "driver" measures)**: 0.0114%
- **Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)**: 0.0114%

### Avoided Cost Value

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy, emissions, risk</td>
<td>$245.25</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>$65.44</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>$14.06</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>$12.02</td>
</tr>
<tr>
<td>Energy</td>
<td>$2.94</td>
</tr>
<tr>
<td>Natural gas</td>
<td>$0.00</td>
</tr>
<tr>
<td>Non-energy benefits</td>
<td>$0.00</td>
</tr>
</tbody>
</table>

### Total Resource Cost

- **Test benefits**: $245.25
- **Incremental customer cost**: $65.44
- **Incremental non-incentive utility cost**: $0.00
- **Total Resource Cost test costs**: $65.44
- **Net TRC $ amount**: $179.81

### TRC benefit / cost ratio
- **3.75**
Light colored roof (from .8 to .45 absorptivity)

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.360 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>58%</td>
<td></td>
</tr>
<tr>
<td>$0.023 PV of avoided cost of energy (T&amp;D losses)</td>
<td>4%</td>
<td></td>
</tr>
<tr>
<td>$184.47 $</td>
<td>0.190 PV of avoided cost of generation capacity</td>
<td>31%</td>
</tr>
<tr>
<td>$44.23 $</td>
<td>0.046 PV of avoided cost of T&amp;D capacity</td>
<td>7%</td>
</tr>
<tr>
<td>$0.619</td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

- measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 10 Measure life
- 0.118 Annual kWh savings per unit
- 0.1031% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0547% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

Avoided Cost Value

- $0.04 PV of avoided cost of energy (energy + emissions + risk)
- $0.00 PV of avoided cost of energy (T&D losses)
- $0.02 PV of avoided cost of generation capacity
- $0.01 PV of avoided cost of T&D capacity
- $0.00 PV of avoided cost of natural gas
- $0.00 PV of non-energy benefits
- $0.07 Total Resource Cost test benefits

- $0.24 Incremental customer cost
- $0.00 Incremental non-incentive utility cost
- $0.24 Total Resource Cost test costs

($0.17) Net TRC $ amount

0.30 TRC benefit / cost ratio

Light colored roof (from .8 to .45 absorptivity)
### Occupancy sensors for lighting

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Benefit</th>
<th>Per first year kWh</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.481 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$237.24</td>
<td>$0.036</td>
<td>86%</td>
</tr>
<tr>
<td>$0.031 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$57.34</td>
<td>$0.009</td>
<td>6%</td>
</tr>
<tr>
<td>$0.05 PV of avoided cost of generation capacity</td>
<td>$57.34</td>
<td>$0.009</td>
<td>6%</td>
</tr>
<tr>
<td>$0.06 PV of avoided cost of T&amp;D capacity</td>
<td></td>
<td>$0.00</td>
<td>2%</td>
</tr>
<tr>
<td>$0.00 PV of avoided cost of natural gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$0.00 PV of non-energy benefits</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>$0.89</strong> Total Resource Cost test benefits</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$0.05 Incremental customer cost</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$0.00 Incremental non-incentive utility cost</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>$0.89</strong> Total Resource Cost test benefits</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### TRC $ amount

- **$0.31** Net TRC $ amount

- **1.53** TRC benefit / cost ratio

---

**Avoided Cost Value**

- **Generation capacity**
- **T&D capacity**
- **T&D losses**
- **Energy, emissions, risk**

---

**Summary**

- **Occupancy sensors for lighting**
- **Summarization of AC benefits and comparison to TRC costs**
- **Benefits breakdown**
  - $0.481 PV of avoided cost of energy (energy + emissions + risk)
  - $0.031 PV of avoided cost of energy (T&D losses)
  - $0.05 PV of avoided cost of generation capacity
  - $0.06 PV of avoided cost of T&D capacity
  - $0.00 PV of avoided cost of natural gas
  - $0.00 PV of non-energy benefits
- **Total Resource Cost test benefits**: $0.89
- **Net TRC $ amount**: $0.31
- **TRC benefit / cost ratio**: 1.53
### Light fixture reconfiguration

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>86% PV of avoided cost of energy (energy + emissions + risk)</th>
<th>6% PV of avoided cost of energy (T&amp;D losses)</th>
<th>2% PV of avoided cost of generation capacity</th>
<th>2% PV of avoided cost of T&amp;D capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>$260.14 $</td>
<td>$0.040 $</td>
<td>$0.035 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.035 PV of avoided cost of generation capacity</td>
<td>$0.010 PV of avoided cost of T&amp;D capacity</td>
<td>$0.619</td>
</tr>
<tr>
<td>$63.11 $</td>
<td>$0.010 $</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$92% Total energy</td>
<td>$86% Total energy</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### Non-driver, "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- 7.41% Discount rate
- 16 Measure life
- 0.716 Annual kWh savings per unit
- 0.0207% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0153% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

<table>
<thead>
<tr>
<th>86% PV of avoided cost of energy (energy + emissions + risk)</th>
<th>6% PV of avoided cost of generation capacity</th>
<th>2% PV of avoided cost of T&amp;D capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.38</td>
<td>$0.035 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.010 PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$0.02</td>
<td>$0.035 PV of avoided cost of generation capacity</td>
<td>$0.010 PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$0.01</td>
<td>$0.035 PV of avoided cost of T&amp;D capacity</td>
<td>$0.010 PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$0.00</td>
<td>$0.035 PV of avoided cost of natural gas</td>
<td>$0.010 PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$0.00</td>
<td>$0.035 PV of non-energy benefits</td>
<td>$0.010 PV of avoided cost of T&amp;D capacity</td>
</tr>
<tr>
<td>$0.44</td>
<td>$0.0620 Levelized cost/kWh of four energy components of AC</td>
<td>$0.0054 Levelized cost/kWh of two capacity components of AC</td>
</tr>
</tbody>
</table>

#### Avoided Cost Value

- 86% Energy, emissions, risk
- 6% T&D losses
- 6% Generation capacity
- 2% T&D capacity

- $0.50 Incremental customer cost
- $0.00 Incremental non-incentive utility cost
- $0.50 Total Resource Cost test costs
- ($0.06) Net TRC $ amount

- 0.89 TRC benefit / cost ratio

---

**Light fixture reconfiguration**

Avista Corp 2007 Electric IRP
### MH 250 to Pulse Start MH 175, installed

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th></th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>93%</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>1%</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>0%</td>
</tr>
<tr>
<td>Total energy</td>
<td>99%</td>
</tr>
<tr>
<td>Total capacity</td>
<td>1%</td>
</tr>
</tbody>
</table>

#### Key Parameters

- **Discount rate**: 7.41%
- **Measure life**: 16 years
- **Annual kWh savings per unit**: $349,000
- **Percent of annual energy in maximum hour**: 0.0229%
- **Percent of annual energy in average hour of designated system peak**: 0.0020%

#### Avoided Cost Value

<table>
<thead>
<tr>
<th>Component</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$174.77</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$11.36</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$1.82</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$0.44</td>
</tr>
<tr>
<td>PV of avoided cost of natural gas</td>
<td>$0.00</td>
</tr>
<tr>
<td>PV of non-energy benefits</td>
<td>$0.00</td>
</tr>
<tr>
<td>Total Resource Cost test benefits</td>
<td>$188.39</td>
</tr>
<tr>
<td>Incremental customer cost</td>
<td>$196.86</td>
</tr>
<tr>
<td>Incremental non-incentive utility cost</td>
<td>$0.00</td>
</tr>
<tr>
<td>Total Resource Cost test costs</td>
<td>$196.86</td>
</tr>
<tr>
<td>Net TRC $ amount</td>
<td>($8.47)</td>
</tr>
</tbody>
</table>

#### TRC Benefit / Cost Ratio

- **TRC benefit / cost ratio**: 0.96

---

**Avista Corp**  
**2007 Electric IRP**  
**Page 58**
**MH to T5 Fluorescents (400W to 4 HO, 3,000 hr)**

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.509</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>86%</td>
</tr>
<tr>
<td>$0.033</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$248.96</td>
<td>$0.038 PV of avoided cost of generation capacity</td>
<td>6%</td>
</tr>
<tr>
<td>$60.28</td>
<td>$0.009 PV of avoided cost of T&amp;D capacity</td>
<td>2%</td>
</tr>
<tr>
<td>$0.589</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

- **non-driver** "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
  - 7.41% Discount rate
  - 15 Measure life
  - 672 Annual kWh savings per unit
  - 0.0207% Percent of annual energy in maximum hour (use for "driver" measures)
  - 0.0153% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

- **Avoided Cost Value**
  - $341.97 PV of avoided cost of energy (energy + emissions + risk)
  - $22.23 PV of avoided cost of energy (T&D losses)
  - $25.52 PV of avoided cost of generation capacity
  - $6.18 PV of avoided cost of T&D capacity
  - $0.00 PV of avoided cost of natural gas
  - $0.00 PV of non-energy benefits
  - $395.90 Total Resource Cost test benefits
  - $250.00 Incremental customer cost
  - $0.00 Incremental non-incentive utility cost
  - $250.00 Total Resource Cost test costs
  - $145.90 Net TRC $ amount

- **TRC benefit / cost ratio** 1.58

MH to T5 Fluorescents (400W to 4 HO, 3,000 hr)
## Occupancy sensors for 1-zone A/C & PTAC (per sq. ft.)

### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Benefit Description</th>
<th>Costs</th>
<th>% of Total Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avoided cost of energy</td>
<td>$0.503</td>
<td>59%</td>
</tr>
<tr>
<td>Avoided cost of T&amp;D losses</td>
<td>$0.033</td>
<td>4%</td>
</tr>
<tr>
<td>Avoided cost of generation capacity</td>
<td>$0.257</td>
<td>30%</td>
</tr>
<tr>
<td>Avoided cost of T&amp;D capacity</td>
<td>$0.062</td>
<td>7%</td>
</tr>
<tr>
<td>Total</td>
<td>$0.854</td>
<td>100%</td>
</tr>
</tbody>
</table>

### Measure Details

- **Measure Life**: 15 years
- **Annual kWh savings per unit**: 1.694
- **Discount rate**: 7.41%
- **Percent of annual energy in maximum hour**: 0.1031%
- **Percent of annual energy in average hour of designated system peak**: 0.0547%

### Avoided Cost Value

<table>
<thead>
<tr>
<th>Component</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy, emissions, risk</td>
<td>$0.85</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>$0.43</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>$0.11</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>$0.06</td>
</tr>
<tr>
<td>Non-energy benefits</td>
<td>$0.00</td>
</tr>
<tr>
<td>Total Resource Cost test benefits</td>
<td>$1.45</td>
</tr>
</tbody>
</table>

### Incremental Costs

- **Incremental customer cost**: $0.20
- **Incremental non-incentive utility cost**: $0.00
- **Total Resource Cost test costs**: $0.20

### Net TRC $ amount

<table>
<thead>
<tr>
<th>Amount</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$1,250</td>
<td>Net TRC $ amount</td>
</tr>
</tbody>
</table>

### TRC benefit / cost ratio

- **TRC benefit / cost ratio**: 7.23
### Prescriptive sidestream filtration

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th></th>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of</td>
<td>$0.503</td>
<td>59%</td>
<td></td>
</tr>
<tr>
<td>energy (energy +</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>emissions + risk)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PV of avoided cost of</td>
<td>$0.033</td>
<td>4%</td>
<td></td>
</tr>
<tr>
<td>energy (T&amp;D losses)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PV of avoided cost of</td>
<td>$0.062</td>
<td>7%</td>
<td></td>
</tr>
<tr>
<td>generation capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PV of avoided cost of</td>
<td>$0.854</td>
<td>100%</td>
<td></td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Driver**, "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

**7.41%** Discount rate

**15** Measure life

**200,000** Annual kWh savings per unit

**0.1031%** Percent of annual energy in maximum hour (use for "driver" measures)

**0.0547%** Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

|                         | $100,542.88         |
| PV of avoided cost of   | $6,535.29           |
| energy (energy +       | $51,329.97          |
| emissions + risk)      | $12,429.16          |
| PV of avoided cost of   | $0.00               |
| generation capacity    | $0.00               |
| PV of avoided cost of   | $170,837.29         |
| T&D capacity           | $28,000.00          |
| PV of avoided cost of   | $0.00               |
| T&D losses             | $142,837.29         |

- **6.10** TRC benefit / cost ratio

**$100,542.88** PV of avoided cost of energy (energy + emissions + risk)

**$6,535.29** PV of avoided cost of energy (T&D losses)

**$51,329.97** PV of avoided cost of generation capacity

**$12,429.16** PV of avoided cost of T&D capacity

**$0.00** PV of avoided cost of natural gas

**$0.00** PV of non-energy benefits

**$170,837.29** Total Resource Cost test benefits

**$28,000.00** Incremental customer cost

**$0.00** Incremental non-incentive utility cost

**$28,000.00** Total Resource Cost test costs

**$142,837.29** Net TRC $ amount

### Avoided Cost Value

- T&D capacity
- Generation capacity
- Energy, emissions, risk
- T&D losses

---

Avista Corp 2007 Electric IRP
# Refrigeration tune-up/commissioning (per sq. ft.)

## Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.135 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$64.65</td>
<td>87%</td>
</tr>
<tr>
<td>$0.009 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.009</td>
<td>6%</td>
</tr>
<tr>
<td>$15.26 PV of avoided cost of generation capacity</td>
<td>$0.002</td>
<td>1%</td>
</tr>
<tr>
<td>$0.154</td>
<td>$0.154</td>
<td>100%</td>
</tr>
</tbody>
</table>

- **non-driver**: "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 3 Measure life
- 1.209 Annual kWh savings per unit
- 0.0152% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0139% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

### Avoided Cost Value

![Avoided Cost Value](https://via.placeholder.com/150)

- Energy, emissions, risk
- Generation capacity
- T&D losses
- T&D capacity

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>% of Total Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.0550 Levelized cost/kWh of four energy components of AC</td>
<td>93% Total energy</td>
</tr>
<tr>
<td>$0.0043 Levelized cost/kWh of two capacity components of AC</td>
<td>7% Total capacity</td>
</tr>
<tr>
<td>$0.16 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.006 Incremental customer cost</td>
</tr>
<tr>
<td>$0.01 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.00 Incremental non-incentive utility cost</td>
</tr>
<tr>
<td>$0.01 PV of avoided cost of generation capacity</td>
<td>$0.06 Total Resource Cost test benefits</td>
</tr>
<tr>
<td>$0.00 PV of avoided cost of T&amp;D capacity</td>
<td>$0.13 Net TRC $ amount</td>
</tr>
<tr>
<td>$0.00 PV of avoided cost of natural gas</td>
<td><strong>3.11 TRC benefit / cost ratio</strong></td>
</tr>
<tr>
<td>$0.00 PV of non-energy benefits</td>
<td><strong>Refrigeration tune-up/commissioning (per sq. ft.)</strong></td>
</tr>
</tbody>
</table>

---

Avista Corp 2007 Electric IRP 62
### Rooftop DX maintenance (per sq. ft.)

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy, emissions, risk</td>
<td>60%</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>4%</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>29%</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>7%</td>
</tr>
<tr>
<td>Total energy</td>
<td>64%</td>
</tr>
<tr>
<td>Total capacity</td>
<td>36%</td>
</tr>
</tbody>
</table>

#### Measure life

| Measure life | 3 |
| Percent of annual energy in maximum hour (use for "driver" measures) | 0.1031% |
| Percent of annual energy in average hour of designated system peak (use for "non-driver" measures) | 0.0547% |

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>$0.09</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.137</td>
</tr>
<tr>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.009</td>
</tr>
<tr>
<td>PV of avoided cost of generation capacity</td>
<td>$0.067</td>
</tr>
<tr>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>$0.016</td>
</tr>
<tr>
<td>Total Resource Cost test benefits</td>
<td>$0.15</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>$0.23</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental customer cost</td>
<td>$0.01</td>
</tr>
<tr>
<td>Incremental non-incentive utility cost</td>
<td>$0.04</td>
</tr>
<tr>
<td>Total Resource Cost test costs</td>
<td>$0.01</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>$0.00</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net TRC $ amount</td>
<td>$0.08</td>
</tr>
</tbody>
</table>

**Discount rate**

7.41%

**TRC benefit / cost ratio**

0.65
### Pre-rinse sprayers

#### Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Per first year kWh</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.208 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>$0.208 PV of avoided cost of energy (T&amp;D losses)</td>
<td>87%</td>
<td></td>
</tr>
<tr>
<td>$0.014 PV of avoided cost of energy (T&amp;D losses)</td>
<td>$0.013 PV of avoided cost of generation capacity</td>
<td>6%</td>
<td></td>
</tr>
<tr>
<td>$0.003 PV of avoided cost of T&amp;D capacity</td>
<td>$0.239</td>
<td>1%</td>
<td></td>
</tr>
</tbody>
</table>

- **non-driver** "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

  - 7.41% Discount rate
  - 5 Measure life
  - 3.800.000 Annual kWh savings per unit
  - 0.0212% Percent of annual energy in maximum hour (use for "driver" measures)
  - 0.0131% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>$792.01 PV of avoided cost of energy (energy + emissions + risk)</th>
<th>$51.48 PV of avoided cost of energy (T&amp;D losses)</th>
<th>$51.13 PV of avoided cost of generation capacity</th>
<th>$12.13 PV of avoided cost of T&amp;D capacity</th>
<th>$0.00 PV of avoided cost of natural gas</th>
<th>$0.00 PV of non-energy benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>$906.74 Total Resource Cost test benefits</td>
<td>$162.00 Incremental customer cost</td>
<td>$0.00 Incremental non-incentive utility cost</td>
<td>$162.00 Total Resource Cost test costs</td>
<td>$744.74 Net TRC $ amount</td>
<td>5.60 TRC benefit / cost ratio</td>
<td>Pre-rinse sprayers</td>
</tr>
<tr>
<td>$0.0547 Levelized cost/kWh of four energy components of AC</td>
<td>$0.0041 Levelized cost/kWh of two capacity components of AC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$93% Total energy</td>
<td>7% Total capacity</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Avoided Cost Value**

- Generation capacity
- T&D losses
- Energy, emissions, risk
- T&D capacity

---

*Avista Corp 2007 Electric IRP*
### CFL 20W screw-in for incandescent 75W (retrofit)

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.096</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>87%</td>
</tr>
<tr>
<td>$0.006</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$44.10</td>
<td>0.007 PV of avoided cost of generation capacity</td>
<td></td>
</tr>
<tr>
<td>$10.39</td>
<td>0.002 PV of avoided cost of T&amp;D capacity</td>
<td>1%</td>
</tr>
<tr>
<td>$0.111</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

#### Non-driver
- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 2.1 Measure life
- 260 Annual kWh savings per unit
- 0.0207% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0153% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

### Avoided Cost Value

<table>
<thead>
<tr>
<th>Component</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy, emissions, risk</td>
<td>$28.84</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>$1.63</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>$1.75</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>$0.41</td>
</tr>
<tr>
<td>Natural gas</td>
<td>$0.00</td>
</tr>
<tr>
<td>Non-energy benefits</td>
<td>$0.00</td>
</tr>
</tbody>
</table>

**Total Resource Cost test benefits**: $28.84

**Incremental customer cost**: $10.25

**Incremental non-incentive utility cost**: $0.00

**Total Resource Cost test costs**: $10.25

**Net TRC $ amount**: $18.59

**TRC benefit / cost ratio**: 2.81

---

**Avista Corp 2007 Electric IRP**

Page 65
Prescriptive sidestream filtration

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.503</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>59%</td>
</tr>
<tr>
<td>$0.033</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>4%</td>
</tr>
<tr>
<td>$248.96</td>
<td>0.257 PV of avoided cost of generation capacity</td>
<td>30%</td>
</tr>
<tr>
<td>$60.28</td>
<td>0.062 PV of avoided cost of T&amp;D capacity</td>
<td>7%</td>
</tr>
<tr>
<td>$0.854</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

- % of total energy: 63%
- % of total capacity: 37%
- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 15 Measure life
- 200,000 Annual kWh savings per unit
- 0.1031% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0547% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$100,542.88 PV of avoided cost of energy (energy + emissions + risk)
$6,535.29 PV of avoided cost of energy (T&D losses)
$51,329.97 PV of avoided cost of generation capacity
$12,429.16 PV of avoided cost of T&D capacity
$0.00 PV of avoided cost of natural gas
$0.00 PV of non-energy benefits

$170,837.29 Total Resource Cost test benefits

$28,000.00 Incremental customer cost
$0.00 Incremental non-incentive utility cost

$28,000.00 Total Resource Cost test costs

$142,837.29 Net TRC $ amount

6.10 TRC benefit / cost ratio

Avoided Cost Value

- Energy, emissions, risk
- T&D capacity
- T&D losses

Supplemental- Section 3
Signage: incandescent to LED/incandescent to cold cathode

<table>
<thead>
<tr>
<th>Summarization of AC benefits and comparison to TRC costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Per first year kW</td>
</tr>
<tr>
<td>$0.194</td>
</tr>
<tr>
<td>$0.013</td>
</tr>
<tr>
<td>$0.209</td>
</tr>
<tr>
<td>102.97</td>
</tr>
<tr>
<td>24.42</td>
</tr>
<tr>
<td>$0.93</td>
</tr>
<tr>
<td>$0.15</td>
</tr>
<tr>
<td>$0.04</td>
</tr>
<tr>
<td>$0.00</td>
</tr>
<tr>
<td>$0.00</td>
</tr>
<tr>
<td>$15.47</td>
</tr>
<tr>
<td>$15.00</td>
</tr>
<tr>
<td>$0.00</td>
</tr>
<tr>
<td>$15.00</td>
</tr>
<tr>
<td>$0.00</td>
</tr>
<tr>
<td>$0.47</td>
</tr>
</tbody>
</table>

1.03 TRC benefit / cost ratio

Avoided Cost Value
### Smart programmable thermostat (per sq. ft.)

**Summary of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Avoided Cost Value</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.360 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>58%</td>
</tr>
<tr>
<td>$0.023 PV of avoided cost of energy (T&amp;D losses)</td>
<td>4%</td>
</tr>
<tr>
<td>$0.190 PV of avoided cost of generation capacity</td>
<td>31%</td>
</tr>
<tr>
<td>$0.046 PV of avoided cost of T&amp;D capacity</td>
<td>7%</td>
</tr>
<tr>
<td>$0.619</td>
<td>100%</td>
</tr>
<tr>
<td>$0.10 PV of avoided cost of energy (energy + emissions + risk)</td>
<td></td>
</tr>
<tr>
<td>$0.01 PV of avoided cost of energy (T&amp;D losses)</td>
<td></td>
</tr>
<tr>
<td>$0.05 PV of avoided cost of generation capacity</td>
<td></td>
</tr>
<tr>
<td>$0.01 PV of avoided cost of T&amp;D capacity</td>
<td></td>
</tr>
<tr>
<td>$0.00 PV of avoided cost of natural gas</td>
<td></td>
</tr>
<tr>
<td>$0.00 PV of non-energy benefits</td>
<td></td>
</tr>
<tr>
<td>$0.17 Total Resource Cost test benefits</td>
<td></td>
</tr>
<tr>
<td>$0.15 Incremental customer cost</td>
<td></td>
</tr>
<tr>
<td>$0.00 Incremental non-incentive utility cost</td>
<td></td>
</tr>
<tr>
<td>$0.15 Total Resource Cost test costs</td>
<td></td>
</tr>
<tr>
<td>$0.02 Net TRC $ amount</td>
<td></td>
</tr>
<tr>
<td><strong>1.15 TRC benefit / cost ratio</strong></td>
<td></td>
</tr>
</tbody>
</table>

Smart programmable thermostat (per sq. ft.)

---

**Discount rate:** 7.41%

**Measure life:** 10 years

**Annual kWh savings per unit:** 0.279

**Percent of annual energy in maximum hour (use for "driver" measures):** 0.1031%

**Percent of annual energy in average hour of designated system peak (use for "non-driver" measures):** 0.0547%

---

**Avoided Cost Value**

- **Energy, emissions, risk**
- **T&D losses**
- **Generation capacity**
- **T&D capacity**

---

**Avista Corp 2007 Electric IRP**
### Solar water heating

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Benefit Type</th>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy + emissions + risk</td>
<td>$0.509</td>
<td></td>
<td>87%</td>
</tr>
<tr>
<td>T&amp;D losses</td>
<td>$0.033</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>Generation capacity</td>
<td>$0.033</td>
<td></td>
<td>6%</td>
</tr>
<tr>
<td>T&amp;D capacity</td>
<td>$0.008</td>
<td></td>
<td>1%</td>
</tr>
<tr>
<td>Total</td>
<td>$0.582</td>
<td></td>
<td>100%</td>
</tr>
<tr>
<td>Total energy</td>
<td>93%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total capacity</td>
<td>7%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Measure life**
- 15 years

**Non-driver**
- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- 7.41% Discount rate

- 2,566,000 Annual kWh savings per unit

- 0.0212% Percent of annual energy in maximum hour (use for "driver" measures)

- 0.0131% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

**Avoided Cost Value**

- $1,305.08 PV of avoided cost of energy (energy + emissions + risk)
- $84.83 PV of avoided cost of energy (T&D losses)
- $83.48 PV of avoided cost of generation capacity
- $20.21 PV of avoided cost of T&D capacity
- $0.00 PV of avoided cost of natural gas
- $0.00 PV of non-energy benefits
- $1,493.59 Total Resource Cost test benefits

- $5,310.00 Incremental customer cost
- $0.00 Incremental non-incentive utility cost
- $5,310.00 Total Resource Cost test costs

- ($3,816.41) Net TRC $ amount

- 0.28 TRC benefit / cost ratio
## T12 EEmag to Super T8 Flourescents (retrofit)

**Summary of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.396</td>
<td>$198.60</td>
<td>86%</td>
</tr>
<tr>
<td>$0.026</td>
<td>$0.030</td>
<td>6%</td>
</tr>
<tr>
<td>$47.71</td>
<td>$0.007</td>
<td>2%</td>
</tr>
<tr>
<td>$0.459</td>
<td></td>
<td>100%</td>
</tr>
</tbody>
</table>

**Non-driver**

- "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
- 7.41% Discount rate
- 11 Measure life
- 105 Annual kWh savings per unit
- 0.0207% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0153% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

- $41.54 PV of avoided cost of energy (energy + emissions + risk)
- $2.70 PV of avoided cost of energy (T&D losses)
- $3.18 PV of avoided cost of generation capacity
- $0.76 PV of avoided cost of T&D capacity
- $0.00 PV of avoided cost of natural gas
- $0.00 PV of non-energy benefits

- $48.18 Total Resource Cost test benefits
- $26.84 Incremental customer cost
- $0.00 Incremental non-incentive utility cost
- $26.84 Total Resource Cost test costs
- $21.34 Net TRC $ amount

## Avoided Cost Value

- T&D losses
- Energy, emissions, risk
- Generation capacity
- T&D capacity

**TRC benefit / cost ratio**

### 1.80 TRC benefit / cost ratio
Commissioning/retro-commissioning

Summarization of AC benefits and comparison to TRC costs

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.363</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>86%</td>
</tr>
<tr>
<td>$0.024</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$0.028</td>
<td>PV of avoided cost of generation capacity</td>
<td>7%</td>
</tr>
<tr>
<td>$0.007</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>2%</td>
</tr>
<tr>
<td>$0.422</td>
<td>Total cost</td>
<td>100%</td>
</tr>
</tbody>
</table>

- **Non-driver** measure type (based upon coincidence with managed system peak period)
  - 7.41% Discount rate
  - 1612.000 Annual kWh savings per unit
  - 0.0205% Percent of annual energy in maximum hour (use for "driver" measures)
  - 0.0154% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

- **Avoided Cost Value**
  - $585.70 PV of avoided cost of energy (energy + emissions + risk)
  - $38.07 PV of avoided cost of energy (T&D losses)
  - $45.81 PV of avoided cost of generation capacity
  - $10.98 PV of avoided cost of T&D capacity
  - $0.00 PV of avoided cost of natural gas
  - $0.00 PV of non-energy benefits

- **Total Resource Cost test benefits**: $680.57
- **Incremental customer cost**: $215.50
- **Incremental non-incentive utility cost**: $0.00
- **Total Resource Cost test costs**: $215.50

- **Net TRC $ amount**: $465.07

- **TRC benefit / cost ratio**: 3.16
VF Drives for HVAC

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$0.503</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>86%</td>
</tr>
<tr>
<td>$0.033</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$248.96</td>
<td>$0.042 PV of avoided cost of generation capacity</td>
<td>7%</td>
</tr>
<tr>
<td>$60.28</td>
<td>$0.010 PV of avoided cost of T&amp;D capacity</td>
<td>2%</td>
</tr>
<tr>
<td>$0.588</td>
<td>$0.042 PV of avoided cost of generation capacity</td>
<td>7%</td>
</tr>
<tr>
<td></td>
<td>$0.010 PV of avoided cost of T&amp;D capacity</td>
<td>2%</td>
</tr>
<tr>
<td></td>
<td>$0.00 PV of avoided cost of natural gas</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$0.00 PV of non-energy benefits</td>
<td></td>
</tr>
<tr>
<td>$0.34</td>
<td>PV of avoided cost of energy (energy + emissions + risk)</td>
<td>37%</td>
</tr>
<tr>
<td>$0.02</td>
<td>PV of avoided cost of energy (T&amp;D losses)</td>
<td>6%</td>
</tr>
<tr>
<td>$0.03</td>
<td>PV of avoided cost of generation capacity</td>
<td>7%</td>
</tr>
<tr>
<td>$0.01</td>
<td>PV of avoided cost of T&amp;D capacity</td>
<td>2%</td>
</tr>
<tr>
<td>$0.00</td>
<td>PV of avoided cost of natural gas</td>
<td></td>
</tr>
<tr>
<td>$0.00</td>
<td>PV of non-energy benefits</td>
<td></td>
</tr>
<tr>
<td>$0.40</td>
<td>Total Resource Cost test benefits</td>
<td></td>
</tr>
<tr>
<td>$0.21</td>
<td>Incremental customer cost</td>
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<tr>
<td>$0.00</td>
<td>Incremental non-incentive utility cost</td>
<td></td>
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<tr>
<td>$0.21</td>
<td>Total Resource Cost test costs</td>
<td></td>
</tr>
<tr>
<td>$0.19</td>
<td>Net TRC $ amount</td>
<td></td>
</tr>
<tr>
<td>1.89</td>
<td>TRC benefit / cost ratio</td>
<td></td>
</tr>
</tbody>
</table>

*Non-driver* "driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)

- 4.1% Discount rate
- 15 Measure life
- 0.675 Annual kWh savings per unit
- 0.0217% Percent of annual energy in maximum hour (use for "driver" measures)
- 0.0170% Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

![Avoided Cost Value](attachment:image.png)

- **Energy, emissions, risk**: $0.503
- **T&D losses**: $0.033
- **Generation capacity**: $0.042
- **T&D capacity**: $0.010

**Levelized cost/kWh**

- $0.0604 4 energy components of AC
- $0.0059 2 capacity components of AC

**TRC benefit / cost ratio**: 1.89
## Window films

**Summarization of AC benefits and comparison to TRC costs**

<table>
<thead>
<tr>
<th>Per first year kW</th>
<th>Per first year kWh</th>
<th>% of total value</th>
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</thead>
<tbody>
<tr>
<td>$0.360 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>58%</td>
<td></td>
</tr>
<tr>
<td>$0.023 PV of avoided cost of energy (T&amp;D losses)</td>
<td>4%</td>
<td></td>
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<tr>
<td>$0.190 PV of avoided cost of generation capacity</td>
<td>31%</td>
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<tr>
<td>$0.046 PV of avoided cost of T&amp;D capacity</td>
<td>7%</td>
<td></td>
</tr>
<tr>
<td>$0.619</td>
<td>100%</td>
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</table>

<table>
<thead>
<tr>
<th>Measure type</th>
<th>Avoided Cost Value</th>
<th>% of total value</th>
</tr>
</thead>
<tbody>
<tr>
<td>&quot;driver&quot;, &quot;non-driver&quot; or &quot;zero&quot; measure type (based upon coincidence with managed system peak period)</td>
<td>$18.01 PV of avoided cost of energy (energy + emissions + risk)</td>
<td>62% Total energy</td>
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<td>7.41% Discount rate</td>
<td>$1.17 PV of avoided cost of energy (T&amp;D losses)</td>
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<td>10</td>
<td>$9.51 PV of avoided cost of generation capacity</td>
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<tr>
<td>0.00 Annual kWh savings per unit</td>
<td>$2.28 PV of avoided cost of T&amp;D capacity</td>
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<tr>
<td>0.1031% Percent of annual energy in maximum hour (use for &quot;driver&quot; measures)</td>
<td>$0.00 PV of avoided cost of natural gas</td>
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<tr>
<td>0.0547% Percent of annual energy in average hour of designated system peak (use for &quot;non-driver&quot; measures)</td>
<td>$0.00 PV of non-energy benefits</td>
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<tr>
<td>$30.97</td>
<td>$0.0557 Levelized cost/kWh of four energy components of AC</td>
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</tr>
<tr>
<td>$100.00</td>
<td>$0.0342 Levelized cost/kWh of two capacity components of AC</td>
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</tbody>
</table>

**Avoided Cost Value**

- **T&D capacity**
- **Generation capacity**
- **Energy, emissions, risk**
- **T&D losses**

**Measure Life**

- Annual kWh savings per unit: 50,000

**Discount Rate**

- 7.41%

**Percent of Annual Energy**

- Maximum hour (use for "driver" measures): 0.1031%
- Average hour of designated system peak (use for "non-driver" measures): 0.0547%

**Net TRC $ amount**

- $100.00 Incremental customer cost
- $0.00 Incremental non-incentive utility cost
- $100.00 Total Resource Cost test costs

**Net TRC $ amount**

- ($69.03)

**TRC benefit / cost ratio**

- 0.31

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Supplemental- Section 3

Avista Corp 2007 Electric IRP 73
Estimated Resource Integration Costs

March 26, 2007

R. Gnaedinger
S. Koeff
S. Waples
Estimated Resource Integration Costs for the 2007 IRP

Introduction

Avista-LSE requested integration costs for potential future resources to meet its state-jurisdictional service obligations to Avista’s bundled retail native load customers. While points of integration are critical for this discussion, the type of generation is immaterial. Future resources may vary in fuel type, but these variations are not considered in this study.

Several different project sizes were requested for this analysis: 50 MW, 100 MW, 250 MW and over 400 MW. Transmission capability comes in “lumps” and plant sizes may be able to be altered based upon transmission capacity that might be available at a particular site, so we have separated the alternatives into 50 MW, 100 MW, 400 MW, 750 MW and 1,000 MW sizes. If an alternative is requested for 50 or 100 MW, only those will be discussed; however the 400, 750 and 1,000 MW sizes will be discussed separately for the projects over 400 MW.

The various integration points requested for this study have been roughly divided into two classes: those which would integrate directly onto Avista’s transmission system, and those that would integrate on other transmission systems. Integration of large amounts of generation on our system could fit into both classes since there would be broad impacts to both our system and neighboring systems. It should be noted that rigorous study has not been completed for any of the alternatives where the resources would be integrated on a foreign system (the estimates presented below are based on engineering judgment only), because it is not possible to provide meaningful results without the knowledge, input and approval of the owners of those systems. If a detailed cost and capacity estimate of these options became necessary, Avista-LSE would be required to request transmission from these other systems and would need to pay for any study work that these systems deem necessary. Therefore, the costs provided are not, and can not be, construction estimate quality. Additionally, only limited study work has been done for the alternatives within our system; comprehensive study work requires detailed machine parameters which are available only when an actual project is specified.

Also note that as the size of the resource to be integrated increases, the certainty of any estimates becomes less precise. A 50 MW resource can be integrated in many places on the Avista system with relatively little system impact, and likely little or no impact on neighboring systems. Projects over 400 MW can be integrated only in specific areas, which will most likely impact neighboring systems. Due to the uncertainty of impacts to any system where such resources would be integrated as well as the most likely significant impacts to neighboring systems, an approximate worst case cost estimate has been assigned based on engineering judgment.

Depending upon the size, scope, placement, and timing of a new resource, a detailed regional process may be required to determine the exact system impacts and integration/mitigation costs for all affected systems. This process may increase complexity, cost, and time to project energization.

Interconnection costs listed for locations within the Avista transmission system include all costs beyond the fence line of the plant location including transmission to and substation equipment at the interconnection point. Substation costs include any additional substation upgrades that are needed beyond upgrades needed at the interconnection point. Transmission costs include all costs to add/upgrade transmission beyond the transmission needed to get to the interconnection point. The annual operation and maintenance (O&M) costs for the transmission system are

Avista Corp 2007 Electric IRP 2
calculated from Avista’s 2005 FERC form No. 1 financial report. The report was used to calculate an average annual O&M cost for Avista’s transmission system on a per mile basis. All internal cost estimates are in 2015 year dollars and are based on engineering judgment with +/- 50% error.

Time to construct, for this study, is defined from the beginning of the permitting process to the final energization date for.

**External to the Avista System**

**Boardman, Oregon**

The present transmission system which serves the Boardman generating complex consists of two 500 kV circuits which are owned and operated by Portland General Electric (PGE) which integrate into several 500 kV circuits owned and operated by the Bonneville Power Administration (BPA). Boardman lies to the north and east of several transmission constraints which could be an issue with respect to BPA’s transmission pricing and availability policies.

Because Avista owns no transmission in the Boardman area, Avista-LSE would be required to undertake a transmission request on the PGE system and would also be required to fund a study to determine potential impacts caused by this project on BPA. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area. Note that since two transmission systems (other than the Avista system) would be involved in the integration of this project, Avista-LSE would pay two wheeling charges or “pancaked” rates for transmission service.

The following estimates might be reasonable for integration of energy at this site:

**400 MW:** 400 MW would most likely require reinforcement to both PGE and BPA’s “local” 500 kV system, and might require additional 500 kV facilities “downstream” of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

**750 MW:** 750 MW almost certainly requires reinforcement to both PGE and BPA’s “local” 500 kV grid in the area, and would also almost certainly require additional 500 kV facilities “downstream” of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

**1000 MW:** 1000 MW would most likely require an additional 500 kV line in the local area, and would almost certainly require additional 500 kV facilities “downstream” of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

As noted above, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate more that 400 MW of resources at this site.
John Day, Washington

The transmission system which presently serves the John Day generating complex consists of several 500 kV circuits which are owned and operated by BPA. John Day is to the north and east of several transmission constraints which could be an issue with respect to BPA’s transmission pricing and availability policies.

Because Avista owns no transmission in the John Day area, Avista-LSE would be required to undertake a transmission request on the BPA transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

The following estimates might be reasonable for integration of energy at this site:

50 MW: The North of John Day Path is presently in a constrained state, depending upon generation on the upper and mid Columbia River. Because of these existing constraints, a transmission integration study on the BPA system would be required to determine if 50 MW would be able to be integrated at a low cost.

100 MW: The North of John Day Path is presently in a constrained state, depending upon generation on the upper and mid Columbia River. Because of these existing constraints, a transmission integration study on the BPA system would be required to determine if 100 MW would be able to be integrated at a low cost.

Because this is presently a constrained path, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate any new resources at this site.

Kalama, Washington

The transmission system which presently serves the Kalama area consists of two 500 kV circuits and two 230 kV circuits, all of which are owned and operated by BPA. This area lies in the center of several transmission constraints (from Canada to and into California) which could be an issue with respect to BPA’s transmission pricing and availability policies.

Because Avista owns no transmission in the Kalama area, Avista-LSE would be required to undertake a transmission request on the BPA transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

The following estimates might be reasonable for integration of energy at this site:

400 MW: 400 MW would most likely require reinforcement to BPA’s “local” 500 kV system, and might require additional 500 kV facilities “downstream” of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

750 MW: 750 MW almost certainly require reinforcement to BPA’s “local” 500 kV grid in the area, and would also almost certainly require additional 500 kV facilities “downstream” of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4M per mile for construction of new
500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown.

**1000 MW:** 1000 MW would most likely require an additional 500 kV line in the local area, and would almost certainly require additional 500 kV facilities “downstream” of the plant. Engineering estimates of construction costs (taken from the recent Canada>Northwest>California integration studies) are $1.4 million per mile for construction of new 500 kV lines. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown—although the costs for this alternative could be well over $1.5 billion.

As noted above, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate more that 400 MW of resources at this site.

**LaGrande, Oregon**
The transmission system which presently serves the LaGrande area consists of a 230 kV line which is owned and operated by BPA and which terminates at McNary, and a 230 kV line which is owned and operated by Idaho Power Company (IPC) and which terminates at Brownlee. IPC also owns a 69 kV line out of LaGrande which is normally operated in a radial configuration. LaGrande lies in the center of one of the four lines which make up the Idaho>Northwest transmission path (the Brownlee-McNary 230 kV line). There is presently a WECC rating process that is being undertaken for the Idaho>Northwest path which could affect any potential available transmission capacity on these lines.

Because Avista owns no transmission in the LaGrande area, Avista-LSE would be required to undertake a transmission request on either the BPA or IPC transmission systems. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

**50 or 100 MW:** Because of the above rating study, there is no way to perform a reasonable study for additional generation in this area until that study has been resolved.

Because this is presently a constrained path, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate any new resources at this site.

**Northeast Wyoming**
The transmission system which presently serves northeastern Wyoming consists of several 230 kV circuits which are owned and operated by PacifiCorp and Black Hills Power Company. Additional circuits are owned by or presently planned by Basin Electric. Northeast Wyoming is south, north, east, and west of several transmission constraints.

Because Avista owns no transmission in northeastern Wyoming, Avista-LSE would be required to undertake a transmission request on one of the multiple transmission systems in the area. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

The following estimates might be reasonable for integration of energy at this site:

**400-1000 MW:** Because there are constraints from this area both to the north and west (Montana–Wyoming, as well as all of the serial constraints from the Colstrip area to the Spokane
area) and to the south and west (the Bridger transmission system, Path C, and Idaho->Northwest), moving 400-1000 MW from this area into our native system would be difficult, time consuming, and most likely quite expensive from a construction standpoint. In the lowest power, lowest cost case at least one 500 kV line would be required (at least as far as into the IPC system). In the 1000 MW case, two 500 kV lines might well be required. In addition, depending upon the arrangements, wheeling expense might also be incurred.

Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown- although the costs for this effort could be between $2.0 and $3.0 billion.

A regional study would likely be needed to integrate more that 400 MW of resources at this site.

**Southeast Idaho**

The transmission system which presently serves southeastern Idaho consists of a 500 kV line, several 345 kV lines, and several 230 kV circuits which are owned and operated by PacifiCorp and IPC. Southeastern Idaho is east and west of several transmission constraints.

Because Avista owns no transmission in southeastern Idaho, Avista-LSE would be required to undertake a transmission request on either the PacifiCorp or IPC systems in the area. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

The following estimates are reasonable expectations for integration costs at this site:

**400-1000 MW:** Because there are constraints from this area both to the east and west (Path C as well as Idaho->Northwest), moving 400-1000 MW from this area into our native system would be difficult, time consuming, and most likely quite expensive from a construction standpoint. In the lowest power, lowest cost case at least one additional 345 kV line would be required (at least as far as into the center of the IPC system). In the 1000 MW case, two 500 kV lines might well be required, all of the way to the Avista system. In addition, depending upon the arrangements, wheeling expense might also be incurred. Because the amount of new transmission will not be known until studies on the area are complete, total integration costs are presently unknown, although the costs for this effort could be between $1.0 and $3.0 billion.

As noted above, a regional study would likely be necessary to integrate more that 400 MW of resources at this site.

**Central Alberta, Canada**

Presently, there is no available transfer capability, nor is there any suitable method of inexpensively integrating energy from central Alberta into the Avista system. Because of the distances and costs involved, integration into the United States power grid at capacity levels less than 2000-3000 MW is unlikely. Because of the capacity required for the economics of the project to “pencil”, it is anticipated that transmission from central Alberta would be a direct current (DC) 500 kV line. It is assumed that one of the DC terminals would be either in the Spokane area or at the Mid-Columbia. Avista could then purchase portions of this energy to be delivered to its system from either of those places. It should be noted that a regional scoping effort to estimate costs for this (and other similar) project(s) has just been completed and can be obtained (assuming the requirements for obtaining Critical Infrastructure Information are met) from the Northwest Power Pool. Estimates for these projects are in the range of two to five billion dollars.
The following estimates might be reasonable for integration of energy at this site:

**50 – 250 MW:** A 300 MW transmission interconnection project between southern Alberta and northern Montana (MATL) has been proposed. Available capacity on this project is not known at this time. However, additional transmission would be required between central Alberta and southern Alberta, as well as from northern Montana to the Spokane area (which passes through the Great Falls-Garrison constraints as well as the Montana>Northwest constraints). Until it is known if the MATL project will be constructed, it is difficult to provide estimates on whether 50 MW of energy can be economically integrated into our system from central Alberta. Note that Avista-LSE would be required to undertake a transmission request on the BPA system for this service. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

**400-1000-3000 MW:** Integration of anything over 300 MW would most likely require a high voltage DC tie directly from the resource, which would most likely be integrated into the Mid-Columbia area. Please see the attached CNC study to determine estimates of integration costs. Integration of more than 400 MW from the Mid-Columbia would be expected to cost in the range of $300 – 500 million. Note that this is exclusive of the 500 kV DC tie project.

As noted above, a regional study would likely be necessary to integrate more that 400 MW of resources at this site.

**Central Washington**

The transmission system which presently serves the Central Washington area consists of a couple 500 kV circuits and several 230 kV circuits which are owned and operated by several entities. One of the 230 kV lines into the Mid-Columbia area is jointly owned by Avista and PacifiCorp. However, presently there is no long term available transfer capability from central Washington into the Avista system via the jointly owned transmission line. There is a regional study through the Northwest Power Pool in progress which will be analyzing resource integration in the Mid-Columbia area (which includes Avista’s system). This study should be complete sometime in mid 2007.

The following estimates might be reasonable for integration of energy at this site:

**50 – 300 MW:** The Mid-Columbia area is presently in a constrained state, depending upon generation on the mid Columbia River. Because of these existing constraints, a transmission integration study (most likely on the BPA or Avista system) would be required to determine if 50 MW would be able to be integrated.

**400-1000 MW:** The integration of more than 400 MW from the Mid-Columbia would be expected to cost in the range of $300 – 500 million.

As noted above, a regional study would likely be necessary to integrate more that 400 MW of resources at this site.

**Eastern Montana**

The present transmission system to the west of (and serving) the present generation in Montana is a double circuit 500 kV line and two 230 kV lines. A regional study under the auspices of the Northwest Power Pool (NWPP) NTAC was completed last year which indicates that either additional transmission or transmission upgrades would need to be constructed for integration of energy from Montana. Eastern Montana is also to the east of several transmission constraints.
(West of Colstrip, West of Broadview, West of Garrison, Montana to the Northwest, and West of Hatwai) which could be an issue with respect to BPA’s transmission pricing and availability policies.

A more detailed study effort which will focus on constraints from Central and Eastern Montana has recently been announced. This study will clearly identify constraints and costs for such integration. It is expected that results of this study will be released some time in early 2007.

Avista-LSE would be required to undertake a transmission request on the NWE system and would also be required to fund a study to determine potential impacts caused by this project on the BPA system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area. Note that since two transmission systems (BPA and Northwestern Energy) may be involved in the integration of this project, the merchant may pay two wheeling charges or “pancaked” rates for transmission service.

**Walla Walla, Washington:**

The present transmission system serving the Walla Walla, Washington area is a single 230 kV line with dual ownership by Avista and PacifiCorp. There is also a 115 kV line in the area owned by BPA and a 69 kV line owned by PacifiCorp.

Avista has contractual transmission rights, but owns no transmission in the Walla Walla area. Therefore, Avista-LSE would be required to undertake a transmission request on the PacifiCorp transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area.

**50 or 100 MW:** Due to the presently constrained paths in the area, such as the Idaho to Northwest path, a transmission integration study on the PacifiCorp system would be required to determine integration costs.

Because there are presently constrained paths in the area, a regional study under the auspices of the Northwest Power Pool NTAC would likely be necessary to integrate any new resources at this site.

**Internal to the Avista System**

**Sprague, Washington**

The present transmission system serving the Sprague, Washington area is a low capacity 115 kV line. It would not be suitable for integration of 250-400 MW in its present configuration. Each connection below (which are the major transmission interconnection points in the area), would require 230 kV transmission and substation work for the generation integration. Any added generation greater than 400 MW will simply further increase costs and regional impacts.

The following estimates might be reasonable for integration of energy at this site:

**250 MW:** It is expected to integrate 250 MW at Westside, the existing 115 kV would have to be rebuilt 230/115 double circuit back to the main BPA corridor. Then to connect at Westside additional 230 kV would be constructed utilizing BPA’s transmission or by building new 230 kV. The time to construct will be approximately 4 years.
Cost: **Interconnection $994k/mile (total miles = 56 at 800 MVA capacity)**
- Transmission $0
- Substation $2M
- **Annual O&M $300k**
- Total $58 million

It is expected to integrate 250 MW at Rosalia on the Benewah-Shawnee 230 kV line. New 230 kV would have to be constructed for 30 miles to Rosalia and a 230 kV switching station would also have to be built. The time to construct will be approximately 4 years.

Cost: **Interconnection $852k/mile (total miles = 32 at 800 MVA capacity)**
- Transmission $0
- Substation $8M
- **Annual O&M $200k**
- Total $35 million

**400 MW**: It is expected to integrate 400 MW at Westside, the existing 115 kV would have to be rebuilt 230/115 double circuit back to the main BPA corridor. Then to connect at Westside additional 230 kV would be constructed utilizing BPA’s transmission or by building new 230 kV. The time to construct will be approximately 4 years.

Cost: **Interconnection $994k/mile (total miles = 56 at 800 MVA capacity)**
- Transmission $796k/mile (total miles = 25 at 800 MVA capacity)
- Substation $2M
- **Annual O&M $400k**
- Total $80 million (approximate)

It is expected to integrate 400 MW at Rosalia on the Benewah-Shawnee 230kV line. New 230 kV would have to be constructed for 30 miles to Rosalia and a 230kV switching station would also have to be built. The time to construct will be approximately 4 years.

Cost: **Interconnection $852/mile (total miles = 30 at 800 MVA capacity)**
- Transmission $442/mile (total miles = 30 at 800 MVA capacity)
- Substation $8M
- **Annual O&M $300k**
- Total $50 million (approximate)
Spokane/Coeur d’Alene

There are a number of 230 kV stations and transmission lines in the Spokane/Coeur d’Alene area that make good generation interconnection points. Westside, Beacon, Bell, Boulder, and Rathdrum are all large stations with 230/115 kV transformation in the Spokane/Coeur d’Alene area. However, with integrating large generation in this area the greatest concern is the thermal loading on the underlying 115 kV system. Without knowing a specific spot that generation would want to be brought on all of the 115 kV work is an approximation. The Spokane/Coeur d’Alene area covers too much land to be any more specific on costs. Any added generation greater than 250 MW will simply further increase costs and regional impacts.

The following estimates might be reasonable for integration of energy at this site:

50 MW: It is expected to integrate 50 MW in the Spokane/Coeur d’Alene, can be done with little (<10 mi.) or no 115 kV reconductor work. The time to construct will be approximately 1 year.

Cost: Interconnection $1M
      Transmission $184k/mile (total miles = 10 at 140 MVA capacity)
      Substation $0
      Annual O&M $44k
      Total $3 million

100 MW: It is expected to integrate 100 MW in the Spokane/Coeur d’Alene, can be done with little (<30 mi.) of 115 kV reinforcement. The time to construct will be approximately 2 year.

Cost: Interconnection $1M
      Transmission $184k/mile (total miles = 30 at 140 MVA capacity)
      Substation $0
      Annual O&M $200k
      Total $7 million

>250 MW: It is expected to integrate >250 MW in the Spokane/Coeur d’Alene that generation of this size would be connected at the 230 kV level. Adding generation in this range would require extensive 115 kV reconductoring. The radial operation of Avista’s 115 kV lines in Spokane and Coeur d’Alene or generation dropping for 230 kV outages would probably be needed. Additional 230 kV work would likely be needed depending on the interconnection point. The time to construct will be approximately 5 year.
Cost:  Interconnection $1M
Transmission $184k/mile (total miles = 50+ at 140 MVA capacity)
Transmission $442k/mile (total miles = 30+ at 800 MVA capacity)
Substation $8M
Annual O&M $400k
Total $32 to $500 million (at higher levels of generation)

**Mica Peak**

The present transmission system around Mica Peak is fairly close to existing Avista 115 kV lines with available capacity.

The following estimates might be reasonable for integration of energy at this site:

**50 MW:** It is expected to integrate 50 MW at the Post Falls substation would require 6 miles of 115kV line and a new breaker position at Post Falls. The time to construct will be approximately 1 year.

Cost:  Interconnection $426k/mile (total miles = 6 at 140 MVA capacity)
Transmission $0
Substation $1M
Annual O&M $24k
Total $4 million

**Clark Fork Hydro Upgrades**

The present transmission system in the area consists of both Avista and BPA 230kV lines that served to integrate the Western Montana Hydro (WMH) projects. The WMH refers to the four major hydroelectric plants operated in northwestern Montana and on the northern Montana-Idaho border. These include the federally operated Libby and Hungry Horse projects and the Cabinet Gorge and Noxon Rapids (Clark Fork hydro) projects operated by Avista. After Avista’s completion of its planned upgrades to Cabinet Gorge and Noxon Rapids, these projects will have peak generation capacities of 268 MW and 558 MW, respectively, for a combined capacity of 826 MW.

Avista and BPA have executed a WMH operating agreement that provides for a 50-50 allocation of a 1700 MW WMH operating limit between the federal projects and Avista projects. This agreement relates to Avista-LSE’s ability to operate its Clark Fork hydro projects for service to Avista’s bundled retail native load customers. After completion of Avista’s planned generation upgrades, Avista’s total Clark Fork hydro generation capacity will be at 826 MW, below Avista’s WMH operational allocation of 850 MW. Dependent upon continuation of the operational allocation of WMH hydro capability between Avista and BPA, no new transmission upgrades will be needed for Avista to integrate the planned upgrades of its Clark Fork hydro projects.
**Dayton, Washington**

The present transmission system serving the Dayton, Washington area is a single 230 kV line with dual ownership by Avista and PacifiCorp. There is also a 115 kV line in the area owned by BPA and a 69 kV line owned by PacifiCorp.

The following estimates might be reasonable for integration of energy at this site:

### 50 MW:

It is expected to integrate 50 MW on the Dry Creek-Walla Walla 230 kV line at the ownership change between Avista and PacifiCorp, a new switching station and a 15 mile 230 kV line to this location would be necessary. At present this line lacks capacity to support 50 MW due to current contractual obligations. Therefore, the Dry Creek-Walla Walla 230 kV line would need to be recon ductored to support additional capacity. The time to construct will be approximately 4 years.

**Cost:**

- **Interconnection $746k/mile (total miles = 15 at 450 MVA capacity)**
- **Transmission $442k/mile (total miles = 28.5 at 800 MVA capacity)**
- **Substation $8M**
- **Annual O&M $200k**
- **Total $32M**

### 100 MW:

It is expected to integrate 100 MW on the Dry Creek-Walla Walla 230 kV line at the ownership change between Avista and PacifiCorp, a new switching station and a 15 mile 230 kV line to this location would be necessary. At present this line lacks capacity to support 100 MW due to current contractual obligations.

The Dry Creek-Walla Walla 230 kV line would need to be recon ductored to support additional capacity. The time to construct will be approximately 4 years.

**Cost:**

- **Interconnection $746k/mile (total miles = 15 at 450 MVA capacity)**
- **Transmission $442k/mile (total miles = 28.5 at 800 MVA capacity)**
- **Substation $8M**
- **Annual O&M $200k**
- **Total $32 million**

Note that there may be a potential real time solution using real time thermal monitoring (using the Valley Group’s Cat-1 or other similar technology).

**Reardan, Washington**

The present transmission system serving the Reardan, Washington area is a low capacity 115 kV line.

The following estimates might be reasonable for integration of energy at this site:

### 50 MW:

It is expected that to integrate 50 MW at the Reardan substation, at minimum the 115 kV line from Garden Springs to Sunset would need to be recon ductored along with a new air switch at Westside on the Nine Mile line. The time to construct will be approximately 1 year.
Cost:  **Interconnection $1.4M**  
*Transmission $184k/mile (total miles = 2.5 at 140 MVA capacity)*  
*Substation $100k*  
**Annual O&M $14k**  
Total $2 million

100 MW: It is expected that to integrate 100 MW at the Reardan substation, at minimum the 115 kV line from Reardan to Devils Gap would need to be reconducted and a new line out of Reardan would be necessary. The time to construct will be approximately 2 years.

Cost:  **Interconnection $1.4M**  
*Transmission $184k/mile (total miles = 14 at 140 MVA capacity)*  
*Transmission $426k/mile (total miles = 20 at 140 MVA capacity)*  
*Substation $0*  
**Annual O&M $200k**  
Total $13 million

*Lind, Washington*

The present transmission system serving the Lind, Washington, area is a low capacity 115 kV line and two 115 kV lines that are operated in a radial configuration.

The following estimates might be reasonable for integration of energy at this site:

50 MW: It is expected that to integrate 50 MW at the Lind substation, very little new transmission would be required. The time to construct will be approximately 1 year.

Cost:  **Interconnection $1.4M**  
*Transmission $0*  
*Substation $0*  
**Annual O&M $10k**  
Total $1.5 million

100 MW: It is expected that to integrate 100 MW at the Lind substation, at minimum the 115kV line from Lind to Warden would need to be reconducted. The time to construct will be approximately 1 year.

Cost:  **Interconnection $1.4M**  
*Transmission $184k/mile (total miles = 22 at 140 MVA capacity)*  
*Substation $0*  
**Annual O&M $100k**  
Total $6 million
**Othello, Washington**

The present transmission system serving the Othello, Washington, area is low capacity 115 kV lines.

The following estimates might be reasonable for integration of energy at this site:

**50 MW:** It is expected that to integrate 50 MW at the Othello substation, very little new transmission would be required. The time to construct will be approximately 1 year.

**Cost:**
- **Interconnection** $1.4M
- **Transmission** $0
- **Substation** $0
- **Annual O&M** $10k
- **Total $1.5 million**

**Colfax, Washington**

The present transmission system serving the Colfax, Washington, area is a low capacity 115 kV line.

The following estimates might be reasonable for integration of energy at this site:

**50 MW:** It is expected that to integrate 50 MW at the East Colfax substation, very little new transmission would be required. The time to construct will be approximately 1 year.

**Cost:**
- **Interconnection** $1.4M
- **Transmission** $0
- **Substation** $0
- **Annual O&M** $10k
- **Total $1.5 million**