2007 Avista Integrated Resource Plan
Supplemental Material

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

	Topic	Time	Staff
1.	Introductions	10:00	Barcus
2.	New and Potential Rules and Laws For Integrated Resource Planning	10:05	Lyons
3.	Work Plan Discussion	10:20	Gall
4.	Transmission Planning	10:45	Folsom
5.	2005 IRP and TAC Comments	11:15	Lyons
6.	Lunch	11:45	
7.	2007 IRP Topic Discussions • Resource Planning • Conservation • Analytical Process • Capacity Planning • Other	12:30	Kalich
8.	Adjourn	2:00	

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

Work Plan Background

- 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^{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

Avg. Response	Scale	Questions
2.9	0 – 7	Have many TAC meetings did you attend?
7.9	1 – 10	Rank the number and length of TAC meetings.
8.4	1 – 10	Rank of content of the meetings.
8.2	1 – 10	Rank of overall TAC process.

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	
- Emissions		Lyons
- 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	

We answer to you.

AVISTA

Review of First TAC Meeting & 2005 IRP Action Plan Review

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

John Lyons

We answer to you.

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

We answer to you.

AVISTA

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

We answer to you.

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

We answer to you.

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

We answer to you.

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

We answer to you.

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

We answer to you.

AVISTA Corp.

2006 Renewables Request for Proposals

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

Steve Silkworth

We answer to you.

AVISTA Corp.

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.

We answer to you.

AVISTA Corp.

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

We answer to you.

AVISTA Corp.

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

We answer to you.

AVISTA

Alternative Energy Future

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

John Lyons

We answer to you.

AVISTA

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

We answer to you.

AVISTA

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 that 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

We answer to you.

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

We answer to you.

AVISTA

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

We answer to you.

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

We answer to you.

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 CO_2 – 1 kW of solar energy reduces CO_2 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

We answer to you.

Modeling Overview: Emissions

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

John Lyons

We answer to you.

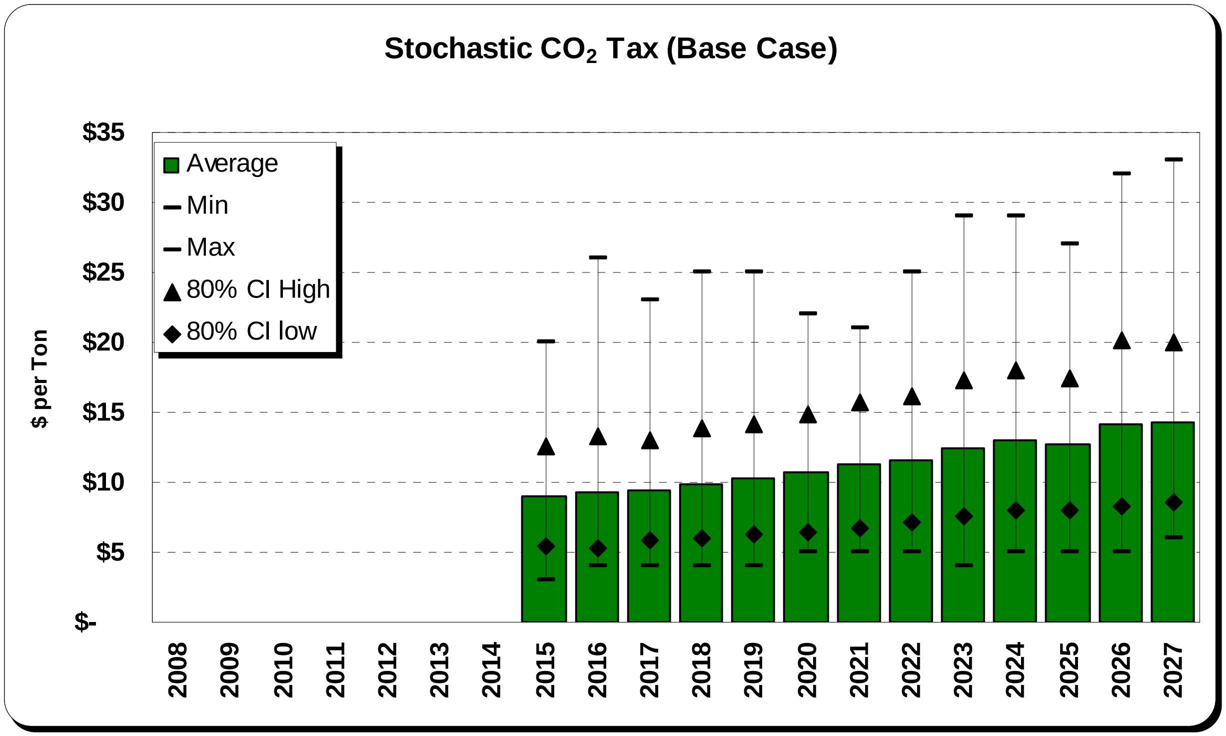
Emissions in the IRP

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

- CO_2 – carbon dioxide, the primary greenhouse gas
- SO2 – sulfur dioxide, causes acid rain, the Clean Air Act of 1990 capped at 8.9 million tons per year starting in 2008
- NOx – nitrogen oxide, causes acid rain, the Clean Air Act of 1990 capped emissions at 2.0 million tons per year starting in 2008
- 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

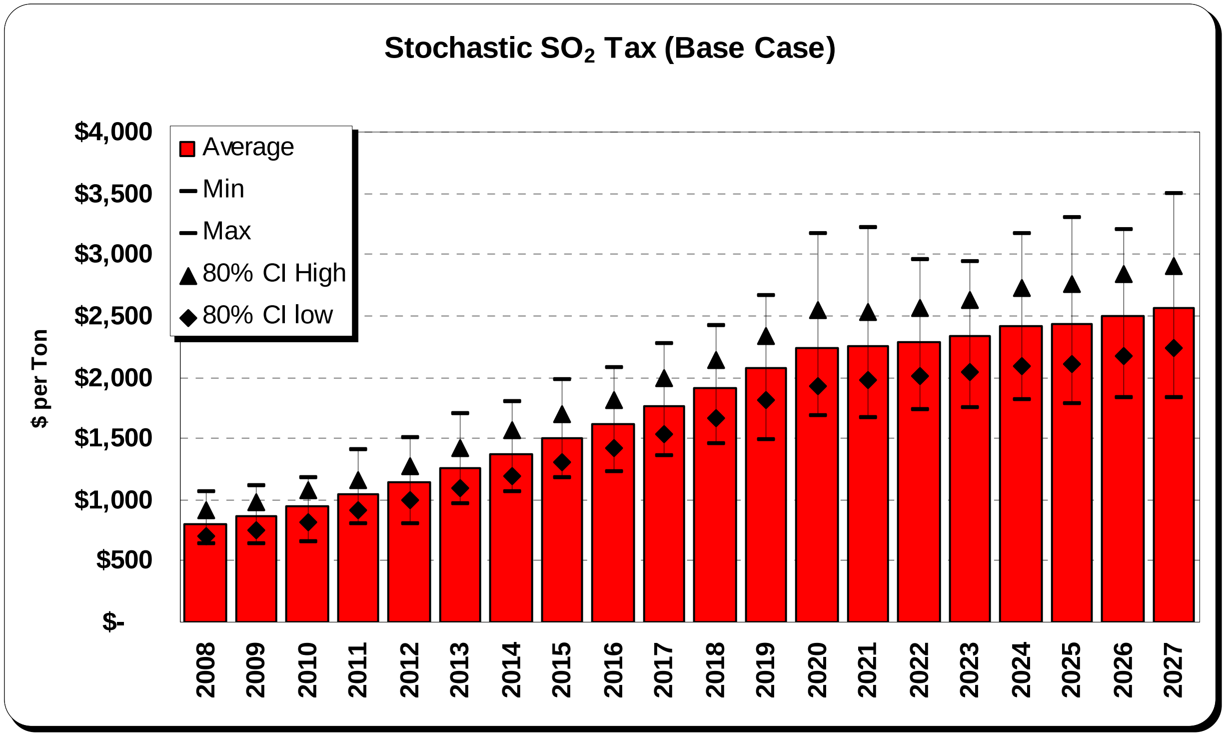
We answer to you.

Base Case – Greenhouse Gas Costs



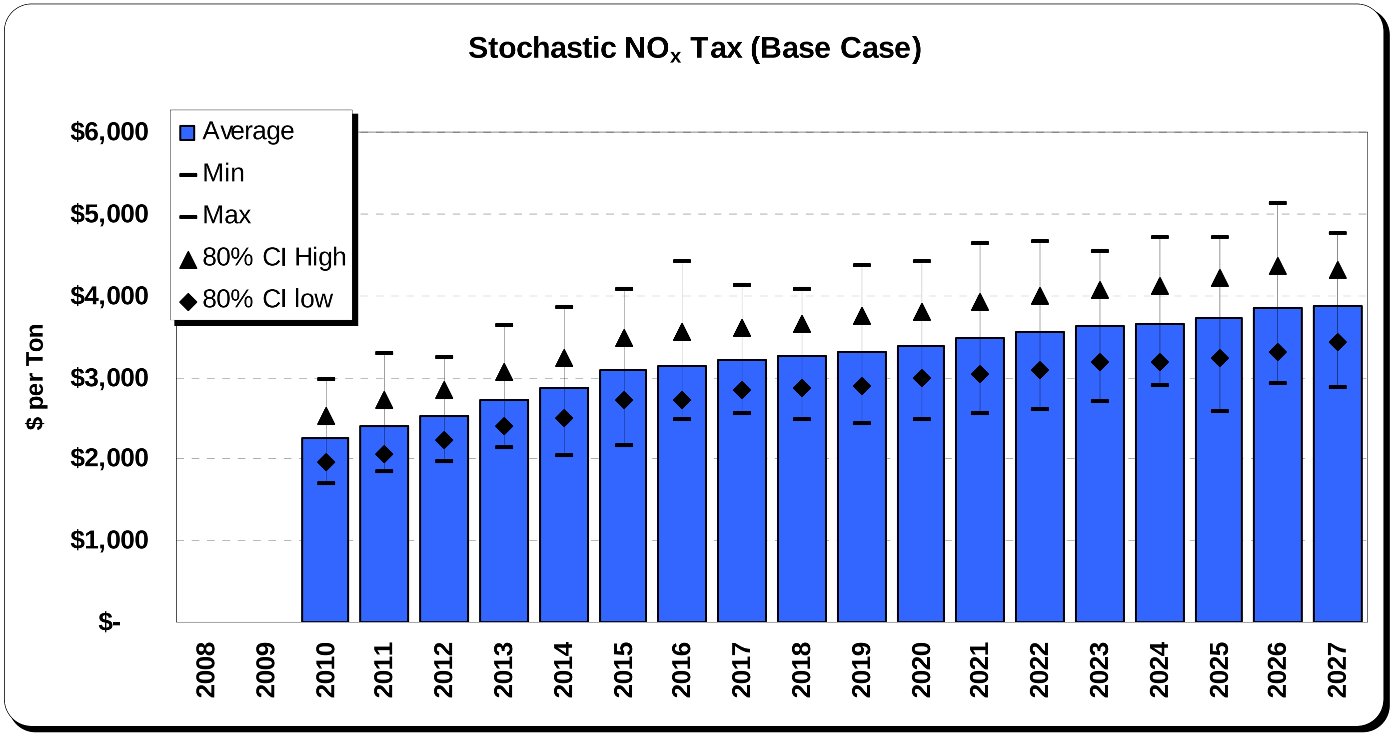
We answer to you.

Base Case - SO_2 Emissions Costs



We answer to you.

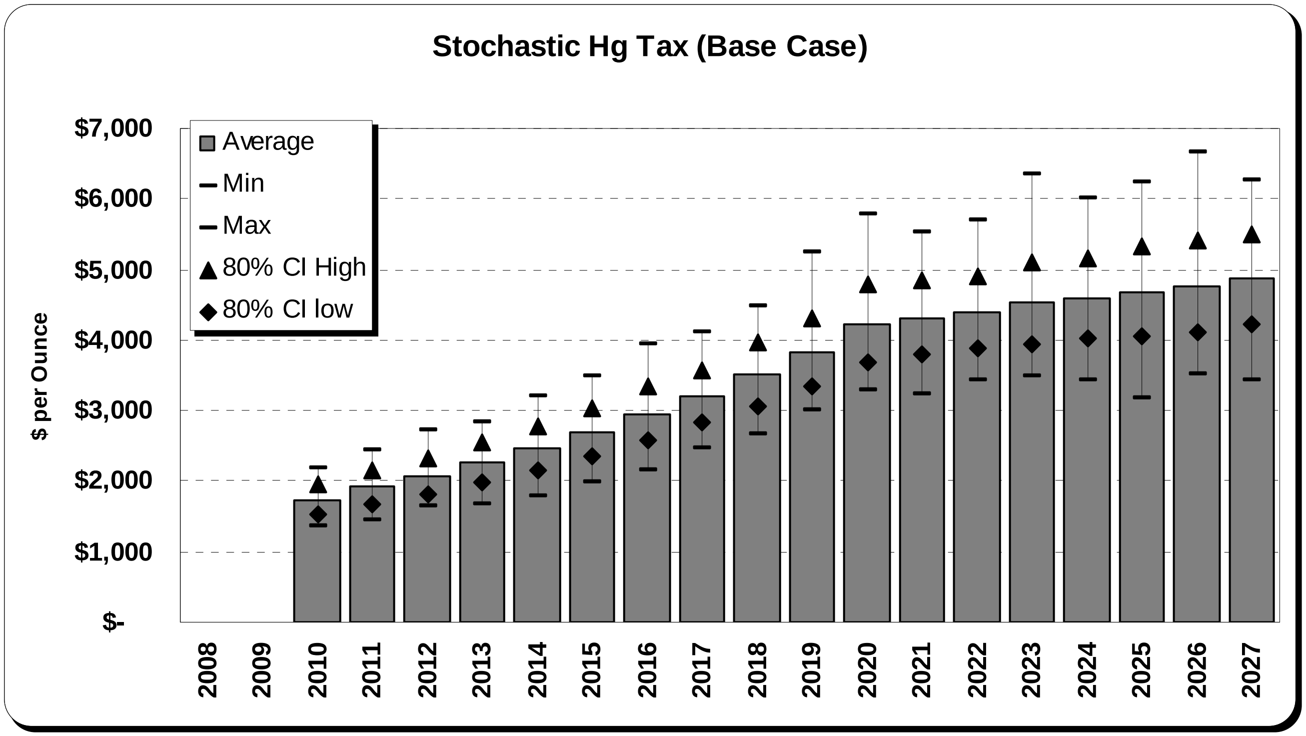
Base Case – Stochastic NO_x Costs



We answer to you.

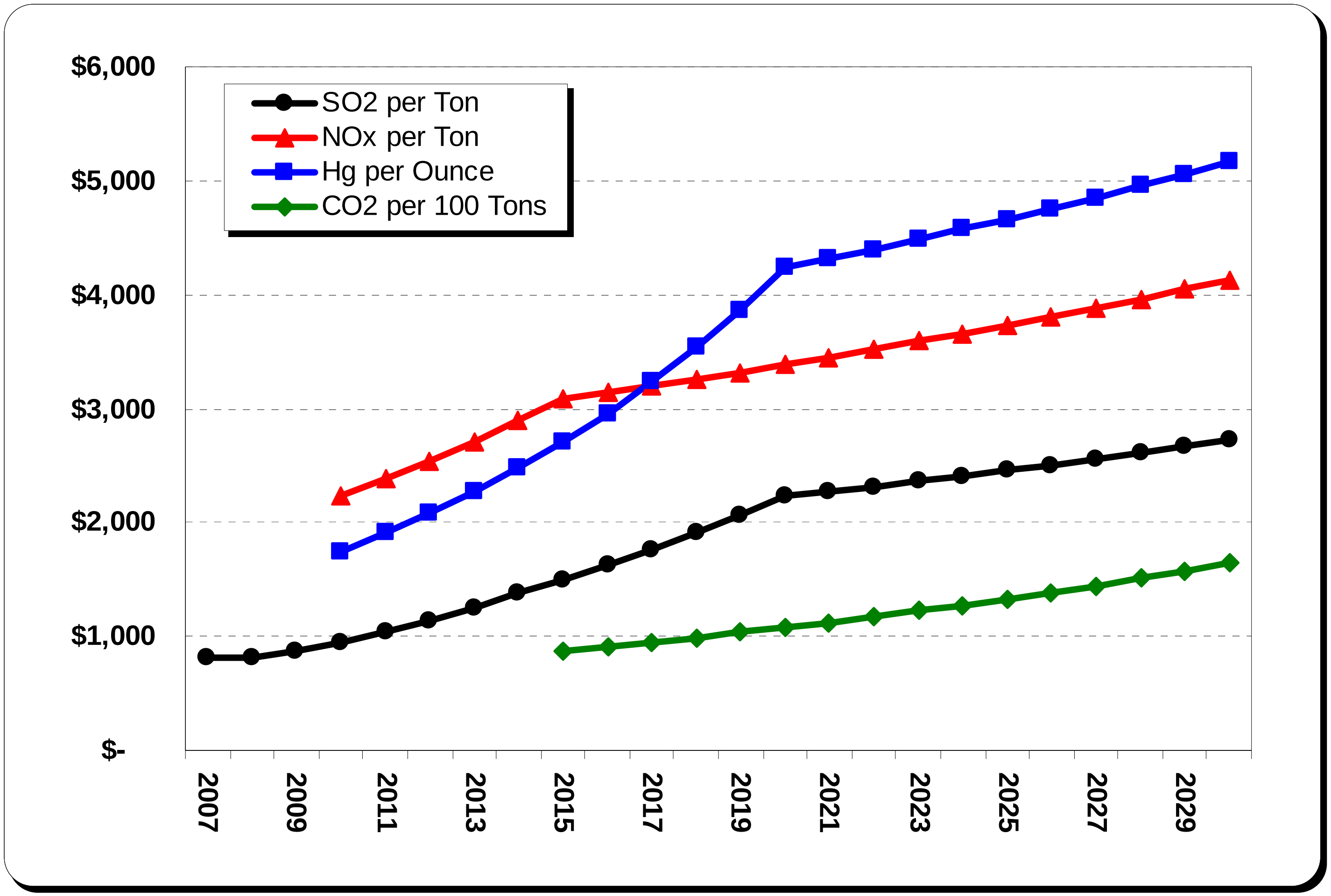
AVISTA

Base Case – Stochastic Hg Tax



We answer to you.

Emission Costs - Nominal Dollars



We answer to you.

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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

We answer to you.

AVISTA

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):** SO_2= 0.0001 NO_X= 0.011 CO_2= 117 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

We answer to you.

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

We answer to you.

AVISTA

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):** SO_2= 0.12 NO_X= 0.07 CO_2= 205 Hg= 0.00002
- **Location Options:** Montana and Wyoming
- **Production Tax Credit:** No

We answer to you.

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):** SO_2= 0.12 NO_X= 0.07 CO_2= 205 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):** SO_2= 0.12 NO_X= 0.07 CO_2= 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):** SO_2= 0.55 NO_X= 0.18 CO_2= 205 Hg= 0.00033
- **Location Options:** Northwest, Montana, and Wyoming
- **Production Tax Credit:** No

We answer to you.

AVISTA

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):** SO_2= 0.03 NO_X= 0.15 CO_2= 205 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 (kW/Year):** $63.21 - $64.87
- **Emissions (lbs/mmbtu):** SO_2= 0.003 NO_X= .015 CO_2= 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):** SO_2= N/A NO_X= N/A CO_2= 720 – 1,116 Hg= N/A
- **Location Options:** Northwest
- **Production Tax Credit:** Yes through 2014

We answer to you.

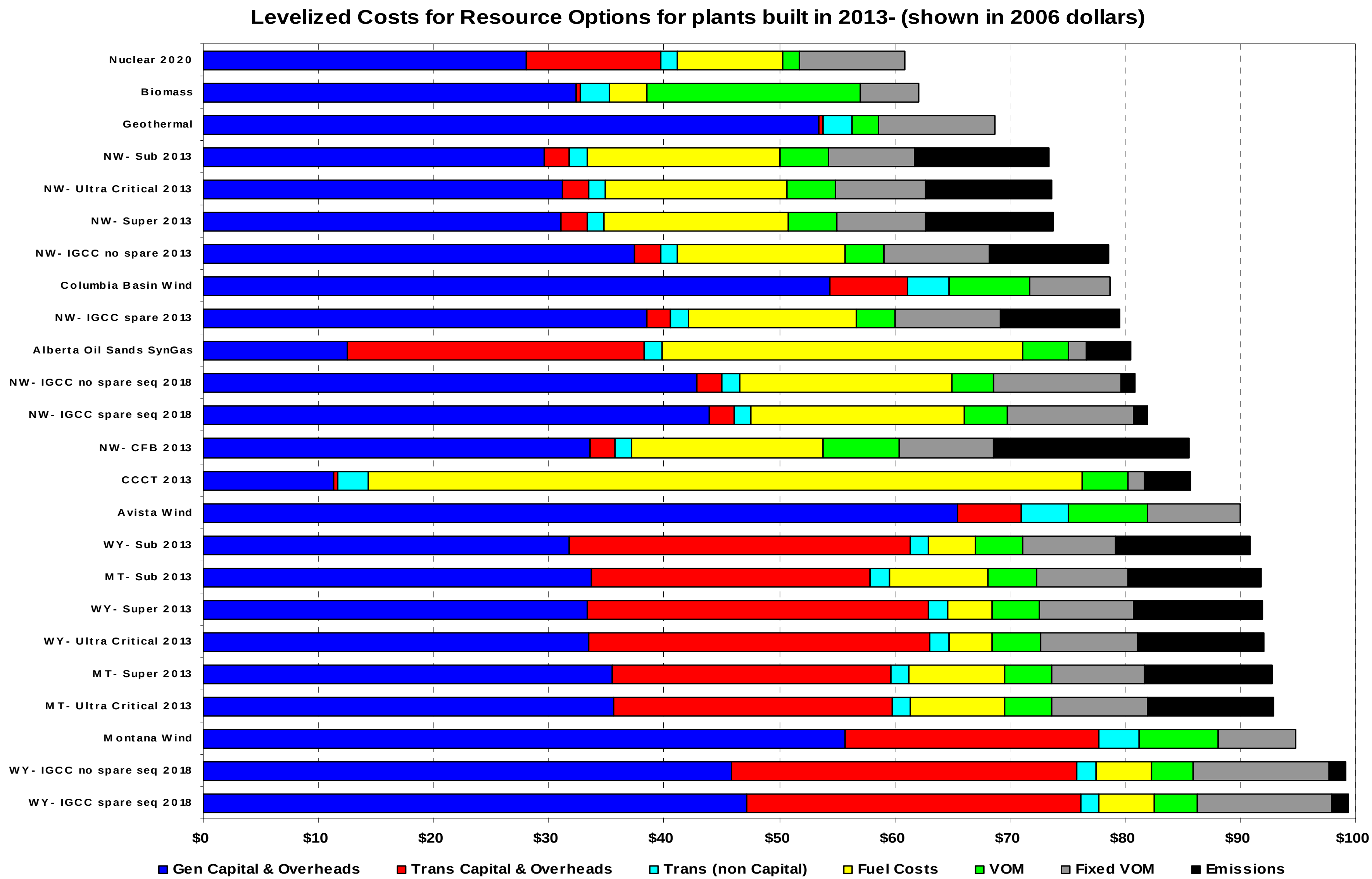
Alberta Oil Sands

- **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

We answer to you.

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


Levelized Costs for Resource Options for plants built in 2013- (shown in 2006 dollars)
Nuclear 2020
Biomass
Geothermal
NW- Sub 2013
NW- Ultra Critical 2013
NW- Super 2013
NW- IGCC no spare 2013
Columbia Basin Wind
NW- IGCC spare 2013
Alberta Oil Sands SynGas
NW- IGCC no spare seq 2018
NW- IGCC spare seq 2018
NW- CFB 2013
CCCT 2013
Avista Wind
WY- Sub 2013
MT- Sub 2013
WY- Super 2013
WY- Ultra Critical 2013
MT- Super 2013
MT- Ultra Critical 2013
Montana Wind
WY- IGCC no spare seq 2018
WY- IGCC spare seq 2018
$0
$10
$20
$30
$40
$50
$60
$70
$80
$90
$100
Gen Capital & Overheads
Trans Capital & Overheads
Trans (non Capital)
Fuel Costs
VOM
Fixed VOM
Emissions

We answer to you. AVISTA

Other Modeling Assumptions

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

James Gall

AURORAxmp®

@RISK

We answer to you. AVISTA

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 then a single point estimate, used to feed Emissions and Wind data into AURORA

We answer to you.

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)

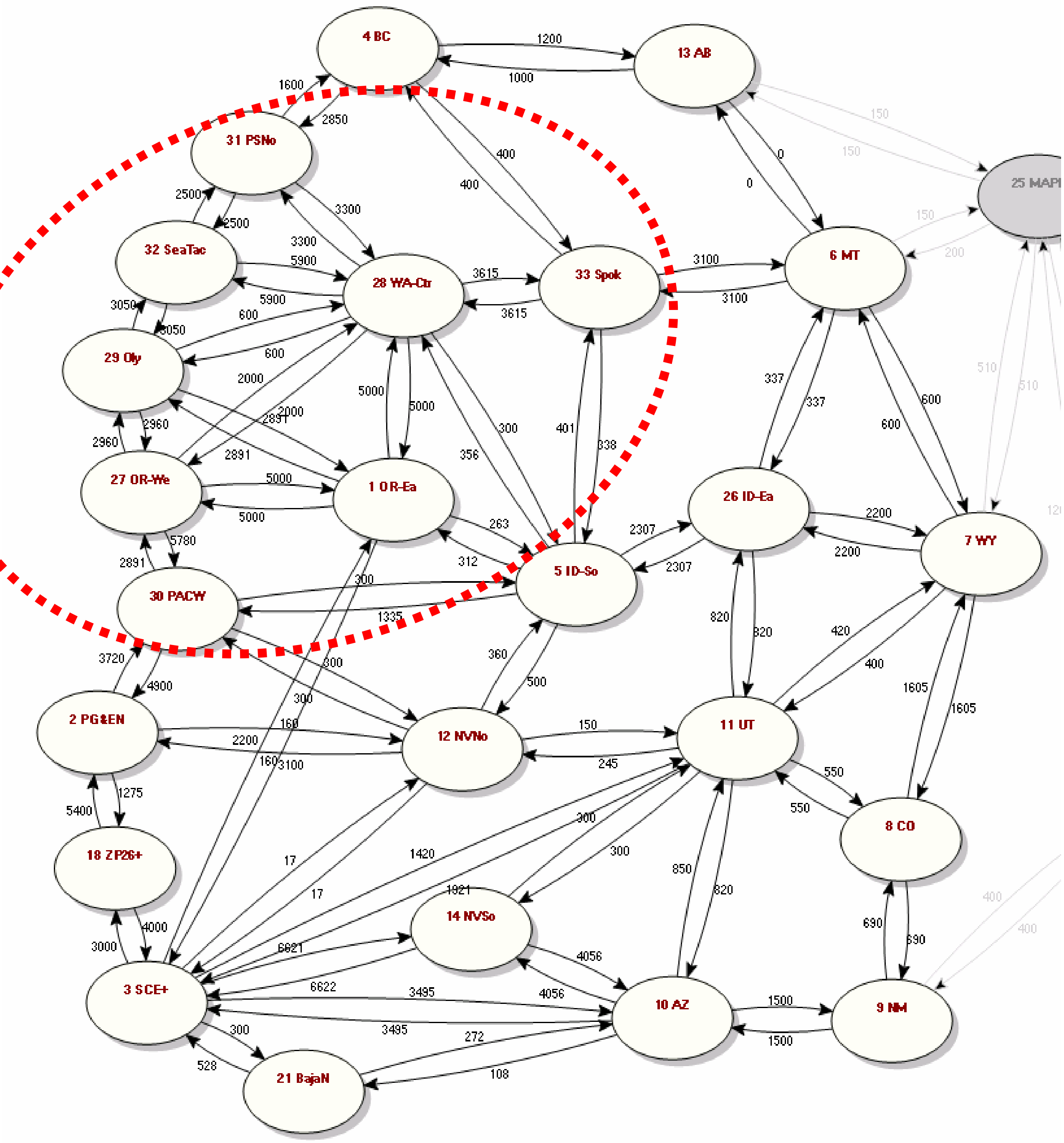
We answer to you. AVISTA

Changes to Market Modeling Techniques

- Model random forced outages
- Use daily natural gas prices
- Modeling of emissions CO_2, SO_2, NO_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

We answer to you.

AURORA Topology



We answer to you. AVISTA

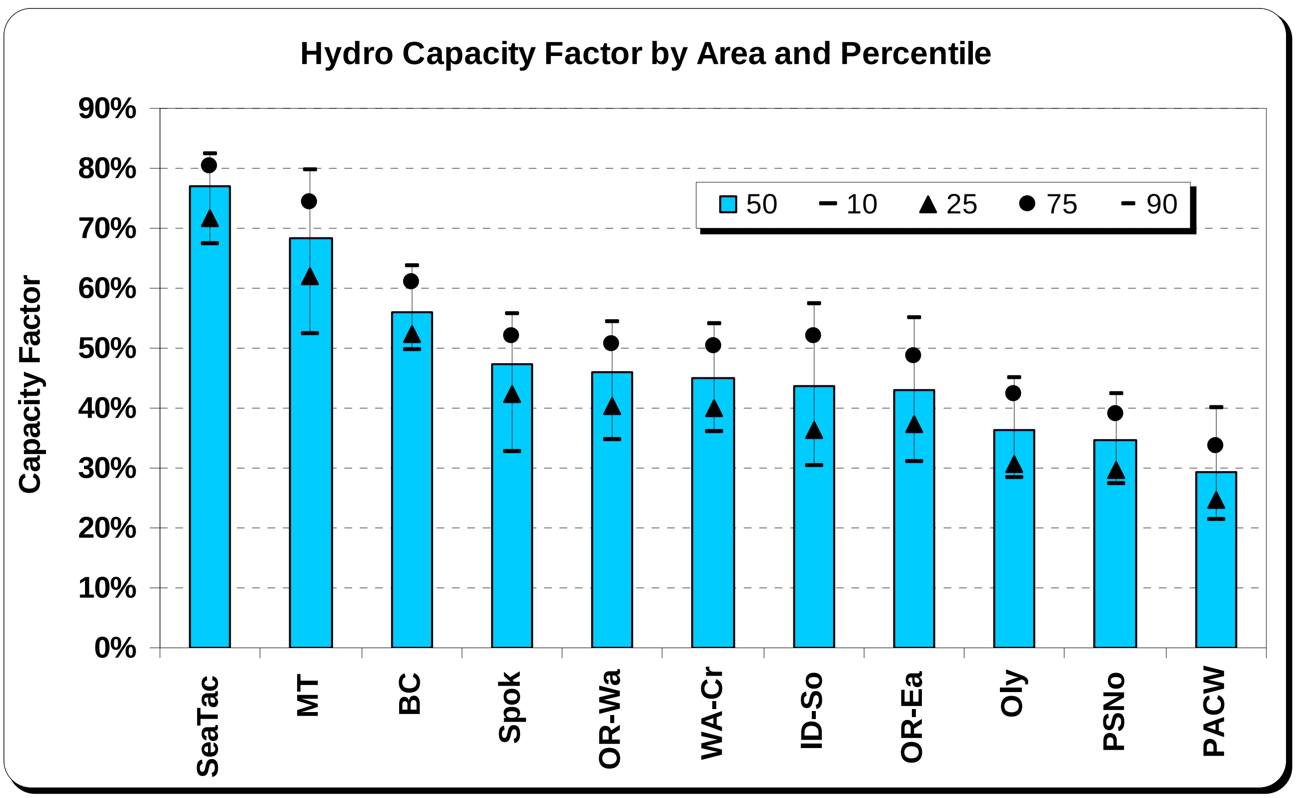
Regional Hydro Modeling

- 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.

We answer to you. AVISTA

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.

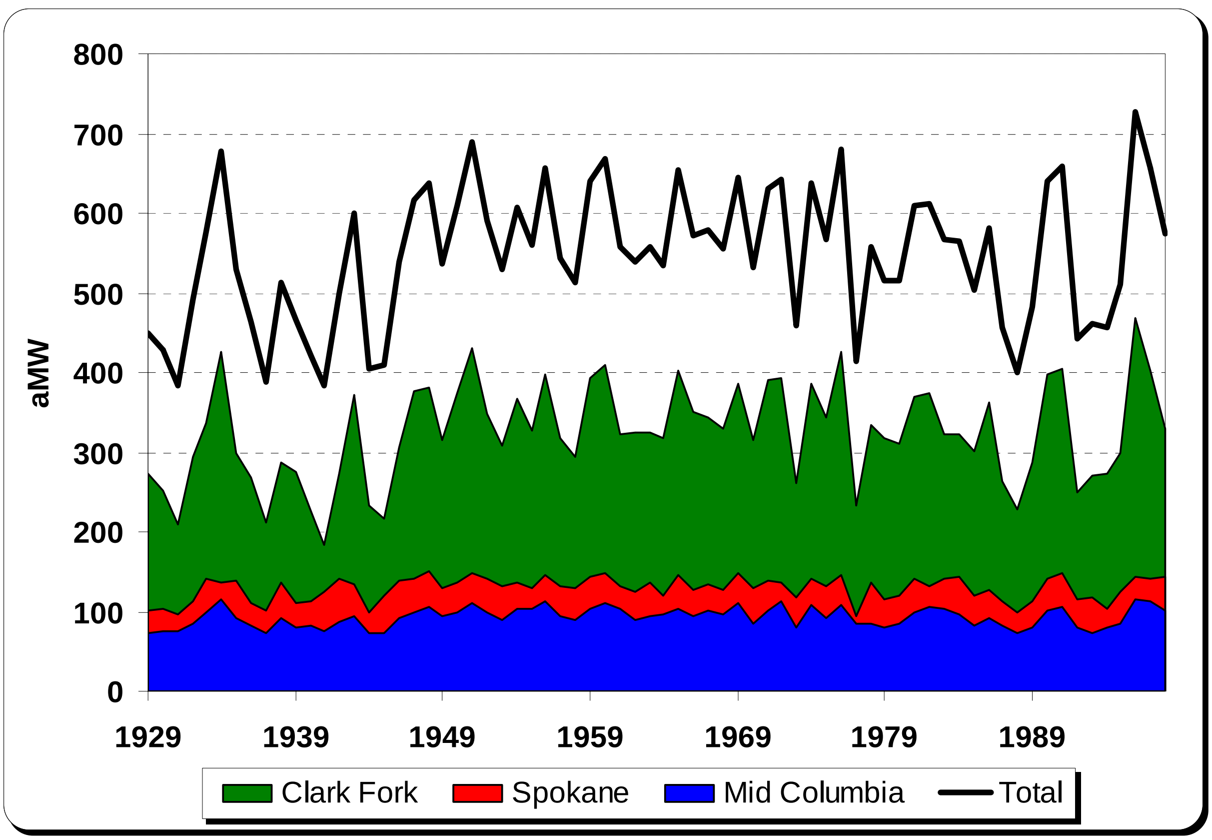


We answer to you. AVISTA

Avista Hydro Generation

70-Year Hydro Generation for 2008 available generation

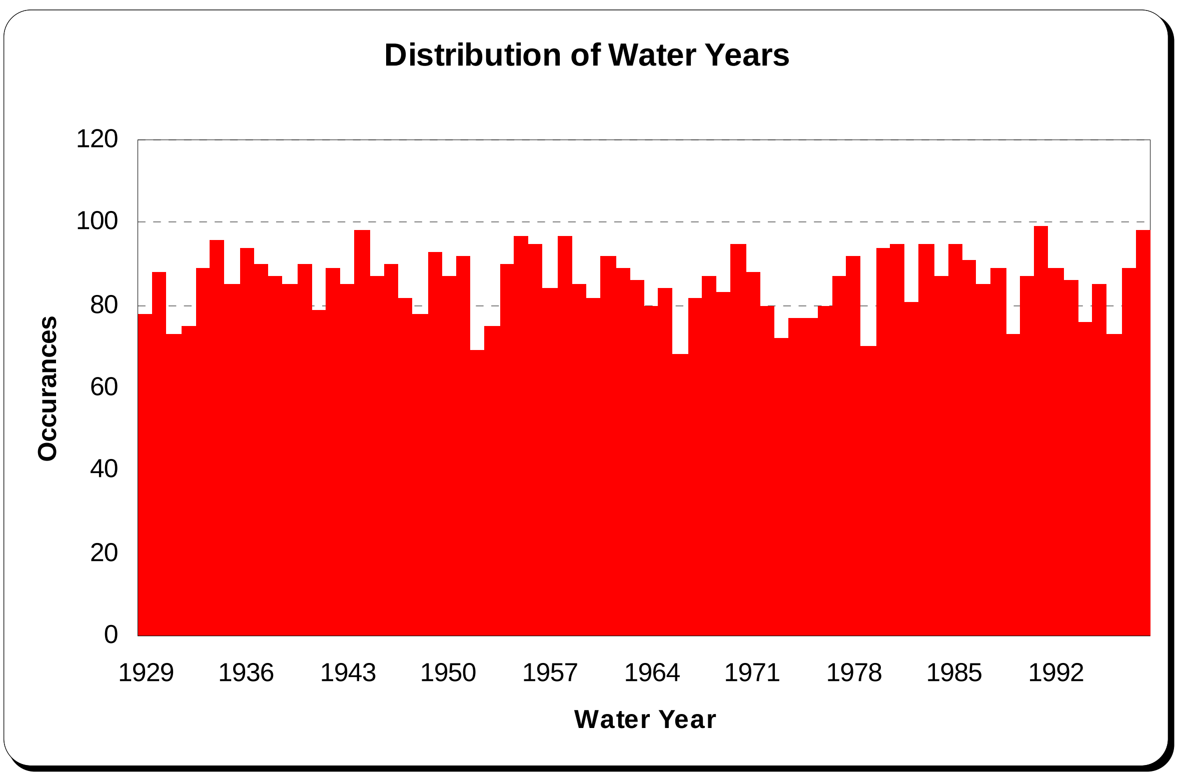
- Clark Fork: 325 MW
- Spokane: 129 MW
- Mid Columbia: ~93 MW



We answer to you. AVISTA

Stochastic Hydro

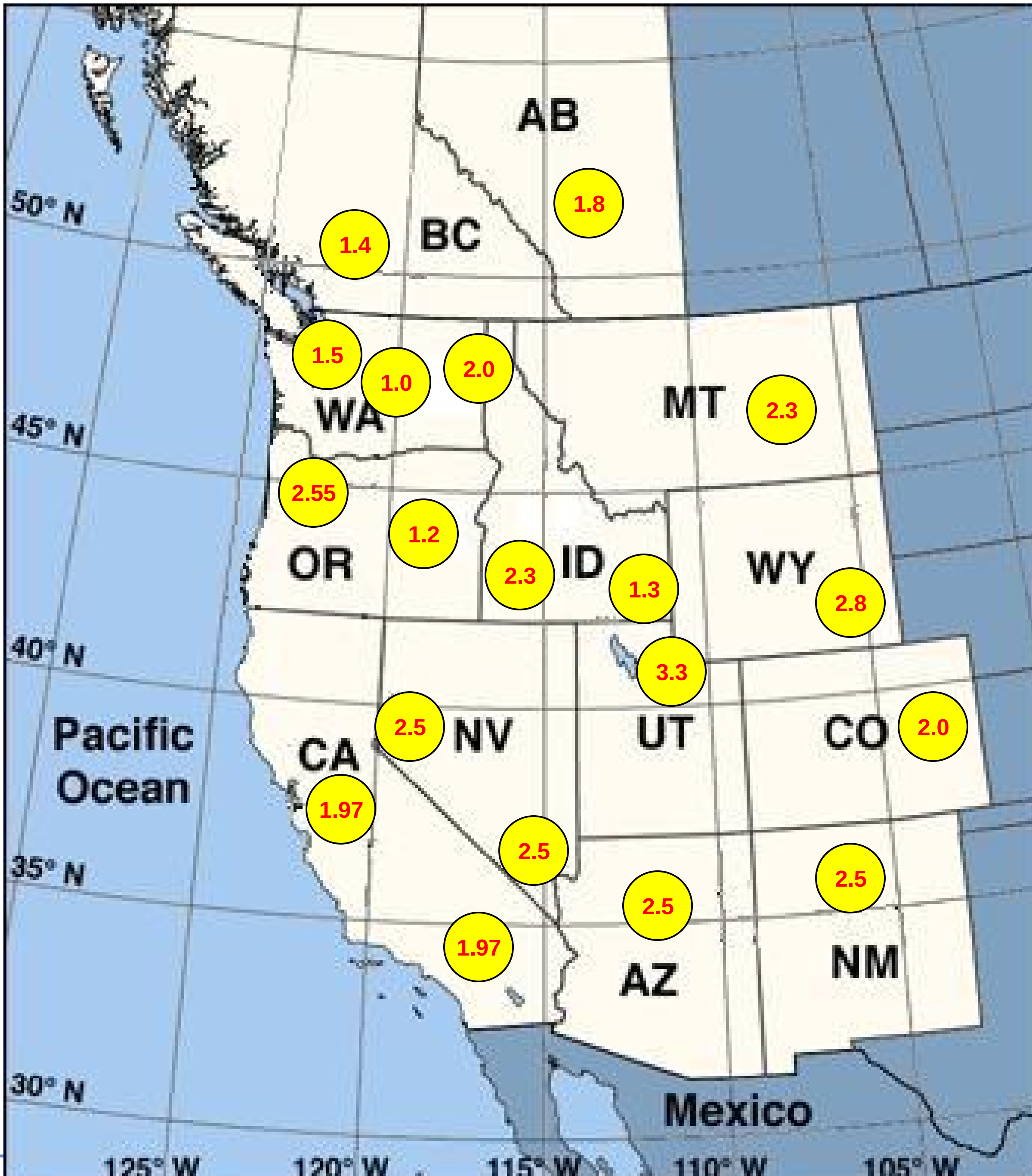
- Each hydro year is randomly drawn for each study year (2008-2027) and each of the 300 iterations
- This methodology attempts to create a uniform distribution of used hydro years of the available 70-year hydro study



We answer to you.

Regional Load Growth

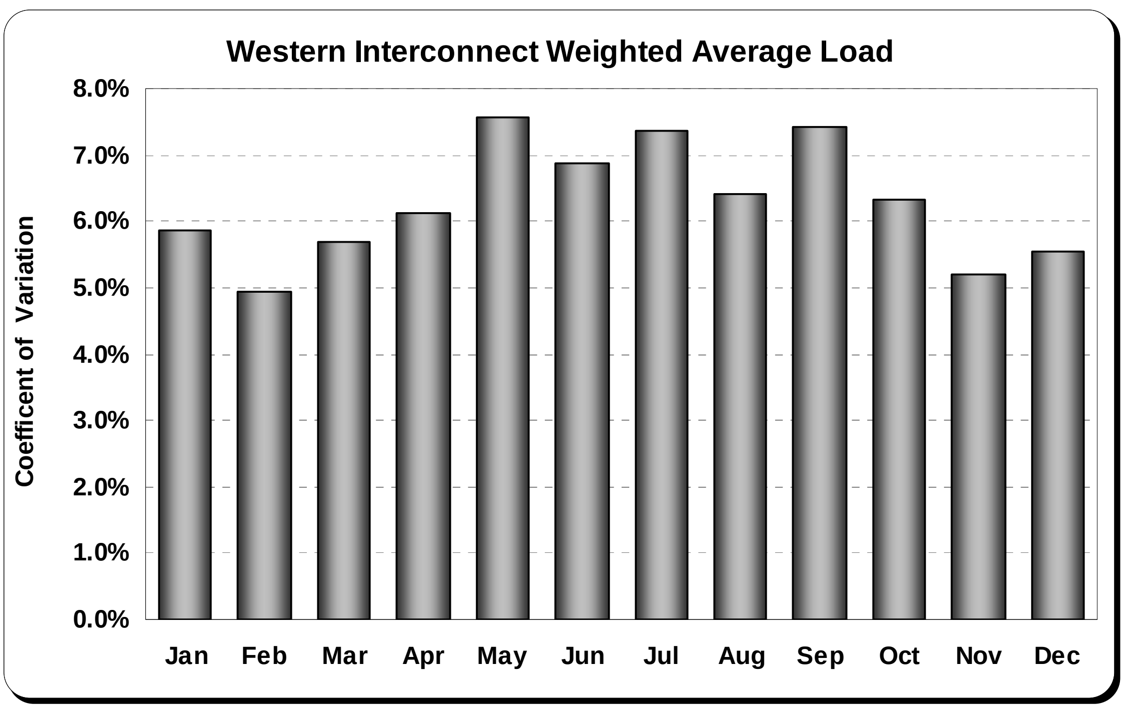
(Annualized Percent Growth)



We answer to you.

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



We answer to you. AVISTA

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

We answer to you.

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

We answer to you.

Modeling Overview: Futures & Scenarios

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

John Lyons

We answer to you.

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 asses 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

We answer to you.

AVISTA

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

We answer to you.

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*

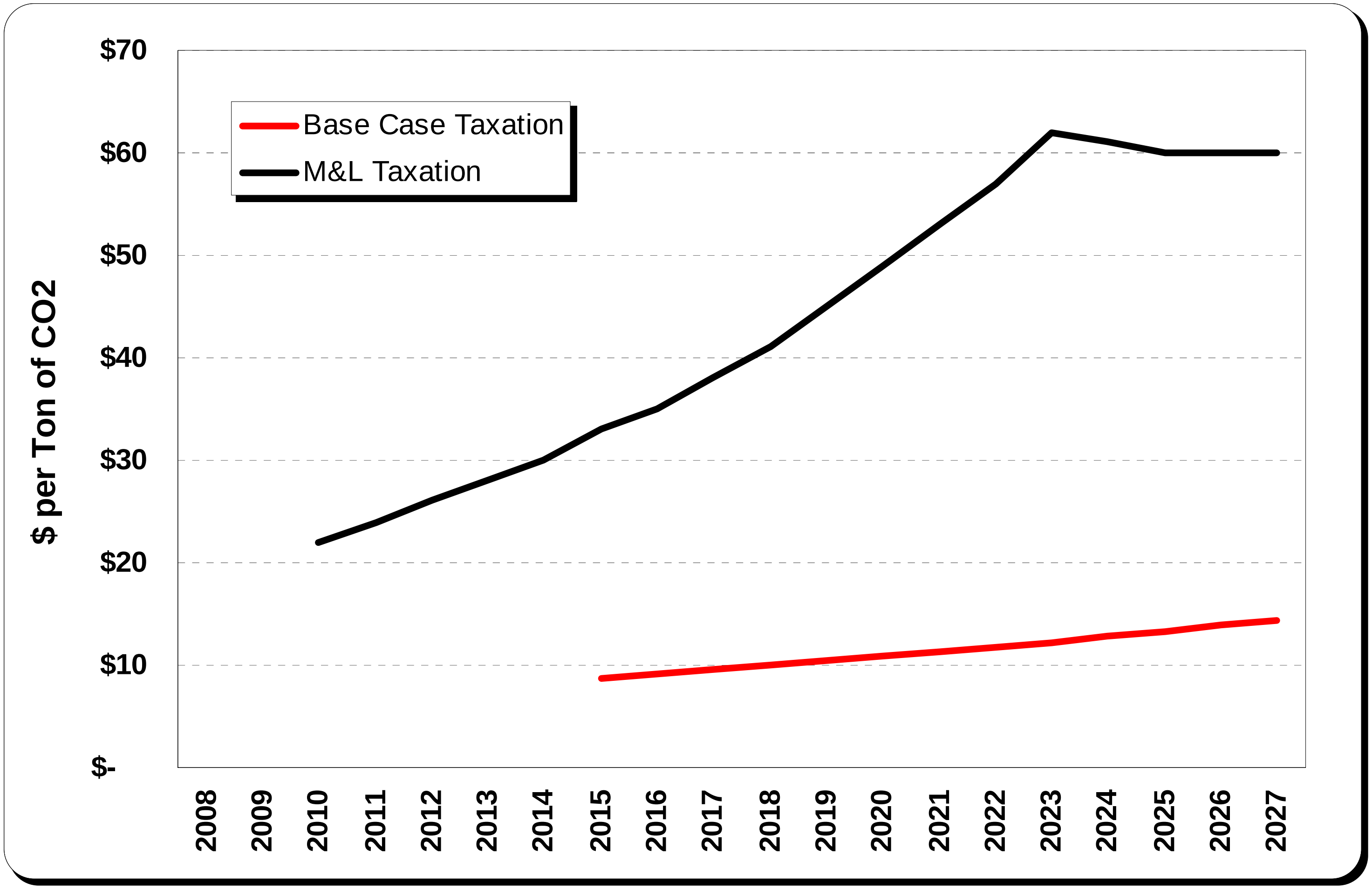
We answer to you.

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

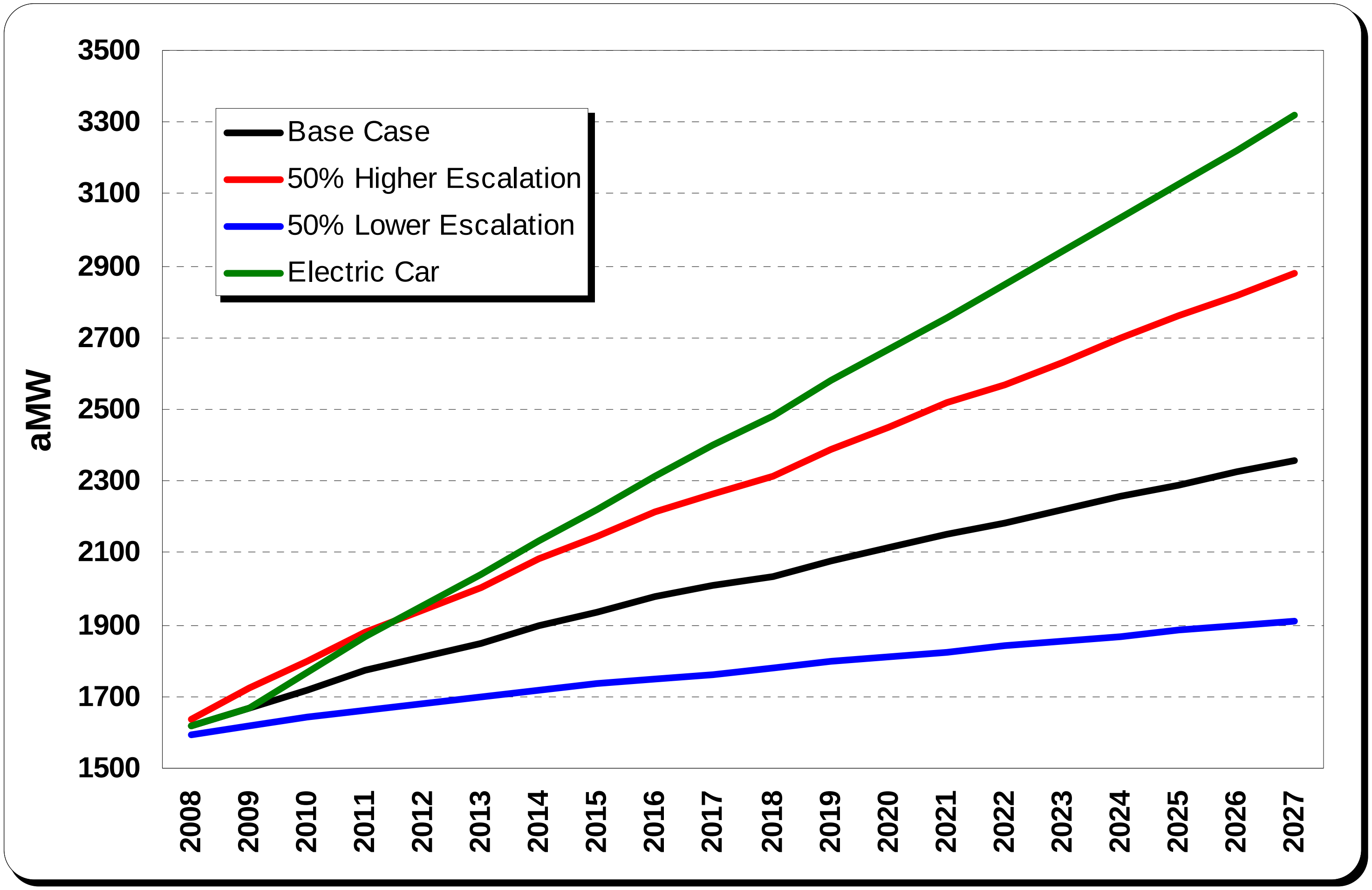
We answer to you.

Base Case vs. McCain & Lieberman CO_2 Tax



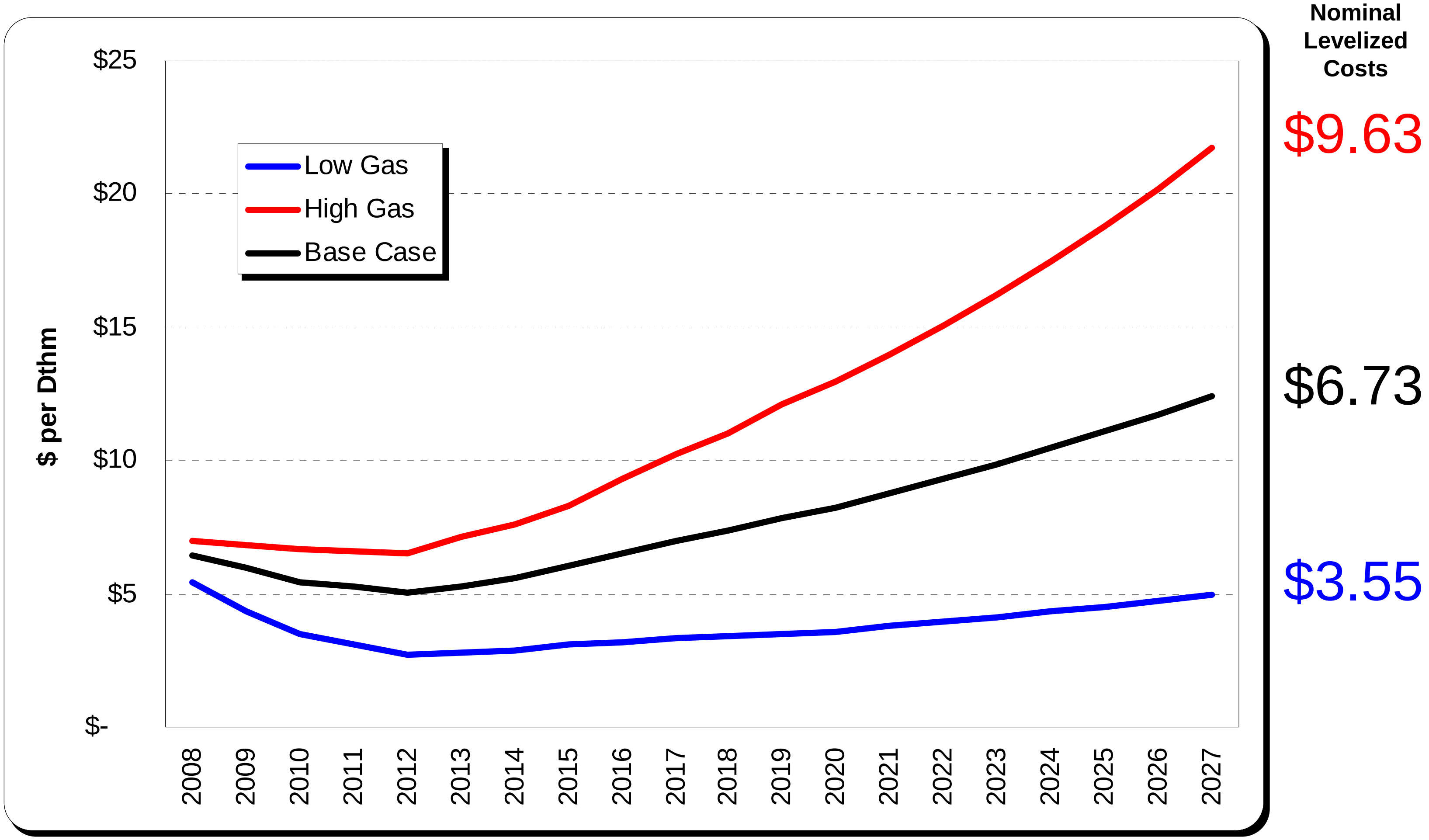
We answer to you.

Load Growth: Eastern Washington Energy



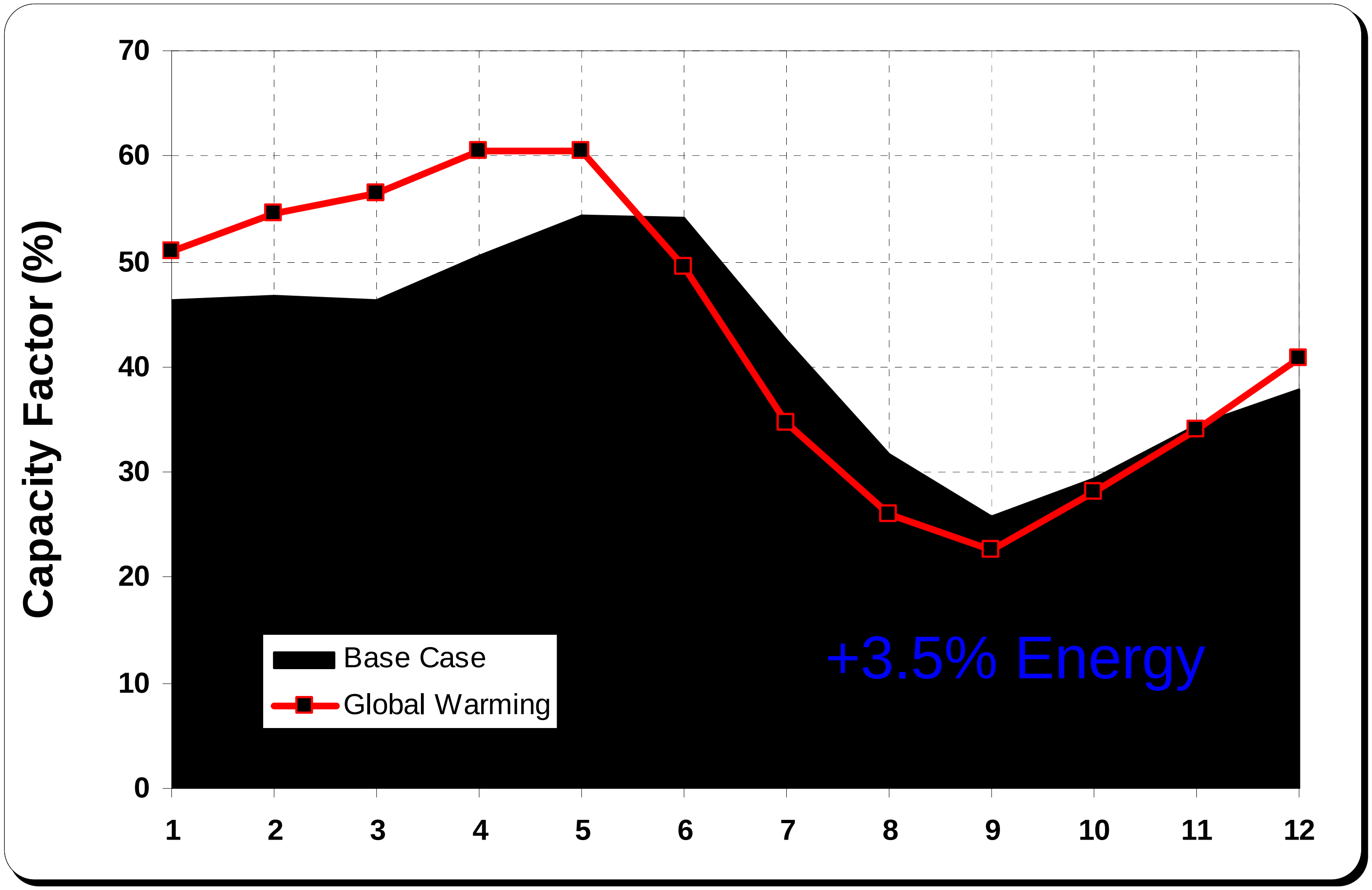
We answer to you.

Gas Price Scenarios - Sumas



We answer to you.

Global Warming Scenario- NW Hydro CF



We answer to you.

Fuel Price Forecasts

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

James Gall



We answer to you.

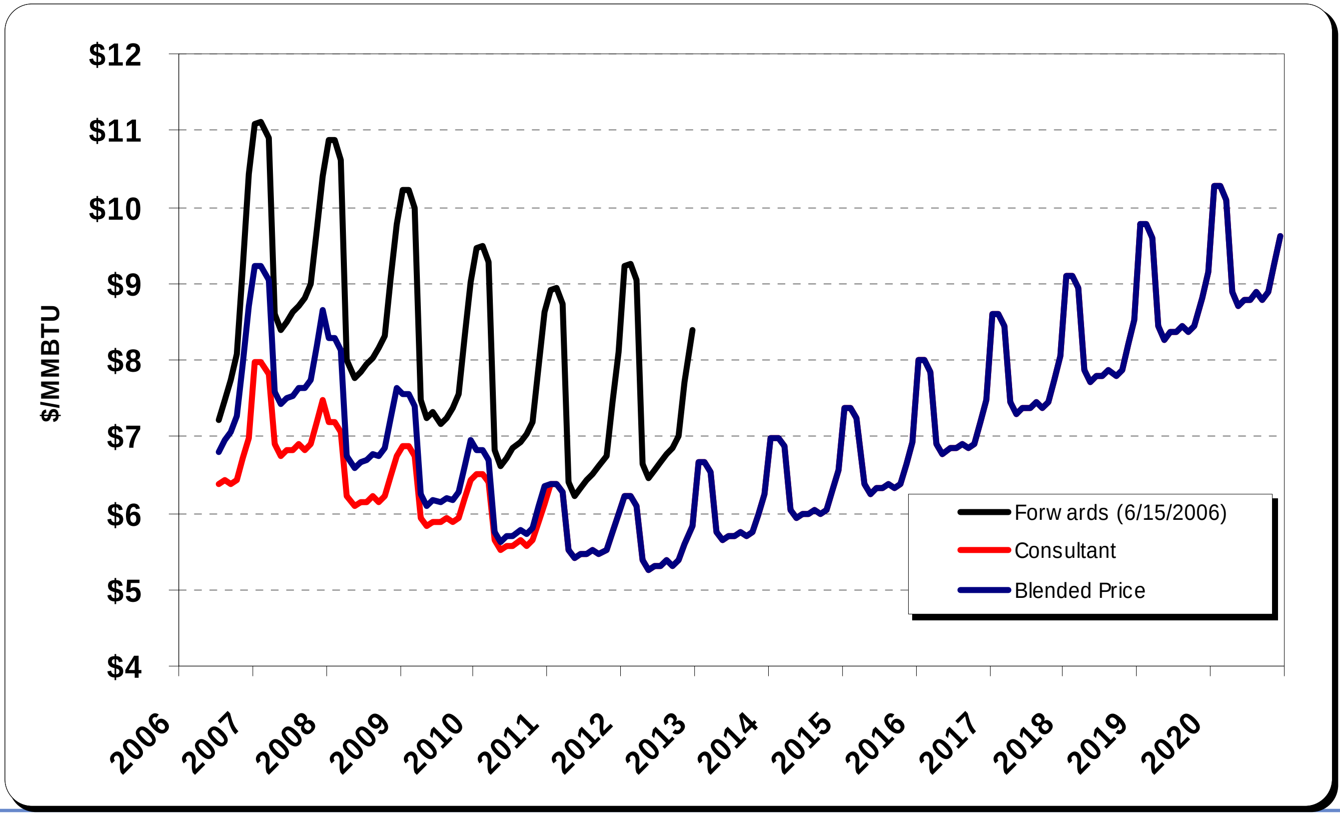
Levelized Natural Gas and Coal Costs

20-Year Levelized (2008 to 2027) shown in 2006 dollars	Nominal Price per Dthm	Real Price per Dthm
Henry Hub NG	$7.47	$6.31
AECO NG	$6.58	$5.56
Sumas NG	$6.73	$5.68
Mine Mouth PRB Coal	$0.38	$0.32
Short Haul PRB Coal	$0.76	$0.64
Long Haul PRB Coal	$1.42	$1.20

We answer to you.

Methodology

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



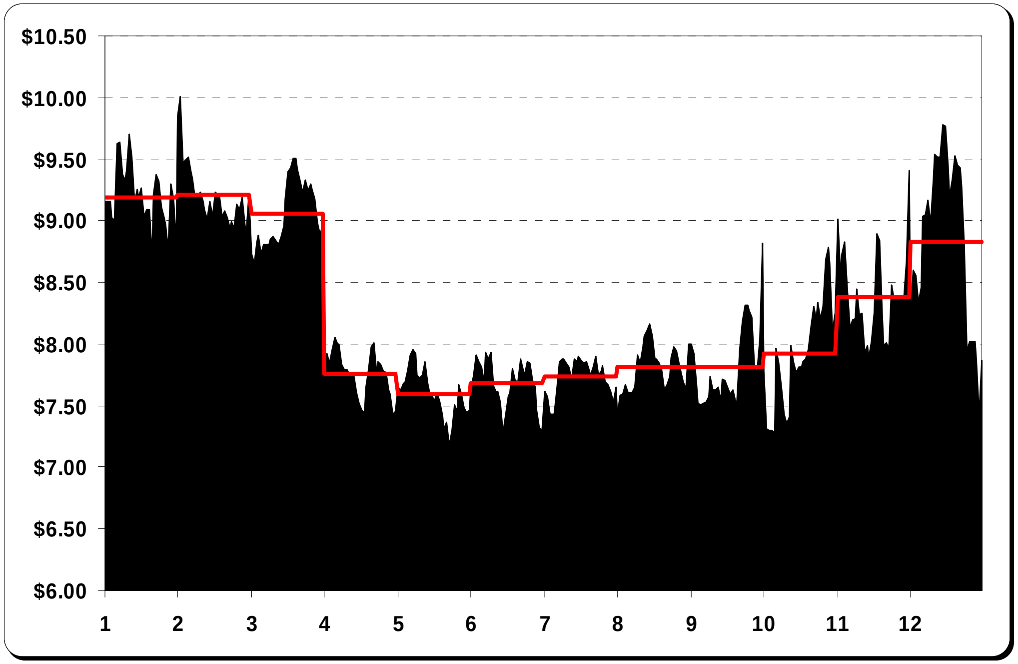
We answer to you. AVISTA

Intra Year Gas Prices

Month	Percent of Annual	Month	Percent of Annual
Jan	111%	Jul	95%
Feb	111%	Aug	96%
Mar	109%	Sep	95%
Apr	96%	Oct	96%
May	94%	Nov	100%
Jun	95%	Dec	104%

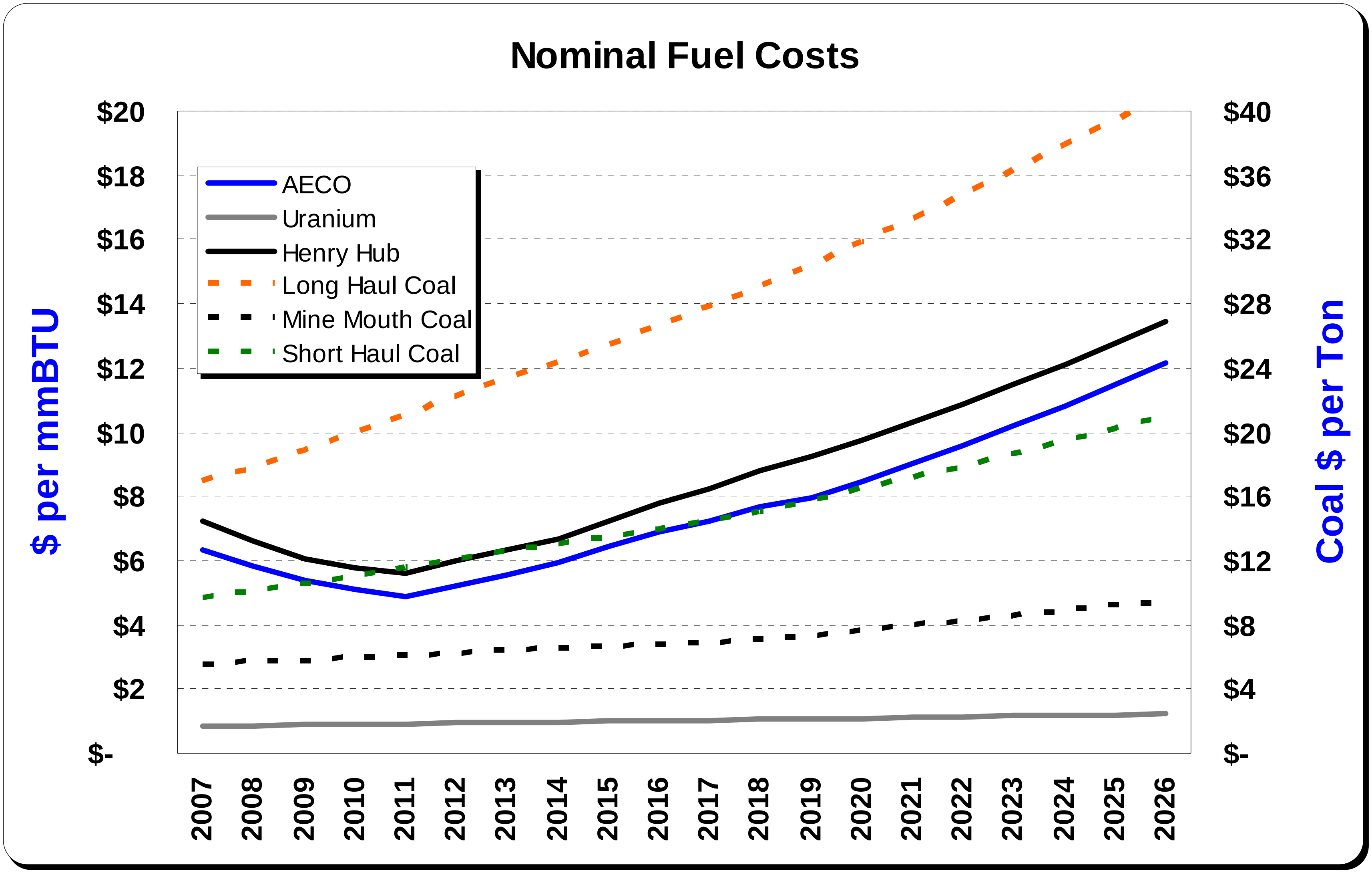
Monthly Gas Shape: Consistent with 2006 Gas IRP, average of monthly forward prices available on July 1, 2005 (these prices were used to avoid hurricane related price skews). All gas prices use this monthly shape.

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



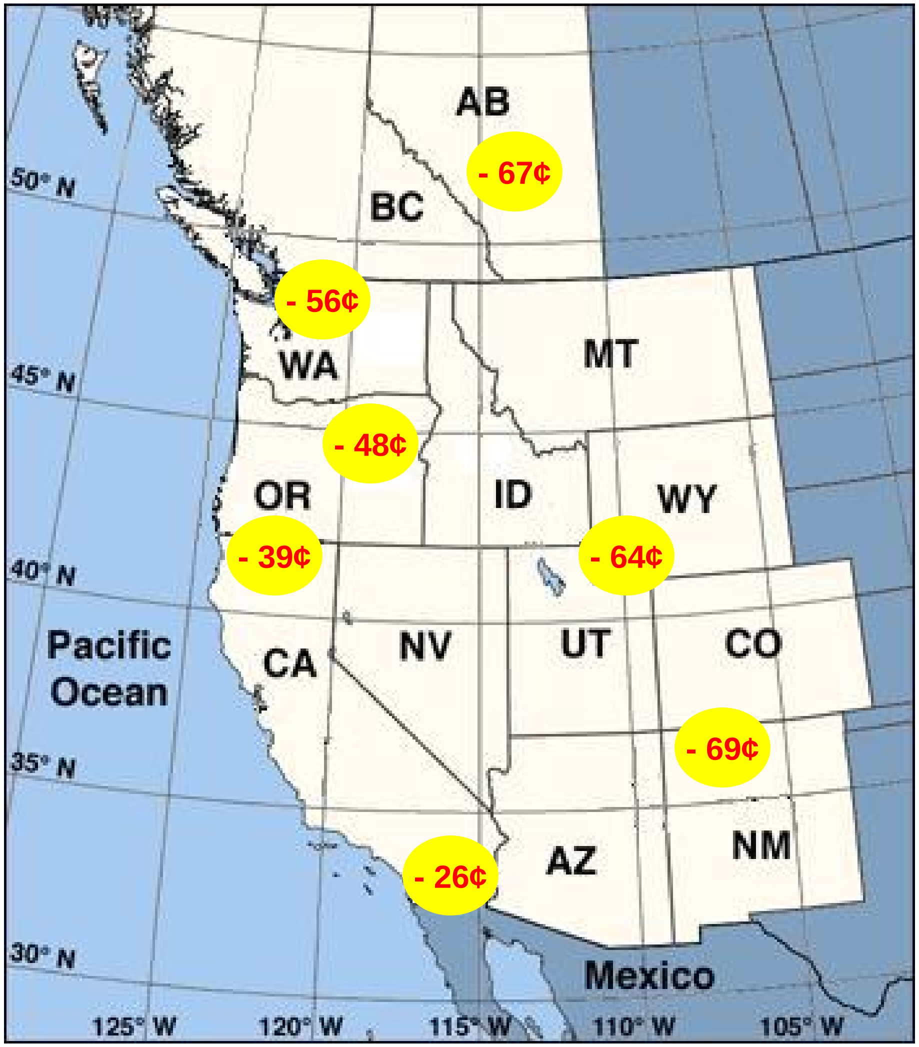
We answer to you.

AVISTA



We answer to you.

Basin Differentials/Gas Transportation

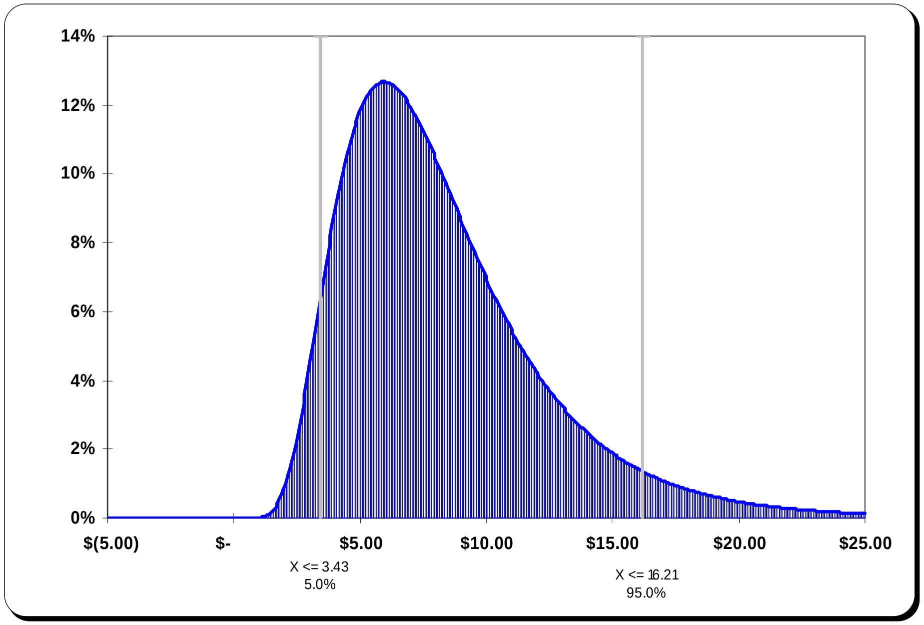


- Differentials are based on long-term forecast by a Consultant between 2008 and 2020, shown as a delta from Henry Hub
- Prices shown are a nominal levelized cost between 2008 & 2027, values are shown in 2006 dollars
- Differentials after 2020 use the rate of growth from 2019/20 for all time periods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

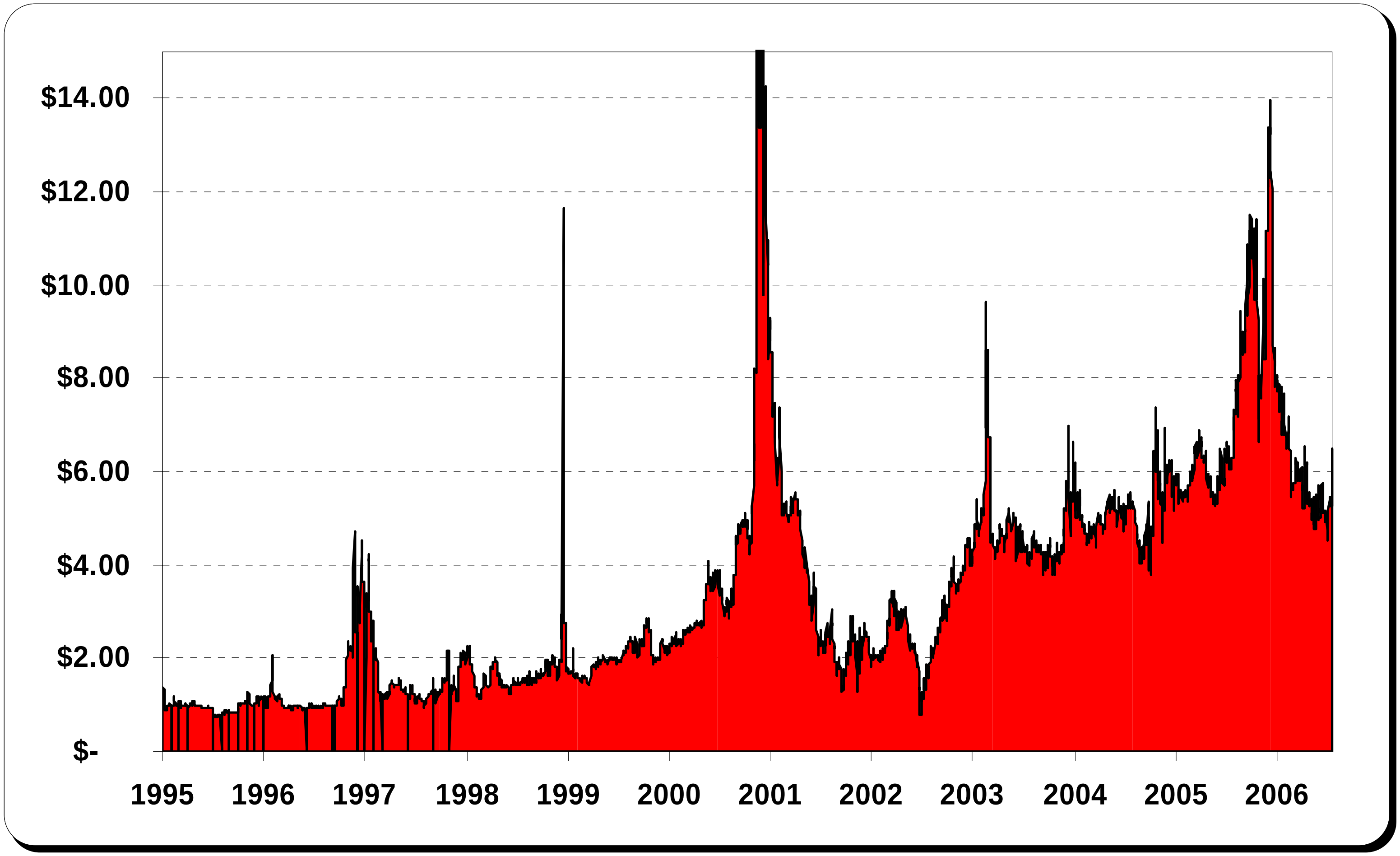
We answer to you.

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



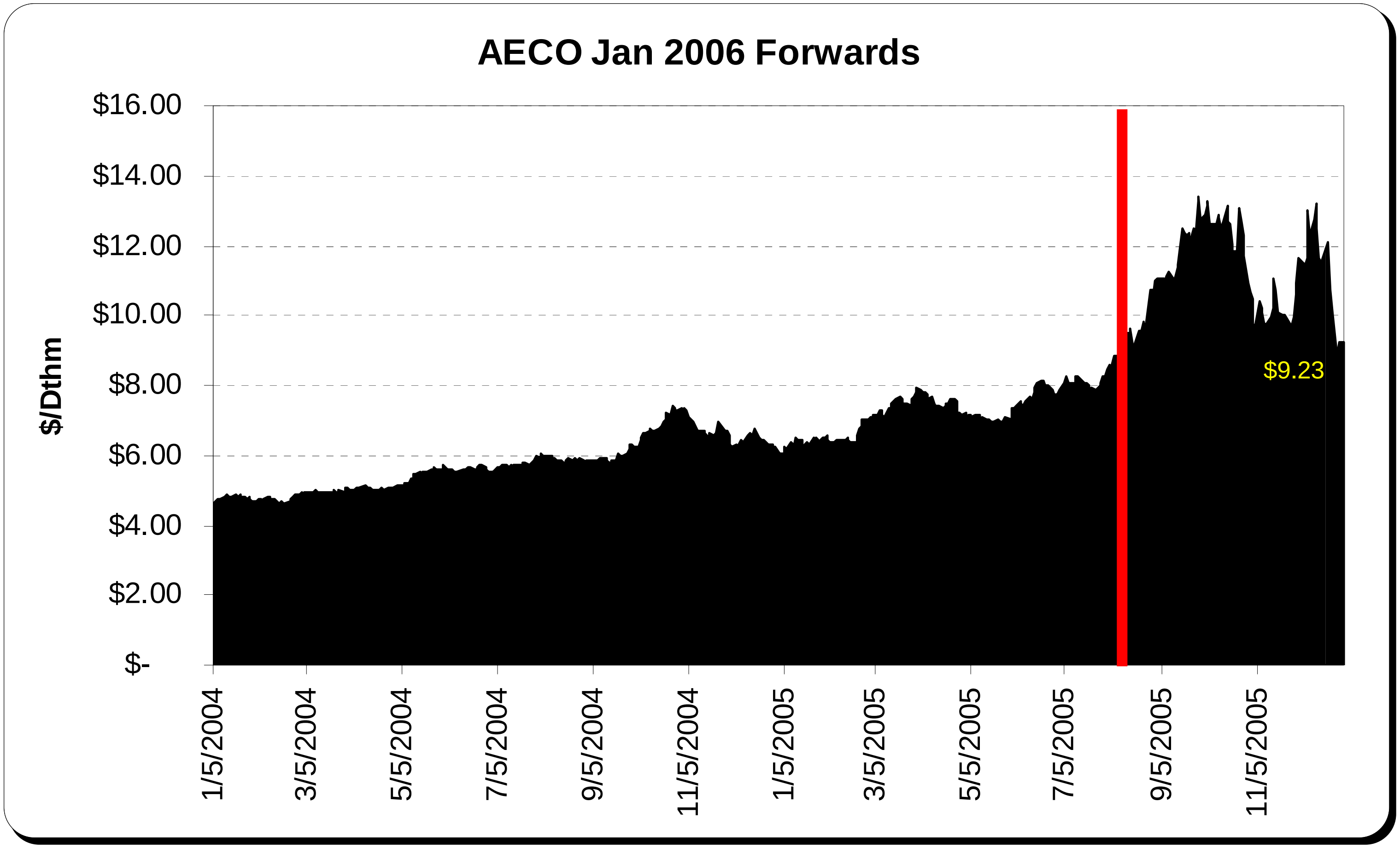
Historical Daily Sumas NG Prices



We answer to you.

AVISTA

Historical Volatility (forward prices)

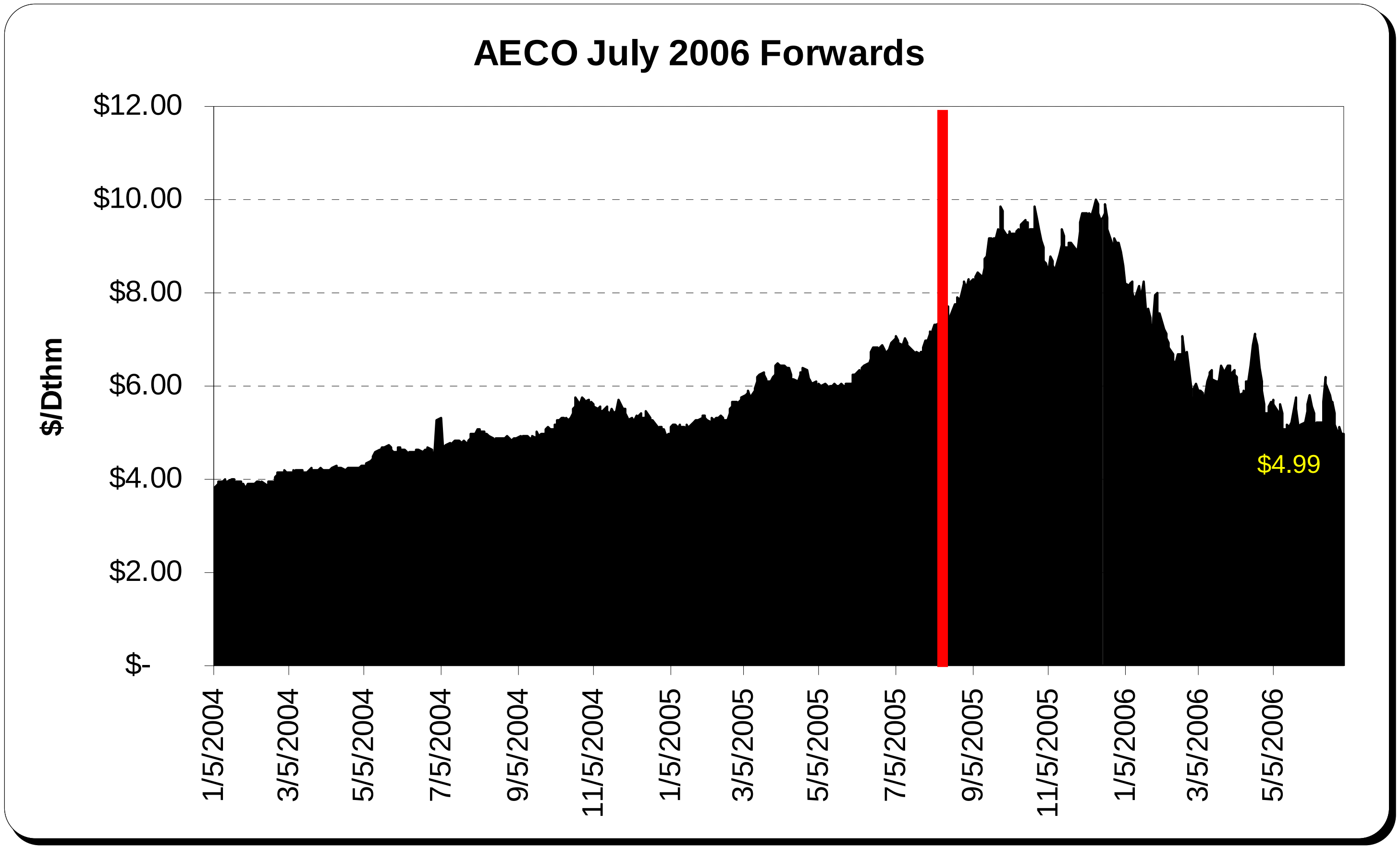


Mean: $7.26
Stdev: $2.22

We answer to you.

AVISTA

Historical Volatility (forward prices)

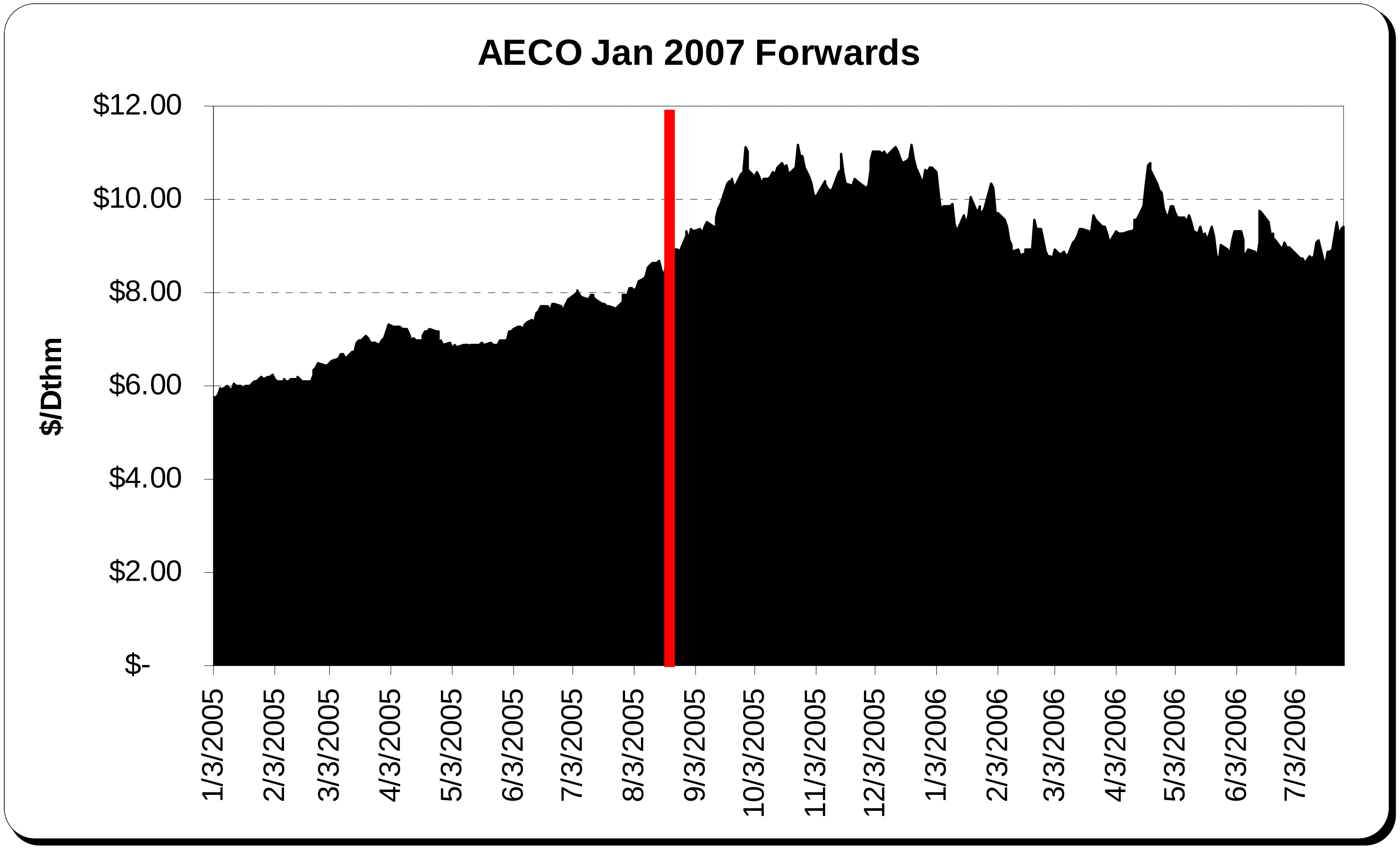


Mean: $6.03
Stdev: $1.59

We answer to you.

AVISTA

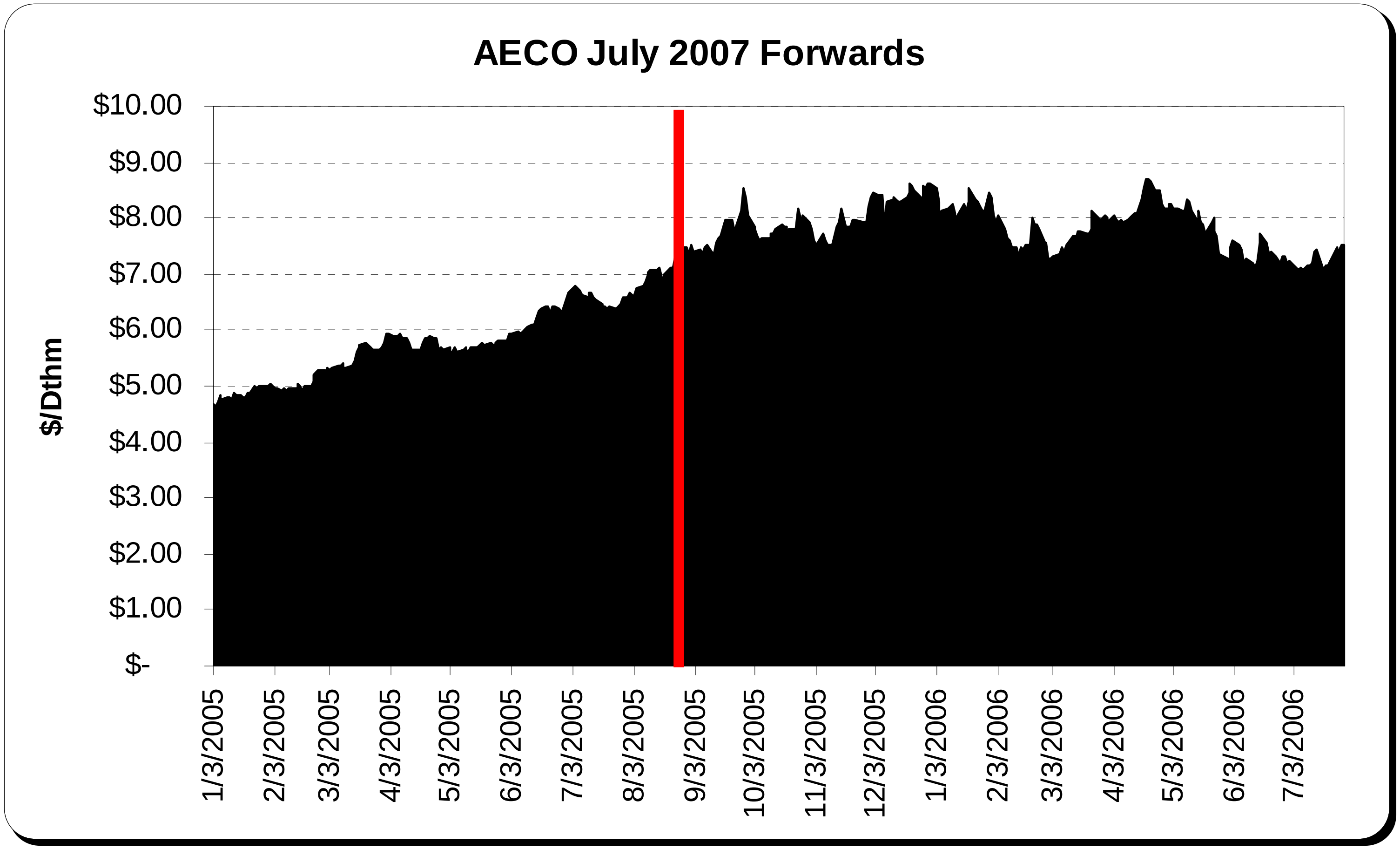
Historical Volatility (forward prices)



Mean: $8.64
Stdev: $1.51

We answer to you.

Historical Volatility (forward prices)



Mean: $6.99
Stdev: $1.14

We answer to you.

IRP Modeling Overview: Preliminary Transmission Costs & Paths

2007 Integrated Resource Plan

Second Technical Advisory Committee Meeting

August 31, 2006

Heidi Heath

We answer to you.

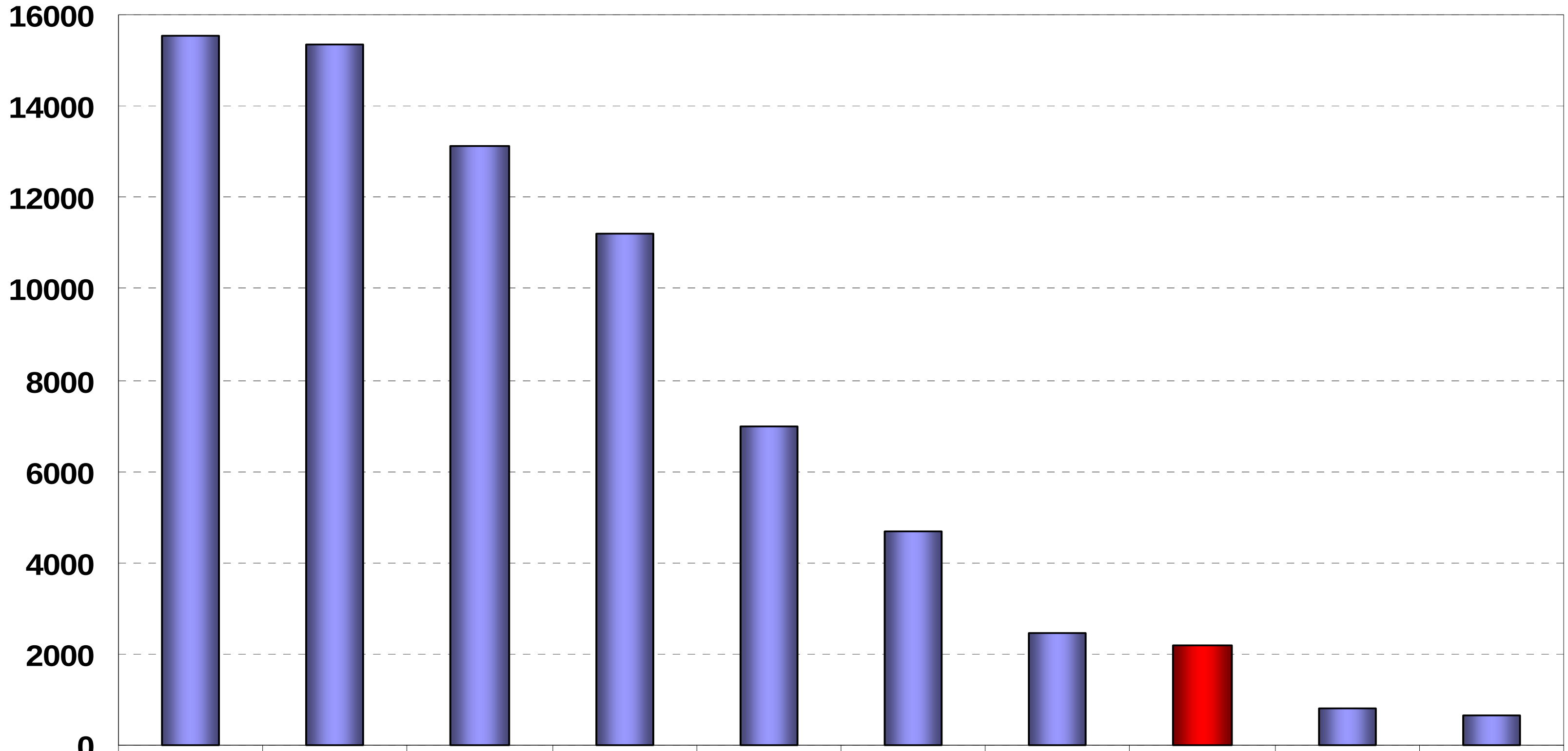
AVISTA

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

We answer to you.

Miles of High-Voltage Transmission Lines



	Pacifi Corp	BPA	Alberta	BC Hydro	North-western	Idaho Power	Sierra Pacific	Avista	PGE	SCL
Miles	15530	15342	13132	11185	7000	4671	2446	2169	815	657

We answer to you.

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)

We answer to you.

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

We answer to you.

AVISTA

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.

We answer to you.

AVISTA

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

We answer to you.

Generation Integration Cost Estimates

- Transmission data from the 2005 IRP used for this study
- Updated estimates will be provided for the final 2007 IRP

We answer to you.

AVISTA

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

We answer to you.

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

We answer to you.

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

We answer to you.

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

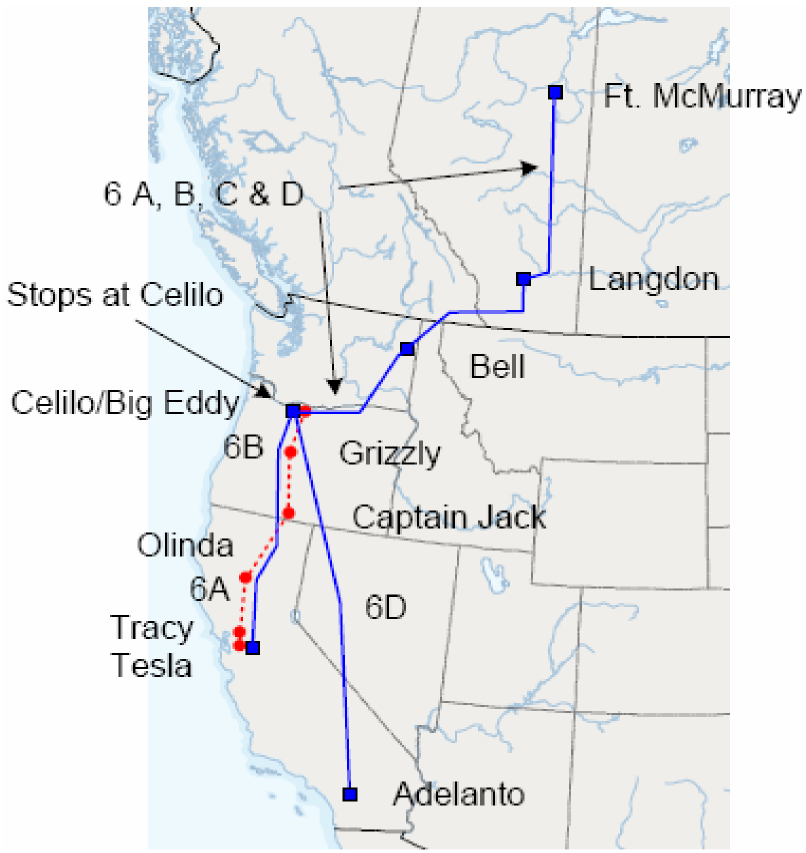
1000 MW

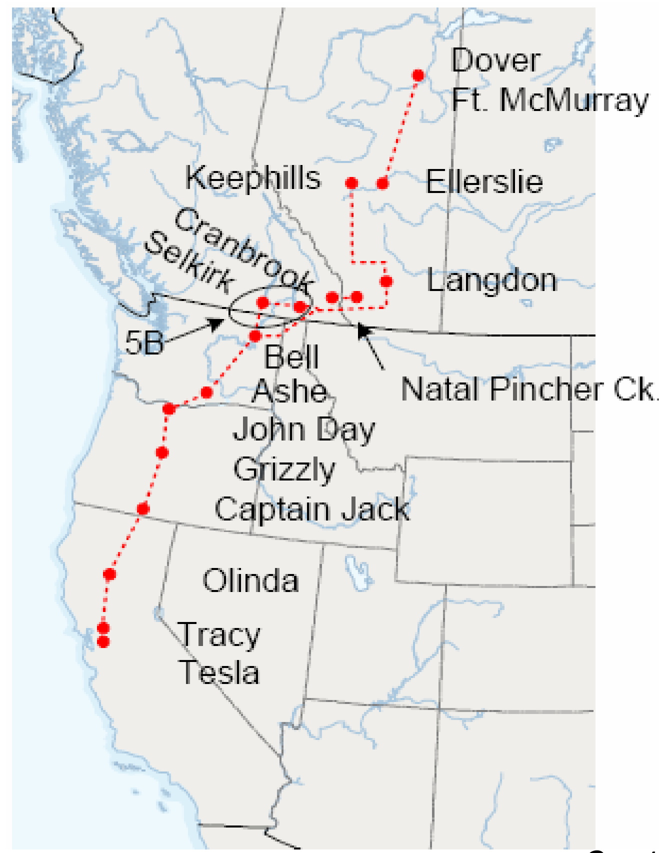
- Major new 500 kV facilities required, $1.5 billion

We answer to you.

Alberta Oil Sands

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





Courtesy of NTAC

We answer to you.

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.

We answer to you.

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

We answer to you. AVISTA

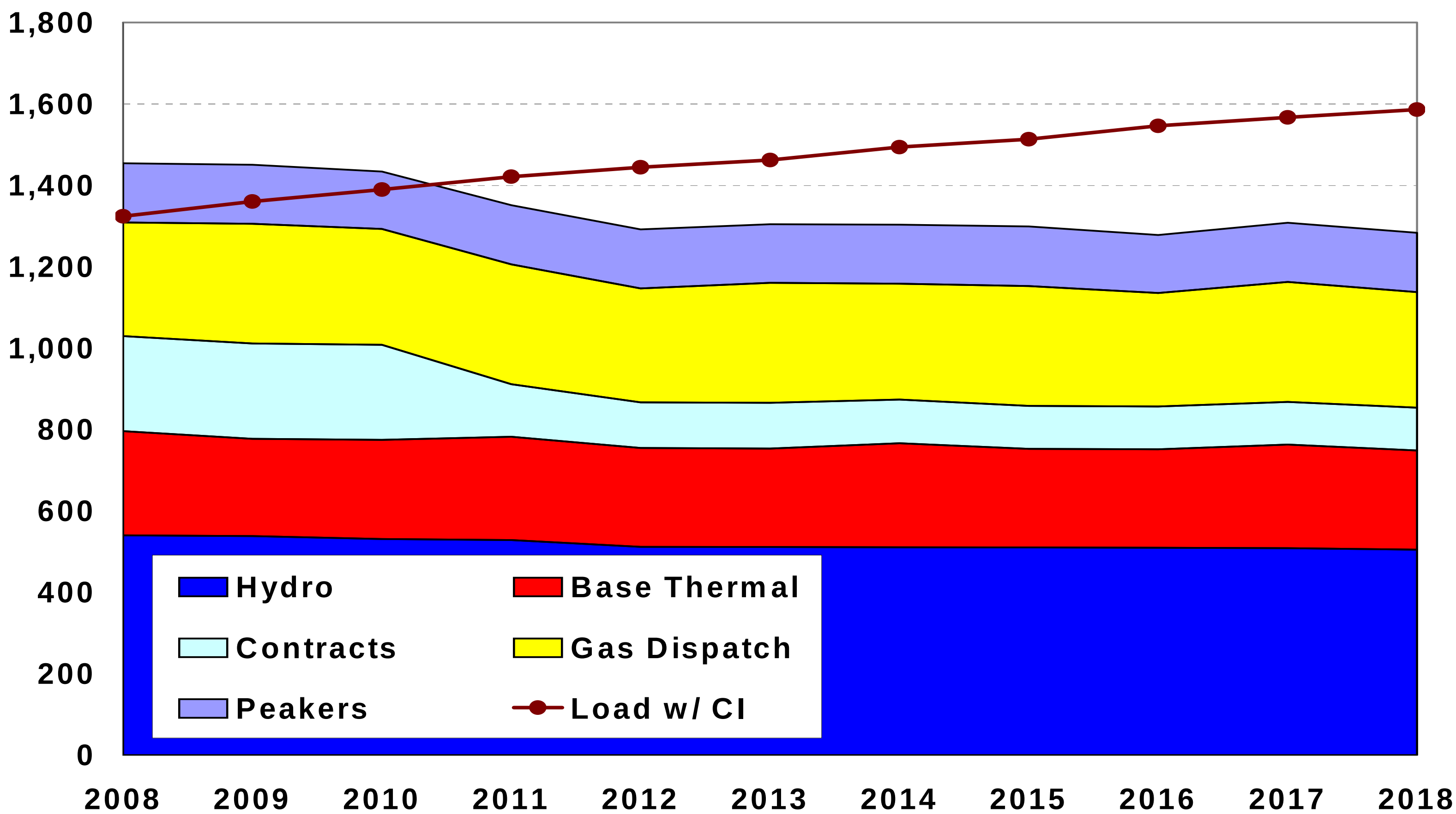
Energy Loads and Resources

	Last Updated August 14, 2006	Notes	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	AVERAGE LOAD & HYDRO PLANNING											
	REQUIREMENTS											
1	System Load	1	(1,124)	(1,161)	(1,194)	(1,226)	(1,252)	(1,270)	(1,302)	(1,321)	(1,354)	(1,375)
2	Contract Obligations	2	(61)	(61)	(60)	(60)	(59)	(59)	(59)	(59)	(59)	(11)
3	Total Requirements		(1,185)	(1,222)	(1,254)	(1,286)	(1,311)	(1,329)	(1,361)	(1,380)	(1,413)	(1,385)
	RESOURCES											
4	Contract Rights	4	295	295	294	189	172	172	166	164	164	116
5	Hydro	3	540	538	531	528	512	511	510	510	509	509
6	Base Load Thermals	5	256	239	244	254	243	242	256	243	242	254
7	Gas Dispatch Units	6	279	294	284	294	279	294	284	295	279	294
8	Total Resources		1,370	1,366	1,353	1,266	1,205	1,219	1,217	1,211	1,194	1,173
9	**POSITION**		**185**	**145**	**99**	**(20)**	**(106)**	**(110)**	**(144)**	**(169)**	**(218)**	**(212)**
	CONTINGENCY PLANNING											
10	Confidence Interval	7	(167)	(166)	(163)	(162)	(159)	(159)	(159)	(159)	(159)	(159)
11	WNP-3 Obligation	8	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
12	Peaking Resources	9	145	145	141	146	145	144	146	146	142	145
13	**CONTINGENCY NET POSITION**		**130**	**90**	**44**	**(70)**	**(152)**	**(158)**	**(191)**	**(215)**	**(268)**	**(259)**

We answer to you.

AVISTA

Energy L&R – Annual Resource Capability



We answer to you.

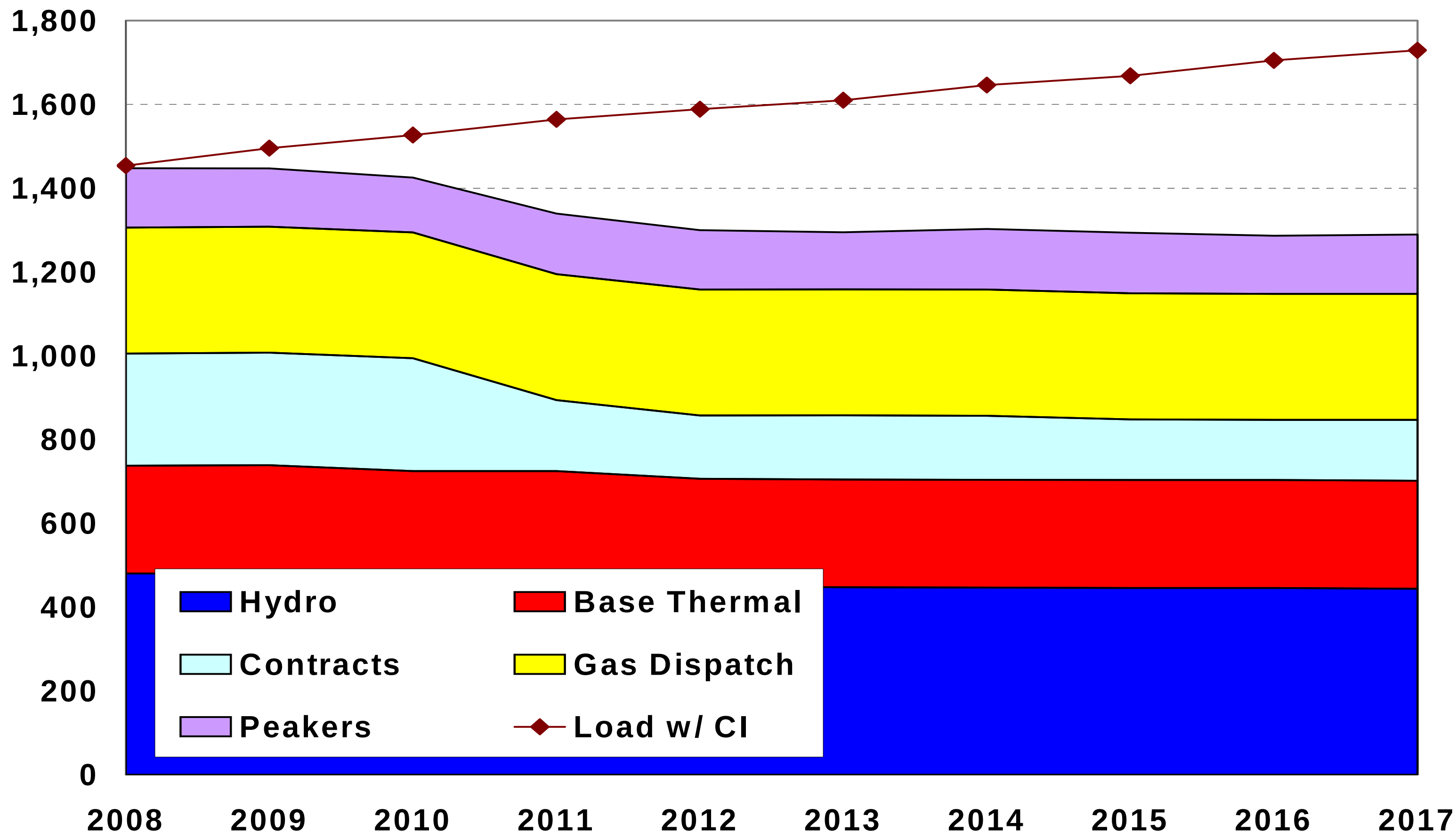
AVISTA

Energy L&R – Annual Resource Capability

	2008	2009	2010	2011	2012	2017	2022	2027
Load w/ CI	1,324	1,360	1,390	1,421	1,444	1,567	1,649	1,777
Contracts	234	234	234	129	113	105	106	106
Hydro	540	538	531	528	512	509	491	491
Base Thermal	256	239	244	254	243	254	243	242
Gas Dispatch	279	294	284	294	279	294	284	294
Peakers	145	145	141	146	145	145	145	145
Total Resources	1,454	1,450	1,434	1,351	1,292	1,308	1,269	1,278
Load/Resources Balance	130	90	44	-70	-152	-259	-380	-499

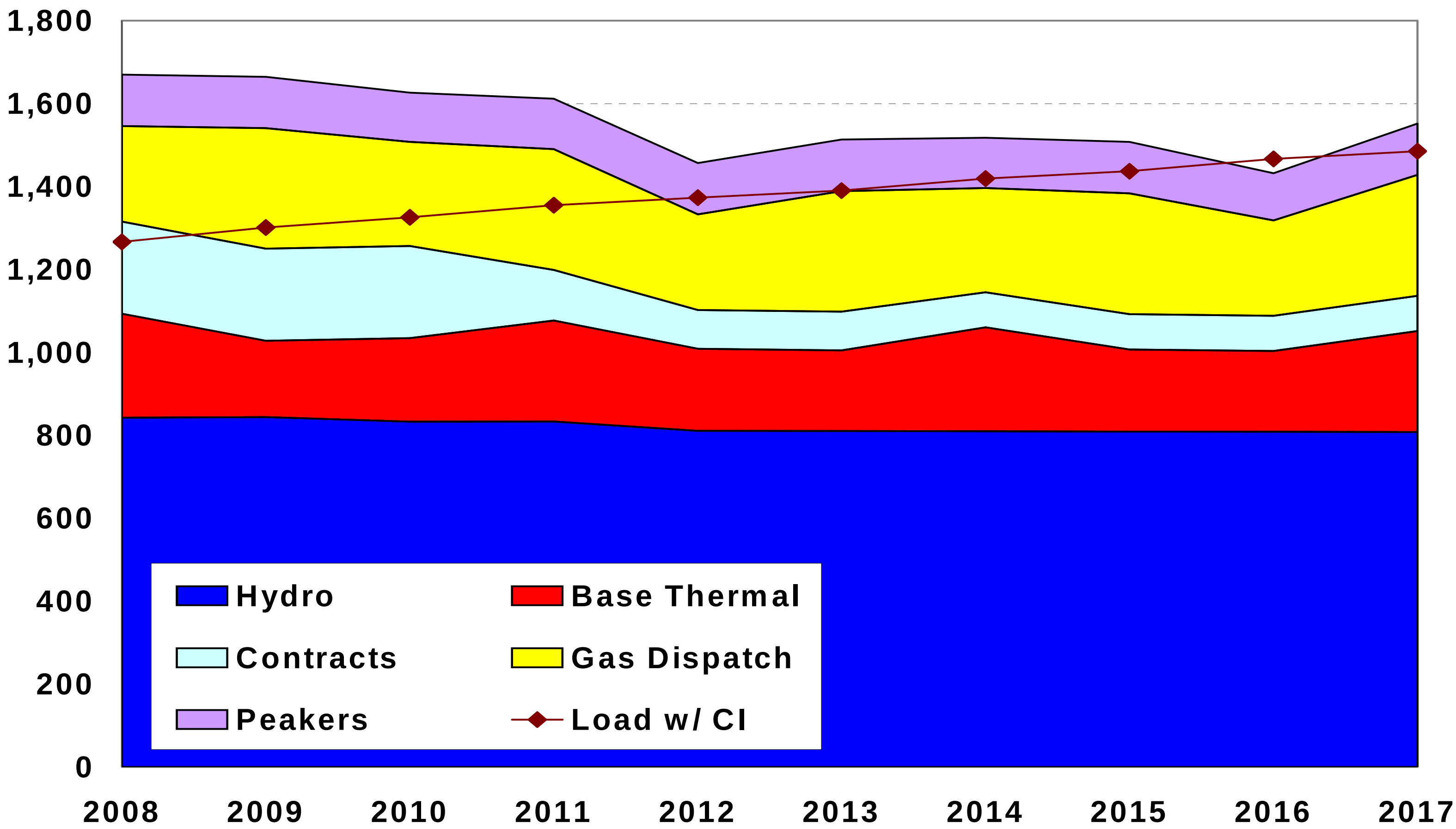
We answer to you.

Energy L&R – First Quarter Resource Capability



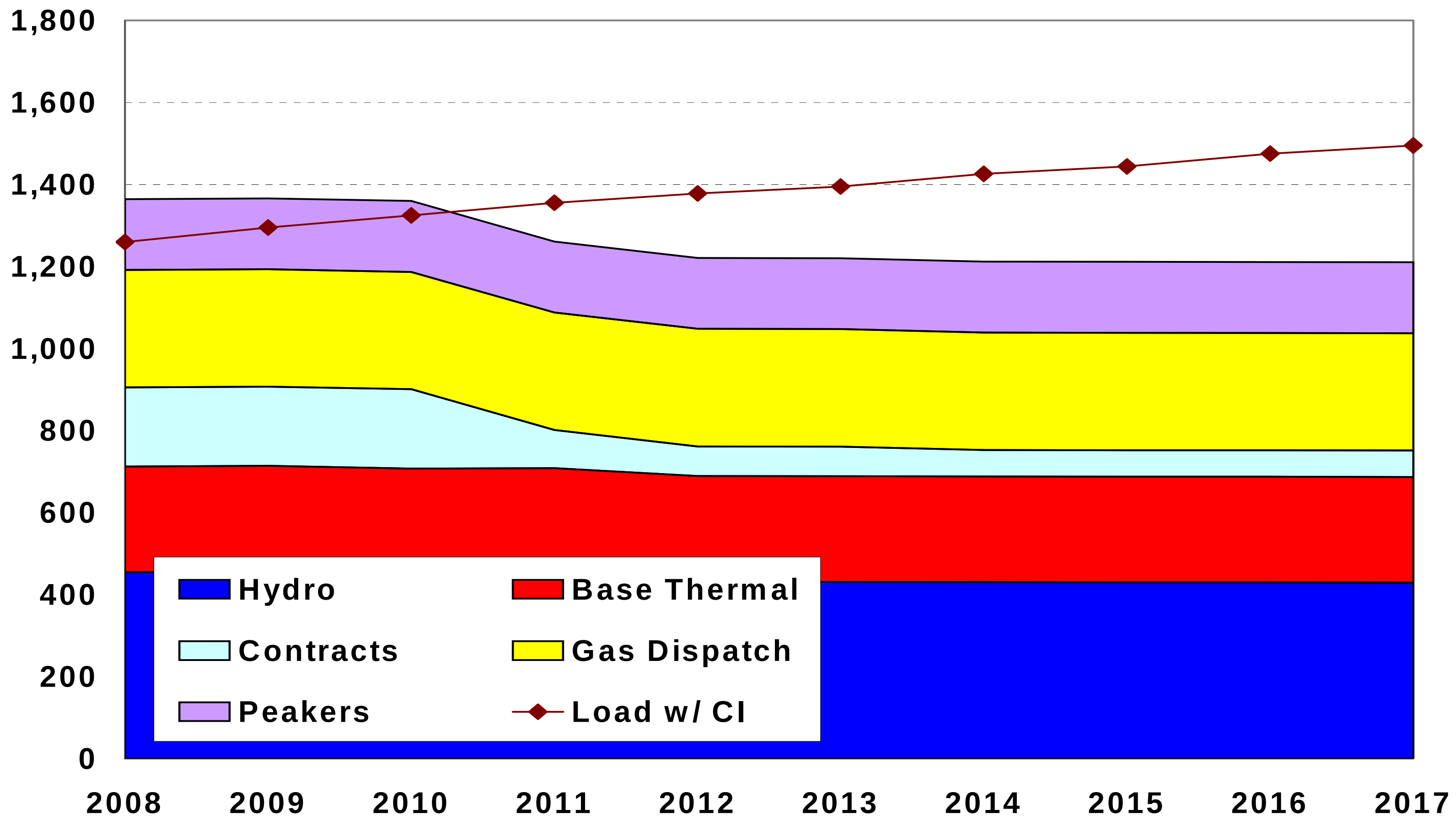
We answer to you.

Energy L&R – Second Quarter Resource Capability

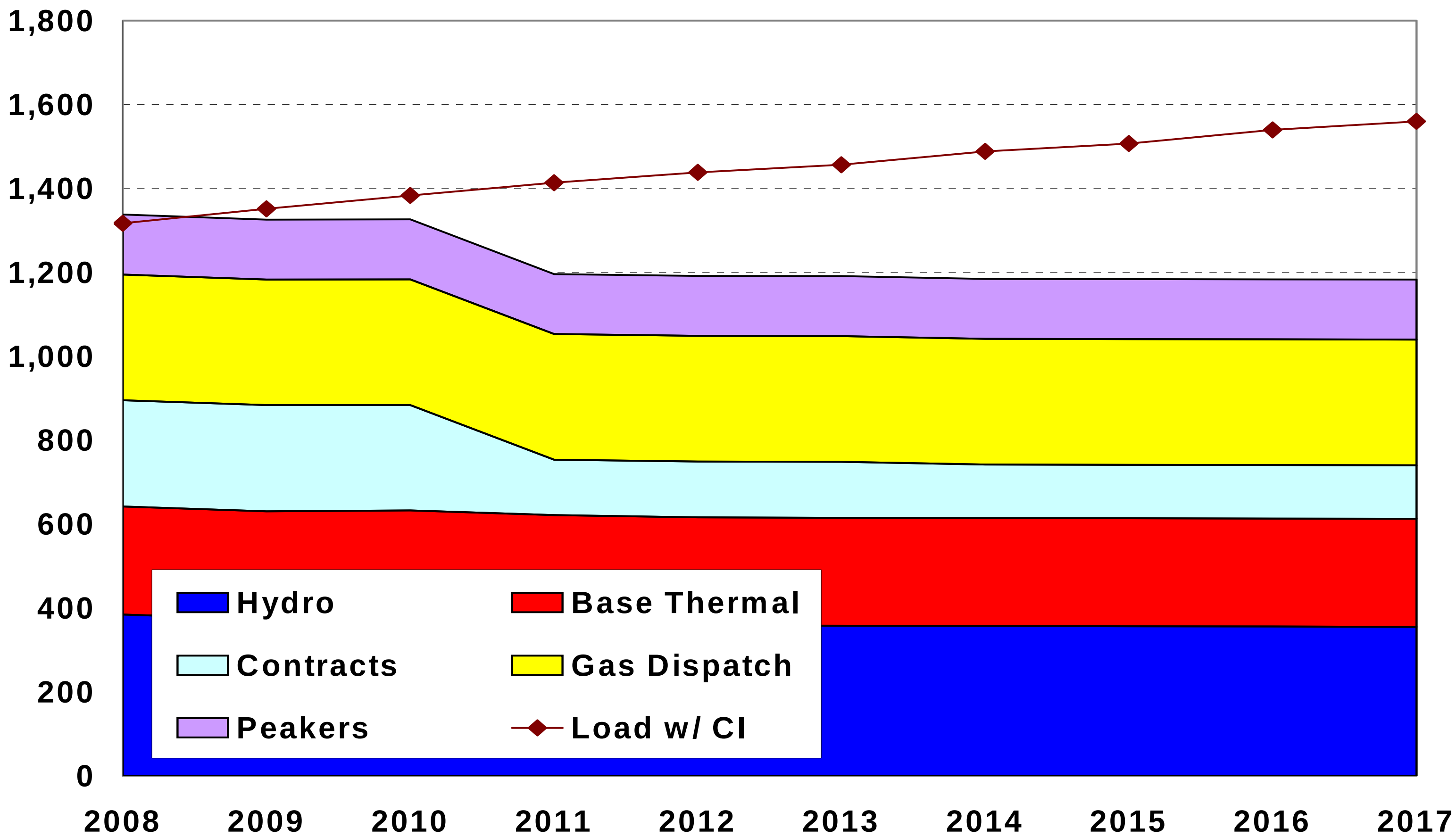


We answer to you.

Energy L&R – Third Quarter Resource Capability



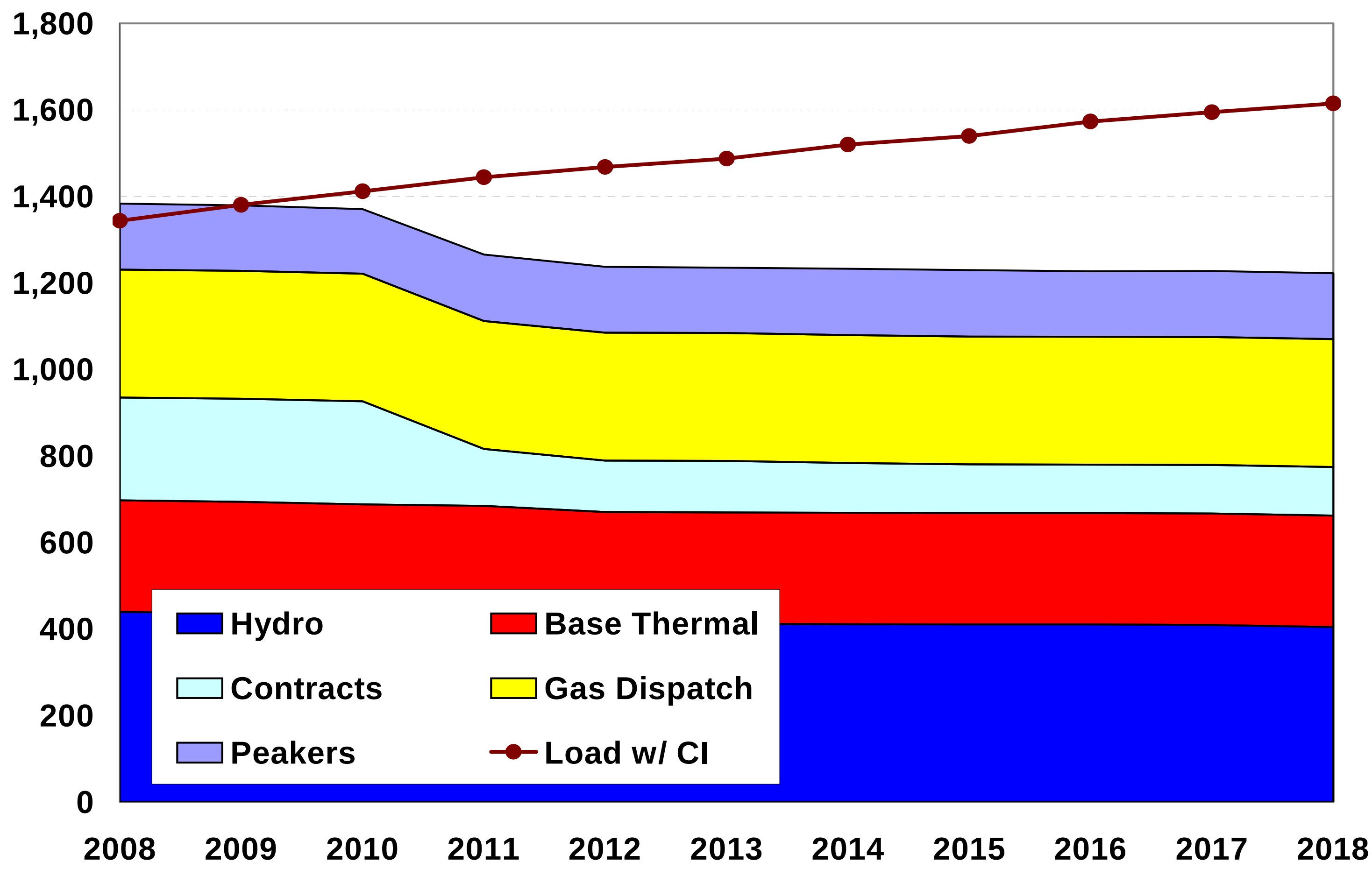
Energy L&R – Fourth Quarter Resource Capability



We answer to you.

AVISTA

Energy L&R – Annual Capability Without Q2



We answer to you.

Energy L&R – Annual Capability Without Q2

	2008	2009	2010	2011	2012	2017	2022	2027
Load w/ CI	1,343	1,381	1,412	1,444	1,468	1,595	1,679	1,812
Contracts	238	238	238	132	119	112	113	113
Hydro	440	437	431	427	413	410	393	393
Base Thermal	258	258	258	258	258	258	258	258
Gas Dispatch	296	296	295	296	296	296	296	296
Peakers	153	152	149	153	153	153	153	153
Total Resources	1,383	1,380	1,370	1,265	1,237	1,227	1,211	1,211
Load/Resources Balance	40	-1	-41	-179	-231	-367	-468	-600

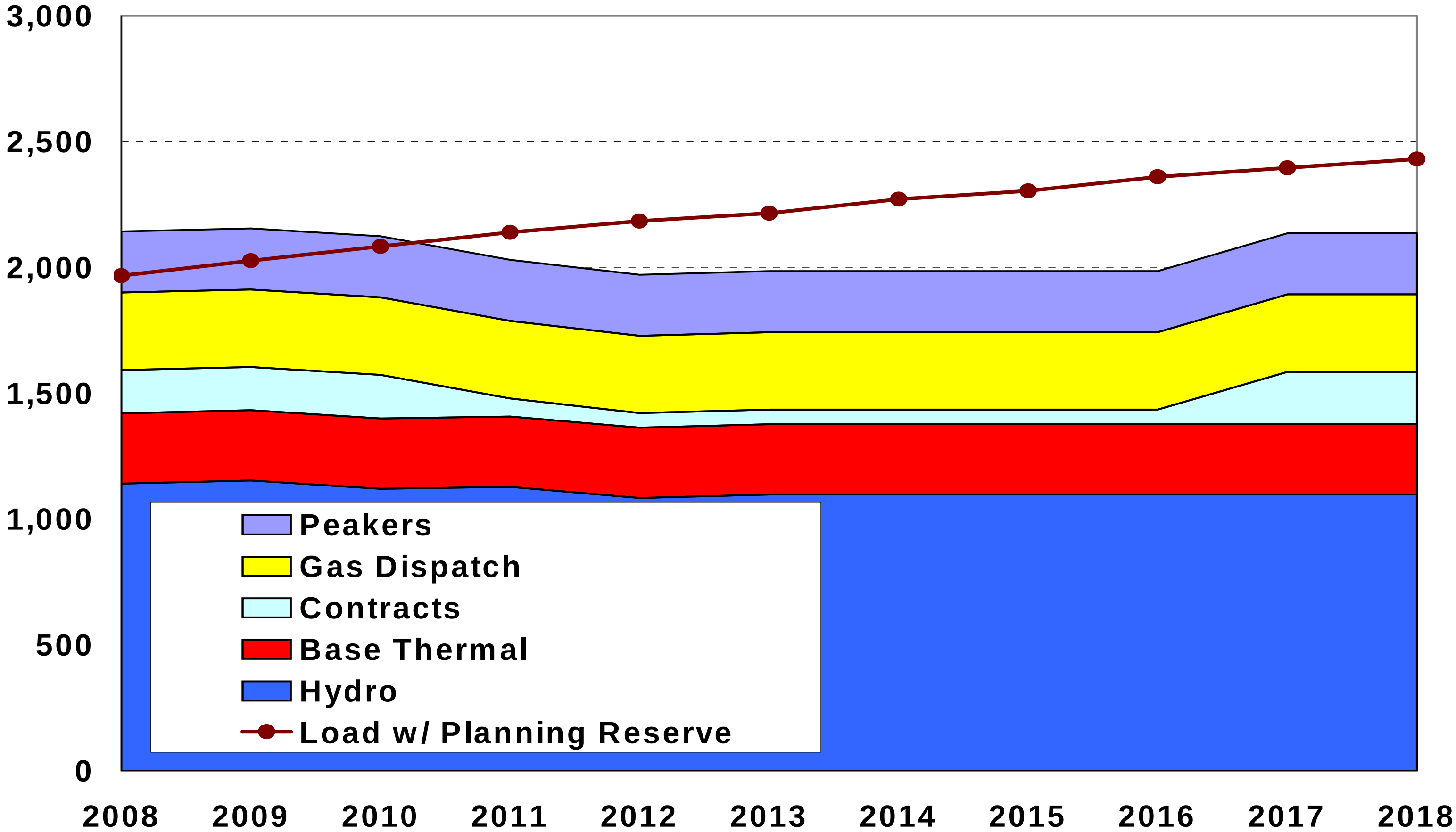
We answer to you.

Capacity Loads and Resources

	Last Updated August 14, 2006	Notes	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	PEAK LOAD AND RESOURCE PLANNING											
	REQUIREMENTS											
1	Native Load	1	(1,707)	(1,761)	(1,812)	(1,864)	(1,904)	(1,933)	(1,983)	(2,013)	(2,064)	(2,097)
2	Contracts Obligations	2	(169)	(169)	(168)	(168)	(166)	(165)	(165)	(165)	(165)	(15)
3	Total Requirements		(1,876)	(1,930)	(1,980)	(2,031)	(2,070)	(2,098)	(2,148)	(2,178)	(2,229)	(2,112)
	RESOURCES											
4	Contracts Rights	3	341	341	340	240	223	223	223	223	223	223
5	Hydro Resources	4	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,098	1,098	1,098
6	Base Load Thermals	5	280	280	280	280	280	280	280	280	280	280
7	Gas Dispatch Units	6	308	308	308	308	308	308	308	308	308	308
8	Peaking Units	7	243	243	243	243	243	243	243	243	243	243
9	Total Resources		2,312	2,324	2,292	2,199	2,137	2,151	2,151	2,151	2,151	2,151
10	**PEAK POSITION**		**436**	**395**	**312**	**167**	**67**	**53**	**3**	**(27)**	**(78)**	**39**
	RESERVE PLANNING											
11	Planning Reserve Margin	8	(261)	(266)	(271)	(276)	(280)	(283)	(288)	(291)	(296)	(300)
12	**RESERVE PEAK POSITION**		**176**	**129**	**40**	**(109)**	**(213)**	**(230)**	**(285)**	**(318)**	**(375)**	**(260)**

We answer to you.

Capacity L&R – Annual Resource Capability



Capacity L&R – Annual Resource Capability

	2008	2009	2010	2011	2012	2017	2022	2027
Load w/ Planning Reserve	1,968	2,027	2,084	2,140	2,185	2,361	2,600	2,822
Contracts	172	172	173	73	58	58	128	128
Hydro	1,142	1,154	1,121	1,128	1,084	1,098	1,056	1,070
Base Thermal	280	280	280	280	280	280	280	280
Gas Dispatch	308	308	308	308	308	308	308	308
Peakers	243	243	243	243	243	243	243	243
Total Resources	2,144	2,156	2,124	2,031	1,972	1,986	2,014	2,028
Loads/Resources Balance	176	129	40	-109	-213	-375	-586	-794

We answer to you.

AVISTA

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

We answer to you.

AVISTA

Fundamental Modeling

Futures and Scenarios

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

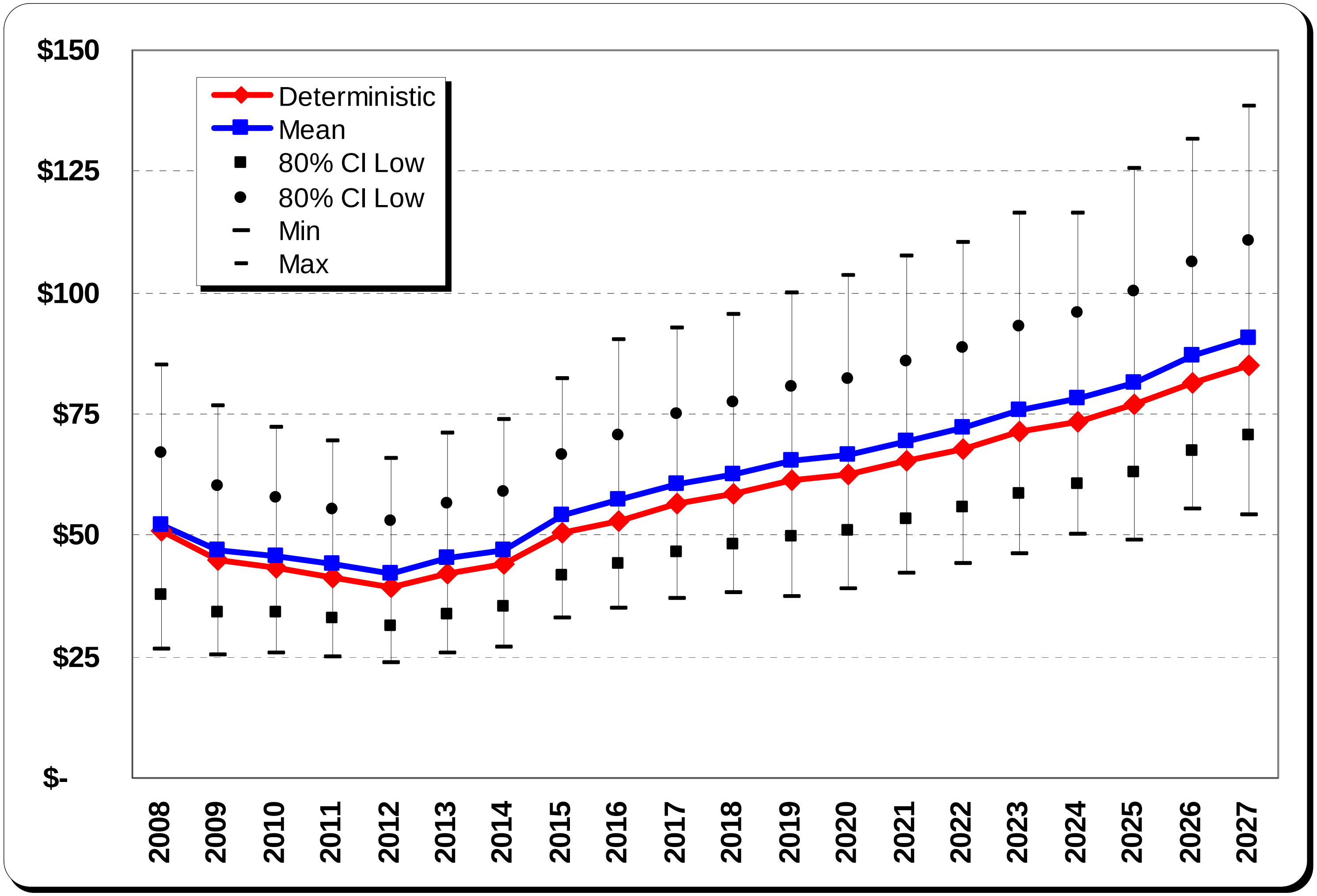
James Gall

AURORAxmp®

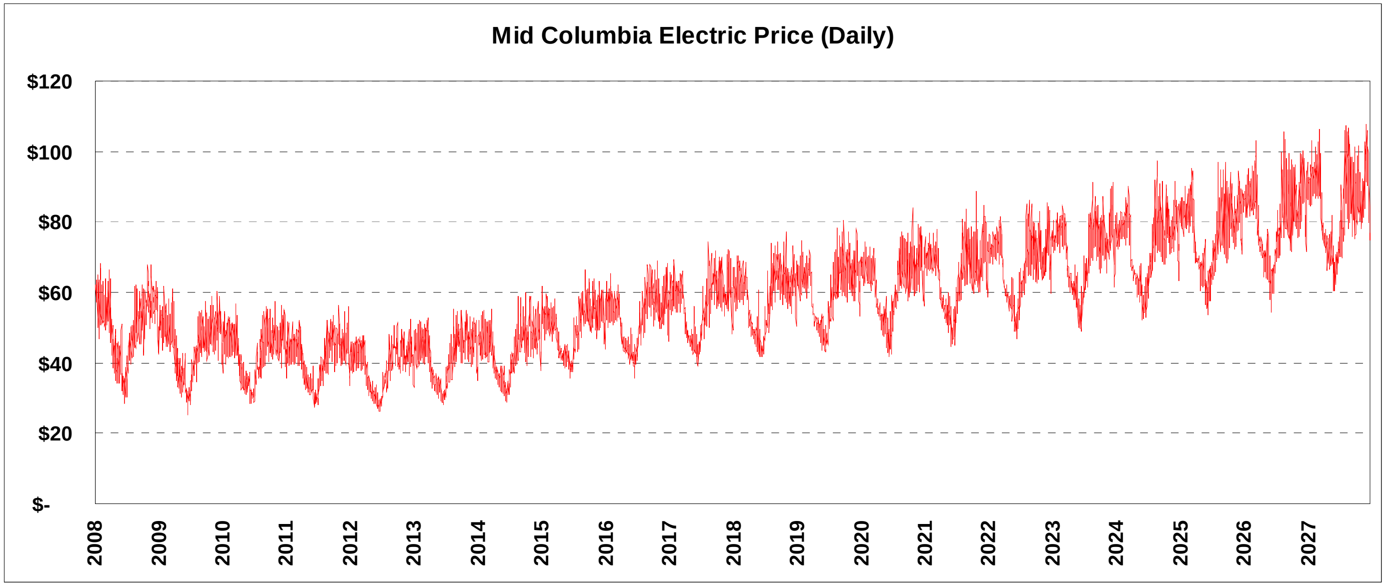
We answer to you.

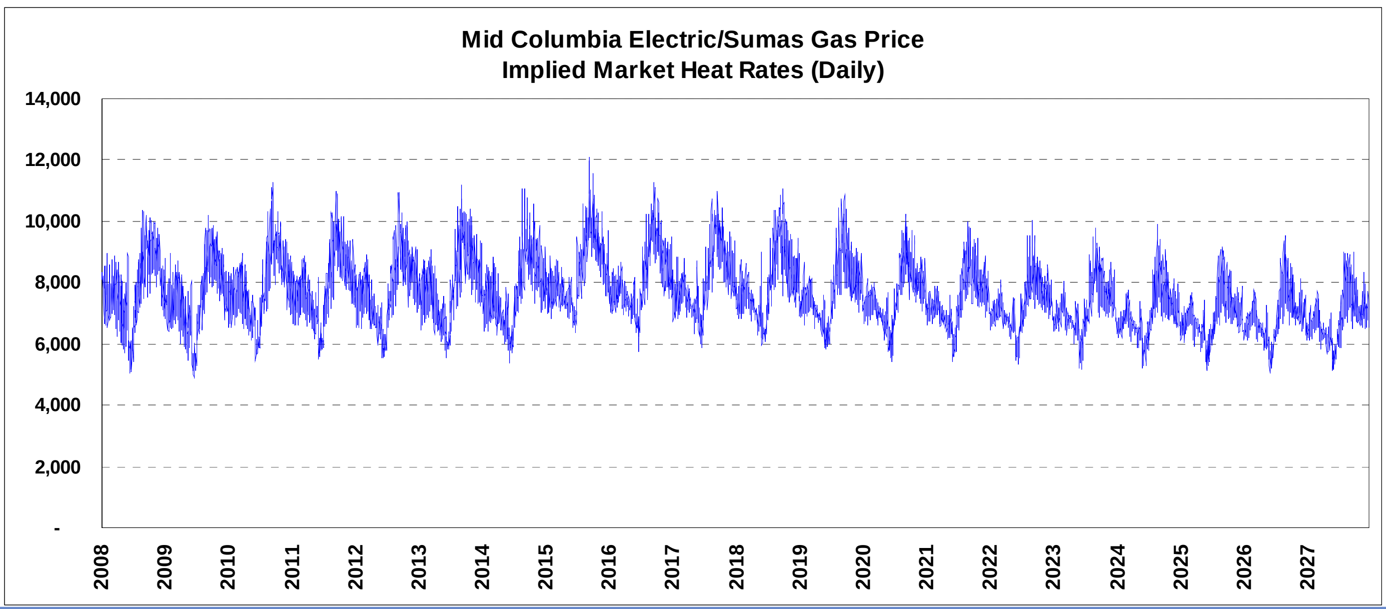
AVISTA

Base Case: Mid-C Annual Average Prices



We answer to you.





We answer to you.

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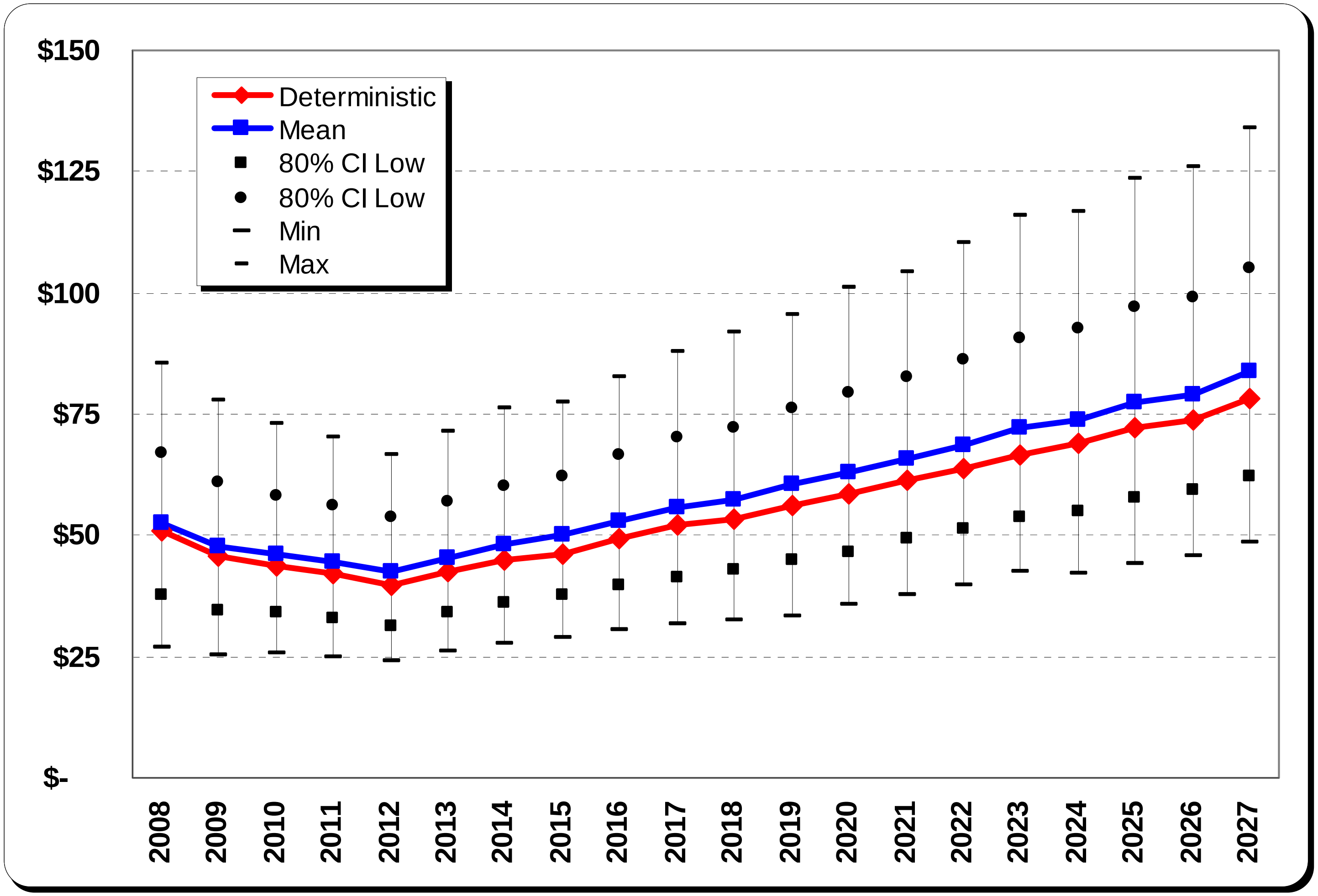
No CO_2 Tax Future: Mid-C Annual Average Prices



We answer to you.

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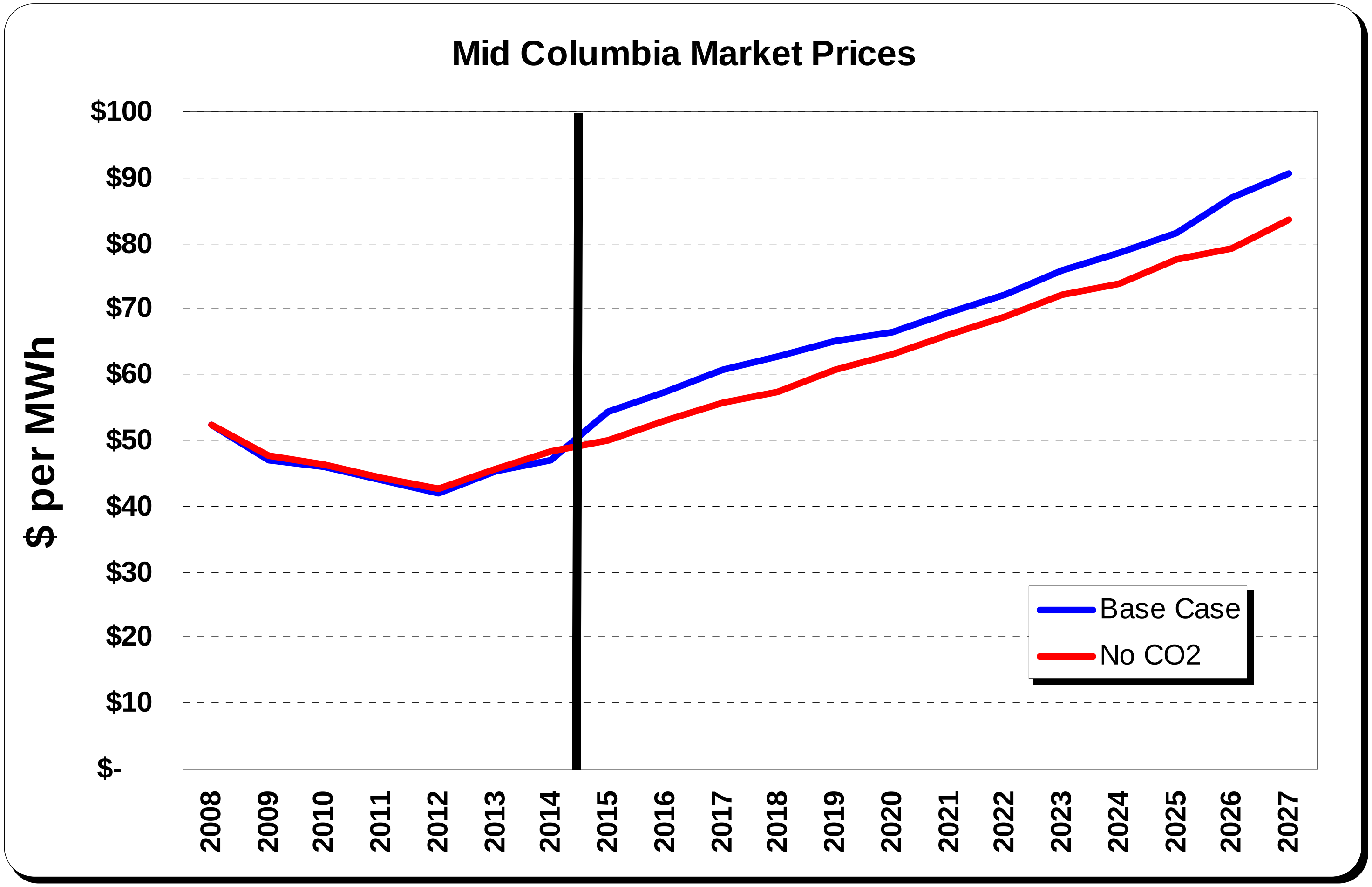
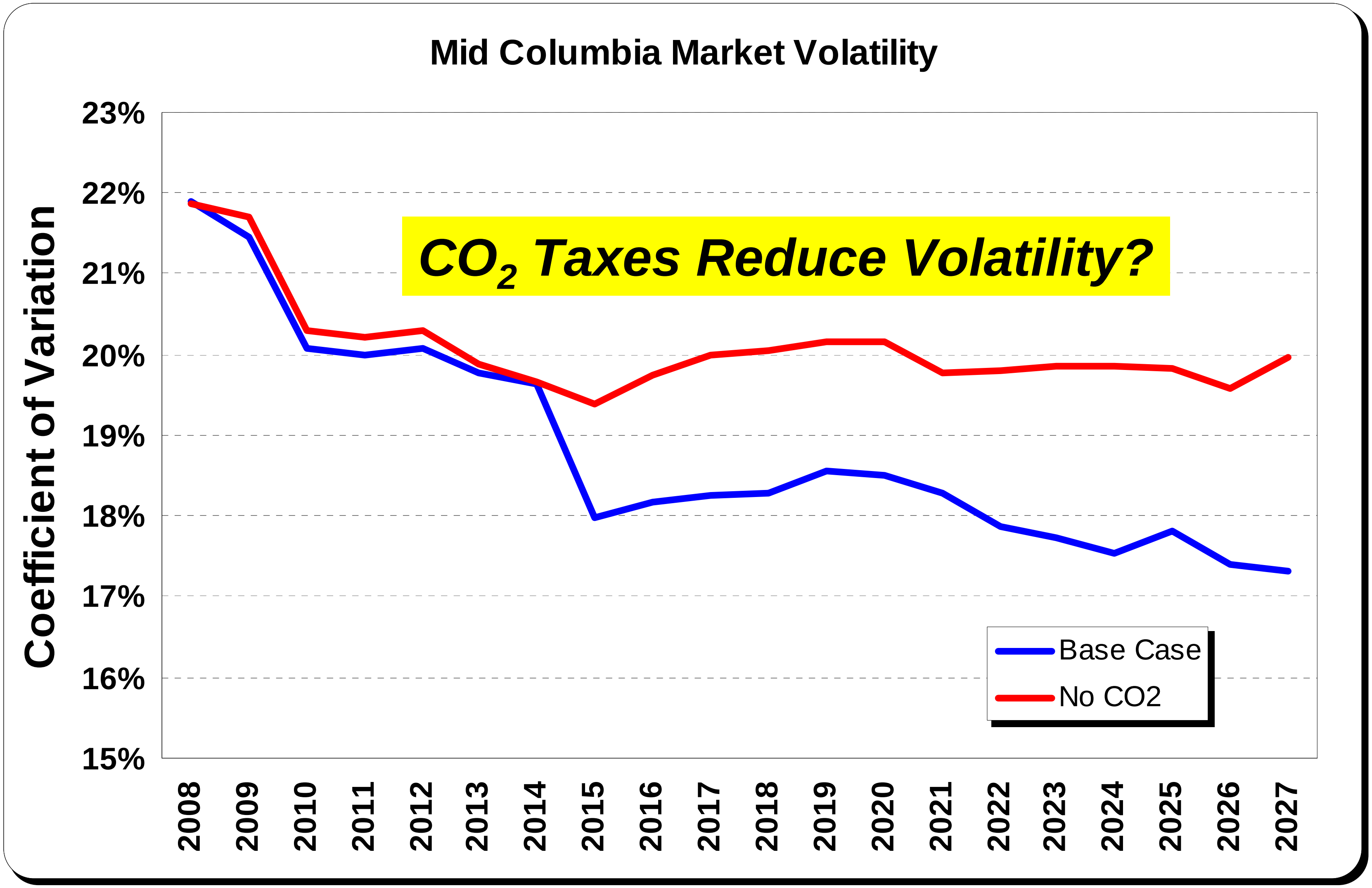
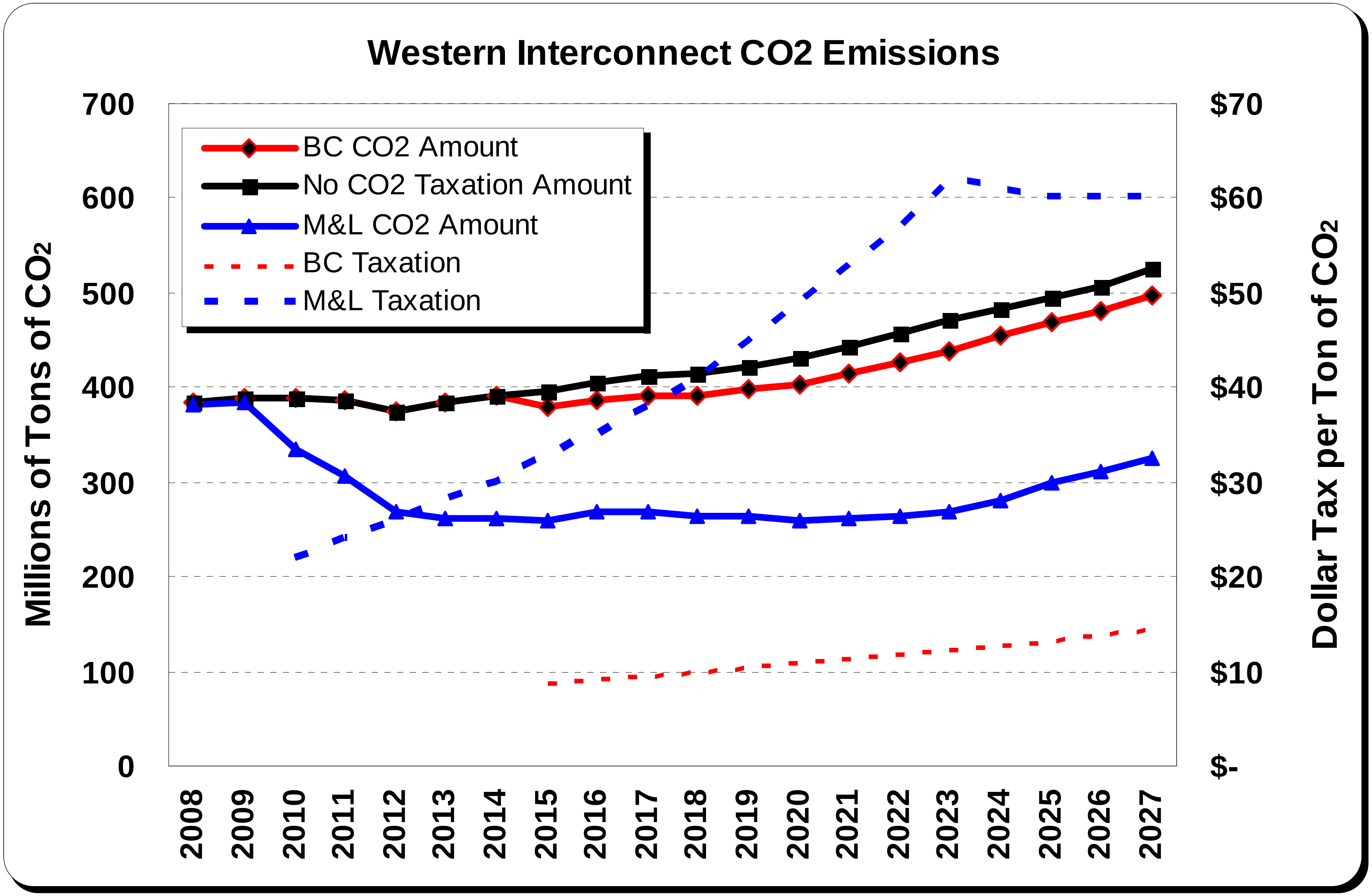
Cost of CO_2 Taxation to Market (~$4.50)




Mid Columbia Market Volatility
Coefficient of Variation
23%
22%
21%
20%
19%
18%
17%
16%
15%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
CO_2 Taxes Reduce Volatility?
Base Case
No CO2

We answer to you.

AVISTA

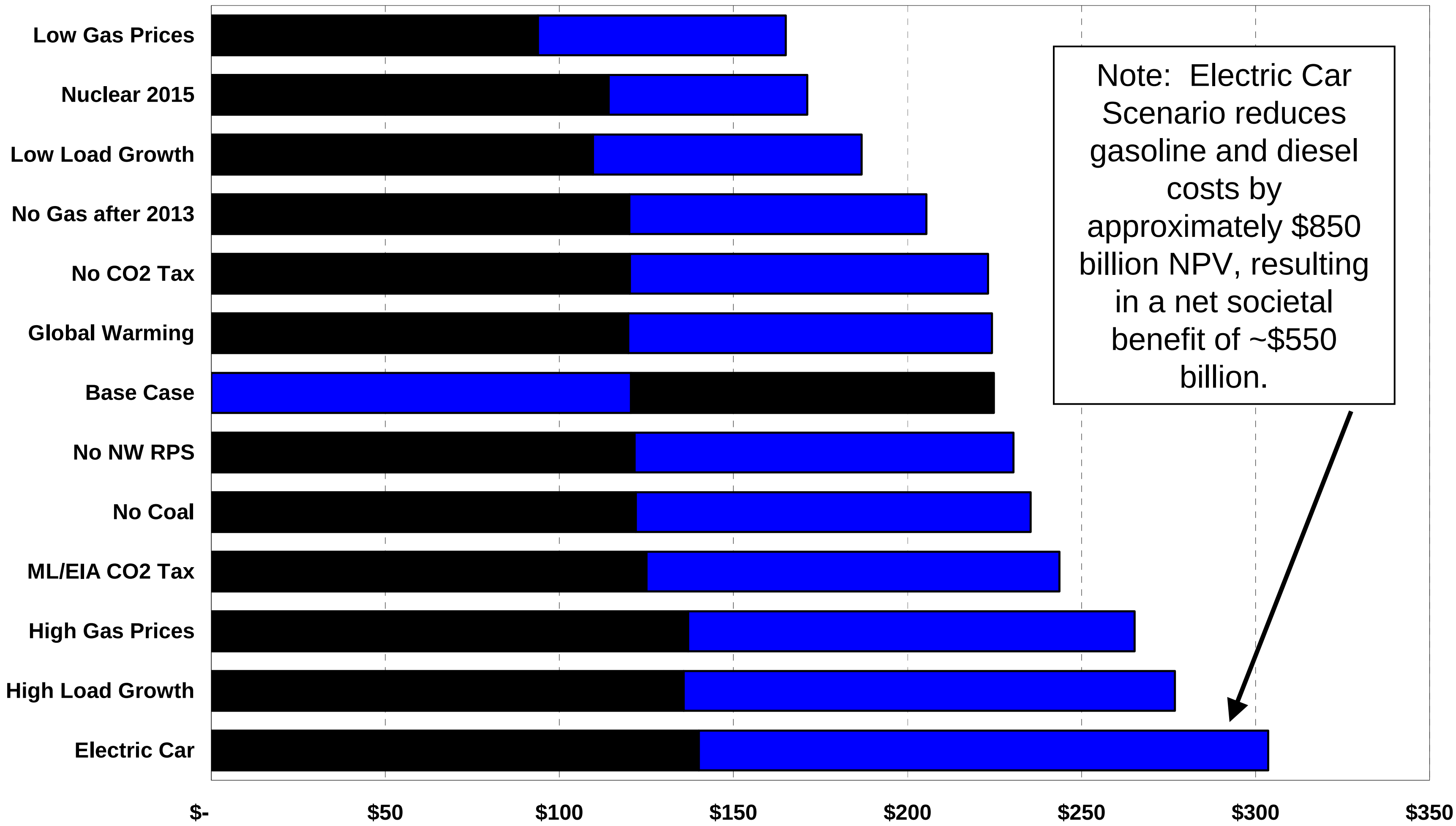


We answer to you.

AVISTA

Western Interconnect Total Fuel Cost in Billions

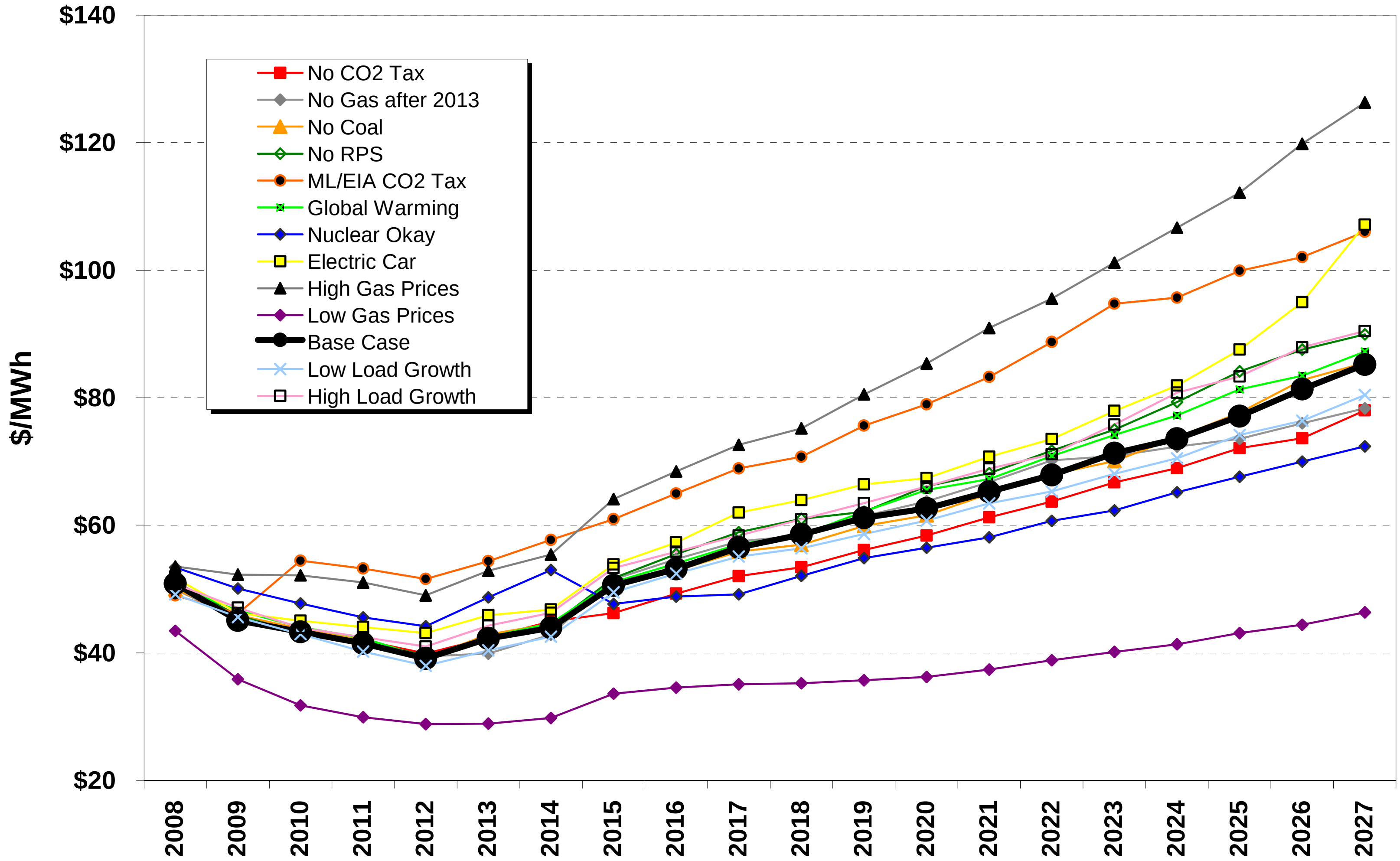
(Does Not Include Emission Taxes)



We answer to you.

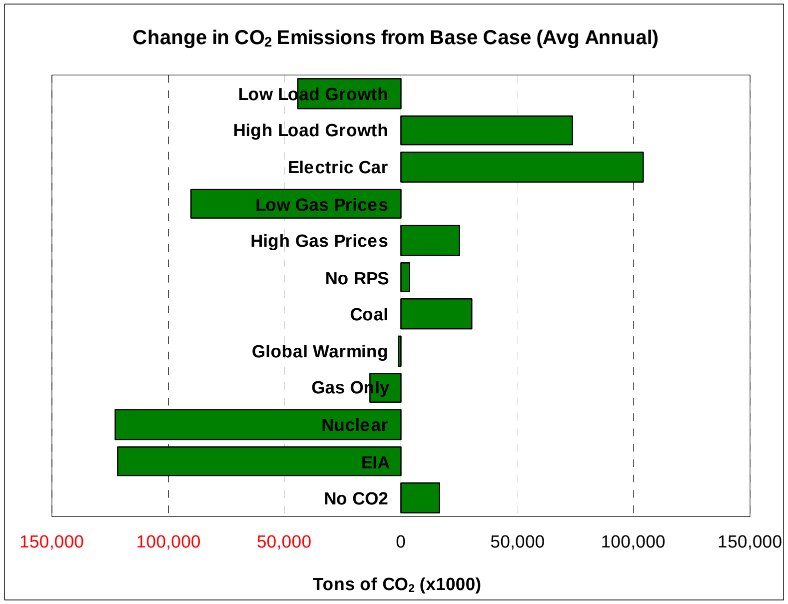
AVISTA

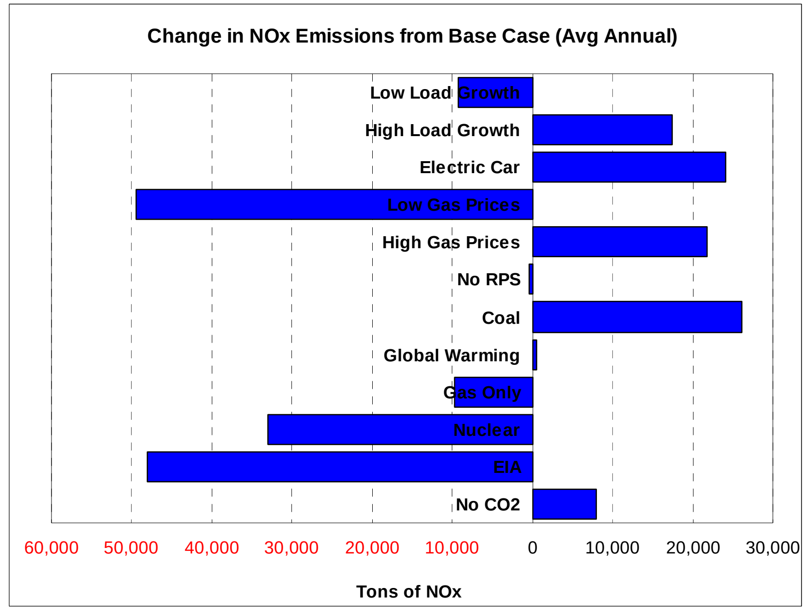
Mid C Electric Prices For All Studies

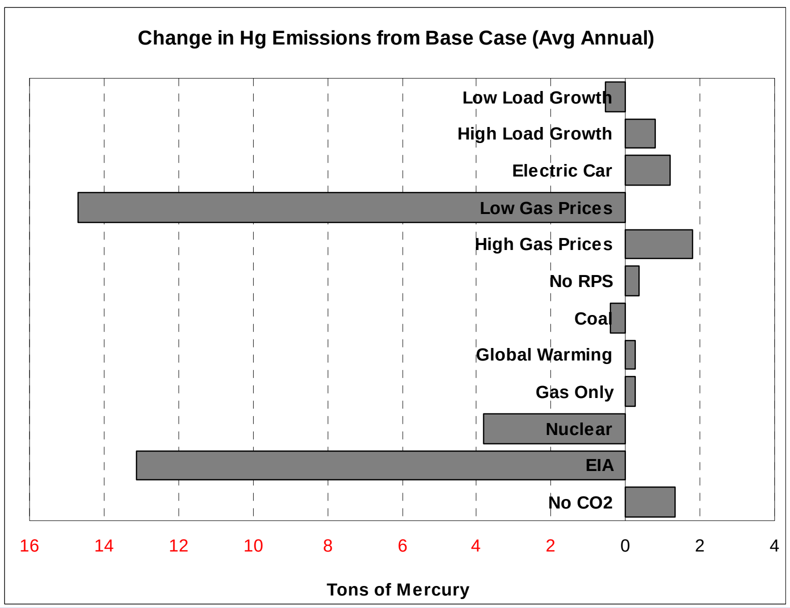


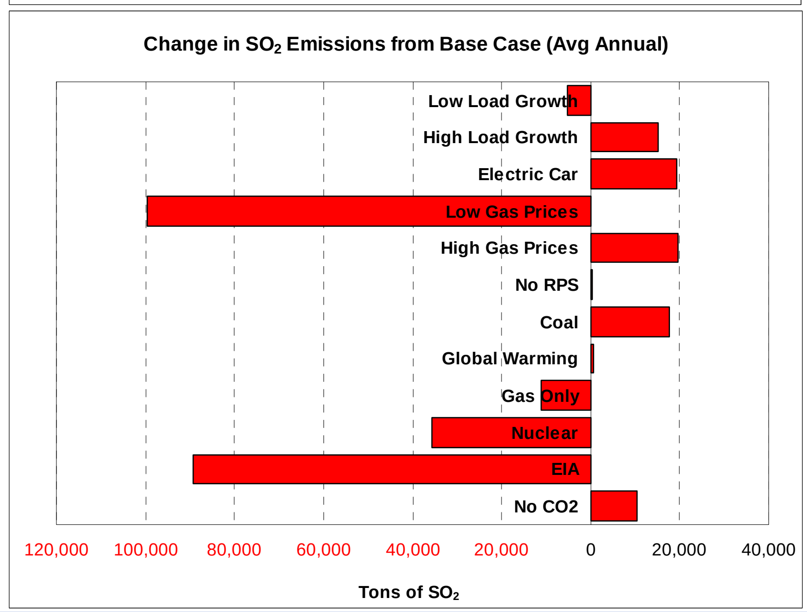
We answer to you.

Electric Car Scenario does not include offsets from reduced gasoline/diesel consumption



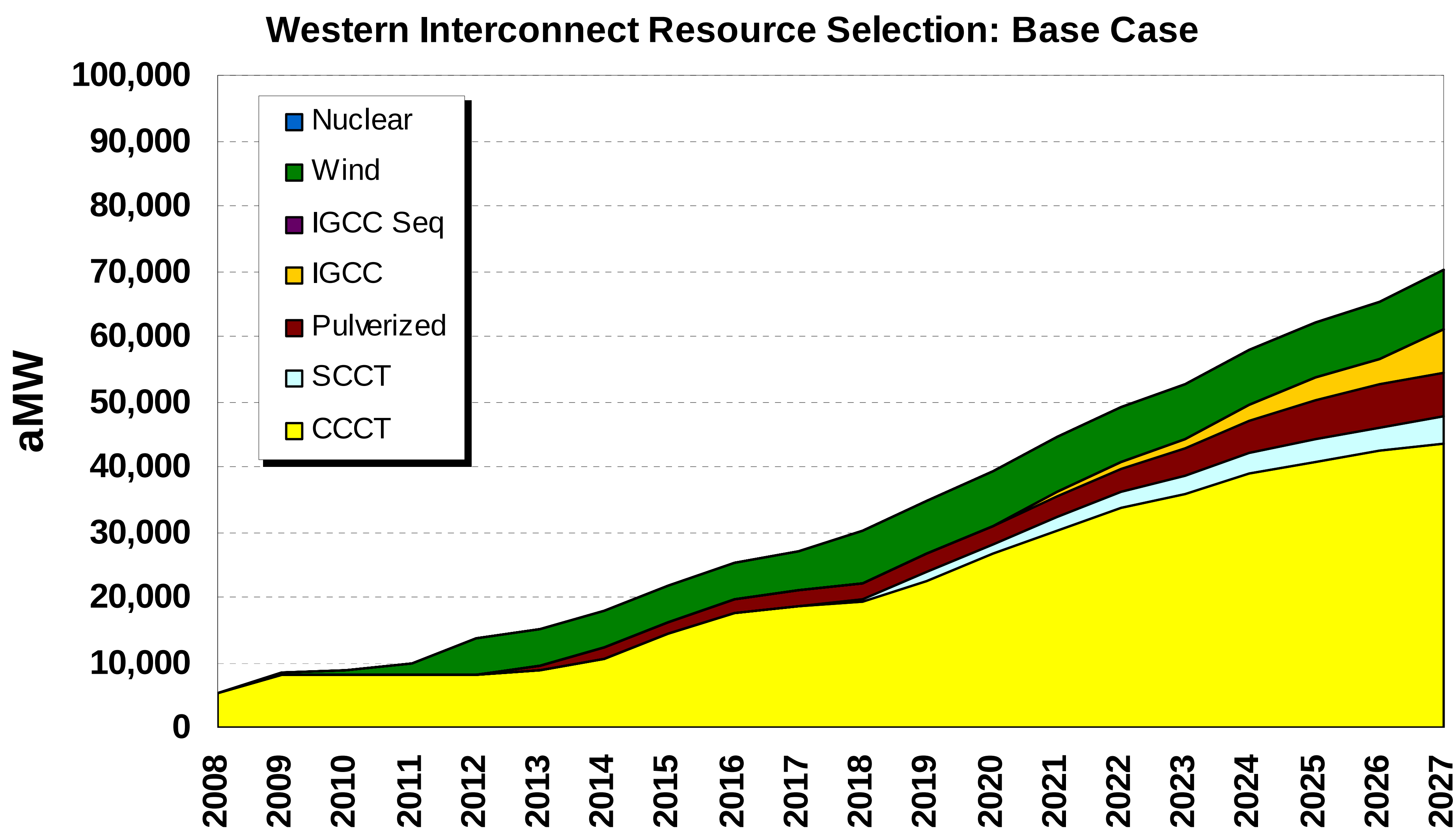






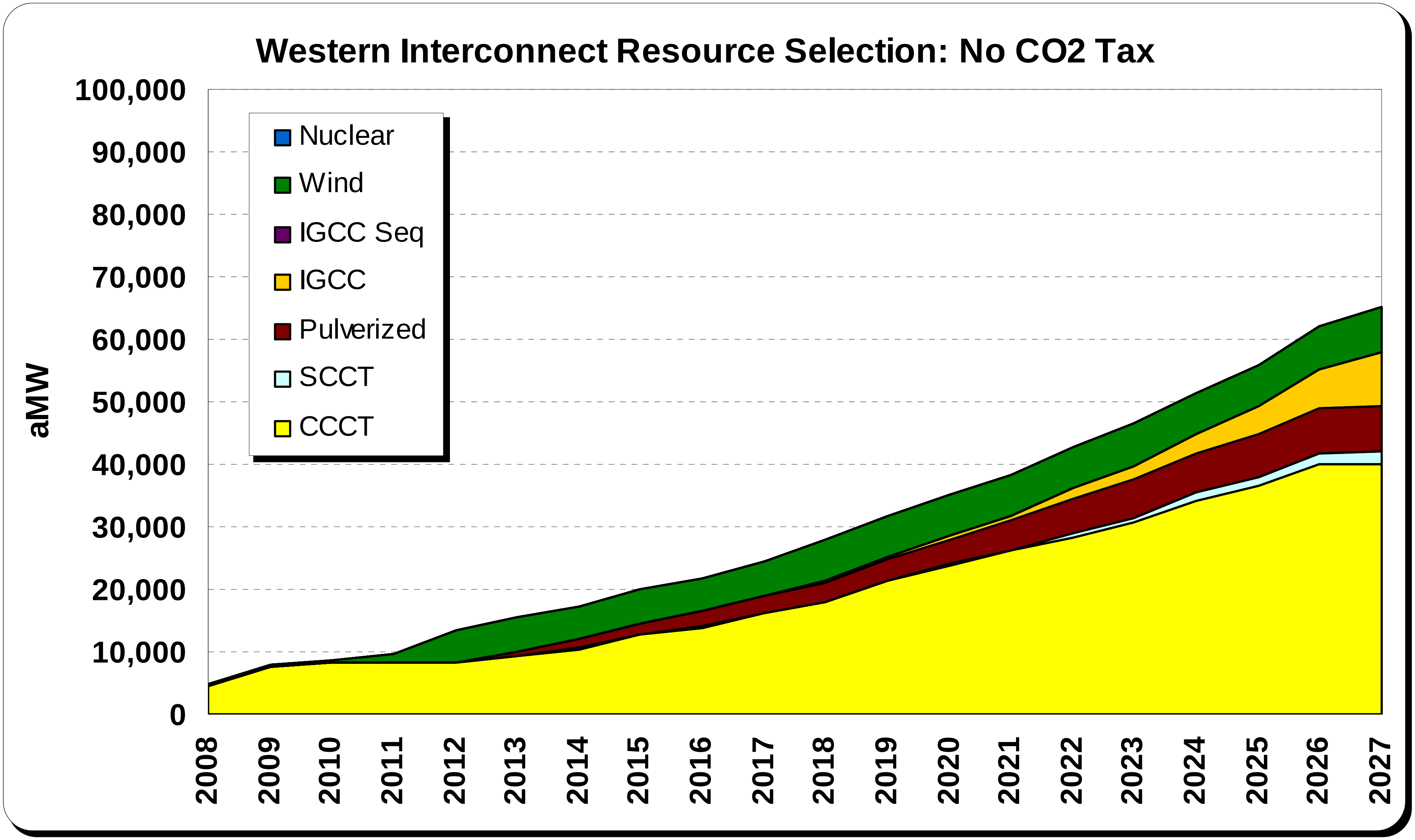
We answer to you.

AVISTA



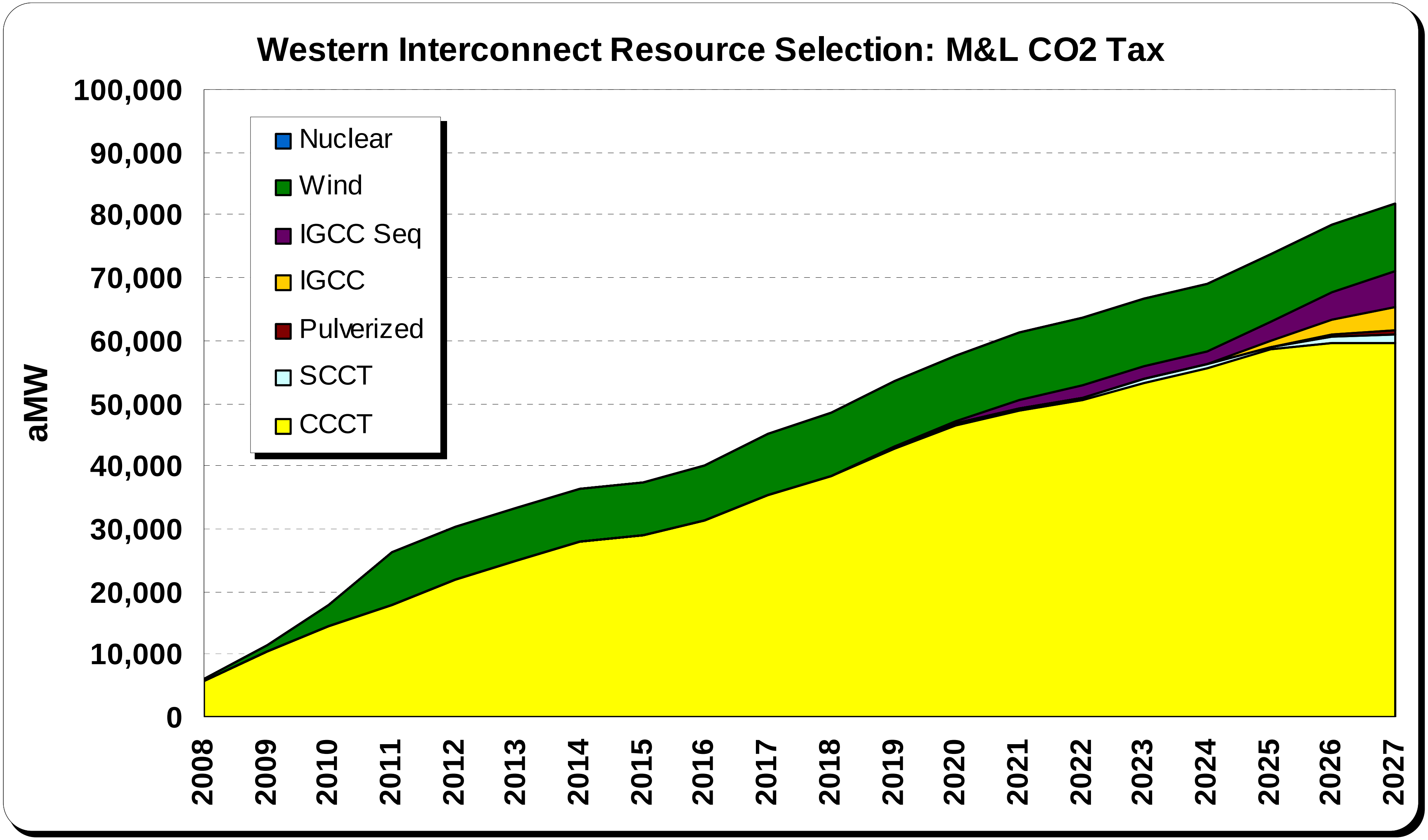
We answer to you.

AVISTA

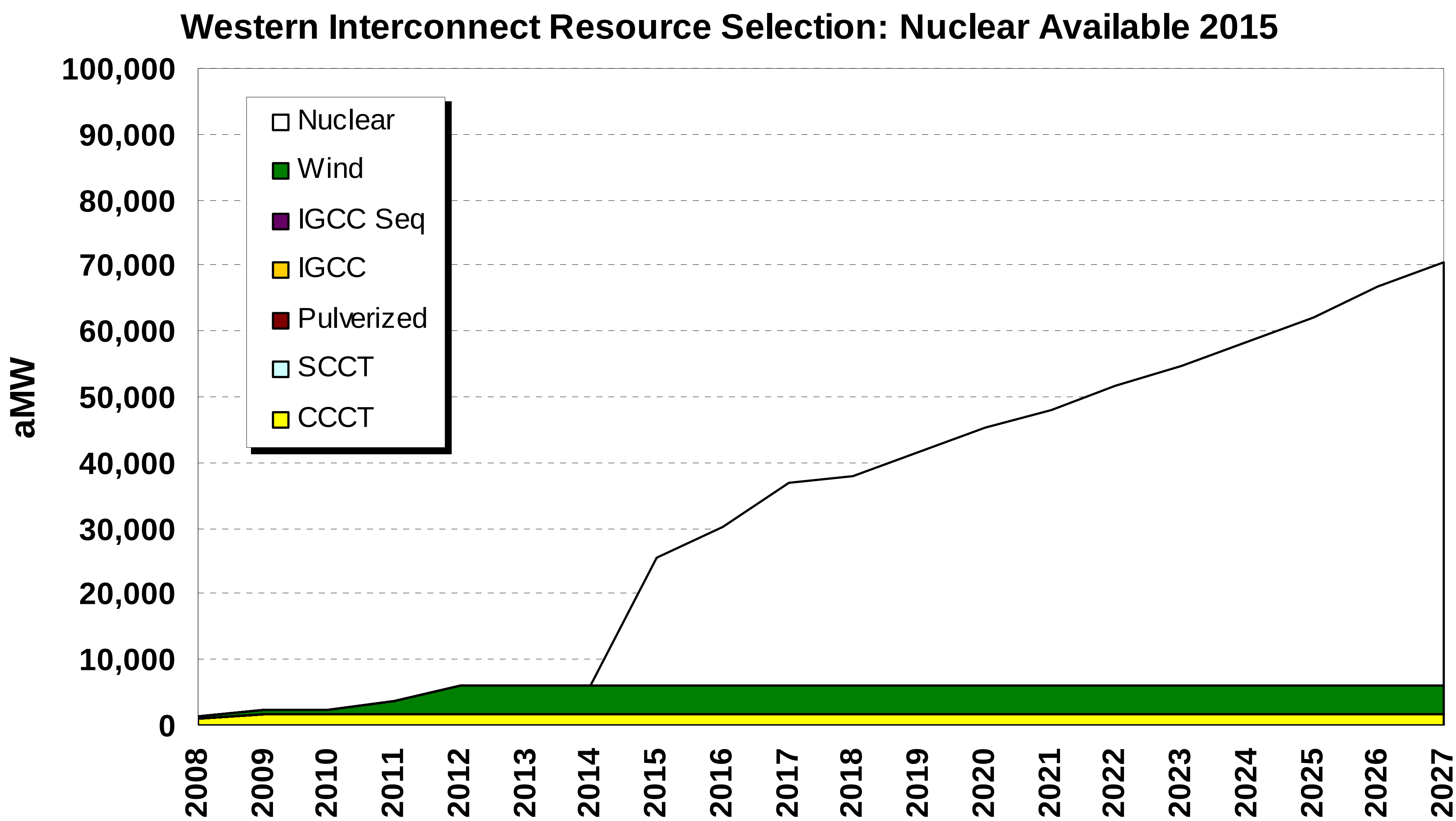


We answer to you.

AVISTA

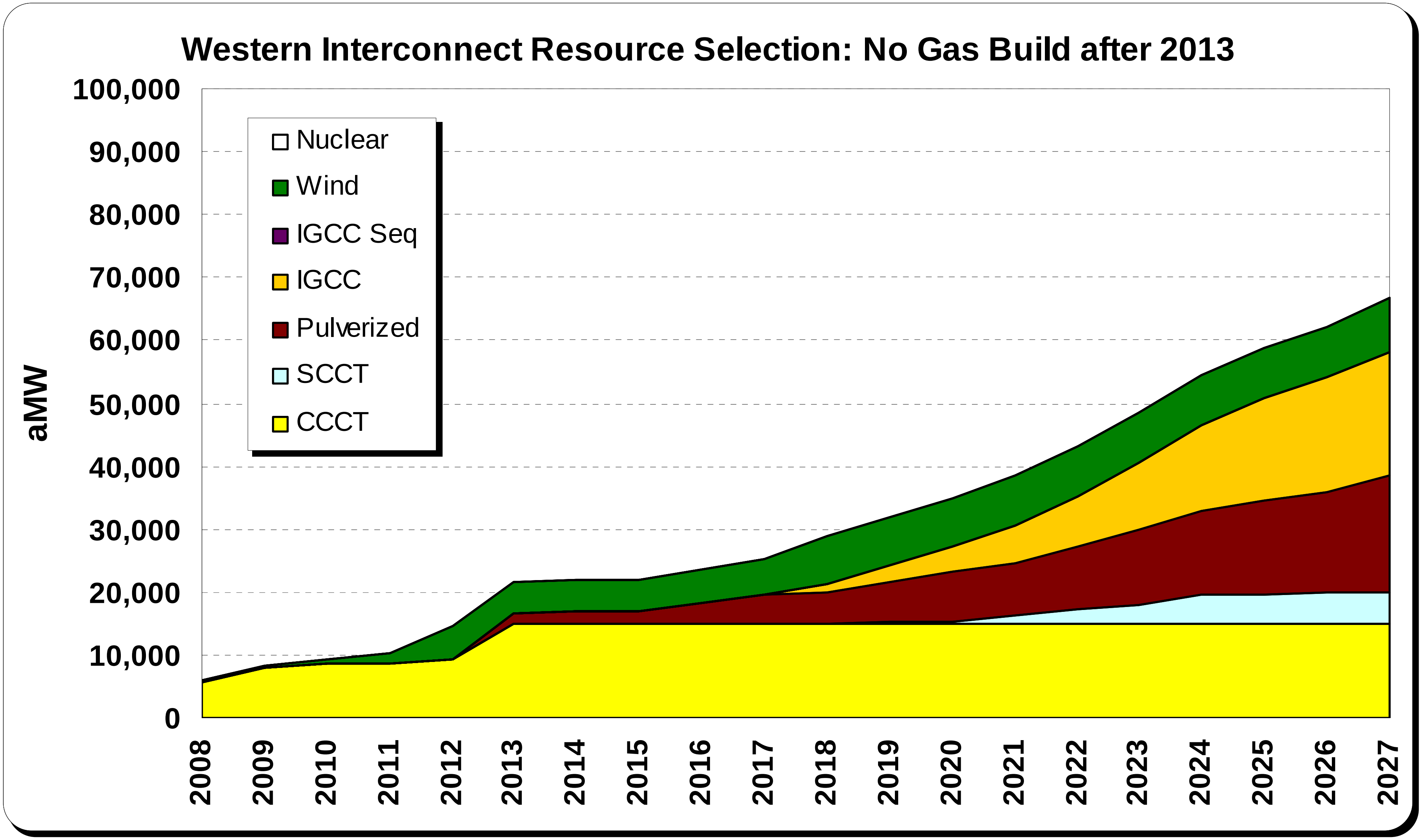


We answer to you.



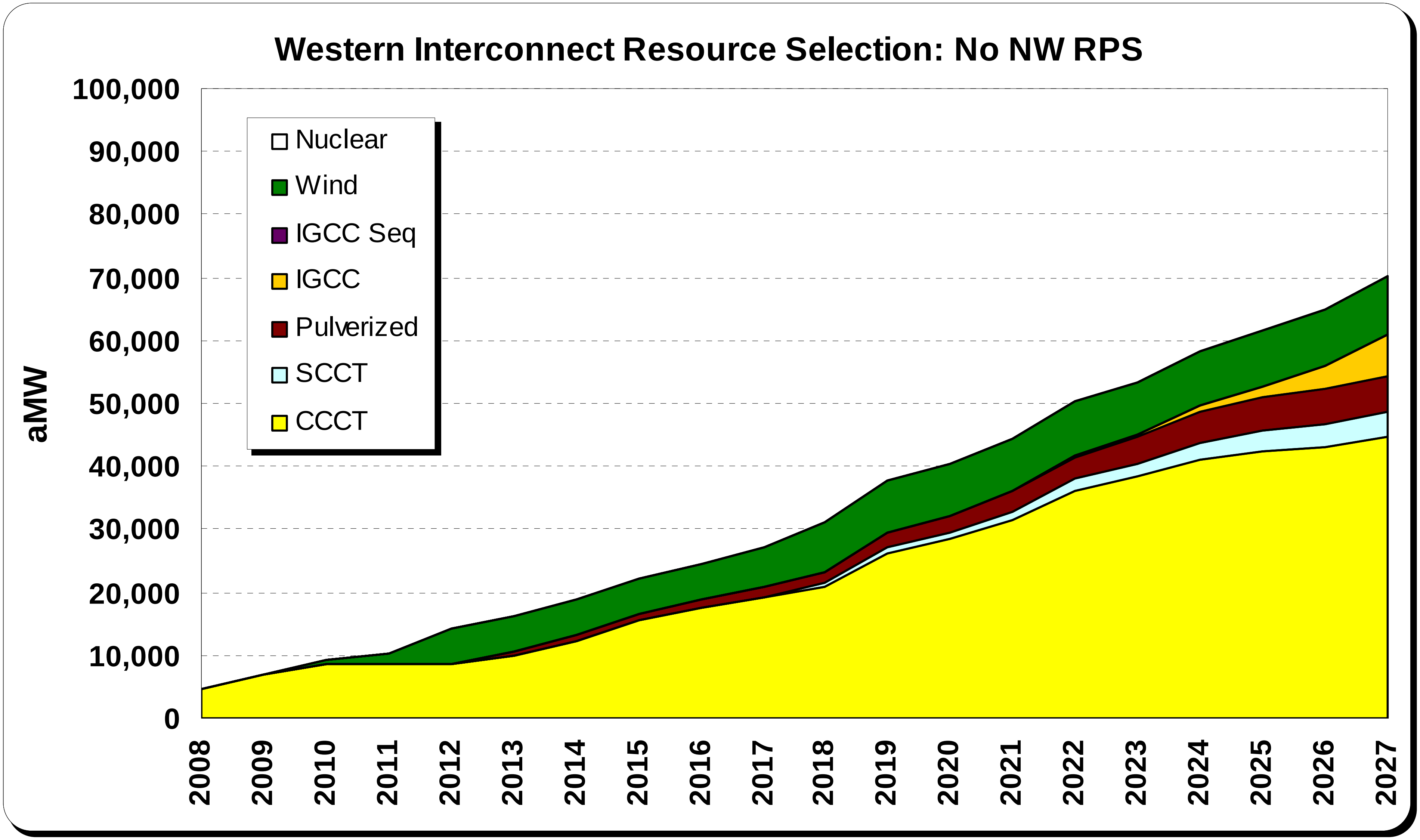
We answer to you.

AVISTA



We answer to you.

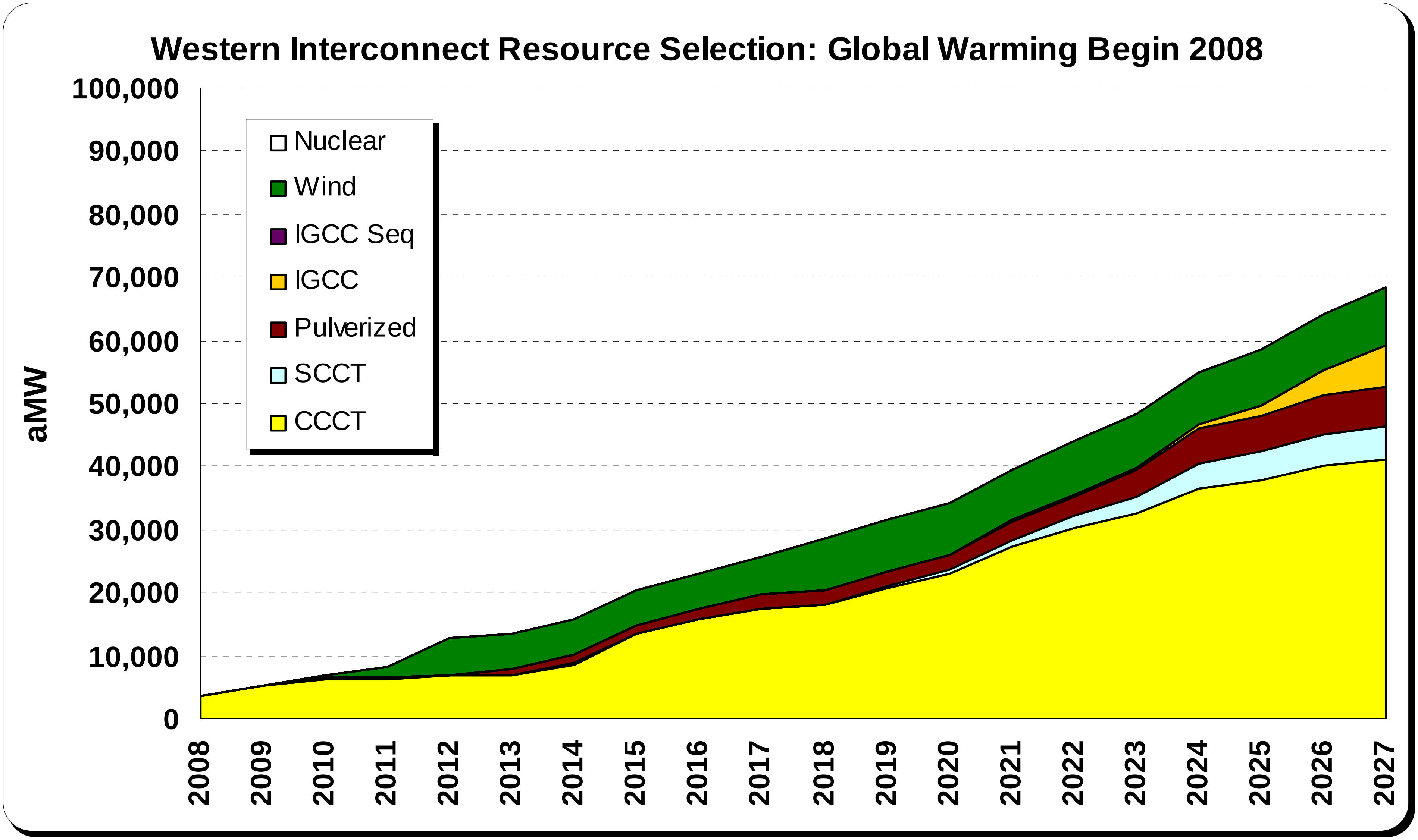
AVISTA

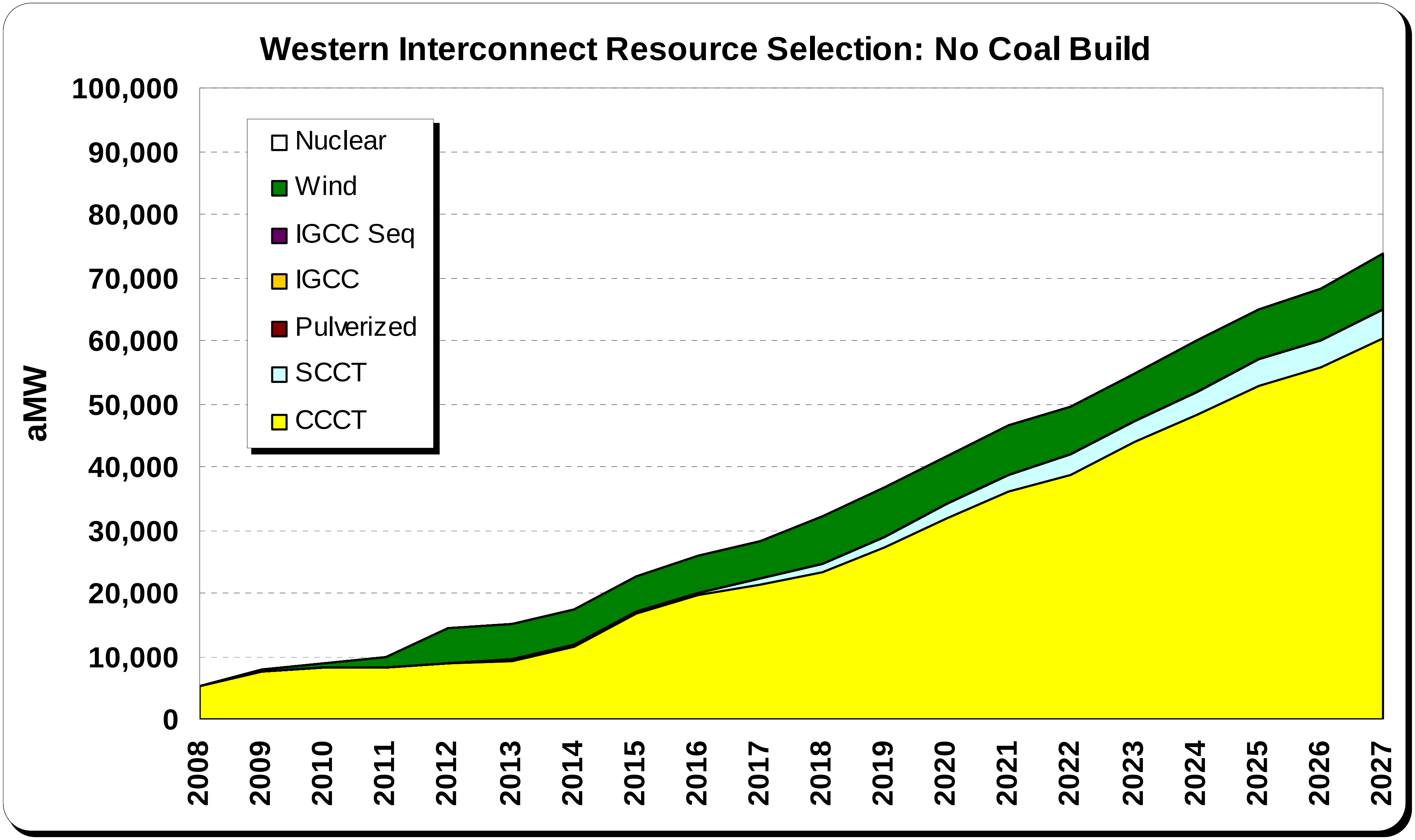


Tuesday, September 05, 2006

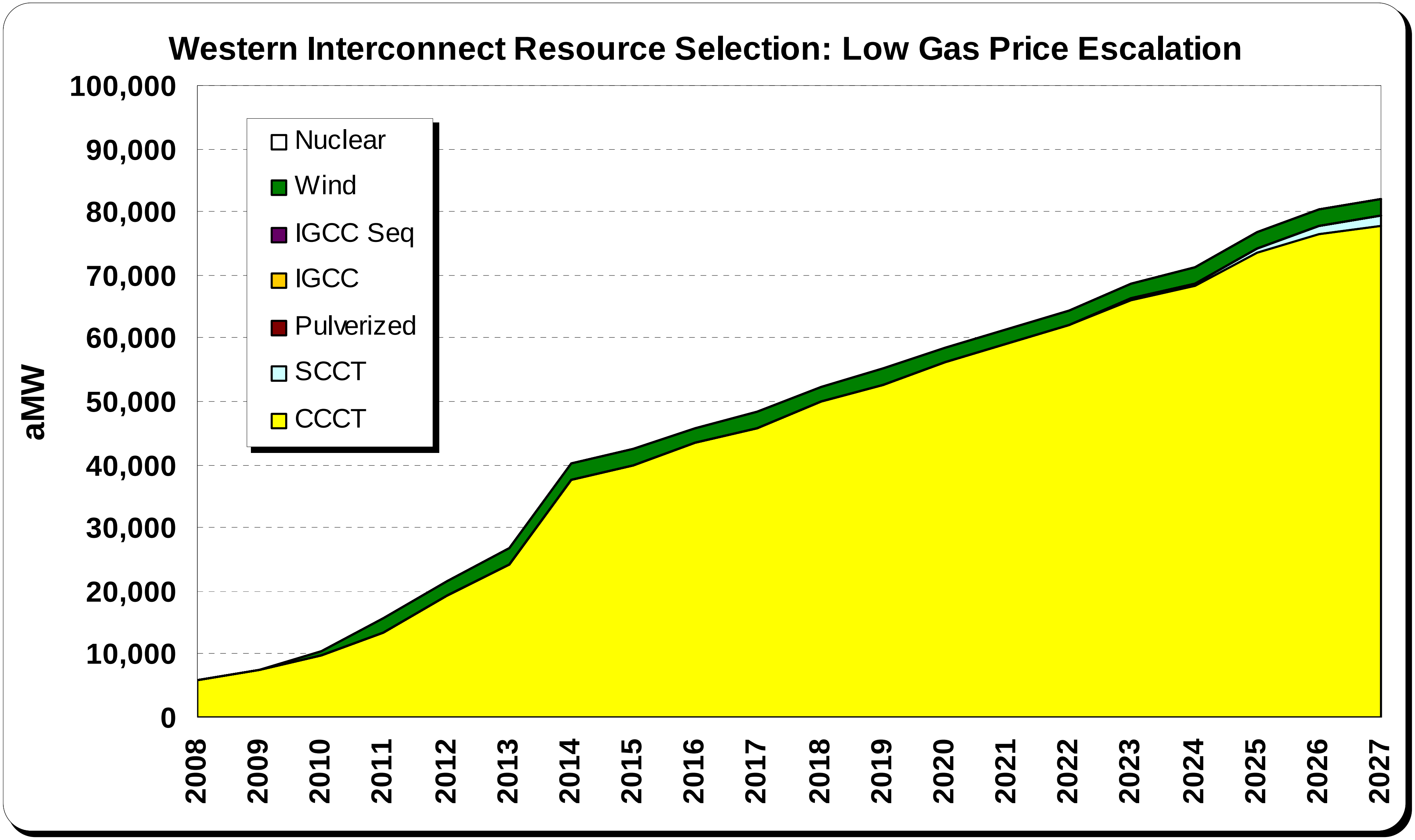
16

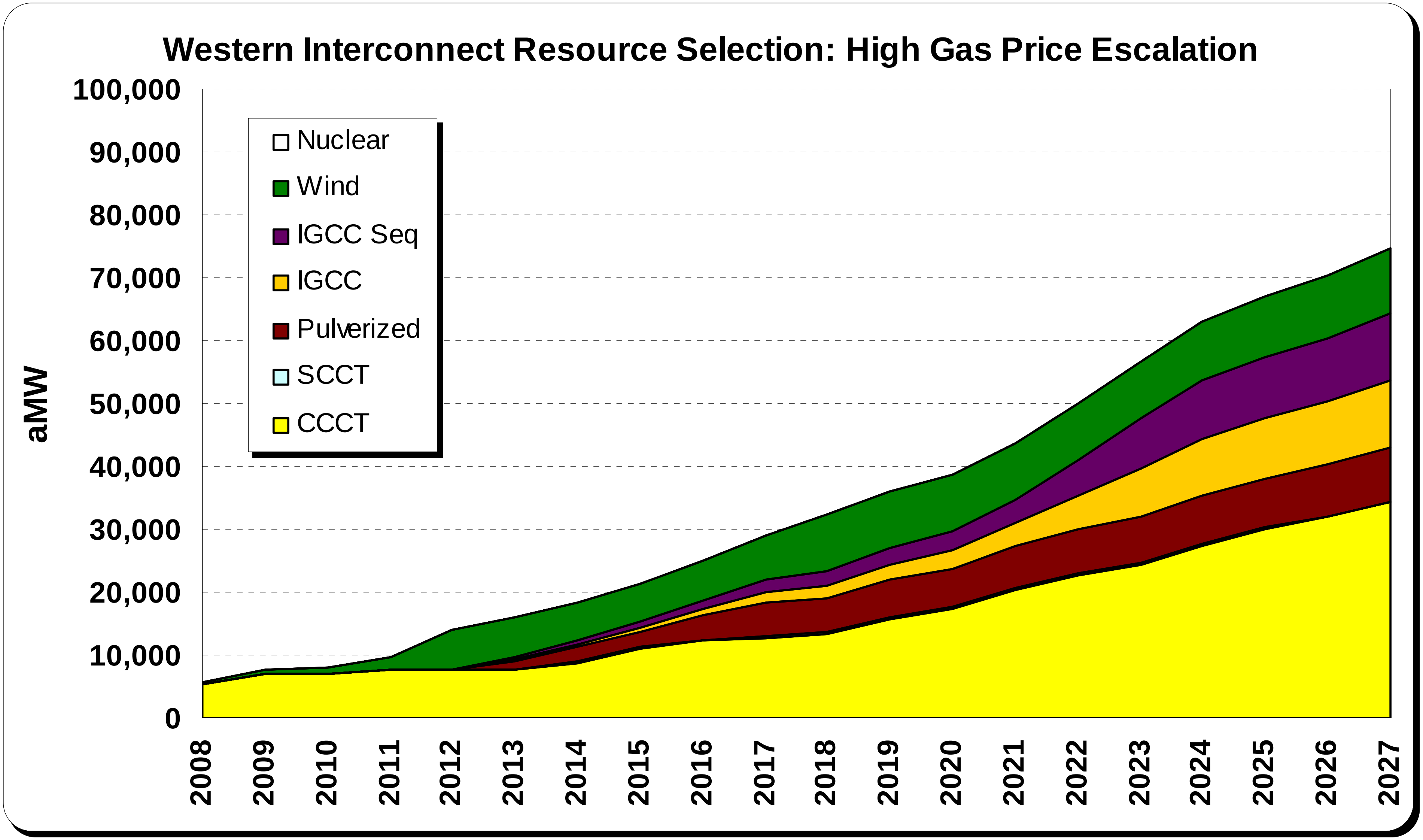
We answer to you.




Western Interconnect Resource Selection: No Coal Build
aMW
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Nuclear
Wind
IGCC Seq
IGCC
Pulverized
SCCT
CCCT
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027

We answer to you.




Western Interconnect Resource Selection: High Gas Price Escalation
aMW
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Nuclear
Wind
IGCC Seq
IGCC
Pulverized
SCCT
CCCT
2008
2009
2010
2011
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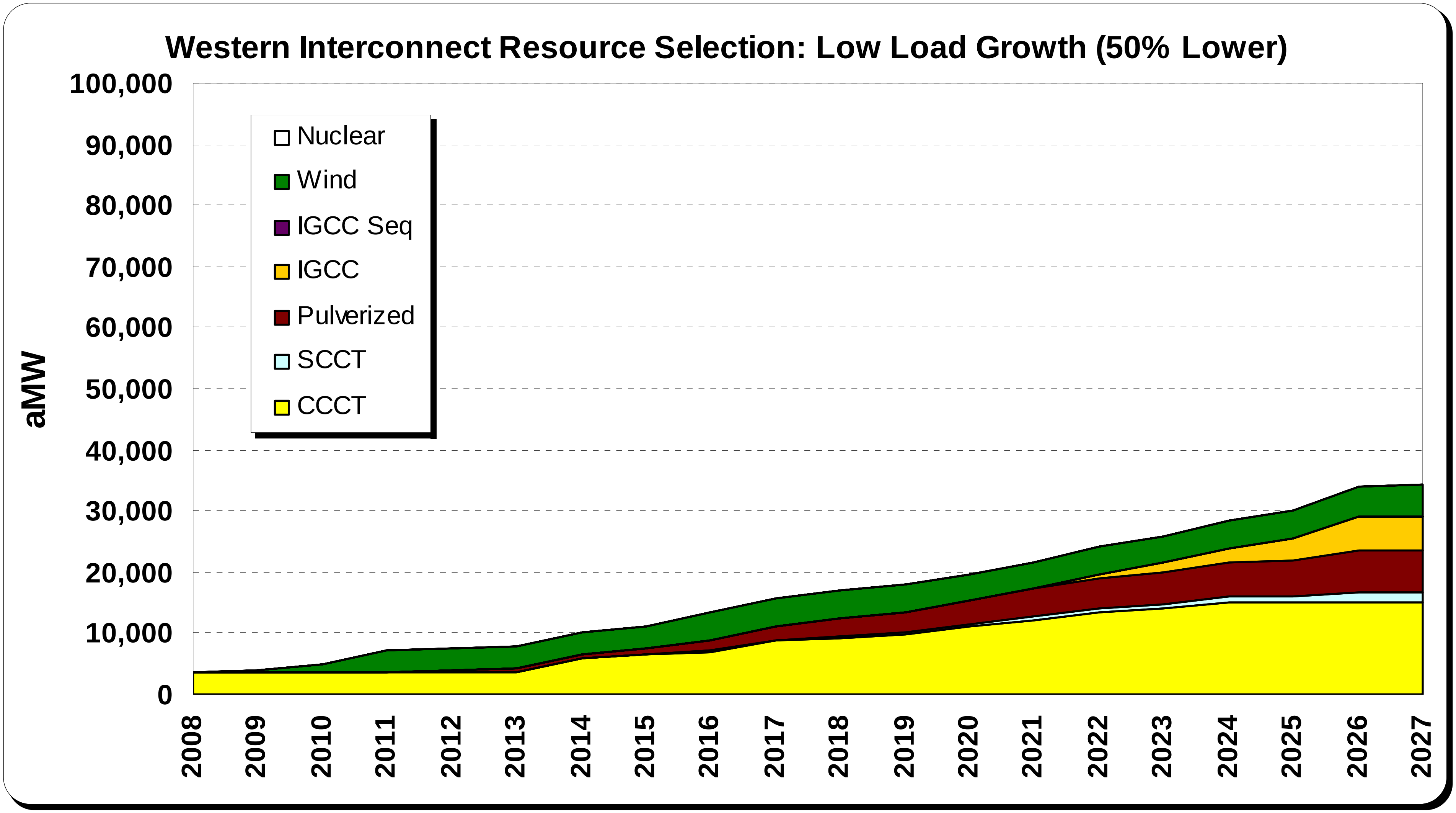
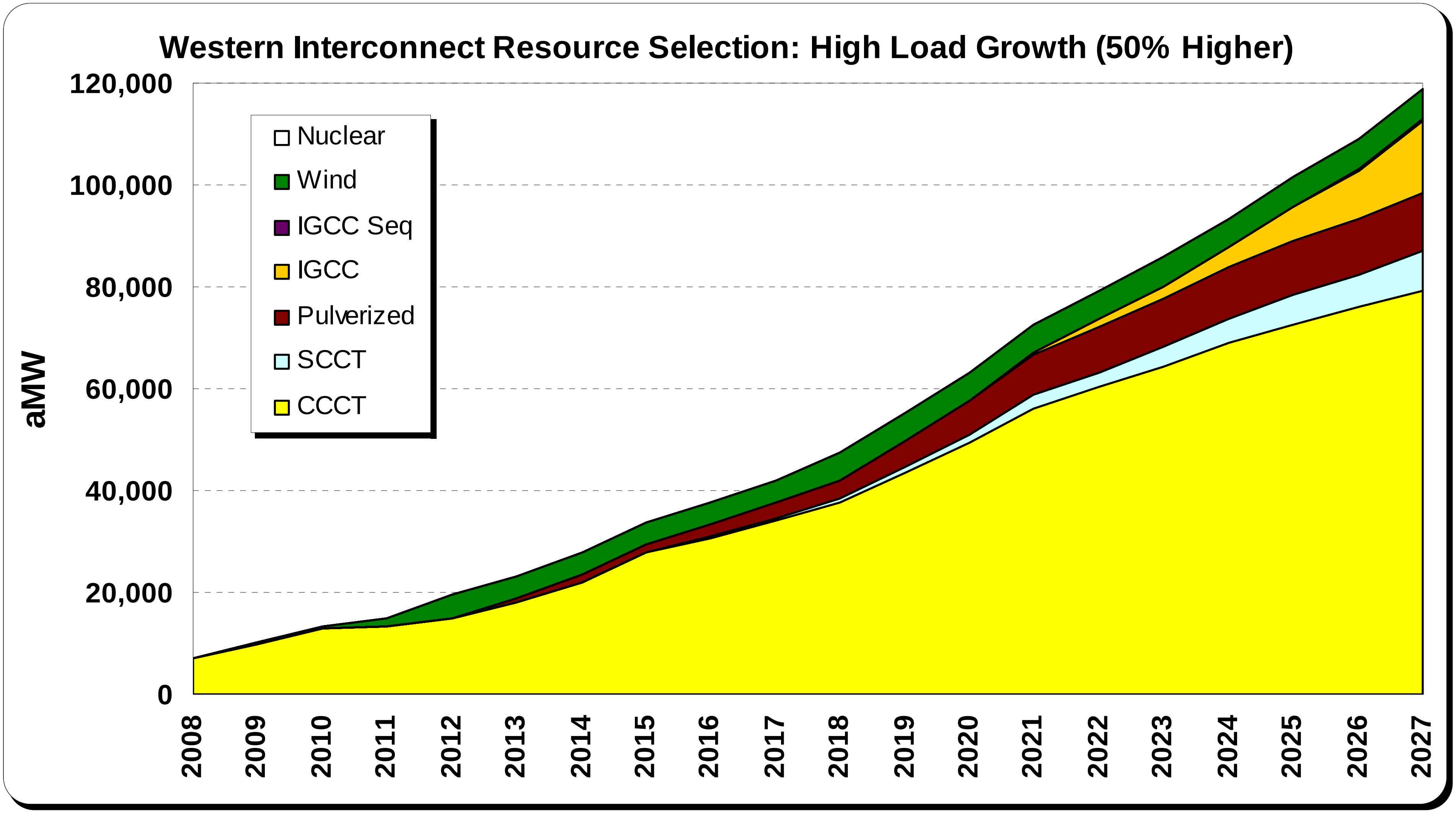
2026
2027

We answer to you.




Western Interconnect Resource Selection: High Load Growth (50% Higher)
aMW
120,000
100,000
80,000
60,000
40,000
20,000
0
Nuclear
Wind
IGCC Seq
IGCC
Pulverized
SCCT
CCCT
2008
2009
2010
2011
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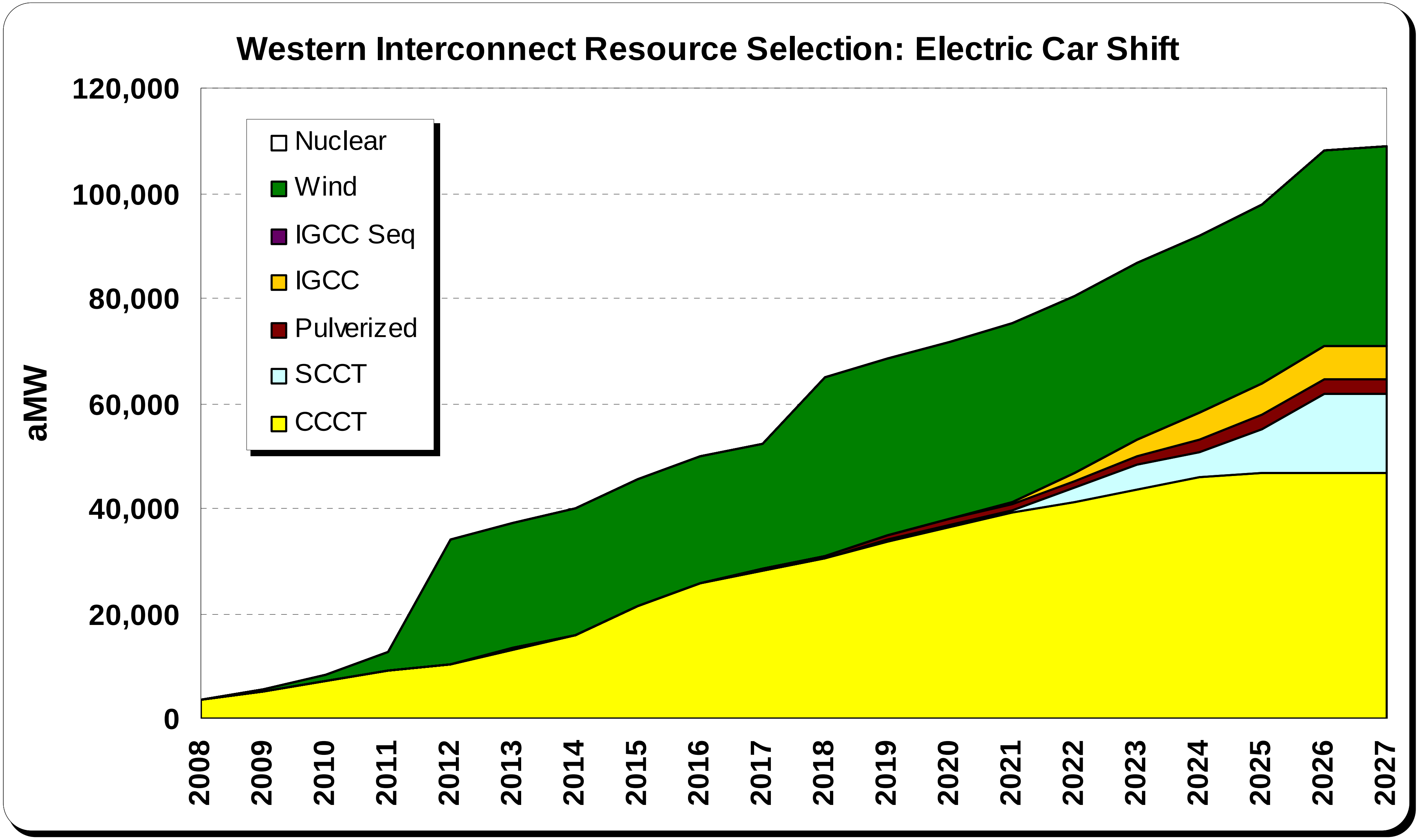
2027

We answer to you.



We answer to you.

AVISTA

Preliminary PRS Discussion

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

James Gall & Clint Kalich

Prior Preferred Resource Strategies

Time Period	Resource Type	2005 IRP	2003 IRP
2007-2016	Coal	215	325
	Wind	122	30
	Gas	0	200
	Other Renewables	57	0
	Conservation and Plant Upgrades	69	46
2007-2026	Coal	474	775
	Wind	188	30
	Gas	0	200
	Other Renewables	137	0
	Conservation and Plant Upgrades	138	92

We answer to you.

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

We answer to you.

Constraints

Resource

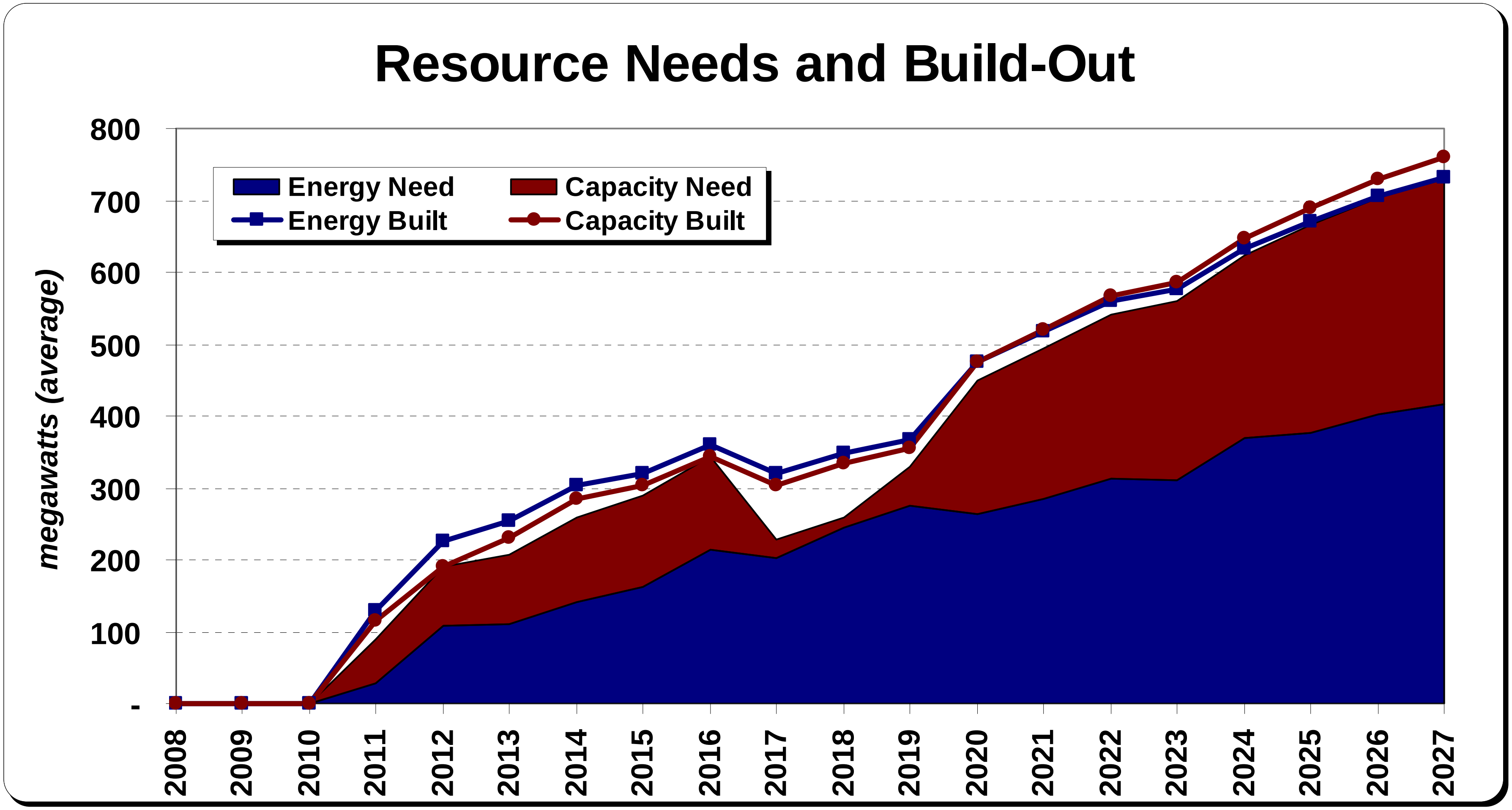
- Coal
  - Available after 2013
  - no NW pulverized
- Alberta Oil Sands
  - Available after 2013-no minimum constraint
- Wind
  - Columbia Basin: 200MW Tier 1, 100 MW Tier 2
  - Montana: No Constraints
  - Avista Service Territory Area: 200MW Tier 1, 200 MW Tier 2
  - 100MW limitation per year, 650 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

We answer to you.

AVISTA



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

We answer to you.

Prior Preferred Resource Strategies (Energy)

Time Period	Resource Type	2007 "Draft" IRP	2005 IRP	2003 IRP
2007-2017	Coal	55	215	325
	Wind (nameplate)	300*	400	75
	Gas	110	0	200
	Other Renewables	73	57	0
	Conservation and Plant Upgrades	69	69	46
	Nuclear & Alberta Oil Sands	16	0	0
2007-2027	Coal	55	474	775
	Wind (nameplate)	300*	650	75
	Gas	110	0	200
	Other Renewables	145	137	0
	Conservation and Plant Upgrades	138	138	92
	Nuclear & Alberta Oil Sands	356	0	0

* Includes 100MW of RFP Wind

We answer to you.

Preliminary Avista Resource Selection (Nameplate MW)

Year	Coal	CCCT	Wind	Oil Sands	Other Renewables	Nuclear
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0
2010	0	0	0	0	0	0
2011	0	57	100	0	50	0
2012	0	7	100	0	10	0
2013	66	16	0	0	10	0
2014	0	44	0	0	10	0
2015	0	0	0	20	0	0
2016	0	0	0	0	0	0
2017	0	0	0	0	0	0
2018	0	0	0	25	10	0
2019	0	0	0	13	10	0
2020	0	0	0	124	10	0
2021	0	0	0	40	10	0
2022	0	0	0	42	10	0
2023	0	0	0	10	10	0
2024	0	0	0	48	20	0
2025	0	0	0	0	0	43
2026	0	0	0	0	0	40
2027	0	0	0	0	0	31

We answer to you.

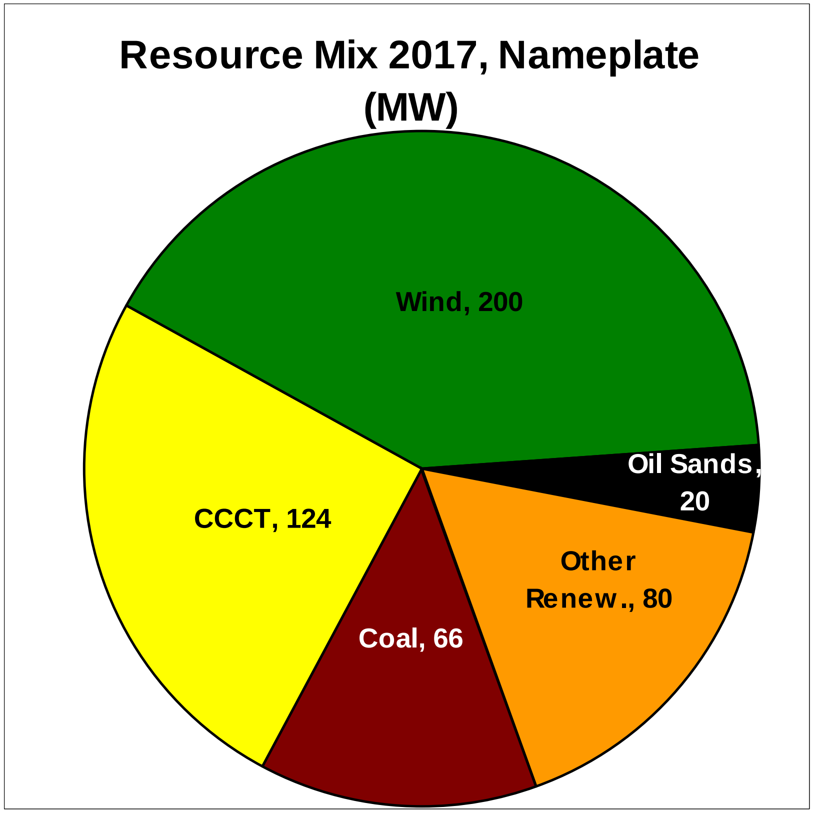
Base Case: PRS Model Details

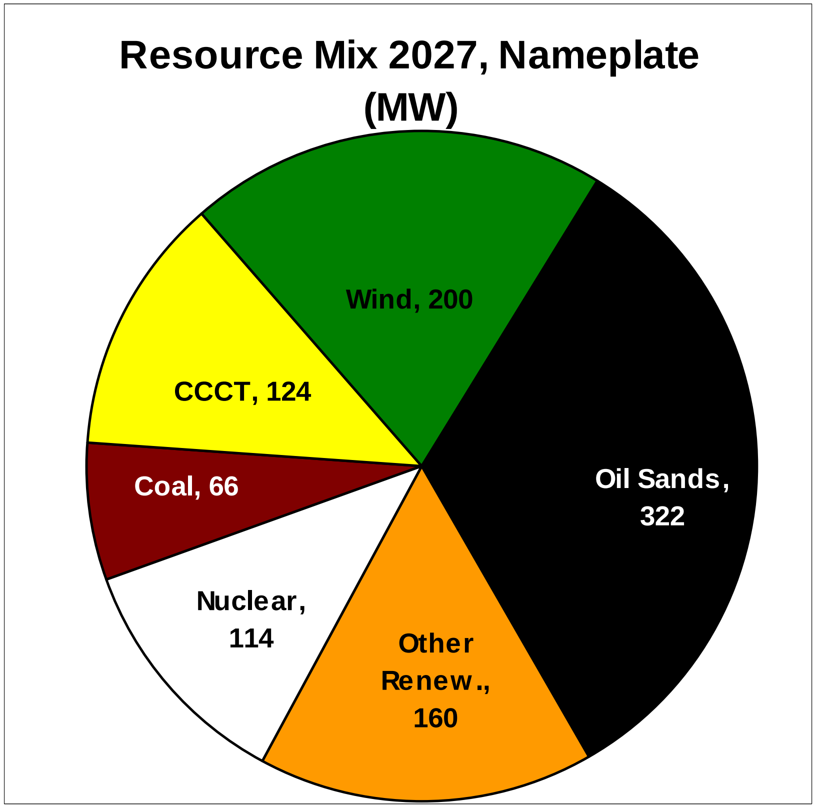
Summary Stats for Scenario

Line	Values	100/0	90/10	75/25	50/50	25/75	10/90	0/100
1	NPV 17	1,563.8	1,576.2	1,576.7	1,765.7	1,920.7	1,920.7	2,015.9
2	NPV 27	3,509.4	3,552.8	3,639.1	3,844.5	4,246.2	4,246.2	4,463.6
3	Cost 2017	383.3	385.7	385.8	408.9	447.6	447.6	482.8
4	Cost 2027	803.5	810.1	820.0	771.4	800.9	800.9	831.1
5	St. Deviation 2017	72.1	62.9	62.9	53.1	47.6	47.6	47.2
6	St. Deviation 2027	151.7	126.7	92.3	78.2	62.9	62.9	62.7
7	Capital Cost 2017	311.8	388.6	388.6	1,091.2	1,587.4	1,587.4	1,838.4
8	Capital Cost 2027	284.8	842.2	1,869.4	1,821.4	2,451.0	2,451.0	2,461.5
9	Rate AARG 2017	5.0%	5.1%	5.1%	5.5%	6.2%	6.2%	6.7%
10	Rate AARG 2027	4.5%	4.5%	4.6%	4.3%	4.5%	4.5%	4.6%
11	Rate Max Year	9.9%	10.9%	9.7%	15.8%	18.0%	18.0%	18.0%
12	2017 95th% Diff	130.2	114.6	114.6	95.8	90.1	90.1	89.0
13	Coal Cap 17	0.0	0.0	0.0	64.5	133.3	133.3	133.3
14	CCCT Cap 17	0.0	254.7	254.7	121.7	43.8	43.8	43.8
15	CT Cap 17	254.7	0.0	0.0	0.0	0.0	0.0	0.0
16	Wind Cap 17	0.0	0.0	0.0	19.6	28.8	28.8	28.8
17	OtherRenew Cap 17	39.2	39.2	39.2	78.4	78.5	78.5	78.5
18	Other Cap 17	0.0	0.0	0.0	18.1	18.1	18.1	18.1
19	Coal Cap 27	0.0	0.0	0.0	64.5	133.3	133.3	133.3
20	CCCT Cap 27	0.0	254.7	254.7	121.7	43.8	43.8	43.8
21	CT Cap 27	695.5	290.0	0.0	0.0	0.0	0.0	0.0
22	Wind Cap 27	0.0	0.0	0.0	19.6	52.8	52.8	52.8
23	OtherRenew Cap 27	39.2	78.5	117.7	156.9	157.0	157.0	157.0
24	Other Cap 27	0.0	111.6	387.3	396.9	372.9	372.9	372.9

We answer to you.

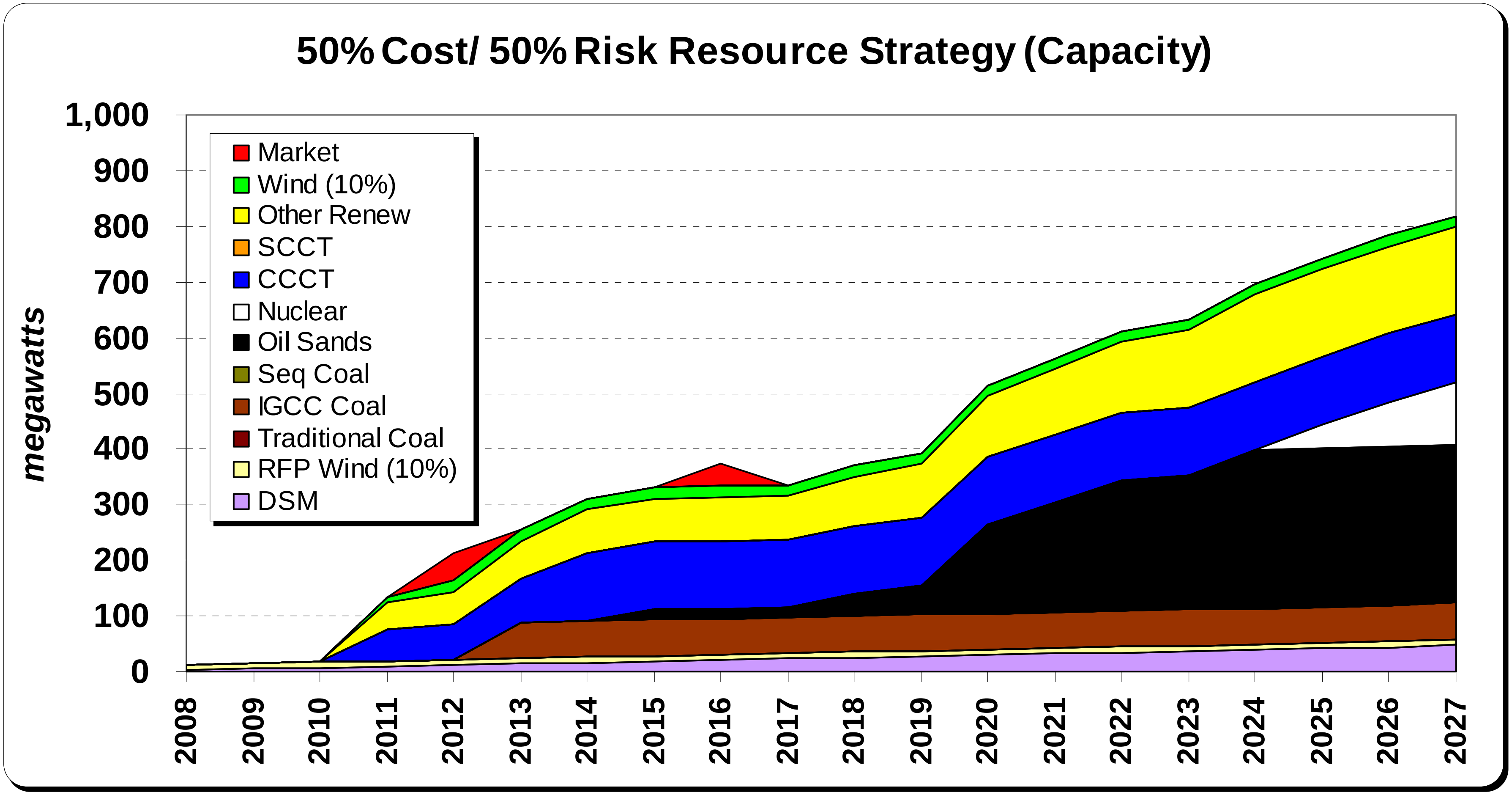
New Resource Mix (2017 & 2027)



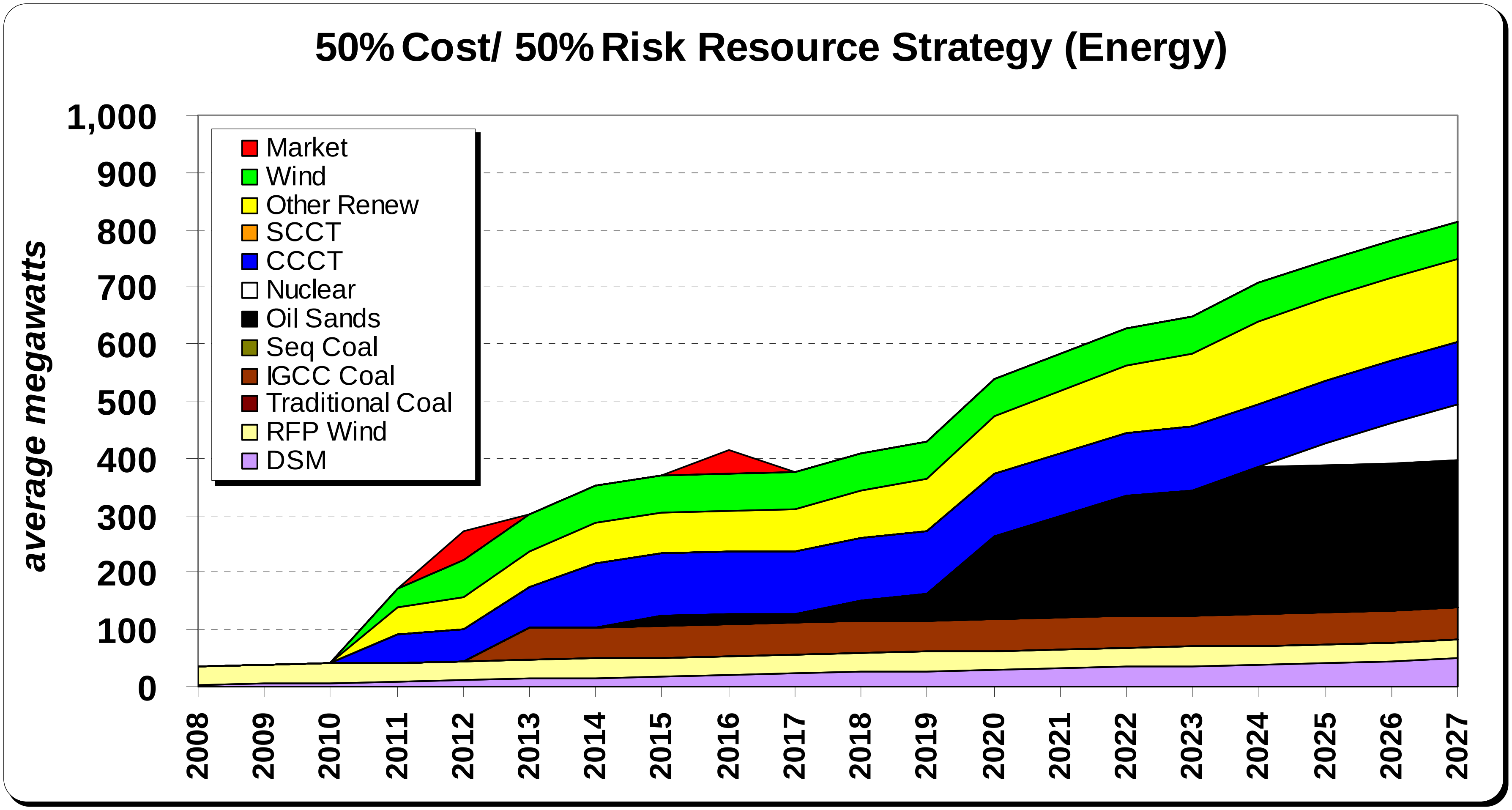


We answer to you.

AVISTA



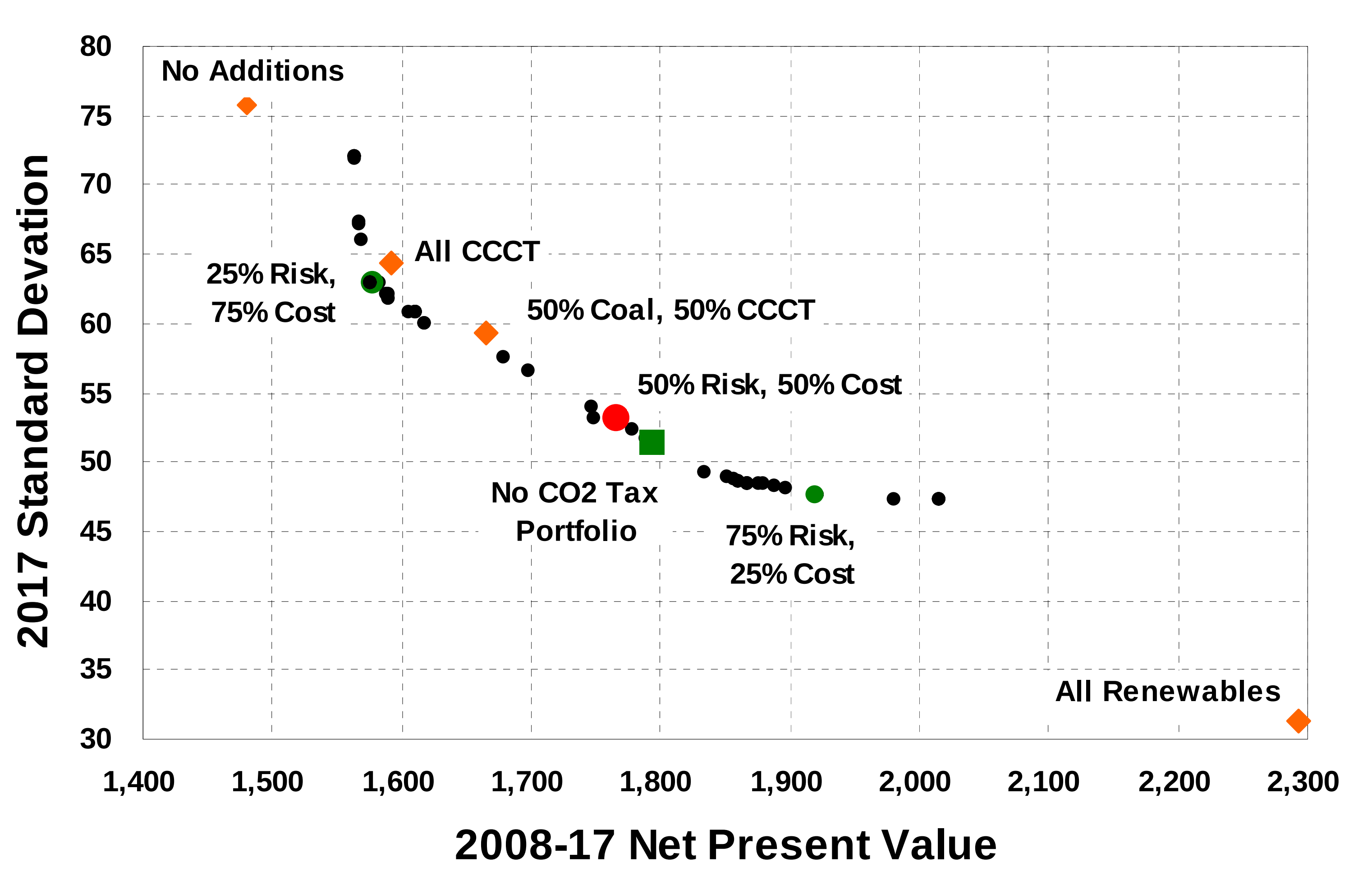
We answer to you.

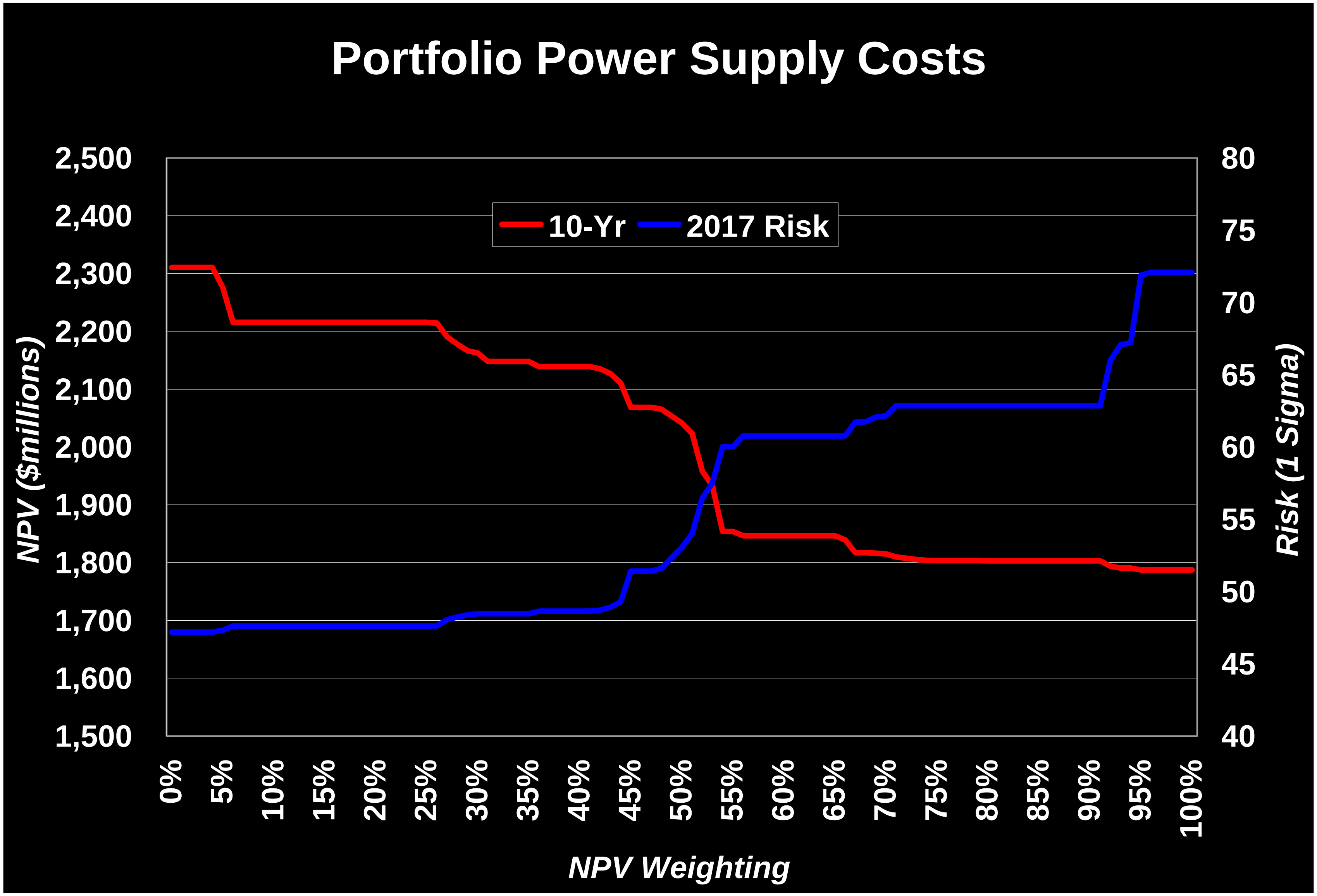


We answer to you.

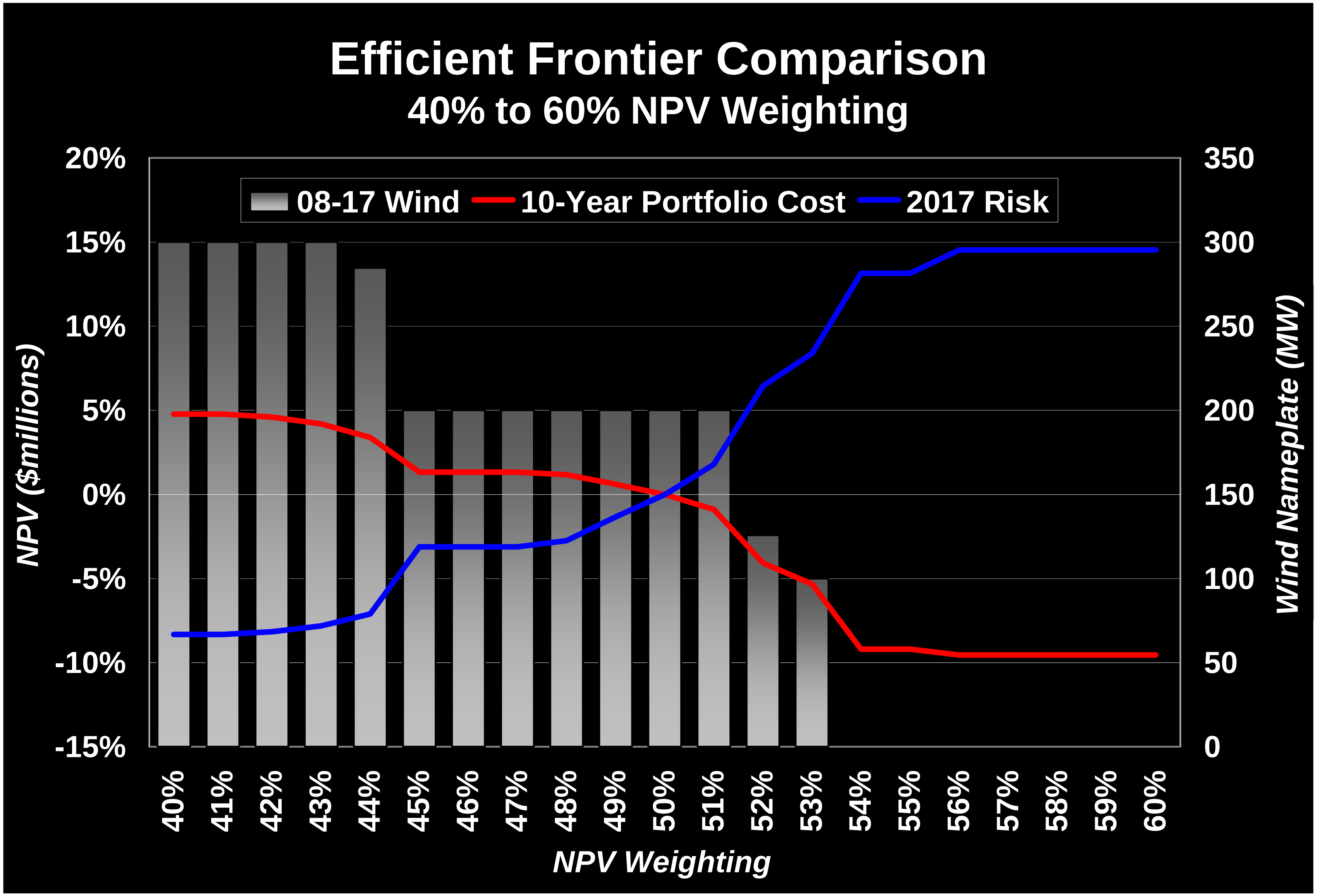
AVISTA

Efficient Frontier




Portfolio Power Supply Costs
10-Yr
2017 Risk
NPV ($millions)
Risk (1 Sigma)
NPV Weighting
2,500
2,400
2,300
2,200
2,100
2,000
1,900
1,800
1,700
1,600
1,500
80
75
70
65
60
55
50
45
40
0%
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
100%

We answer to you.



We answer to you.

No CO2 Taxation: PRS Model Details

Line	Values	Summary Stats for Scenario						
		100/0	90/10	75/25	50/50	25/75	10/90	0/100
1	NPV 17	1,507.3	1,523.1	1,528.6	1,736.8	1,868.6	1,868.6	1,961.1
2	NPV 27	3,305.1	3,335.9	3,413.2	3,665.7	4,054.7	4,054.7	4,239.8
3	Cost 2017	348.0	350.1	349.6	382.1	414.0	414.0	447.5
4	Cost 2027	738.4	746.0	749.9	713.8	757.6	757.6	778.0
5	St. Deviation 2017	70.3	58.9	58.9	46.9	42.9	42.9	42.3
6	St. Deviation 2027	155.6	136.9	94.3	70.2	56.6	56.6	56.2
7	Capital Cost 2017	208.0	388.6	387.2	1,208.7	1,587.4	1,587.4	1,838.4
8	Capital Cost 2027	284.8	355.0	1,583.8	1,773.8	2,423.8	2,423.8	2,423.8
9	Rate AARG 2017	4.4%	4.4%	4.4%	5.0%	5.6%	5.6%	6.2%
10	Rate AARG 2027	4.1%	4.2%	4.2%	4.0%	4.2%	4.2%	4.4%
11	Rate Max Year	6.5%	6.6%	8.8%	15.8%	18.0%	18.0%	18.0%
12	2017 95th% Diff	115.7	100.0	100.0	81.3	73.6	73.6	72.8
13	Coal Cap 17	0.0	0.0	0.0	141.3	133.3	133.3	133.3
14	CCCT Cap 17	0.0	254.7	254.7	63.0	43.8	43.8	43.8
15	CT Cap 17	284.1	0.0	0.0	0.0	0.0	0.0	0.0
16	Wind Cap 17	0.0	0.0	0.0	19.6	28.8	28.8	28.8
17	OtherRenew Cap 17	9.8	39.2	39.2	78.4	78.5	78.5	78.5
18	Other Cap 17	0.0	0.0	0.0	0.0	18.1	18.1	18.1
19	Coal Cap 27	0.0	0.0	406.9	184.0	133.3	133.3	133.3
20	CCCT Cap 27	0.0	455.8	254.7	63.0	43.8	43.8	43.8
21	CT Cap 27	724.9	239.7	0.0	0.0	0.0	0.0	0.0
22	Wind Cap 27	0.0	0.0	0.0	19.6	52.8	52.8	52.8
23	OtherRenew Cap 27	9.8	39.2	98.1	156.9	157.0	157.0	157.0
24	Other Cap 27	0.0	0.0	0.0	336.1	372.9	372.9	372.9

We answer to you.

Wind Capital Cost Sensitivities

Wind Capital Costs ($ per KW)	Nameplate: 2008-17 (limit 200MW & PTC)	Nameplate: 2018-27 (limit 250MW & No PTC)
$2,000	0	0
$1,800	0	0
$1,700	100 MW	0
$1,600	200 MW	0
$1,500	200 MW	100 MW
$1,200	200 MW	250 MW

Avista Utilities 2007 Integrated Resource Plan

Technical Advisory Committee Meeting No. 3 Agenda
Wednesday January 10, 2007

	Topic	Time	Staff
1.	Introductions	9:00	Barcus
2.	Review & Feedback of 2nd TAC	9:15	Lyons
3.	Draft PRS Review	9:30	Gall/Lyons
4.	Fuel Price Forecast	11:30	Christie/Gall
5.	Lunch – Clean Coal Presentation	12:00	Lafferty
6.	Emissions Update	12:45	Lyons
7.	Load Forecast	1:30	Barcus
8.	Conservation	2:30	Folsom & Powell
9.	Adjourn	4:30	

We answer to you.

AVISTA

2007 Electric Integrated Resource Plan Third Technical Advisory Committee Meeting

January 10, 2007

Topic	**Presenter**
Review & Feedback of 2nd TAC	Lyons
Draft PRS Review	Gall/Lyons
Fuel Price Forecast	Christie/Gall
Clean Coal Technologies	Lyons
Emissions Update	Lyons
Load Forecast	Barcus
Conservation	Folsom & Powell

We answer to you.

AVISTA

Review & Feedback: Second TAC Meeting

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

John Lyons

We answer to you.

AVISTA

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

We answer to you.

AVISTA

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 CO_2 in the Base Case

We answer to you.

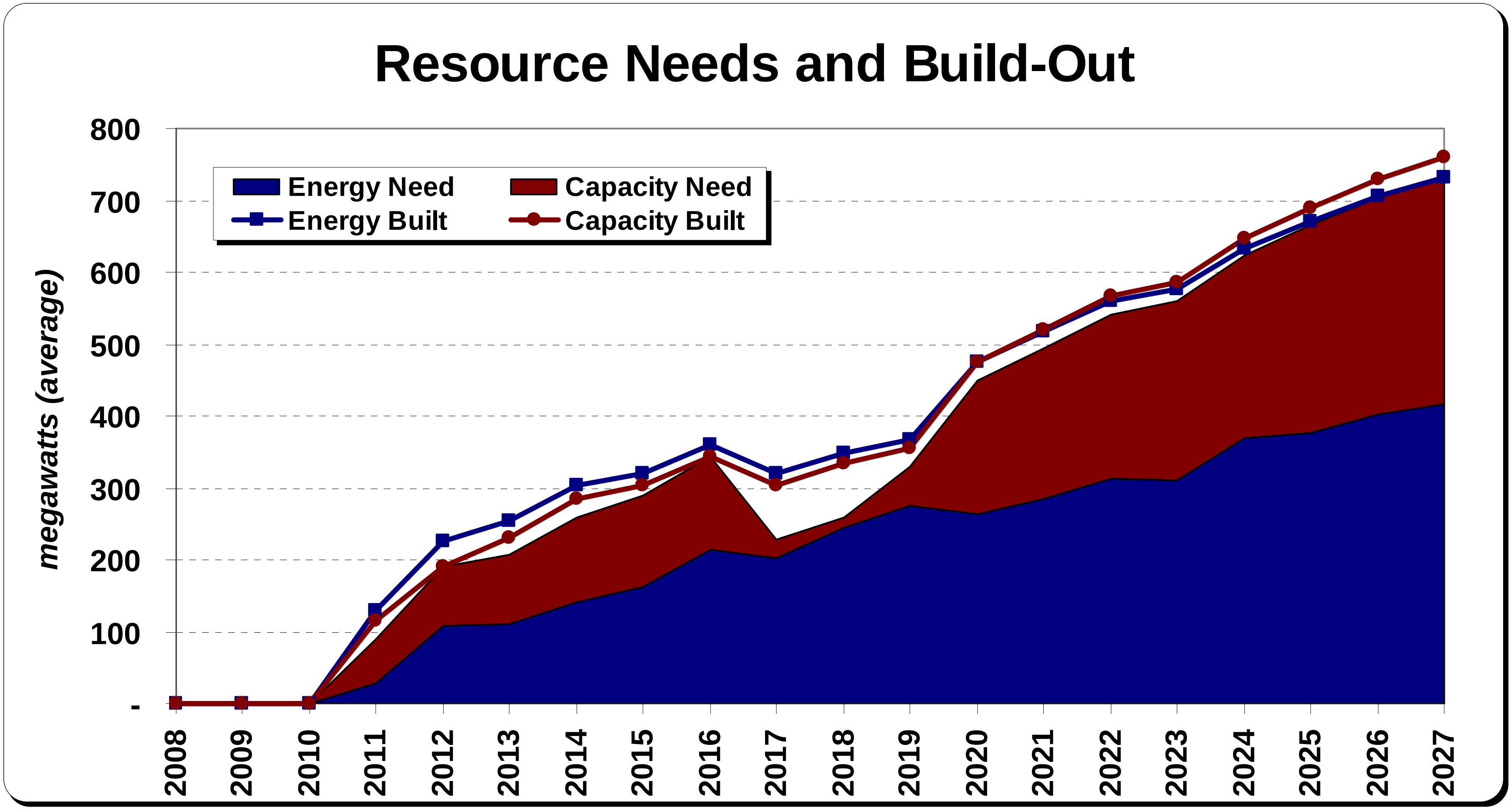
Draft Preferred Resource Strategy Review

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

James Gall & John Lyons

We answer to you.

AVISTA



We answer to you.

DRAFT Preferred Resource Strategies (Energy)

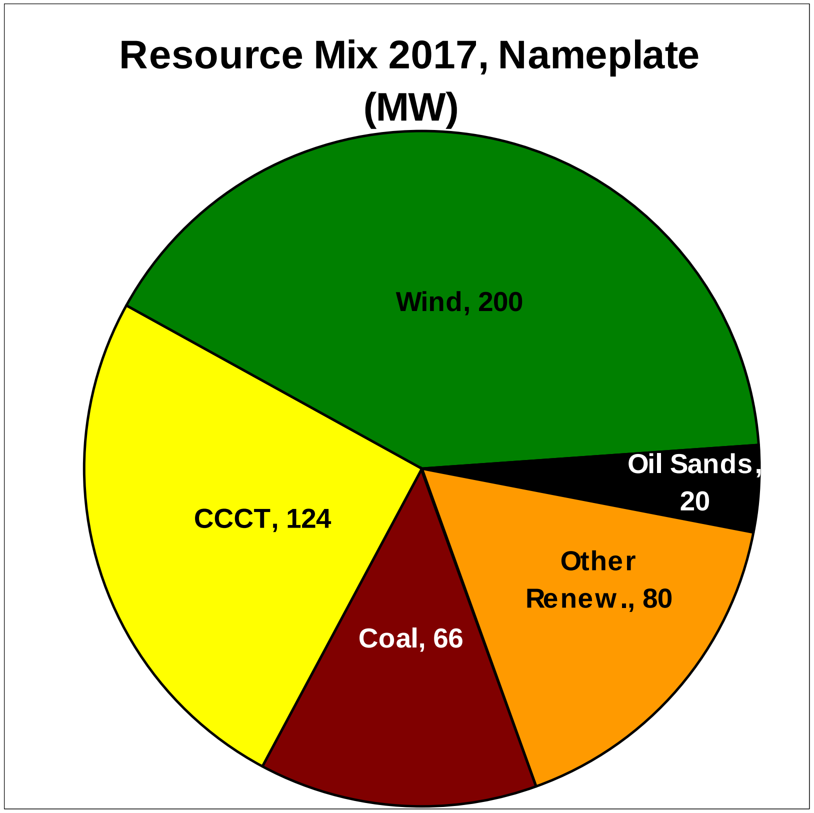
Time Period	Resource Type	2007 "Draft" IRP	2005 IRP	2003 IRP
2007-2017	Coal	55	215	325
	Wind (nameplate)	300*	400	75
	Gas	110	0	200
	Other Renewables	73	57	0
	Conservation and Plant Upgrades	69	69	46
	Nuclear & Alberta Oil Sands	16	0	0
2007-2027	Coal	55	474	775
	Wind (nameplate)	300*	650	75
	Gas	110	0	200
	Other Renewables	145	137	0
	Conservation and Plant Upgrades	138	138	92
	Nuclear & Alberta Oil Sands	356	0	0

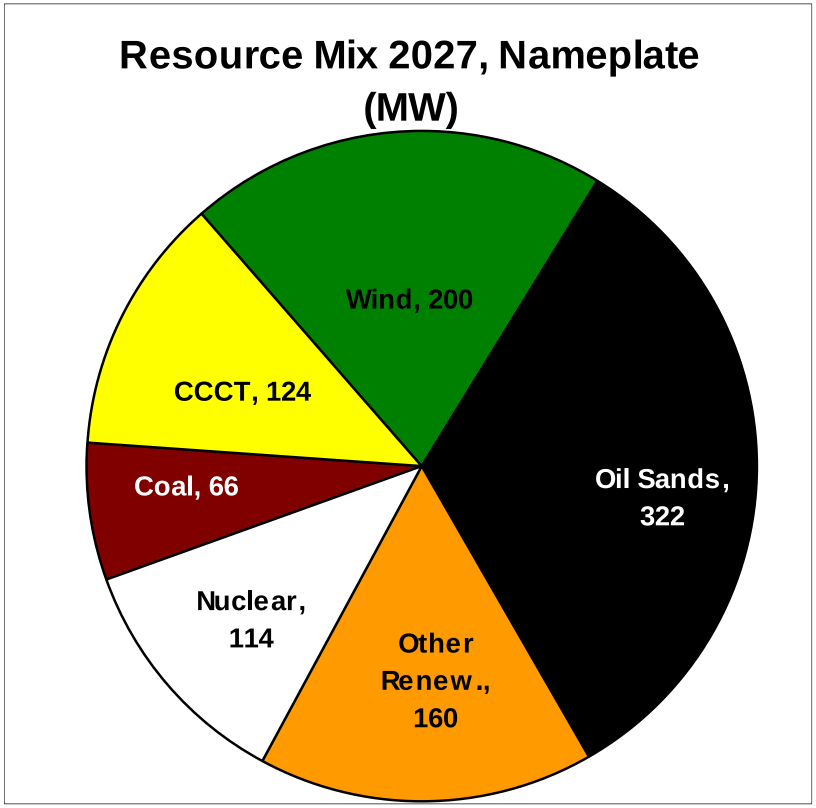
* Includes 100 MW of RFP Wind

We answer to you.

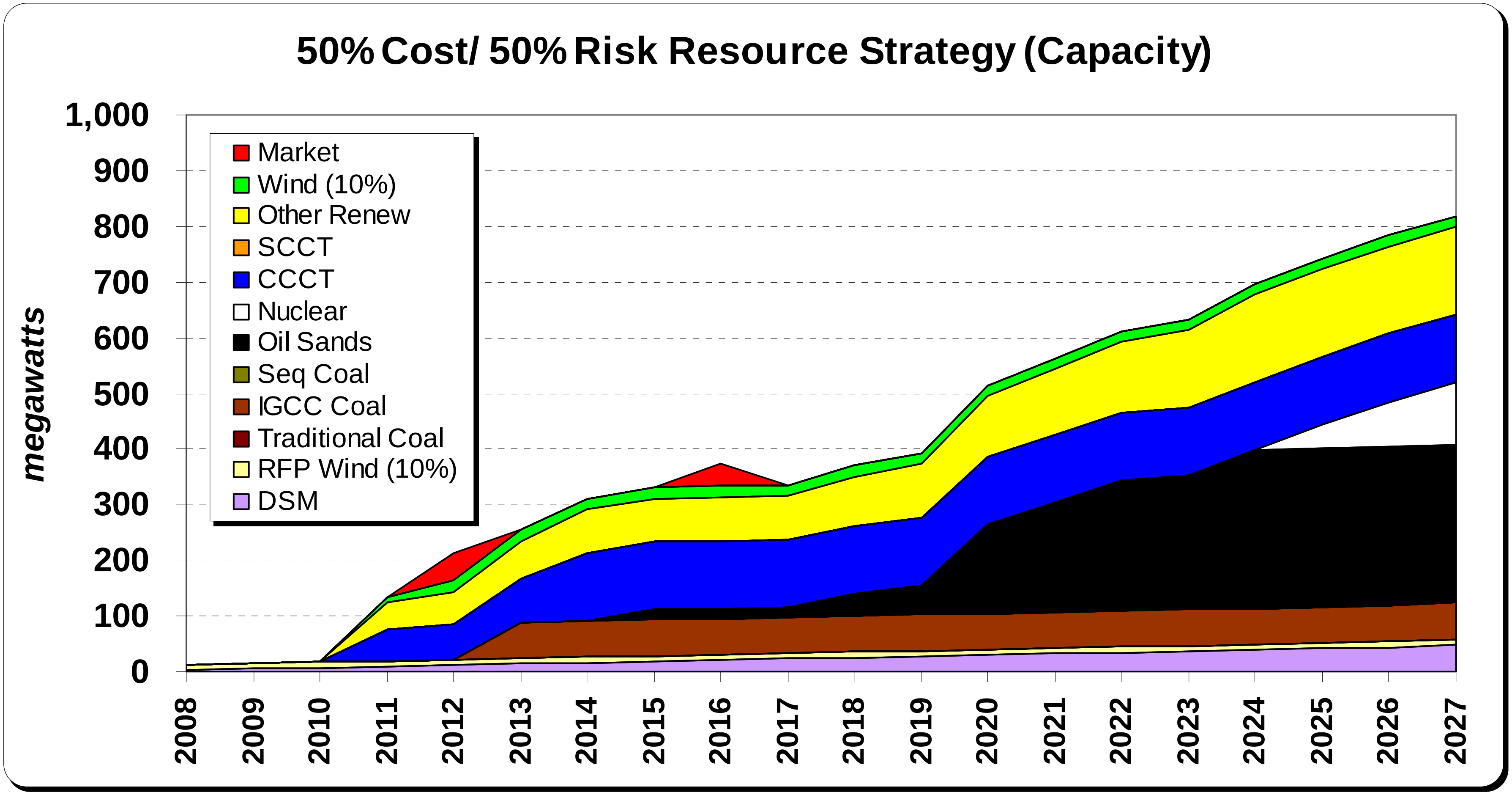
AVISTA

DRAFT New Resource Mix (2017 & 2027)



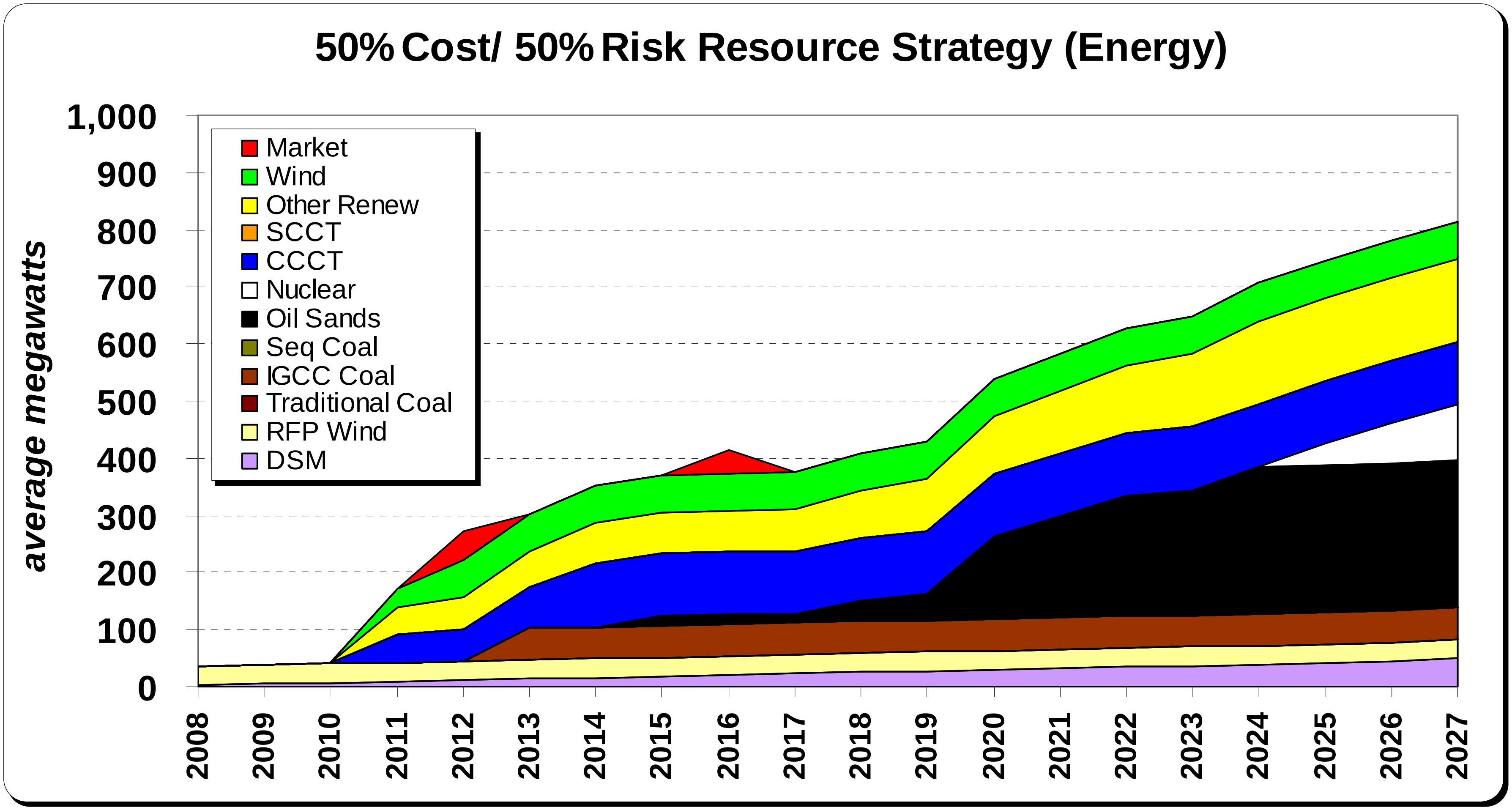


* Does not include the 100 MW of RFP wind


50% Cost/ 50% Risk Resource Strategy (Capacity)
megawatts
1,000
900
800
700
600
500
400
300
200
100
0
Market
Wind (10%)
Other Renew
SCCT
CCCT
Nuclear
Oil Sands
Seq Coal
IGCC Coal
Traditional Coal
RFP Wind (10%)
DSM
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027

We answer to you.

AVISTA



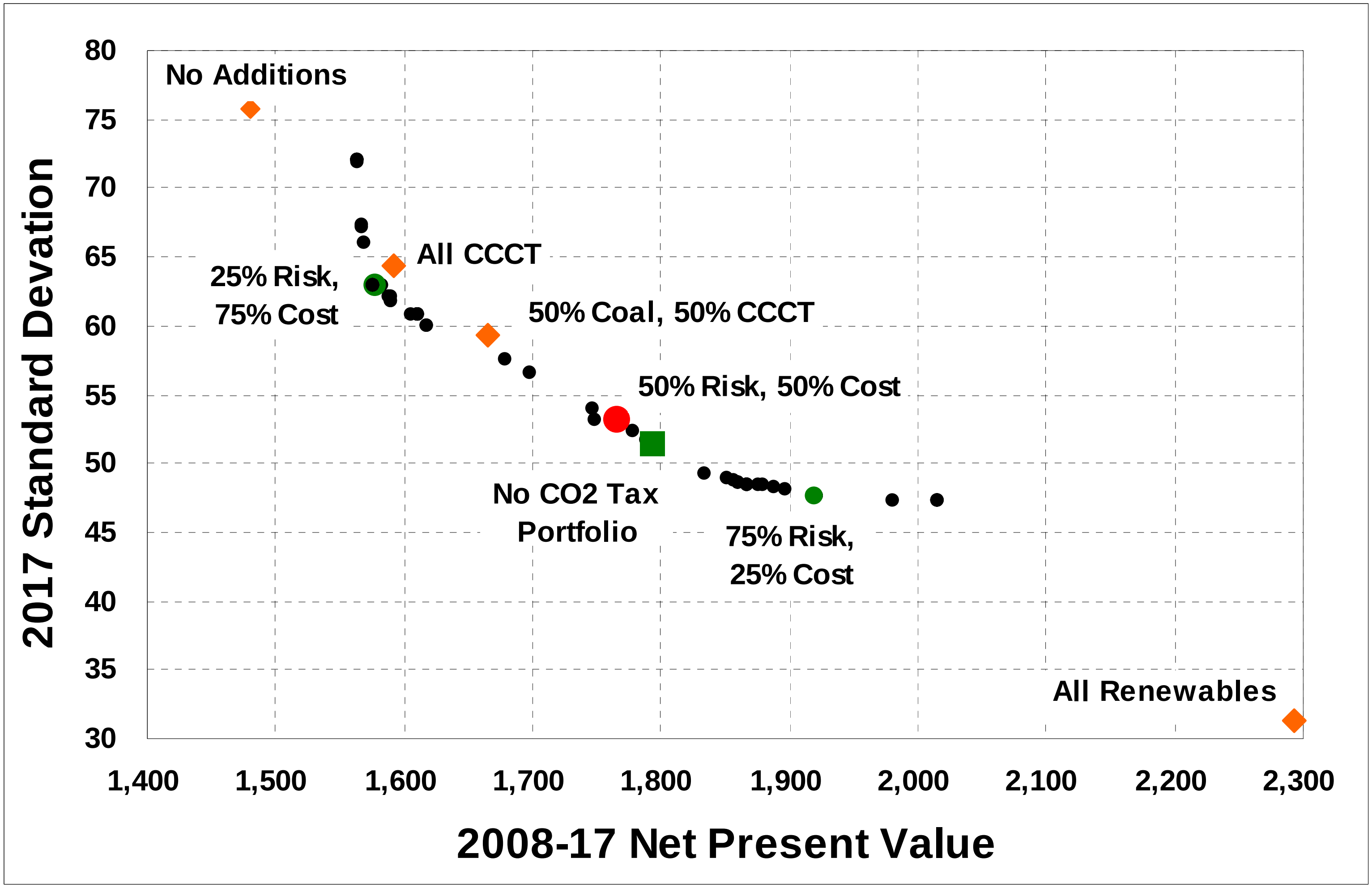
We answer to you.

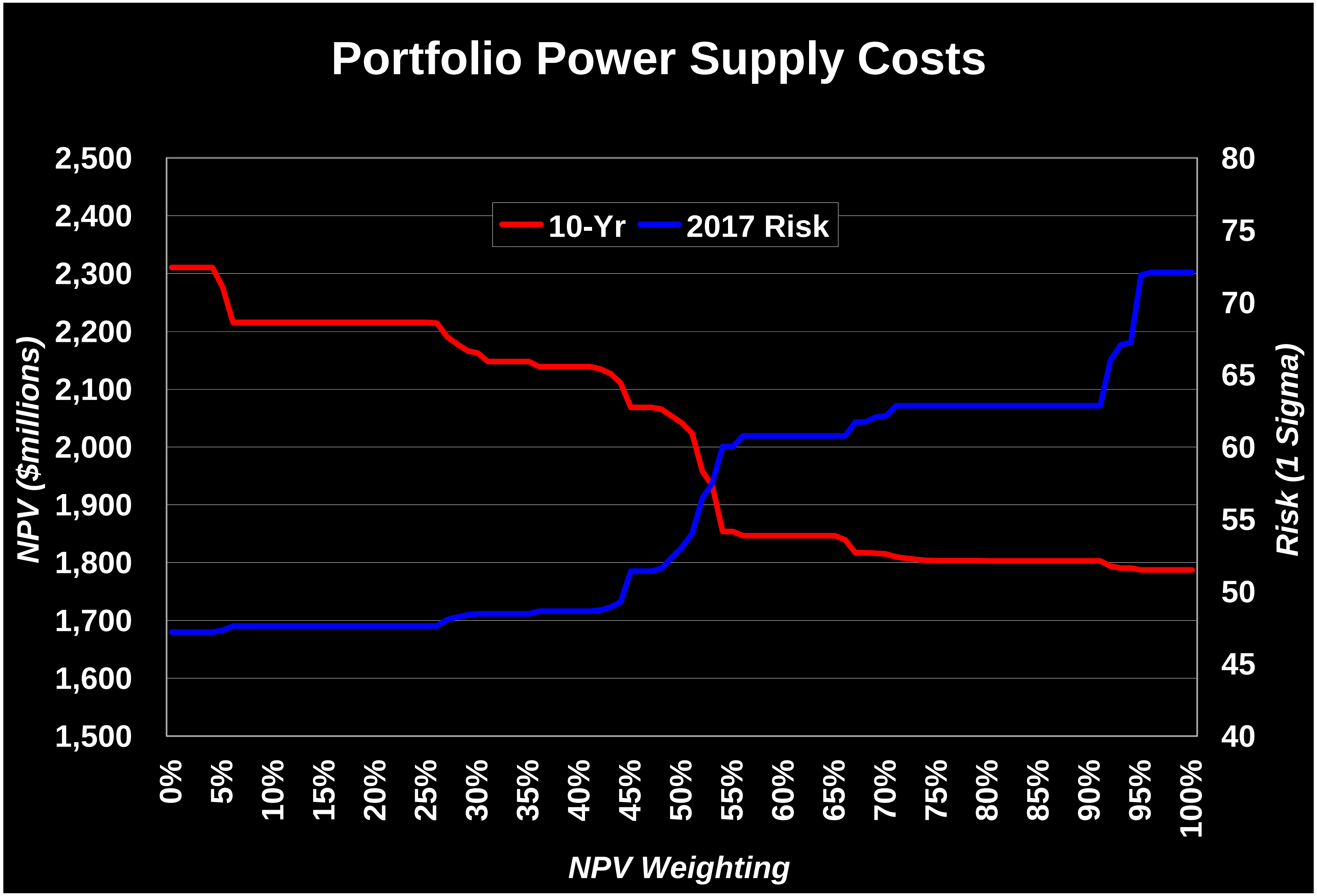
Base Case: DRAFT PRS Model Details

		Summary Stats for Scenario						
Line	Values	100/0	90/10	75/25	50/50	25/75	10/90	0/100
1	NPV 17	1,563.8	1,576.2	1,576.7	1,765.7	1,920.7	1,920.7	2,015.9
2	NPV 27	3,509.4	3,552.8	3,639.1	3,844.5	4,246.2	4,246.2	4,463.6
3	Cost 2017	383.3	385.7	385.8	408.9	447.6	447.6	482.8
4	Cost 2027	803.5	810.1	820.0	771.4	800.9	800.9	831.1
5	St. Deviation 2017	72.1	62.9	62.9	53.1	47.6	47.6	47.2
6	St. Deviation 2027	151.7	126.7	92.3	78.2	62.9	62.9	62.7
7	Capital Cost 2017	311.8	388.6	388.6	1,091.2	1,587.4	1,587.4	1,838.4
8	Capital Cost 2027	284.8	842.2	1,869.4	1,821.4	2,451.0	2,451.0	2,461.5
9	Rate AARG 2017	5.0%	5.1%	5.1%	5.5%	6.2%	6.2%	6.7%
10	Rate AARG 2027	4.5%	4.5%	4.6%	4.3%	4.5%	4.5%	4.6%
11	Rate Max Year	9.9%	10.9%	9.7%	15.8%	18.0%	18.0%	18.0%
12	2017 95th% Diff	130.2	114.6	114.6	95.8	90.1	90.1	89.0
13	Coal Cap 17	0.0	0.0	0.0	64.5	133.3	133.3	133.3
14	CCCT Cap 17	0.0	254.7	254.7	121.7	43.8	43.8	43.8
15	CT Cap 17	254.7	0.0	0.0	0.0	0.0	0.0	0.0
16	Wind Cap 17	0.0	0.0	0.0	19.6	28.8	28.8	28.8
17	OtherRenew Cap 17	39.2	39.2	39.2	78.4	78.5	78.5	78.5
18	Other Cap 17	0.0	0.0	0.0	18.1	18.1	18.1	18.1
19	Coal Cap 27	0.0	0.0	0.0	64.5	133.3	133.3	133.3
20	CCCT Cap 27	0.0	254.7	254.7	121.7	43.8	43.8	43.8
21	CT Cap 27	695.5	290.0	0.0	0.0	0.0	0.0	0.0
22	Wind Cap 27	0.0	0.0	0.0	19.6	52.8	52.8	52.8
23	OtherRenew Cap 27	39.2	78.5	117.7	156.9	157.0	157.0	157.0
24	Other Cap 27	0.0	111.6	387.3	396.9	372.9	372.9	372.9

We answer to you.

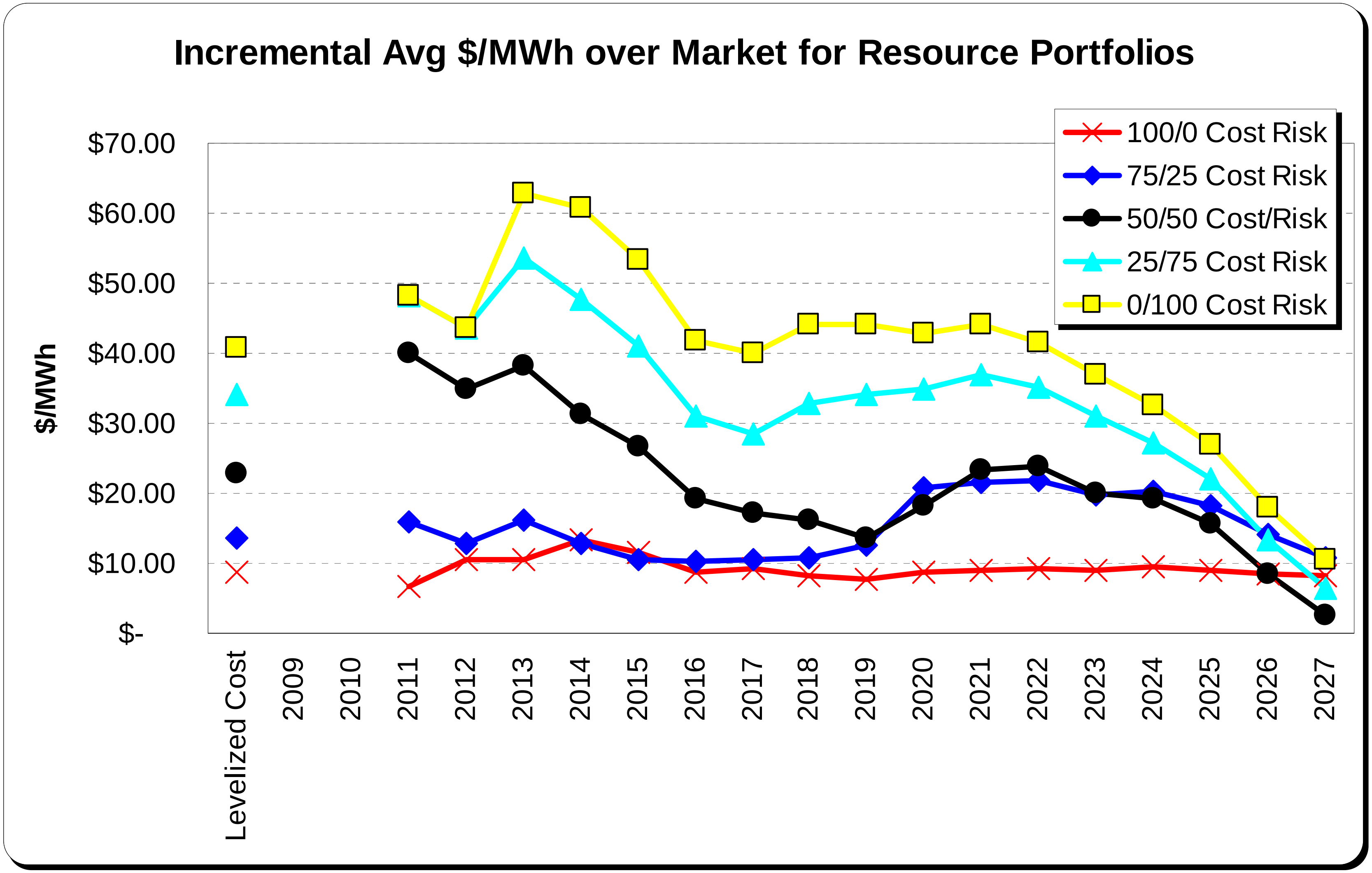
Efficient Frontier




Portfolio Power Supply Costs
10-Yr
2017 Risk
2,500
2,400
2,300
2,200
2,100
2,000
1,900
1,800
1,700
1,600
1,500
NPV ($millions)
80
75
70
65
60
55
50
45
40
Risk (1 Sigma)
0%
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
100%
NPV Weighting

We answer to you.

AVISTA



We answer to you.

Fuel Price Forecast

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

Kevin Christie & James Gall

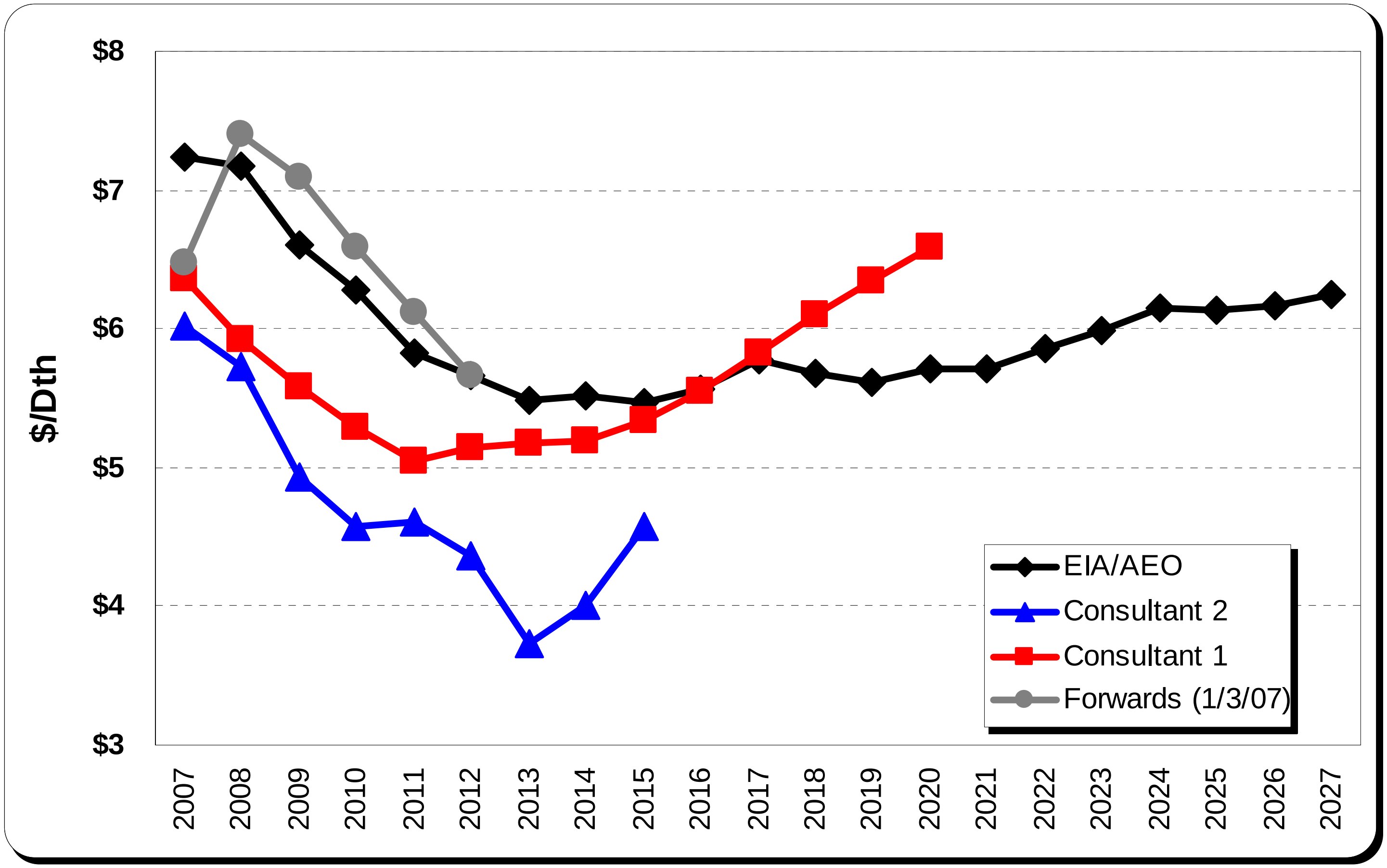
We answer to you.

Levelized Natural Gas and Coal Costs

20-Year Levelized (2008 to 2027) shown in 2007 dollars	Nominal Price per Dth	Real Price per Dth
Henry Hub NG	$7.83	$6.59
AECO NG	$6.67	$5.61
Sumas NG	$6.74	$5.67
Mine Mouth PRB Coal	$0.61	$0.52
Short Haul PRB Coal	$1.19	$1.00
Long Haul PRB Coal	$2.90	$2.44

We answer to you. AVISTA

Henry Hub Price Forecasts (2005$)



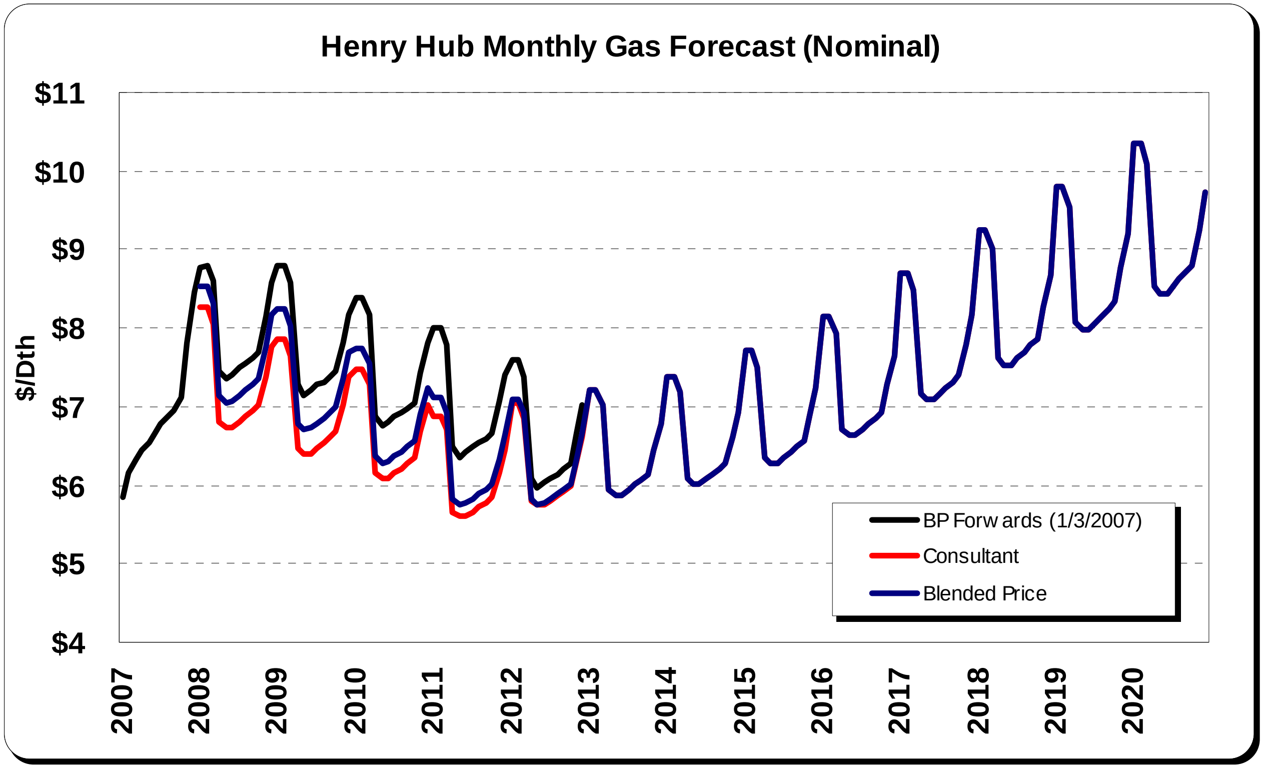
Forecast Assumptions

	Consultant 1			Consultant 2			AEO 2007		
	2006	2010	2015	2006	2010	2015	2006	2010	2015
Forecasted HH Price (2005$)	$ 6.39	$ 5.29	$ 5.33	$ 6.46	$ 4.57	$ 4.57	$ 7.07	$ 6.28	$ 5.46
US Economic Growth (% GDP)	3.50%	3.20%	3.20%	3.00%	3.00%	3.00%	2.90%	2.90%	2.90%
US Gas Demand (bcf/d)	60.52	65.86	68.27	58.40	64.40	67.80	59.50	65.80	69.38
EG Demand (bcf\d)	17.89	19.81	21.54	16.60	22.10	25.40	16.11	17.48	19.48
WTI Oil Price (2005$)	$ 65.00	$ 53.54	$ 50.52	$ 55.15	$ 49.90	$ 44.45	$ 61.75	$ 57.47	$ 49.87
US Gas Prod. (bcf\d)	51.53	52.45	49.77	49.40	48.00	46.50	51.07	53.21	53.89
LNG Imports (bcf\d)	1.61	5.82	10.28	1.60	8.10	11.80	1.51	4.96	8.19
Net Imports (bcf\d)	8.25	7.60	8.22	8.30	8.30	9.00	7.50	7.50	7.20
Mackenzie Delta Pipeline		In service 2014			In service 2012				
Alaska Pipeline			In service 2020			In service 2017			In service 2018

We answer to you.

Methodology

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



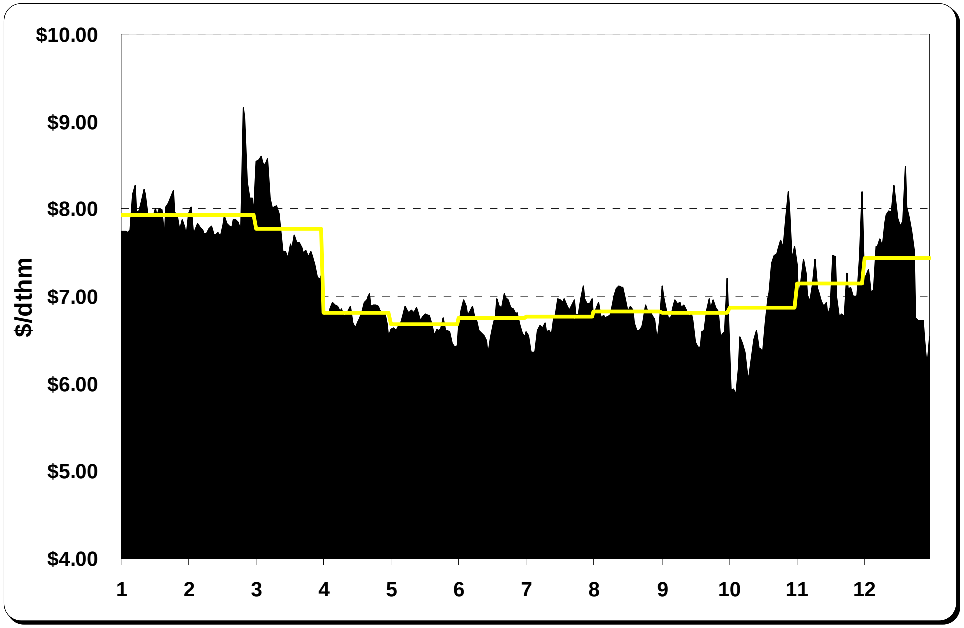
We answer to you.

Intra Year Gas Prices

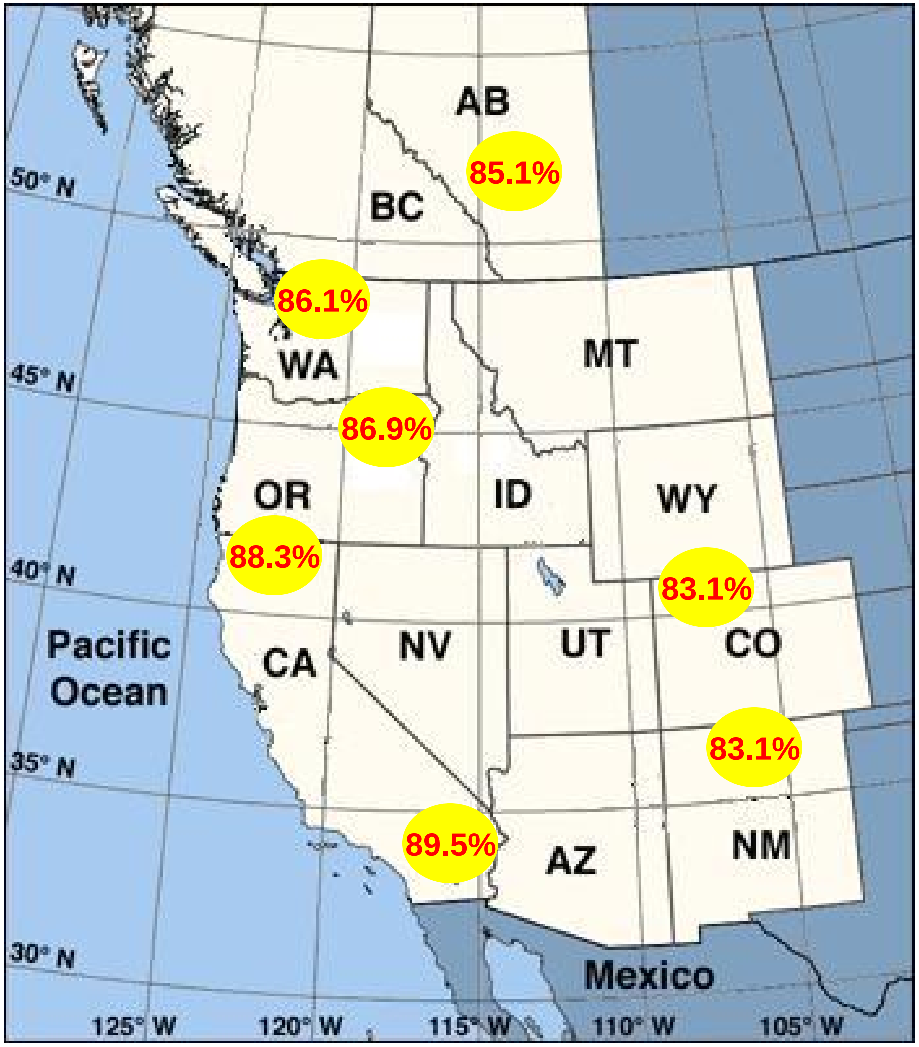
Month	Percent of Annual	Month	Percent of Annual
Jan	113%	Jul	93%
Feb	113%	Aug	94%
Mar	110%	Sep	95%
Apr	93%	Oct	96%
May	92%	Nov	101%
Jun	92%	Dec	106%

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.

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



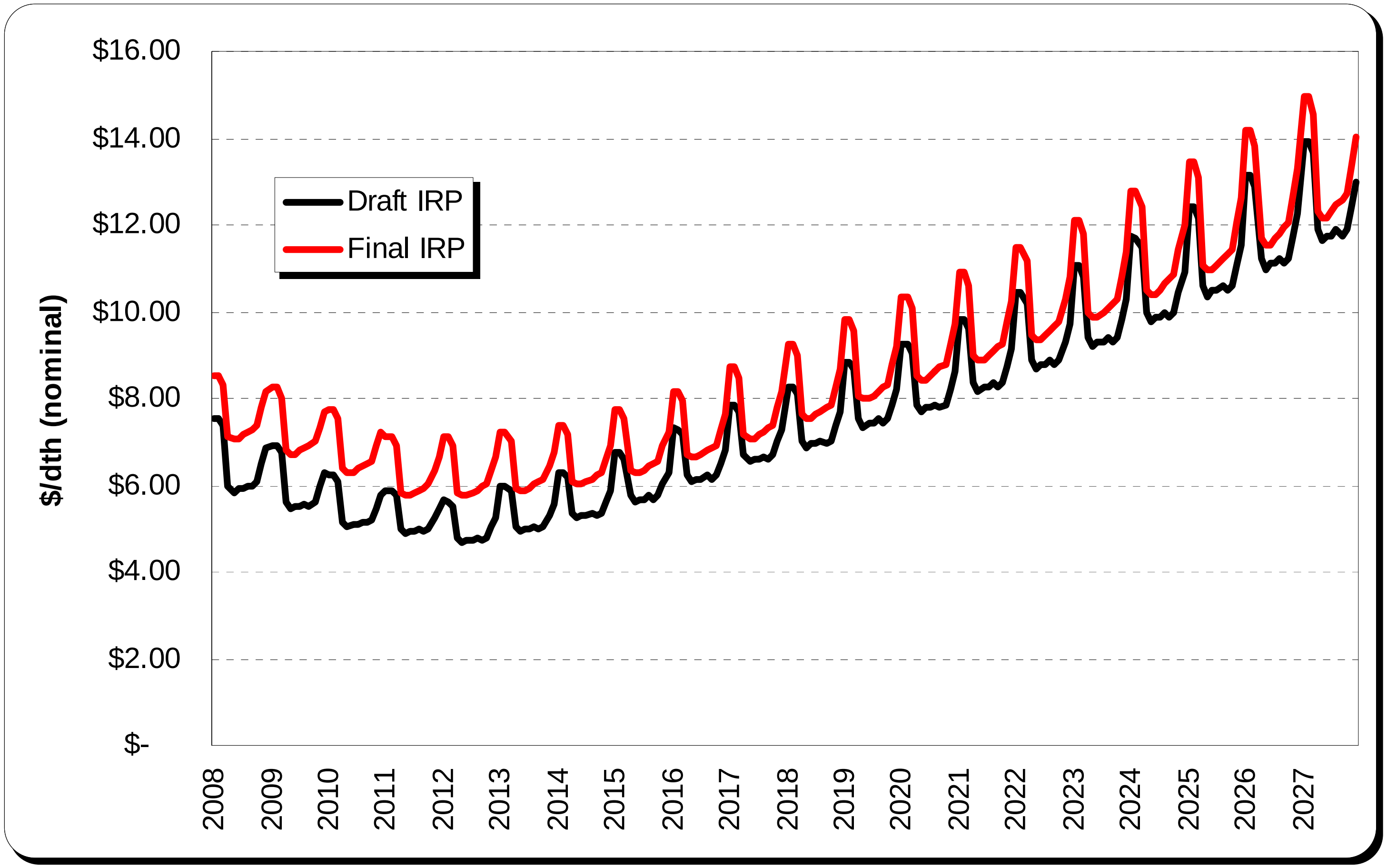
Basin Differentials/Gas Transportation



- Differentials are percent of Henry Hub, based on the average basin differential from a historical perspective
- Post-Kern River Pipeline Expansion - November 2003 to November 2006 period

We answer to you.

Draft IRP Gas Price Forecast vs Final Gas Price Forecast (levelized price increased from $7.47 to $7.83)



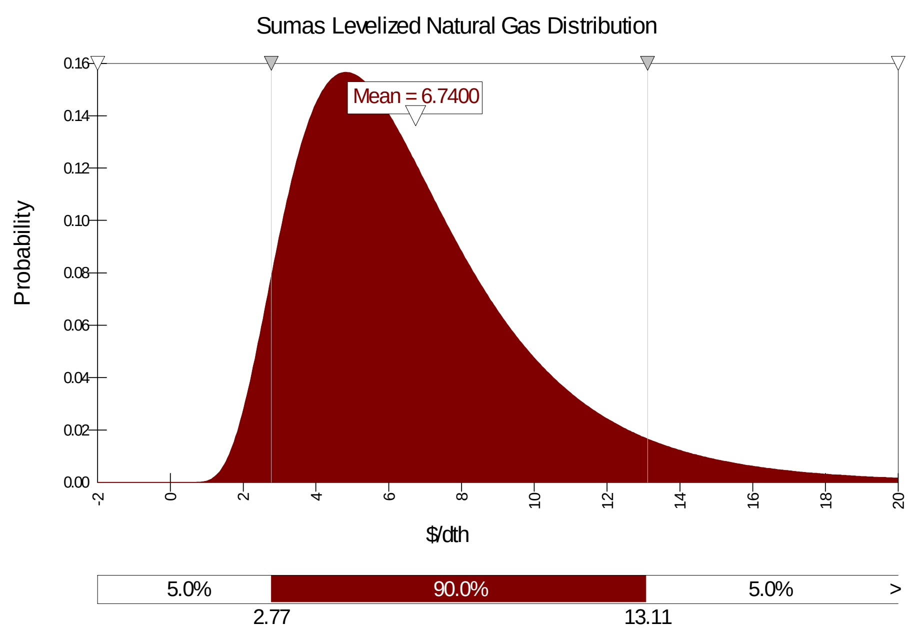
Other NW Utilities IRP Gas Price Methodology

- **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

We answer to you.

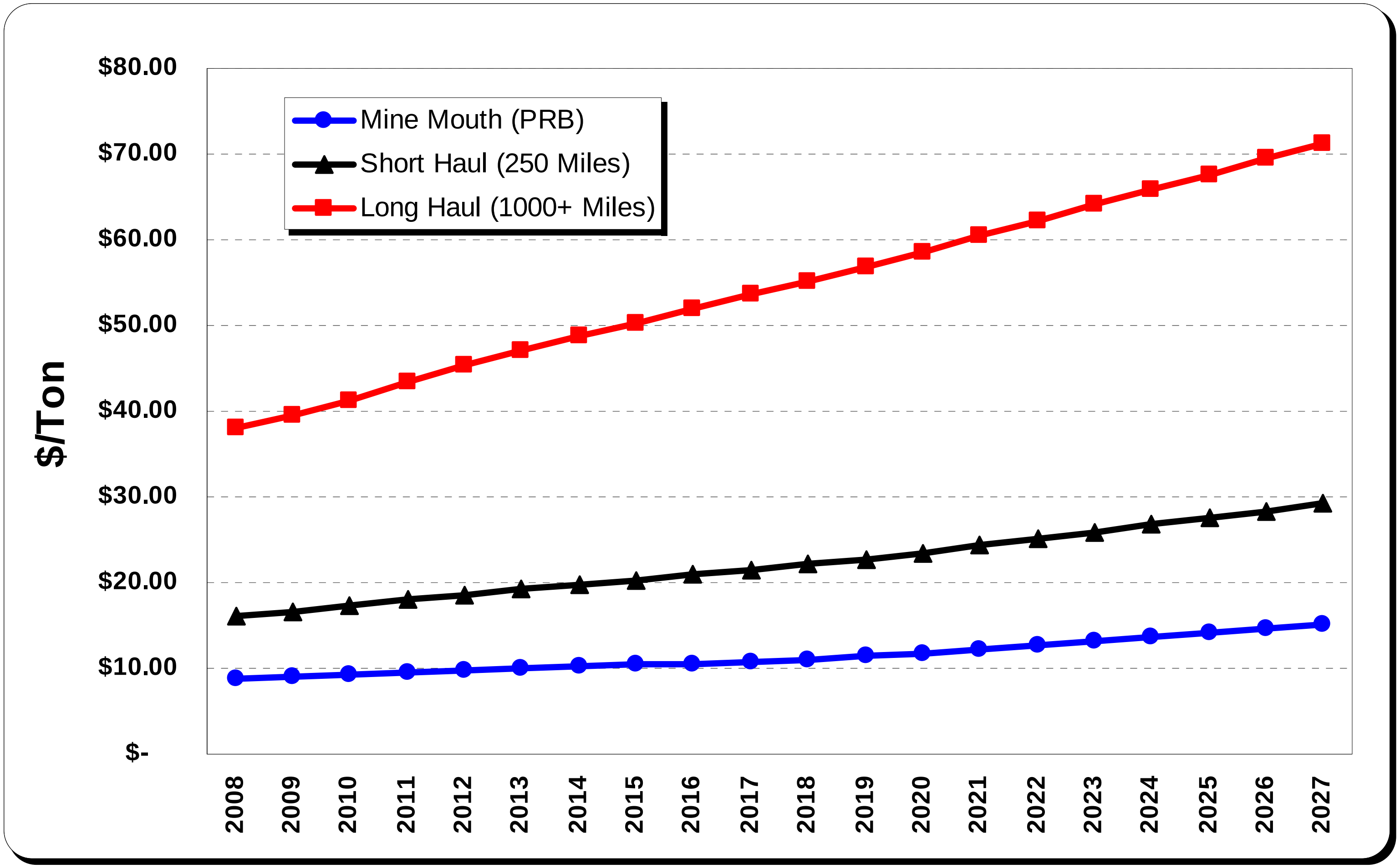
Stochastic Natural Gas- Modeling Uncertainty

- 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



We answer to you.

Coal Prices



We answer to you.

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 SO_2 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 SO_2 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 SO_2 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

We answer to you.

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IGCC

- IGCC removes pollutants before they go up the stack
  - SO_2 and NOx is reduced by over 95%
  - Generating efficiencies increase 40 – 45%, which reduces CO_2 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 CO_2
  - Selected sites in Illinois and Texas as the finalists for the project

We answer to you.

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Carbon Capture and Sequestration

- Carbon capture refers to the technologies to keep CO_2 emissions from fossil fuel generation from being released into the atmosphere Sequestration is the long-term or permanent storage of the CO_2
- 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

We answer to you.

Geologic Sequestration

- Geologic sequestration involves pumping compressed CO_2 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 CO_2 per year for enhanced oil recovery
  - Well understood, studied, and highly stable form of sequestration
- Coal Bed Methane
  - Inject CO_2 instead of pumping water out to depressurize the coal bed
  - Has been successfully field tested, but not commercially utilized yet
- Saline Formations
  - Pump CO_2 into deep saline formations which may store up to 500 billion tons of CO_2
  - Statoil is injecting approximately one million tons of recovered CO_2 into an underwater saline formation – equals the output of a 150 MW coal plant

We answer to you.

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

We answer to you.

Terrestrial Sequestration

- Terrestrial sequestration occurs when atmospheric CO_2 is stored in biomass or the soil
- Sequestration in soil or vegetation can handle about 1/3 of all human generated CO_2 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 CO_2 with chemical or biological conversion
- May help eliminate the need to purify or compress the CO_2 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 CO_2 – 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% CO_2 capture rate, 90% removal of all mercury, 99+% sulfur removal, 99+% particulate capture, more then 80% of the PM 2.5 particulate, and .088 Lbs/ MMBtu of NOx

We answer to you.

Emissions Update

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

John Lyons

We answer to you.

Emissions Modeling in the IRP

Emissions cost included in the 2007 IRP Base Case:

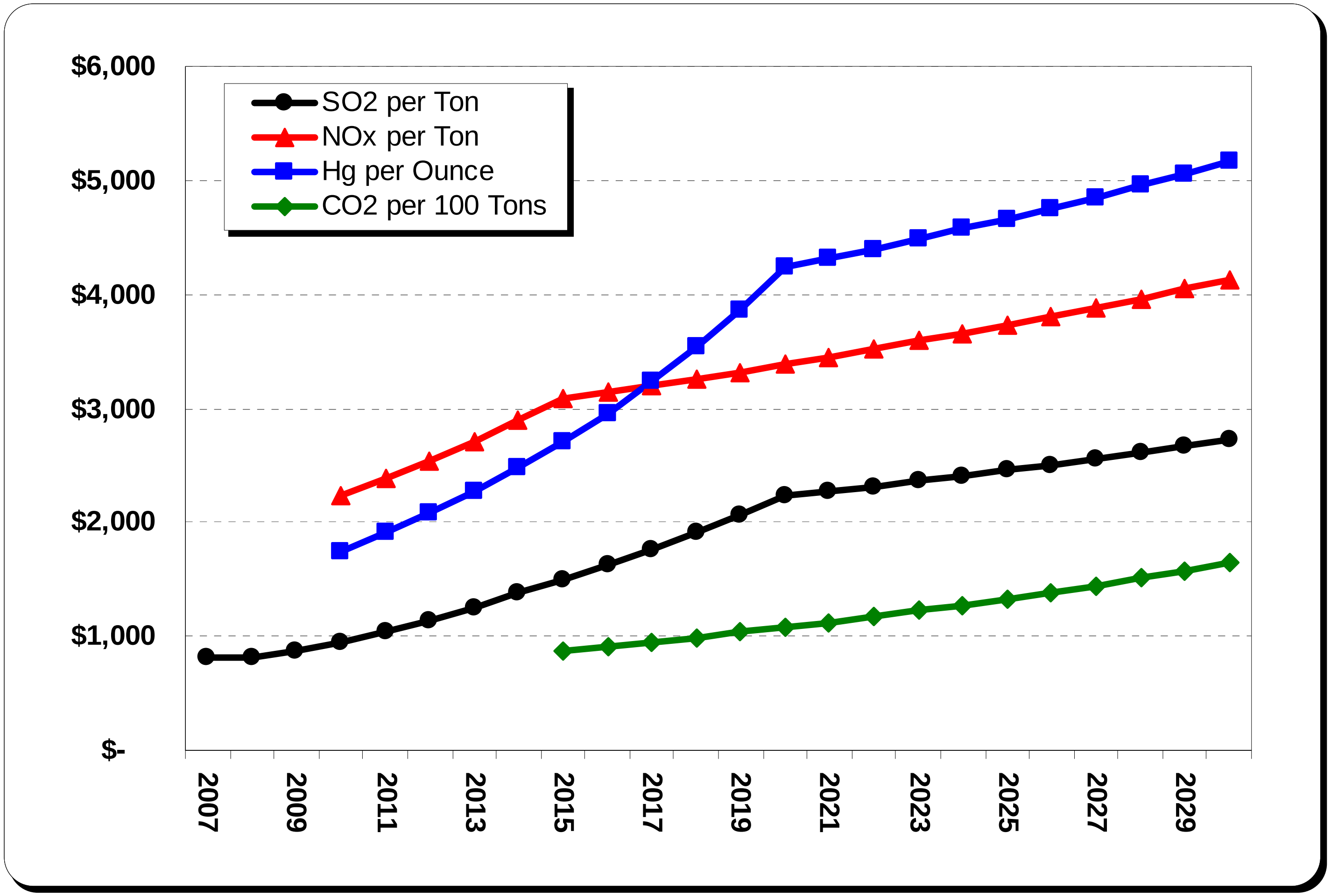
- CO_2 – utilizing a distribution of NCEP, Climate Stewardship Act, and no legislation for each of the 300 draws
- SO_2 – $812/ton in 2007 and $2,717/ton in 2030 (nominal)
- NOx – $2,237 in 2010 and $4,127/ton in 2030 (nominal)
- Hg – $1,748/ounce in 2010 and $5,158/ounce in 2030 (nominal)

We answer to you.

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



We answer to you.

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

We answer to you.

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 CO_2 emissions

We answer to you.

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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 CO_2 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

We answer to you.

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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
  - Oregon Strategy for Greenhouse Gas Reduction (December 2004)
  - Developing a detailed report by the end of 2007
  - Stabilize by 2010 – all GHG, not just CO_2
  - 10% below 1990 levels by 2020
  - 75% below 1990 levels by 2050

We answer to you.

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California Emissions Developments

- Mercury Legislations
  - Considering a more stringent rule than CAMR
- Greenhouse Gas Legislation
  - AB32 – Global Warming Solutions Act: caps state CO_2 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

We answer to you.

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

We answer to you.

Avista's 2007 Load Forecast

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

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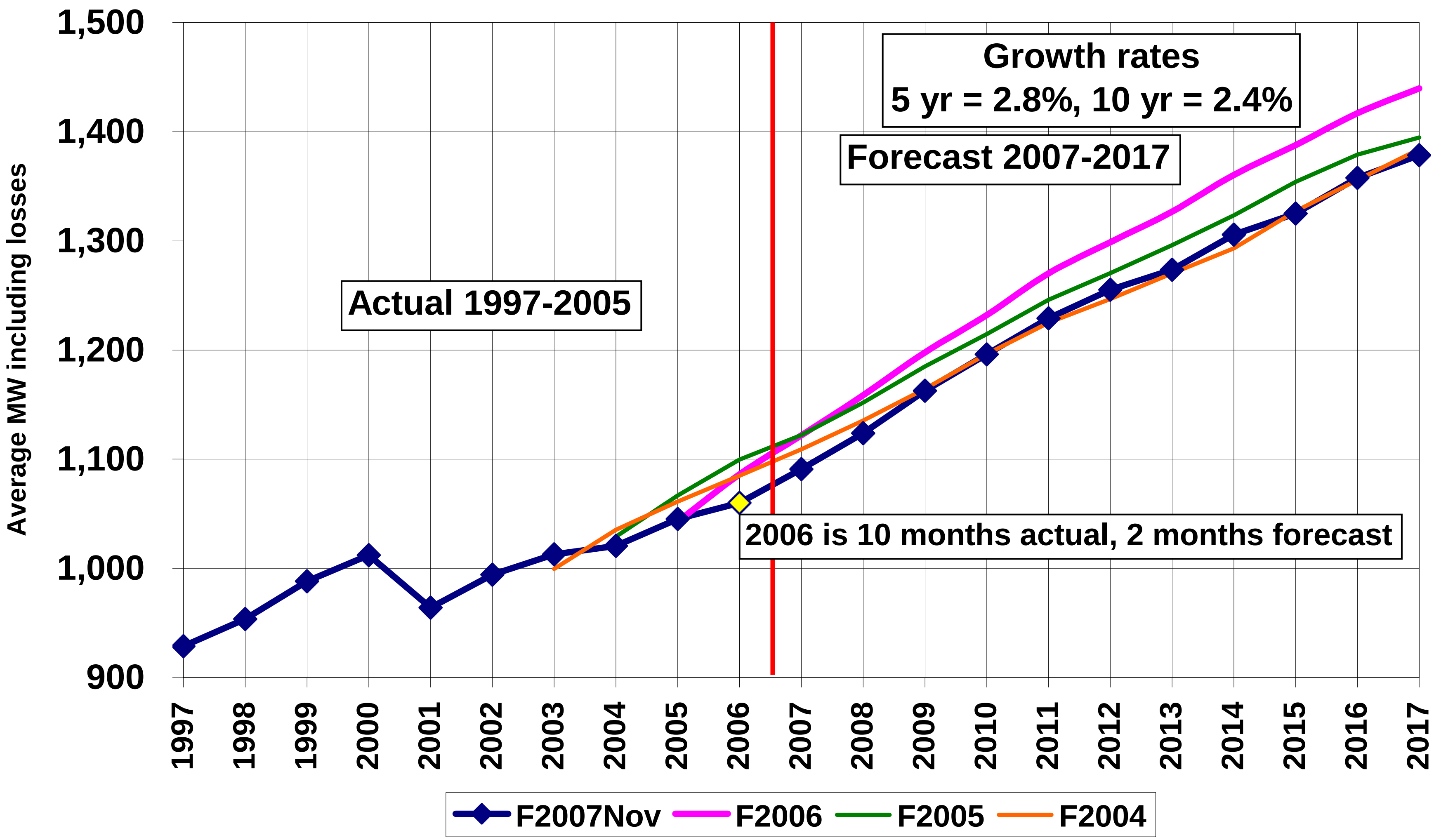
We answer to you.

AVISTA

Net Native Load



Thursday, January 11, 2007

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Native Load Forecast

Load (MW)	**F2007**	744	672	744	720	744	720	744	740	720	744	720	744
BOLD Actual	Annual Avg	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	**929**	**1,098**	**1,035**	**952**	**878**	**832**	**786**	**845**	**918**	**815**	**854**	**1,071**	**1,071**
1998	**954**	**1,065**	**994**	**943**	**902**	**941**	**845**	**966**	**936**	**866**	**886**	**960**	**1,140**
1999	**988**	**1,076**	**1,075**	**1,020**	**950**	**917**	**933**	**971**	**991**	**904**	**933**	**982**	**1,117**
2000	**1,012**	**1,153**	**1,114**	**1,034**	**921**	**889**	**924**	**961**	**985**	**889**	**950**	**1,163**	**1,173**
2001	**964**	**1,147**	**1,110**	**975**	**905**	**862**	**868**	**911**	**956**	**864**	**911**	**957**	**1,114**
2002	**994**	**1,095**	**1,072**	**1,040**	**929**	**898**	**950**	**1,018**	**953**	**891**	**968**	**1,034**	**1,090**
2003	**1,013**	**1,087**	**1,076**	**991**	**926**	**900**	**968**	**1,056**	**997**	**934**	**957**	**1,111**	**1,161**
2004	**1,021**	**1,194**	**1,108**	**987**	**925**	**900**	**963**	**1,037**	**1,023**	**926**	**964**	**1,072**	**1,157**
2005	**1,045**	**1,188**	**1,111**	**1,010**	**976**	**927**	**963**	**1,028**	**1,038**	**942**	**966**	**1,124**	**1,277**
2006	1,060	**1,159**	**1,199**	**1,092**	**966**	**962**	**987**	**1,102**	**1,045**	**959**	**1,000**	1,058	1,200
2007	1,091	1,266	1,198	1,147	1,008	970	987	1,057	1,089	994	1,063	1,087	1,230
2008	1,124	1,307	1,238	1,183	1,038	999	1,017	1,085	1,123	1,026	1,094	1,116	1,266
2009	1,163	1,354	1,280	1,224	1,076	1,034	1,051	1,121	1,163	1,064	1,132	1,152	1,308
2010	1,196	1,396	1,317	1,260	1,108	1,064	1,080	1,151	1,198	1,096	1,164	1,181	1,345
2011	1,229	1,438	1,354	1,296	1,140	1,093	1,110	1,180	1,231	1,128	1,195	1,211	1,381
2012	1,255	1,471	1,383	1,324	1,166	1,116	1,133	1,204	1,257	1,153	1,220	1,235	1,410
2013	1,274	1,493	1,403	1,344	1,183	1,133	1,149	1,220	1,275	1,171	1,238	1,252	1,430
2014	1,306	1,534	1,439	1,378	1,214	1,161	1,178	1,249	1,307	1,202	1,268	1,281	1,466
2015	1,325	1,558	1,460	1,398	1,233	1,178	1,195	1,266	1,327	1,221	1,287	1,298	1,487
2016	1,358	1,599	1,496	1,433	1,265	1,207	1,224	1,295	1,360	1,253	1,318	1,328	1,523
2017	1,379	1,625	1,520	1,456	1,285	1,226	1,242	1,314	1,381	1,273	1,338	1,347	1,546
2018	1,399	1,650	1,542	1,477	1,304	1,244	1,260	1,332	1,401	1,293	1,357	1,365	1,568
2019	1,426	1,684	1,572	1,506	1,331	1,268	1,284	1,356	1,428	1,319	1,383	1,390	1,599
2020	1,449	1,713	1,598	1,531	1,353	1,289	1,305	1,377	1,451	1,342	1,405	1,411	1,624
2021	1,477	1,748	1,629	1,560	1,380	1,313	1,330	1,402	1,479	1,369	1,431	1,436	1,655
2022	1,497	1,773	1,652	1,582	1,400	1,332	1,348	1,420	1,500	1,389	1,451	1,454	1,677
2023	1,518	1,799	1,675	1,605	1,420	1,350	1,366	1,439	1,521	1,409	1,471	1,473	1,701
2024	1,556	1,846	1,716	1,645	1,456	1,383	1,400	1,473	1,558	1,445	1,507	1,507	1,742
2025	1,582	1,879	1,745	1,672	1,481	1,406	1,423	1,496	1,584	1,471	1,531	1,531	1,771
2026	1,606	1,909	1,772	1,698	1,505	1,428	1,444	1,517	1,608	1,494	1,554	1,553	1,797
2027	1,626	1,934	1,795	1,720	1,525	1,446	1,462	1,536	1,629	1,514	1,574	1,571	1,820
2028	1,646	1,959	1,817	1,742	1,544	1,464	1,480	1,554	1,649	1,534	1,593	1,590	1,842
2029	1,674	1,994	1,848	1,771	1,571	1,489	1,505	1,579	1,677	1,561	1,620	1,615	1,873
2030	1,699	2,025	1,876	1,798	1,595	1,511	1,527	1,601	1,702	1,585	1,644	1,638	1,900
2007-2012 growth rate	2.8%	3.0%	2.9%	2.9%	3.0%	2.8%	2.8%	2.6%	2.9%	3.0%	2.8%	2.6%	2.8%
2007-2017 growth rate	2.4%	2.5%	2.4%	2.4%	2.5%	2.4%	2.3%	2.2%	2.4%	2.5%	2.3%	2.2%	2.3%
2007-2027 growth rate	2.0%	2.1%	2.0%	2.0%	2.1%	2.0%	2.0%	1.9%	2.0%	2.1%	2.0%	1.9%	2.0%

Native Peak Demand

Bold= Actual	Calendar	Operating Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	**1,508**		**1,508**	**1,391**	**1,286**	**1,228**	**1,115**	**1,019**	**1,202**	**1,289**	**1,122**	**1,146**	**1,403**	**1,373**
1998	**1,663**	**1,575**	**1,575**	**1,255**	**1,195**	**1,251**	**1,249**	**1,164**	**1,521**	**1,422**	**1,317**	**1,246**	**1,296**	**1,663**
1999	**1,434**	**1,663**	**1,357**	**1,379**	**1,300**	**1,209**	**1,213**	**1,338**	**1,405**	**1,402**	**1,175**	**1,232**	**1,308**	**1,434**
2000	**1,561**	**1,474**	**1,458**	**1,474**	**1,301**	**1,262**	**1,147**	**1,308**	**1,454**	**1,396**	**1,183**	**1,254**	**1,492**	**1,561**
2001	**1,490**	**1,561**	**1,474**	**1,490**	**1,329**	**1,209**	**1,243**	**1,228**	**1,382**	**1,370**	**1,169**	**1,175**	**1,380**	**1,429**
2002	**1,457**	**1,429**	**1,388**	**1,362**	**1,398**	**1,180**	**1,149**	**1,376**	**1,457**	**1,335**	**1,197**	**1,360**	**1,337**	**1,412**
2003	**1,509**	**1,457**	**1,393**	**1,408**	**1,258**	**1,221**	**1,179**	**1,321**	**1,487**	**1,400**	**1,332**	**1,323**	**1,432**	**1,509**
2004	**1,766**	**1,766**	**1,766**	**1,434**	**1,366**	**1,177**	**1,121**	**1,391**	**1,477**	**1,485**	**1,176**	**1,279**	**1,433**	**1,454**
2005	**1,660**	**1,563**	**1,563**	**1,409**	**1,270**	**1,246**	**1,123**	**1,367**	**1,495**	**1,473**	**1,207**	**1,239**	**1,466**	**1,660**
2006	1,656	1,660	**1,475**	**1,656**	**1,427**	**1,234**	**1,398**	**1,531**	**1,642**	**1,490**	**1,378**	**1,424**	1,392	1,571
2007	1,652	1,652	1,652	1,569	1,503	1,344	1,275	1,370	1,533	1,535	1,312	1,397	1,428	1,608
2008	1,703	1,703	1,703	1,618	1,549	1,383	1,311	1,407	1,568	1,579	1,352	1,436	1,465	1,653
2009	1,763	1,763	1,763	1,670	1,601	1,430	1,355	1,450	1,613	1,628	1,399	1,484	1,510	1,706
2010	1,815	1,815	1,815	1,716	1,646	1,471	1,392	1,487	1,651	1,673	1,439	1,523	1,547	1,753
2011	1,868	1,868	1,868	1,763	1,691	1,512	1,429	1,524	1,688	1,714	1,480	1,563	1,585	1,799
2012	1,909	1,909	1,909	1,800	1,726	1,543	1,458	1,553	1,717	1,747	1,512	1,594	1,615	1,835
2013	1,938	1,938	1,938	1,825	1,751	1,566	1,478	1,573	1,737	1,770	1,534	1,616	1,635	1,860
2014	1,989	1,989	1,989	1,870	1,794	1,605	1,514	1,609	1,774	1,810	1,573	1,654	1,672	1,905
2015	2,019	2,019	2,019	1,897	1,820	1,628	1,535	1,630	1,795	1,835	1,597	1,678	1,694	1,932
2016	2,070	2,070	2,070	1,943	1,864	1,668	1,571	1,667	1,832	1,876	1,637	1,717	1,731	1,977
2017	2,103	2,103	2,103	1,972	1,892	1,693	1,594	1,690	1,855	1,902	1,662	1,742	1,755	2,006
2018	2,135	2,135	2,135	2,000	1,919	1,718	1,617	1,712	1,878	1,928	1,687	1,766	1,778	2,034
2019	2,177	2,177	2,177	2,038	1,955	1,751	1,647	1,742	1,908	1,962	1,720	1,798	1,809	2,072
2020	2,214	2,214	2,214	2,070	1,986	1,779	1,673	1,768	1,935	1,991	1,748	1,826	1,835	2,104
2021	2,257	2,257	2,257	2,109	2,024	1,813	1,703	1,799	1,966	2,026	1,782	1,859	1,867	2,142
2022	2,289	2,289	2,289	2,137	2,051	1,838	1,726	1,822	1,989	2,052	1,807	1,884	1,890	2,171
2023	2,322	2,322	2,322	2,166	2,079	1,863	1,749	1,845	2,012	2,078	1,833	1,909	1,914	2,200
2024	2,381	2,381	2,381	2,219	2,130	1,909	1,791	1,887	2,054	2,126	1,879	1,954	1,956	2,252
2025	2,422	2,422	2,422	2,255	2,164	1,940	1,820	1,916	2,083	2,158	1,910	1,985	1,986	2,288
2026	2,460	2,460	2,460	2,288	2,197	1,970	1,846	1,869	1,966	2,085	1,940	2,013	2,013	2,321
2027	2,492	2,492	2,492	2,317	2,224	1,994	1,869	1,892	1,989	2,111	1,965	2,038	2,036	2,350
2028	2,523	2,523	2,523	2,345	2,251	2,019	1,891	1,914	2,012	2,136	1,990	2,062	2,060	2,378
2029	2,567	2,567	2,567	2,384	2,289	2,053	1,922	1,945	2,043	2,171	2,024	2,096	2,091	2,416
2030	2,606	2,606	2,606	2,419	2,322	2,083	1,950	1,973	2,071	2,203	2,054	2,125	2,120	2,451

2007-2012 growth rate 2.9% 2007-2017 growth rate 2.4% 2007-2027 growth rate 2.1%

We answer to you.

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

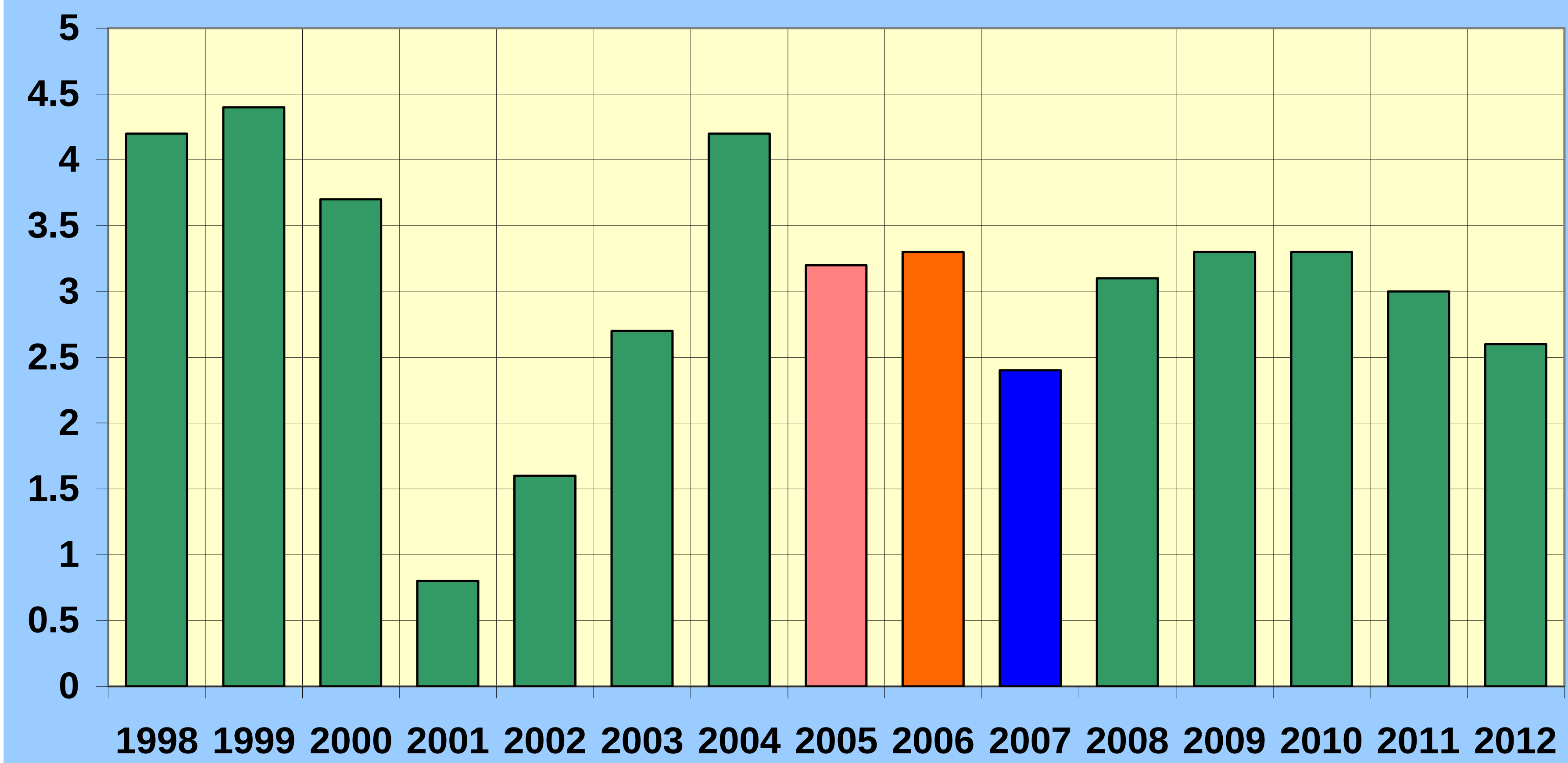
We answer to you.

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

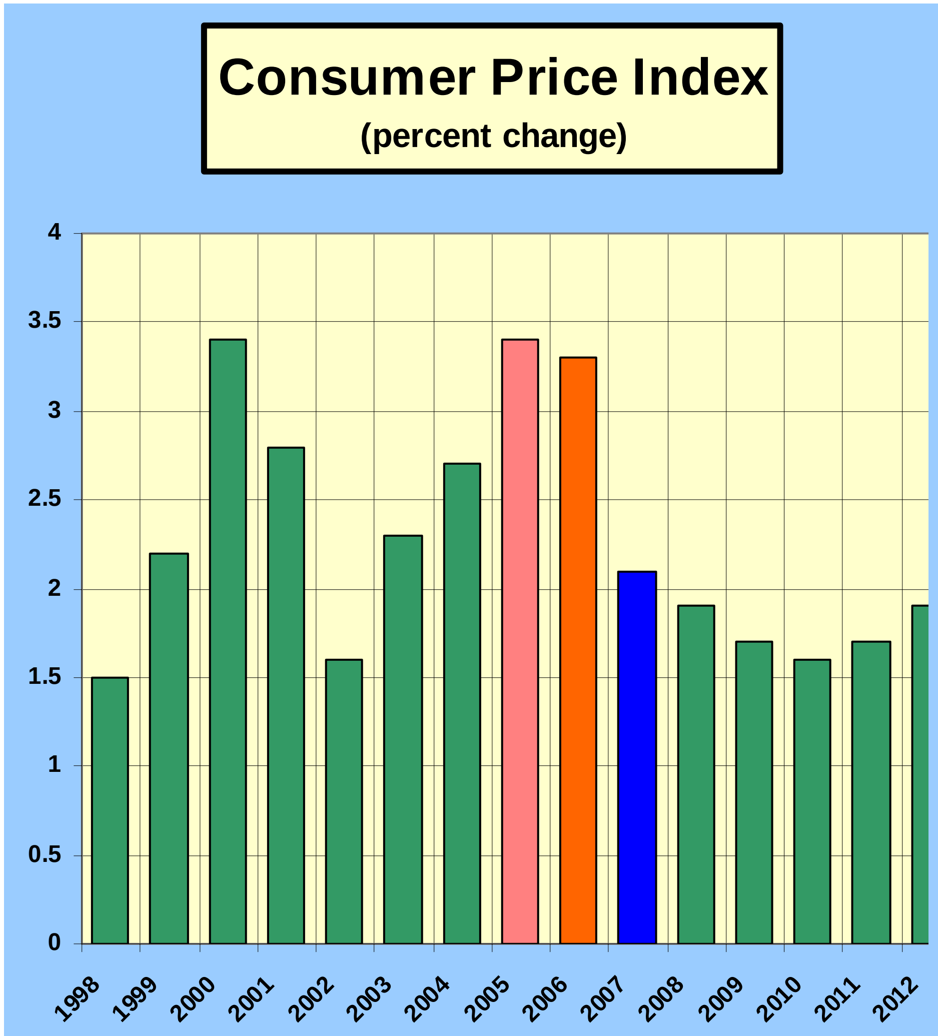
We answer to you.

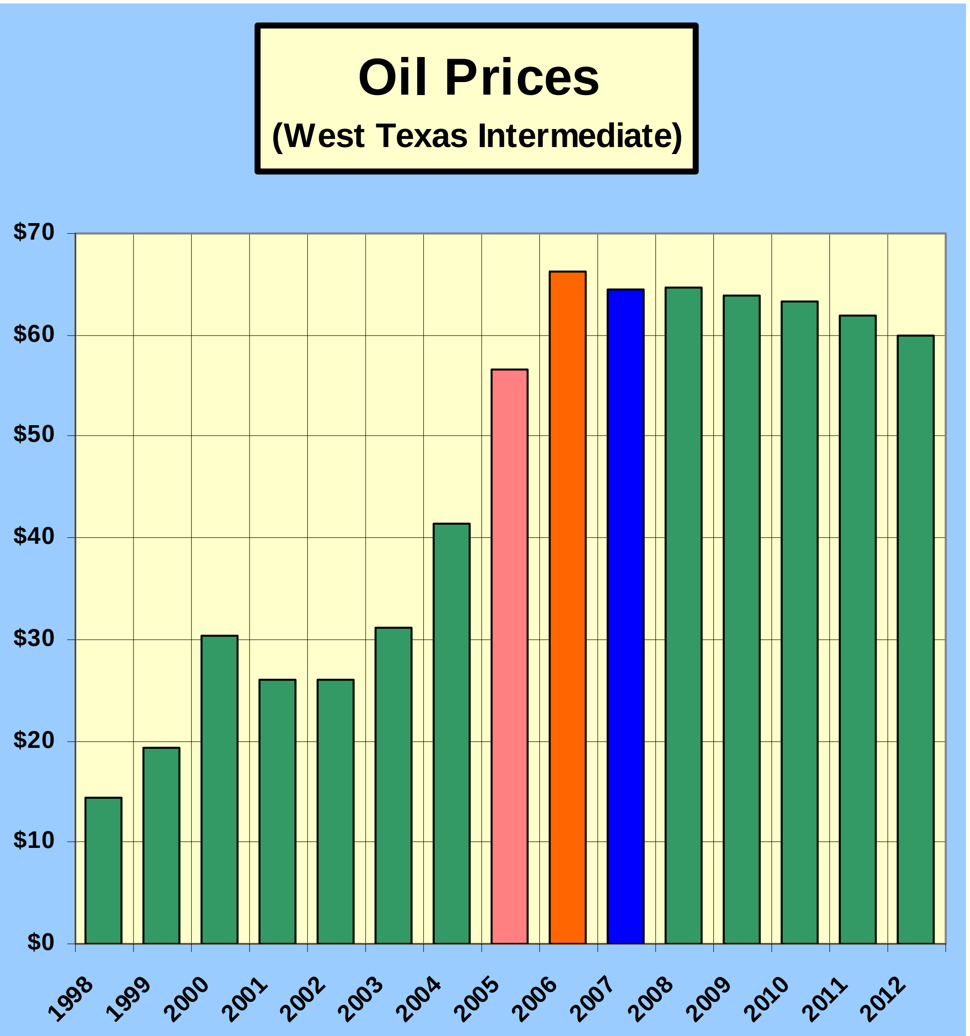
Real GDP
(percent change)



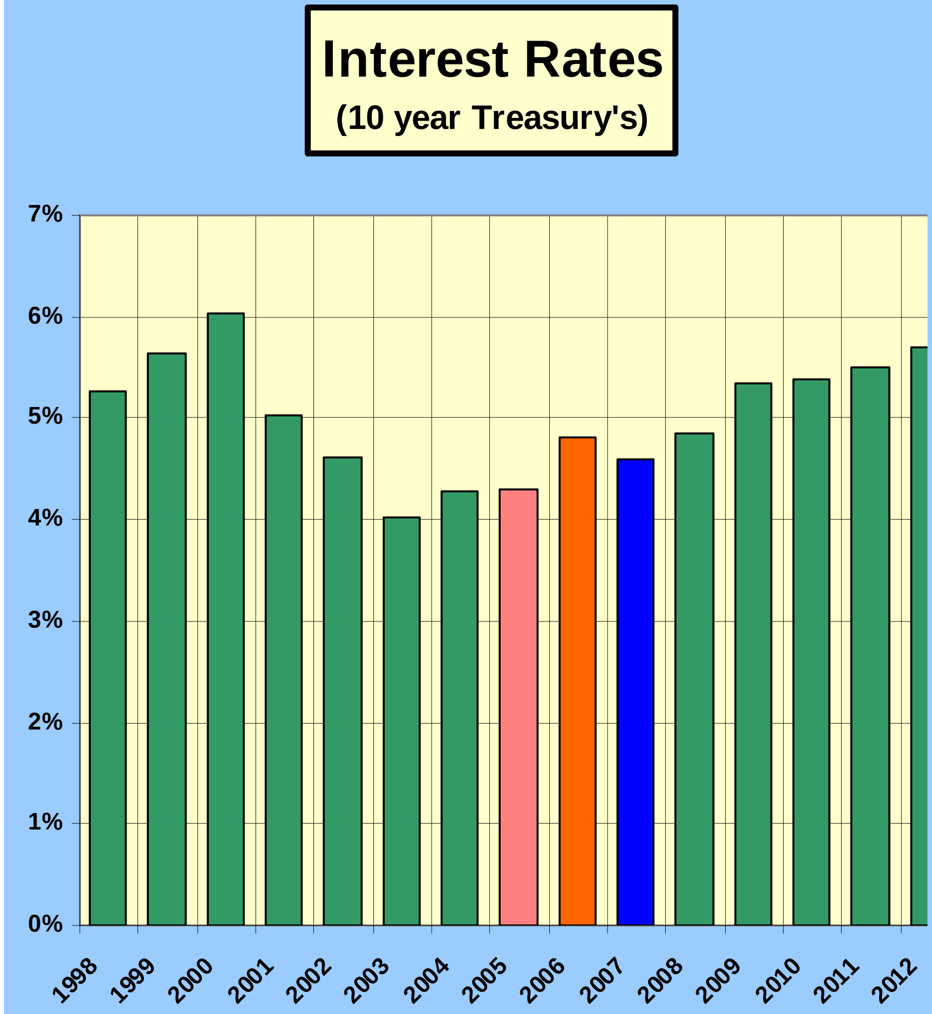
We answer to you.

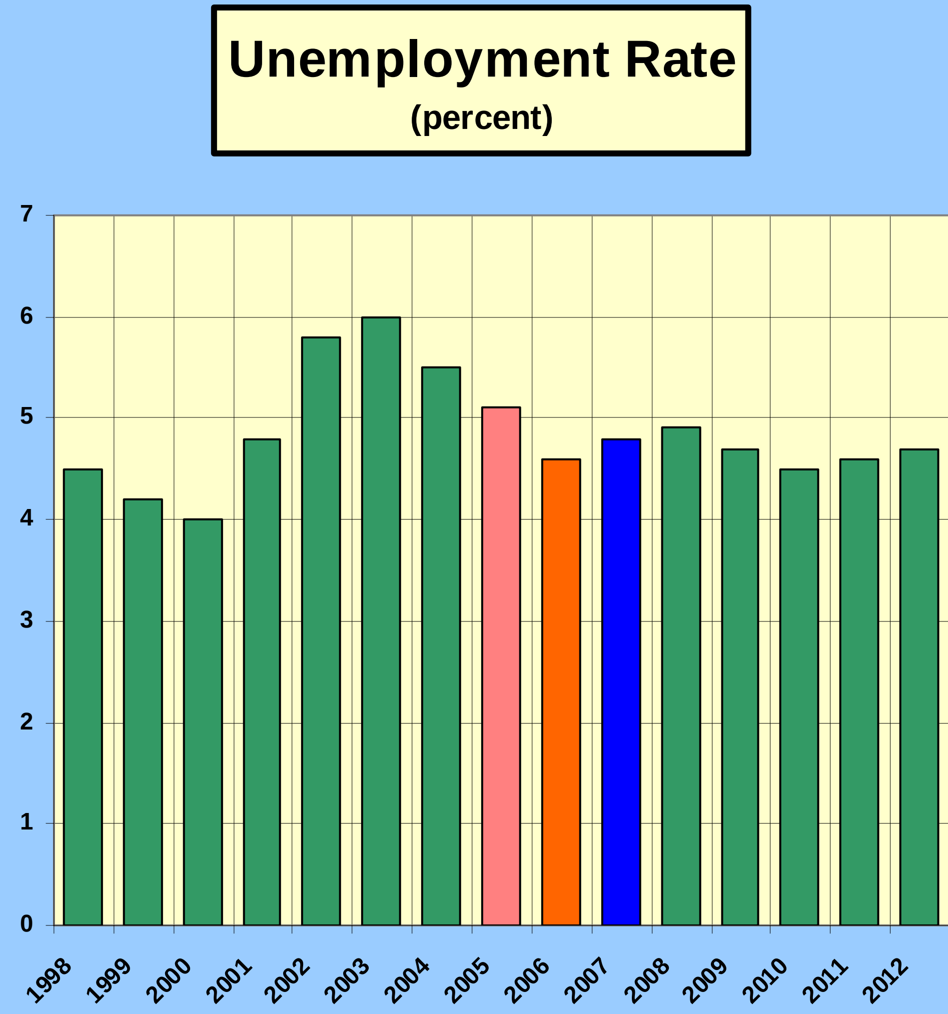
AVISTA



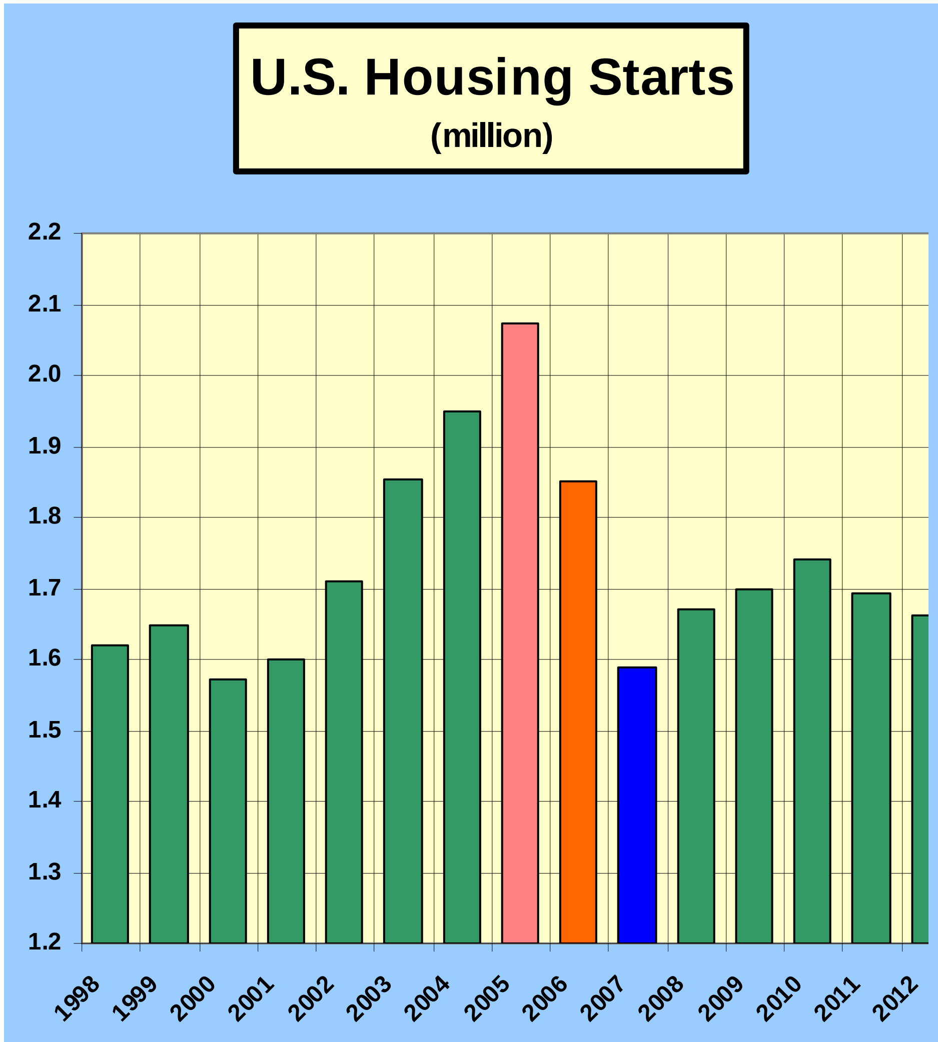


We answer to you.





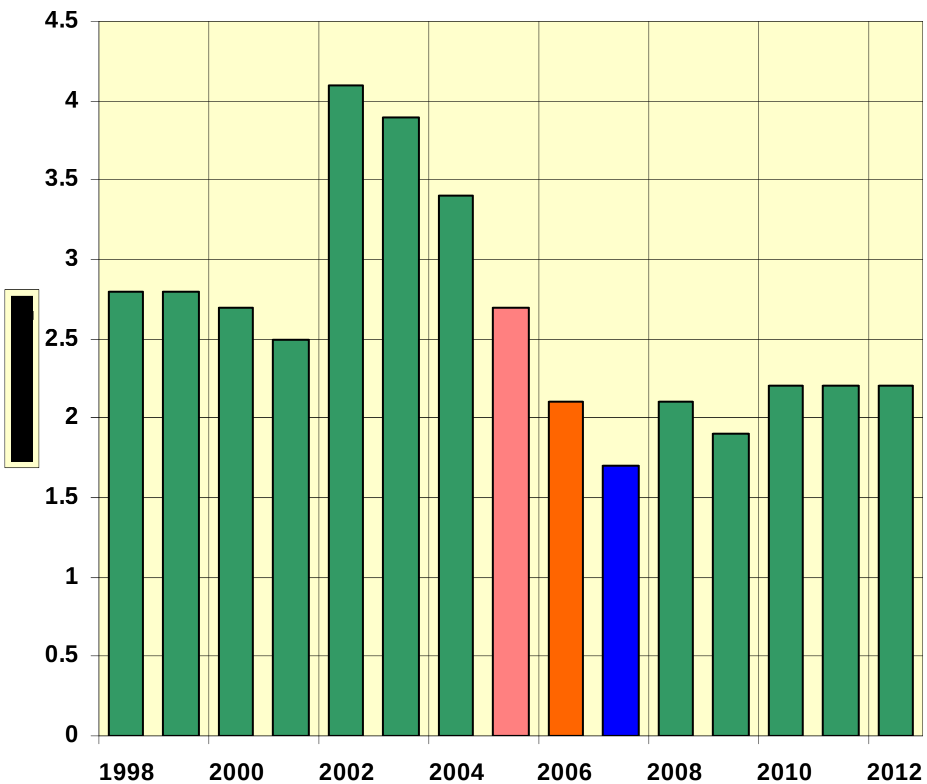
We answer to you.



We answer to you.

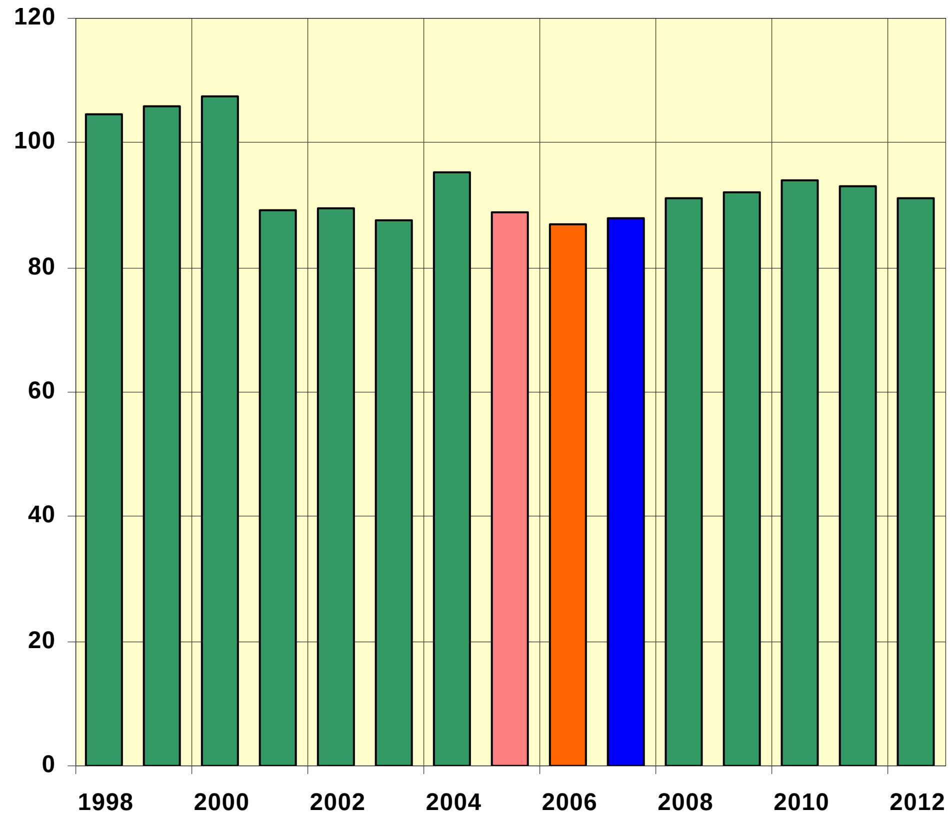
Productivity

Output per Worker



Consumer Sentiment

University of Michigan



We answer to you.

AVISTA

Regional Economy

- Global Insight County Forecasts
- Methodology
- Addressing acknowledgement shortcoming

- Both Idaho and Washington use Global Insight forecasts for various governmental planning efforts

We answer to you.

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

We answer to you.

Historical Data

GLOBAL INSIGHT

- 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

GLOBAL INSIGHT

– 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

We answer to you.

AVISTA

Forecast Methodology Overview

GLOBAL INSIGHT

- 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

We answer to you.

Methodology: Details

- Base Emp: Mfg, Mining, Fed Govt, S&L Govt (if capital)
  - Mfg: EEMFG=EEMFG.1 * (generated ratio)^k.
  - Other Base sectors: Grow like State
- Nonbase Emp
  - Δ Cty NB = Δ Cty Base * (Δ State Base/ Δ State NB)
- Income:
  - Average Annual Wage: Grow like State
  - (Nonwage Income/WD) for Cty grown like same for St
- Population:
  - Δ Cty Pop = Δ Cty Emp * (Δ State Pop/ Δ State Emp)
- Lastly, Constrained to Metro

We answer to you.

Methodology: Details

– Pop Cohorts:
  - Use cohort shares of total population
  - Ctyshr/Ctyshr.1 = (StShr/StShr.1) *

    (Growth in CtyShr between Census Pts)^[1/N] / (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)
  - Δ Headship for Cty Coh moves like Δ Headship for St Coh
  - Headship Rates * Pop → HH Cohort → Sum to Total HH

We answer to you.

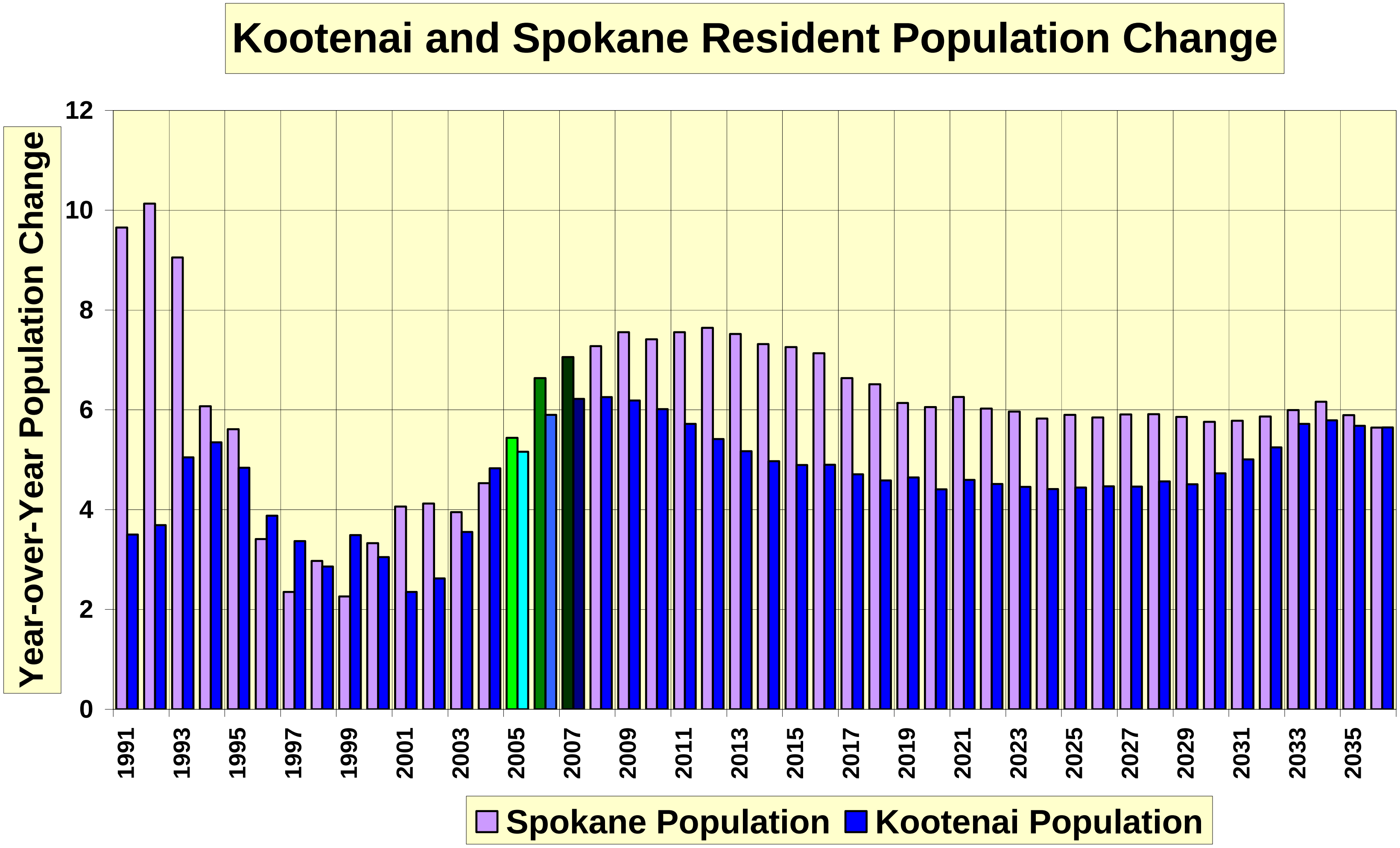
AVISTA

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

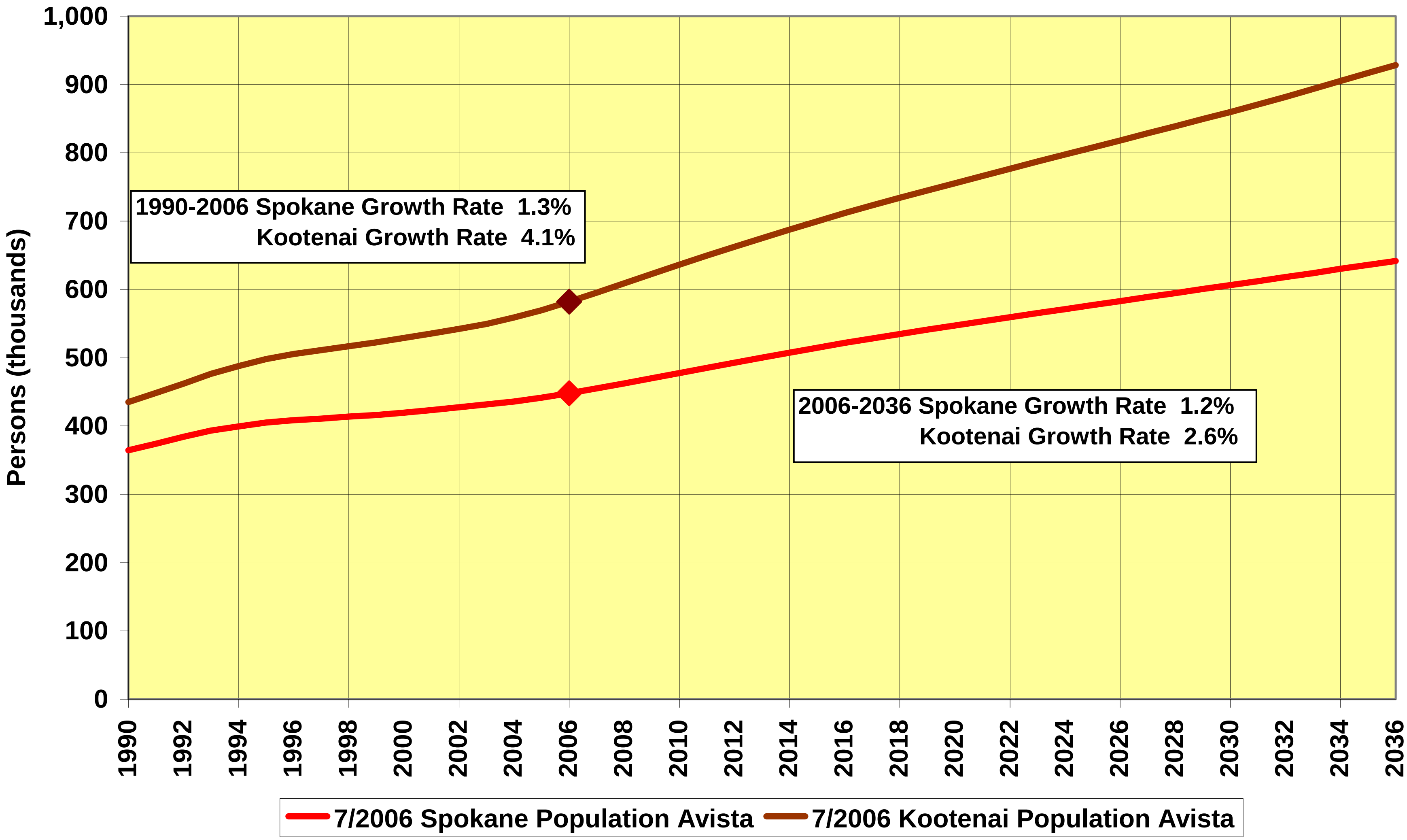
We answer to you.

Kootenai and Spokane County Population Trends



We answer to you.

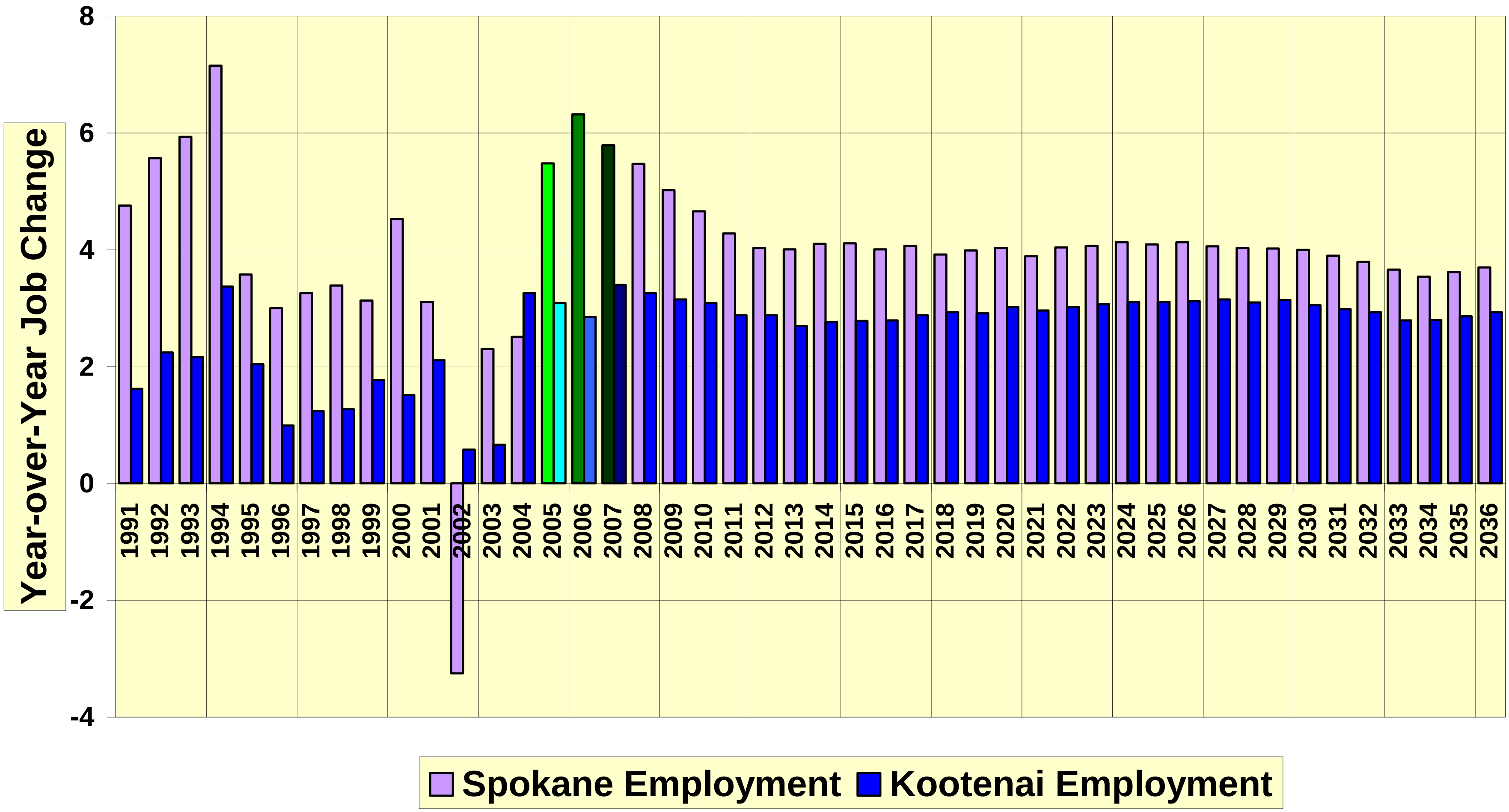
Kootenai and Spokane Population Total



We answer to you.

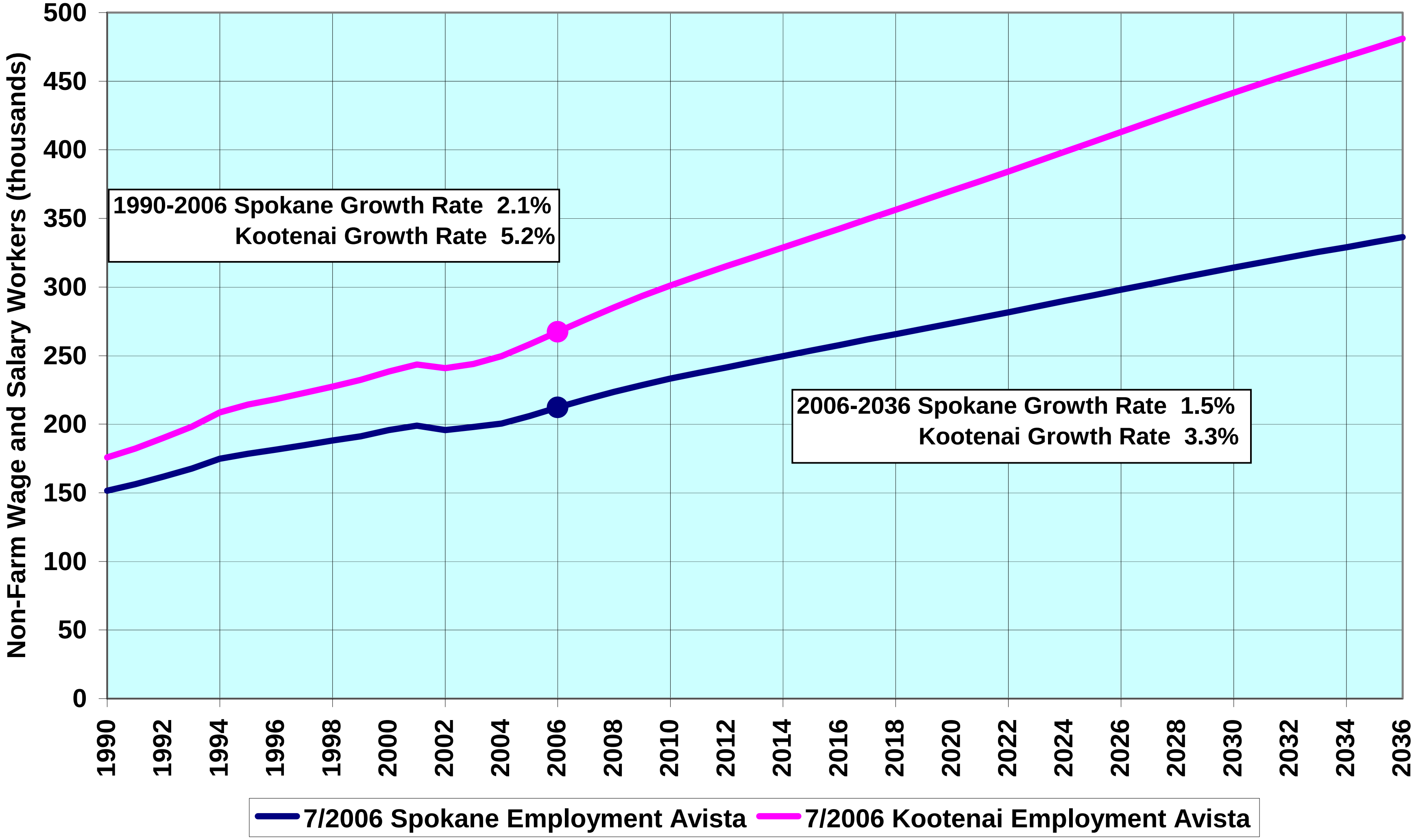
AVISTA

Kootenai and Spokane Non-Farm Employment Change



We answer to you.

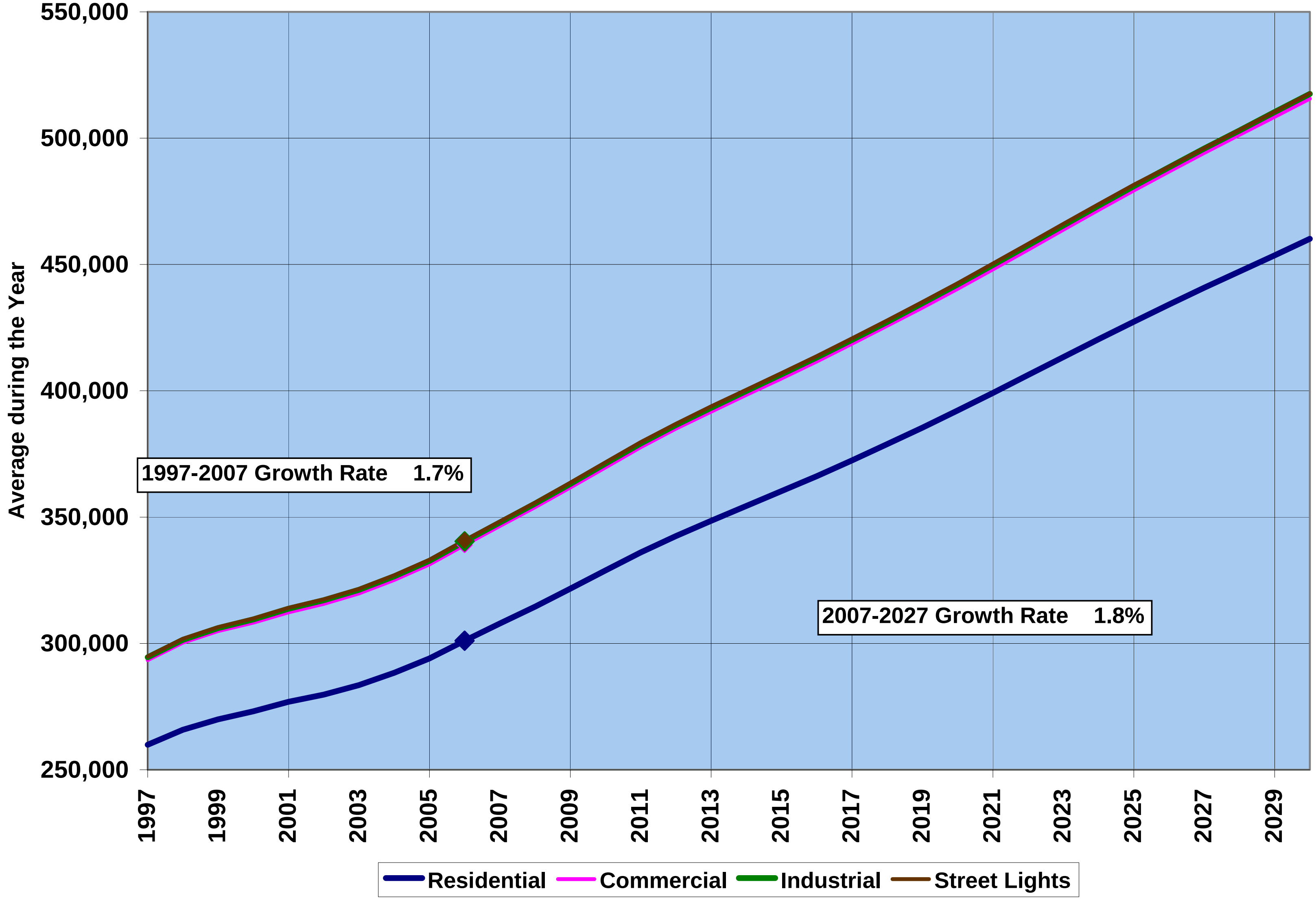
Kootenai and Spokane Job Total



We answer to you.

AVISTA

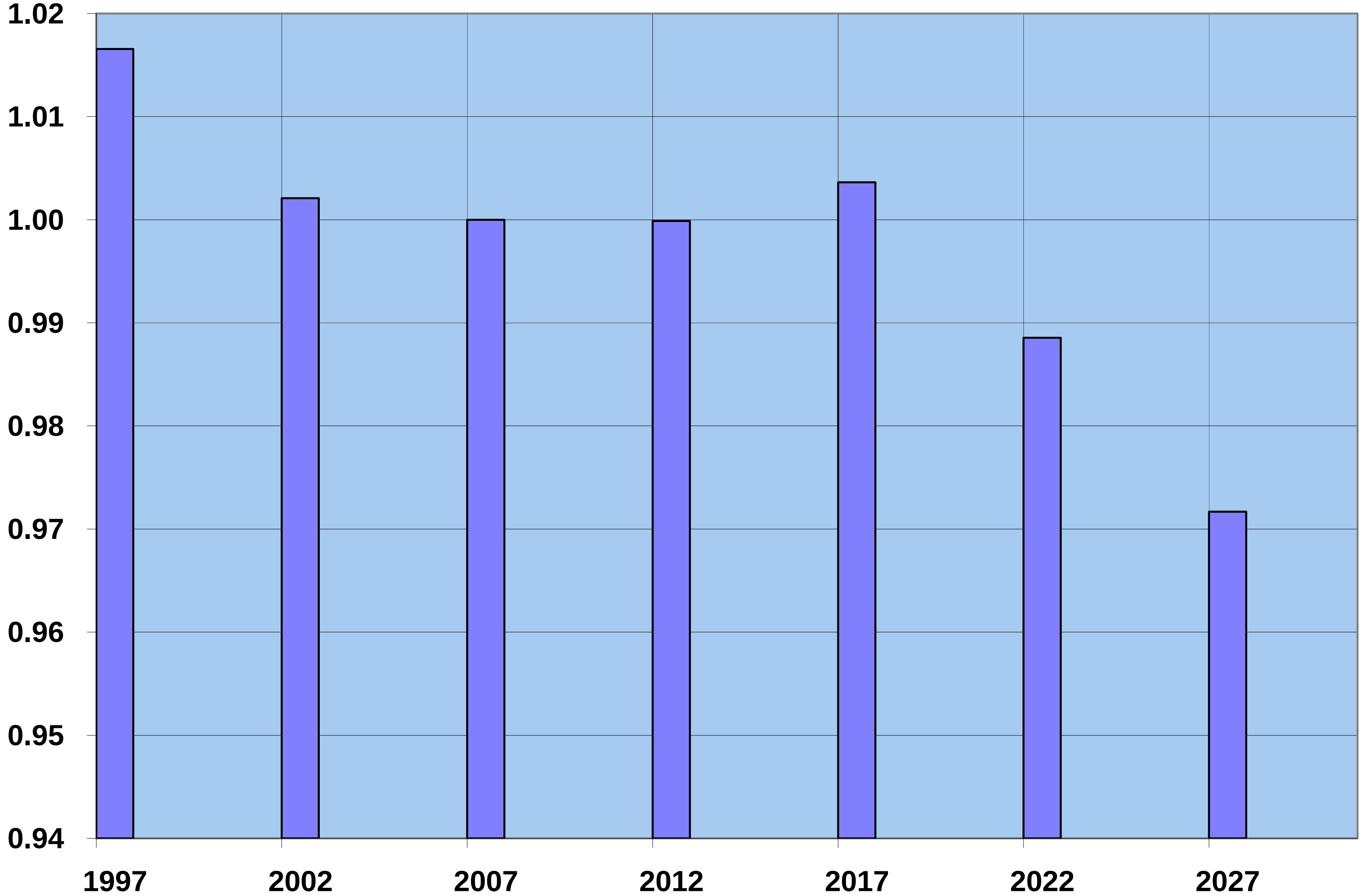
Electric Customer Forecast—Base Case



We answer to you.

AVISTA

Residential Customers—Index of Persons per Unit



We answer to you.

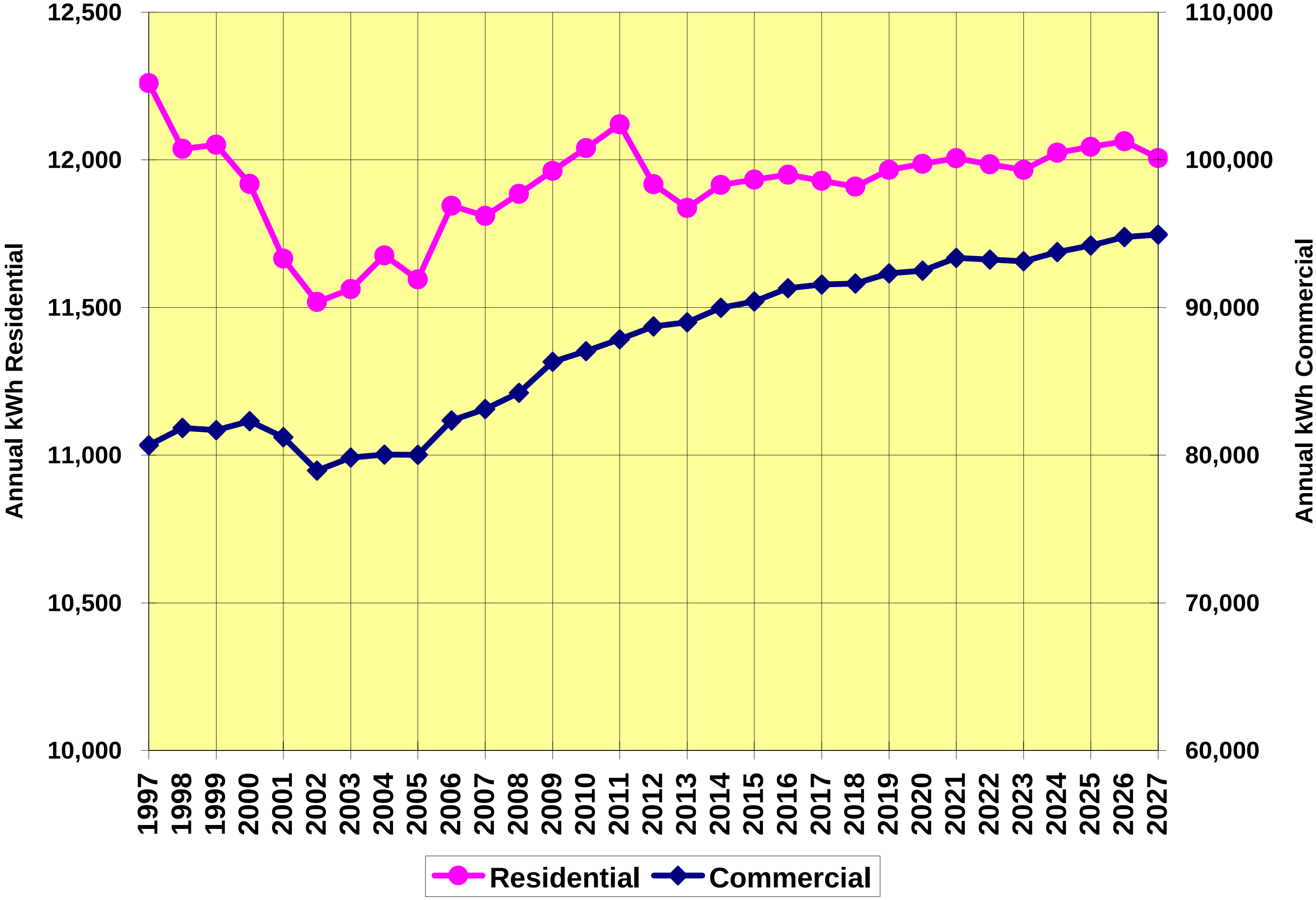
Prices, Price Elasticity, and Use per Customer

- 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
    - Idaho in 2009, 2014, 2019, 2024
    - Washington in 2008, 2013, 2018, 2025
  - 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)

We answer to you.

AVISTA

Residential kWh Use Per Customer

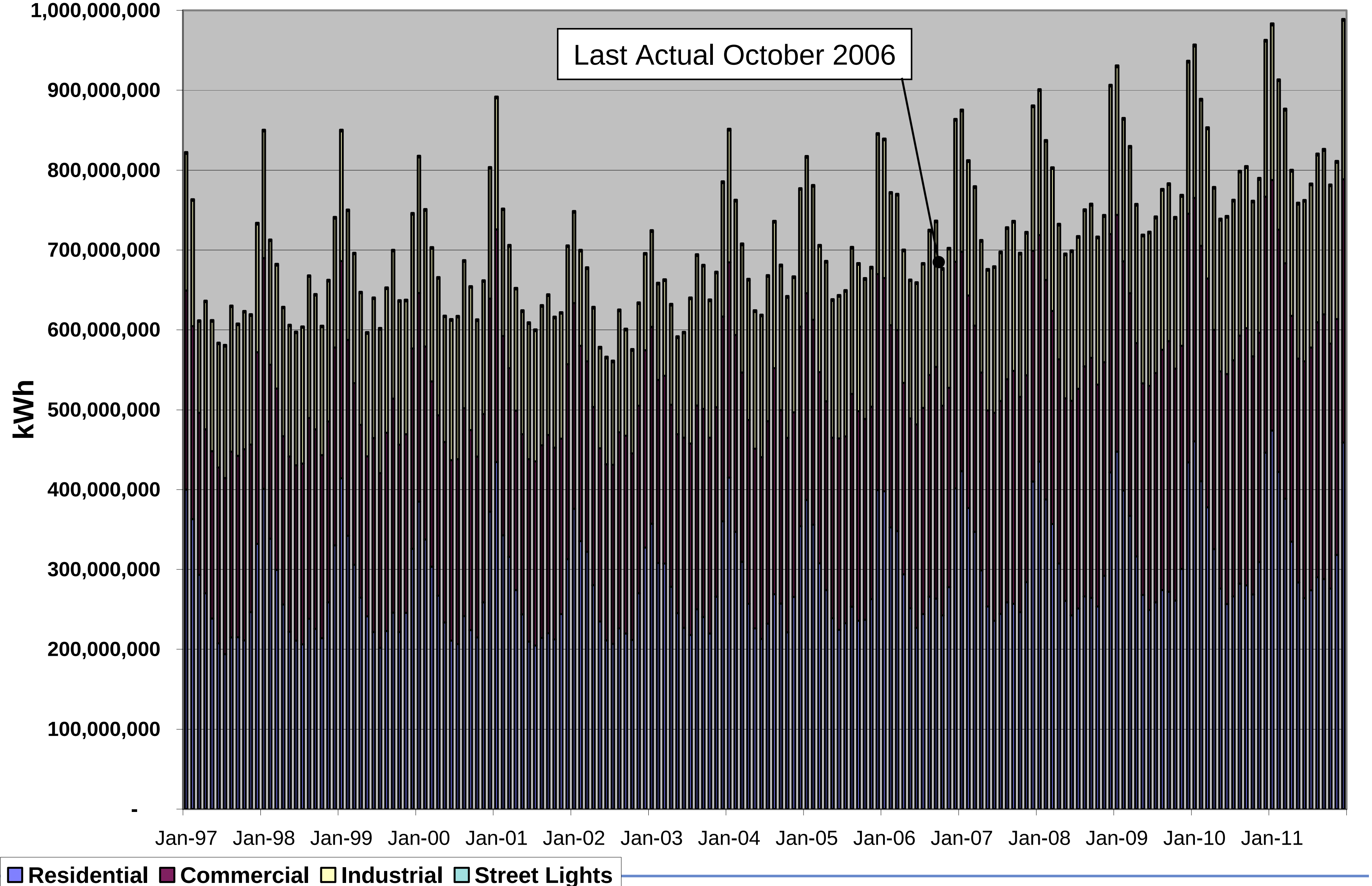


Sales Forecasts

- 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

We answer to you.

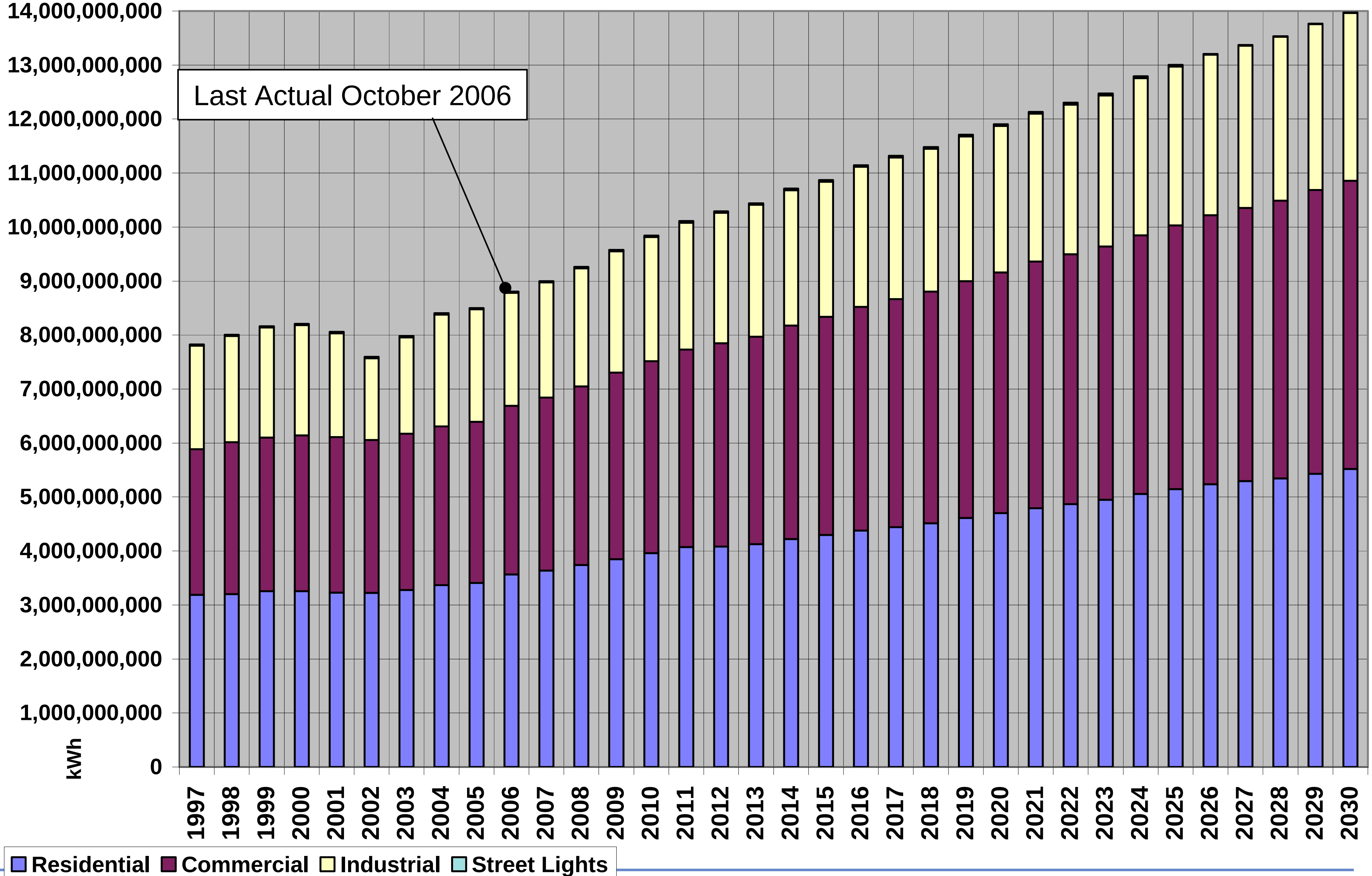
Monthly Historical and Forecast Sales



We answer to you.

AVISTA

Annual Historical and Forecast Sales



Thursday, January 11, 2007

77

We answer to you.

AVISTA

- 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

We answer to you.

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

We answer to you.

Avista, DSM and the 2007 Electric IRP

Bruce Folsom & Jon Powell

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

We answer to you.

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)*

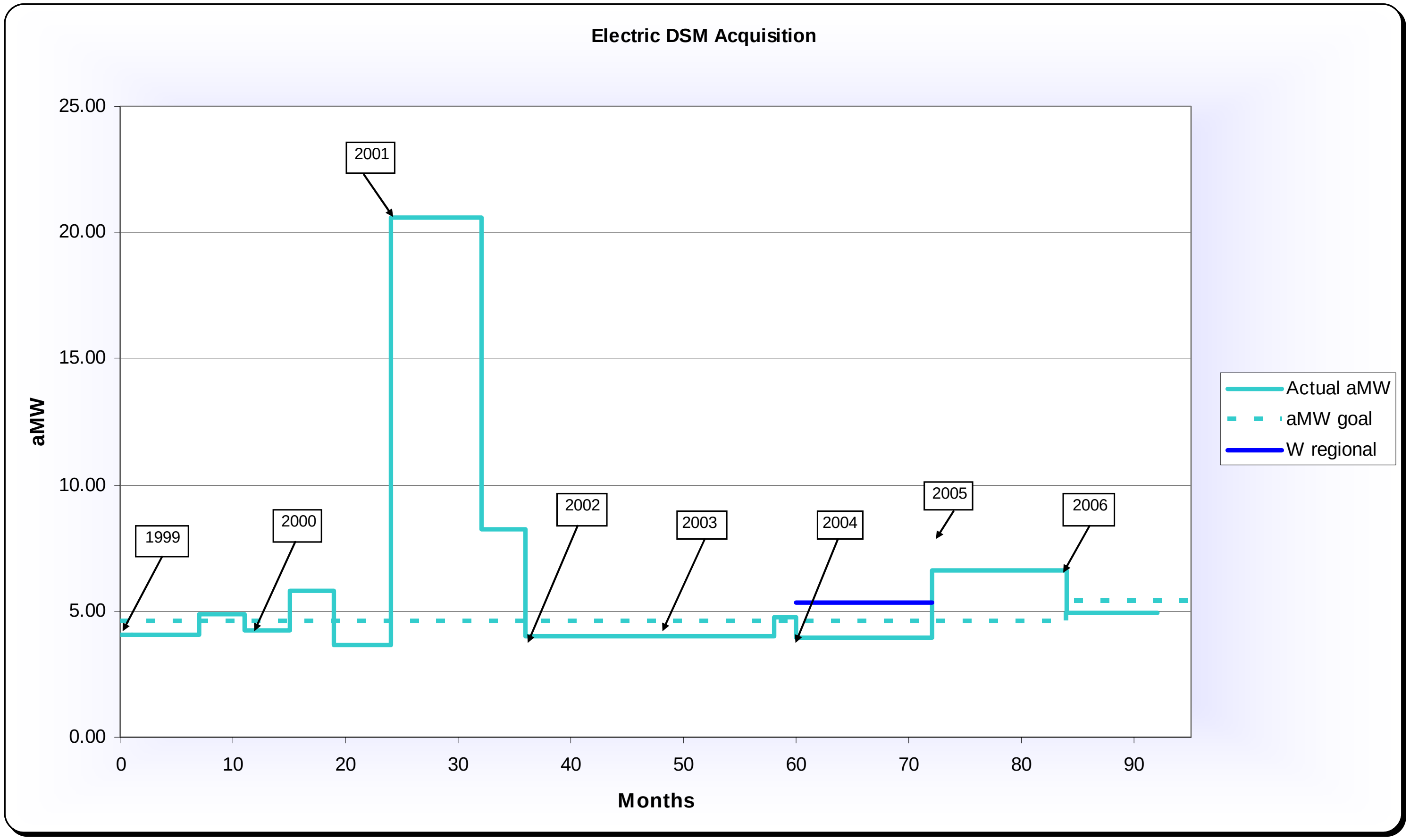
We answer to you.

A Historical Context for Avista DSM

- Electric DSM first offered in 1978
- 1992-1994 Energy Exchanger program
- 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

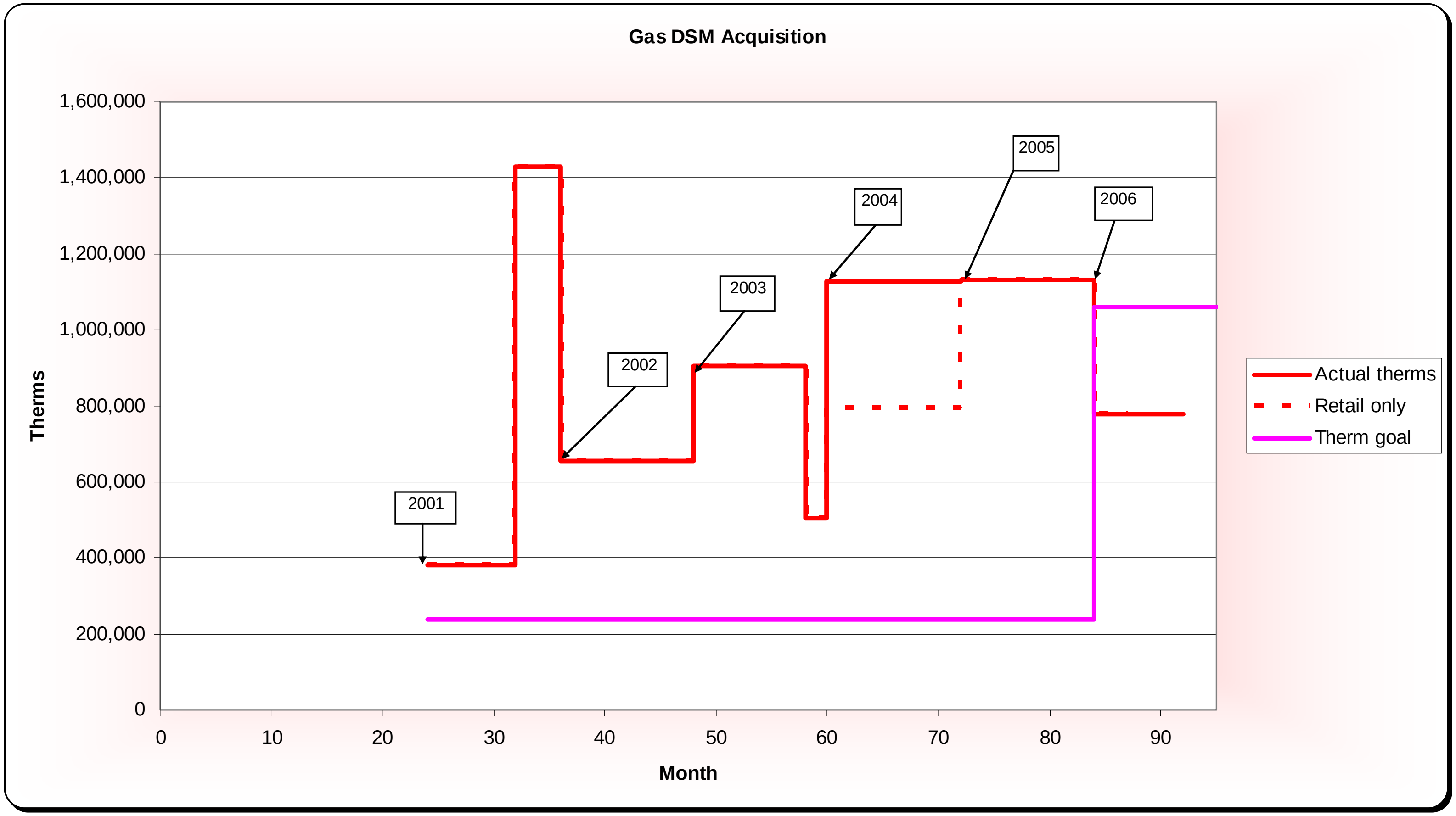
We answer to you.

Avista DSM Achievements



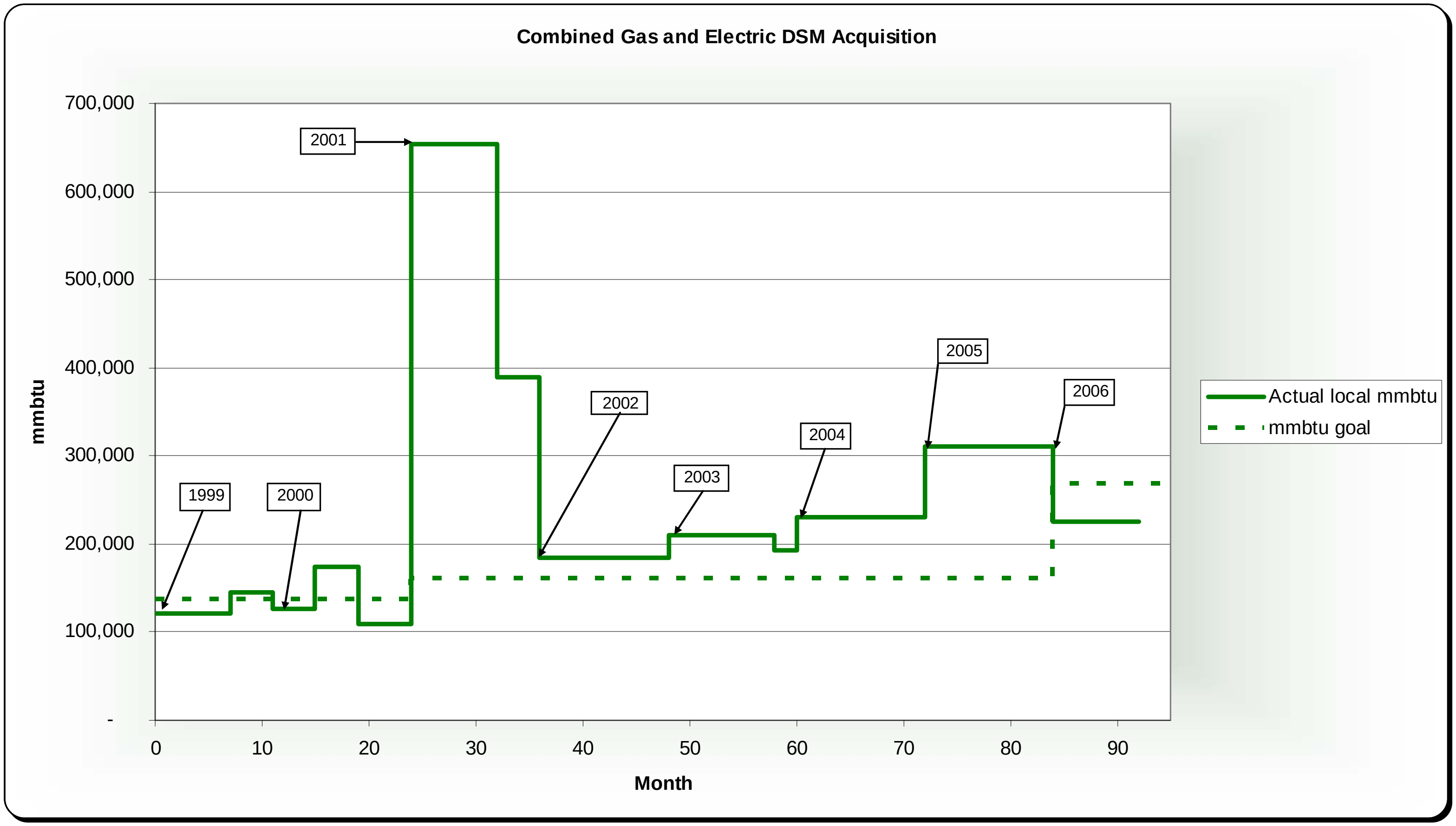
We answer to you.

Avista DSM Achievements



We answer to you.

Avista DSM Achievements



We answer to you.

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

We answer to you.

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

We answer to you.

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

We answer to you.

AVISTA

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

We answer to you.

Starting Point for Expanded Initiative

- Track record of innovation
- Energy efficiency programs among best in the country
  - 1992-1994 – "The Energy Exchanger Era"
  - 1995-2000 – "The Tariff Rider Era"
  - 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

We answer to you.

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

We answer to you.

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

We answer to you.

AVISTA

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

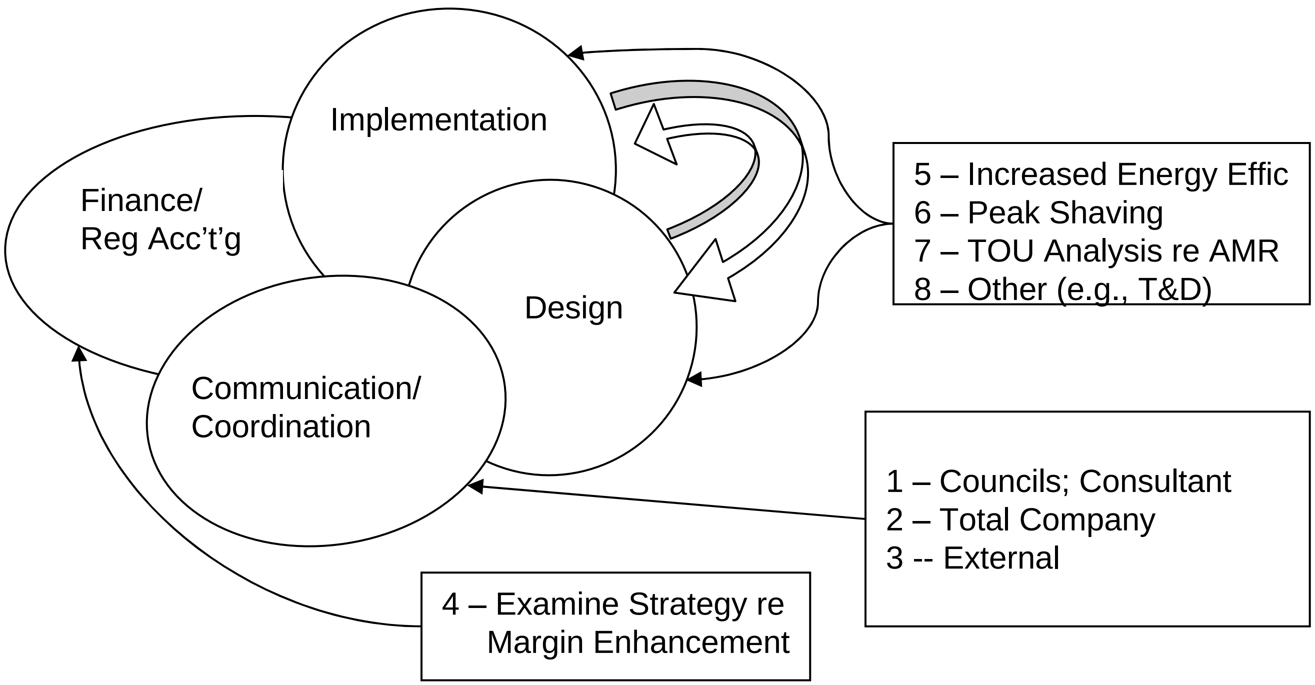
We answer to you.

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



We answer to you.

AVISTA

Some Key Activities

- Assessments
  - Review all potential energy efficiency programs <u>and</u> delivery options
  - Survey industry best practices
  - Survey all demand response programs with segmentation by typ
- Communication and coordination
- Milestone establishment and monitoring

We answer to you.

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

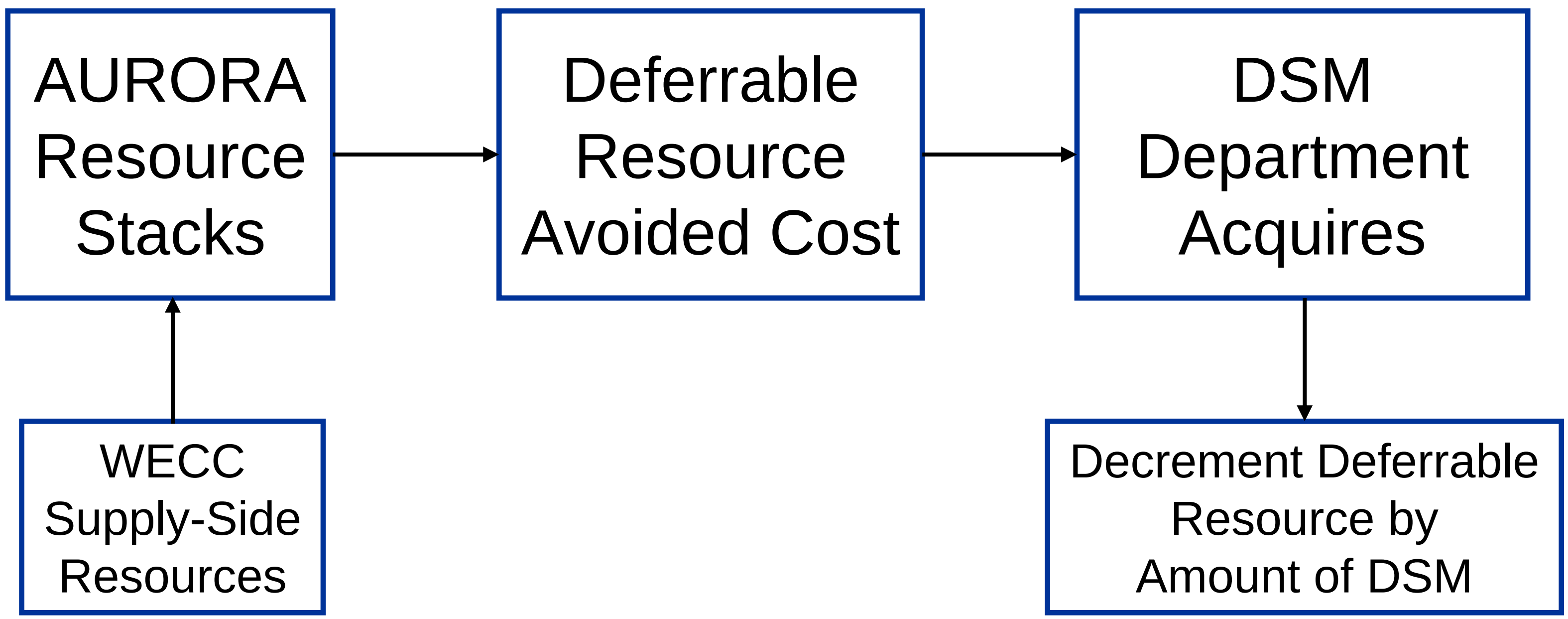
We answer to you.

AVISTA

Integration of DSM into the 2007 IRP

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

Integration by Price Signal



We answer to you.

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.

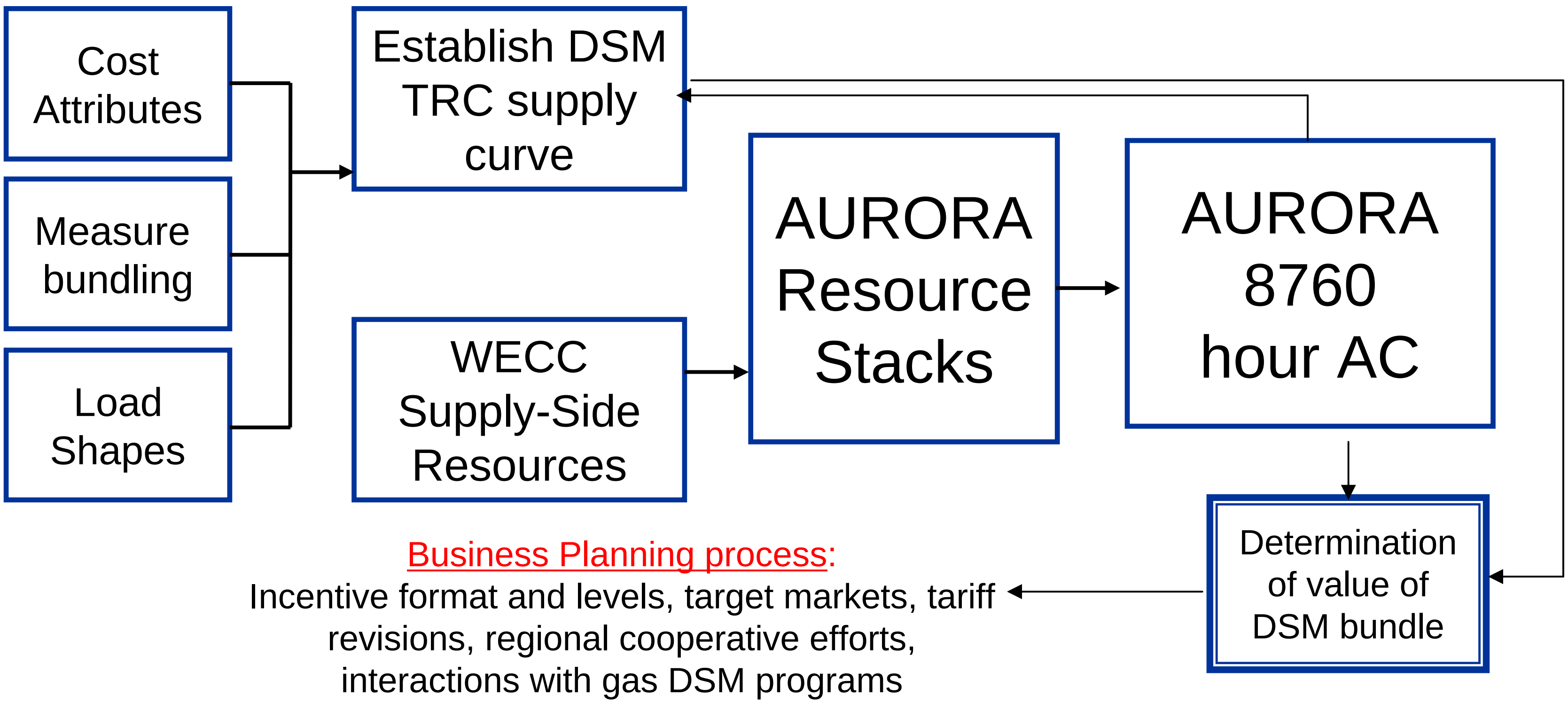
We answer to you.

AVISTA

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



We answer to you.

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

	Topic	Time	Staff
1.	Introductions	9:30	Barcus
2.	Review of 3rd TAC Meeting	9:35	Lyons
3.	Market Analysis	9:45	Gall
4.	Load Forecast – Global Warming	11:00	Barcus
5.	Conservation Program Update	11:30	Folsom
6.	Lunch – DSM Presentation	12:00	
7.	Portfolio Selection Criteria	1:00	Gall
8.	Cost of Service	2:00	Knox
9.	Transmission Estimates	2:30	Gnaedinger
10.	Adjourn	3:30	

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

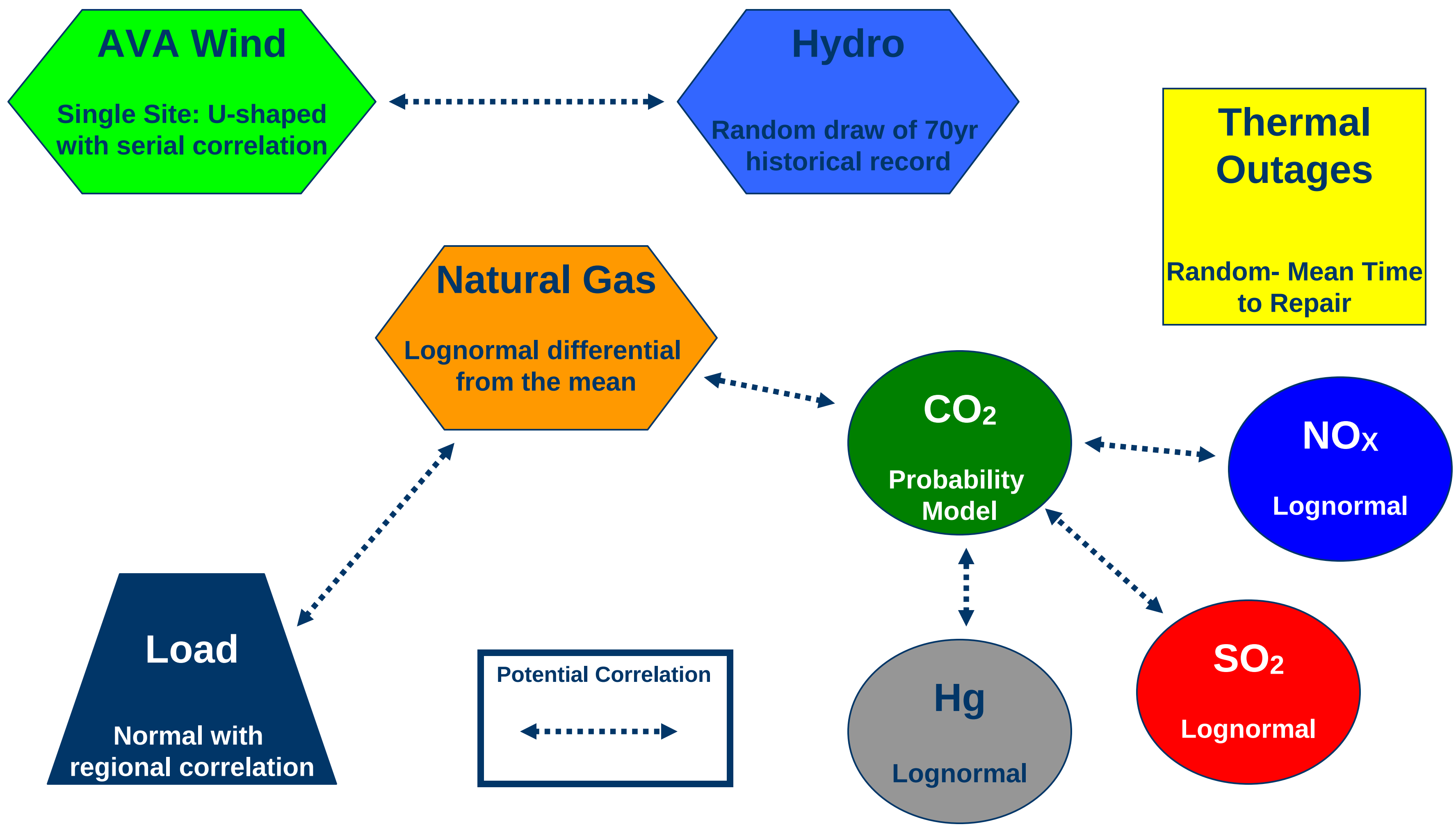
Key Changes

- 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 on 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



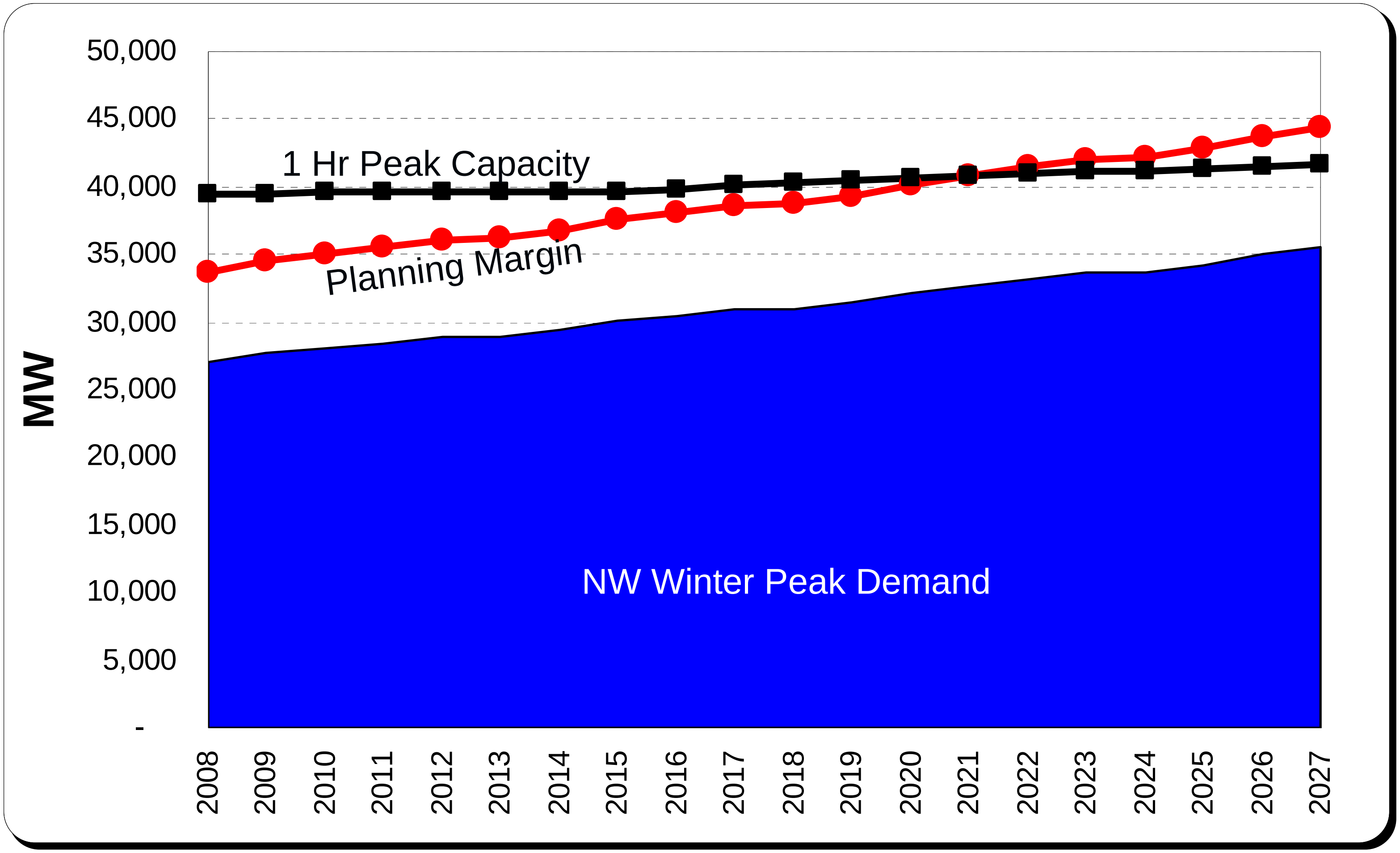
Base Case Key Assumptions

	Entire Study	2008	2017	2027
Natural Gas Price @ Sumas ($/dth)	$5.42 (Real)	$6.54 (Nominal)	$6.44 (Nominal)	$11.18 (Nominal)
Natural Gas Price @ Henry Hub ($/dth)	$6.31 (Real)	$7.62 (Nominal)	$7.50 (Nominal)	$13.02 (Nominal)
Northwest Load (aMW), (WA, OR, N. Idaho)	1.72% (AAGR)	17,584	20,708	24,715
Western Interconnect Load (aMW)	1.95% (AAGR)	100,056	120,056	147,348
Northwest Non-Coincident Peak Demand (MW), (WA, OR, N. Idaho)	1.38% (AAGR)	25,749	29,311	33,863
Western Interconnect Non-Coincident Peak Demand (MW)	2.37% (AAGR)	162,672	202,388	259,667
Hydro Energy (aMW)	14,152	14,067	14,162	14,162
CO_2 Tax ($/Ton)	$4.35 (Real)	$0.00	$9.54 (Nominal)	$14.45 (Nominal)

Base Case: New Resource Selection Western Interconnect *(Cumulative Nameplate MW)*

	2010	2015	2020	2027
CCCT	5,280	15,360	23,040	46,080
SCCT	17,002	31,793	46,661	52,761
Pulverized coal	0	2,800	3,600	5,200
IGCC coal	0	0	2,550	11,900
IGCC coal w/ sequestration	0	0	0	0
Wind (economic)	0	0	0	0
Nuclear	0	0	0	0
RPS wind	2,016	9,499	20,046	29,086
RPS other	638	2,177	4,331	6,457
Total Excluding Wind	*22,920*	*52,130*	*80,182*	*122,398*
Total With Wind @ 33%	*23,585*	*55,265*	*86,797*	*131,966*

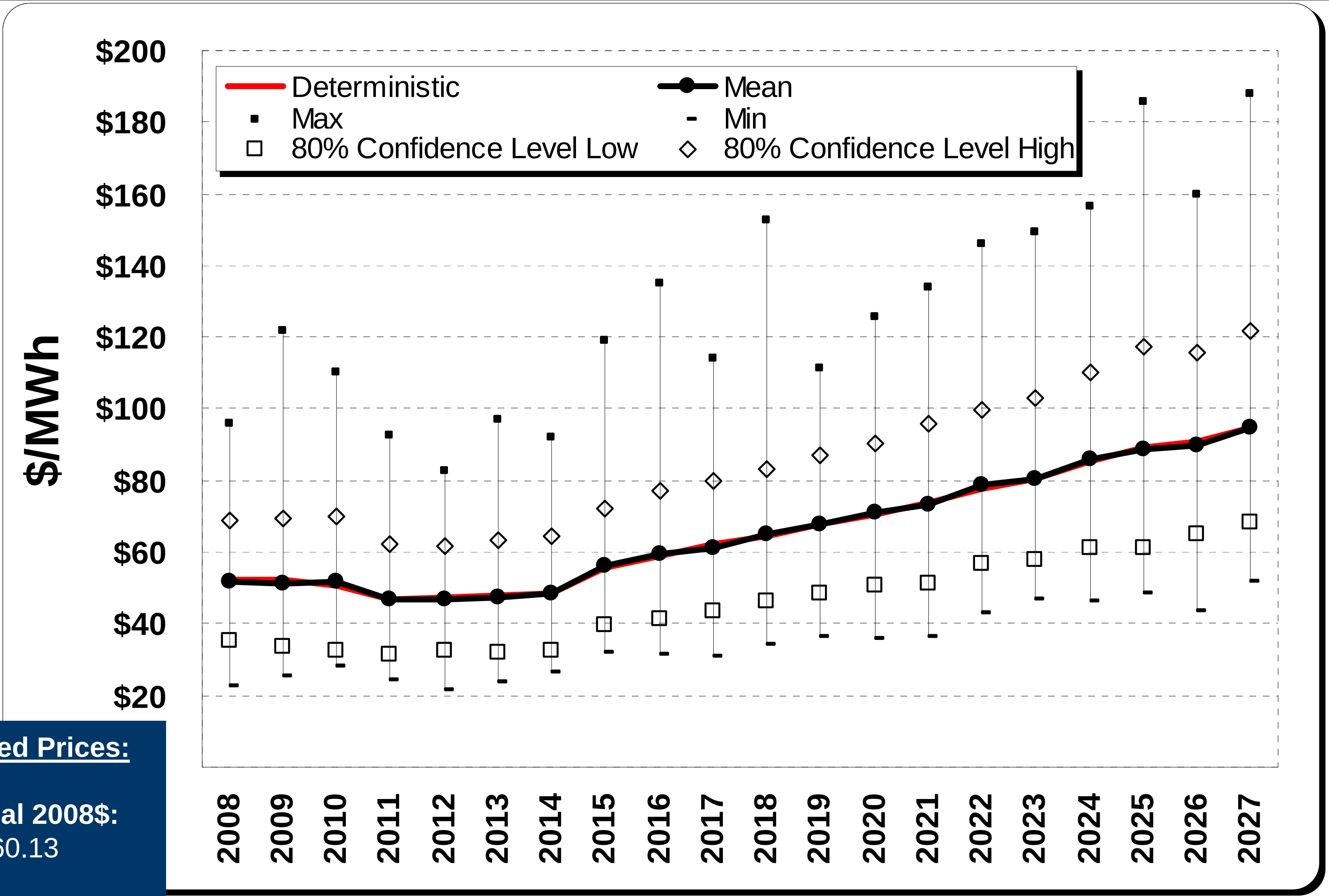
Base Case: Northwest Resource Need
25% Planning Margin, 15% Wind Contribution



Base Case: New Resource Selection in Northwest *(Cumulative Nameplate MW)*

	2010	2015	2020	2027
CCCT	0	0	0	1,920
SCCT	0	0	0	540
Pulverized coal	0	0	0	0
IGCC coal	0	0	0	0
IGCC coal w/ sequestration	0	0	0	0
Wind (economic)	0	0	0	0
Nuclear	0	0	0	0
RPS wind	0	44	2,832	5,835
RPS other	150	261	1,017	1,871
Total Excluding Wind	*150*	*261*	*1,017*	*4,331*
Total With Wind @ 33%	*150*	*276*	*1,952*	*6,257*

Base Case Annual Average Mid-C Prices
Nominal Dollars

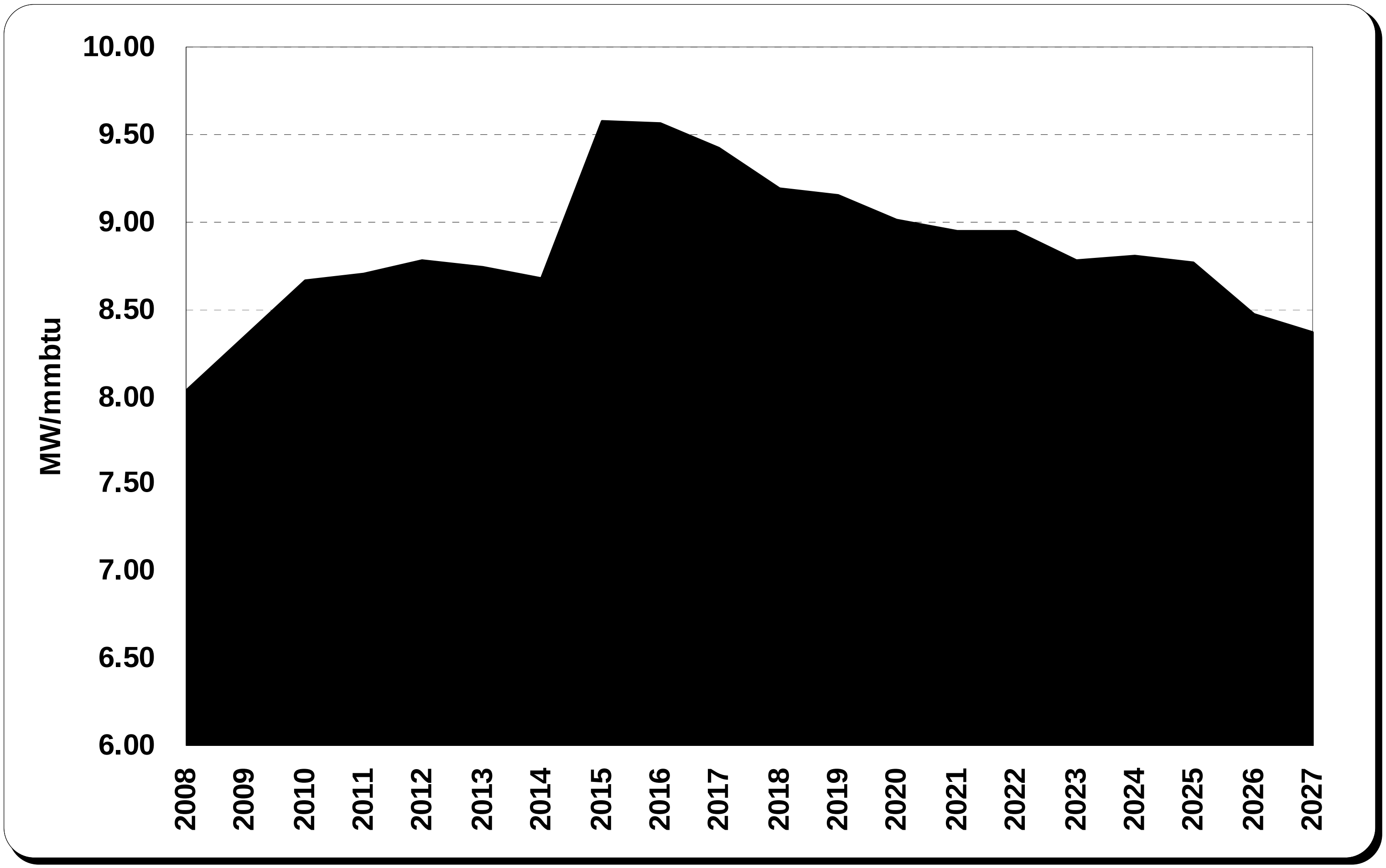


Levelized Prices:

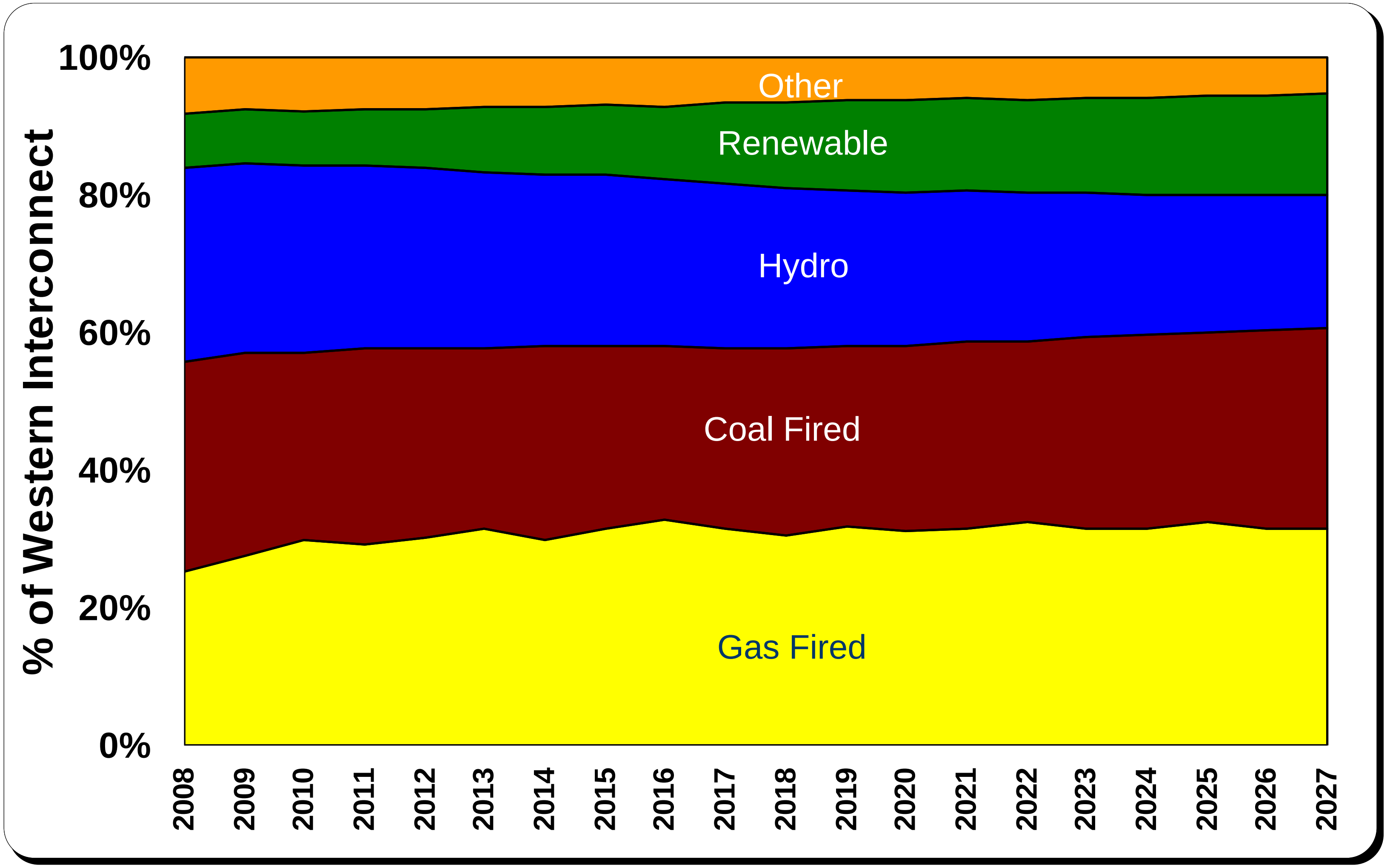
Nominal 2008$:
$60.13

Real 2007$:
$49.59

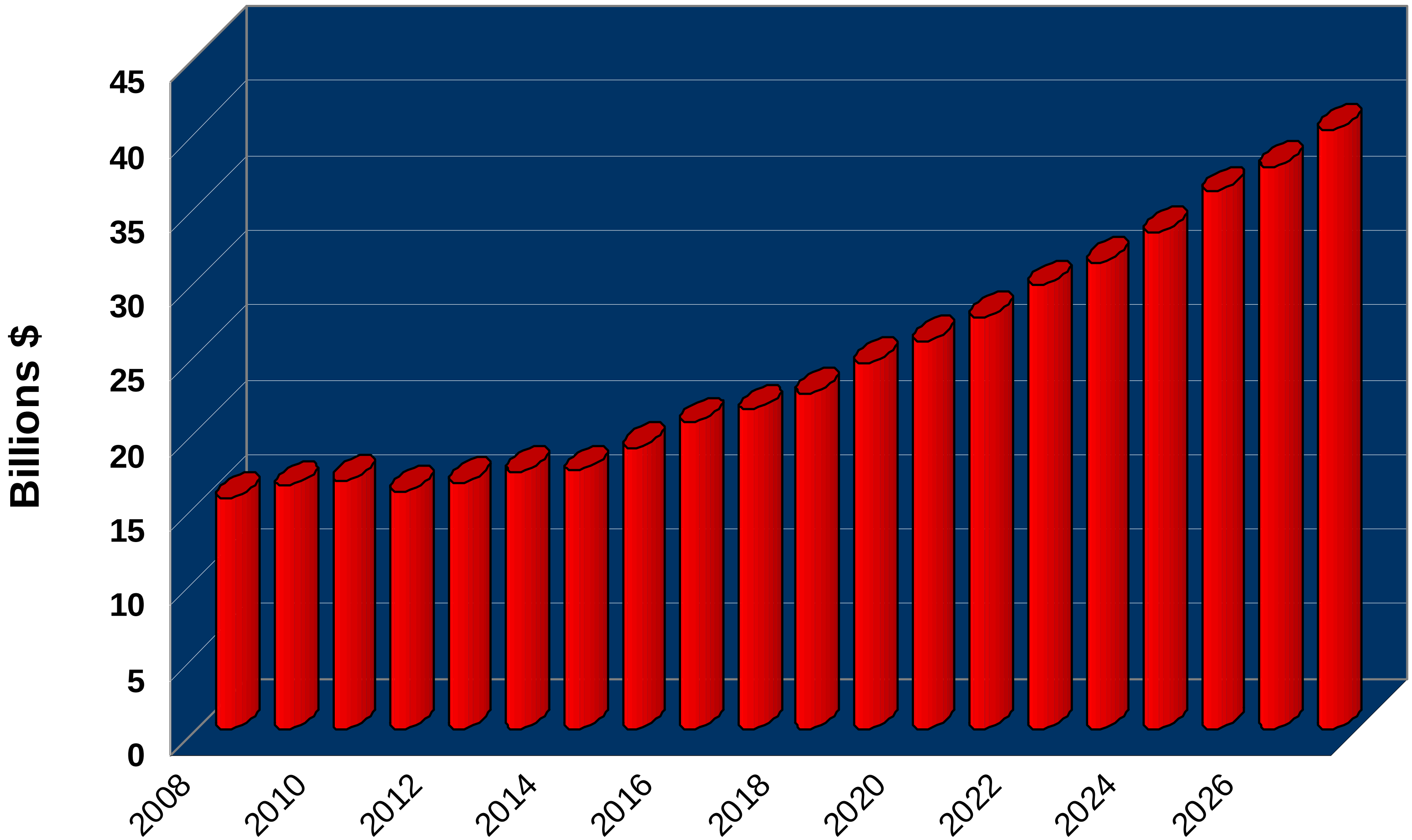
Market Implied Heat Rate- Not Adjusted for CO_2 Tax (Mid-C Electric Price/Sumas NG Price)



Western Interconnect Resource Contribution
(% of Total Energy)



Western Interconnect Total Fuel Costs in Millions Average Annual Growth Rate ~4.9%



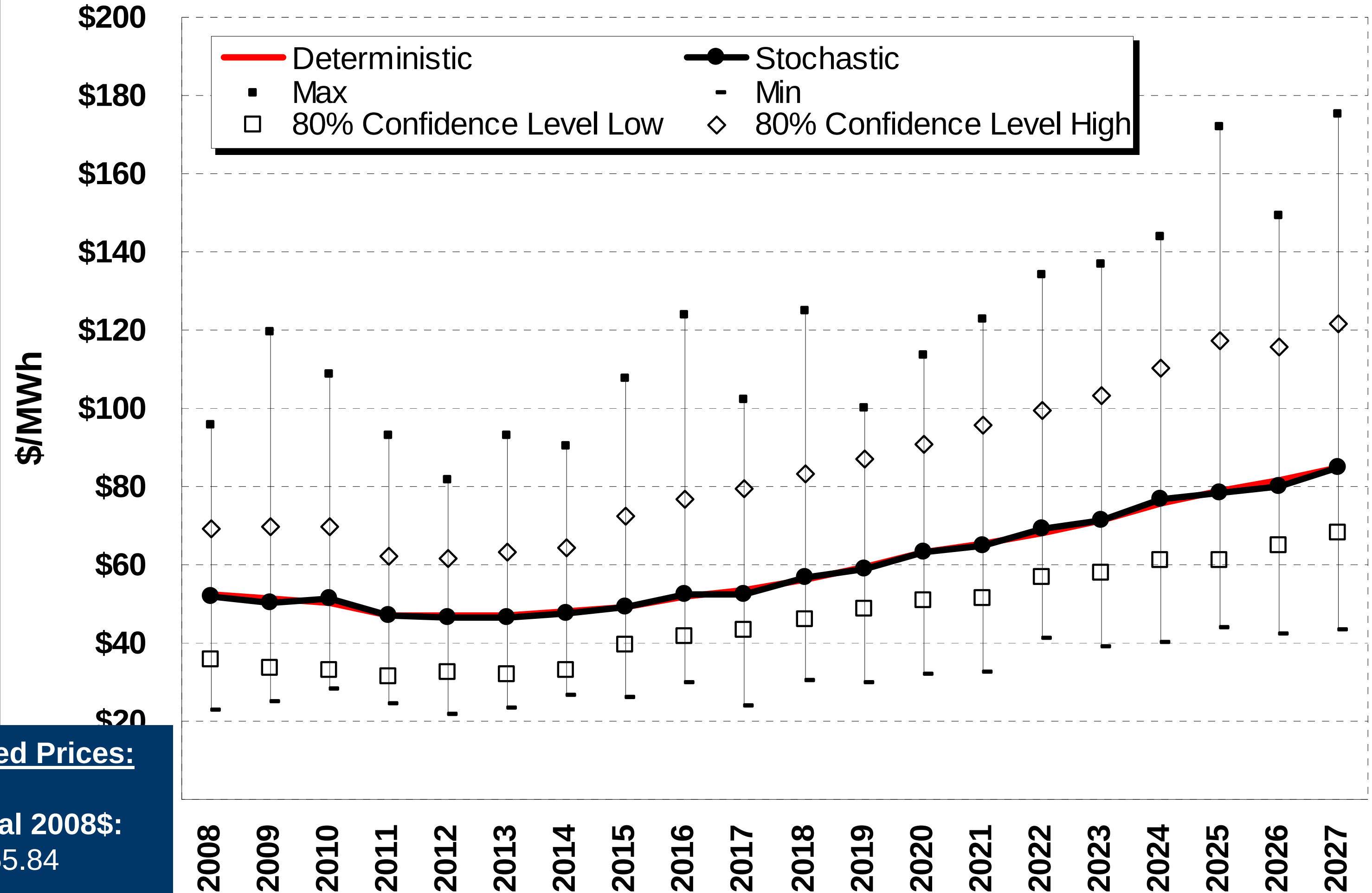
Futures

- 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 CO_2 Taxes: New Resource Selection Western Interconnect *(Cumulative Nameplate)*

	2010	2015	2020	2027
CCCT	2,400	15,360	23,040	48,000
SCCT	19,860	31,693	45,299	49,031
Pulverized coal	0	3,600	4,400	6,800
IGCC coal	0	425	6,375	11,900
IGCC coal w/ sequestration	0	0	0	0
Wind (economic)	0	0	0	0
Nuclear	0	0	0	0
RPS wind	2,016	9,499	20,046	29,086
RPS other	638	2,177	4,331	6,457
Total Excluding Wind	22,898	53,255	83,445	122,188
Total With Wind @ 33%	23,563	56,390	90,060	131,786

No CO_2 Tax: Annual Average Mid-C Prices
Nominal Dollars

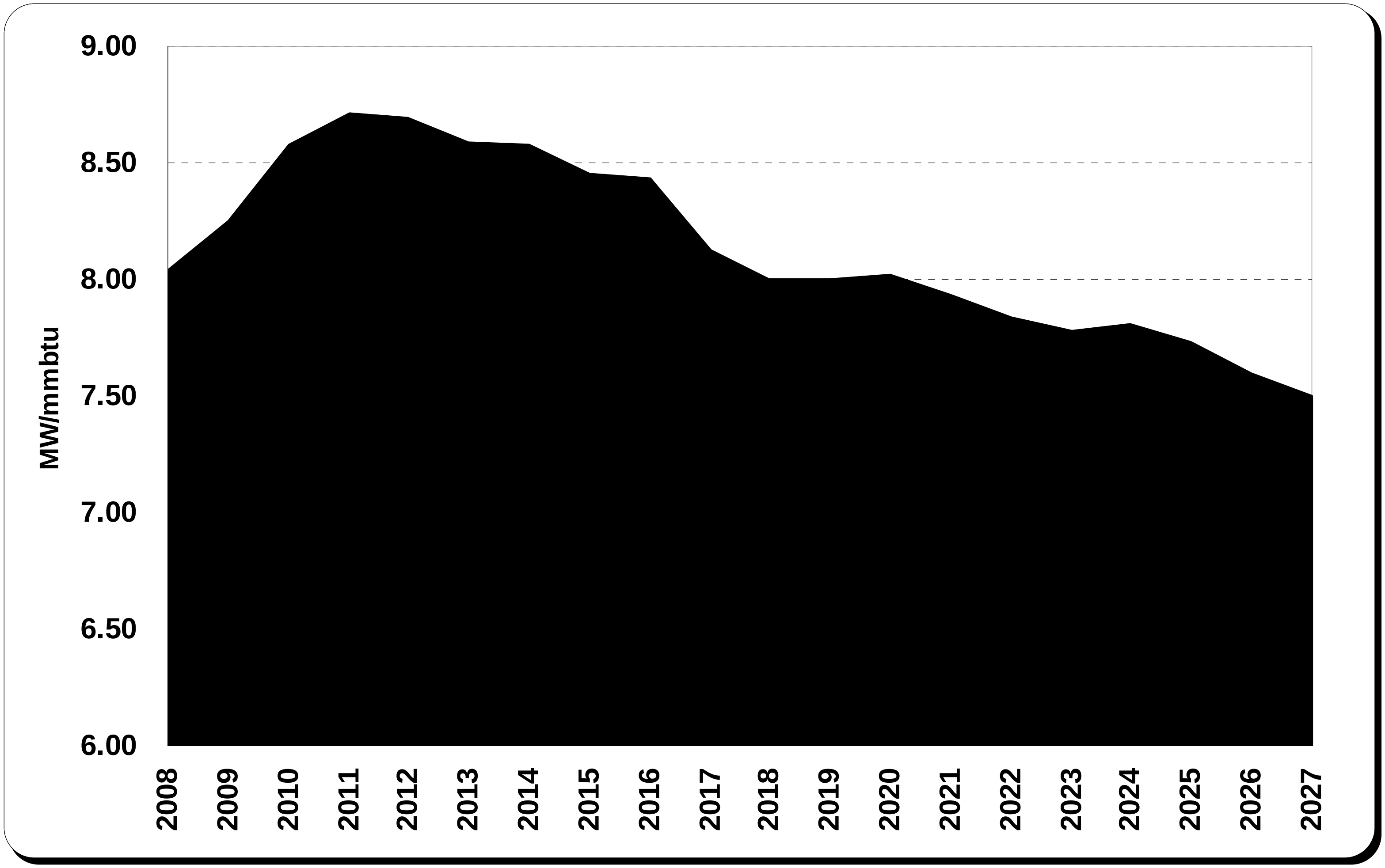


Levelized Prices:

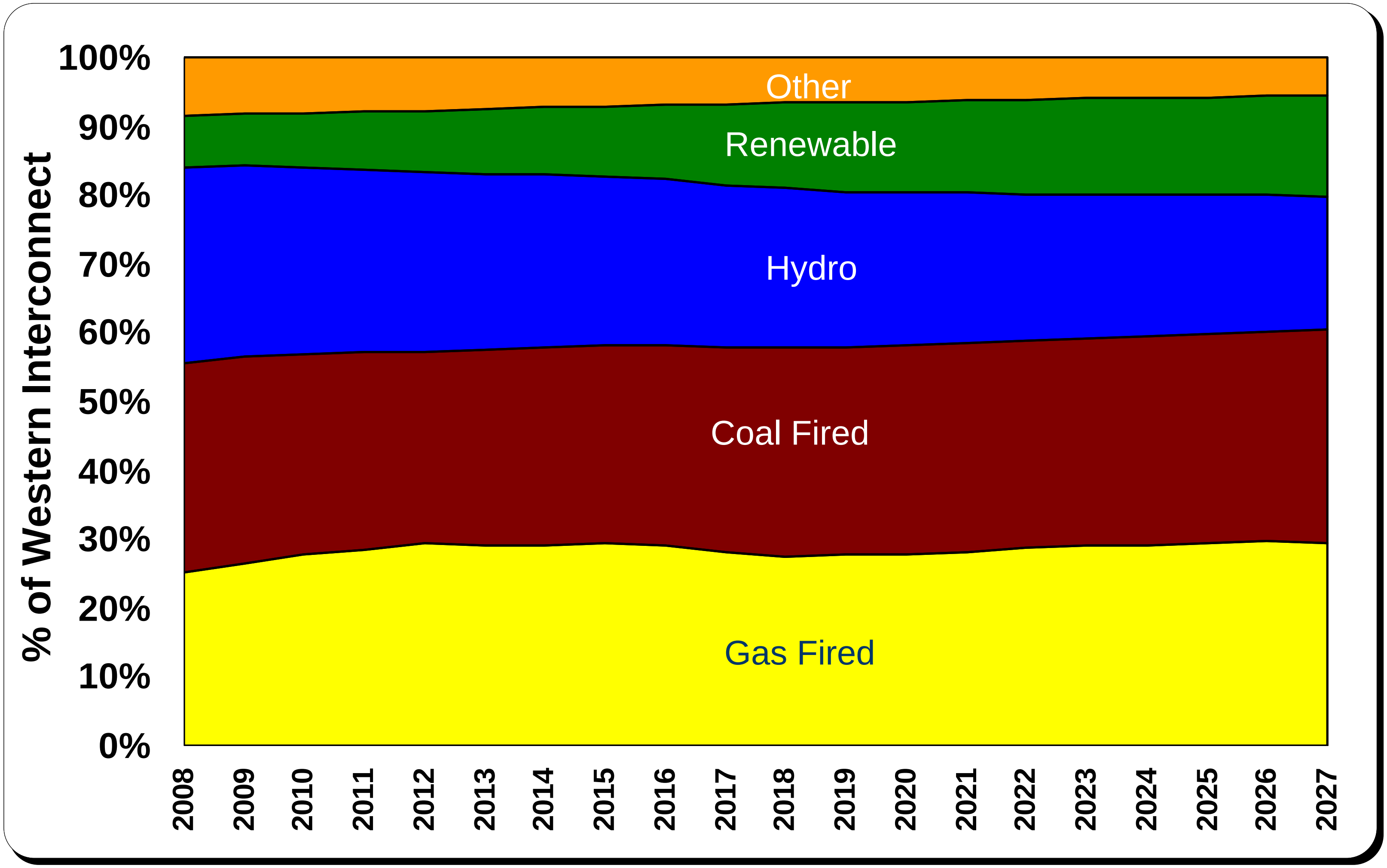
Nominal 2008$:
$55.84

Real 2007$:
$46.05

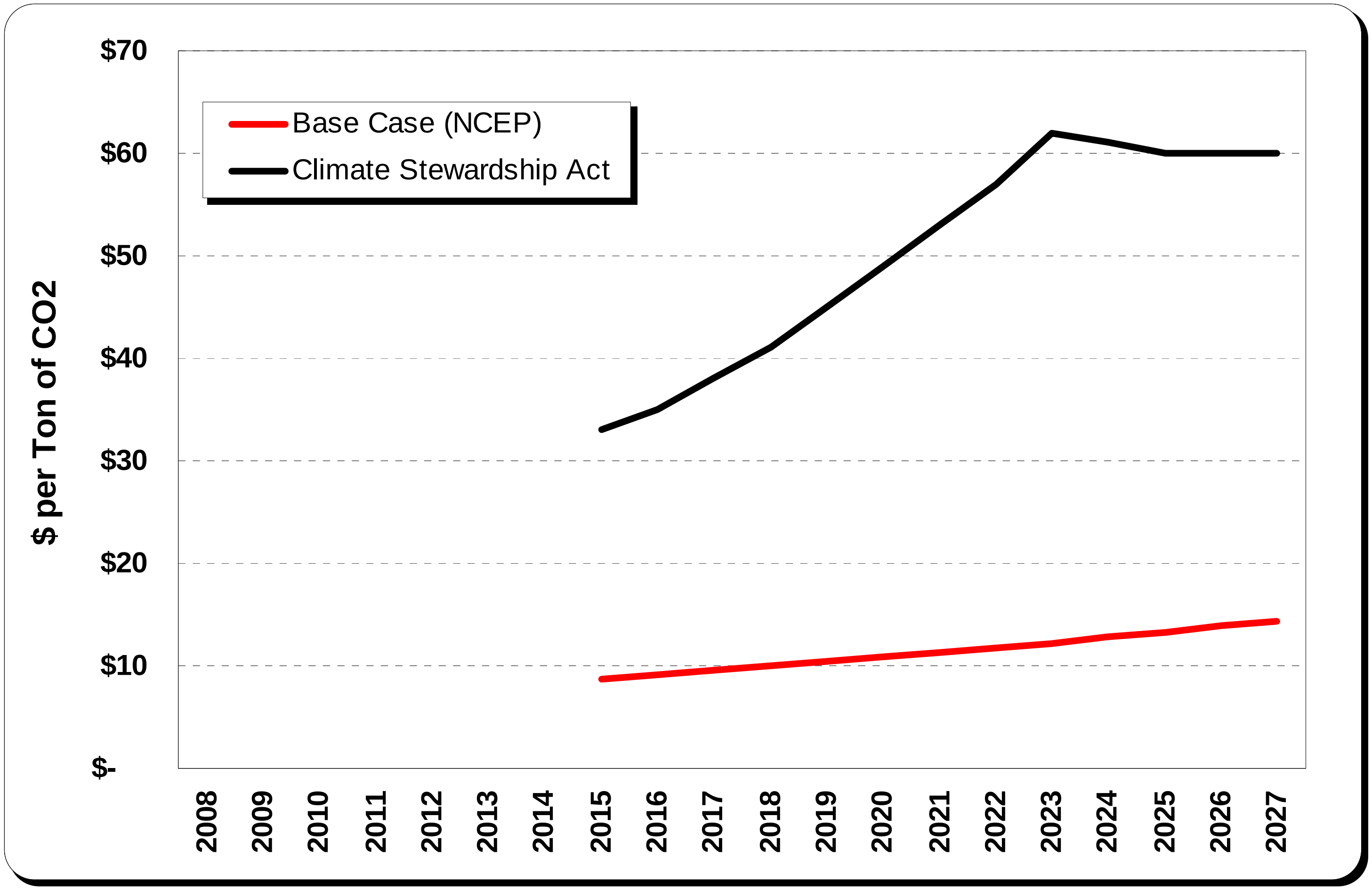
No CO_2 Tax: Market Implied Heat Rate
(Mid-C Electric Price/Sumas NG Price)



No CO_2 Tax: Western Interconnect Resource Contribution *(% of Total Energy)*



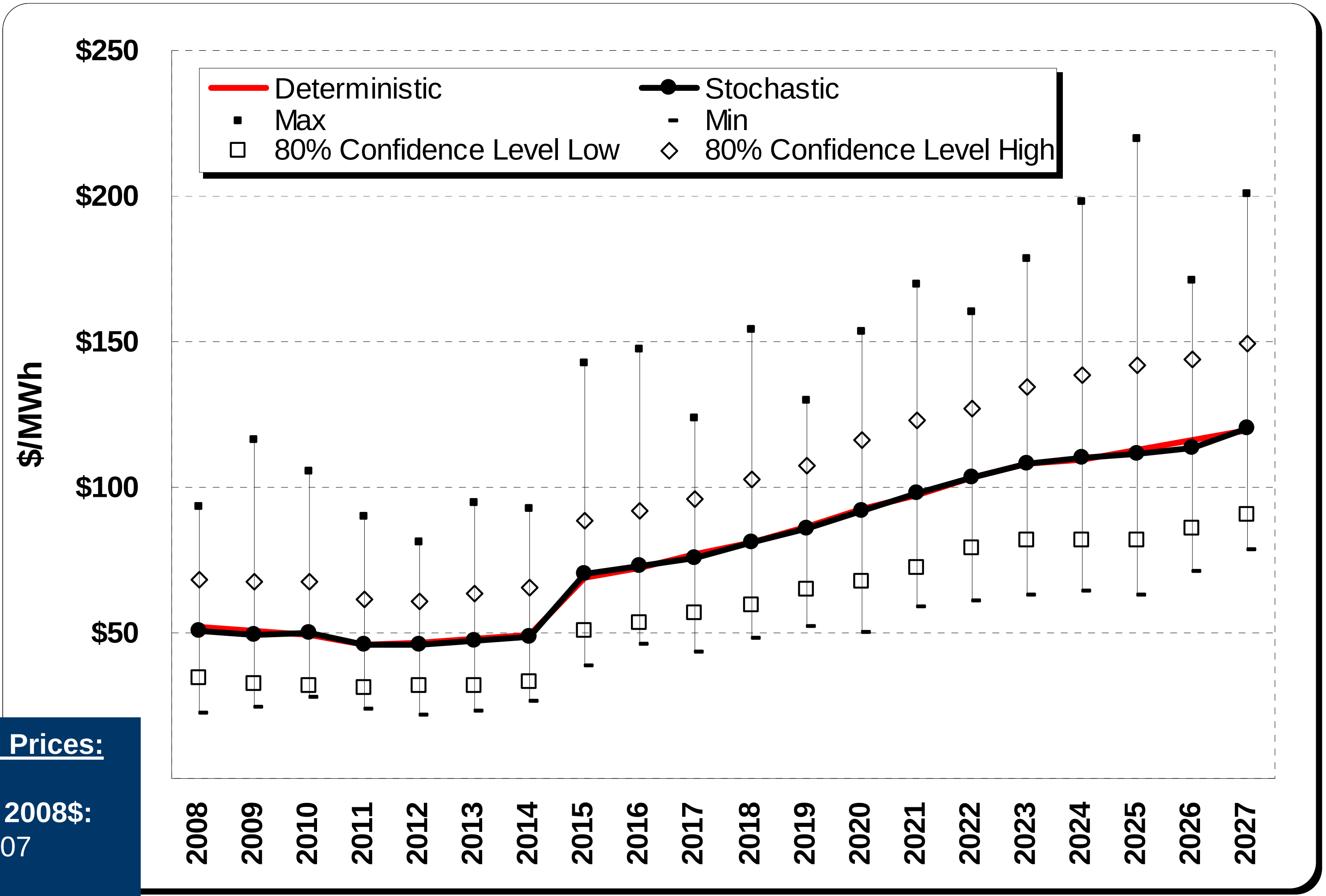
Carbon Tax Assumptions for High Carbon Tax Future (Climate Stewardship Act of 2003)



C.S.A. CO_2 Taxes: New Resource Selection Western Interconnect *(Cumulative Nameplate MW)*

	2010	2015	2020	2027
CCCT	6,240	12,000	23,520	46,560
SCCT	15,176	33,206	44,010	50,573
Pulverized coal	0	1,200	1,200	1,600
IGCC coal	0	0	0	2,975
IGCC coal w/ sequestration	0	0	1,203	5,213
Wind (economic)	0	0	0	0
Nuclear	0	0	0	0
RPS wind	2,016	9,499	20,046	29,086
RPS other	638	2,177	4,331	6,457
Total Excluding Wind	22,054	48,583	74,264	113,378
Total With Wind @ 33%	22,719	51,718	80,879	122,976

C.S.A. CO_2 Taxes: Annual Average Mid-C Prices *Nominal Dollars*



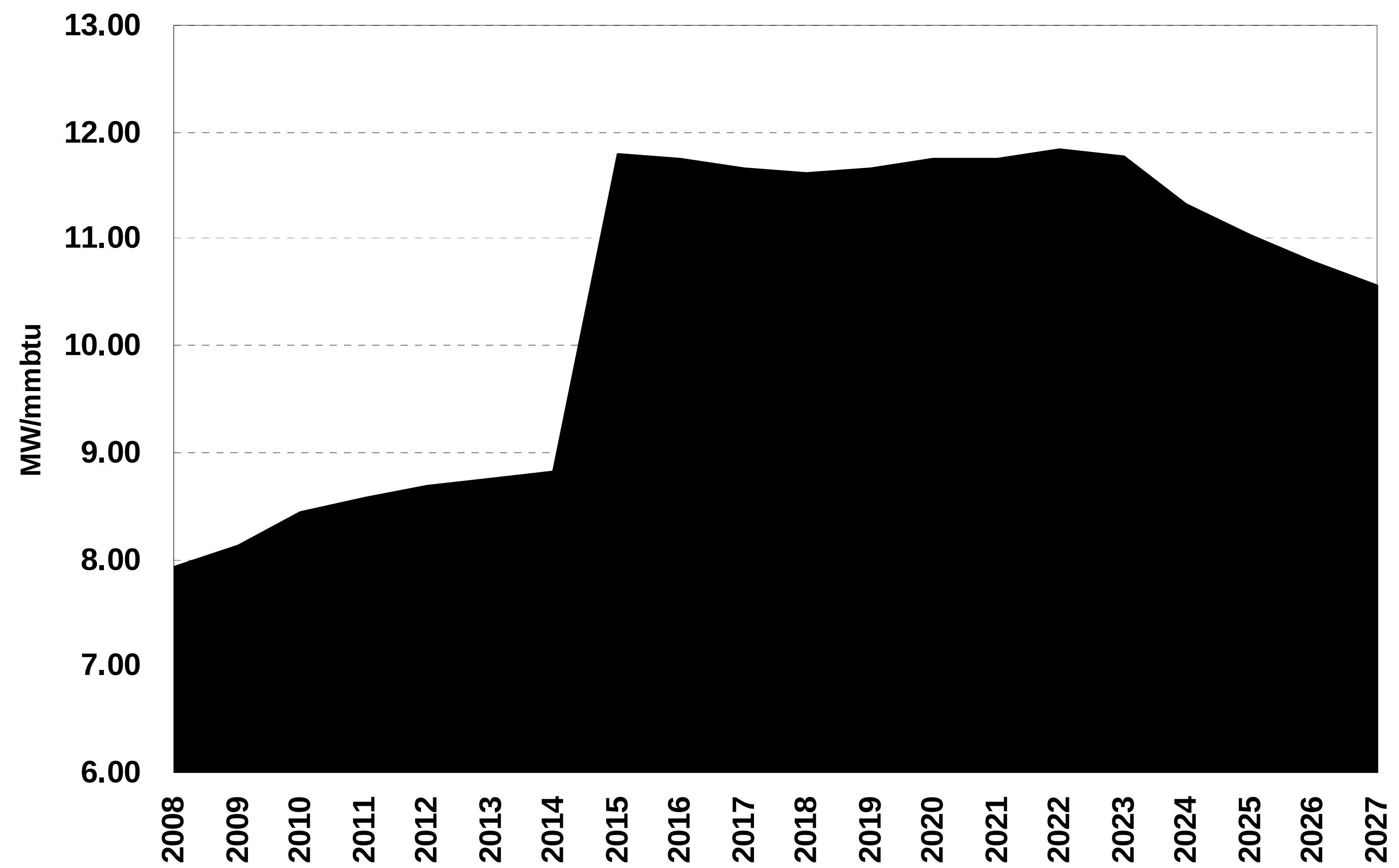
Levelized Prices:

Nominal 2008$:
$69.07

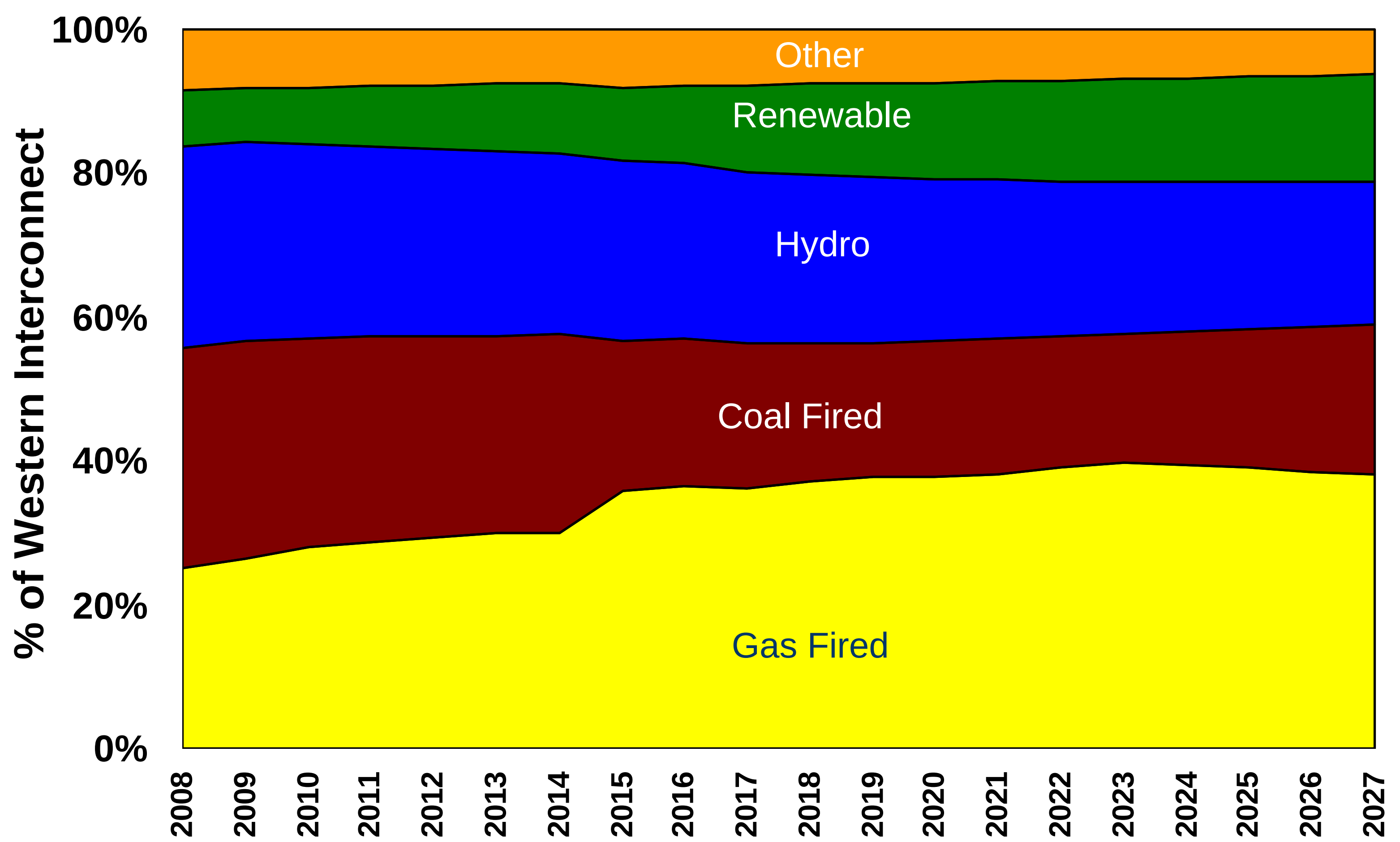
Real 2007$:
$56.96

C.S.A. CO_2 Taxes: Market Implied Heat Rate

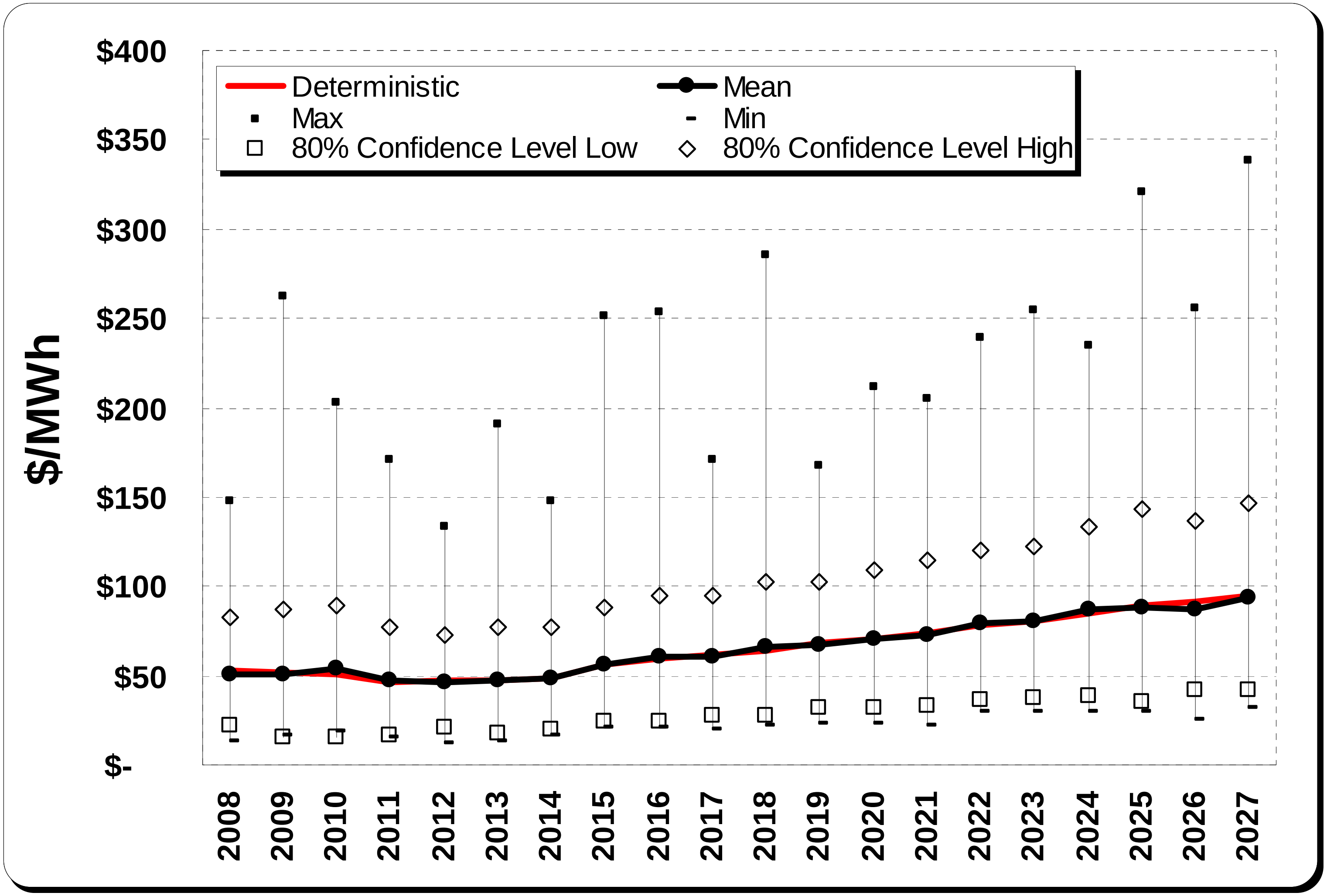
(Mid-C Electric Price/Sumas NG Price)



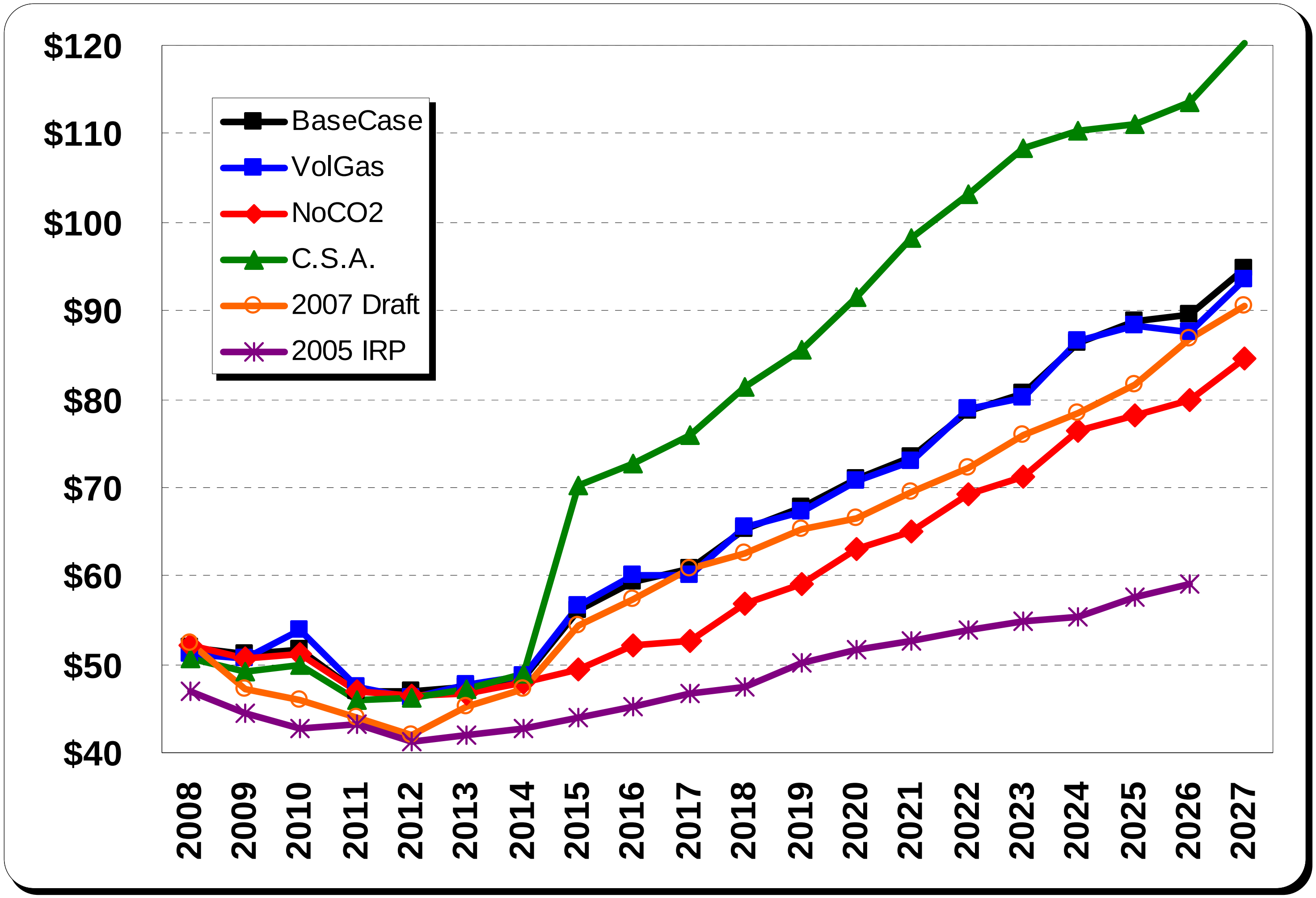
C.S.A. CO_2 Taxes: Western Interconnect Resource Contribution *(% of Total Energy)*



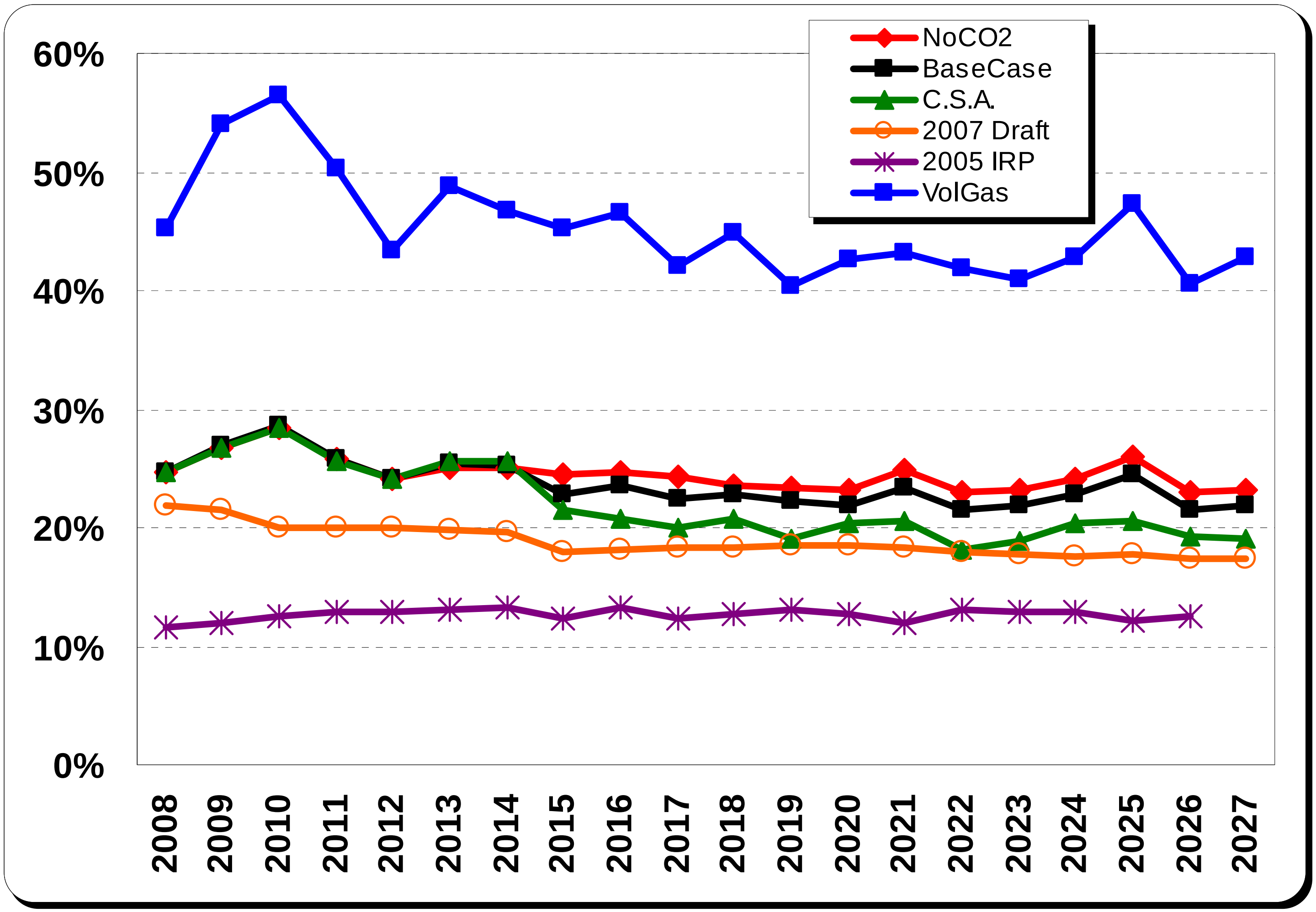
Volatile Gas: Annual Average Mid-C Prices
Nominal Dollars



Mid-C Electric Forecast Comparison



Mid-C Electric Forecast Comparison of Volatility *(Mid-C Annual Avg/ Mid-C Annual Stdev)*



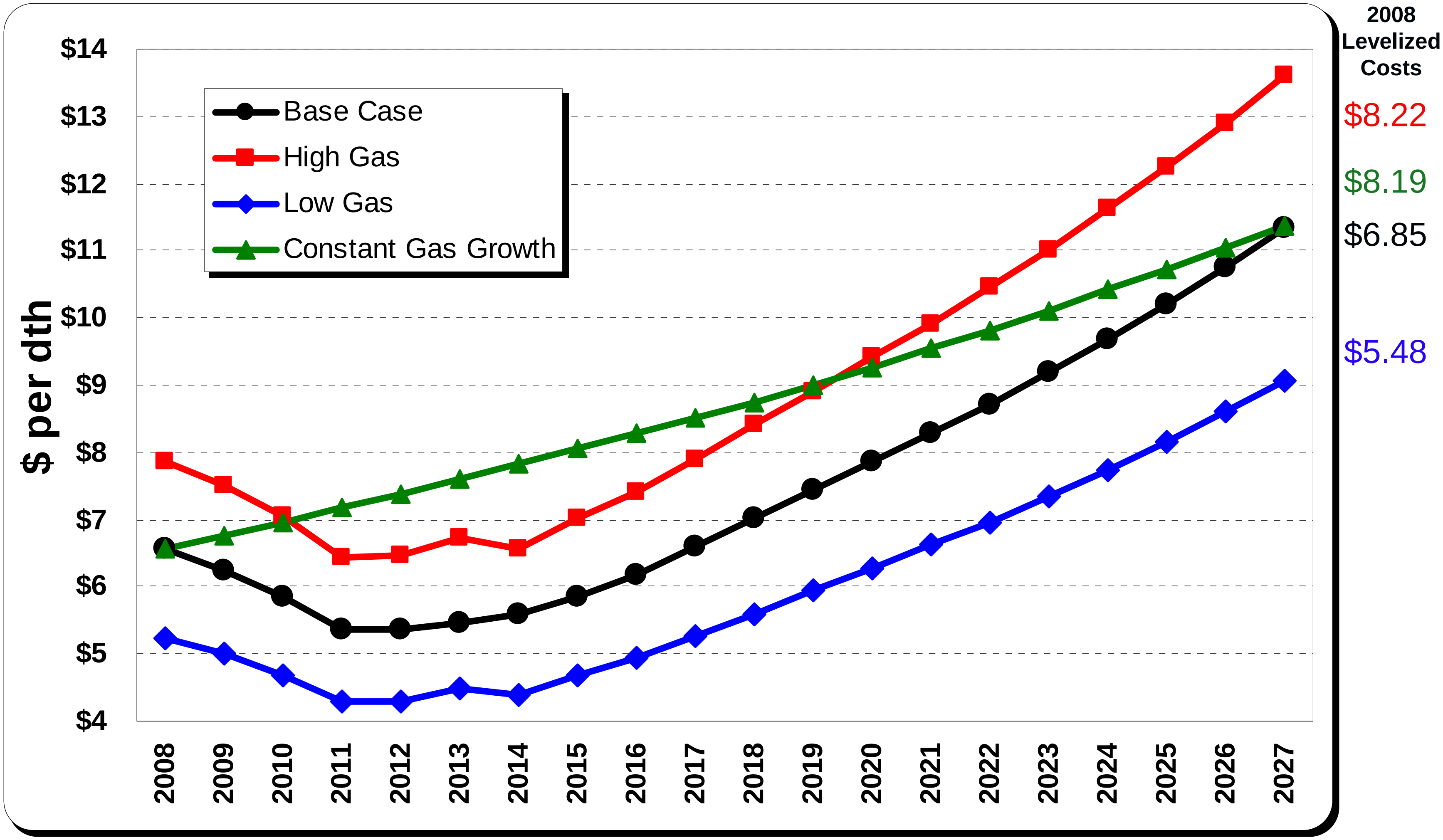
Market Scenarios

- 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

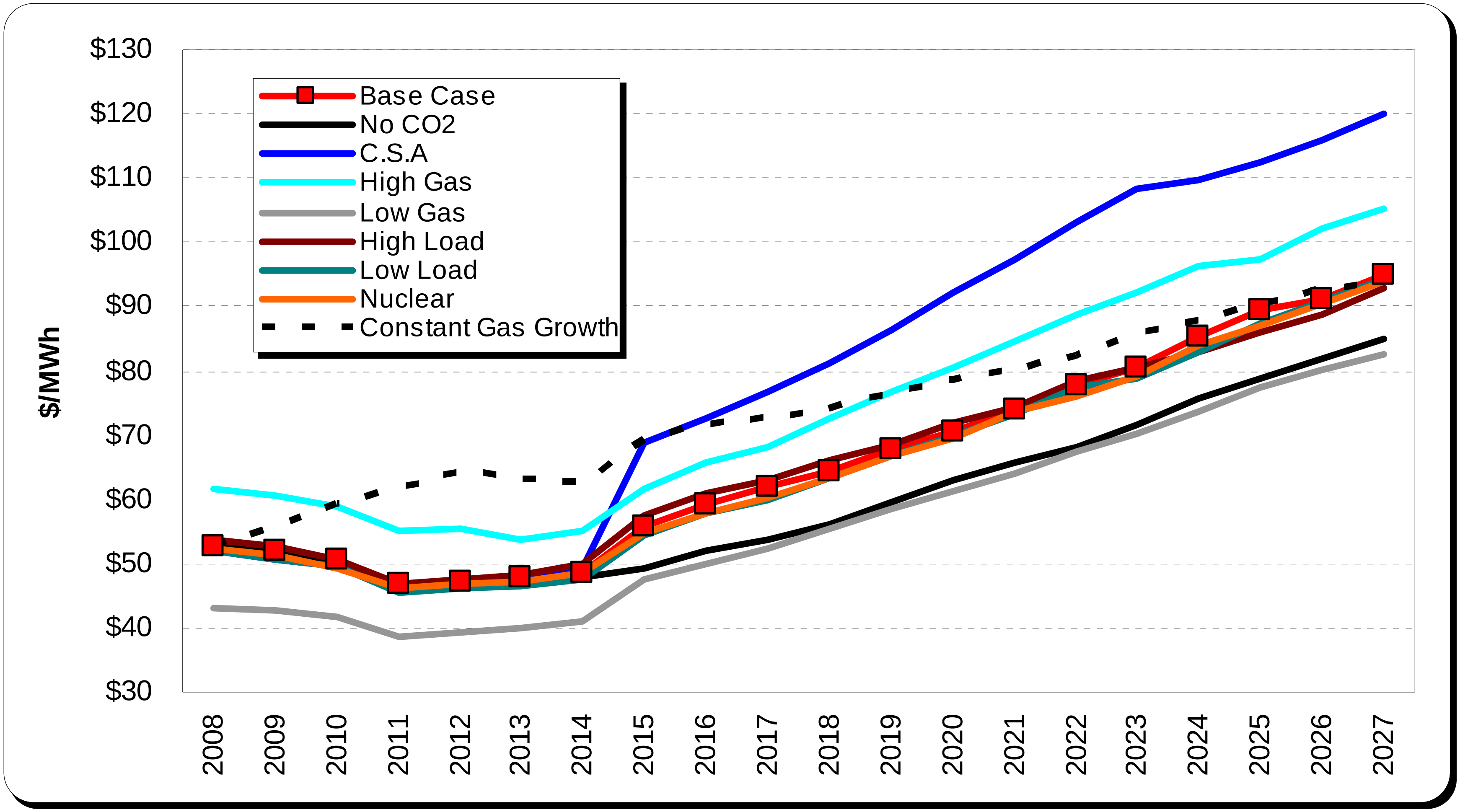
Not Completed Yet!

Others?

Gas Price Scenarios



Scenarios Electric Price Forecasts… So Far



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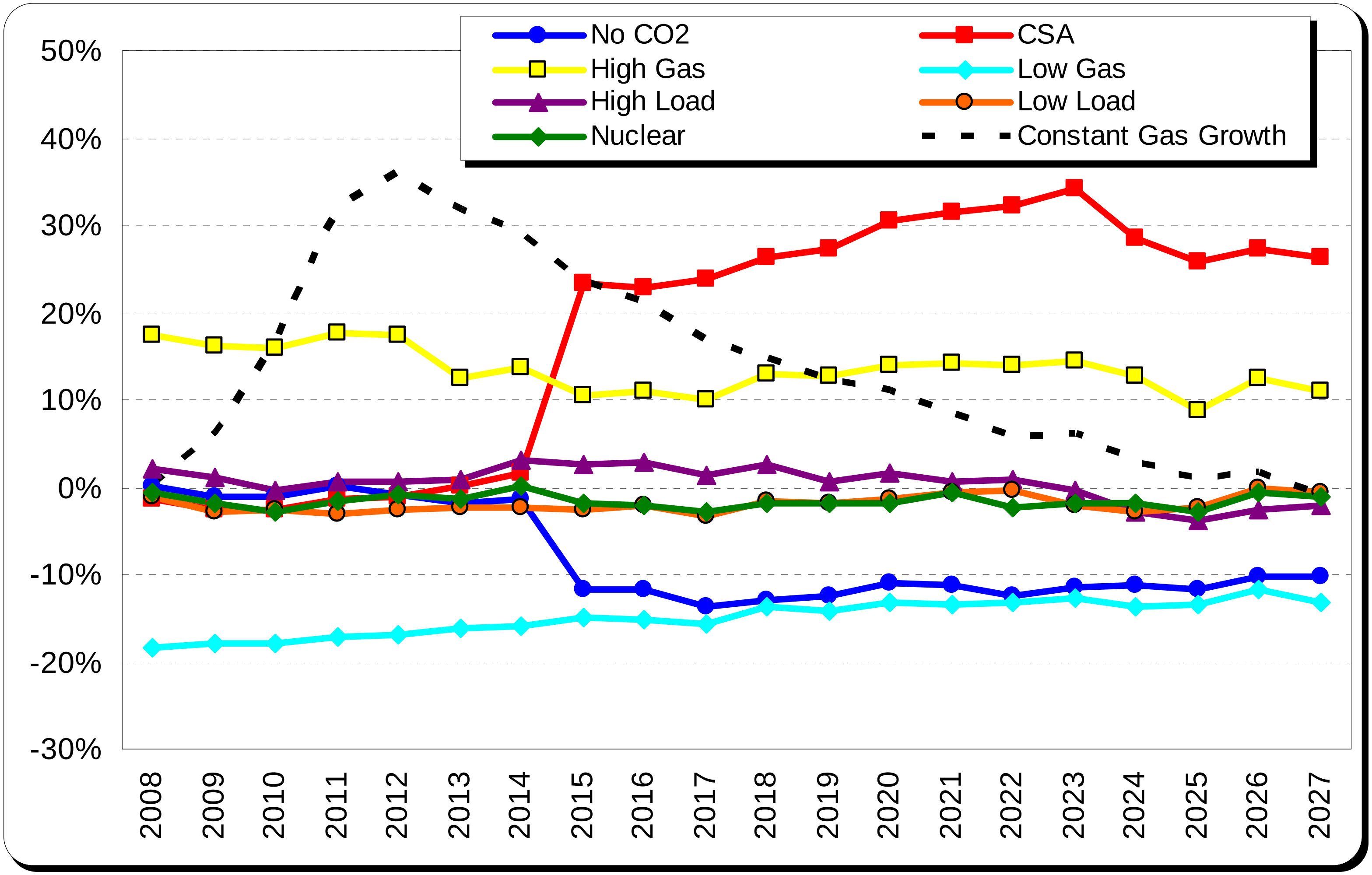
Mid-C Electric Comparison (Nominal $/MWh)

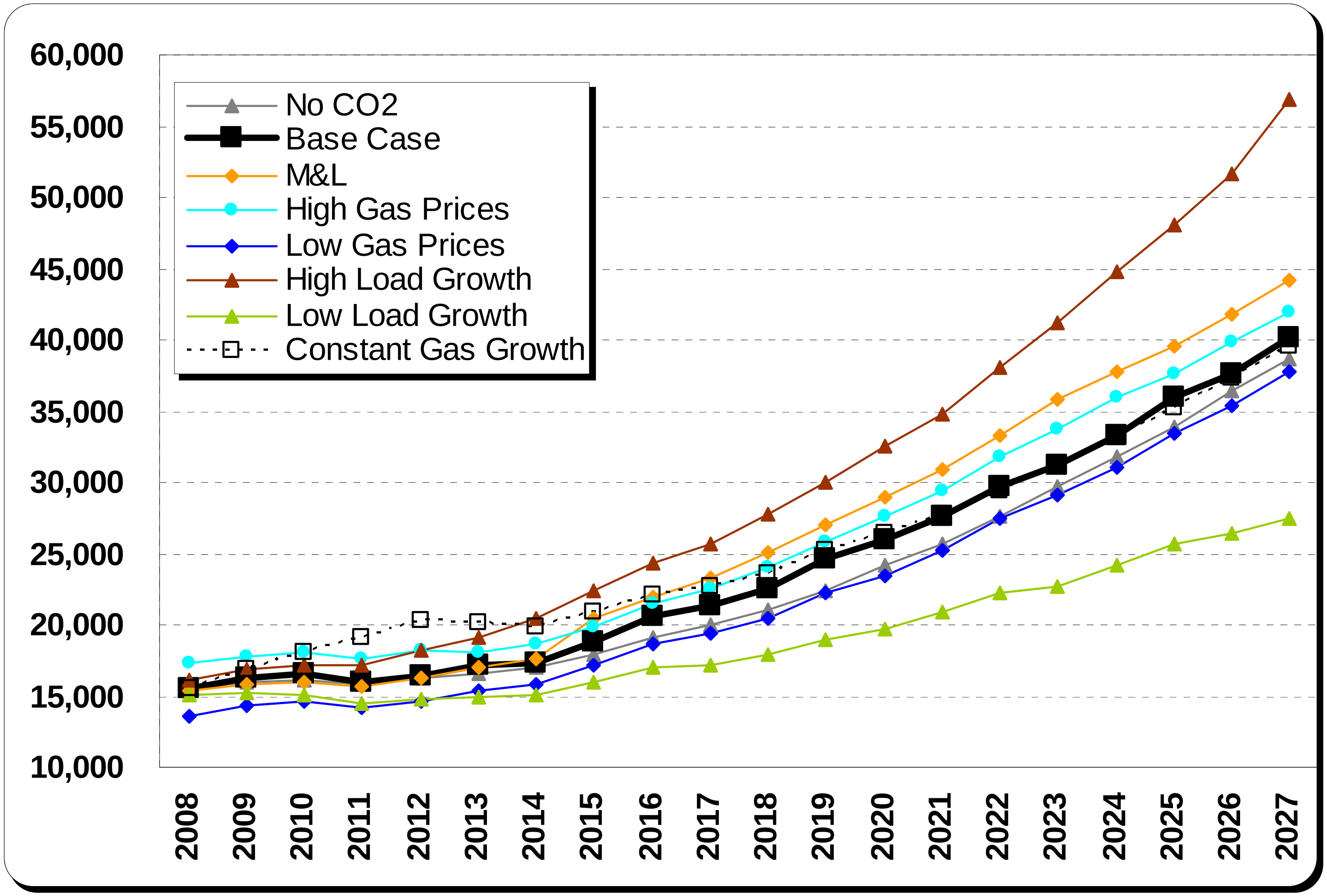
Study	Levelized Cost 2007 $ Real	Levelized Cost 2008 Nominal	2008	2010	2015	2020	2027
Base Case/Volatile Gas	49.59	60.13	52.58	50.79	55.91	70.69	94.86
No CO_2	46.05	55.84	52.65	50.27	49.35	62.98	85.11
C.S.A.	56.96	69.96	51.92	49.42	68.90	92.29	119.89
Constant Gas Growth	58.46	68.82	52.76	59.18	69.12	78.45	94.07
High Gas (20%)	58.32	68.59	61.77	58.93	61.76	80.57	105.35
Low Gas (-20%)	43.43	51.03	42.92	41.68	47.62	61.44	82.43
High Regional Load Growth	51.57	60.65	53.72	50.63	57.37	71.76	92.84
Low Regional Load Growth	50.22	59.05	51.94	49.45	54.47	69.76	94.39
Nuclear available 2015	50.43	59.29	52.27	49.38	54.89	69.42	93.87

Significant Difference from Base Case

All Market Studies Mid-C Price % Change from Base Case



All Market Studies Total Fuel Costs (Nominal)



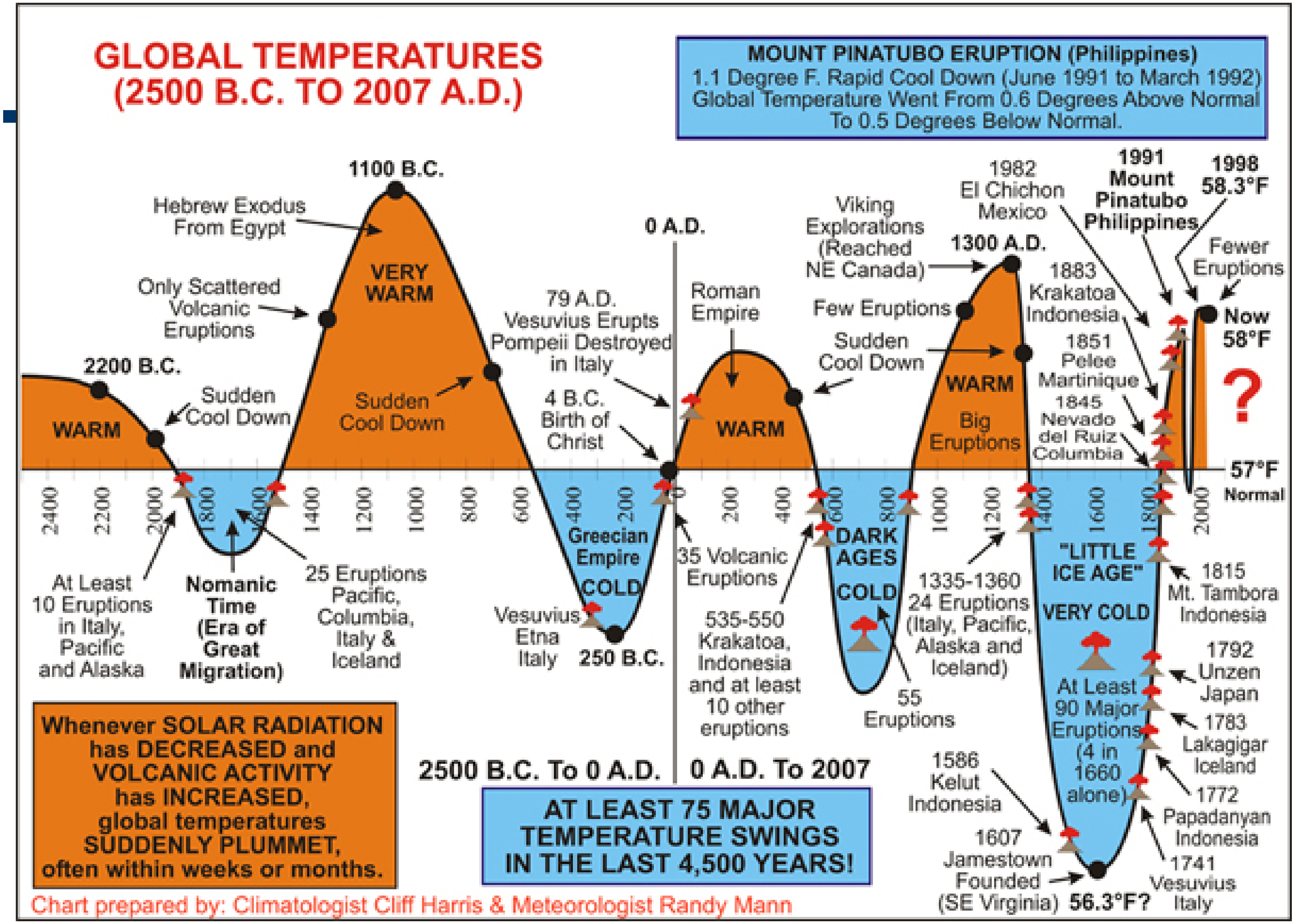
Global Warming Degree Day Trend Scenario

2007 Electric Integrated Resource Plan

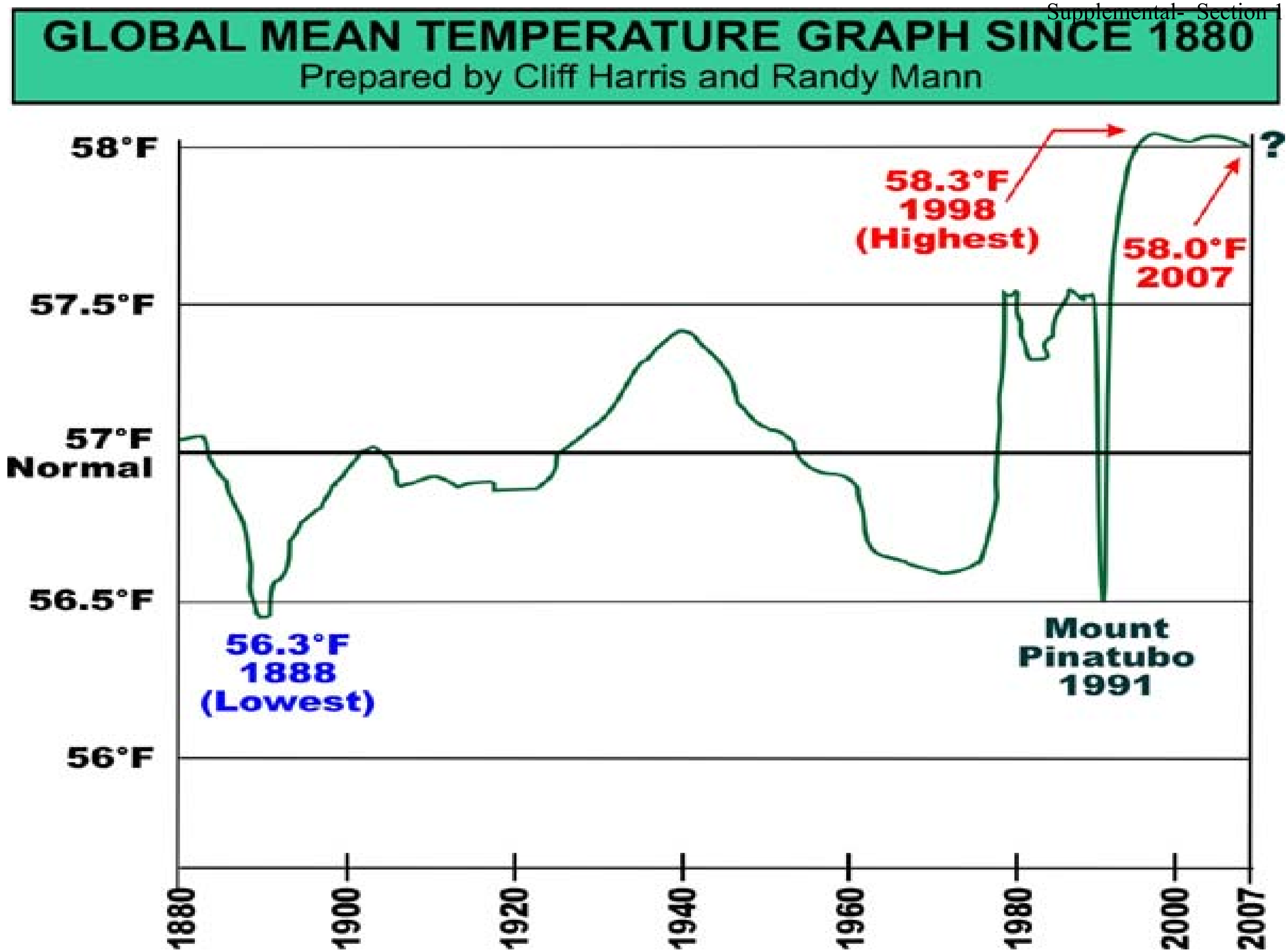
Fourth Technical Advisory Committee Meeting

March 28, 2007

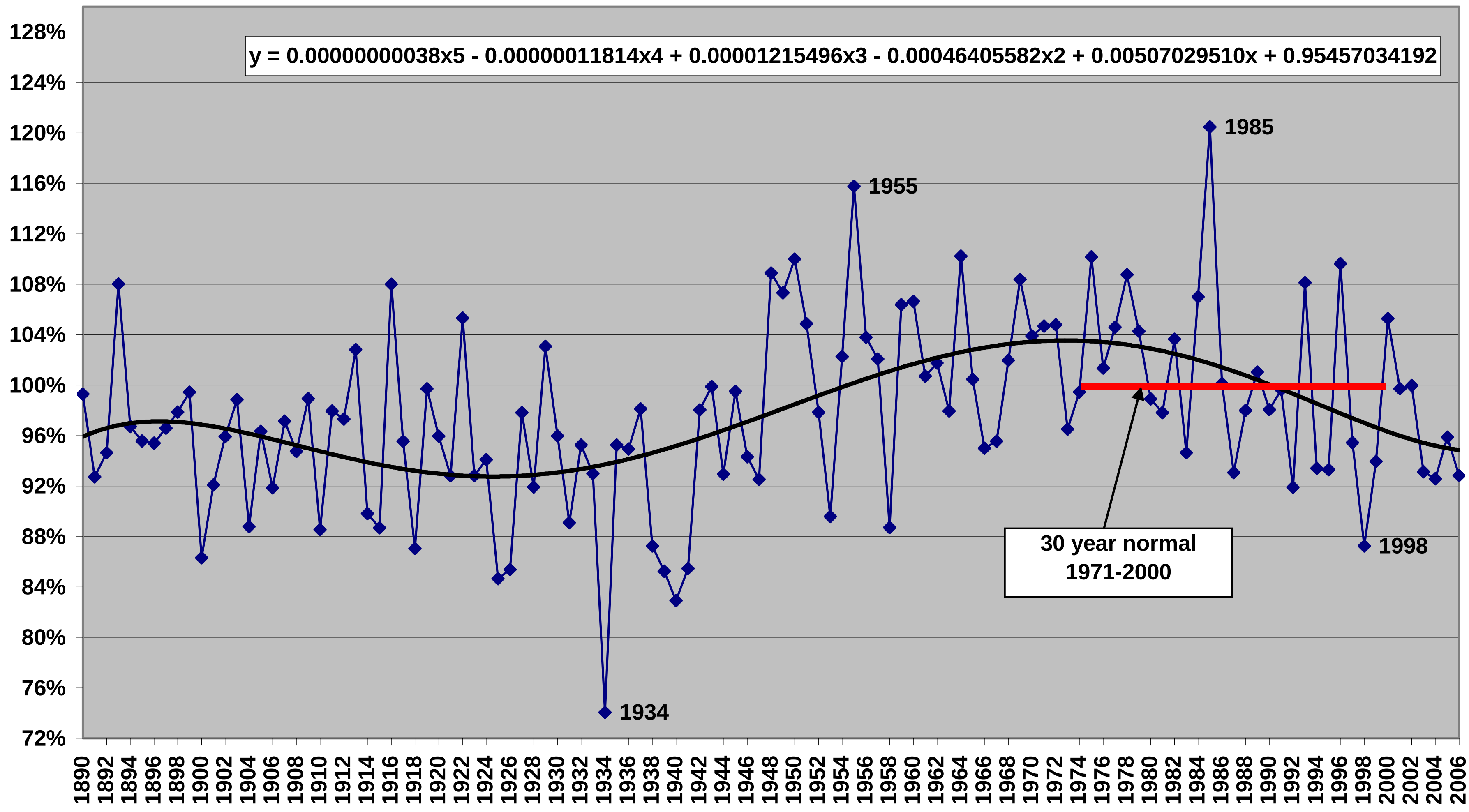
Randy Barcus



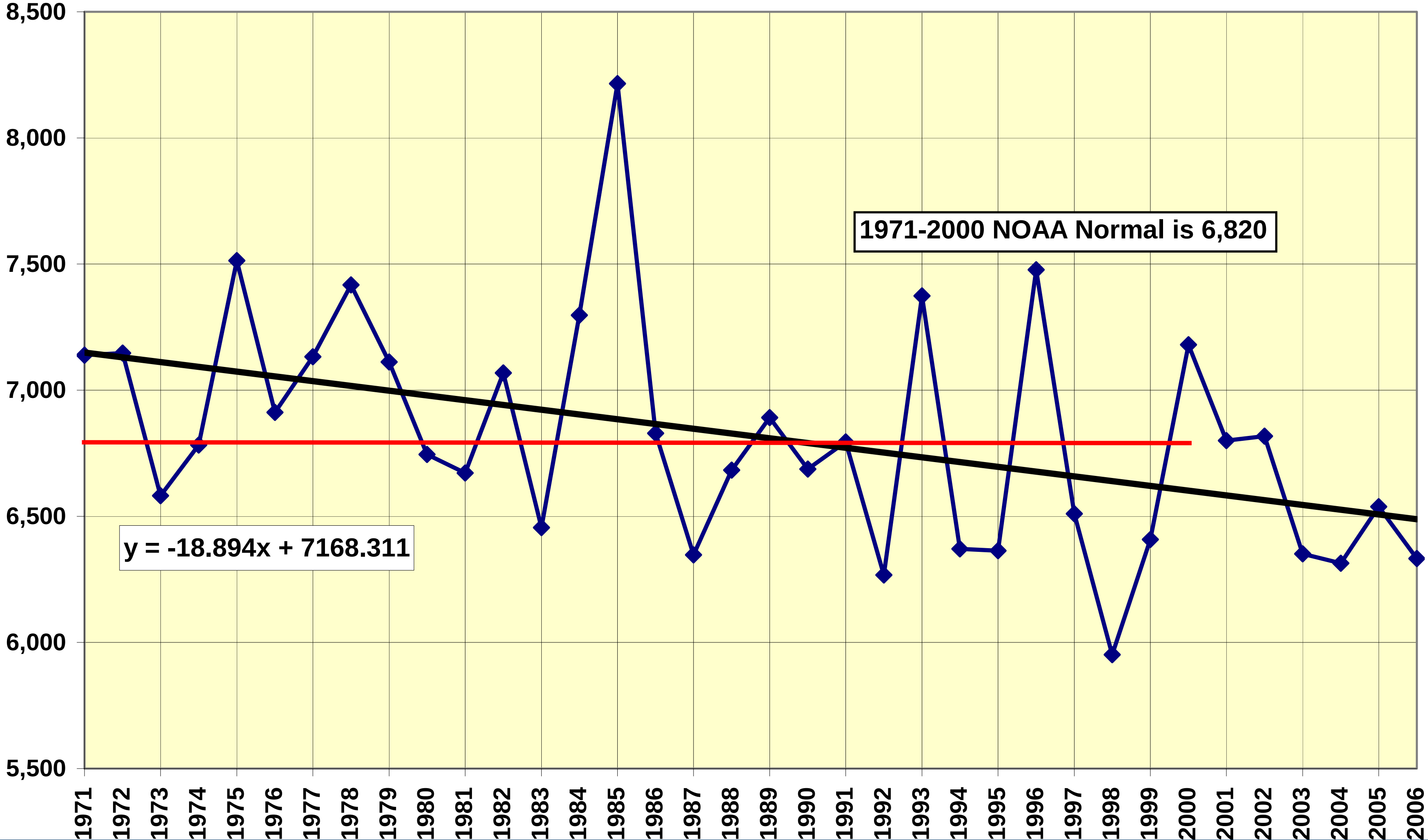
For Discussion Purposes Only


GLOBAL MEAN TEMPERATURE GRAPH SINCE 1880
Prepared by Cliff Harris and Randy Mann
58°F
57.5°F
57°F
Normal
56.5°F
56°F
58.3°F
1998
(Highest)
58.0°F
2007
?
56.3°F
1888
(Lowest)
Mount
Pinatubo
1991
1880
1900
1920
1940
1960
1980
2000
2007

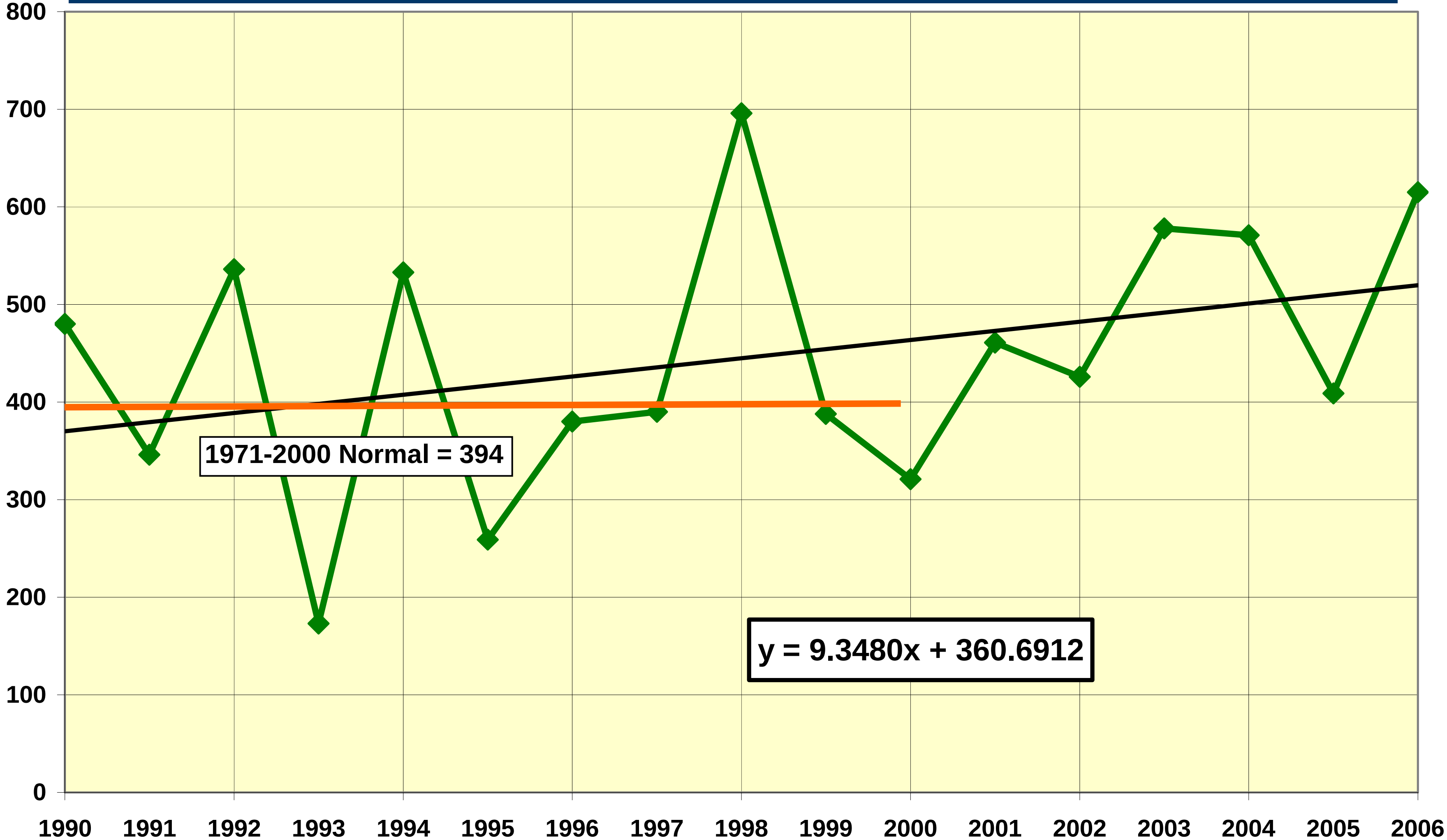
Annual Heating Degree Days, Percent of Normal - Spokane, WA



1971-2006 Spokane HDD Trend



1990-2006 Cooling Degree Day Trend



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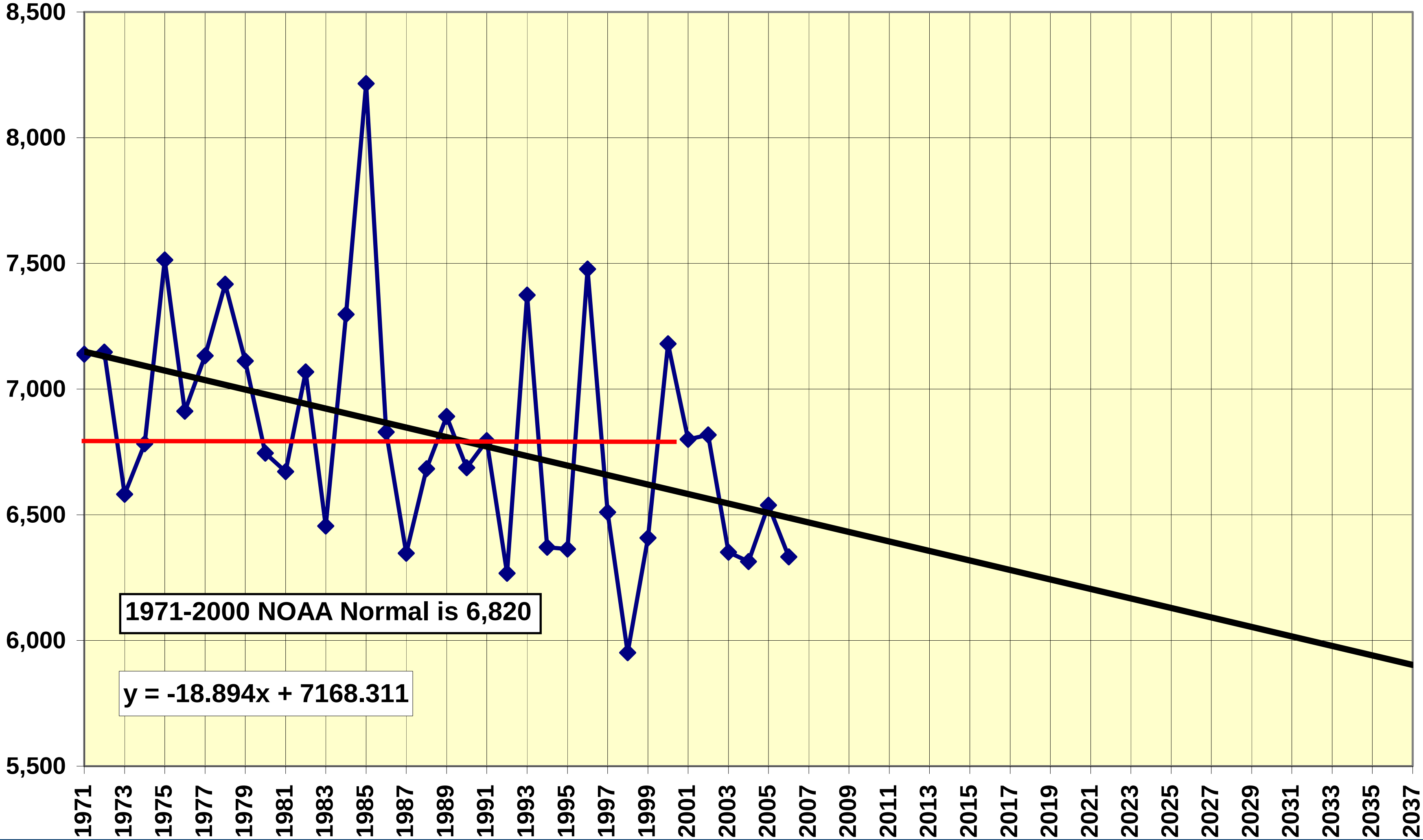
For Discussion Purposes Only

1971-2006 Spokane HDD Trend



For Discussion Purposes Only

AVISTA

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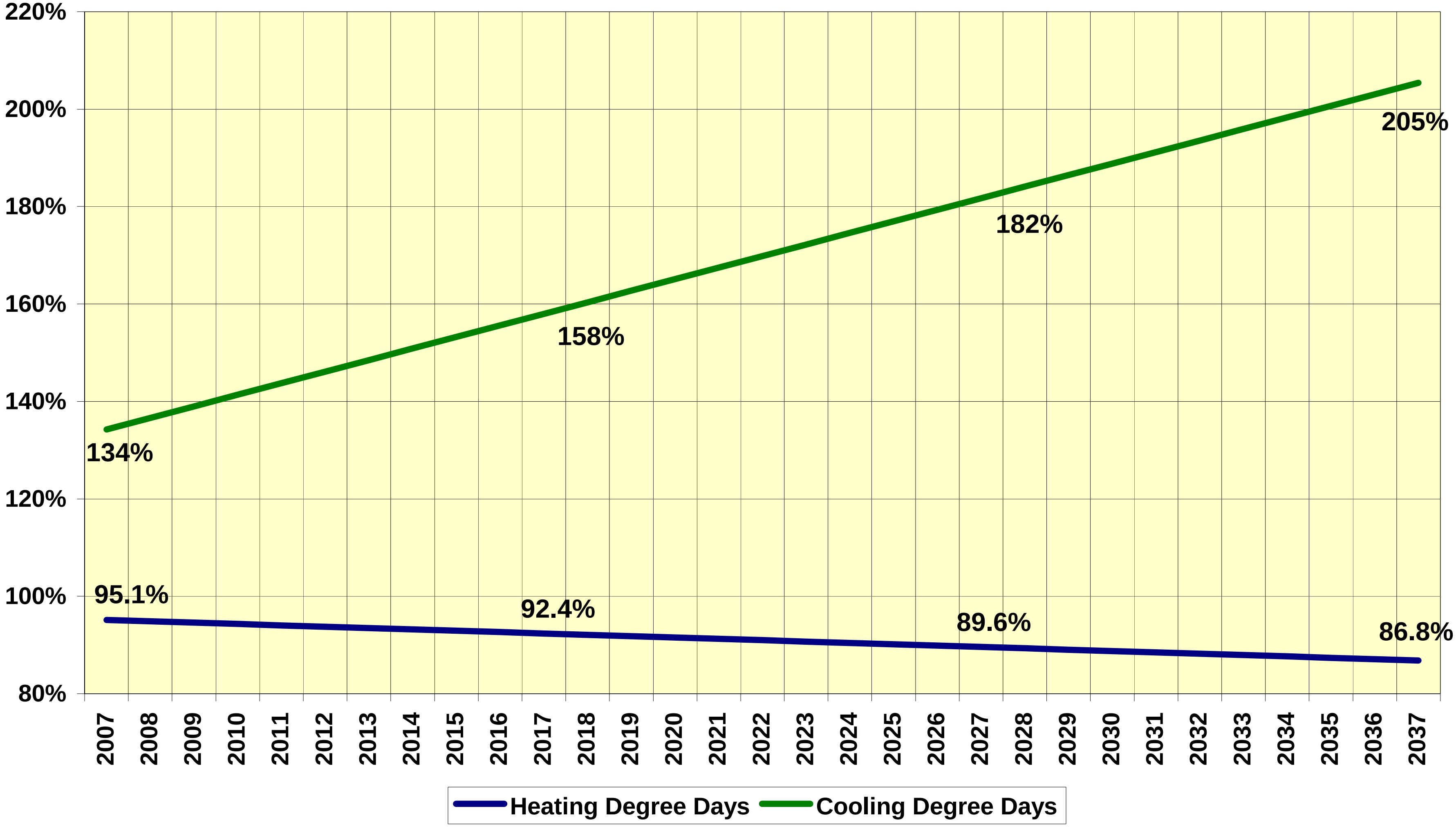
Global Warming Degree Day Trends (2007-2037)



For Discussion Purposes Only

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%

Discussion/Questions

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)

Component	10 yr Energy ($/MW)	20 year Energy ($/MW)	Capacity[5] ($/kW)
Avoided cost of energy	$49[1]	$57[1]	
Avoided emissions cost	$2[2]	$4[2]	
Reduction in energy cost volatility	$16[3]	$18[3]	
Reduction in T&D losses	$4[4]	$5[4]	
Value of deferred gen capacity			$300
Value of deferred T&D capacity			$105
TOTAL COST	**$71**	**$84**	**$405**

1. The flat load assumption is a simplification of a calculation that will be based upon a full 8760-hour stream of avoided energy costs.
2. 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

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

[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

Start Time	Residential & Small Commercial/Industrial	Commercial/Industrial/Institutional
1Q07	• Res & Small C&I Quick Hits Program – Something For Everyone Measures – Fireplace Dampers	• C&I Quick Hits Program – Side-Stream Filtration – Energy/Heat Recovery Ventilation (ERV/HRV) – Demand Control Ventilation (DCV) – Steam Traps
2Q07	• Super Efficient Habitat for Humanity (HFH) Homes	
3Q07	• Geographic Saturation Program	• Retro-Commissioning Program • 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 Reconductor

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:

$(X_1$* NPV of Total $\text{Cost}_{2008\text{-}2017}$ + X_2*Absolute Deviation Power Supply Costs_{2017}* F) + (X_1*(10% NPV of Total $\text{Cost}_{2018\text{-}2027+}$ + X_2*10% Absolute Deviation Power Supply Costs_{2027} * 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

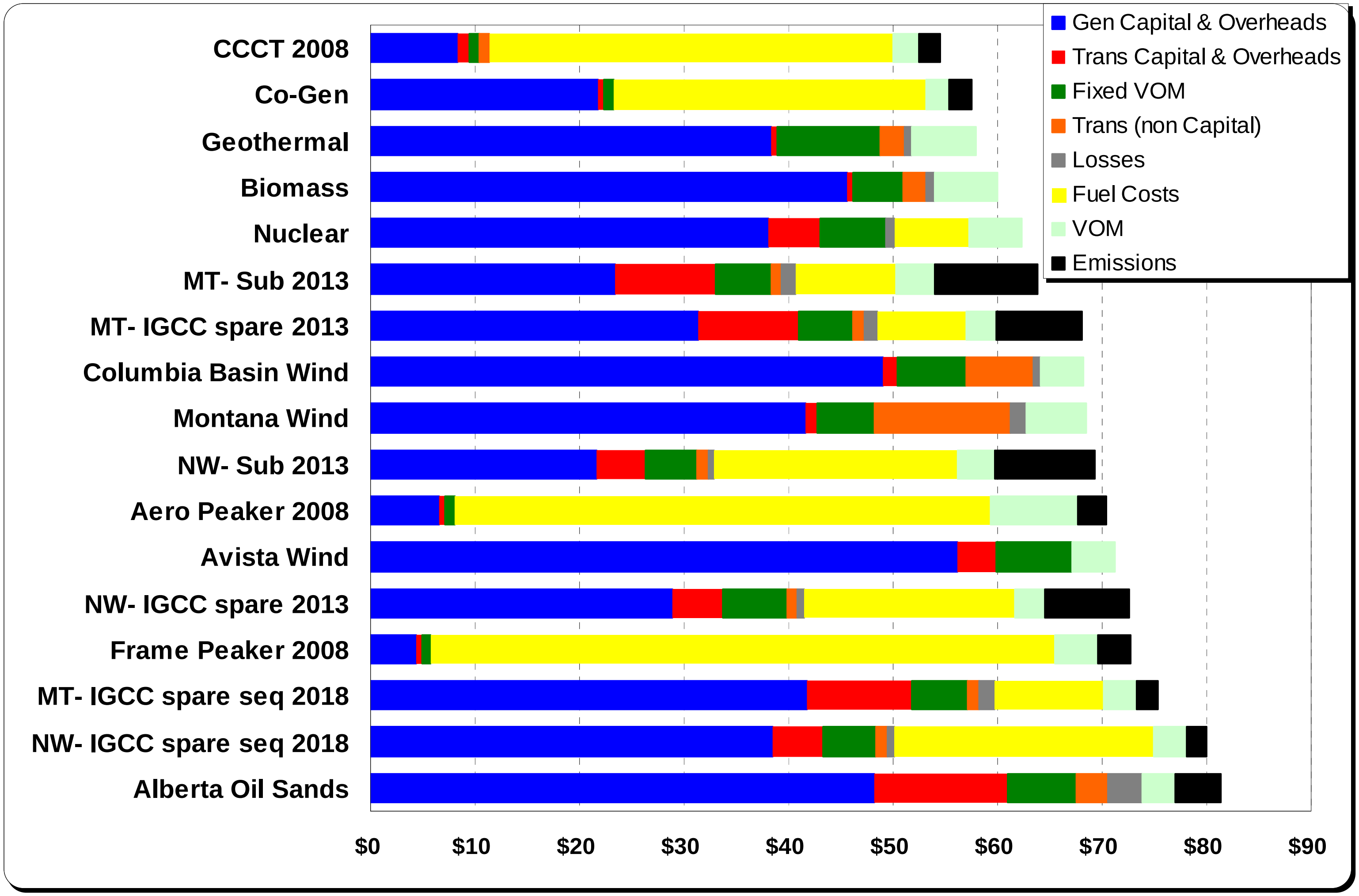
The PRS Model Does Not Make the Decision

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)



Resource Capital Costs *(Excludes Transmission)*

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

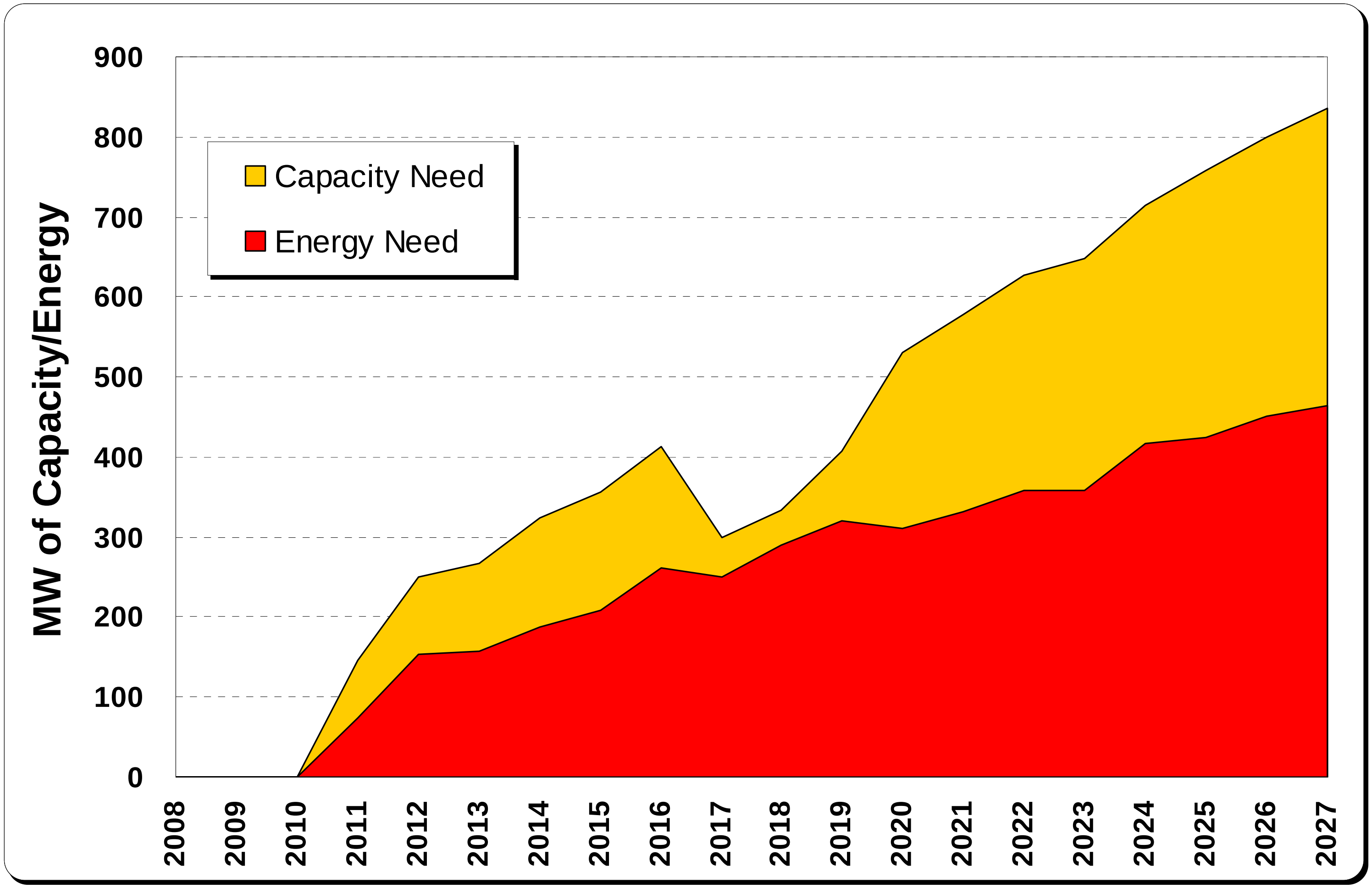
Gas-Fired Combined Cycle With Fixed Gas

- 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

Year	Fixed	Spot	Year	Fixed	Spot
2012	6.75	5.35	**2022**	9.52	8.93
2018	8.3	7.14	**2027**	11.31	11.28

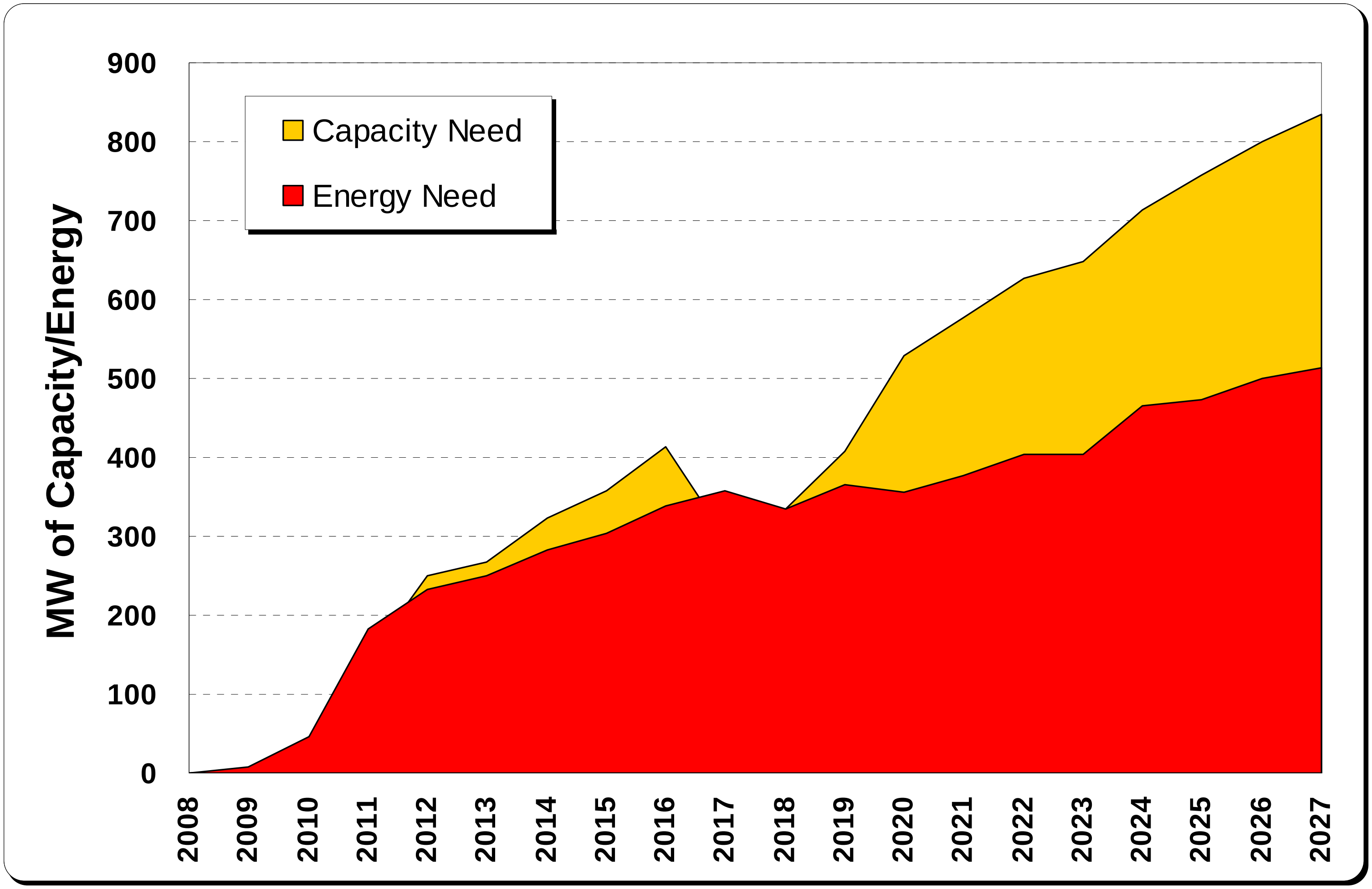
- Intent of this resource is to illustrate the ability to reduce power cost risk without building a coal resource directly

Avista's Annual Average Resource Need



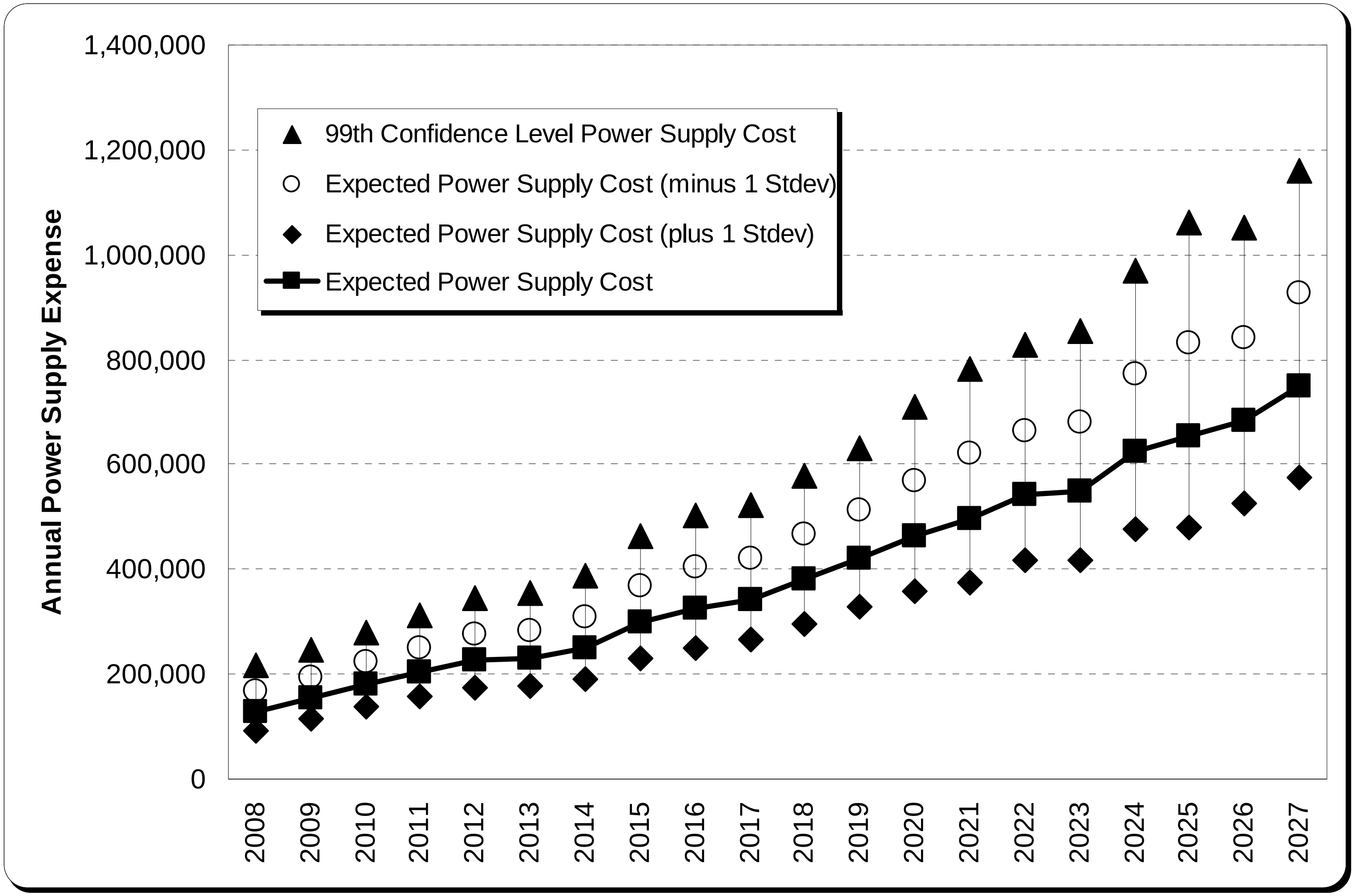
Excludes Additional Conservation

Avista's Annual Average Resource Need (excluding Q2)



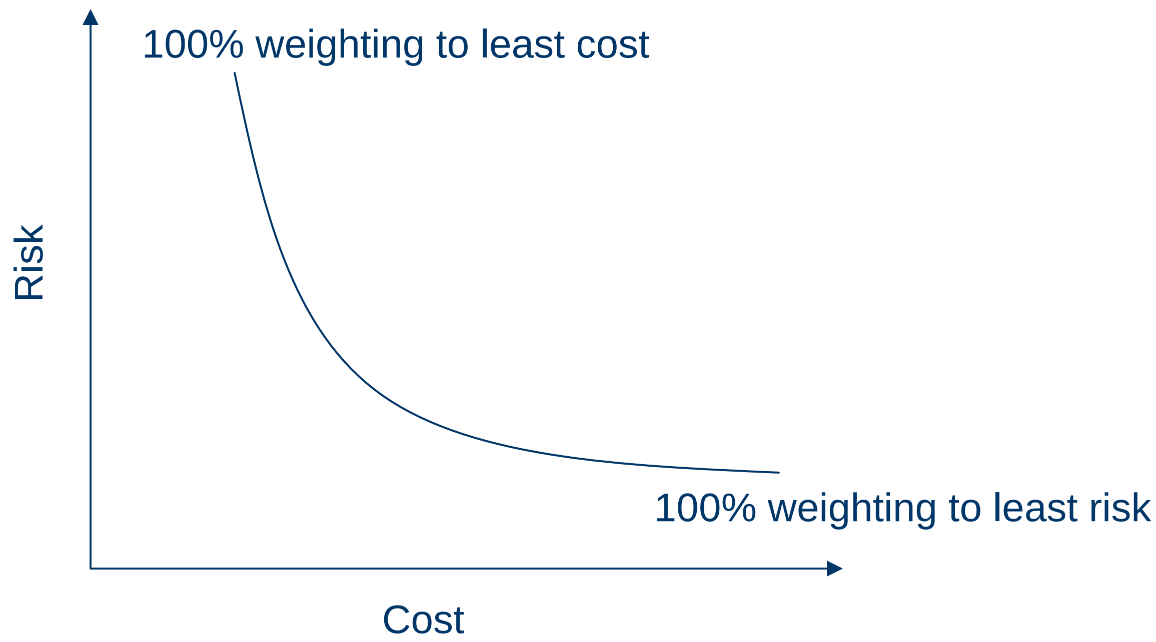
Excludes Additional Conservation

Current Portfolio Costs and Risk

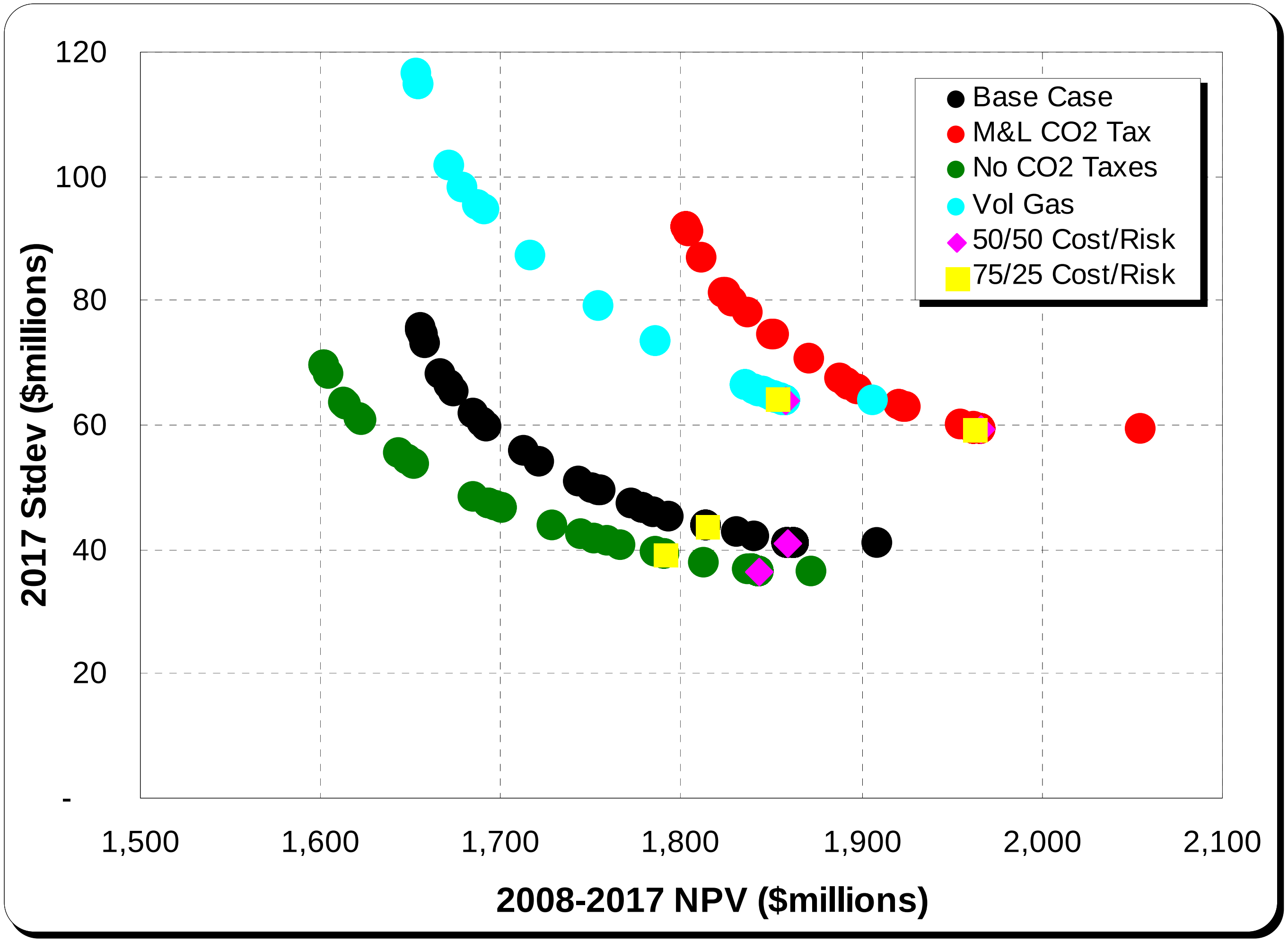


What is the Efficient Frontier?

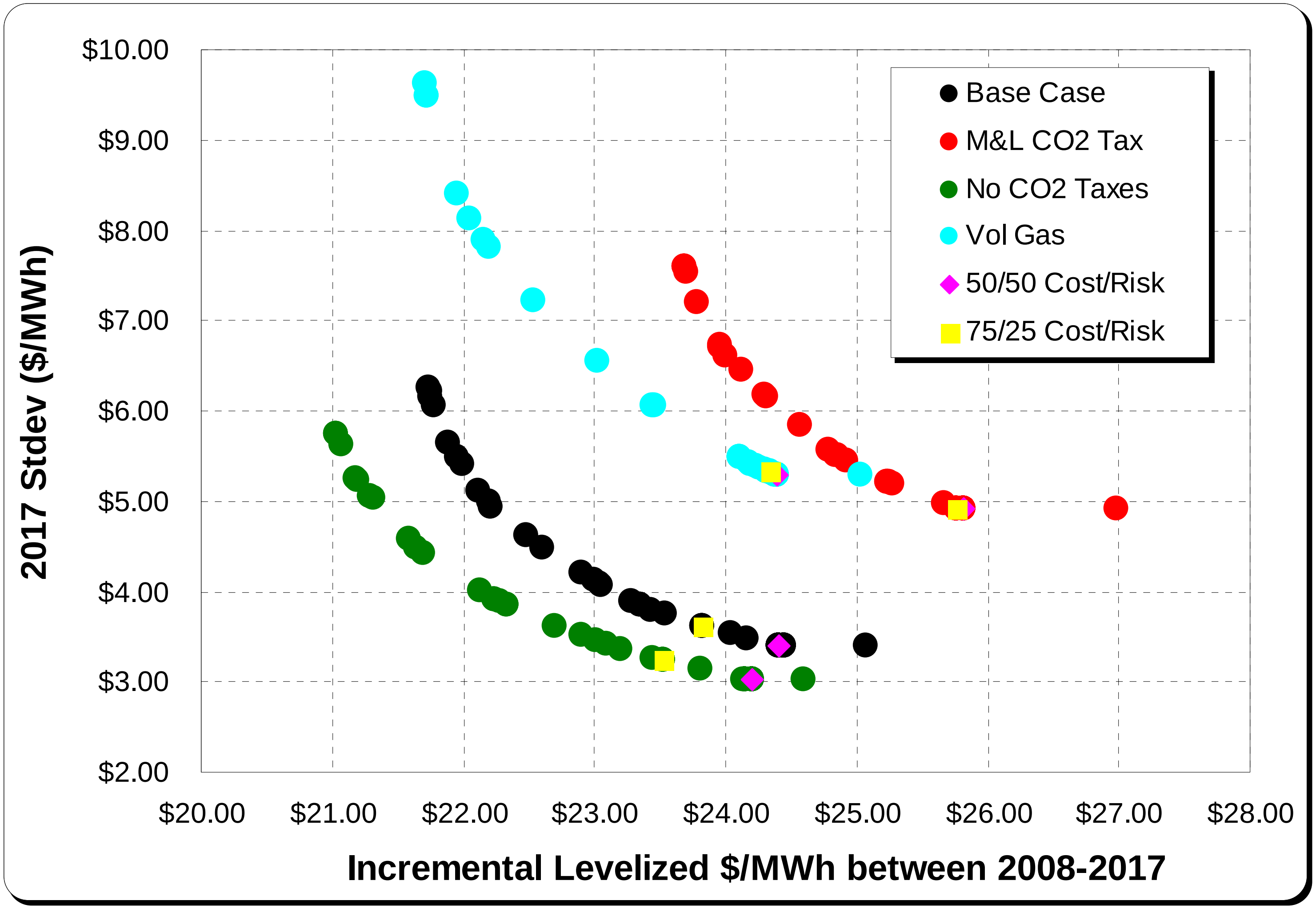
- Demonstrates the trade off of cost and risk
- Difficulty: how much additional cost are we willing to pay to reduce risk



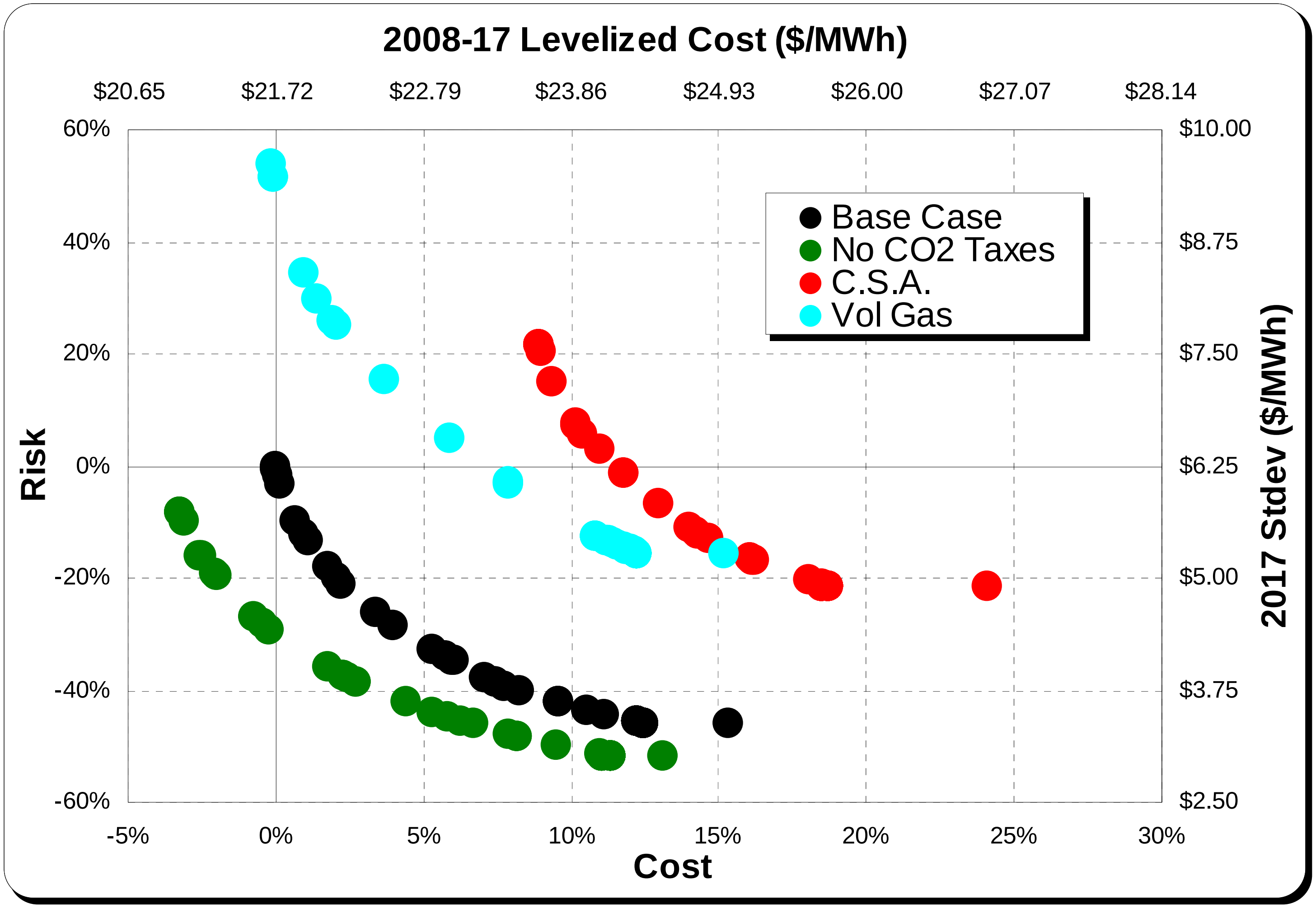
Efficient Frontiers



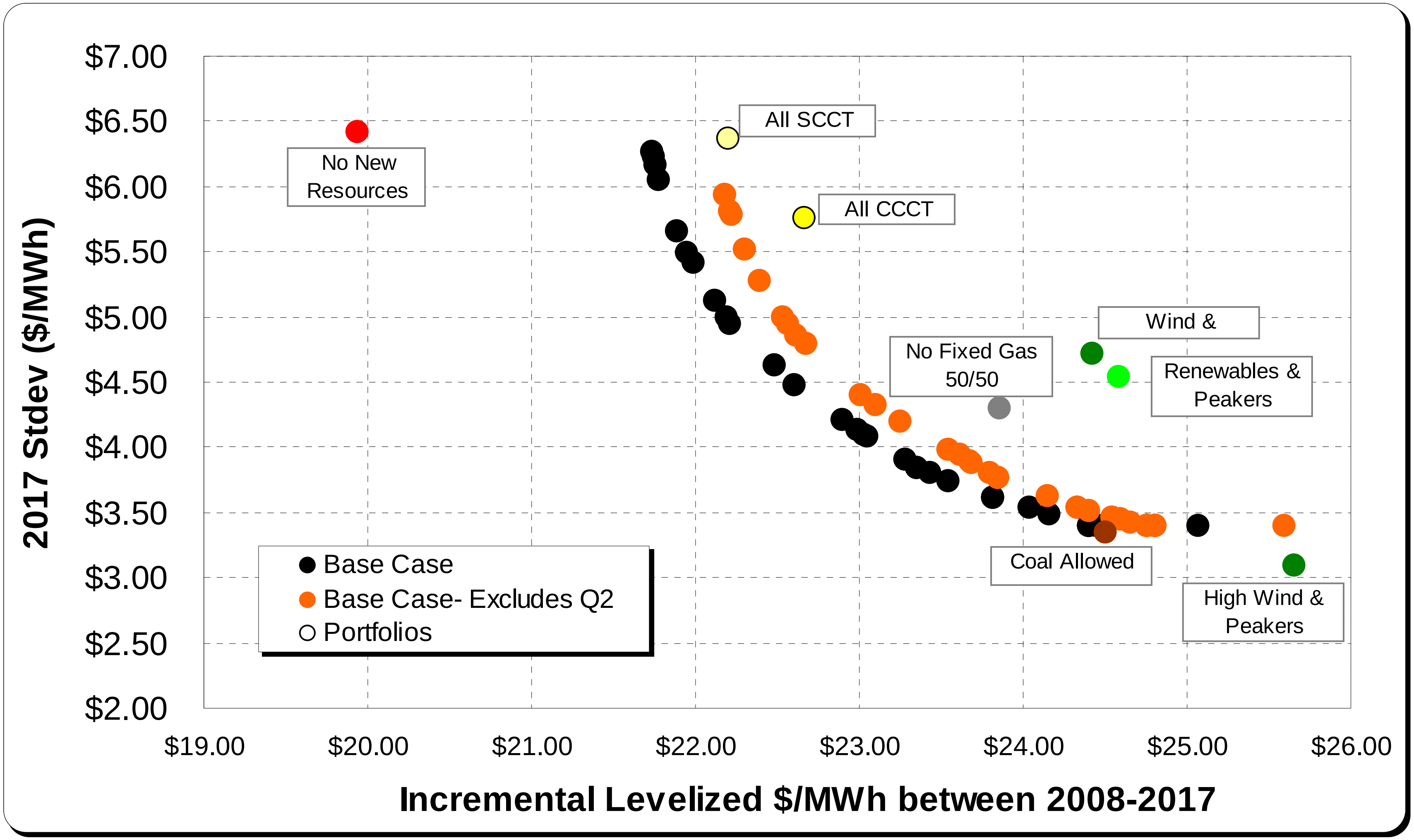
Efficient Frontiers (Incremental $/MWh)



Efficient Frontiers (Incremental $/MWh & Percent Change)



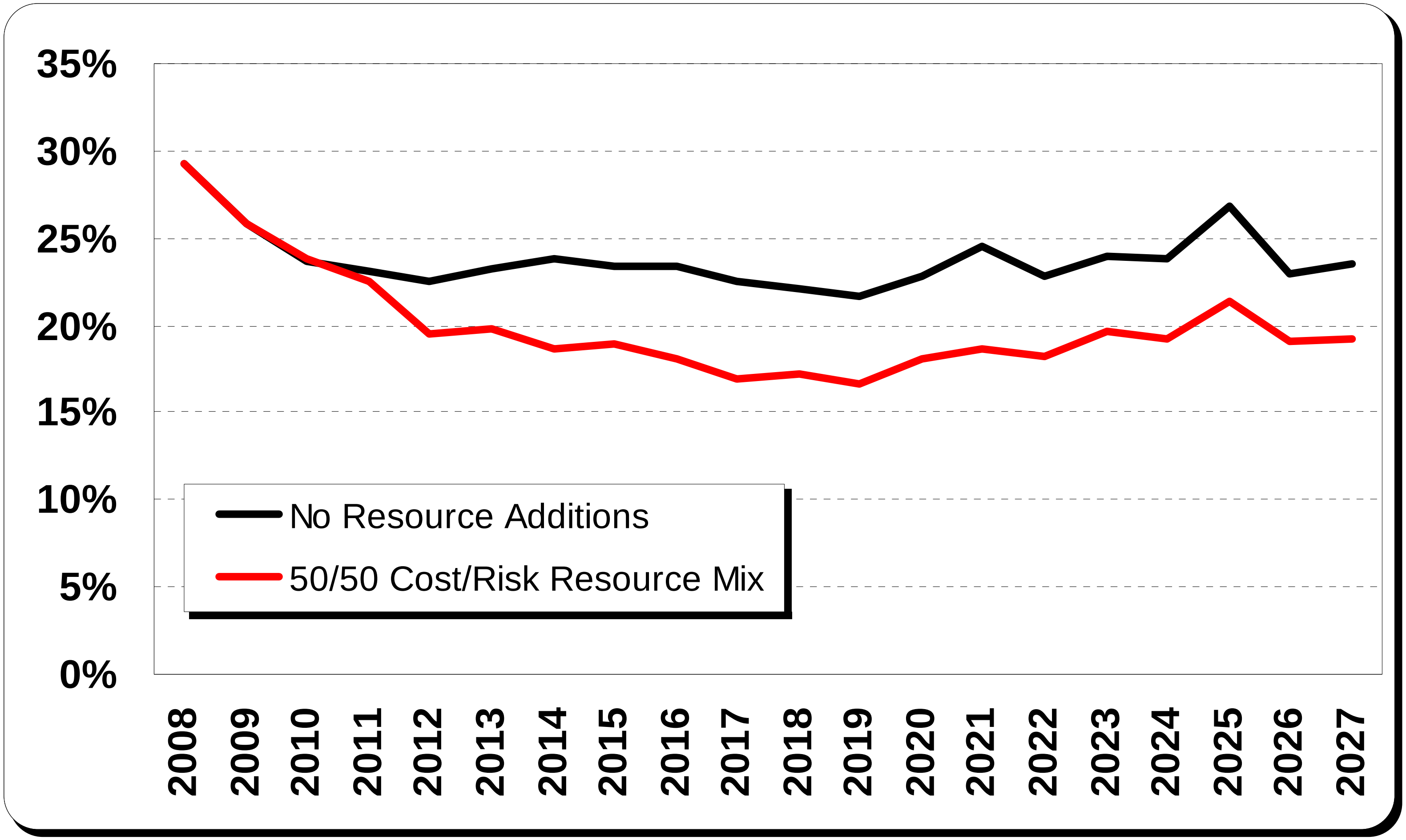
Base Case Options & Portfolios Efficient Frontiers (Incremental $/MWh)



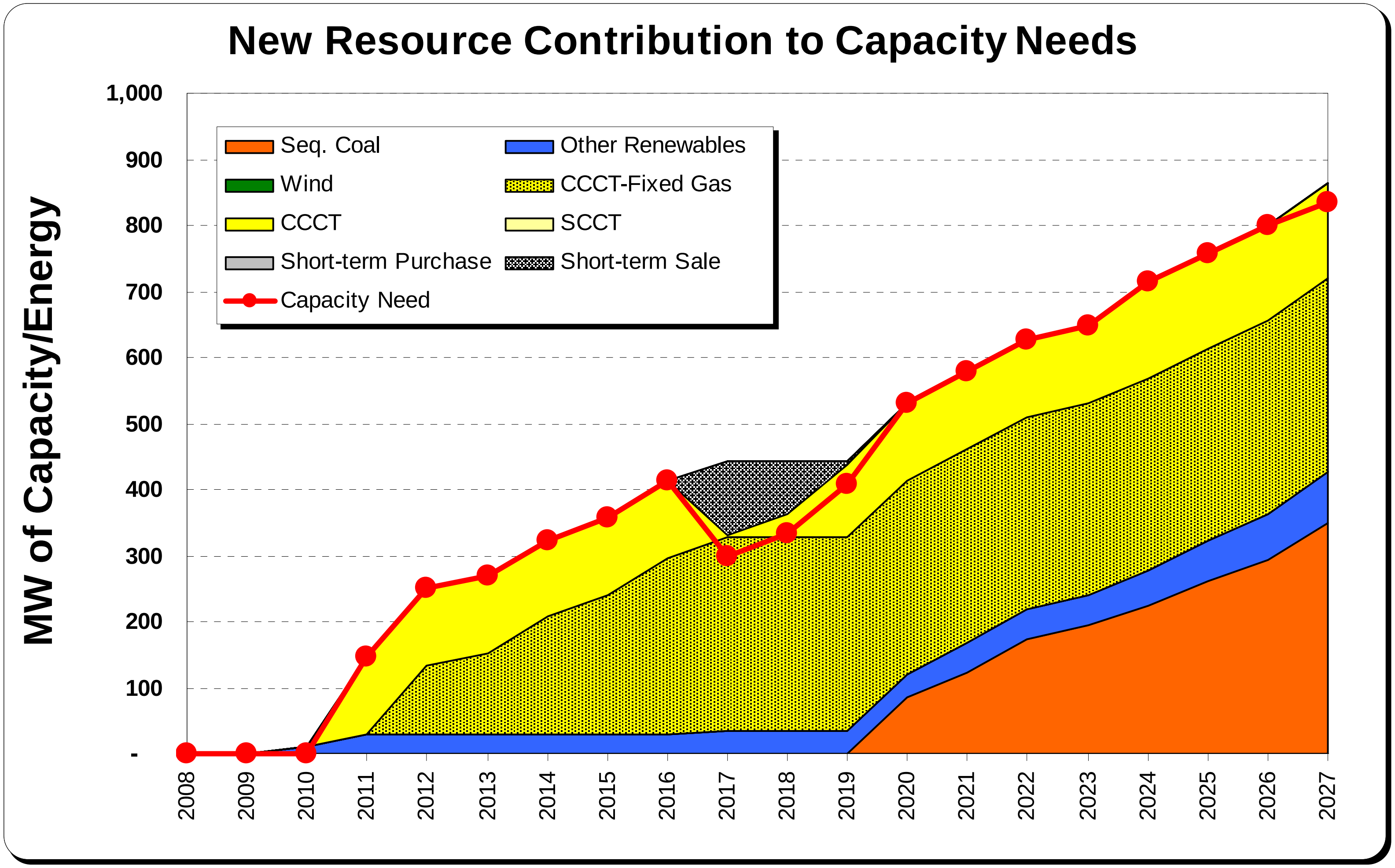
Summary Table: Base Case

#	Item	100/0	90/10	75/25	60/40	50/50	40/60	25/75	10/90	0/100
1	NPV Total Power Cost to 2017	1,656	1,692	1,814	1,859	1,859	1,862	1,862	1,862	1,909
2	NPV Total Power Cost to 2027	4,613	4,735	4,954	5,442	5,586	5,629	5,651	5,872	5,916
3	Power Cost in 2017	392	430	481	491	491	492	492	492	484
4	Power Cost in 2027	832	834	851	953	995	1,006	1,014	1,081	1,072
5	Power Cost Stdev in 2017	76	60	44	41	41	41	41	41	41
6	Power Cost Stdev in 2027	173	145	116	68	60	58	58	56	56
7	Power Cost ABSDEV in 2017	28	22	17	16	16	16	16	16	16
8	Power Cost ABSDEV in 2027	149	138	124	81	71	68	67	65	65
9	C. of V. 2016	19.3%	13.9%	9.1%	8.4%	8.4%	8.3%	8.3%	8.3%	8.5%
10	C. of V. 2027	20.8%	17.4%	13.6%	7.1%	6.0%	5.8%	5.7%	5.2%	5.2%
11	Acc. Capital Cost 2016	232	272	464	594	594	608	608	608	724
12	Acc. Capital Cost 2027	785	1,236	1,983	3,690	3,913	4,043	4,093	4,339	4,505
13	Rate AARG 2017	5.2%	5.8%	6.7%	6.9%	6.9%	6.9%	6.9%	6.9%	6.7%
14	Rate AARG 2027	4.7%	4.7%	4.8%	5.3%	5.4%	5.5%	5.5%	5.8%	5.8%
15	Rate Max Year	9.3%	9.6%	9.5%	9.5%	9.5%	9.9%	9.8%	11.9%	12.6%
16	2017 95th% Diff	144.9	116.6	81.5	72.9	72.9	72.5	72.5	72.5	72.5
17	DSM Reduction to Capacity by 2017									
18	Coal Capacity by 2017	-	-	-	-	-	-	-	-	-
19	CCCT Capacity by 2017	-	16	117	117	117	106	106	106	106
20	CT Capacity by 2017	394	233	-	-	-	-	-	-	-
21	Wind Nameplate by 2017	-	100	300	400	400	400	400	400	400
22	Oil Sands Capacity by 2017	-	-	-	-	-	-	-	-	-
23	OtherRenew Capacity by 2017	20	34	34	34	34	34	34	34	34
24	Other Resources Capacity by 2017	-	160	292	292	292	303	303	303	303
25	DSM Reduction to Capacity by 2027									
26	Coal Capacity by 2027	-	-	-	238	349	377	377	186	171
27	CCCT Capacity by 2027	-	16	249	226	145	106	106	106	106
28	CT Capacity by 2027	815	600	215	-	-	-	-	-	-
29	Wind Nameplate by 2027	-	100	300	600	600	600	600	600	600
30	Oil Sands Capacity by 2027	-	-	-	-	-	-	-	211	226
31	OtherRenew Capacity by 2027	20	59	78	78	78	78	78	59	59
32	Other Resources Capacity by 2027	-	160	292	292	292	303	303	303	303

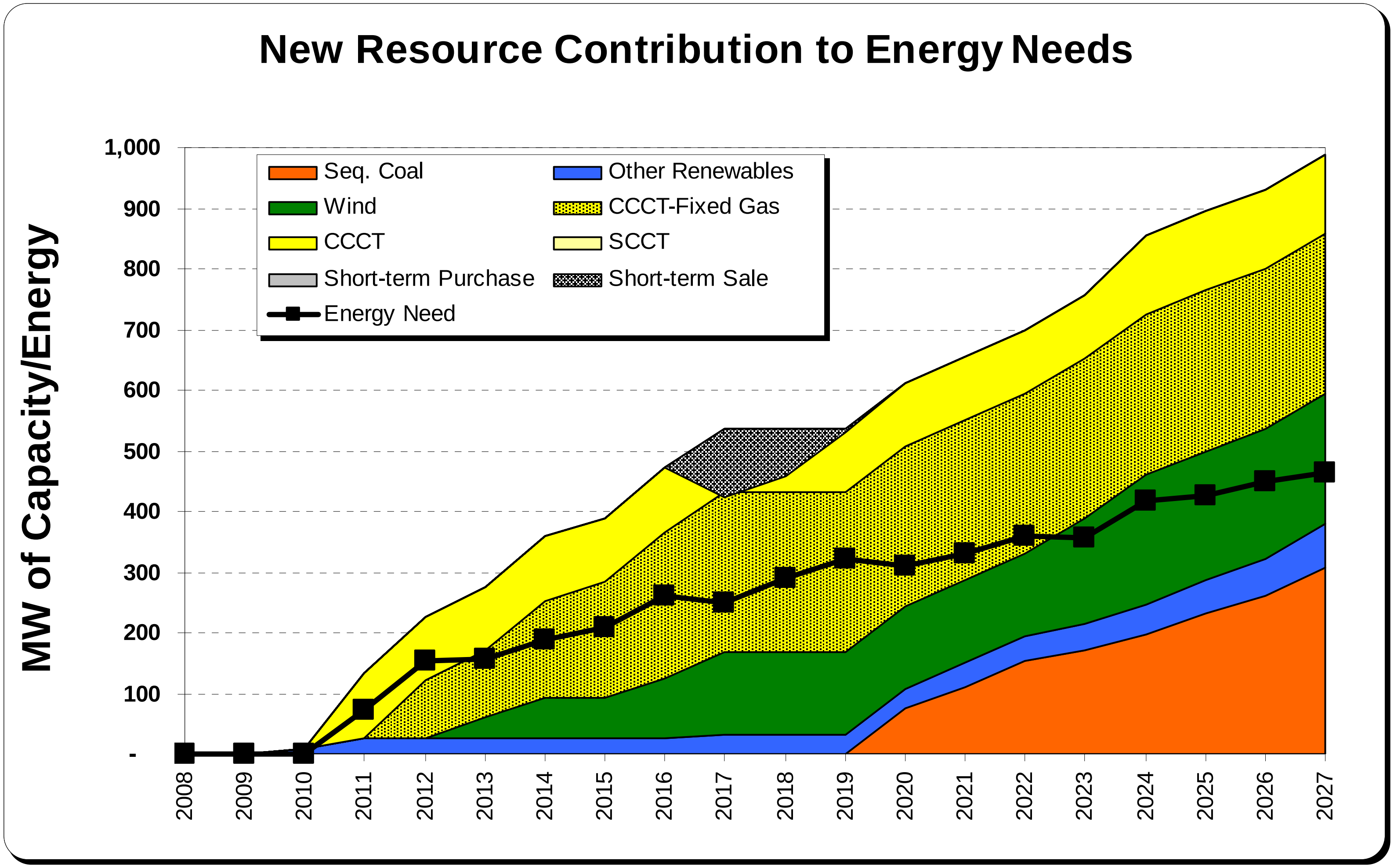
Power Supply Risk Comparison



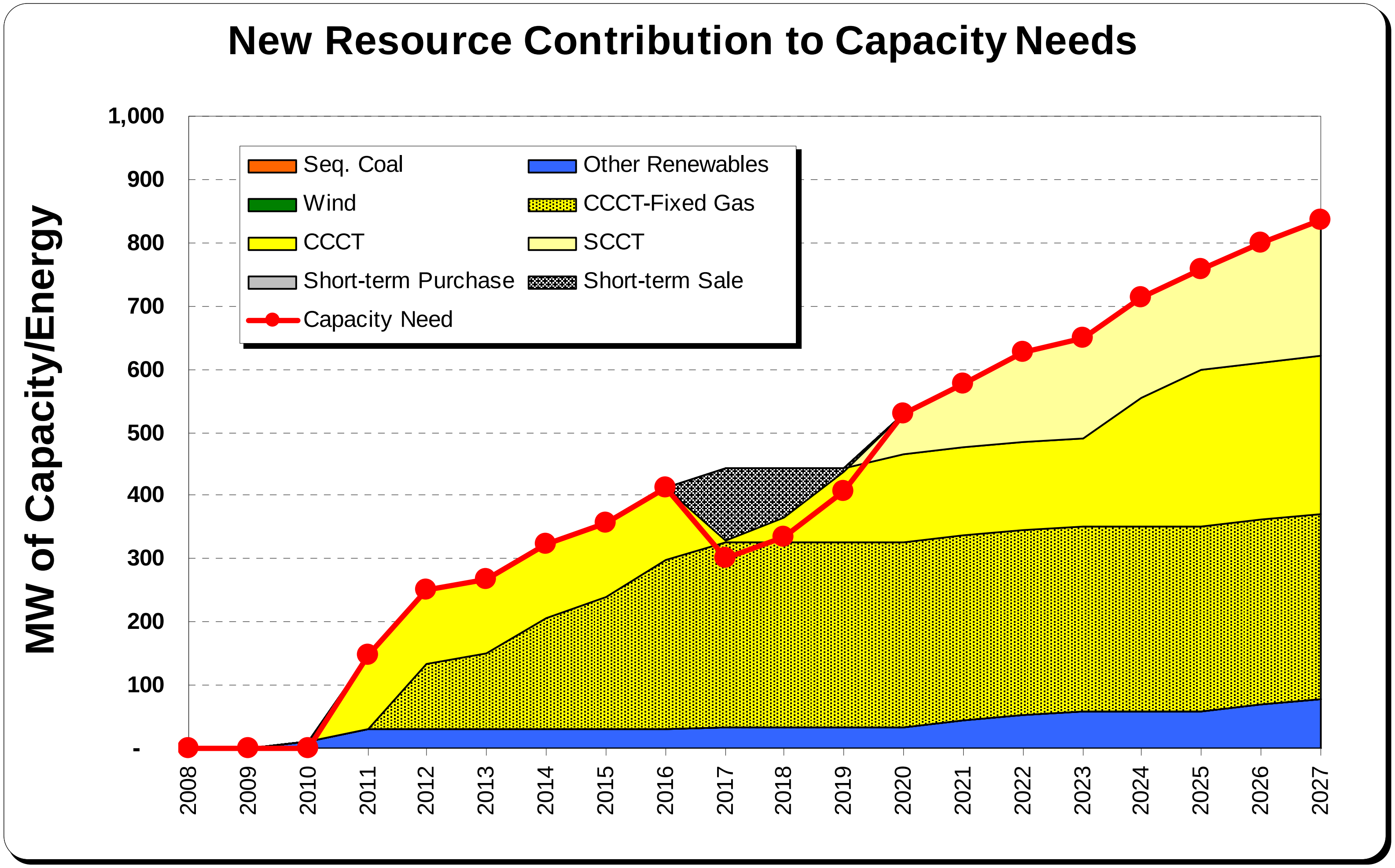
Resource Mix (50/50) Capacity



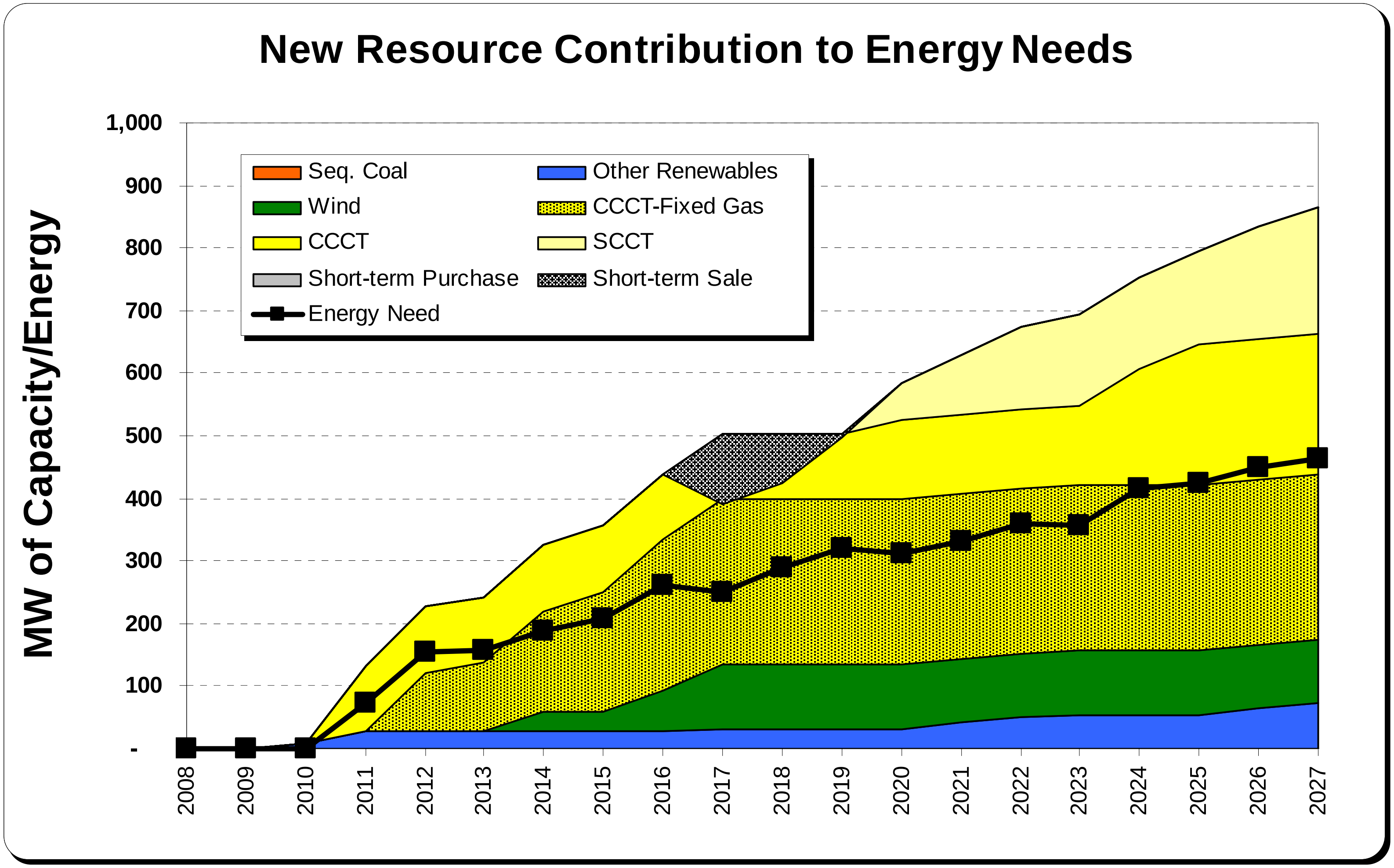
Resource Mix (50/50) Energy



Resource Mix (75/25) Capacity



Resource Mix (75/25) Energy



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

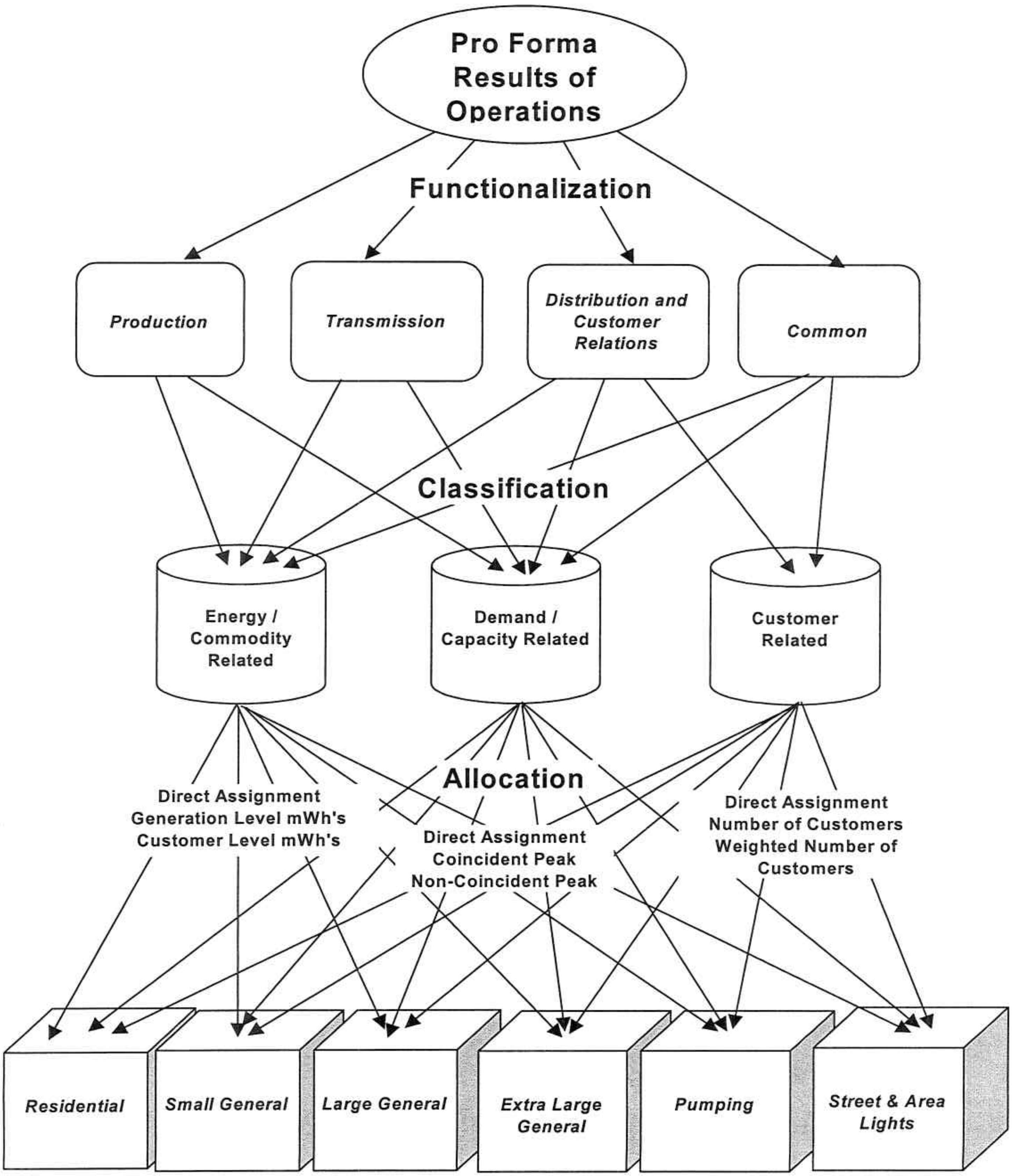
Puget Sound Energy – Cost of Service

- 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 by Customer Group

	Replacement Cost "$" (1)	Installed Capacity KW (2)	Cost per KW $	%	Classification
Thermal and Coyote Springs					
Kettle Falls (212)	169,066,749	50,700	$3,335		
Colstrip (410)	292,403,948				
Colstrip (411)	211,270,898				
Total Colstrip	503,674,846	233,400	$2,158		
Coyote Springs II (610)	162,320,975	287,000	$566		
Total Thermal	835,062,570	571,100	$1,462		
Peaking Units					
Kettle Falls CT (211)	9,164,018	7,200	$1,273		
Norteast Spokane CT (213)	27,081,245	61,800	$438		
Boulder Park CT (216)	31,567,782	24,600	$1,283		
Rathdrum CT (310)	59,872,834	166,500	$360		
Total Peaking Units	127,685,880	260,100	$491		
Hydro Plant					
Monroe Street (201)	46,947,839	14,800	$3,172		
Little Falls (202)	104,086,383	32,000	$3,253		
Long Lake (203)	271,004,114	70,000	$3,871		
Upper Falls (204)	58,288,767	10,000	$5,829		
Nine Mile (205)	82,084,830	26,400	$3,109		
Post Falls (300)	79,262,577	14,800	$5,356		
Cabinet Gorge (304)	433,446,950	265,000	$1,636		
Noxon Rapids (401)	584,184,717	473,400	$1,234		
Total Hydro	1,659,306,177	906,400	$1,831		
Thermal Plant Average Replacement Cost per KW Capacity			$1,462	100.00%	
Less:					
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%	
Less:					
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
50/50 Weighting Thermal and Hydro Energy Percentages				69.81%	Energy
Transmission Peak Credit				100.00%	Total

(1) From Replacement Cost Column on the Plant Report Titled "Insurance Report - FA Cost 2004 2005 - FINAL with Subtotals" for the Year Ended 12-31-2005.

(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

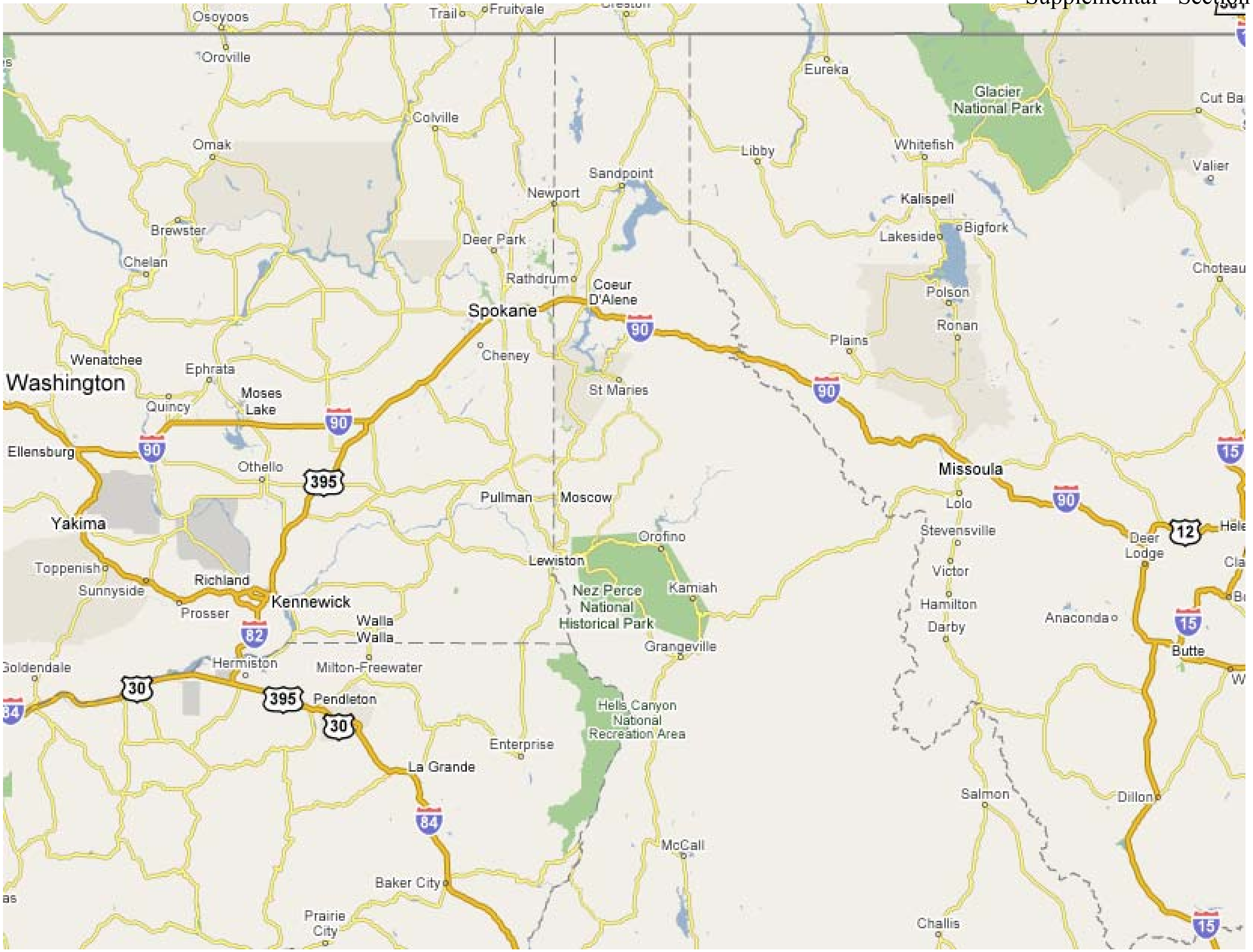
Smaller Project Integration

Larger Project Integration

Cost Estimates

Estimated Integration Costs Inside Avista's System

MW Size / Location	50 MW	100 MW	250 MW	400+ MW
Sprague, WA	NA	NA	$58M	$80+M
Spokane/ Coeur d'Alene	$3M	$7M	$32M	$32M-$500M
Mica Peak	$4M	NA	NA	NA
Clark Fork Hydro	$0	NA	NA	NA
Dayton, WA	$32M	$32M	NA	NA
Reardan, WA	$2M	$13M	NA	NA
Lind, WA	$1.5M	$6M	NA	NA
Othello, WA	$1.5M	NA	NA	NA
Colfax, WA	$1.5M	NA	NA	NA


Osoyoos
Trail
Fruitvale
Oroville
Eureka
Glacier National Park
Cut Bank
Colville
Omak
Libby
Whitefish
Valier
Sandpoint
Newport
Kalispell
Brewster
Deer Park
Lakeside
Bigfork
Chelan
Rathdrum
Coeur D'Alene
Choteau
Polson
Spokane
Ronan
Cheney
Plains
Wenatchee
Ephrata
Washington
Moses Lake
St Maries
Quincy
Ellensburg
Othello
395
Missoula
Lolo
Pullman
Moscow
Yakima
Stevensville
Orofino
Deer Lodge
12
Lewiston
Toppenish
Victor
Richland
Kamiah
Sunnyside
Nez Perce National Historical Park
Kennewick
Hamilton
Prosser
Walla Walla
Anaconda
Darby
Grangeville
Butte
Hermiston
Goldendale
Milton-Freewater
30
Pendleton
Hells Canyon National Recreation Area
Enterprise
La Grande
Salmon
Dillon
McCall
Baker City
Prairie City
Challis
90
82
84
15

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

	Topic	Time	Staff
1.	Introductions	9:30	Barcus
2.	Review of 4th TAC Meeting	9:40	Lyons
3.	Presentation of PRS for 2007 IRP	9:45	Kalich/Gall
4.	Lunch	12:00	
5.	PRS continued	12:45	Kalich/Gall
6.	Action Items	3:00	Lyons
7.	Adjourn	3:30	

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

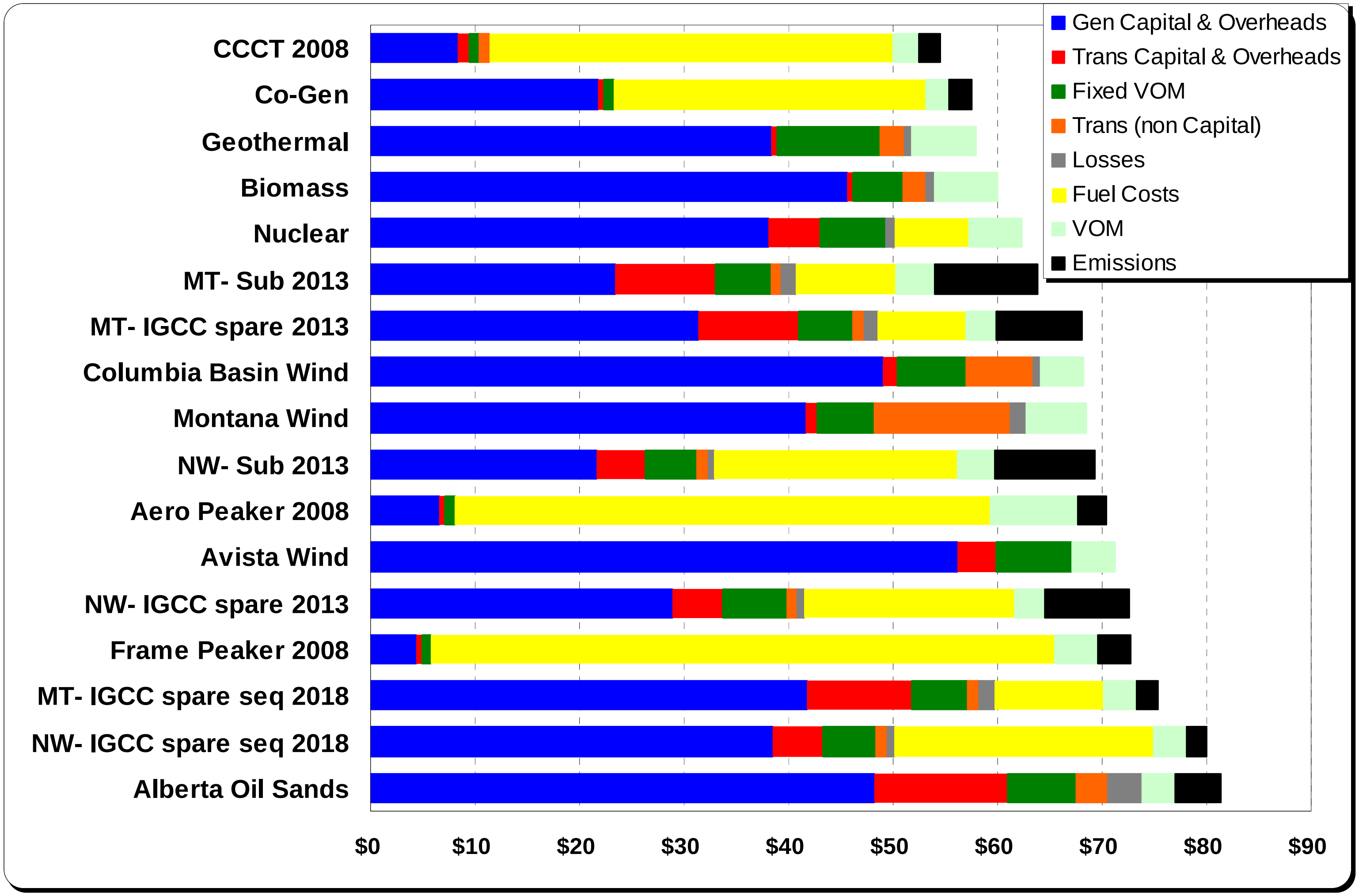
Preferred Resource Strategy Analysis

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)



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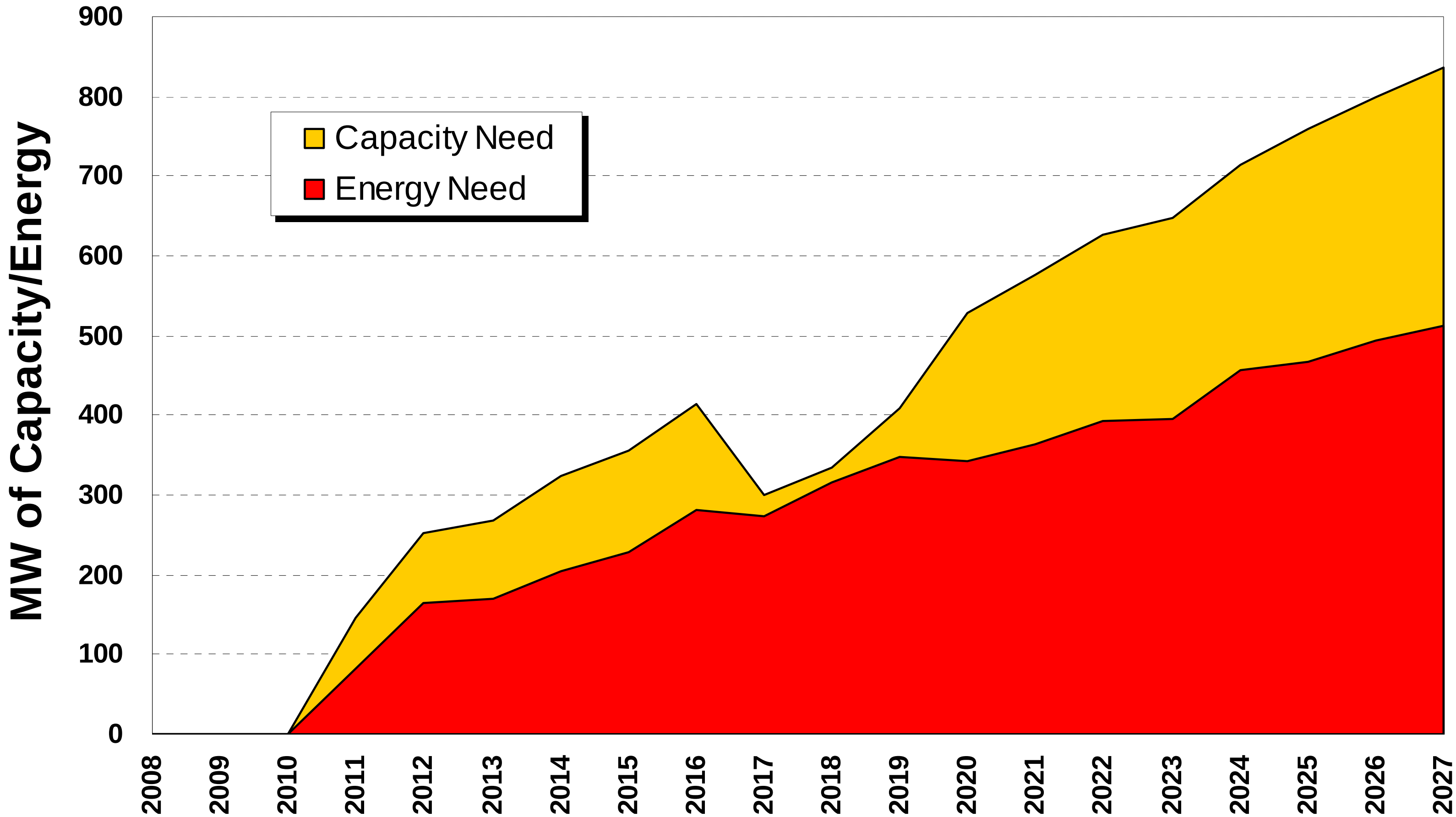
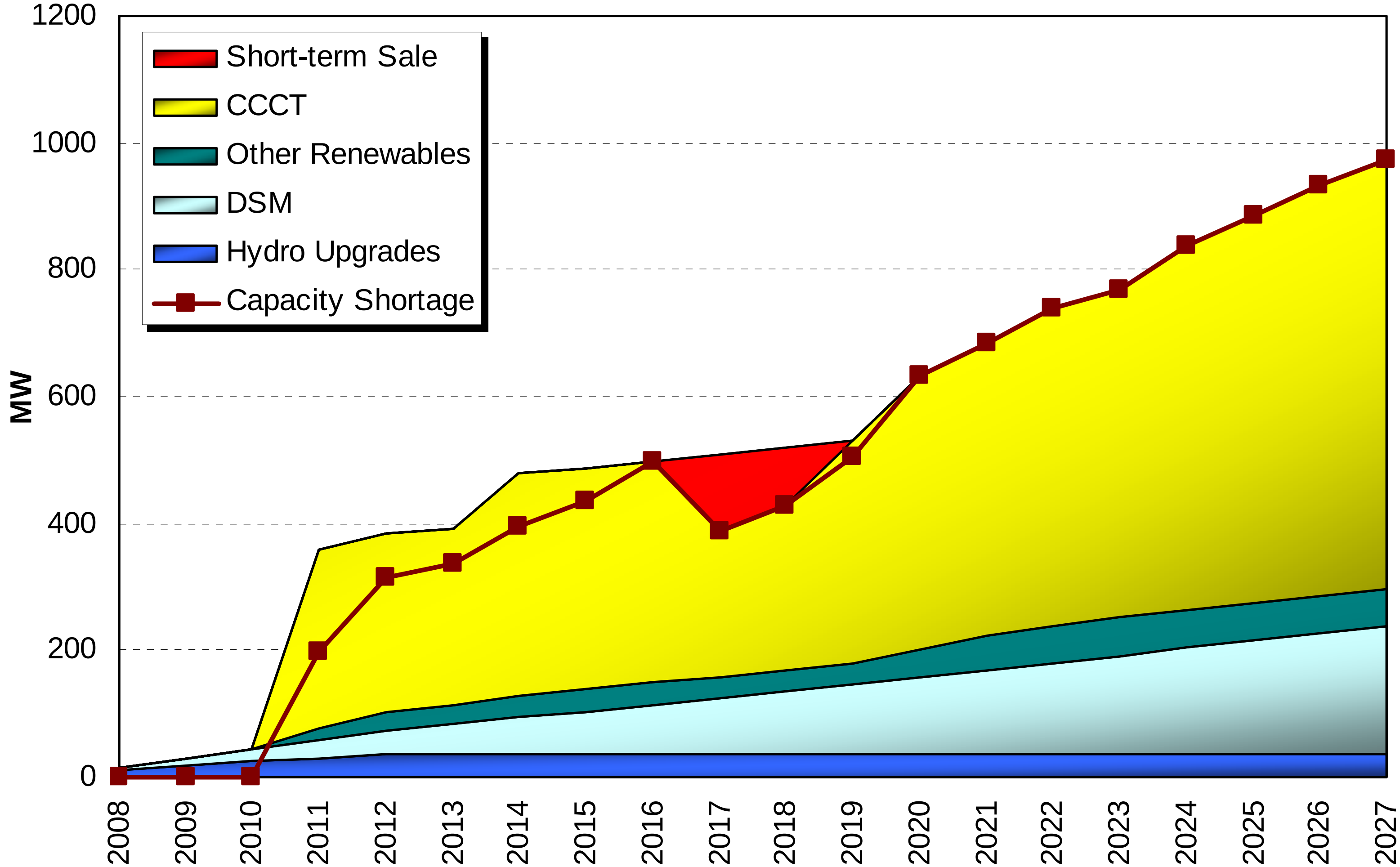
Small Co-Gen	2,100			

Company cannot construct options highlighted in red

Avista's Annual Average Resource Need



Preferred Resource Strategy- Capacity



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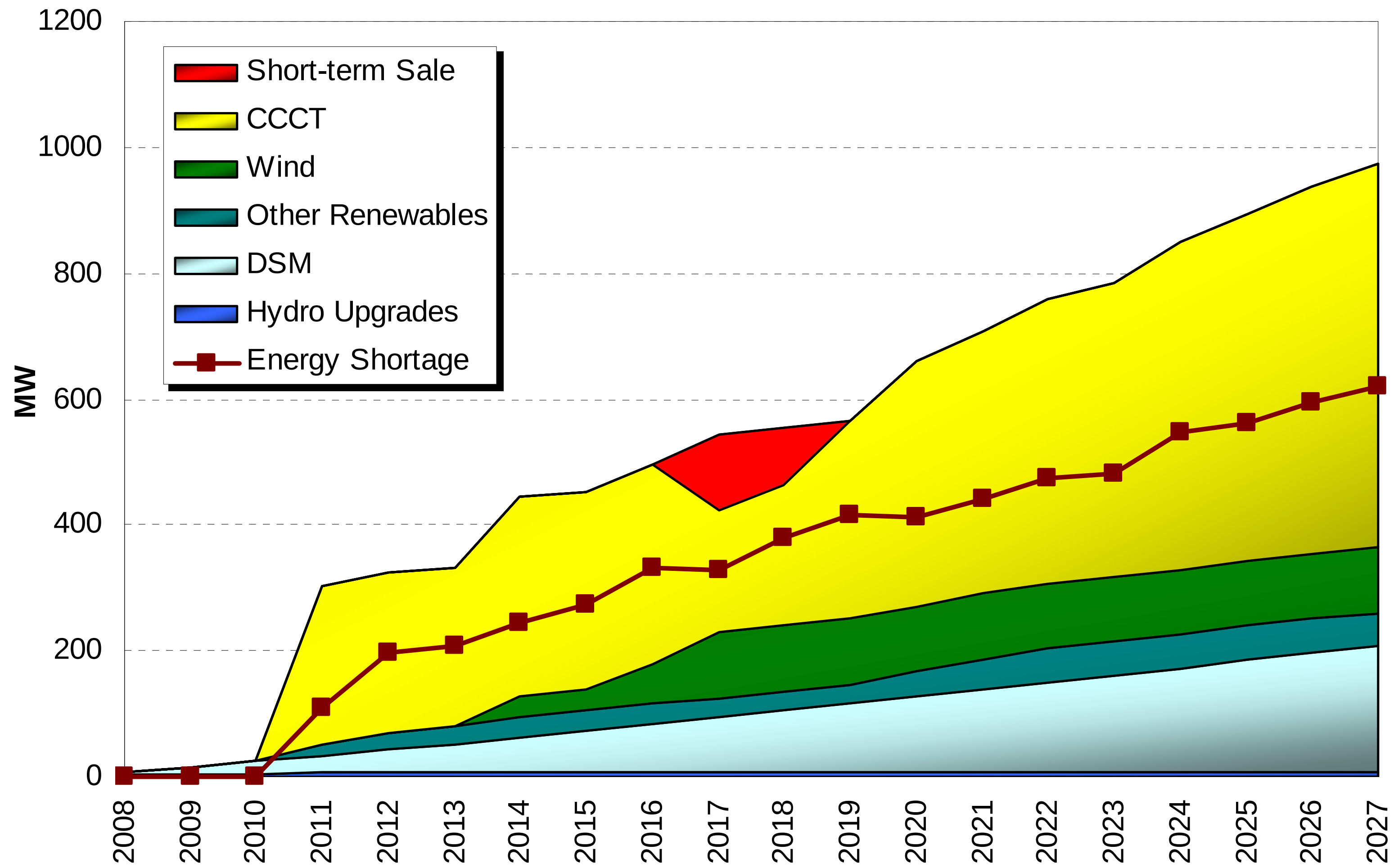
Preferred Resource Strategy- Energy



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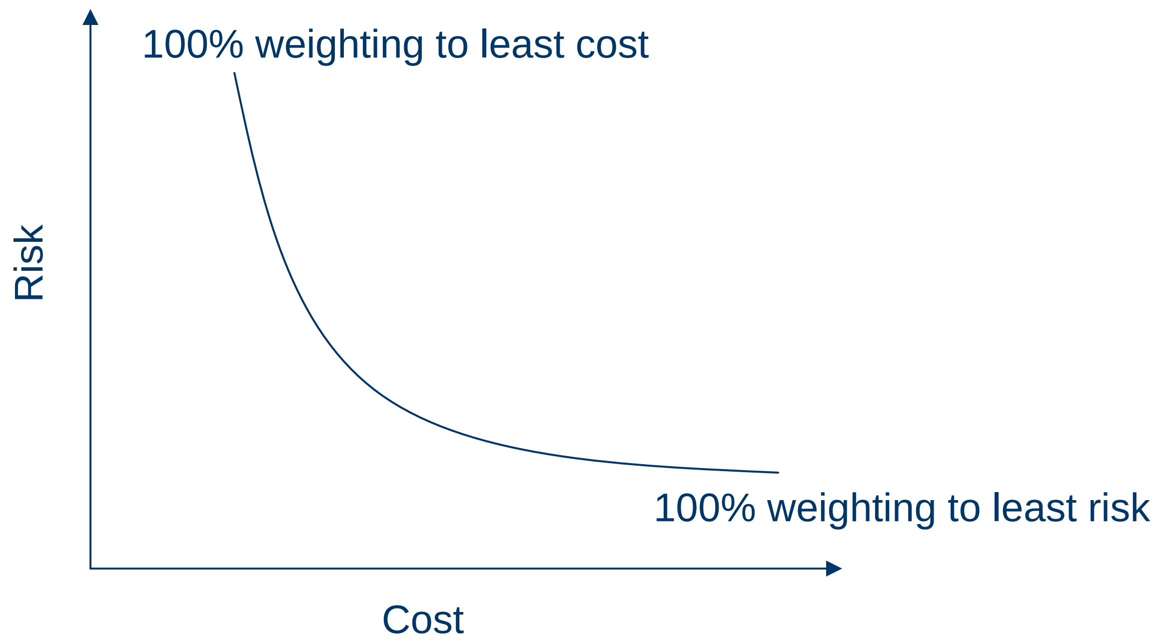
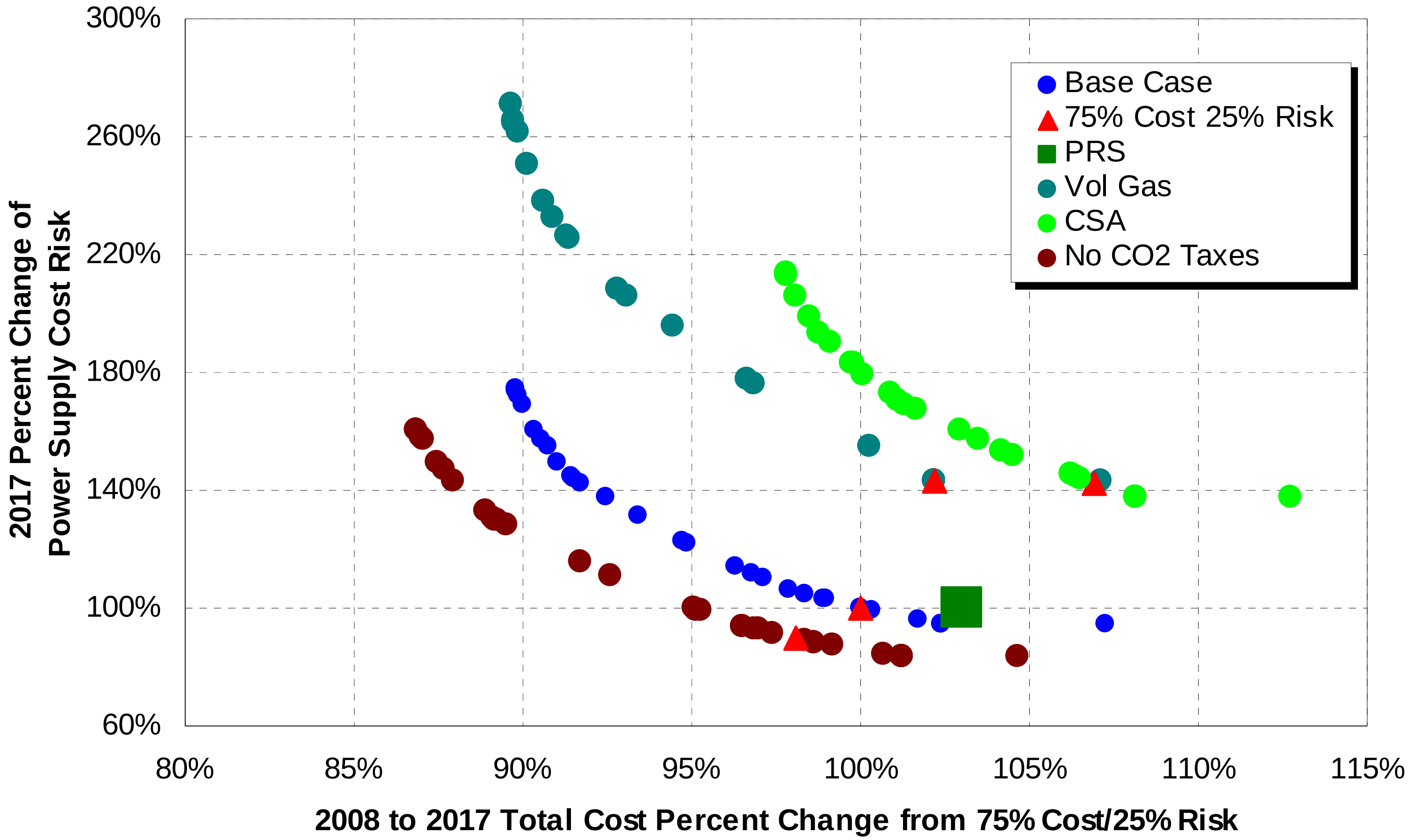
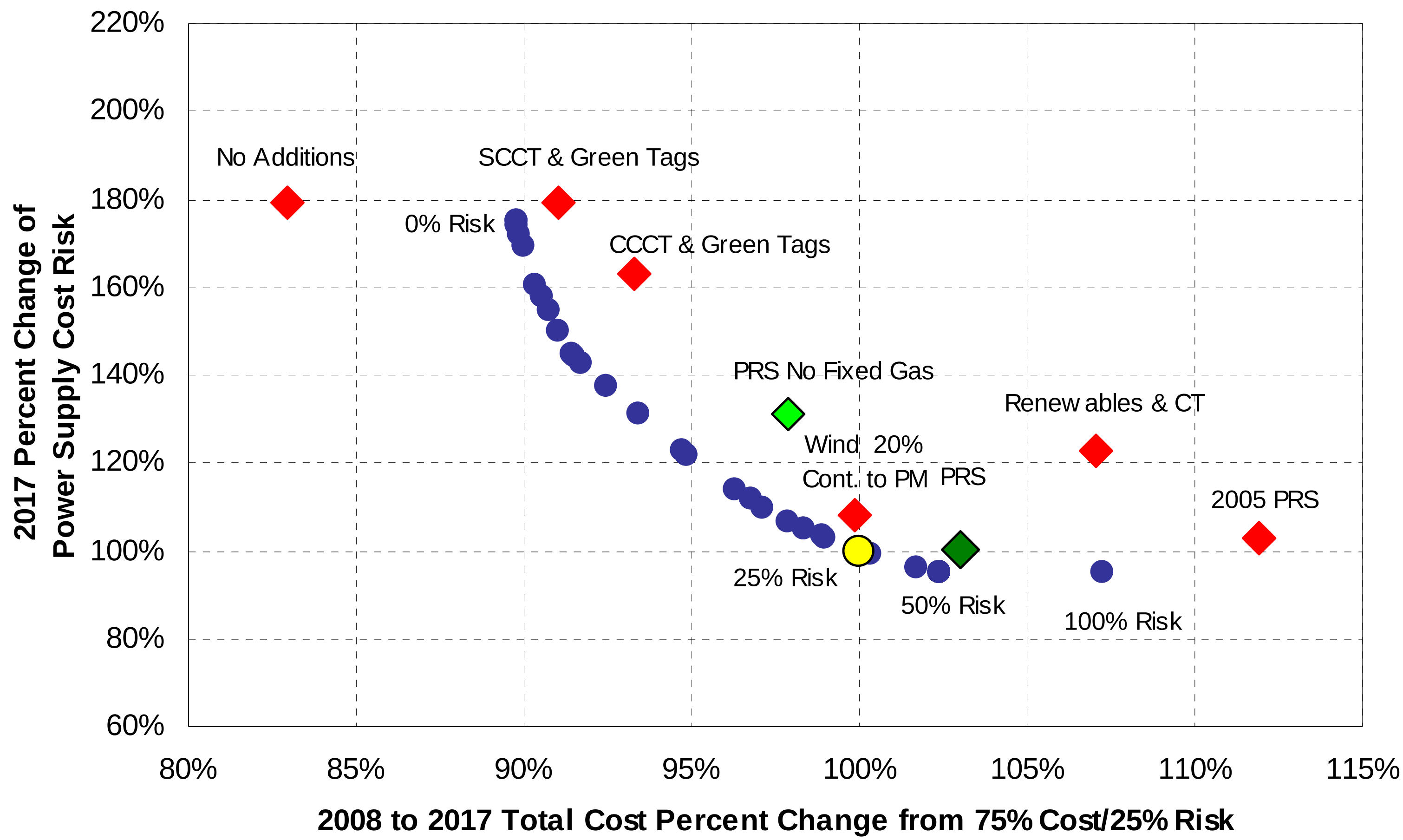
- Difficulty: how much additional cost are we willing to pay to reduce risk



Efficient Frontiers

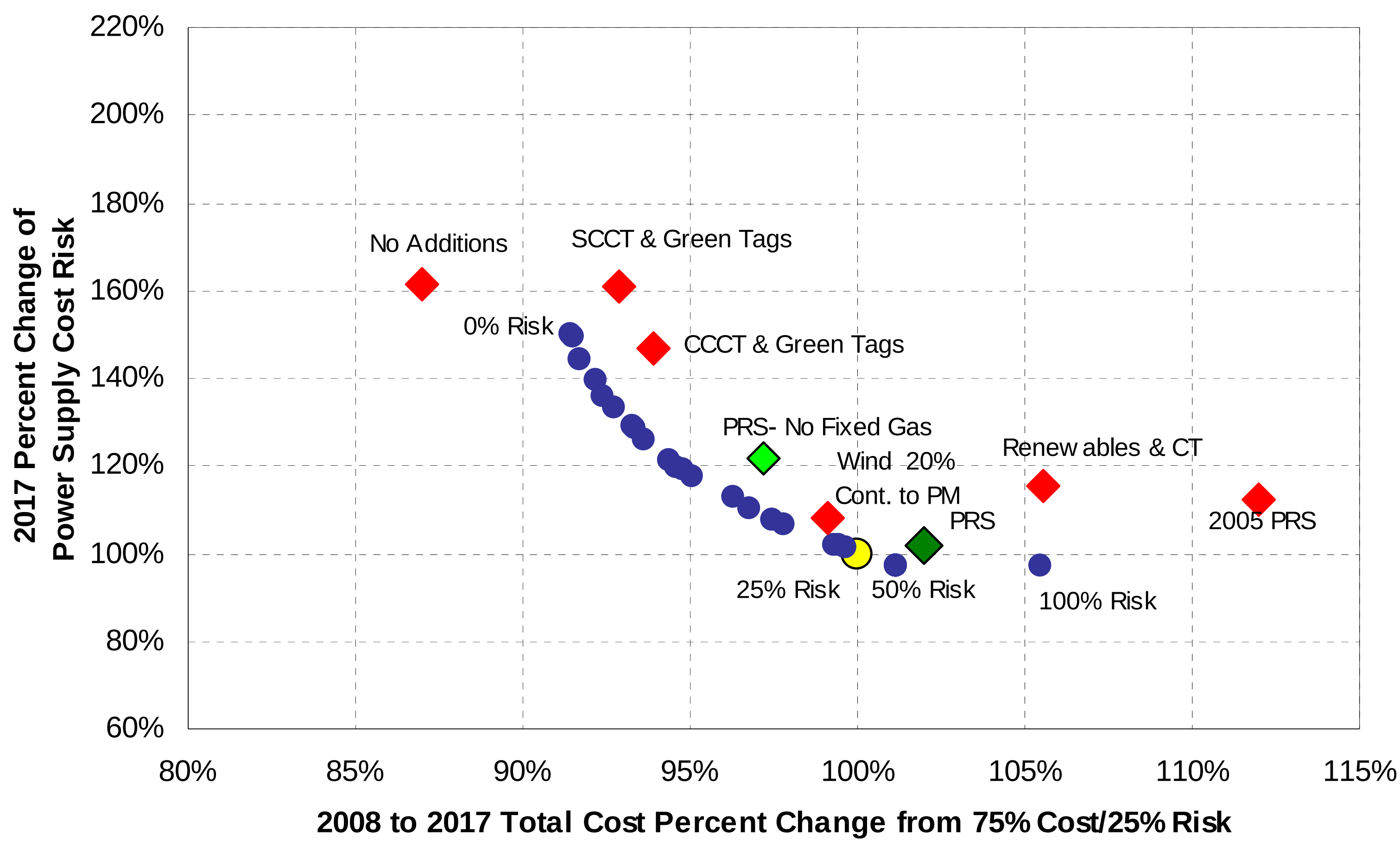


Efficient Frontier- Base Case

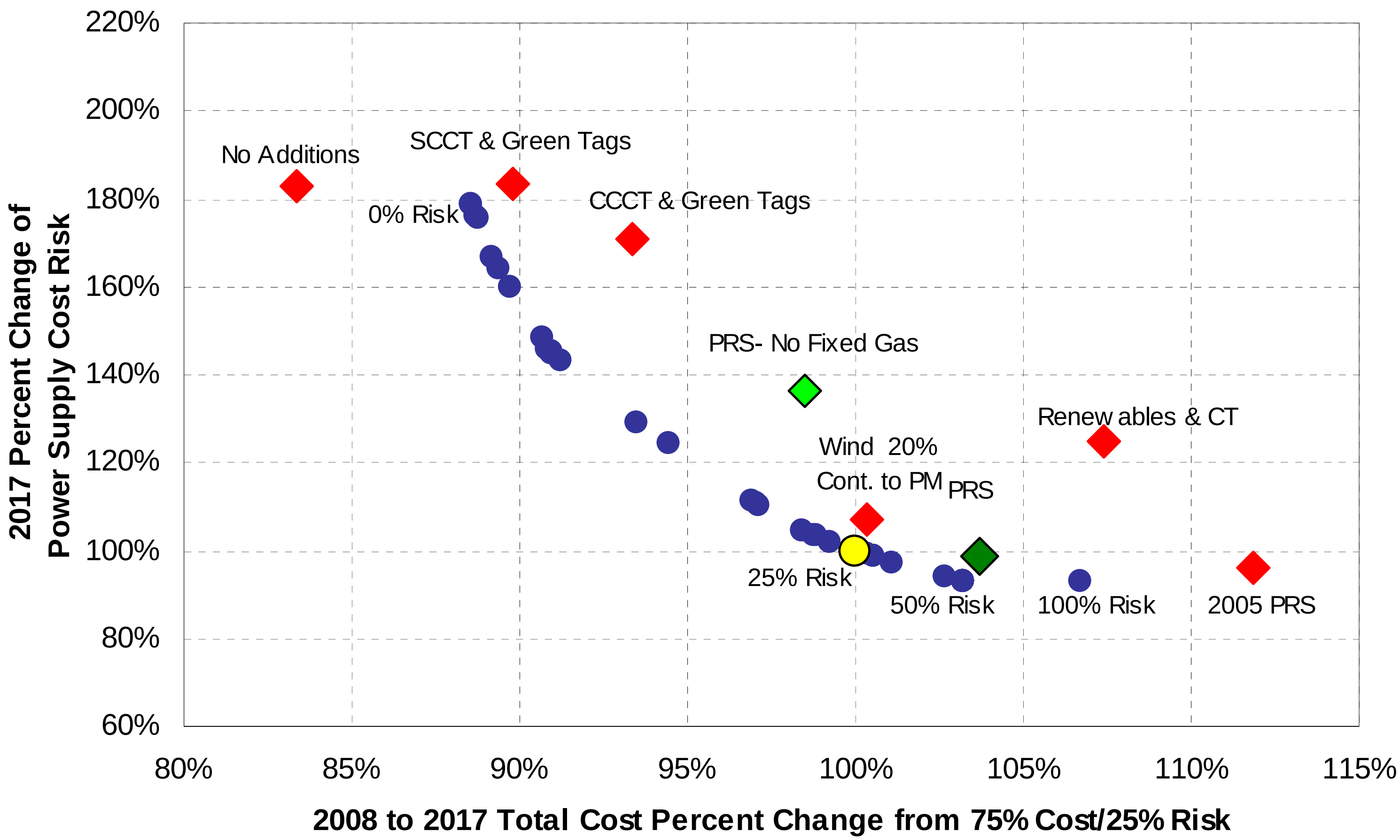


No RPS and Corporate RPS to be included in final document

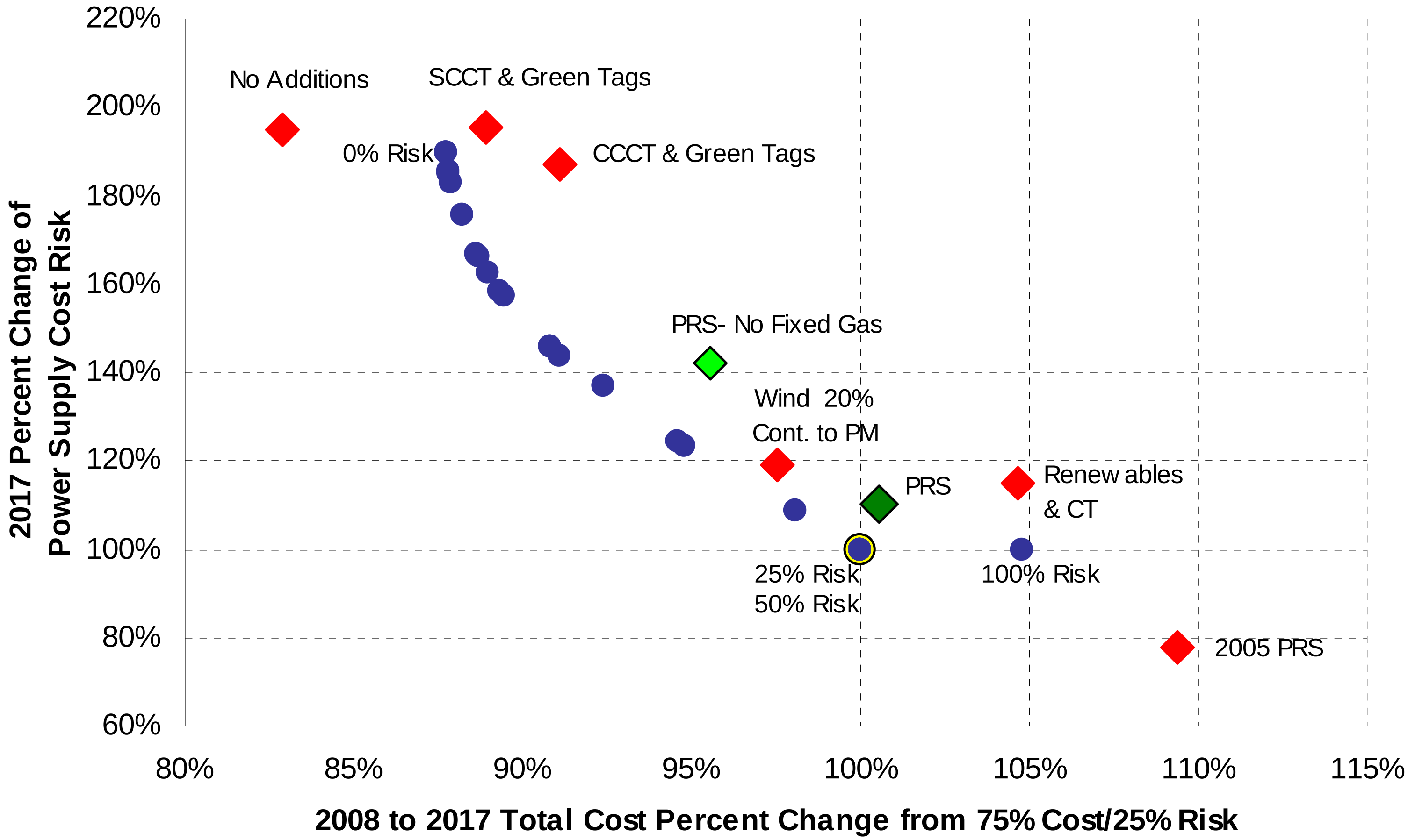
Efficient Frontier- C.S.A. Future



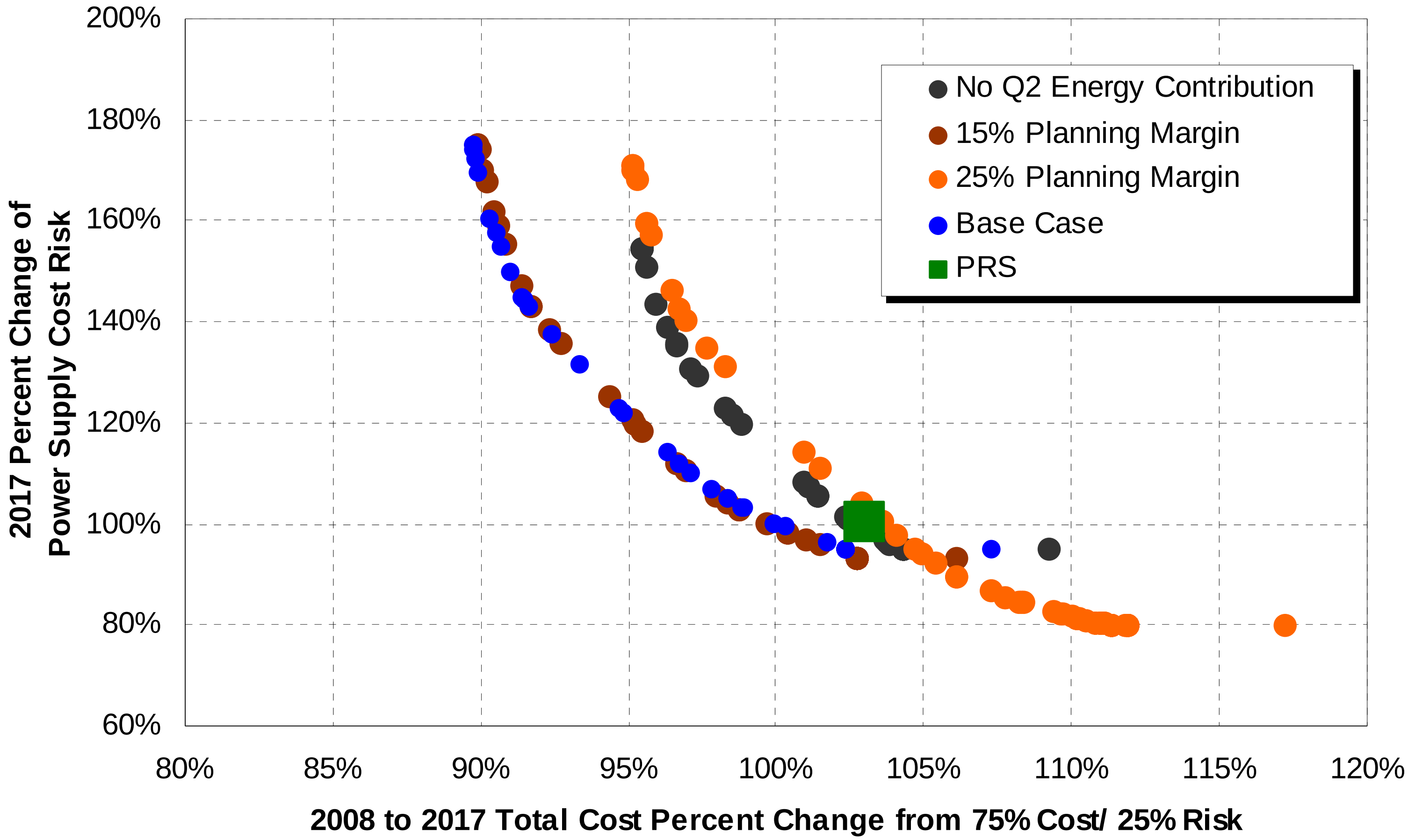
Efficient Frontier- Carbon "Okay" Future



Efficient Frontier- Volatile Natural Gas Price Future

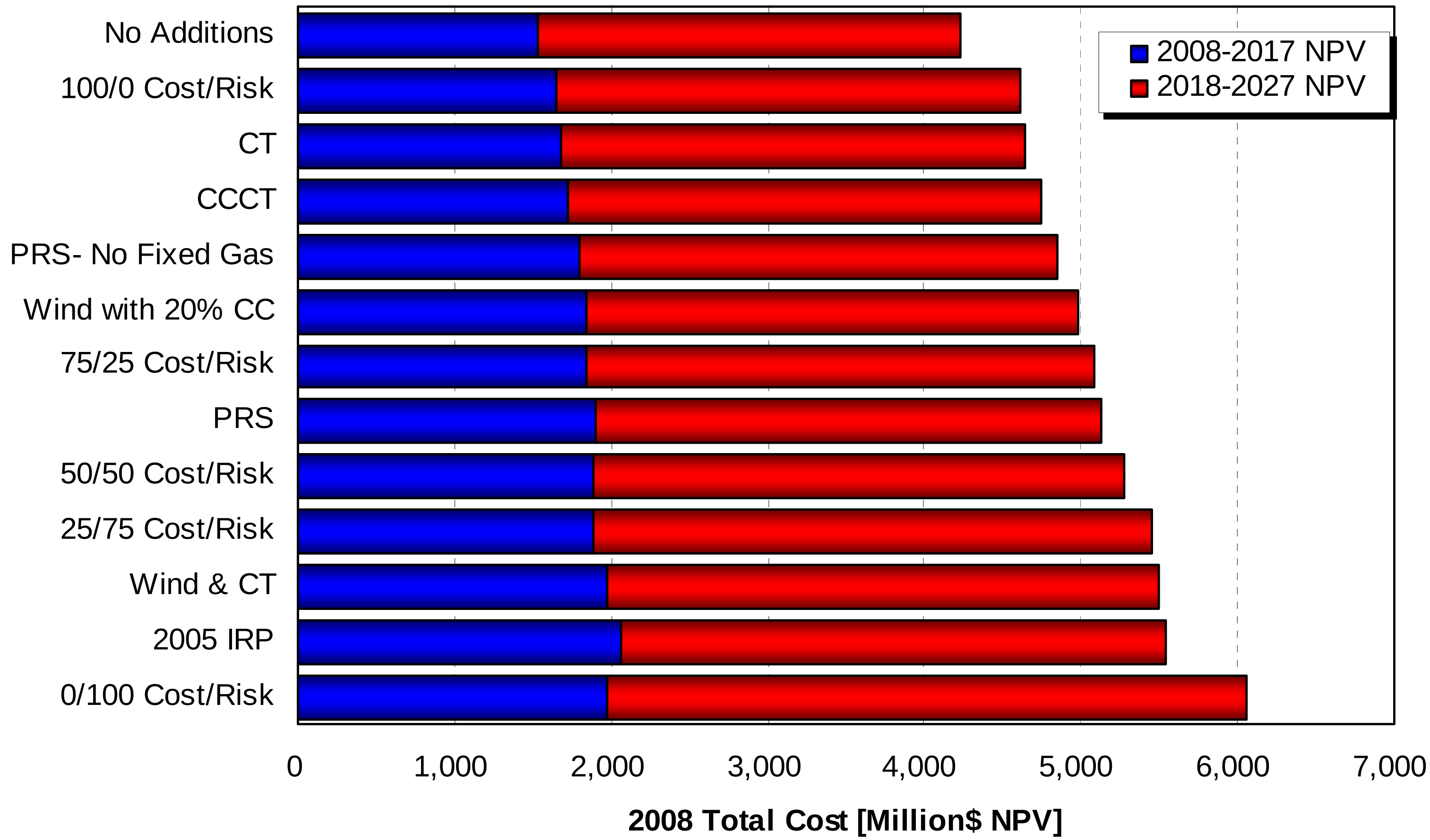


Efficient Frontier- Alternative Planning Criteria



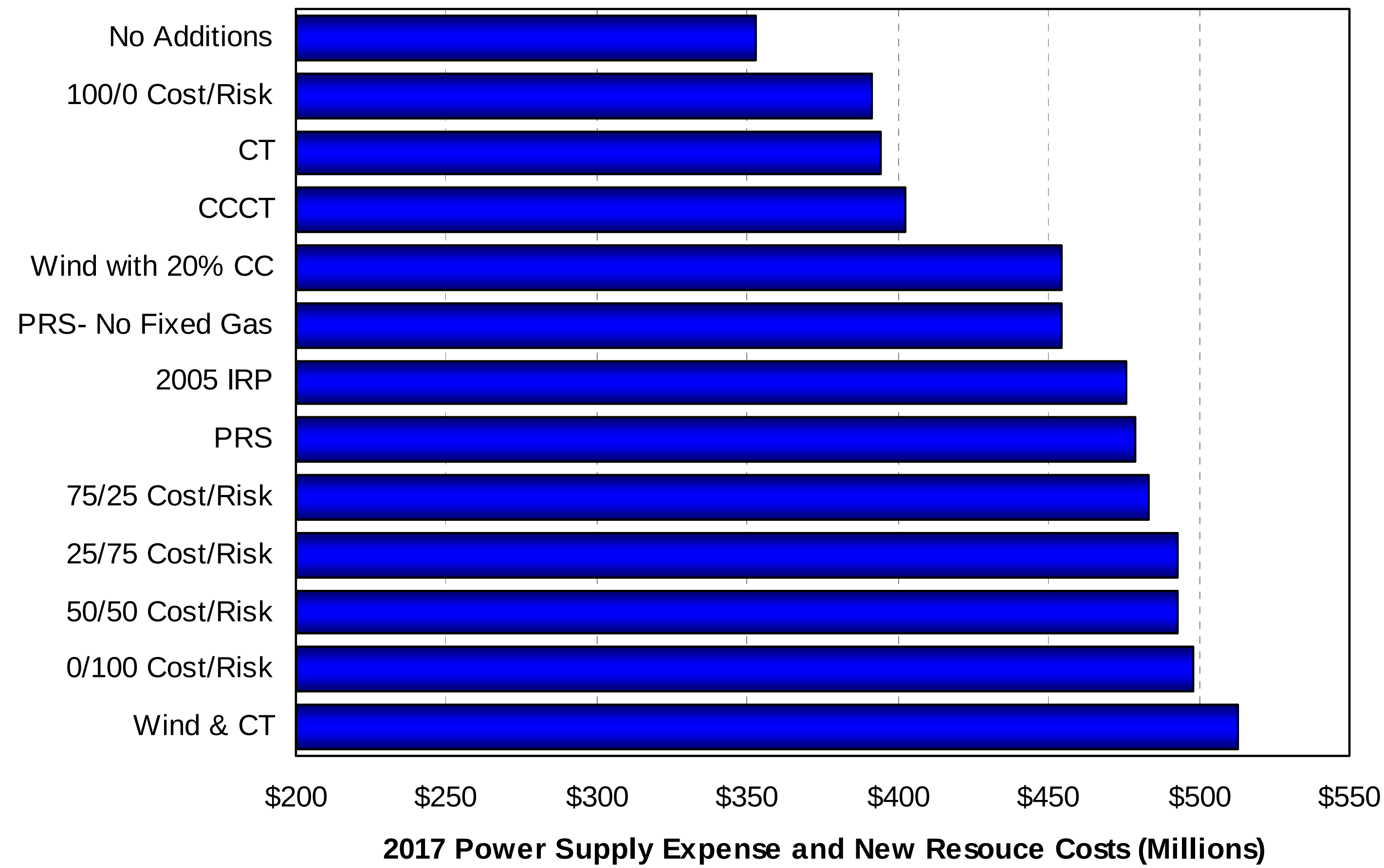
Portfolio Comparison- Total Cost

Power Supply Expense and New Resource Costs



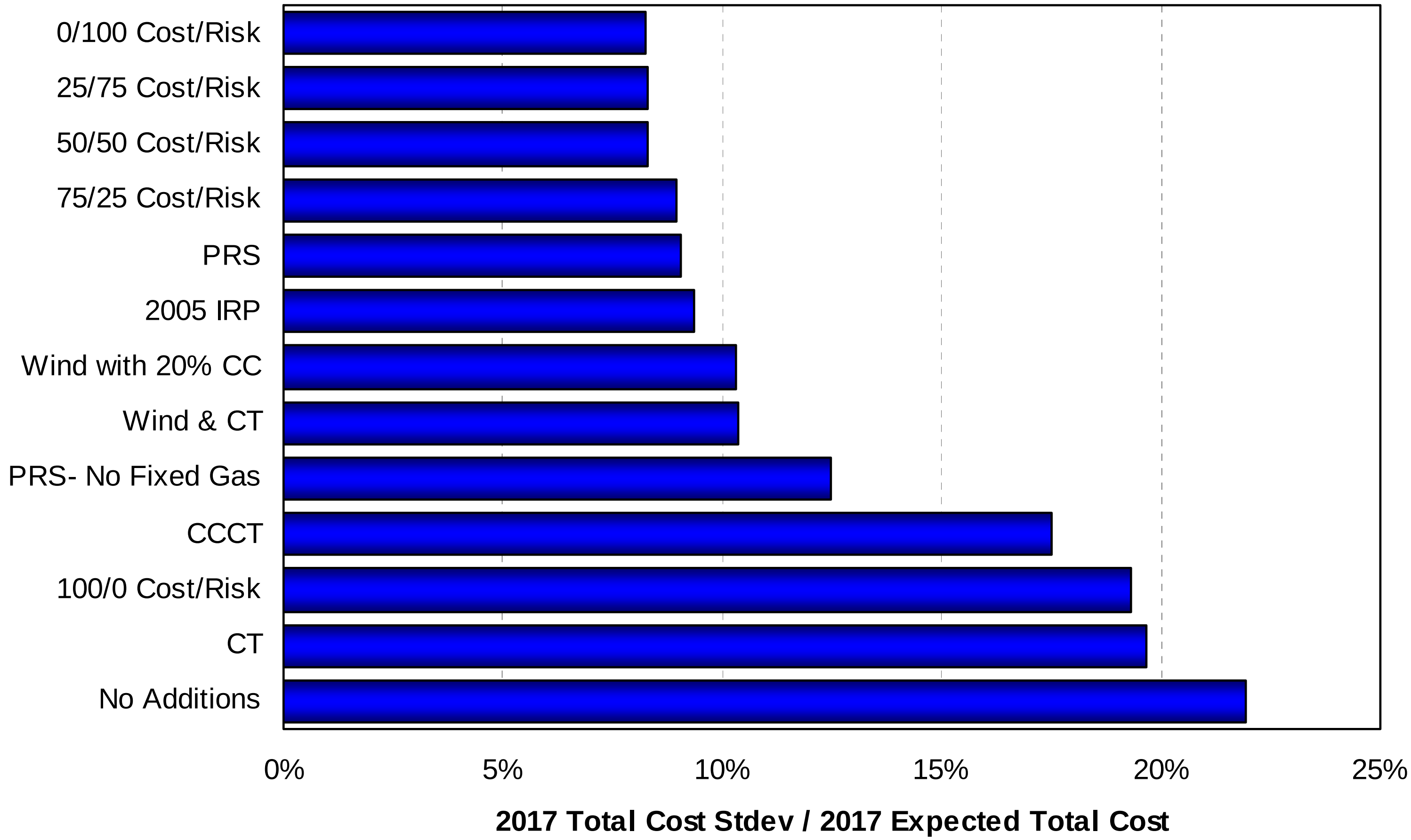
Portfolio Comparison- 2017 Total Cost

Total of existing portfolio and new resources



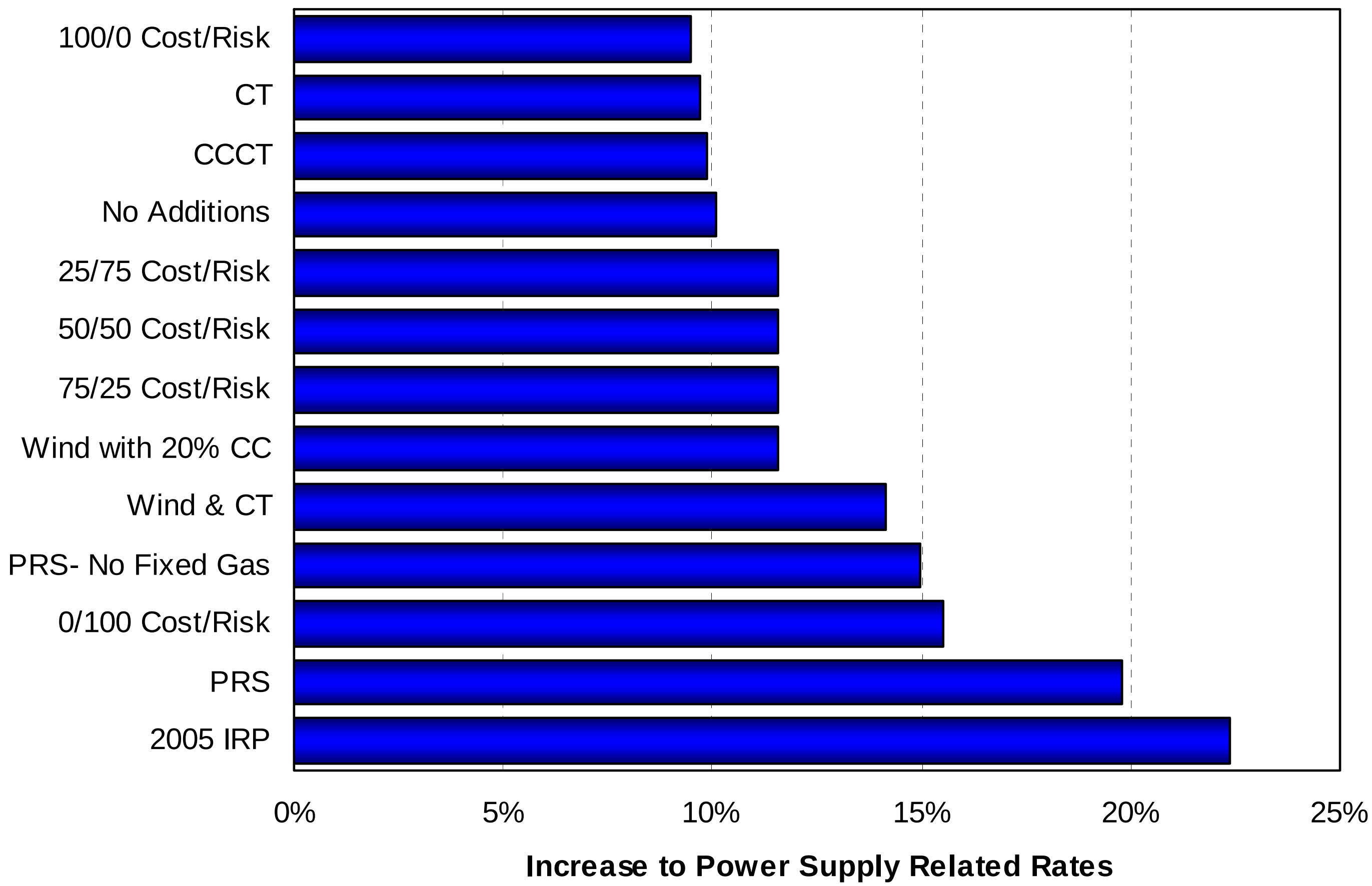
Portfolio Comparison- 2017 Risk

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



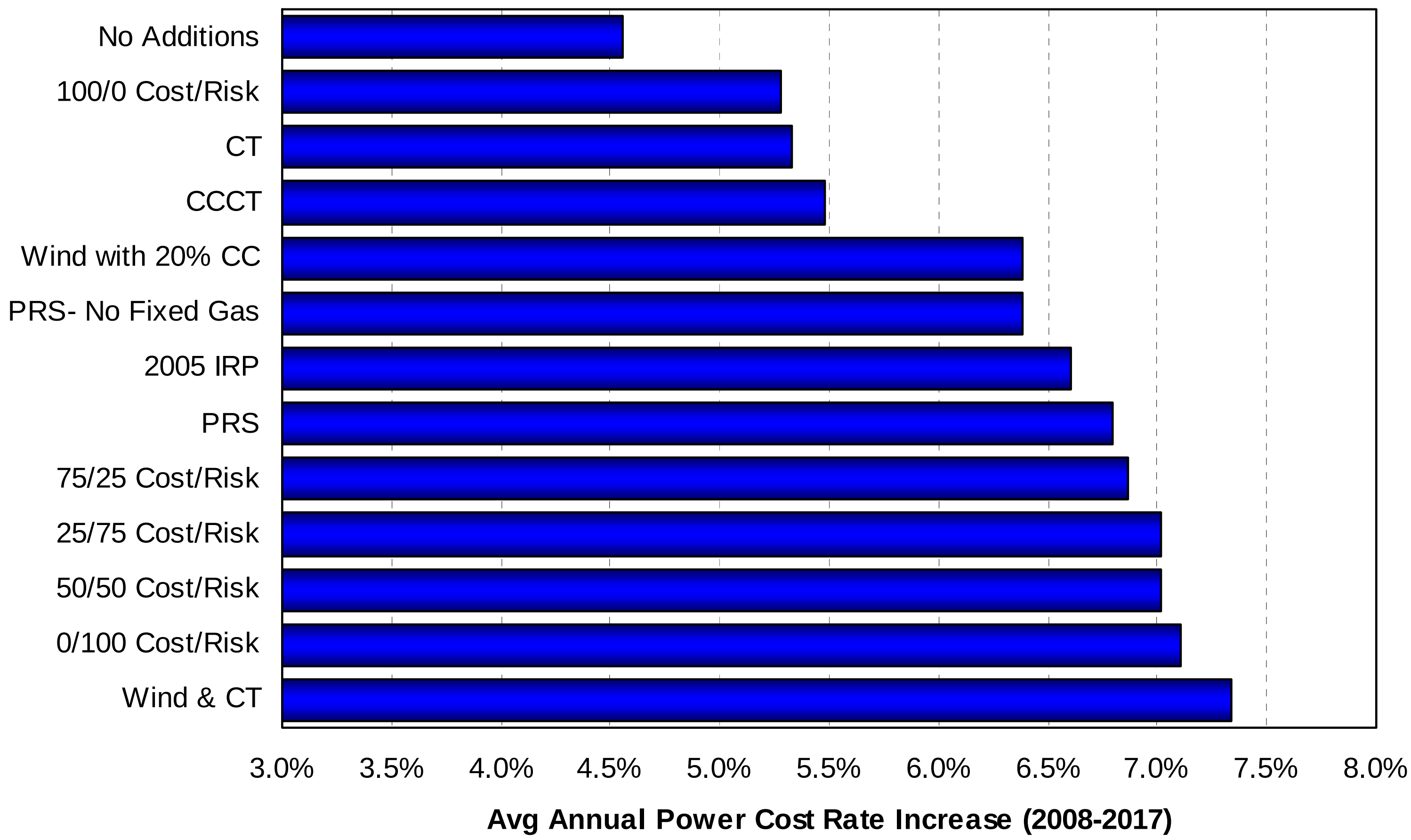
Portfolio Comparison- Max Annual Increase

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



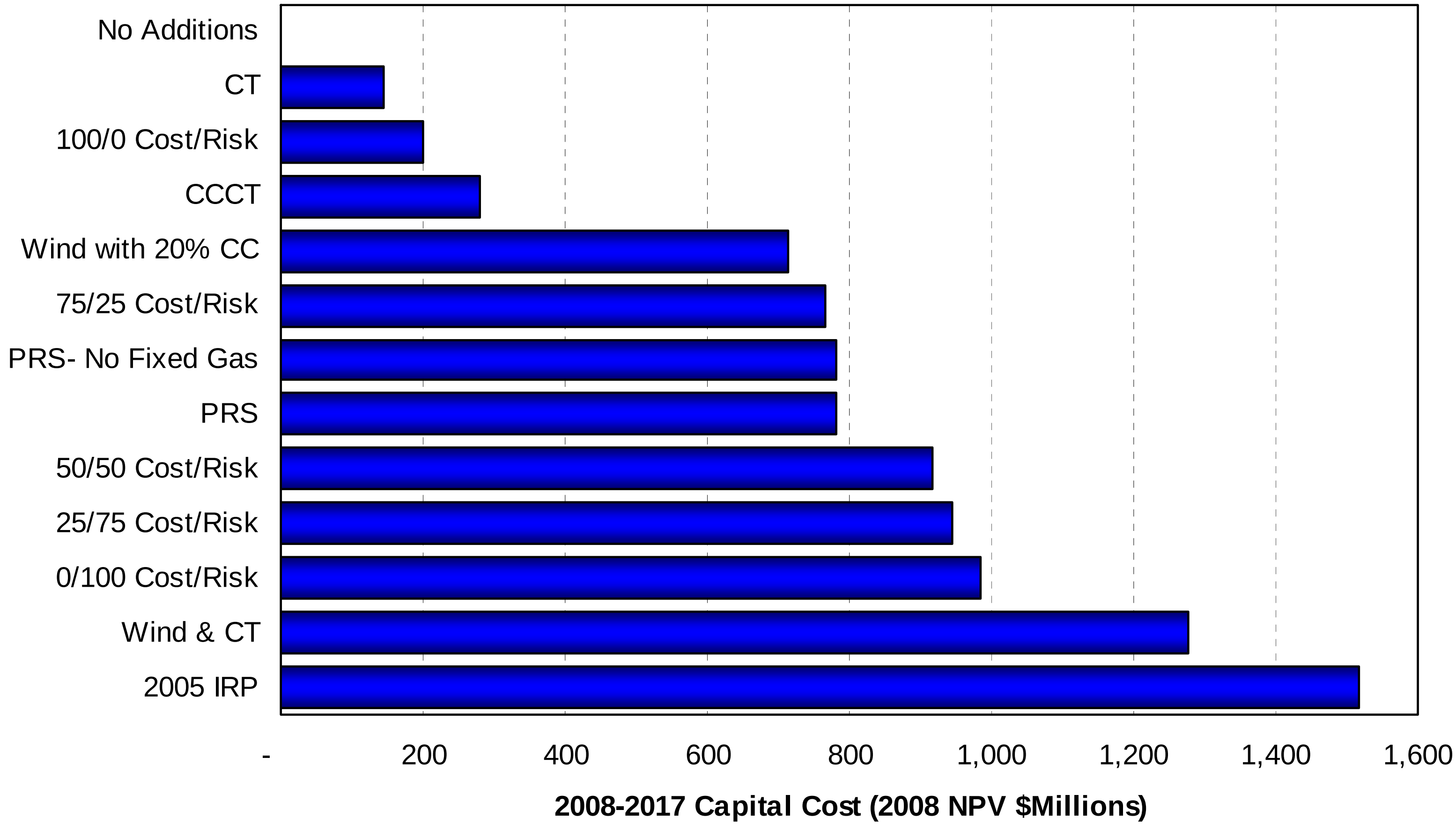
Portfolio Comparison- Avg Increase

Power Supply Related Costs ONLY (2008-2018 timeframe)



Portfolio Comparison- Capital Costs

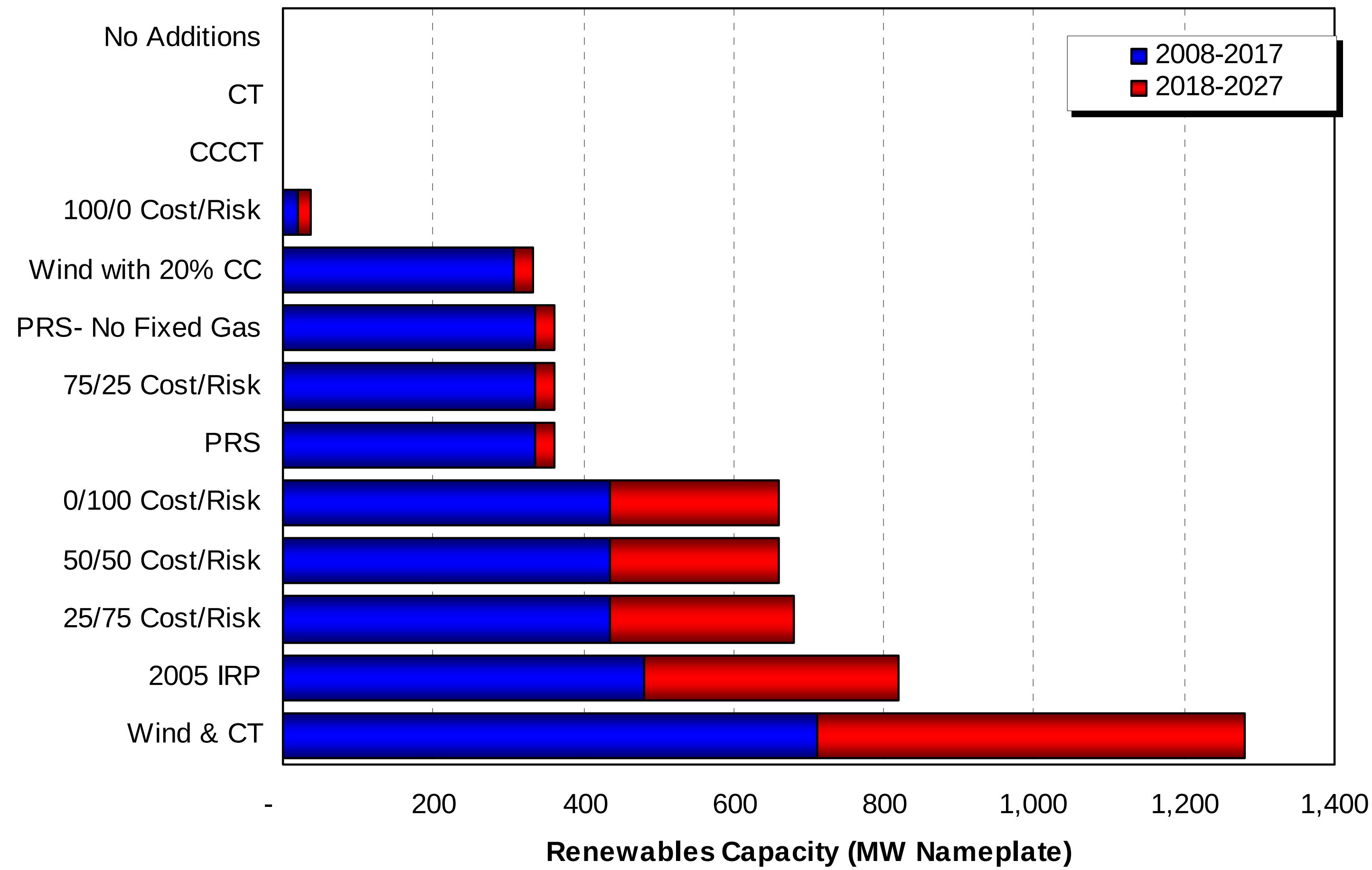
Net Present Value of 2008-2017 Capital Expenditures



PRS may require capital or debt equivalents to stabilize the price of natural gas

Portfolio Comparison- Renewables

Nameplate Renewable Resources



Gas-Fired Combined Cycle With Fixed Gas

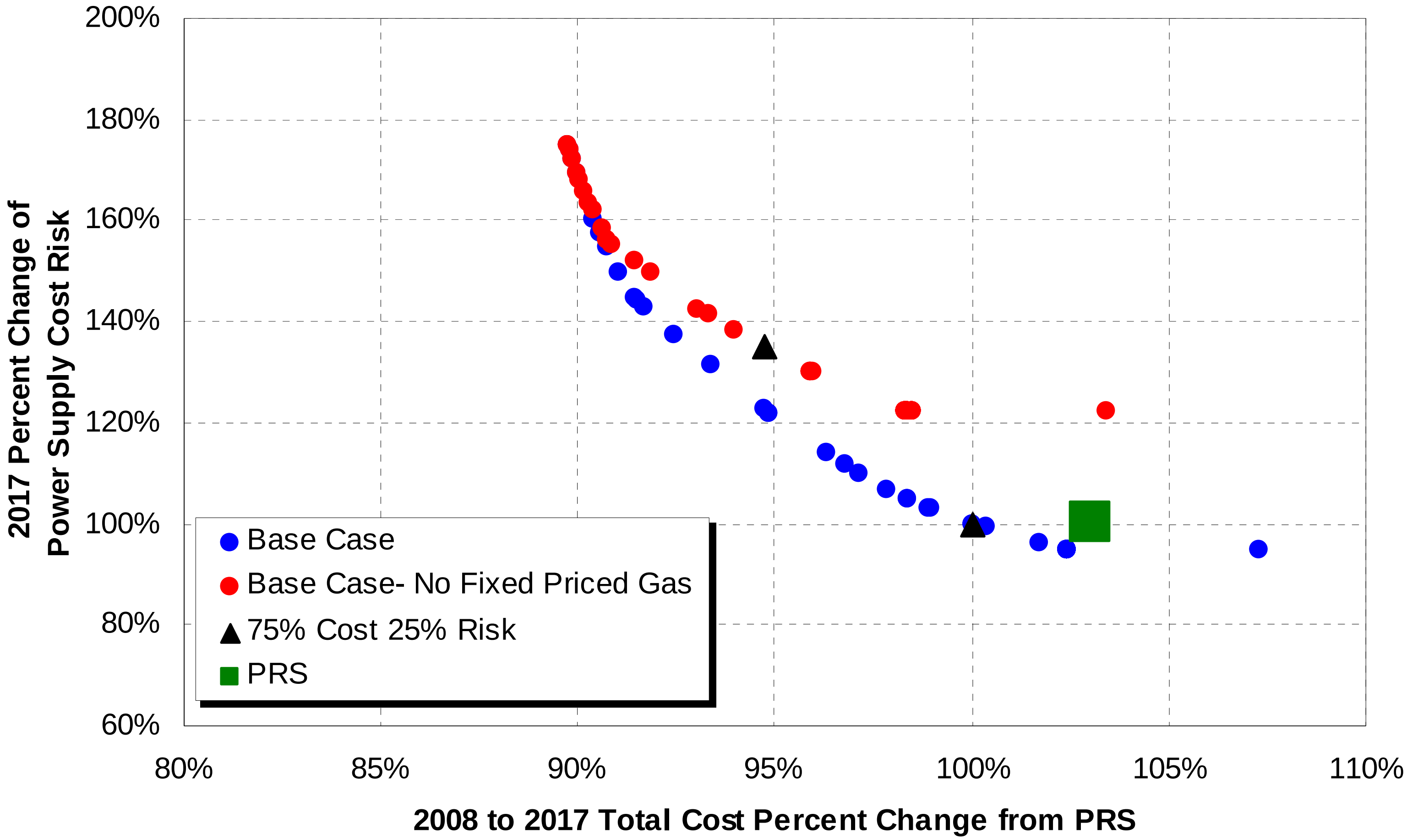
- Medium- to long-term fixed-price gas contract, or
- Could be coal gasified into pipeline-quality gas
  - Provide a significant new source of gas supply
  - Create a sequestered IGCC plant w/o operational trade-offs
    - Remote locations, altitude penalties, gasifier reliability
- Model is flexible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



Fixed Gas Selection Impacts (MW)

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

	CCCT	CCCT Fixed	Wind	Other
PRS (75% fixed gas fueling @ $2/dth premium)	0	350	300	35
$3.50 Gas Price Premium (75% fixed gas)	129	221	322	35
$5.00 Gas Price Premium (75% fixed gas)	211	139	400	35
0% Fixed Price Fueling	340	0	300	40
25% Fixed Price Fueling @ $2/dth premium	0	350	300	35
100% Fixed Price Fueling @ $2/dth premium	31	319	257	35

Impacts of Varying Capital Costs

Applied to 25% Risk Reduction Portfolio Criteria

Assumptions: $/kW

Resource	Low	Base Case	High
Wind	1,300	1,884	2,500
Combined Cycle	600	786	1,000
IGCC Coal w/ Sequestration	2,500	3,232	N/A
Alberta Oil Sands	2,000	3,963	N/A

Sensitivity did not change the amount of resource selection

Wind Results

	2008-2017	2017-2027
Base Case	300	0
Low	400	200
High	143	0

Limit Reached

Impacts of Varying Capital Costs (MW)

Quantifies Low Risk Portfolios Changes to Capital Intensive Resources

	50/50	40/60	25/75	0/100
Base Case				
IGCC w/ Seq	0	0	130	101
Alberta Oil Sands	0	0	0	226
IGCC @ 2,500				
IGCC w/ Seq	0	66	299	101
Alberta Oil Sands	0	0	0	226
Oil Sands @ 2,000				
IGCC w/ Seq	0	0	0	101
Alberta Oil Sands	210	226	226	226

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

2007 IRP Action Plan – Renewable Energy

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

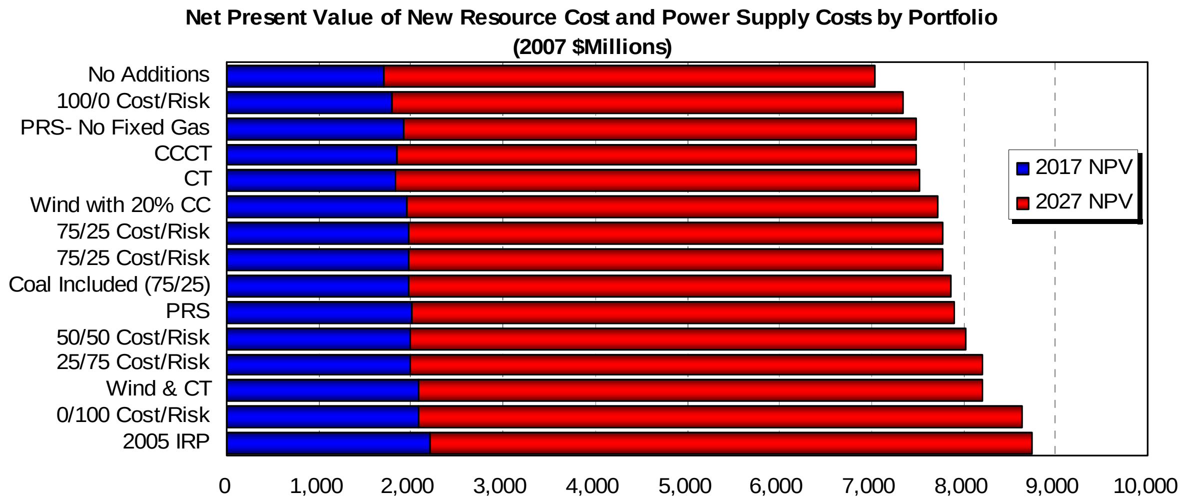
April 25, 2007

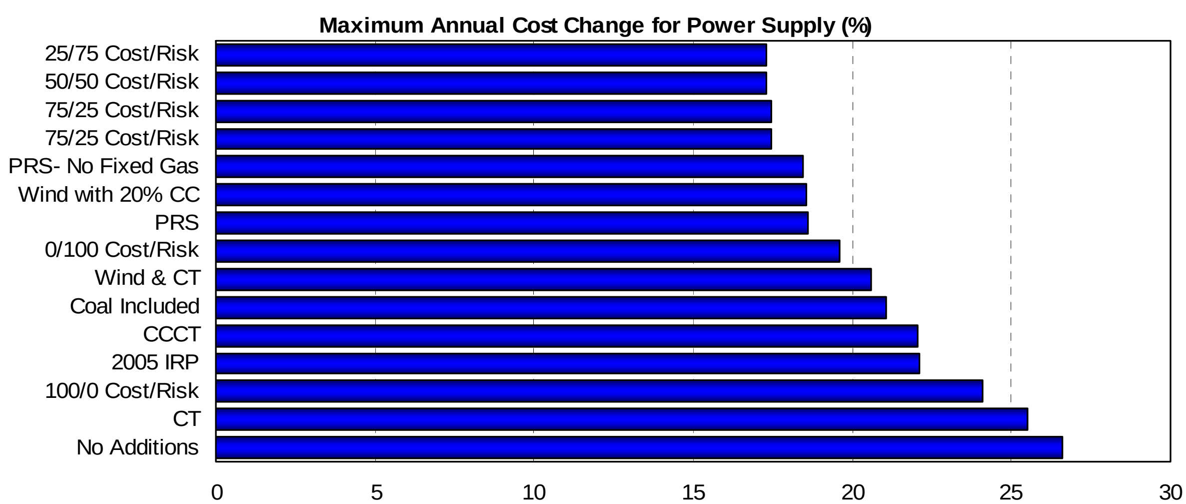
Clint Kalich

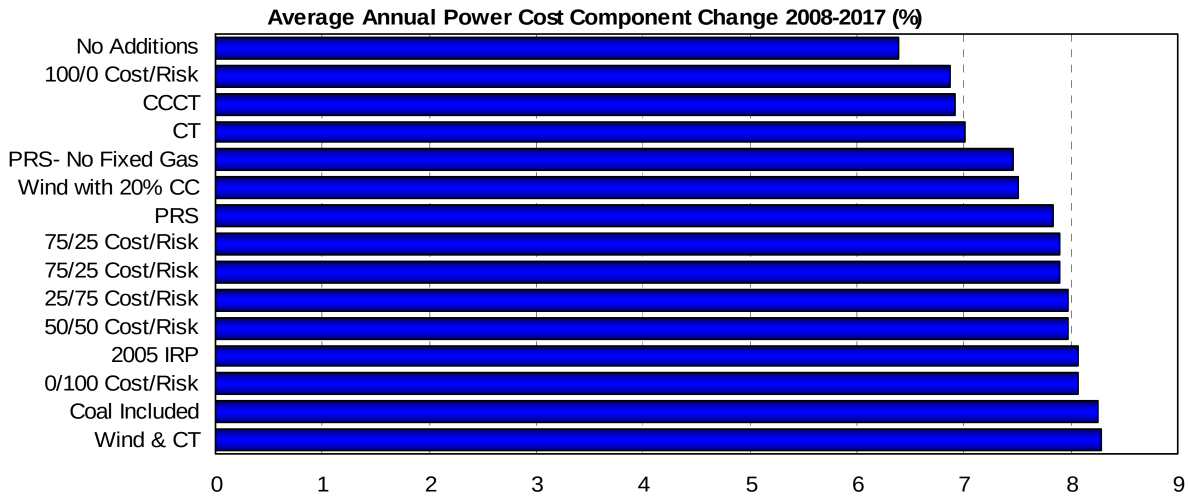
Next Steps

- 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






Average Annual Power Cost Component Change 2008-2017 (%)
No Additions
100/0 Cost/Risk
CCCT
CT
PRS- No Fixed Gas
Wind with 20% CC
PRS
75/25 Cost/Risk
75/25 Cost/Risk
25/75 Cost/Risk
50/50 Cost/Risk
2005 IRP
0/100 Cost/Risk
Coal Included
Wind & CT
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2
3
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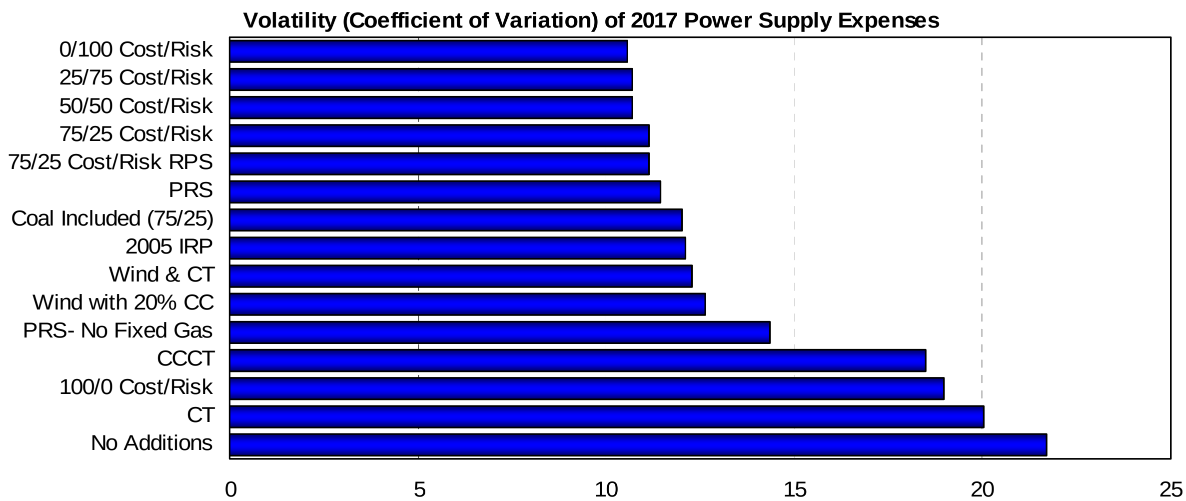
9


Volatility (Coefficient of Variation) of 2017 Power Supply Expenses
0/100 Cost/Risk
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50/50 Cost/Risk
75/25 Cost/Risk
75/25 Cost/Risk RPS
PRS
Coal Included (75/25)
2005 IRP
Wind & CT
Wind with 20% CC
PRS- No Fixed Gas
CCCT
100/0 Cost/Risk
CT
No Additions
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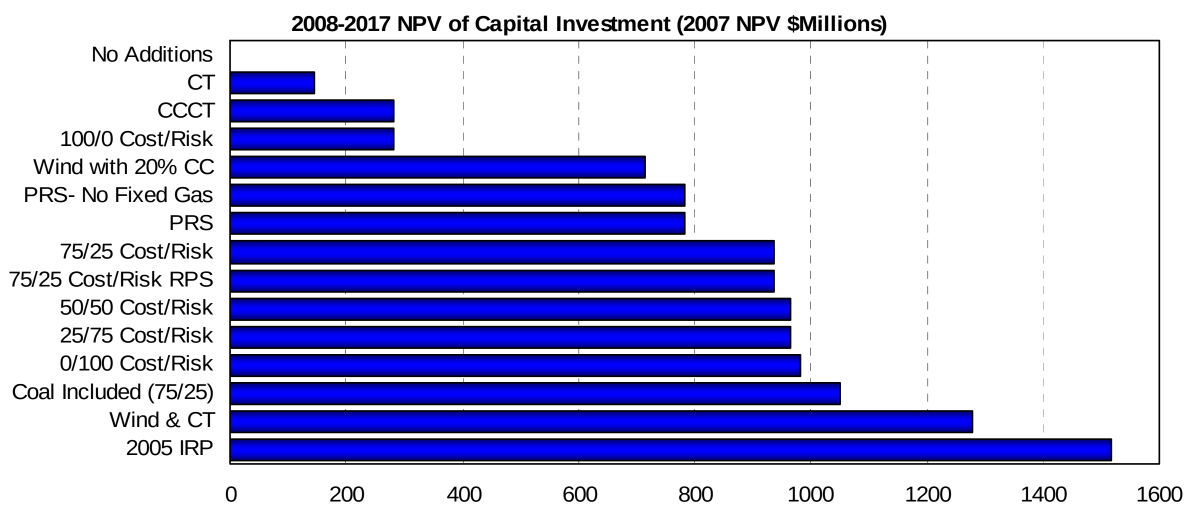
15
20
25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Coal Included (75/25)
Wind & CT
2005 IRP
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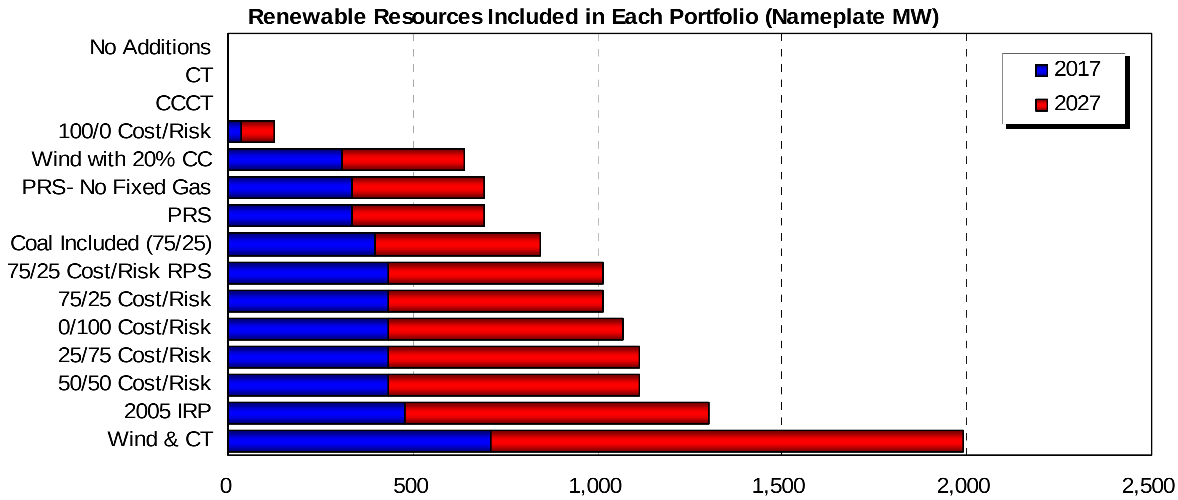
Renewable Resources Included in Each Portfolio (Nameplate MW)
2017
2027
No Additions
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CCCT
100/0 Cost/Risk
Wind with 20% CC
PRS- No Fixed Gas
PRS
Coal Included (75/25)
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75/25 Cost/Risk
0/100 Cost/Risk
25/75 Cost/Risk
50/50 Cost/Risk
2005 IRP
Wind & CT
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1,500
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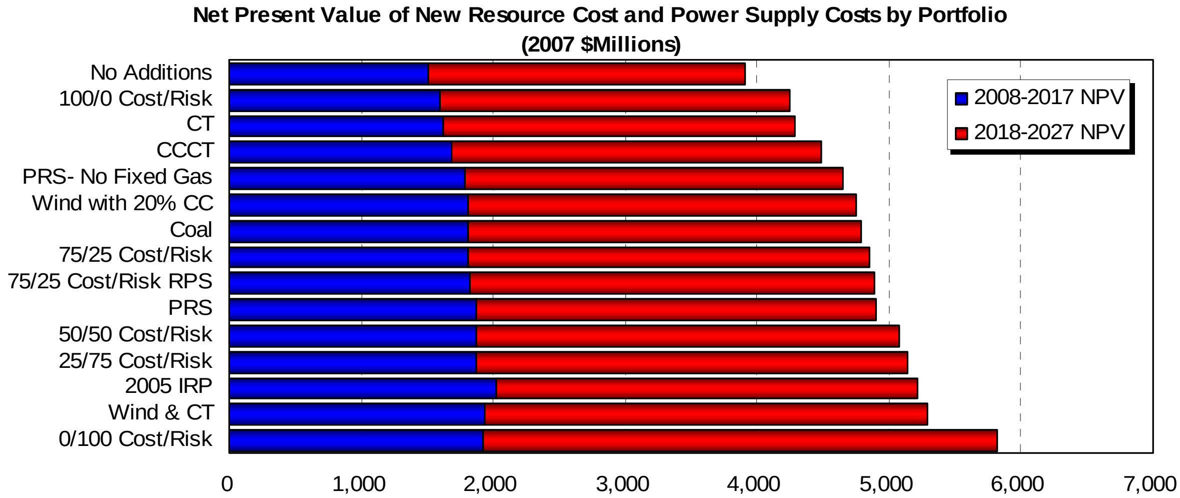
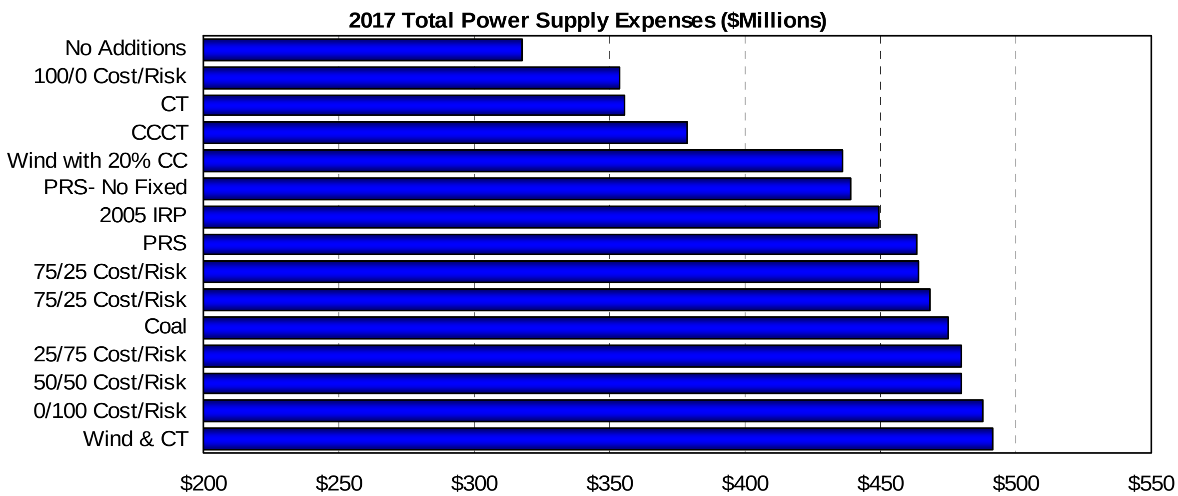
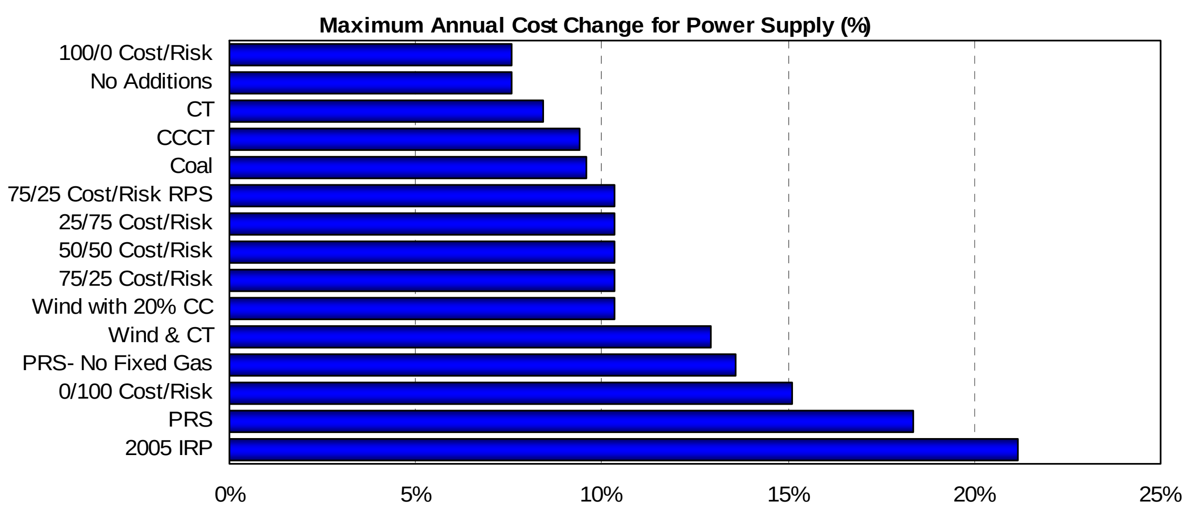
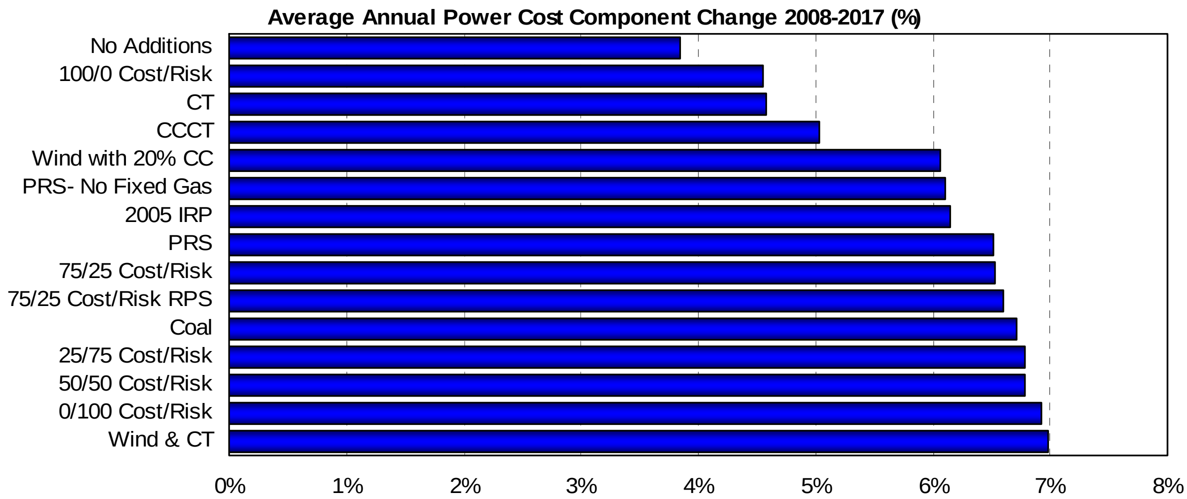
2,500

No Carbon Legislation Future





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Coal
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0/100 Cost/Risk
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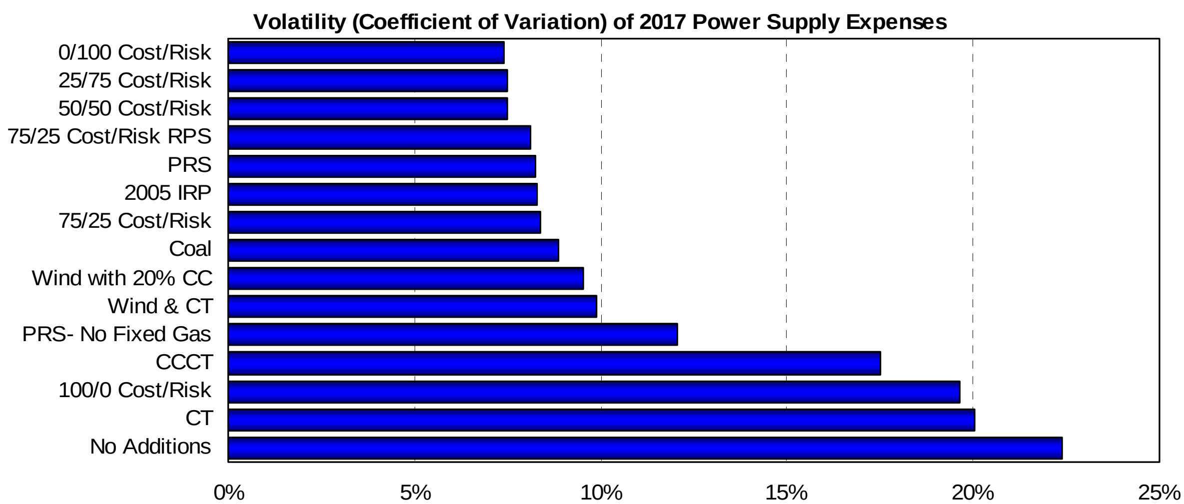
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Wind & CT
PRS- No Fixed Gas
CCCT
100/0 Cost/Risk
CT
No Additions
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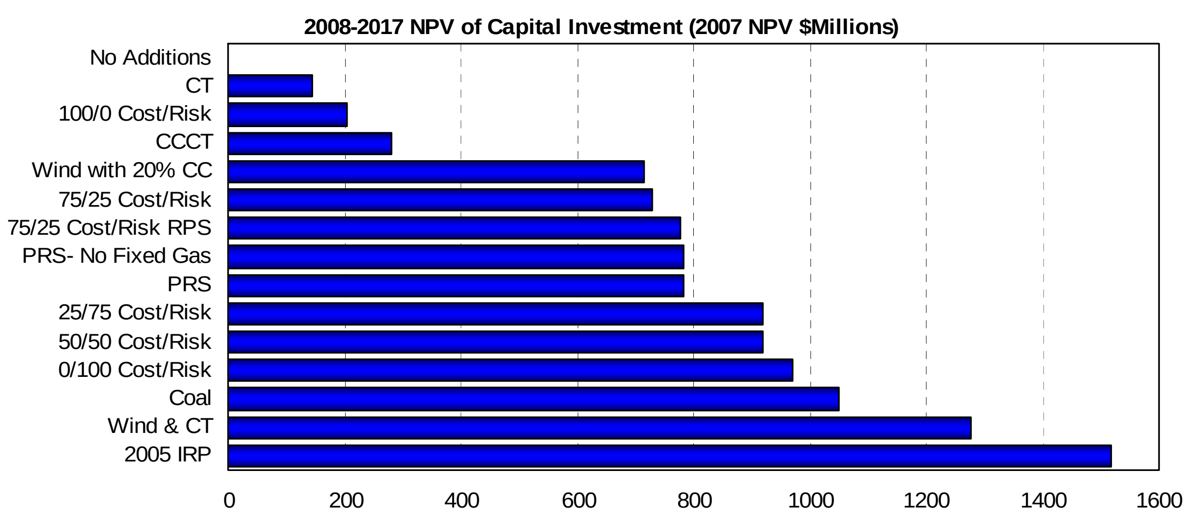
15%
20%
25%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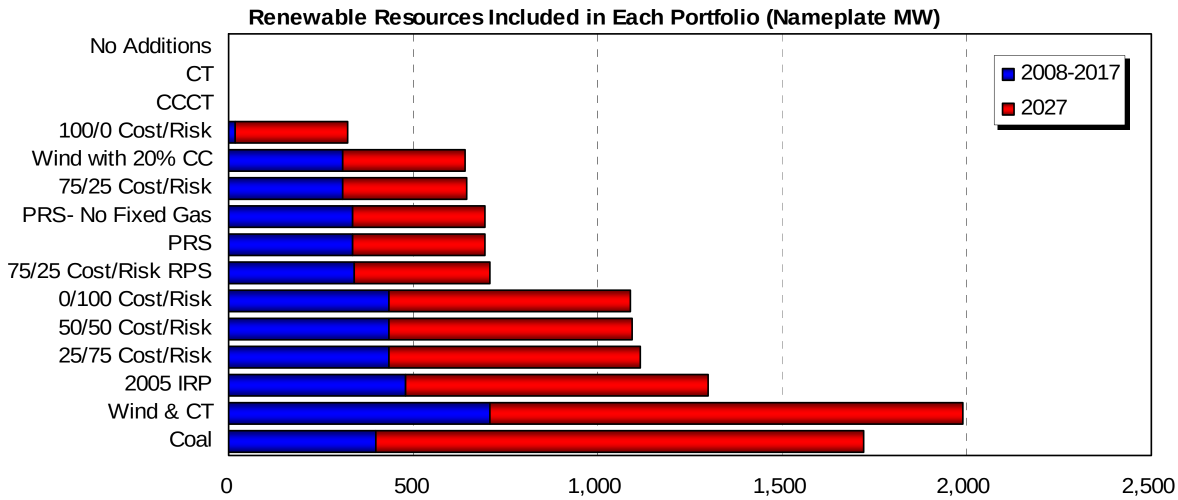
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Coal
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2027
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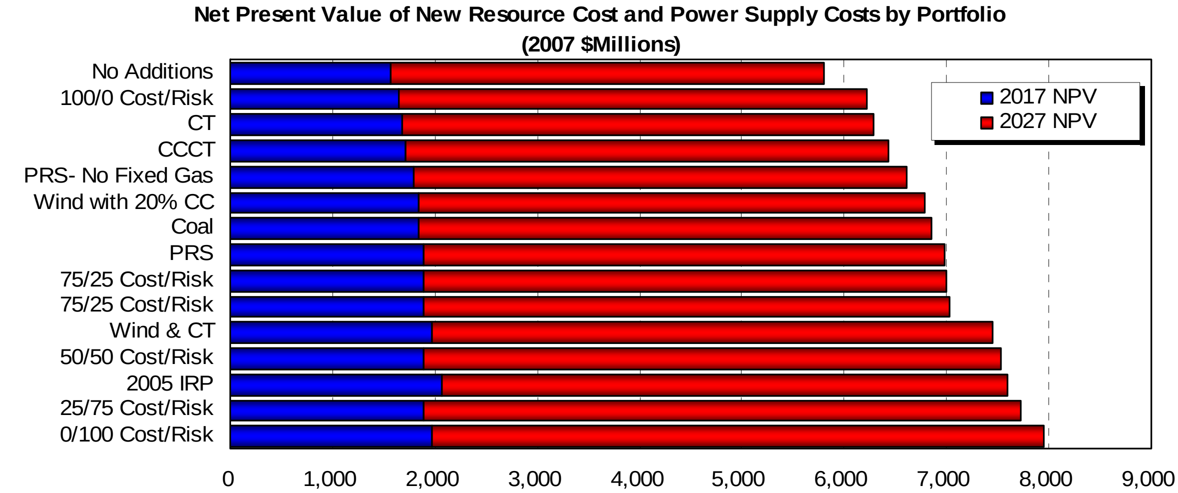
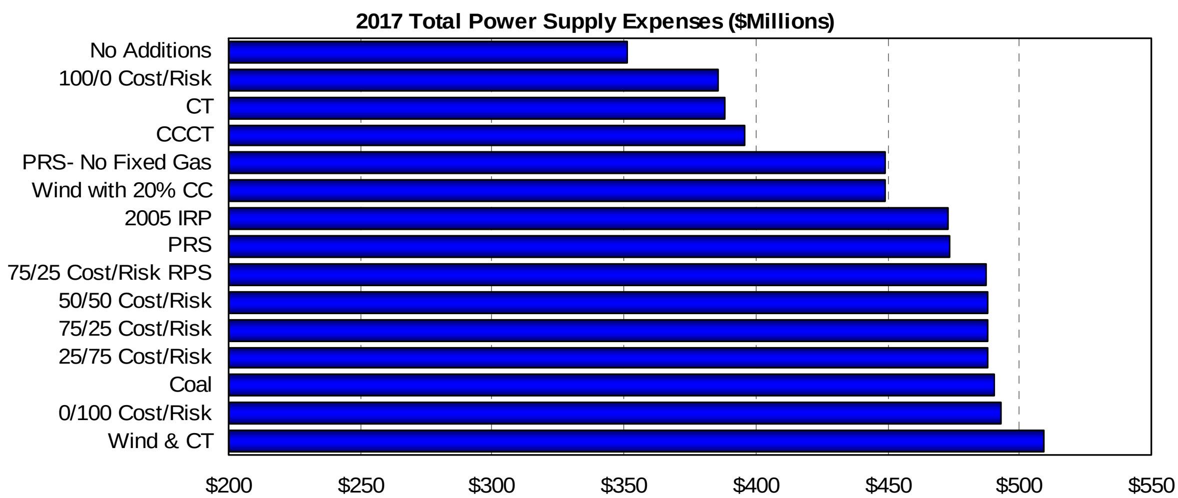
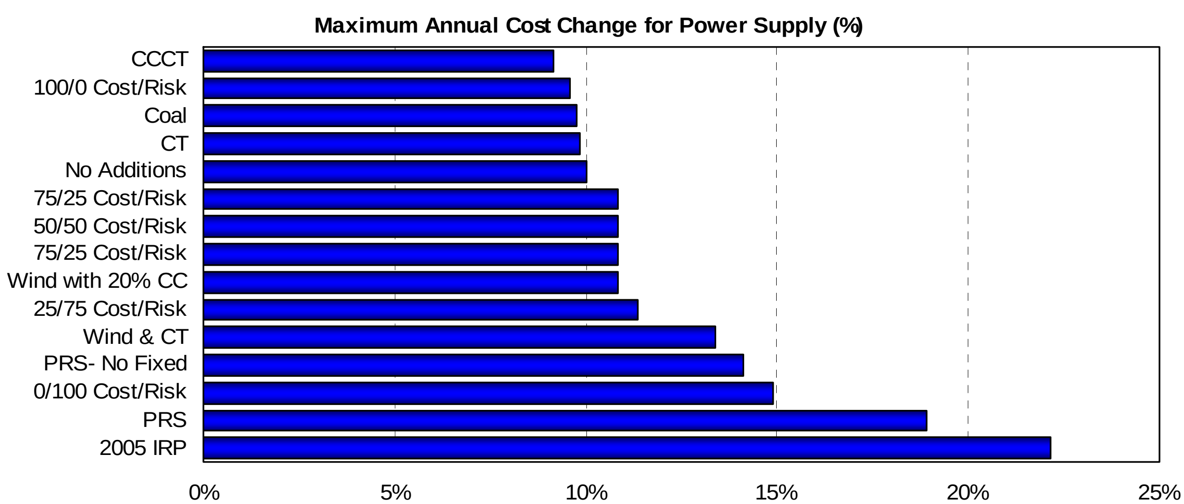
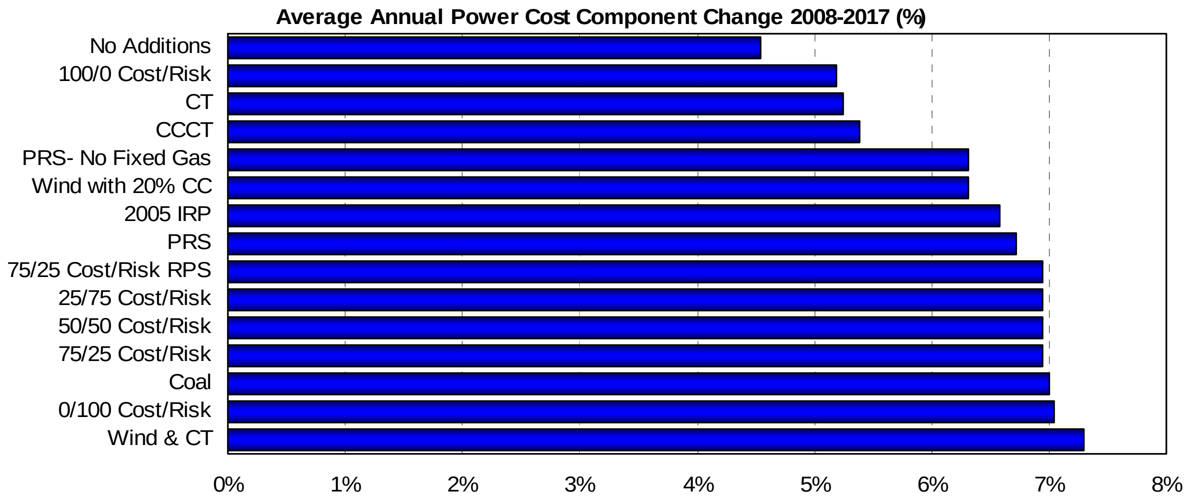
Volatile Gas Future





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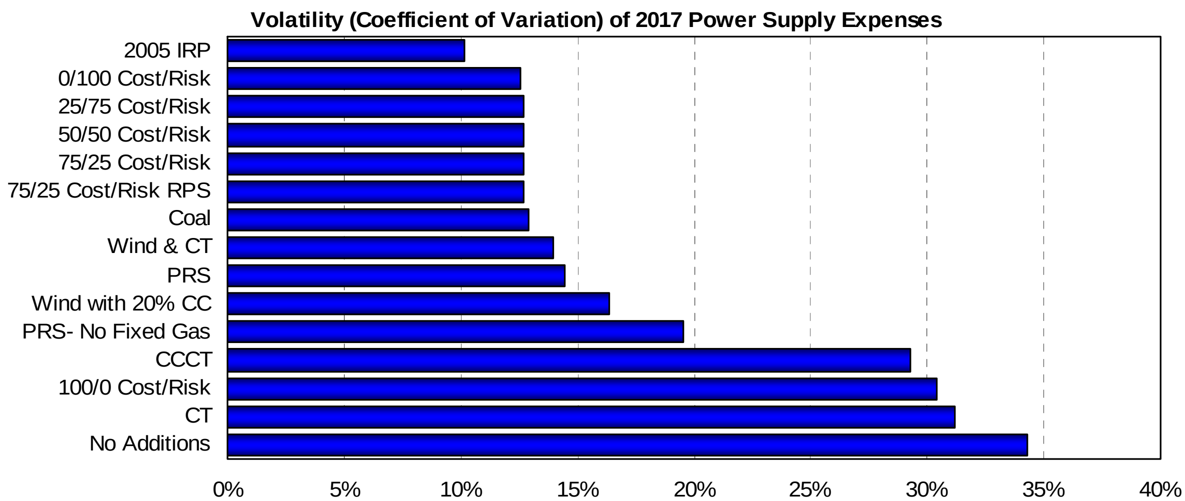
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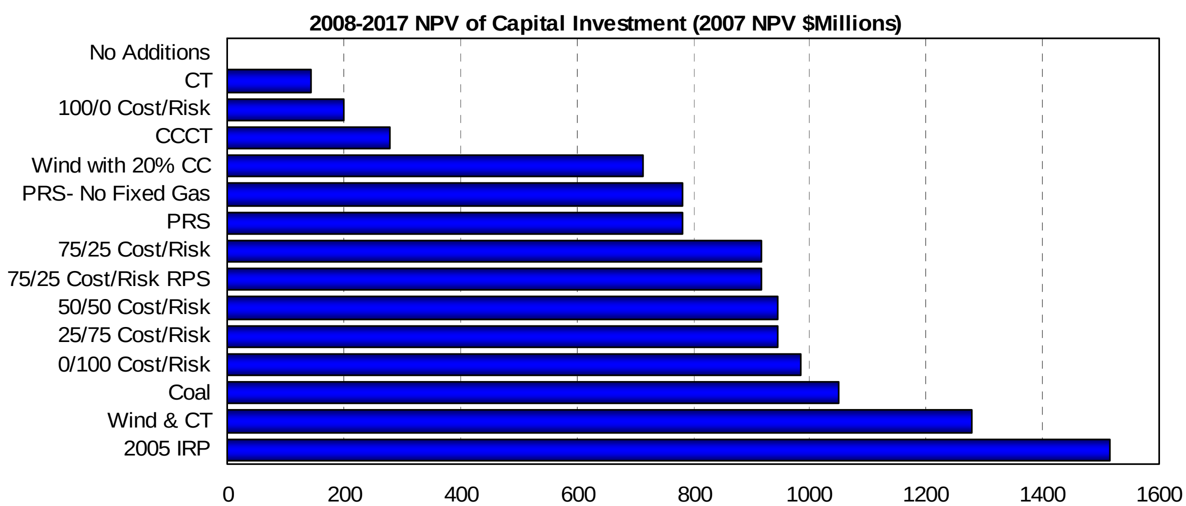
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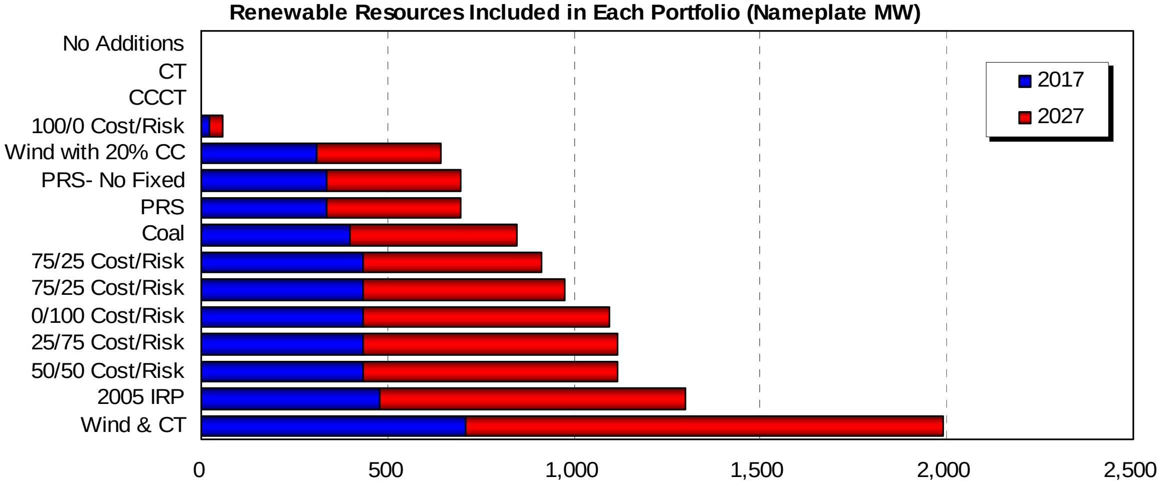
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2005 IRP
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2017
2027

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 measures 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

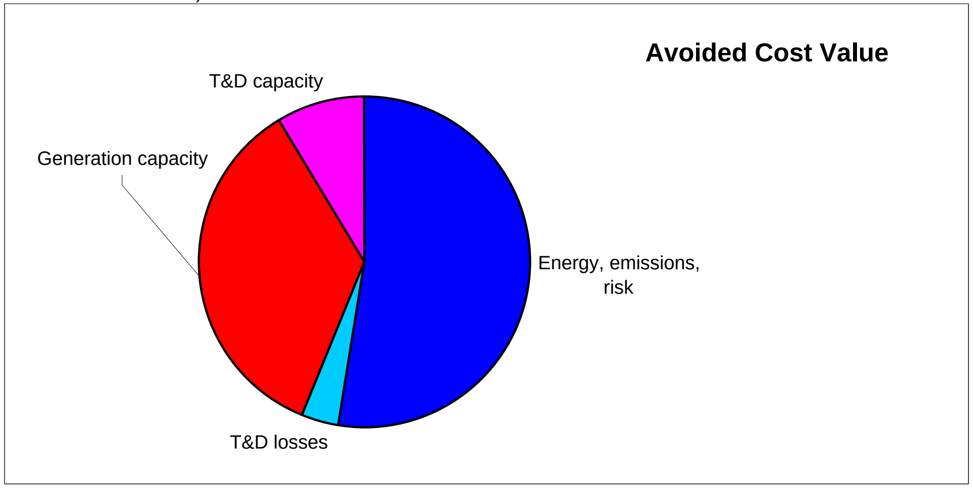
Per first year kW	Per first year kWh		% of total value
	$0.548	PV of avoided cost of energy (energy + emissions + risk)	53%
	$0.036	PV of avoided cost of energy (T&D losses)	3%
$ 281.00	$ 0.369	PV of avoided cost of generation capacity	35%
$ 68.42	$ 0.090	PV of avoided cost of T&D capacity	9%
	$1.042		100%
			56% Total energy
			44% Total capacity

driver	"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)

$0.0597	Levelized cost/kWh of four energy components of AC
$0.0469	Levelized cost/kWh of two capacity components of AC

$ 127.03	PV of avoided cost of energy (energy + emissions + risk)
$ 8.26	PV of avoided cost of energy (T&D losses)
$ 85.53	PV of avoided cost of generation capacity
$ 20.82	PV of avoided cost of T&D capacity
$ -	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

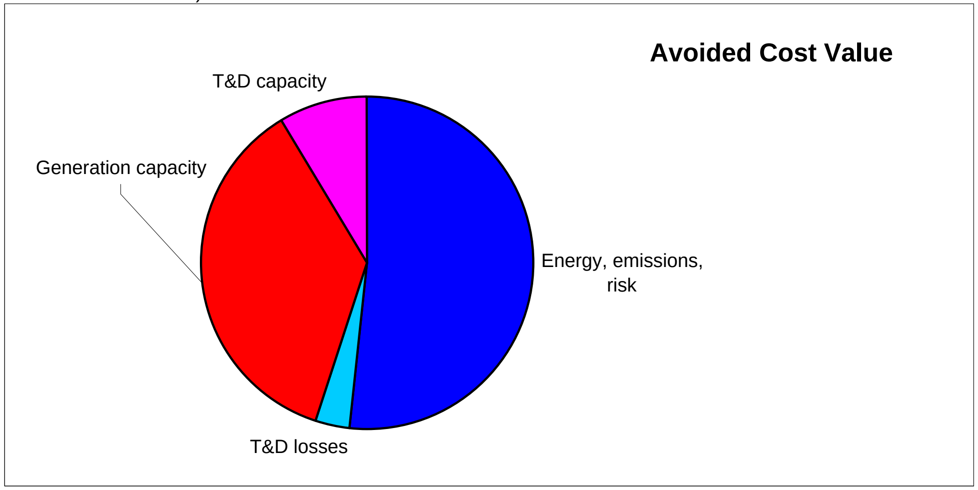
Per first year kW	Per first year kWh		% of total value
	$0.192	PV of avoided cost of energy (energy + emissions + risk)	52%
	$0.012	PV of avoided cost of energy (T&D losses)	3%
$ 102.97	$ 0.135	PV of avoided cost of generation capacity	36%
$ 24.42	$ 0.032	PV of avoided cost of T&D capacity	9%
	$0.371		100%
			55% Total energy
			45% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
5	Measure life
125	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)

$0.0503	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)
$ 1.56	PV of avoided cost of energy (T&D losses)
$ 16.89	PV of avoided cost of generation capacity
$ 4.00	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 46.39	Total Resource Cost test benefits
$ 123.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 123.00	Total Resource Cost test costs
($77)	Net TRC $ amount
0.38	**TRC benefit / cost ratio**

Central air conditioning efficiency tune-up



Energy efficient window AC (SEER 12 to 14)

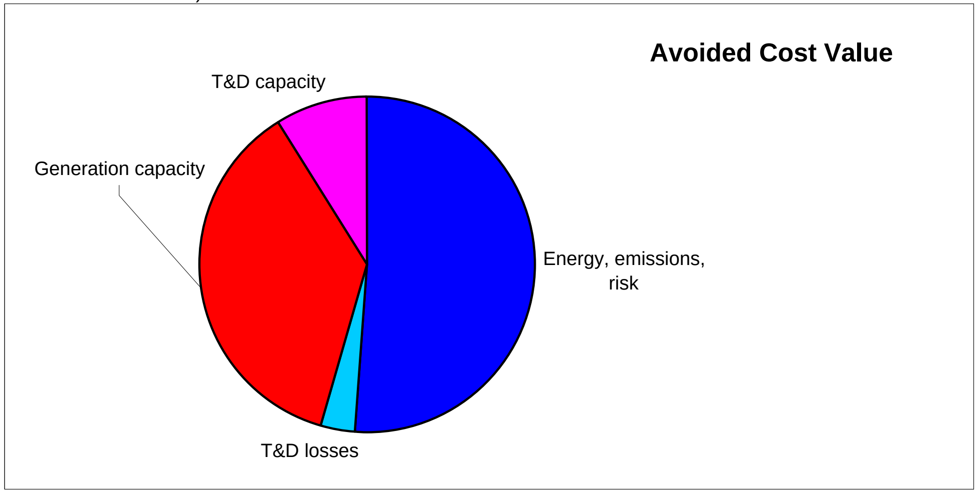
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.338	PV of avoided cost of energy (energy + emissions + risk)	51%	
	$0.022	PV of avoided cost of energy (T&D losses)	3%	
$ 184.47	$ 0.242	PV of avoided cost of generation capacity	37%	
$ 44.23	$ 0.058	PV of avoided cost of T&D capacity	9%	
	$0.660		100%	
			55%	Total energy
			45%	Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0523	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0435	Levelized cost/kWh of two capacity components of AC
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)		

$ 42.95	PV of avoided cost of energy (energy + emissions + risk)
$ 2.79	PV of avoided cost of energy (T&D losses)
$ 30.73	PV of avoided cost of generation capacity
$ 7.37	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 83.84	Total Resource Cost test benefits
$ 106.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 106.00	Total Resource Cost test costs
($22)	Net TRC $ amount
0.79	**TRC benefit / cost ratio**

Energy efficient window AC (SEER 12 to 14)



Buy back inefficient appliances (to avoid reuse)

Summarization of AC benefits and comparison to TRC costs

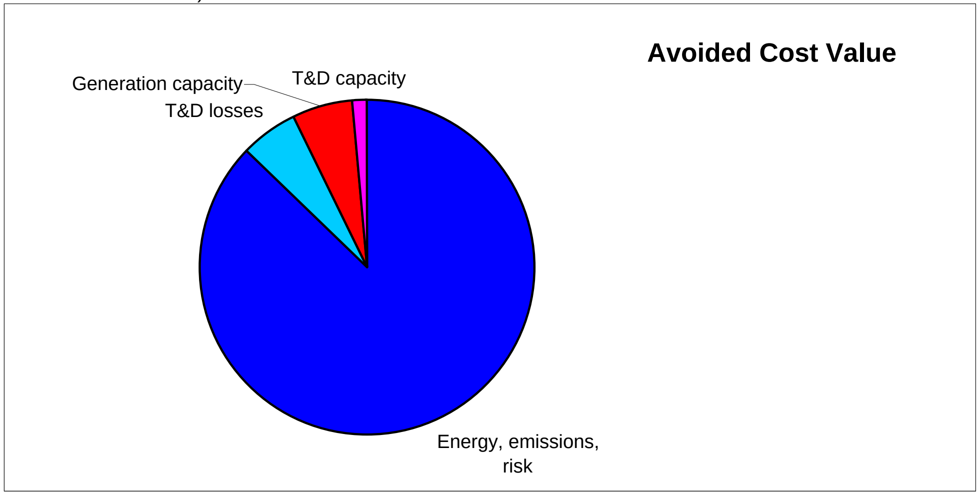
Per first year kW	Per first year kWh		% of total value
	$0.233	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.015	PV of avoided cost of energy (T&D losses)	6%
$ 120.83	$ 0.016	PV of avoided cost of generation capacity	6%
$ 28.72	$ 0.004	PV of avoided cost of T&D capacity	1%
	$0.267		100%

93%	Total energy
7%	Total capacity
$0.0526	Levelized cost/kWh of four energy components of AC
$0.0041	Levelized cost/kWh of two capacity components of AC

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
6	Measure life
625	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)

$ 145.39	PV of avoided cost of energy (energy + emissions + risk)
$ 9.45	PV of avoided cost of energy (T&D losses)
$ 9.74	PV of avoided cost of generation capacity
$ 2.32	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 166.90	Total Resource Cost test benefits
$ 100.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 100.00	Total Resource Cost test costs
$67	Net TRC $ amount
1.67	**TRC benefit / cost ratio**

Buy back inefficient appliances (to avoid reuse)



Caulking and weatherstripping (single family, resistance)

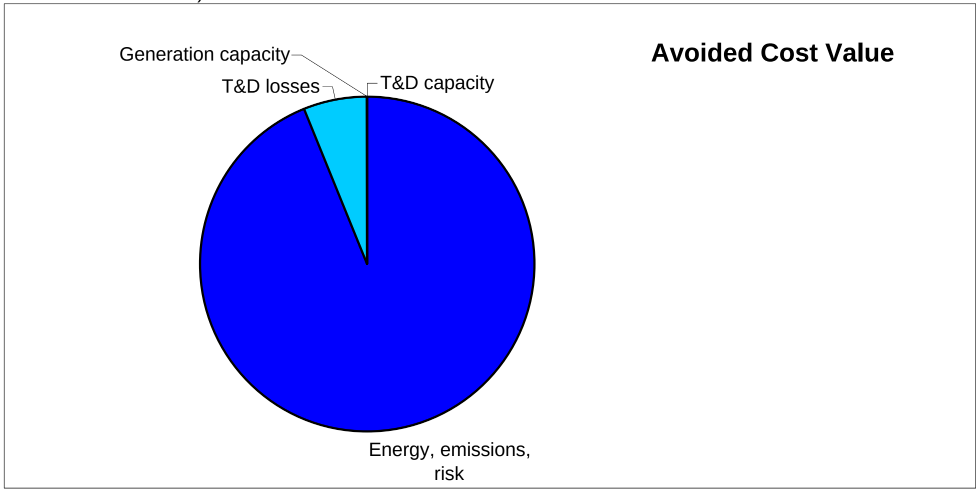
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.371	PV of avoided cost of energy (energy + emissions + risk)	94%	
	$0.024	PV of avoided cost of energy (T&D losses)	6%	
$ 184.47	$ -	PV of avoided cost of generation capacity	0%	
$ 44.23	$ -	PV of avoided cost of T&D capacity	0%	
	$0.395		100%	
			100%	Total energy
			0%	Total capacity

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0573	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
798	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)		

$ 296.14	PV of avoided cost of energy (energy + emissions + risk)
$ 19.25	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
$ 315.39	Total Resource Cost test benefits
$ 650.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 650.00	Total Resource Cost test costs
($335)	Net TRC $ amount
0.49	**TRC benefit / cost ratio**

Caulking and weatherstripping (single family, resistance)



Central heat pump efficiency tune-up

Summarization of AC benefits and comparison to TRC costs

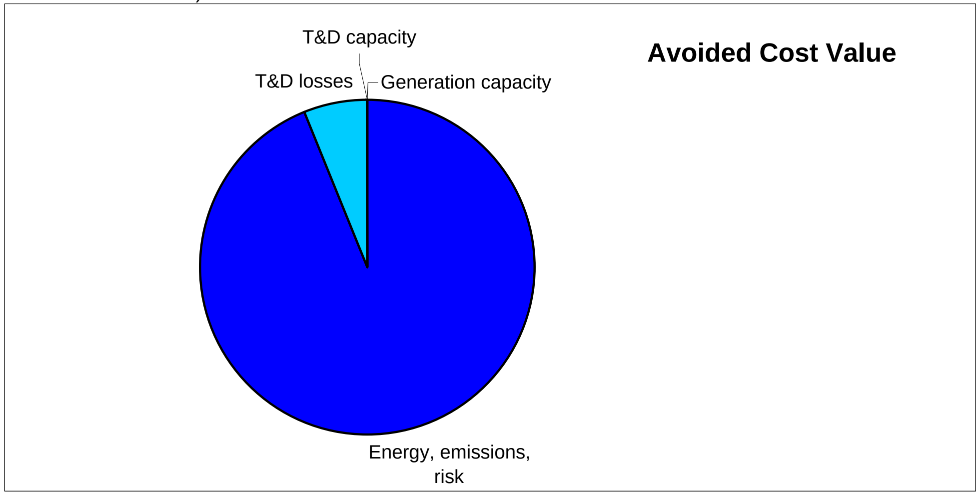
Per first year kW	Per first year kWh		% of total value	
	$0.245	PV of avoided cost of energy (energy + emissions + risk)	94%	
	$0.016	PV of avoided cost of energy (T&D losses)	6%	
$ 120.83	$ -	PV of avoided cost of generation capacity	0%	
$ 28.72	$ -	PV of avoided cost of T&D capacity	0%	
	$0.260		100%	
			100%	Total energy
zero		"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	0%	Total capacity

7.41%	Discount rate
6	Measure life
478	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)

$0.0553	Levelized cost/kWh of four energy components of AC
$0.0000	Levelized cost/kWh of two capacity components of AC

$ 116.91	PV of avoided cost of energy (energy + emissions + risk)
$ 7.60	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
$ 124.51	Total Resource Cost test benefits
$ 123.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 123.00	Total Resource Cost test costs
$2	Net TRC $ amount
1.01	**TRC benefit / cost ratio**

Central heat pump efficiency tune-up



Duct insulation retrofit (R3-R8, single family, resistance)

Summarization of AC benefits and comparison to TRC costs

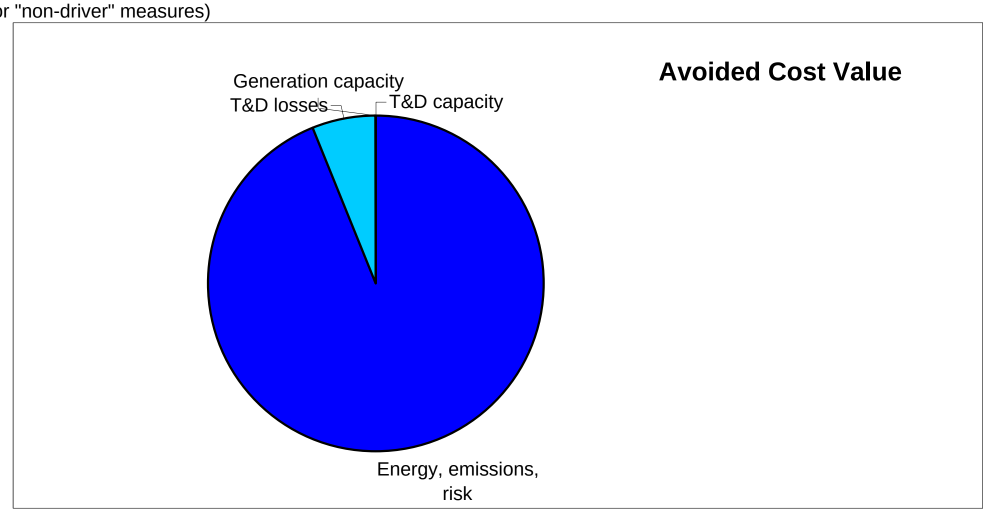
Per first year kW	Per first year kWh		% of total value
	$0.836	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.054	PV of avoided cost of energy (T&D losses)	6%
$ 372.36	$ -	PV of avoided cost of generation capacity	0%
$ 92.43	$ -	PV of avoided cost of T&D capacity	0%
	$0.890		100%
			100% Total energy
			0% Total capacity

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
30	Measure life
1,134	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)

$0.0747	Levelized cost/kWh of four energy components of AC
$0.0000	Levelized cost/kWh of two capacity components of AC

$ 947.54	PV of avoided cost of energy (energy + emissions + risk)
$ 61.59	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
$ 1,009.13	Total Resource Cost test benefits
$ 518.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 518.00	Total Resource Cost test costs
$491	Net TRC $ amount
1.95	**TRC benefit / cost ratio**

Duct insulation retrofit (R3-R8, single family, resistance)



Duct sealing (single family, resistance)

Summarization of AC benefits and comparison to TRC costs

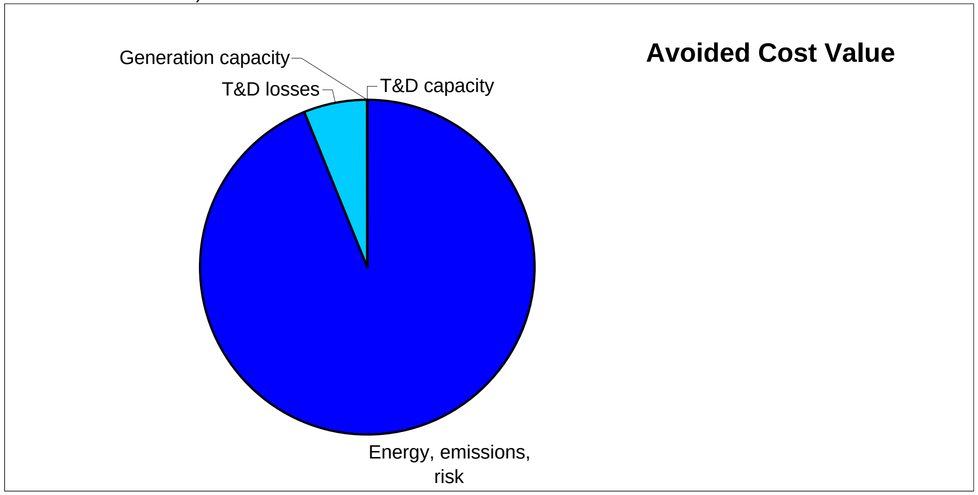
Per first year kW	Per first year kWh		% of total value
	$0.642	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.042	PV of avoided cost of energy (T&D losses)	6%
$ 300.00	$ -	PV of avoided cost of generation capacity	0%
$ 73.31	$ -	PV of avoided cost of T&D capacity	0%
	$0.683		100%
			100% Total energy
			0% Total capacity

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
20	Measure life
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)

$0.0666	Levelized cost/kWh of four energy components of AC
$0.0000	Levelized cost/kWh of two capacity components of AC

$ 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**

Duct sealing (single family, resistance)



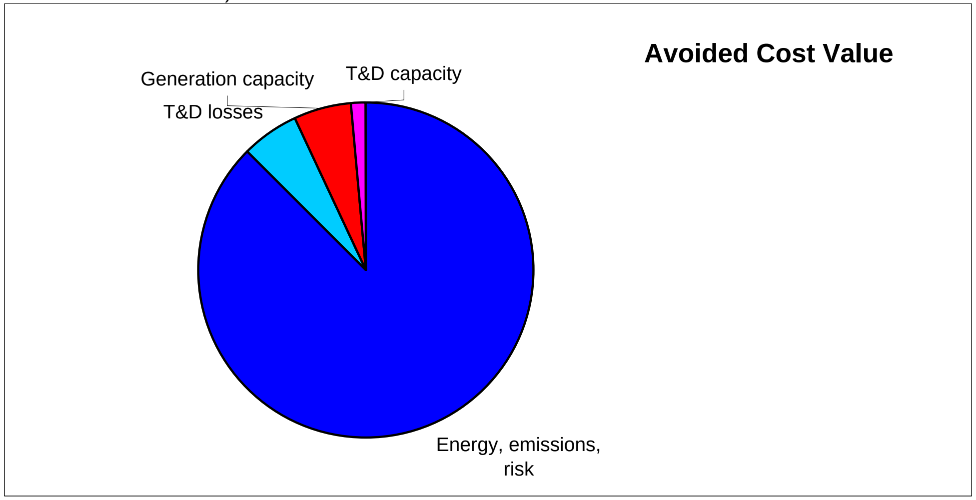
Electric vs gas clothes dryer

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.478	PV of avoided cost of energy (energy + emissions + risk)	87%	
	$0.031	PV of avoided cost of energy (T&D losses)	6%	
$ 237.24	$ 0.030	PV of avoided cost of generation capacity	6%	
$ 57.34	$ 0.007	PV of avoided cost of T&D capacity	1%	
	$0.547		100%	
			93%	Total energy
non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		7%	Total capacity
7.41%	Discount rate		$0.0597	Levelized cost/kWh of four energy components of AC
14	Measure life		$0.0044	Levelized cost/kWh of two capacity components of AC
479	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)			

$229	PV of avoided cost of energy (energy + emissions + risk)
$15	PV of avoided cost of energy (T&D losses)
$14	PV of avoided cost of generation capacity
$3	PV of avoided cost of T&D capacity
$0	PV of avoided cost of natural gas
$0	PV of non-energy benefits
$262	Total Resource Cost test benefits
$200.00	Incremental customer cost
$0	Incremental non-incentive utility cost
$200	Total Resource Cost test costs
$62	Net TRC $ amount
1.31	**TRC benefit / cost ratio**

Electric vs gas clothes dryer



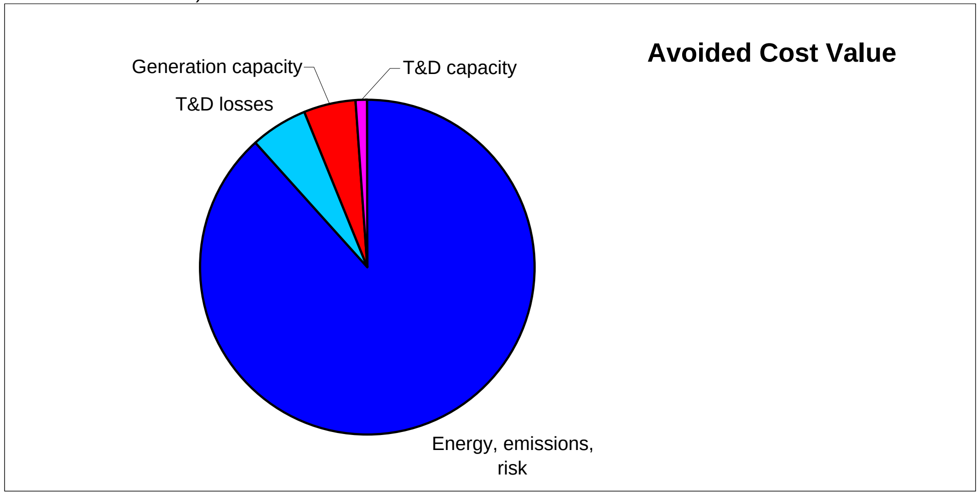
Electric vs HE gas water heater

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.033	PV of avoided cost of energy (T&D losses)	6%	
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%	
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%	
	$0.581		100%	
			94%	Total energy
non-driver		"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	6%	Total capacity
7.41%		Discount rate	$0.0615	Levelized cost/kWh of four energy components of AC
15		Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
5,131		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)		

$ 2,630.25	PV of avoided cost of energy (energy + emissions + risk)
$ 170.97	PV of avoided cost of energy (T&D losses)
$ 144.90	PV of avoided cost of generation capacity
$ 35.09	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 2,981.20	Total Resource Cost test benefits
$ 512.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 512.00	Total Resource Cost test costs
$2,469	Net TRC $ amount
5.82	**TRC benefit / cost ratio**

Electric vs HE gas water heater



More efficient pumps for domestic water systems

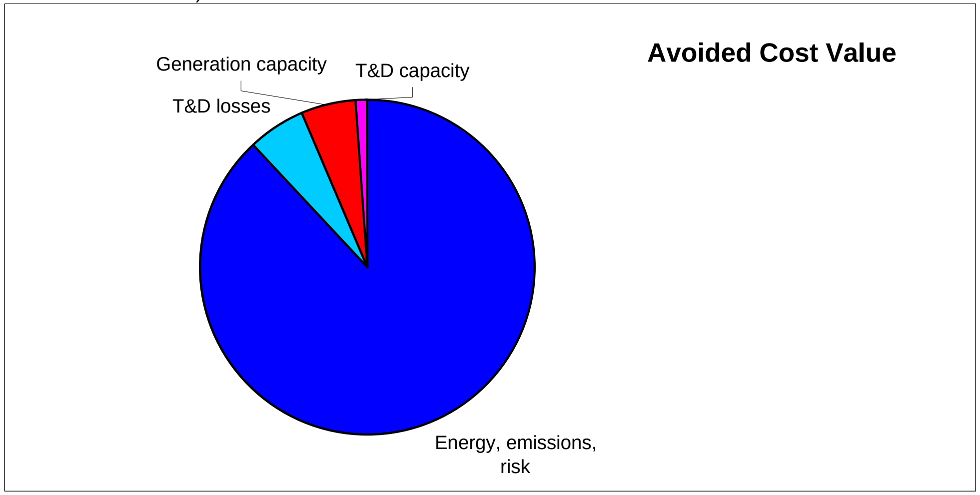
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.496	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.032	PV of avoided cost of energy (T&D losses)	6%	
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%	
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%	
	$0.564		100%	
			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	$0.0595	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
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
0.70	**TRC benefit / cost ratio**

More efficient pumps for domestic water systems



Energy Star Home

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.496	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.032	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.564		100%

94% Total energy

6% Total capacity

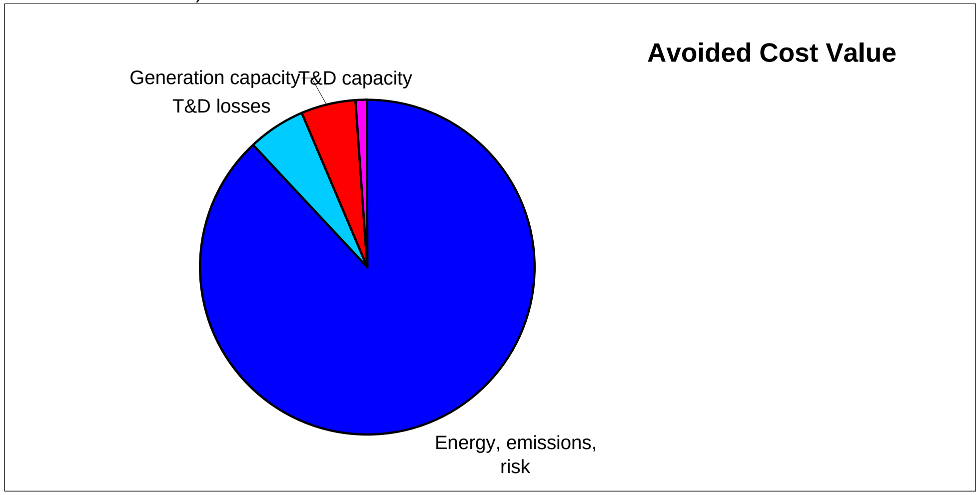
$0.0595 Levelized cost/kWh of four energy components of AC

$0.0040 Levelized cost/kWh of two capacity components of AC

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
1,800	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)

$ 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
$ -	Incremental non-incentive utility cost
$ 3,500.00	Total Resource Cost test costs
($2,486)	Net TRC $ amount
0.29	**TRC benefit / cost ratio**

Energy Star Home



Exterior doors (retrofit)

Summarization of AC benefits and comparison to TRC costs

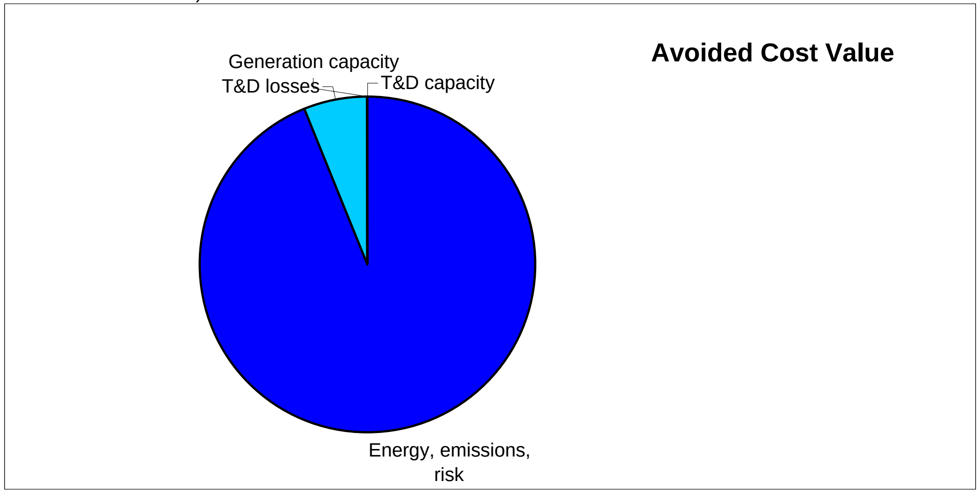
Per first year kW	Per first year kWh		% of total value
	$0.516	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.034	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ -	PV of avoided cost of generation capacity	0%
$ 60.28	$ -	PV of avoided cost of T&D capacity	0%
	$0.550		100%

100% Total energy
0% Total capacity
$0.0619 Levelized cost/kWh of four energy components of AC
$0.0000 Levelized cost/kWh of two capacity components of AC

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**

Exterior doors (retrofit)



Faucet aerator (single and multi-family)

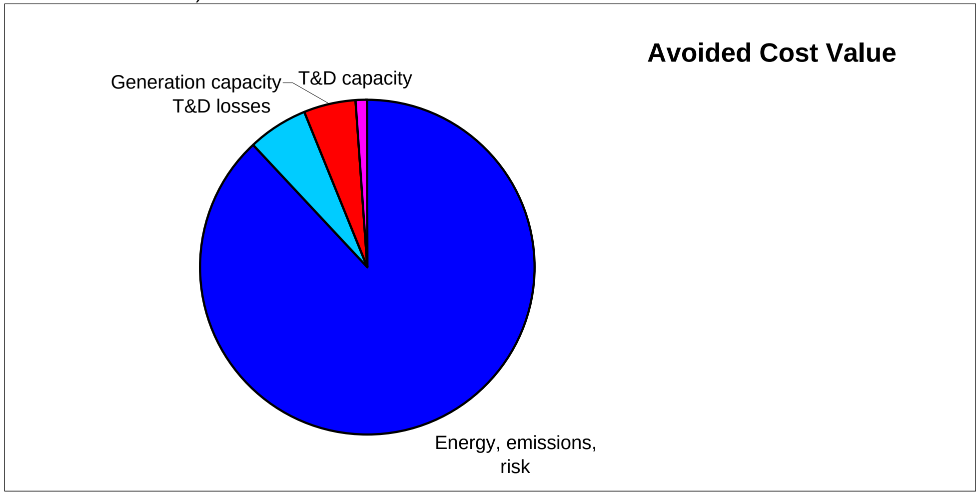
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.337	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.022	PV of avoided cost of energy (T&D losses)	6%	
$ 169.66	$ 0.019	PV of avoided cost of generation capacity	5%	
$ 40.59	$ 0.005	PV of avoided cost of T&D capacity	1%	
	$0.383		100%	
			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	$0.0561	Levelized cost/kWh of four energy components of AC
9	Measure life	$0.0037	Levelized cost/kWh of two capacity components of AC
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)		

$	25.61	PV of avoided cost of energy (energy + emissions + risk)
$	1.66	PV of avoided cost of energy (T&D losses)
$	1.46	PV of avoided cost of generation capacity
$	0.35	PV of avoided cost of T&D capacity
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	29.09	Total Resource Cost test benefits
$	12.69	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	12.69	Total Resource Cost test costs
	$16	Net TRC $ amount
	2.29	**TRC benefit / cost ratio**

Faucet aerator (single and multi-family)



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

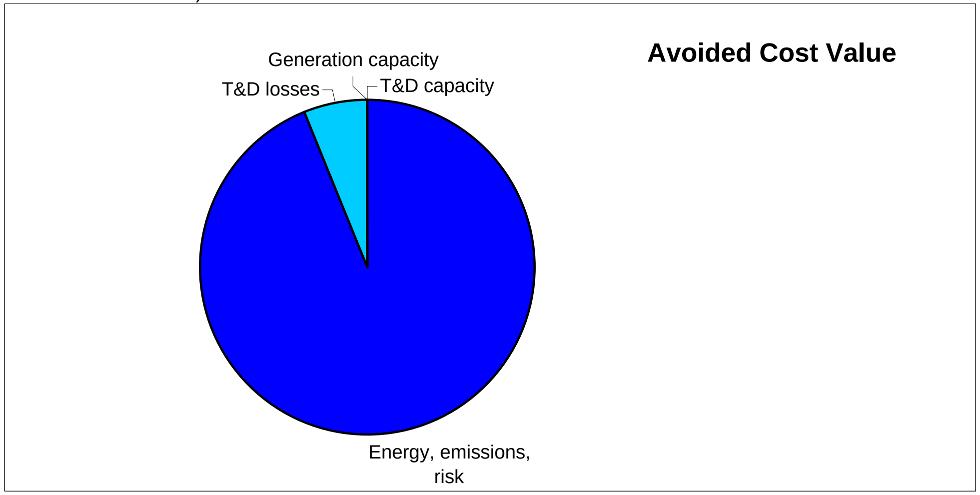
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.516	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.034	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ -	PV of avoided cost of generation capacity	0%
$ 60.28	$ -	PV of avoided cost of T&D capacity	0%
	$0.550		100%
			100% Total energy

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		0% Total capacity
7.41%	Discount rate	$0.0619	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
2,390	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)		

$ 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
$814	Net TRC $ amount
2.63	**TRC benefit / cost ratio**

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



Electric furnace vs condensing gas space heat conversion

Summarization of AC benefits and comparison to TRC costs

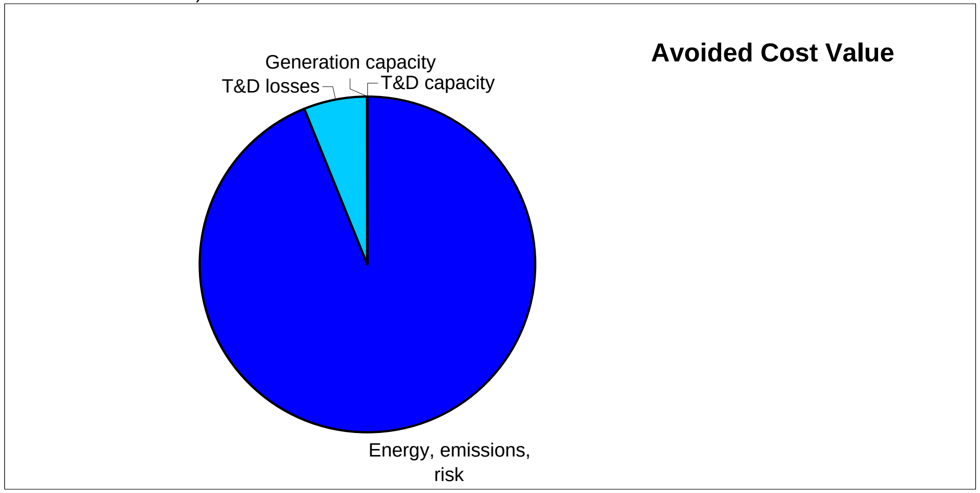
Per first year kW	Per first year kWh		% of total value
	$0.836	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.054	PV of avoided cost of energy (T&D losses)	6%
$ 372.36	$ -	PV of avoided cost of generation capacity	0%
$ 92.43	$ -	PV of avoided cost of T&D capacity	0%
	$0.890		100%
			100% Total energy
			0% Total capacity

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)

$0.0747	Levelized cost/kWh of four energy components of AC
$0.0000	Levelized cost/kWh of two capacity components of AC

$ 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
4.18	**TRC benefit / cost ratio**

Electric furnace vs condensing gas space heat conversion



High efficiency clothes washer (electric DHW, dryer)

Summarization of AC benefits and comparison to TRC costs

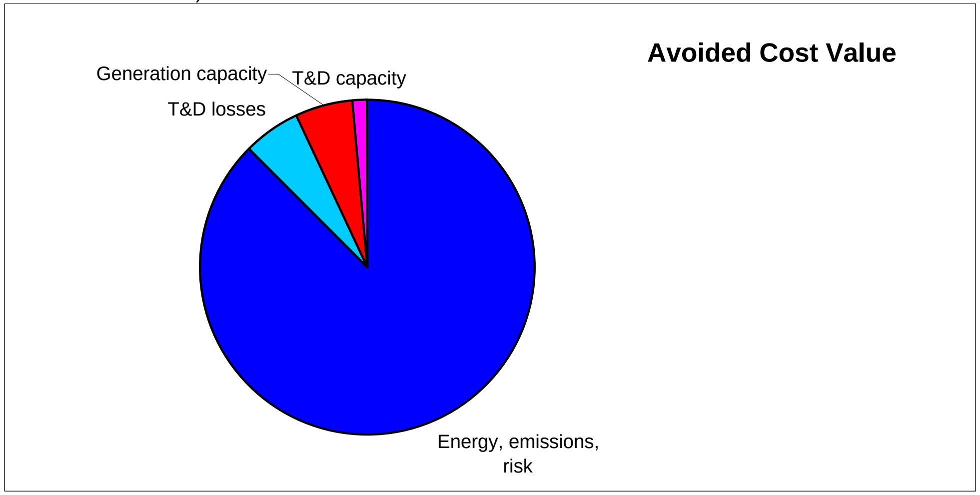
Per first year kW	Per first year kWh		% of total value
	$0.478	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.031	PV of avoided cost of energy (T&D losses)	6%
$ 237.24	$ 0.030	PV of avoided cost of generation capacity	6%
$ 57.34	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.547		100%
			93% Total energy
			7% Total capacity

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)

$0.0597	Levelized cost/kWh of four energy components of AC
$0.0044	Levelized cost/kWh of two capacity components of AC

$ 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**

High efficiency clothes washer (electric DHW, dryer)



Home electronics and office equipment

Summarization of AC benefits and comparison to TRC costs

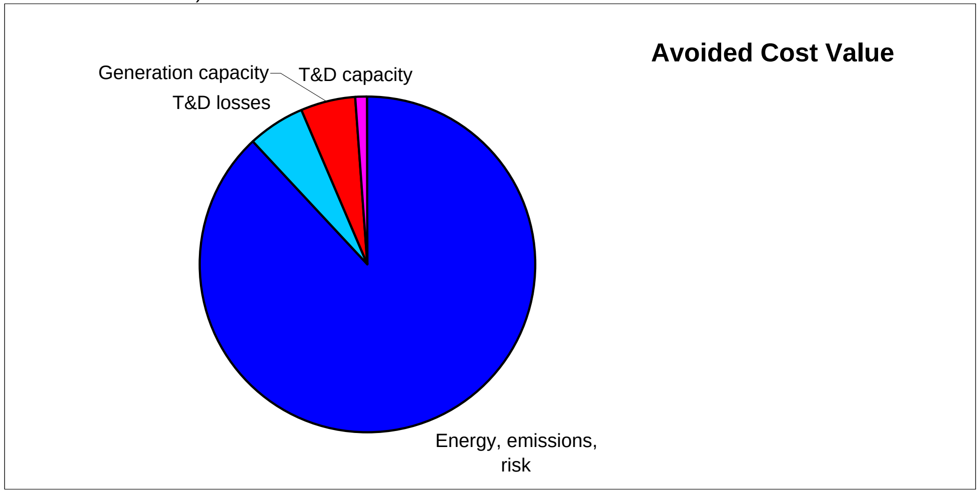
Per first year kW		Per first year kWh			% of total value
			$0.496	PV of avoided cost of energy (energy + emissions + risk)	88%
			$0.032	PV of avoided cost of energy (T&D losses)	6%
$	248.96	$	0.028	PV of avoided cost of generation capacity	5%
$	60.28	$	0.007	PV of avoided cost of T&D capacity	1%
			$0.564		100%
					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
15	Measure life
677	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)

$0.0595	Levelized cost/kWh of four energy components of AC
$0.0040	Levelized cost/kWh of two capacity components of AC

$	335.87	PV of avoided cost of energy (energy + emissions + risk)
$	21.83	PV of avoided cost of energy (T&D losses)
$	19.20	PV of avoided cost of generation capacity
$	4.65	PV of avoided cost of T&D capacity
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	381.55	Total Resource Cost test benefits
$	-	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	-	Total Resource Cost test costs
	$382	Net TRC $ amount
	no cost	**TRC benefit / cost ratio**

Home electronics and office equipment



Hot tub and swimming pool covers

Summarization of AC benefits and comparison to TRC costs

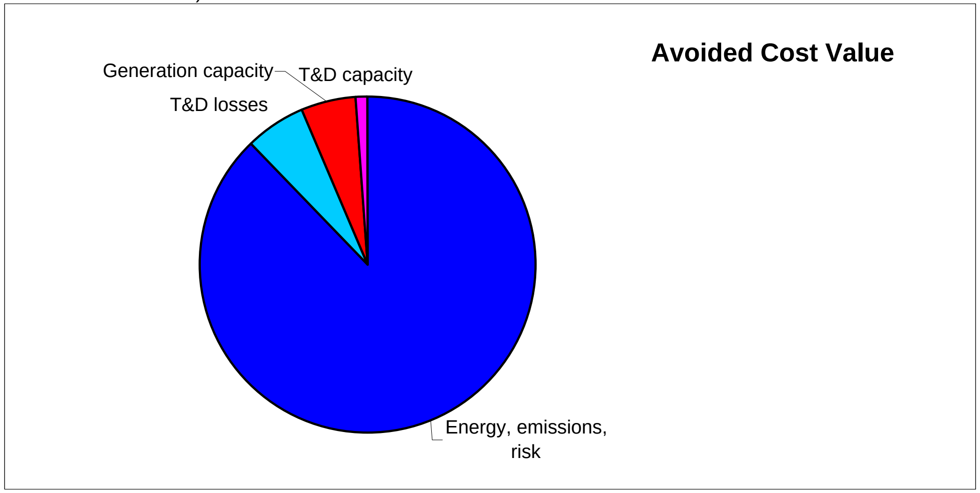
Per first year kW		Per first year kWh			% of total value
			$0.295	PV of avoided cost of energy (energy + emissions + risk)	88%
			$0.019	PV of avoided cost of energy (T&D losses)	6%
$	154.14	$	0.018	PV of avoided cost of generation capacity	5%
$	36.80	$	0.004	PV of avoided cost of T&D capacity	1%
			$0.336		100%
					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
8	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)

$0.0534	Levelized cost/kWh of four energy components of AC
$0.0037	Levelized cost/kWh of two capacity components of AC

$	73.66	PV of avoided cost of energy (energy + emissions + risk)
$	4.79	PV of avoided cost of energy (T&D losses)
$	4.39	PV of avoided cost of generation capacity
$	1.05	PV of avoided cost of T&D capacity
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	83.89	Total Resource Cost test benefits
$	300.00	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	300.00	Total Resource Cost test costs
	($216)	Net TRC $ amount
	0.28	**TRC benefit / cost ratio**

Hot tub ~~and swimming pool~~ covers



Heat pump water heater (single and multi-family)

Summarization of AC benefits and comparison to TRC costs

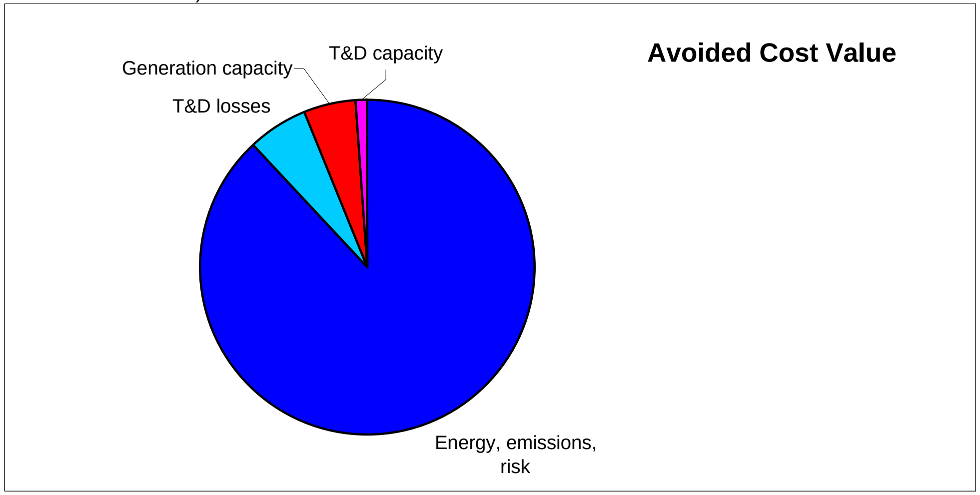
Per first year kW		Per first year kWh			% of total value
			$0.368	PV of avoided cost of energy (energy + emissions + risk)	88%
			$0.024	PV of avoided cost of energy (T&D losses)	6%
$	184.47	$	0.021	PV of avoided cost of generation capacity	5%
$	44.23	$	0.005	PV of avoided cost of T&D capacity	1%
			$0.418		100%
					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
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)

$0.0568	Levelized cost/kWh of four energy components of AC
$0.0038	Levelized cost/kWh of two capacity components of AC

$	649.43	PV of avoided cost of energy (energy + emissions + risk)
$	42.21	PV of avoided cost of energy (T&D losses)
$	36.95	PV of avoided cost of generation capacity
$	8.86	PV of avoided cost of T&D capacity
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	737.46	Total Resource Cost test benefits
$	1,661.96	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	1,661.96	Total Resource Cost test costs
	($925)	Net TRC $ amount
	0.44	**TRC benefit / cost ratio**

Heat pump water heater (single and multi-family)



Proper HVAC sizing

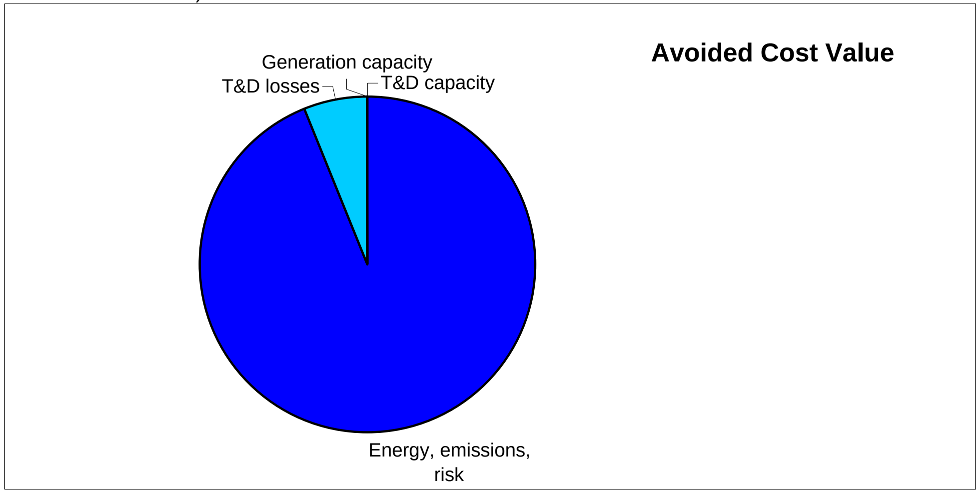
Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value
			$0.595	PV of avoided cost of energy (energy + emissions + risk)	94%
			$0.039	PV of avoided cost of energy (T&D losses)	6%
$	281.00	$	-	PV of avoided cost of generation capacity	0%
$	68.42	$	-	PV of avoided cost of T&D capacity	0%
			$0.633		100%

		100%	Total energy
zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	0%	Total capacity
7.41%	Discount rate	$0.0648	Levelized cost/kWh of four energy components of AC
18	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
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
	#DIV/0!	TRC benefit / cost ratio

Proper HVAC sizing



Induction cooktop

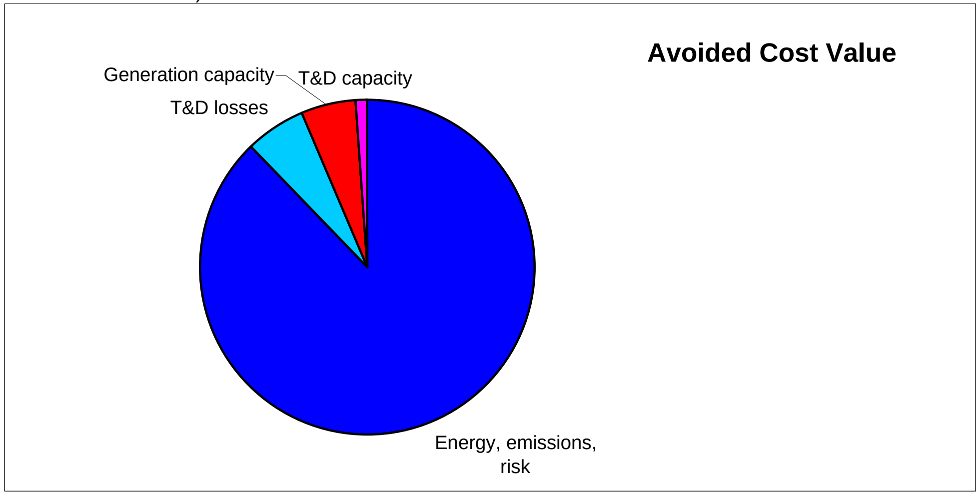
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.356	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.023	PV of avoided cost of energy (T&D losses)	6%	
$ 184.47	$ 0.021	PV of avoided cost of generation capacity	5%	
$ 44.23	$ 0.005	PV of avoided cost of T&D capacity	1%	
	$0.405		100%	
			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	$0.0550	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0038	Levelized cost/kWh of two capacity components of AC
27	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)		

$ 9.60	PV of avoided cost of energy (energy + emissions + risk)
$ 0.62	PV of avoided cost of energy (T&D losses)
$ 0.57	PV of avoided cost of generation capacity
$ 0.14	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 10.93	Total Resource Cost test benefits
$ 264.42	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 264.42	Total Resource Cost test costs
($253)	Net TRC $ amount
0.04	**TRC benefit / cost ratio**

Induction cooktop



Insulation (R19-R38, single family, resistance)

Summarization of AC benefits and comparison to TRC costs

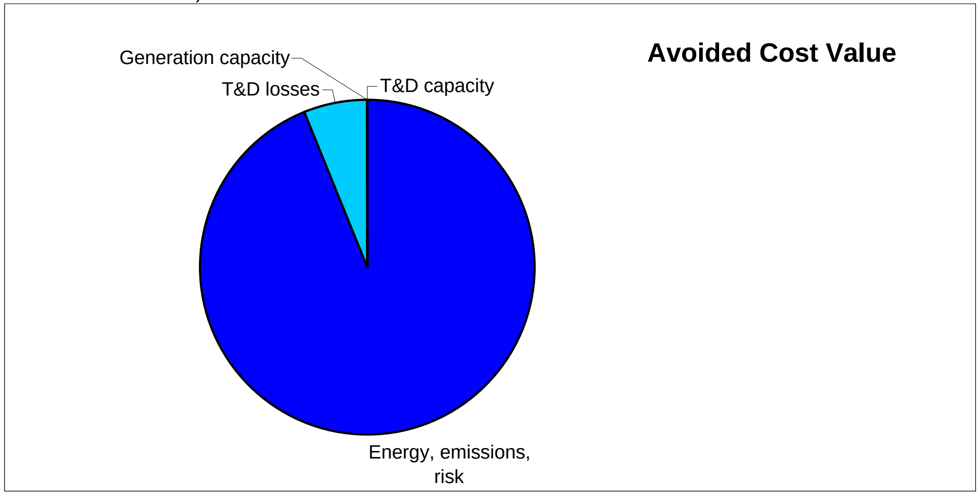
Per first year kW	Per first year kWh		% of total value
	$0.836	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.054	PV of avoided cost of energy (T&D losses)	6%
$ 372.36	$ -	PV of avoided cost of generation capacity	0%
$ 92.43	$ -	PV of avoided cost of T&D capacity	0%
	$0.890		100%
			100% Total energy
			0% Total capacity

zero	"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)

$0.0747	Levelized cost/kWh of four energy components of AC
$0.0000	Levelized cost/kWh of two capacity components of AC

$ 897.41	PV of avoided cost of energy (energy + emissions + risk)
$ 58.33	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
$ 955.74	Total Resource Cost test benefits
$ 812.70	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 812.70	Total Resource Cost test costs
$143	Net TRC $ amount
1.18	**TRC benefit / cost ratio**

Insulation (R19-R38, single family, resistance)



Low flow showerhead

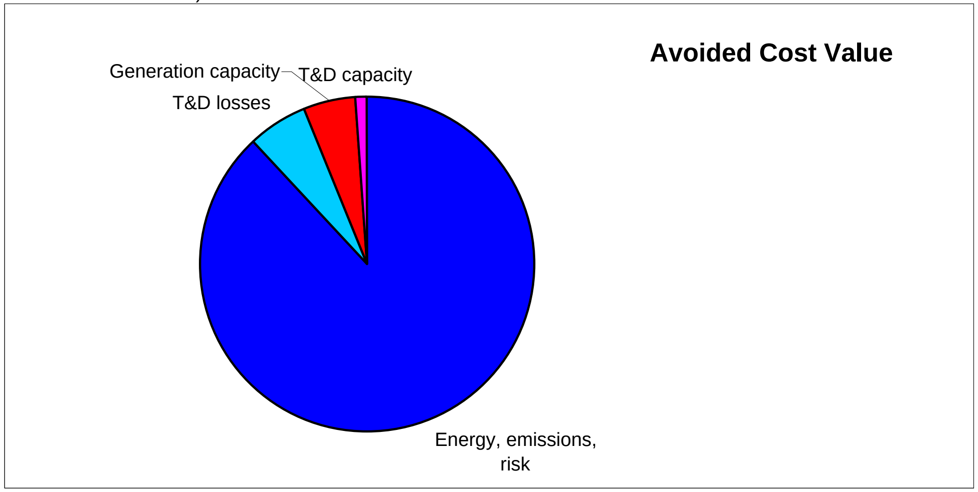
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.368	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.024	PV of avoided cost of energy (T&D losses)	6%	
$ 184.47	$ 0.021	PV of avoided cost of generation capacity	5%	
$ 44.23	$ 0.005	PV of avoided cost of T&D capacity	1%	
	$0.418		100%	
			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	$0.0568	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0038	Levelized cost/kWh of two capacity components of AC
101	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)		

$	37.14	PV of avoided cost of energy (energy + emissions + risk)
$	2.41	PV of avoided cost of energy (T&D losses)
$	2.11	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
$	42.18	Total Resource Cost test benefits
$	37.95	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	37.95	Total Resource Cost test costs
	$4	Net TRC $ amount
	1.11	**TRC benefit / cost ratio**

Low flow showerhead



Pipe insulation (single family, per foot installed)

Summarization of AC benefits and comparison to TRC costs

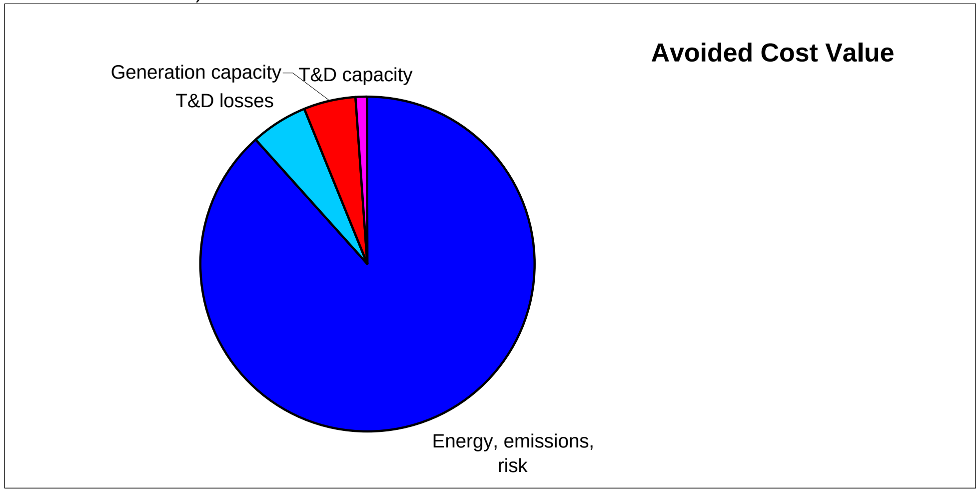
Per first year kW	Per first year kWh		% of total value
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.581		100%
			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
15	Measure life
133	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)

$0.0615	Levelized cost/kWh of four energy components of AC
$0.0040	Levelized cost/kWh of two capacity components of AC

$	68.18	PV of avoided cost of energy (energy + emissions + risk)
$	4.43	PV of avoided cost of energy (T&D losses)
$	3.76	PV of avoided cost of generation capacity
$	0.91	PV of avoided cost of T&D capacity
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	77.28	Total Resource Cost test benefits
$	2.81	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	2.81	Total Resource Cost test costs
	$74	Net TRC $ amount
	27.50	**TRC benefit / cost ratio**

Pipe insulation (single family, per foot installed)



Smart programmable thermostats

Summarization of AC benefits and comparison to TRC costs

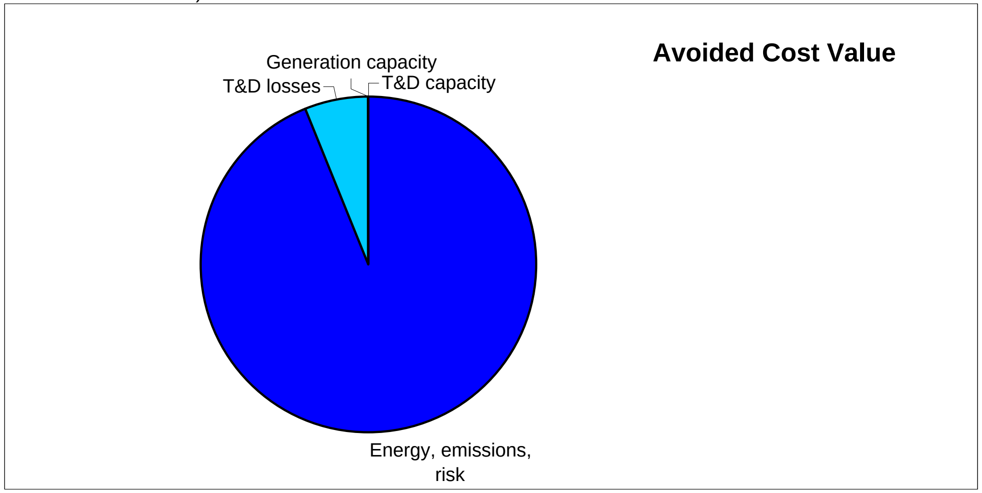
Per first year kW	Per first year kWh		% of total value
	$0.431	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.028	PV of avoided cost of energy (T&D losses)	6%
$ 212.09	$ -	PV of avoided cost of generation capacity	0%
$ 51.06	$ -	PV of avoided cost of T&D capacity	0%
	$0.460		100%

100%	Total energy
0%	Total capacity
$0.0591	Levelized cost/kWh of four energy components of AC
$0.0000	Levelized cost/kWh of two capacity components of AC

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
12	Measure life
755	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)

$ 325.78	PV of avoided cost of energy (energy + emissions + risk)
$ 21.18	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
$ 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**

Smart programmable thermostats



CFL 20W screw-in for incandescent 75W

Summarization of AC benefits and comparison to TRC costs

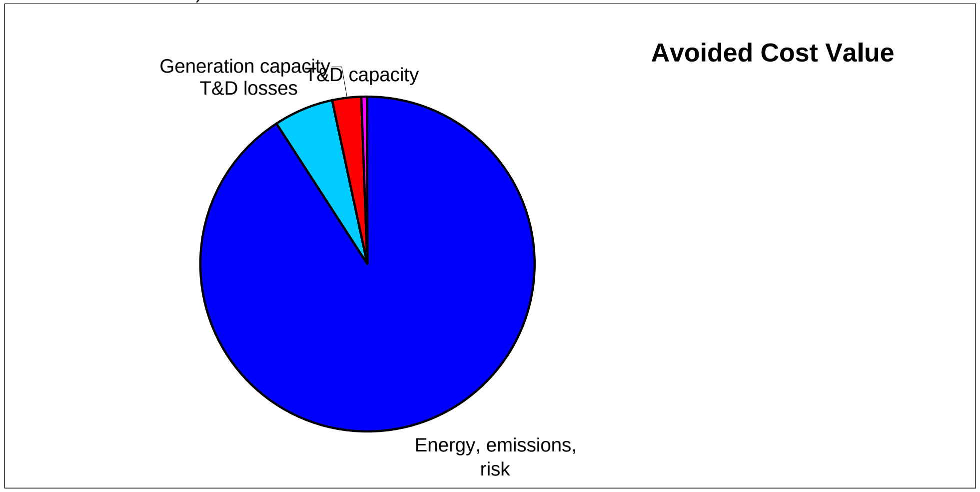
Per first year kW		Per first year kWh			% of total value
			$0.332	PV of avoided cost of energy (energy + emissions + risk)	91%
			$0.022	PV of avoided cost of energy (T&D losses)	6%
$	169.66	$	0.010	PV of avoided cost of generation capacity	3%
$	40.59	$	0.002	PV of avoided cost of T&D capacity	1%
			$0.366		100%

97%	Total energy
3%	Total capacity
$0.0535	Levelized cost/kWh of four energy components of AC
$0.0019	Levelized cost/kWh of two capacity components of AC

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)

$	13.94	PV of avoided cost of energy (energy + emissions + risk)
$	0.91	PV of avoided cost of energy (T&D losses)
$	0.42	PV of avoided cost of generation capacity
$	0.10	PV of avoided cost of T&D capacity
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	15.37	Total Resource Cost test benefits
$	6.47	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	6.47	Total Resource Cost test costs
	$9	Net TRC $ amount
	2.38	**TRC benefit / cost ratio**

CFL 20W screw-in for incandescent 75W



Remove second refrigerator

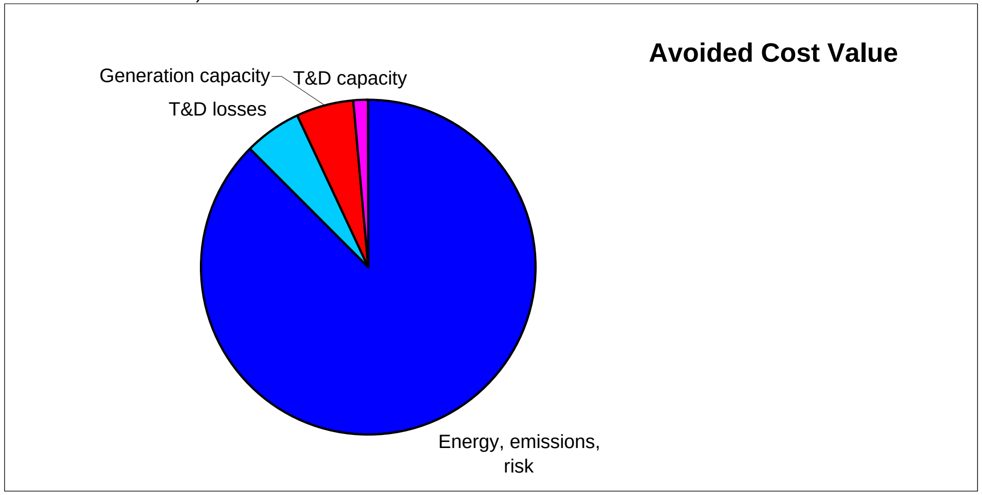
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.615	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.040	PV of avoided cost of energy (T&D losses)	6%
$ 300.00	$ 0.039	PV of avoided cost of generation capacity	6%
$ 73.31	$ 0.009	PV of avoided cost of T&D capacity	1%
	$0.704		100%
			93% Total energy
			7% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0638	Levelized cost/kWh of four energy components of AC
20	Measure life	$0.0047	Levelized cost/kWh of two capacity components of AC
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
#DIV/0!	**TRC benefit / cost ratio**

Remove second refrigerator



Energy efficient windows (retrofit, single family, resistance)

Summarization of AC benefits and comparison to TRC costs

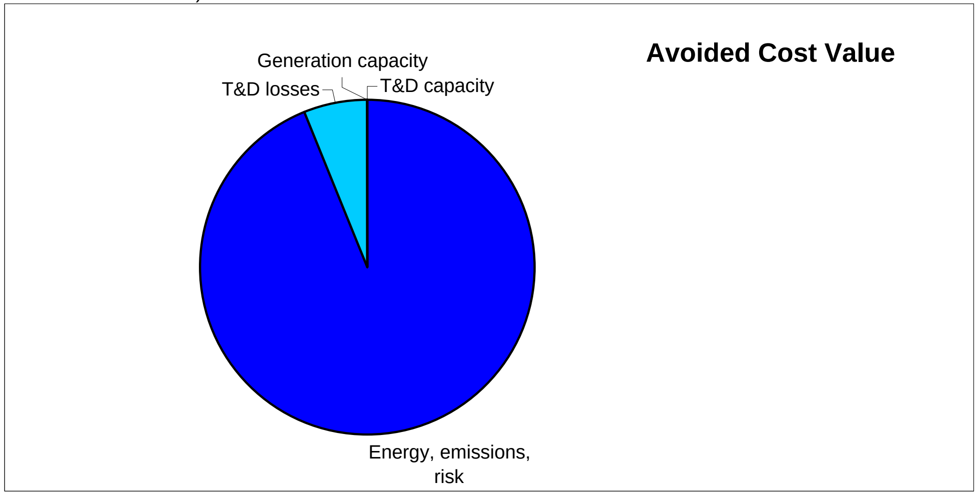
Per first year kW	Per first year kWh		% of total value
	$0.836	PV of avoided cost of energy (energy + emissions + risk)	94%
	$0.054	PV of avoided cost of energy (T&D losses)	6%
$ 372.36	$ -	PV of avoided cost of generation capacity	0%
$ 92.43	$ -	PV of avoided cost of T&D capacity	0%
	$0.890		100%
			100% Total energy
			0% Total capacity

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
30	Measure life
2,127	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)

$0.0747	Levelized cost/kWh of four energy components of AC
$0.0000	Levelized cost/kWh of two capacity components of AC

$ 1,777.26	PV of avoided cost of energy (energy + emissions + risk)
$ 115.52	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
$ 1,892.79	Total Resource Cost test benefits
$ 3,100.69	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 3,100.69	Total Resource Cost test costs
($1,208)	Net TRC $ amount
0.61	**TRC benefit / cost ratio**

Energy efficient windows (retrofit, single family, resistance)



Electric furnace vs heat pump conversion

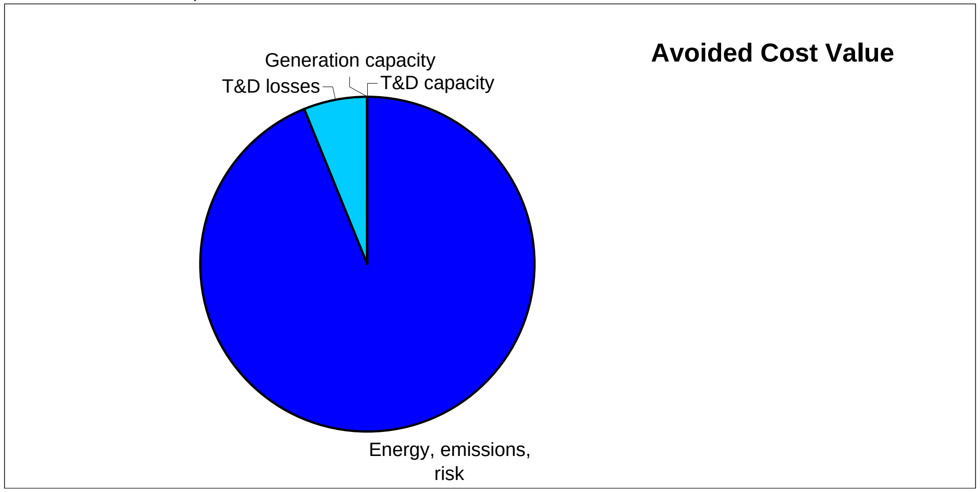
Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value
			$0.595	PV of avoided cost of energy (energy + emissions + risk)	94%
			$0.039	PV of avoided cost of energy (T&D losses)	6%
$	281.00	$	-	PV of avoided cost of generation capacity	0%
$	68.42	$	-	PV of avoided cost of T&D capacity	0%
			$0.633		100%
					100% Total energy

zero	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)	0%	Total capacity
7.41%	Discount rate	$0.0648	Levelized cost/kWh of four energy components of AC
18	Measure life	$0.0000	Levelized cost/kWh of two capacity components of AC
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**

Electric furnace vs heat pump conversion



Smart/energy efficient appliance rebate program

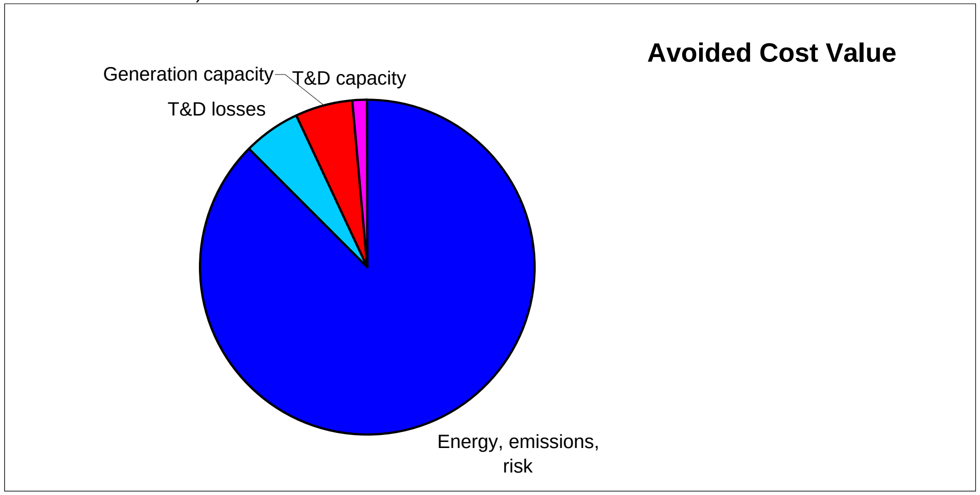
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.570	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.037	PV of avoided cost of energy (T&D losses)	6%
$ 281.00	$ 0.036	PV of avoided cost of generation capacity	6%
$ 68.42	$ 0.009	PV of avoided cost of T&D capacity	1%
	$0.652		100%
			93% Total energy
			7% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0621	Levelized cost/kWh of four energy components of AC
18	Measure life	$0.0046	Levelized cost/kWh of two capacity components of AC
58	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)		

$ 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**

Smart/energy efficient appliance rebate program



Solar water heating

Summarization of AC benefits and comparison to TRC costs

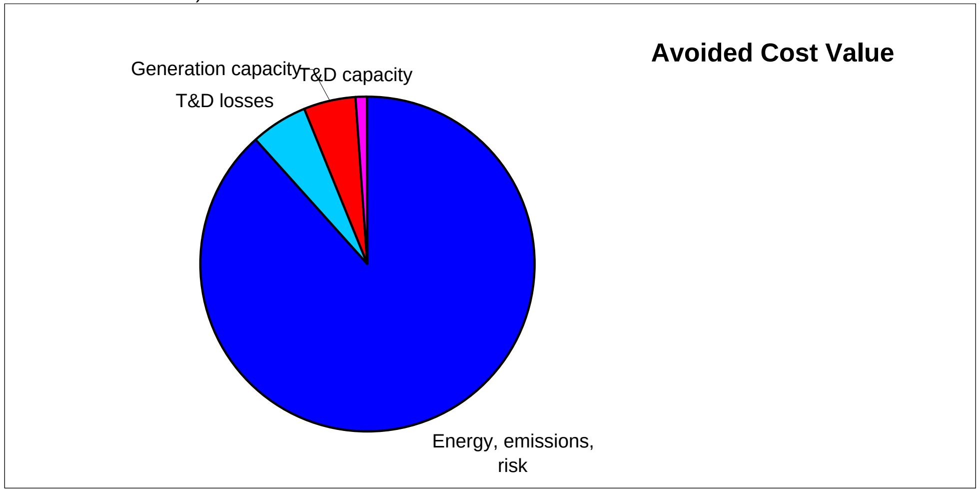
Per first year kW	Per first year kWh		% of total value
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.581		100%
			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
15	Measure life
2,566	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)

$0.0615	Levelized cost/kWh of four energy components of AC
$0.0040	Levelized cost/kWh of two capacity components of AC

$ 1,315.38	PV of avoided cost of energy (energy + emissions + risk)
$ 85.50	PV of avoided cost of energy (T&D losses)
$ 72.46	PV of avoided cost of generation capacity
$ 17.55	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 1,490.89	Total Resource Cost test benefits
$ 5,310.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 5,310.00	Total Resource Cost test costs
($3,819)	Net TRC $ amount
0.28	**TRC benefit / cost ratio**

Solar water heating



Tankless water heater (single family)

Summarization of AC benefits and comparison to TRC costs

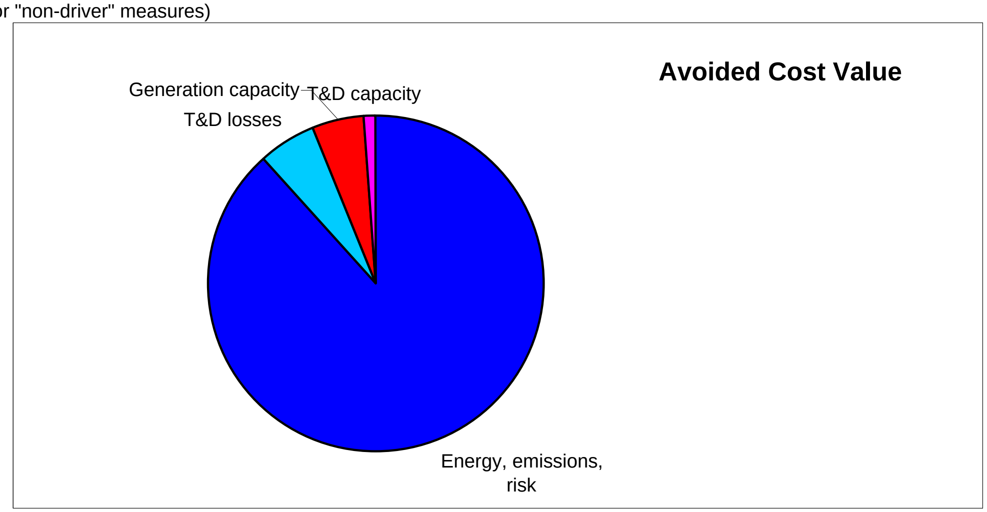
Per first year kW	Per first year kWh		% of total value
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.581		100%
			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
15	Measure life
682	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)

$0.0615	Levelized cost/kWh of four energy components of AC
$0.0040	Levelized cost/kWh of two capacity components of AC

$ 349.61	PV of avoided cost of energy (energy + emissions + risk)
$ 22.72	PV of avoided cost of energy (T&D losses)
$ 19.26	PV of avoided cost of generation capacity
$ 4.66	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 396.25	Total Resource Cost test benefits
$ 1,010.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 1,010.00	Total Resource Cost test costs
($614)	Net TRC $ amount
0.39	**TRC benefit / cost ratio**

Tankless water heater (single family)



HE Variable High Speed Motor

Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh			% of total value
			$0.642	PV of avoided cost of energy (energy + emissions + risk)	94%
			$0.042	PV of avoided cost of energy (T&D losses)	6%
$	300.00	$	0.000	PV of avoided cost of generation capacity	0%
$	73.31	$	0.000	PV of avoided cost of T&D capacity	0%
			$0.684		100%

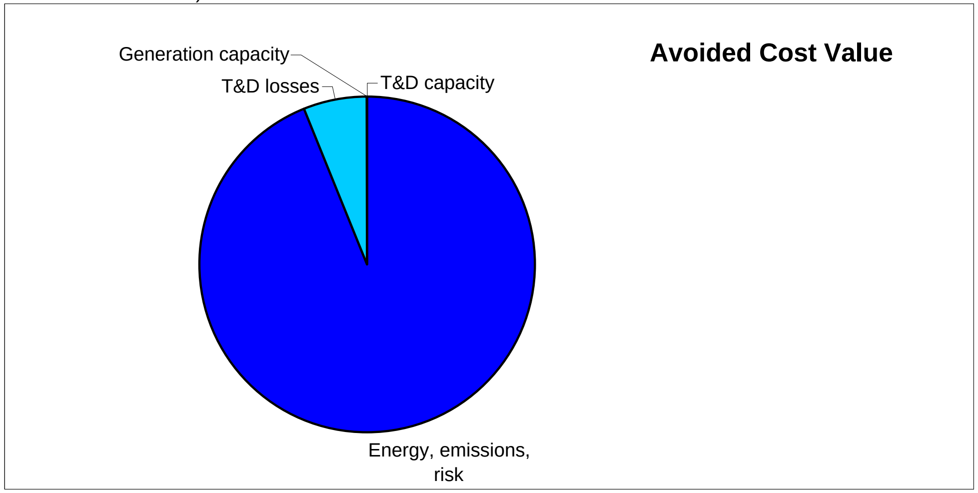
100% Total energy
0% Total capacity

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)

$0.0666 Levelized cost/kWh of four energy components of AC
$0.0000 Levelized cost/kWh of two capacity components of AC

$	160.42	PV of avoided cost of energy (energy + emissions + risk)
$	10.43	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
$	-	PV of avoided cost of natural gas
$	-	PV of non-energy benefits
$	170.89	Total Resource Cost test benefits
$	200.00	Incremental customer cost
$	-	Incremental non-incentive utility cost
$	200.00	Total Resource Cost test costs
	($29)	Net TRC $ amount
	0.85	**TRC benefit / cost ratio**

HE Variable High Speed Motor



Water heater controller

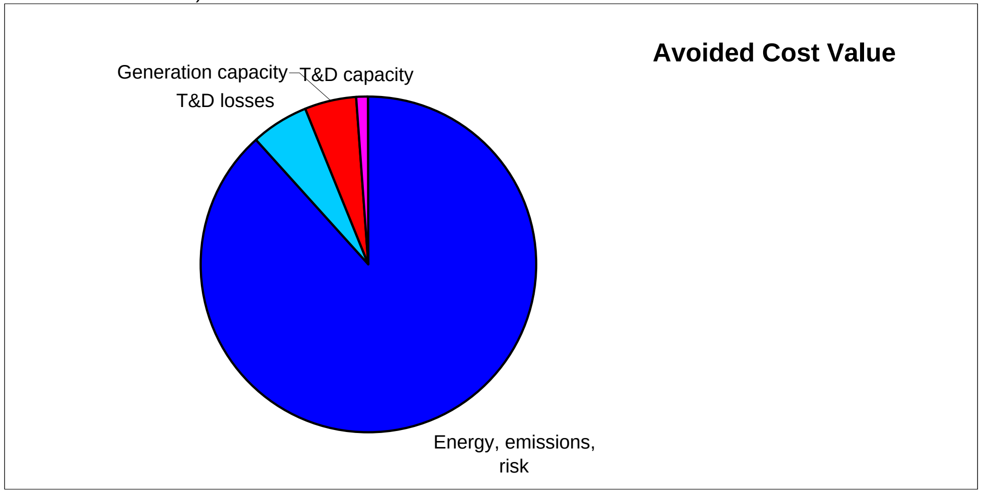
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.581		100%
			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	$0.0615	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0040	Levelized cost/kWh of two capacity components of AC
224	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)		

$ 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
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 130.15	Total Resource Cost test benefits
$ 15.00	Incremental customer cost
$ -	Incremental non-incentive utility cost
$ 15.00	Total Resource Cost test costs
$115	Net TRC $ amount
8.68	**TRC benefit / cost ratio**

Water heater controller



Water heater tank wraps, pads, closet insulation

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.513	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.028	PV of avoided cost of generation capacity	5%
$ 60.28	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.581		100%
			94% Total energy
			6% Total capacity

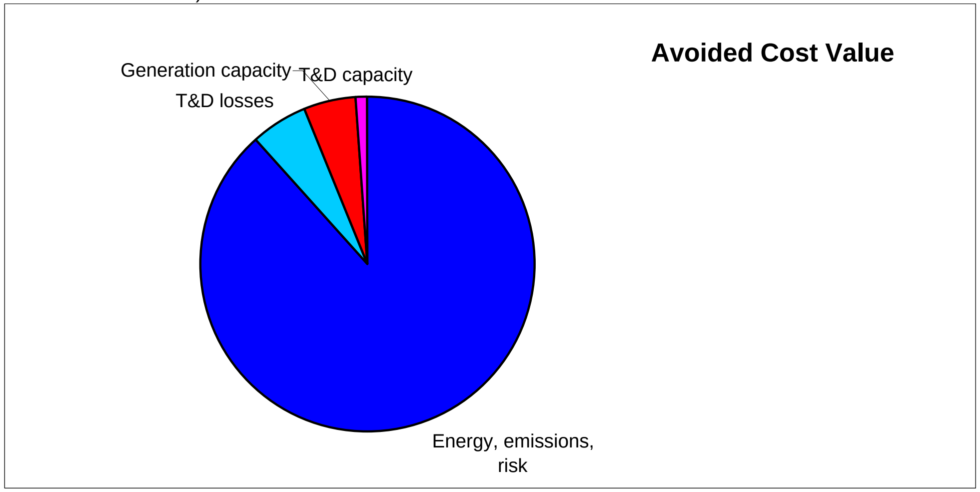
non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
364	Annual kWh savings per unit
0.0160%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0113%	Percent of annual energy in average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

$0.0615 Levelized cost/kWh of four energy components of AC

$0.0040 Levelized cost/kWh of two capacity components of AC

$ 186.59	PV of avoided cost of energy (energy + emissions + risk)
$ 12.13	PV of avoided cost of energy (T&D losses)
$ 10.28	PV of avoided cost of generation capacity
$ 2.49	PV of avoided cost of T&D capacity
$ -	PV of avoided cost of natural gas
$ -	PV of non-energy benefits
$ 211.49	Total Resource Cost test benefits
$ 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**

Water heater tank wraps, pads, closet insulation



Commercial Measures

Light fixture reconfiguration

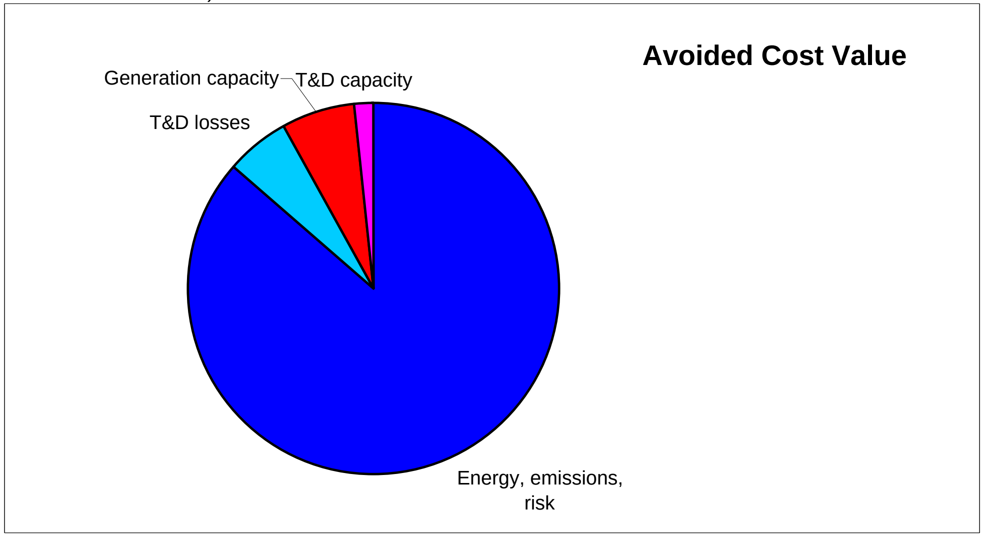
Summarization of AC benefits and comparison to TRC costs

Per first year kW		Per first year kWh		% of total value	
		$0.535	PV of avoided cost of energy (energy + emissions + risk)	86%	
		$0.035	PV of avoided cost of energy (T&D losses)	6%	
$ 260.14	$	0.040	PV of avoided cost of generation capacity	6%	
$ 63.11	$	0.010	PV of avoided cost of T&D capacity	2%	
		$0.619		100%	
				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	$0.0620	Levelized cost/kWh of four energy components of AC
16	Measure life	$0.0054	Levelized cost/kWh of two capacity components of AC
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)		

$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
$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



Energy efficient case fans (grocery, per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.522	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.034	PV of avoided cost of energy (T&D losses)	6%
$ 260.14	$ 0.036	PV of avoided cost of generation capacity	6%
$ 63.11	$ 0.009	PV of avoided cost of T&D capacity	1%
	$0.601		100%

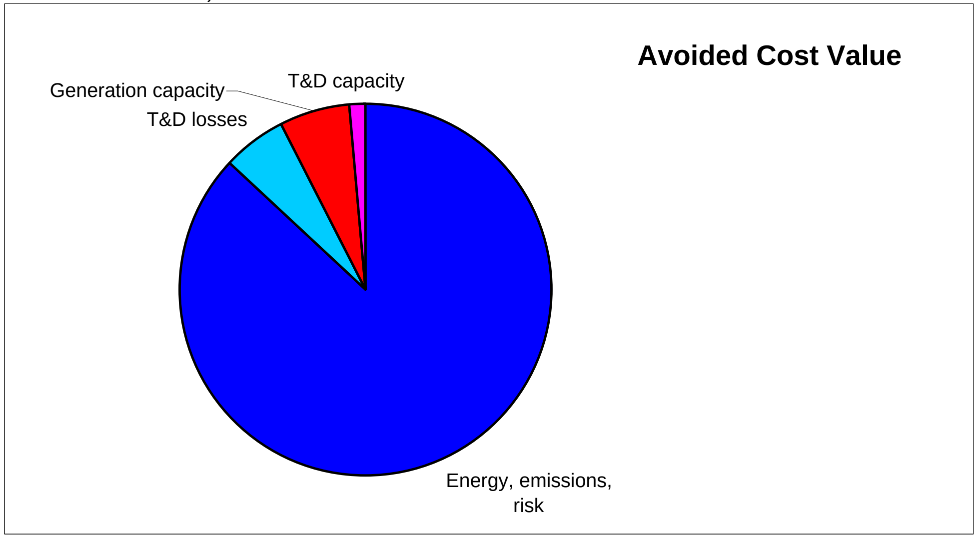
93% Total energy
7% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
16	Measure life
2.897	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)

$0.0605 Levelized cost/kWh of four energy components of AC
$0.0049 Levelized cost/kWh of two capacity components of AC

$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)

Summarization of AC benefits and comparison to TRC costs

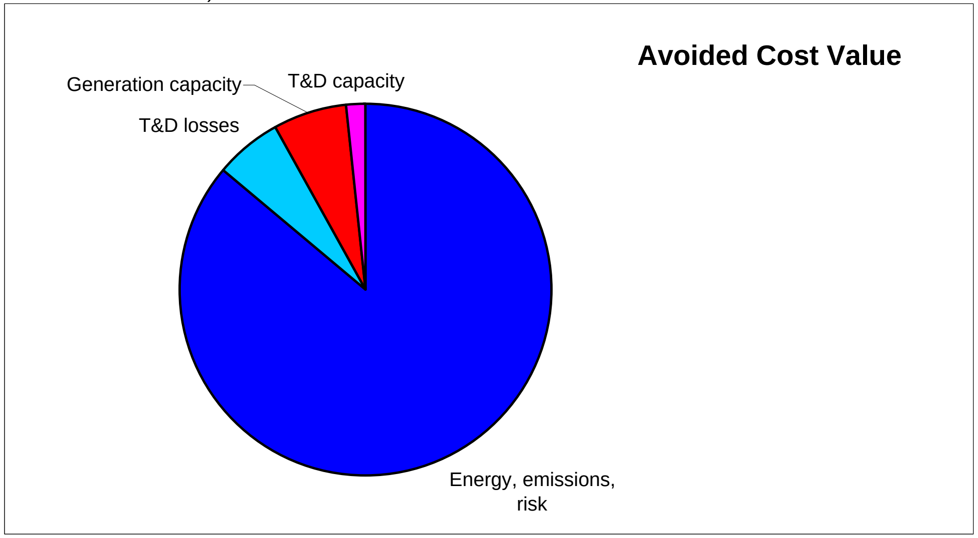
Per first year kW	Per first year kWh		% of total value	
	$0.425	PV of avoided cost of energy (energy + emissions + risk)	86%	
	$0.028	PV of avoided cost of energy (T&D losses)	6%	
$ 212.09	$ 0.032	PV of avoided cost of generation capacity	7%	
$ 51.06	$ 0.008	PV of avoided cost of T&D capacity	2%	
	$0.493		100%	
			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)

$0.0583	Levelized cost/kWh of four energy components of AC
$0.0052	Levelized cost/kWh of two capacity components of AC

$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**

CFL 20W fixture for incandescent 75W (retrofit)



Commissioning/retro-commissioning

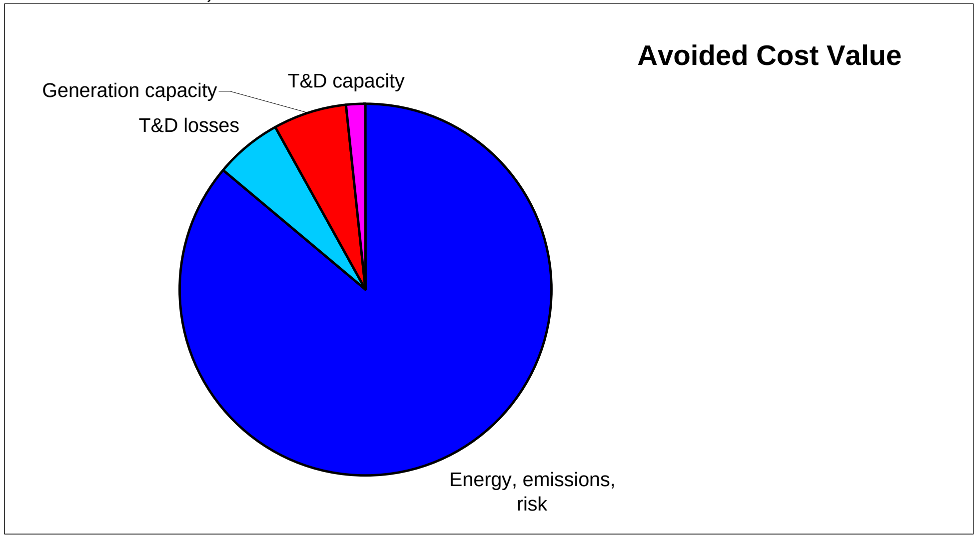
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.207	PV of avoided cost of energy (energy + emissions + risk)	86%	
	$0.013	PV of avoided cost of energy (T&D losses)	6%	
$ 102.97	$ 0.016	PV of avoided cost of generation capacity	7%	
$ 24.42	$ 0.004	PV of avoided cost of T&D capacity	2%	
	$0.240		100%	
			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	$0.0544	Levelized cost/kWh of four energy components of AC
5	Measure life	$0.0048	Levelized cost/kWh of two capacity components of AC
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**

Commissioning/retro-commissioning



Demand defrost (grocery, per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

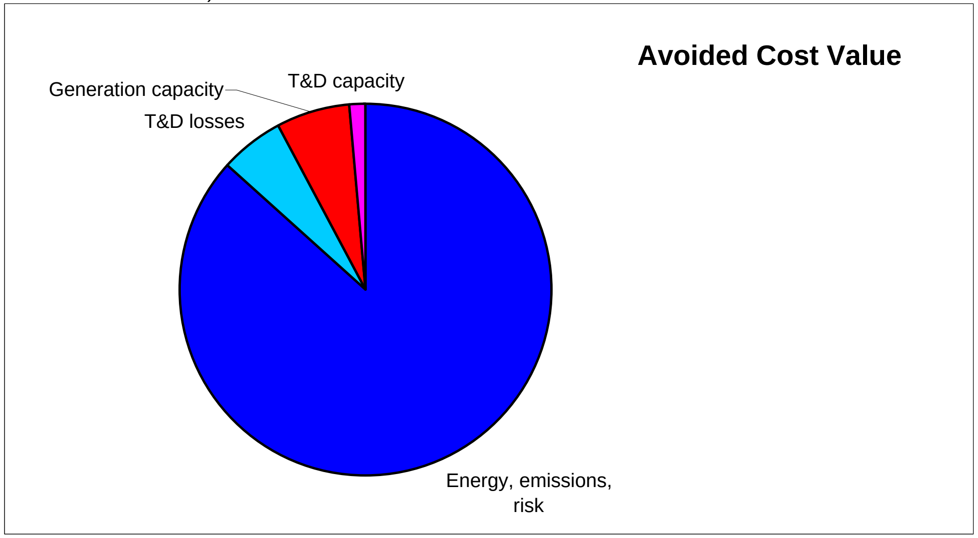
Per first year kW	Per first year kWh		% of total value
	$0.356	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.023	PV of avoided cost of energy (T&D losses)	6%
$ 184.47	$ 0.026	PV of avoided cost of generation capacity	6%
$ 44.23	$ 0.006	PV of avoided cost of T&D capacity	1%
	$0.411		100%
		Total energy	92%
		Total capacity	8%

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
10	Measure life
1.876	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)

$0.0550	Levelized cost/kWh of four energy components of AC
$0.0046	Levelized cost/kWh of two capacity components of AC

$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
$0.77	Total Resource Cost test benefits
$0.04	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.04	Total Resource Cost test costs
$0.73	Net TRC $ amount
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

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%
$ 184.47	$ 0.026	PV of avoided cost of generation capacity	6%
$ 44.23	$ 0.006	PV of avoided cost of T&D capacity	1%
	$0.411		100%

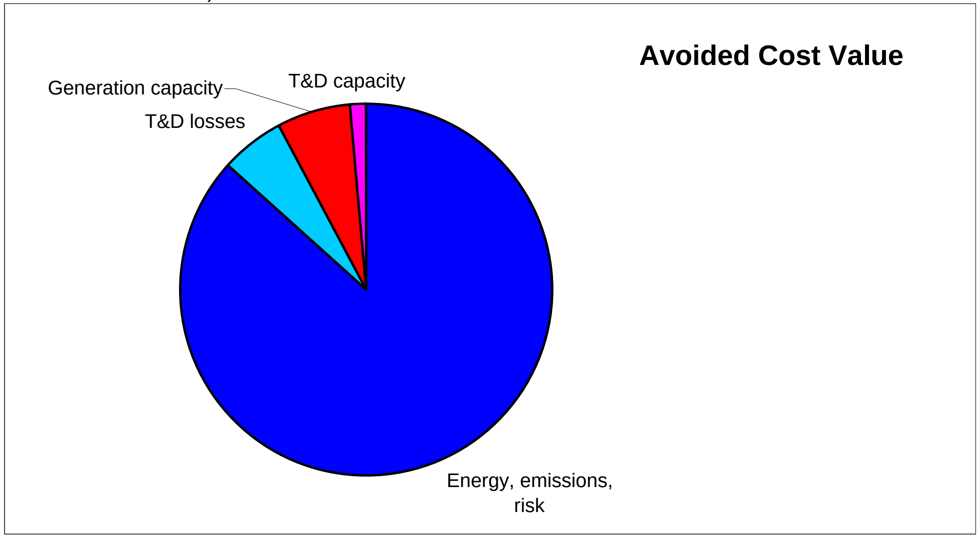
92% Total energy
8% Total capacity

$0.0550 Levelized cost/kWh of four energy components of AC
$0.0046 Levelized cost/kWh of two capacity components of AC

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
10	Measure life
1,639.000	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)

$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

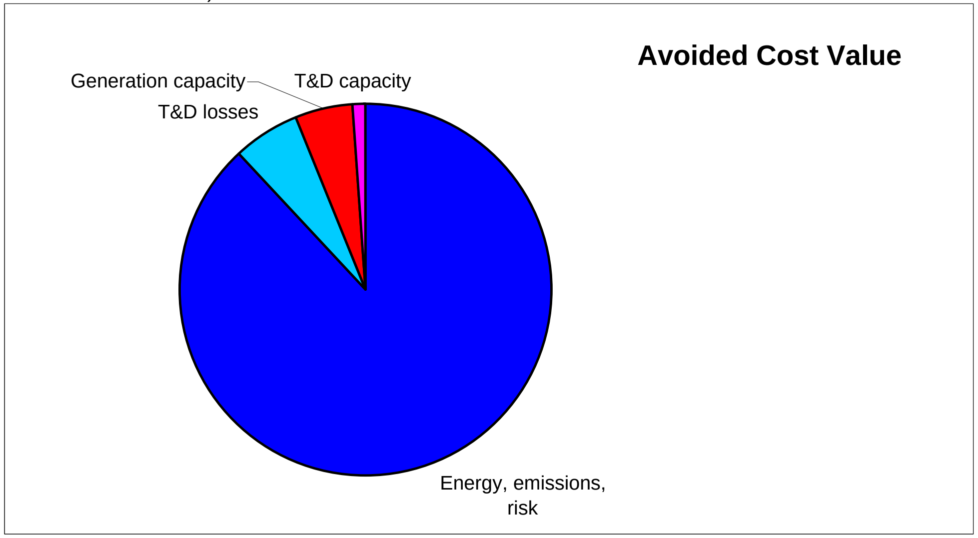
Per first year kW	Per first year kWh		% of total value	
	$0.616	PV of avoided cost of energy (energy + emissions + risk)	88%	
	$0.040	PV of avoided cost of energy (T&D losses)	6%	
$ 300.00	$ 0.034	PV of avoided cost of generation capacity	5%	
$ 73.31	$ 0.008	PV of avoided cost of T&D capacity	1%	
	$0.699		100%	
			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
20	Measure life
381.000	Annual kWh savings per unit
0.0114%	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)

$0.0639	Levelized cost/kWh of four energy components of AC
$0.0042	Levelized cost/kWh of two capacity components of AC

$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)

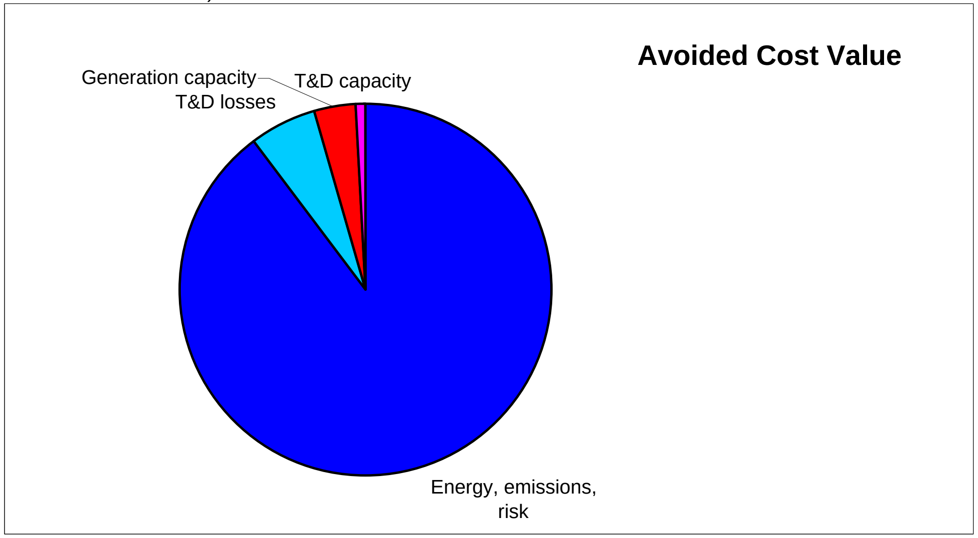
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.506	PV of avoided cost of energy (energy + emissions + risk)	90%	
	$0.033	PV of avoided cost of energy (T&D losses)	6%	
$ 248.96	$ 0.021	PV of avoided cost of generation capacity	4%	
$ 60.28	$ 0.005	PV of avoided cost of T&D capacity	1%	
	$0.564		100%	
			95%	Total energy
			5%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0607	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0029	Levelized cost/kWh of two capacity components of AC
20,000.000	Annual kWh savings per unit		
0.0104%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0082%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$10,119.42	PV of avoided cost of energy (energy + emissions + risk)
$657.76	PV of avoided cost of energy (T&D losses)
$410.54	PV of avoided cost of generation capacity
$99.41	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$11,287.13	Total Resource Cost test benefits
$14,000.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$14,000.00	Total Resource Cost test costs
($2,712.87)	Net TRC $ amount
0.81	**TRC benefit / cost ratio**

Prescriptive Energy Recovery Ventilation (ERV)



Evaporator fan cycling (grocery)

Summarization of AC benefits and comparison to TRC costs

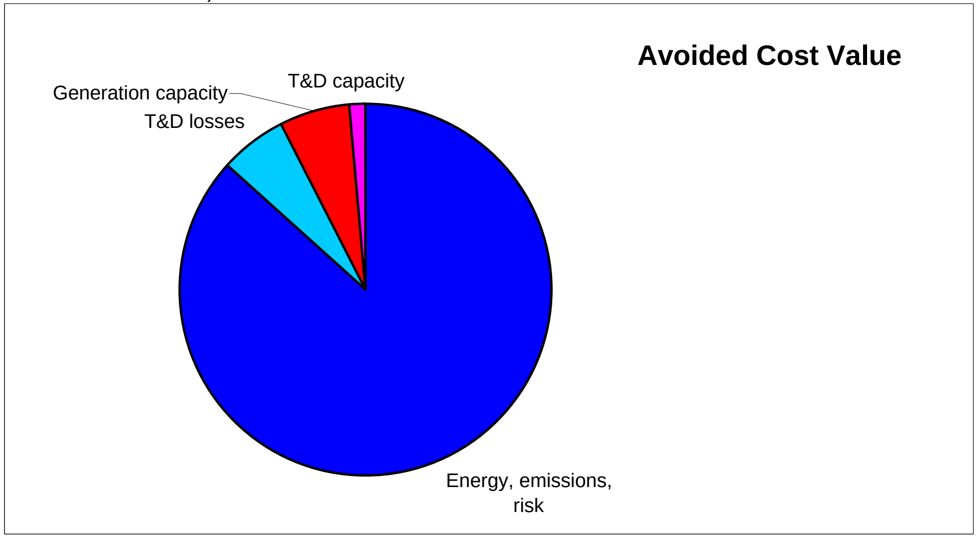
Per first year kW	Per first year kWh		% of total value	
	$0.203	PV of avoided cost of energy (energy + emissions + risk)	87%	
	$0.013	PV of avoided cost of energy (T&D losses)	6%	
$ 102.97	$ 0.014	PV of avoided cost of generation capacity	6%	
$ 24.42	$ 0.003	PV of avoided cost of T&D capacity	1%	
	$0.234		100%	
			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
5	Measure life
0.133	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)

$0.0532	Levelized cost/kWh of four energy components of AC
$0.0044	Levelized cost/kWh of two capacity components of AC

$0.03	PV of avoided cost of energy (energy + emissions + risk)
$0.00	PV of avoided cost of energy (T&D losses)
$0.00	PV of avoided cost of generation capacity
$0.00	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.03	Total Resource Cost test benefits
$0.09	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.09	Total Resource Cost test costs
($0.06)	Net TRC $ amount
0.35	**TRC benefit / cost ratio**

Evaporator fan cycling (grocery)



Fast-acting loading dock doors and seals

Summarization of AC benefits and comparison to TRC costs

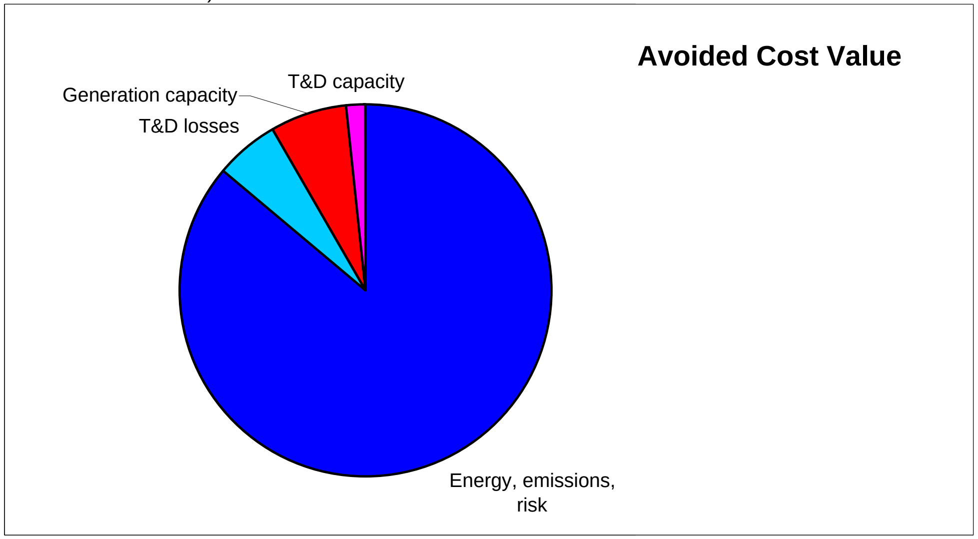
Per first year kW	Per first year kWh		% of total value	
	$0.423	PV of avoided cost of energy (energy + emissions + risk)	86%	
	$0.027	PV of avoided cost of energy (T&D losses)	6%	
$ 212.09	$ 0.033	PV of avoided cost of generation capacity	7%	
$ 51.06	$ 0.008	PV of avoided cost of T&D capacity	2%	
	$0.491		100%	
			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
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)

$0.0579	Levelized cost/kWh of four energy components of AC
$0.0052	Levelized cost/kWh of two capacity components of AC

$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**

Fast-acting loading dock doors and seals



HE Chiller, 0.51 kW/ton, 300 Tons (per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

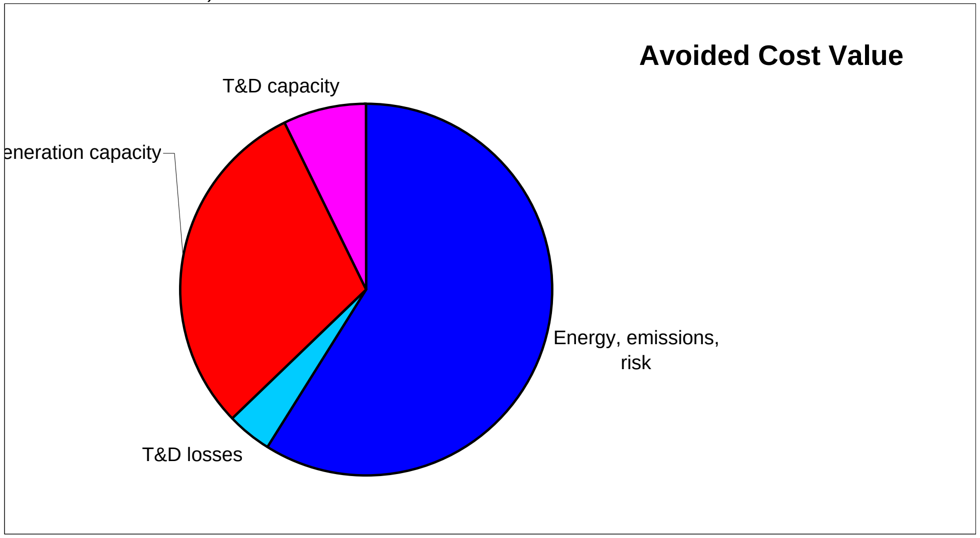
Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%
	$0.033	PV of avoided cost of energy (T&D losses)	4%
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%
	$0.854		100%
			63% Total energy
			37% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
0.728	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)

$0.0603	Levelized cost/kWh of four energy components of AC
$0.0359	Levelized cost/kWh of two capacity components of AC

$0.37	PV of avoided cost of energy (energy + emissions + risk)
$0.02	PV of avoided cost of energy (T&D losses)
$0.19	PV of avoided cost of generation capacity
$0.05	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.62	Total Resource Cost test benefits
$0.18	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.18	Total Resource Cost test costs
$0.44	Net TRC $ amount
3.45	**TRC benefit / cost ratio**

HE Chiller, 0.51 kW/ton, 300 Tons (per sq. ft.)



HE DX, 10 tons, EER=11.3 (per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

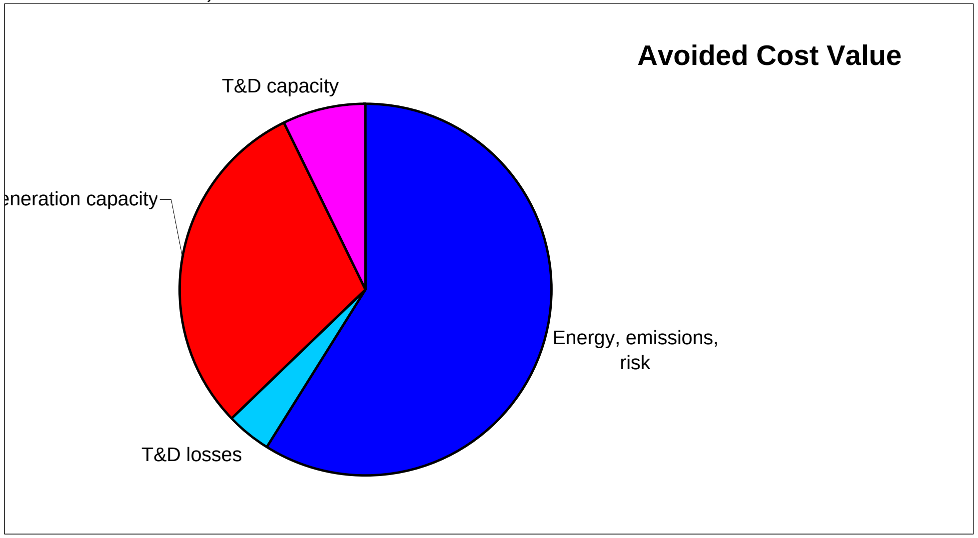
Per first year kW	Per first year kWh		% of total value	
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%	
	$0.033	PV of avoided cost of energy (T&D losses)	4%	
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%	
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%	
	$0.854		100%	
			63%	Total energy
			37%	Total capacity

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)

$0.0603	Levelized cost/kWh of four energy components of AC
$0.0359	Levelized cost/kWh of two capacity components of AC

$0.25	PV of avoided cost of energy (energy + emissions + risk)
$0.02	PV of avoided cost of energy (T&D losses)
$0.13	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
$0.43	Total Resource Cost test benefits
$0.29	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.29	Total Resource Cost test costs
$0.14	Net TRC $ amount
1.47	**TRC benefit / cost ratio**

HE DX, 10 tons, EER=11.3 (per sq. ft.)



Electric vs gas water, 40 gal., EF=.95 (per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.509	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.033	PV of avoided cost of generation capacity	6%
$ 60.28	$ 0.008	PV of avoided cost of T&D capacity	1%
	$0.582		100%

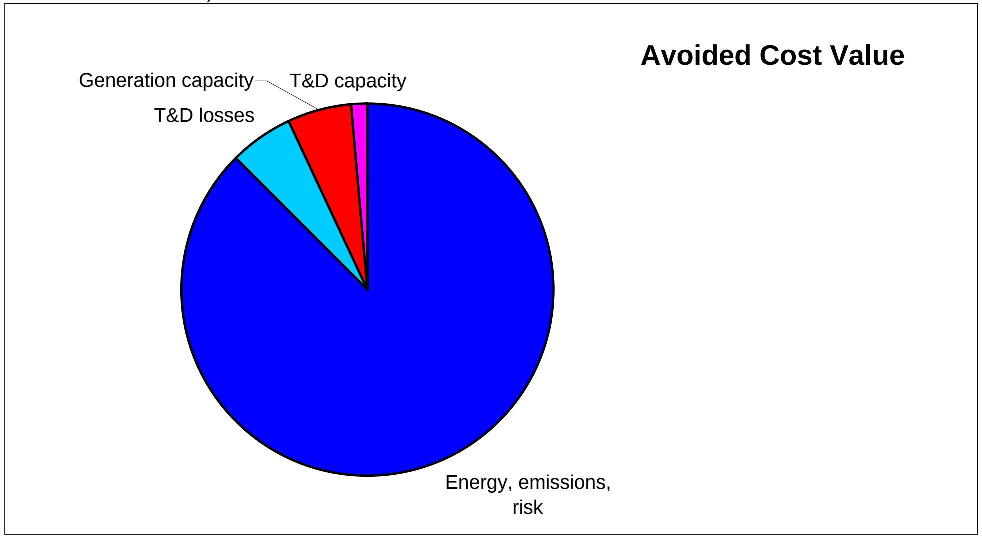
93% Total energy
7% Total capacity

$0.0610 Levelized cost/kWh of four energy components of AC
$0.0046 Levelized cost/kWh of two capacity components of AC

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)
$0.10	PV of avoided cost of energy (T&D losses)
$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
2.61	**TRC benefit / cost ratio**

Electric vs gas water, 40 gal., EF=.95 (per sq. ft.)



Humidistat controls (grocery, per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

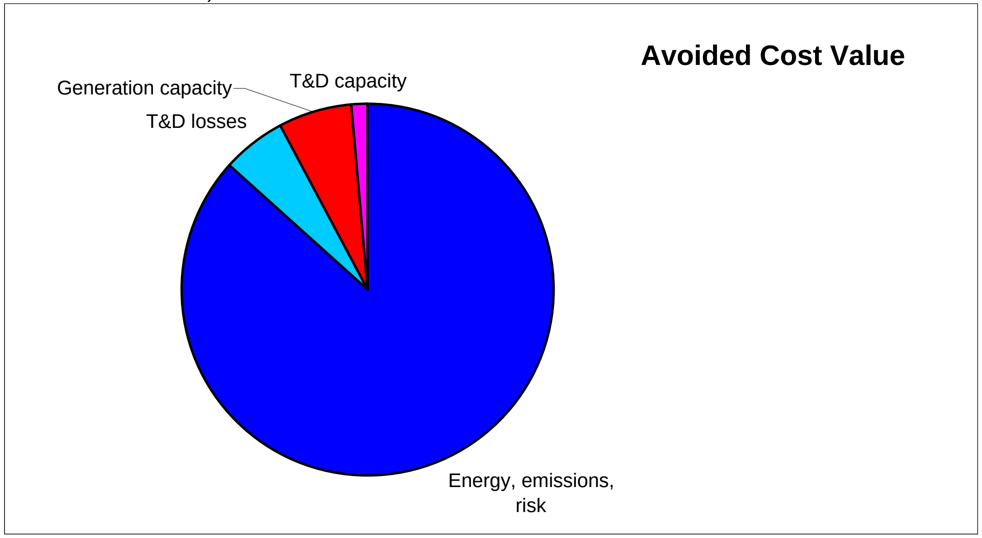
Per first year kW	Per first year kWh		% of total value
	$0.414	PV of avoided cost of energy (energy + emissions + risk)	87%
	$0.027	PV of avoided cost of energy (T&D losses)	6%
$ 212.09	$ 0.029	PV of avoided cost of generation capacity	6%
$ 51.06	$ 0.007	PV of avoided cost of T&D capacity	1%
	$0.478		100%

92%	Total energy
8%	Total capacity
$0.0568	Levelized cost/kWh of four energy components of AC
$0.0047	Levelized cost/kWh of two capacity components of AC

non-driver	"driver", "non-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**

Humidistat controls (grocery, per sq. ft.)



Exit sign replacement (LED)

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.616	PV of avoided cost of energy (energy + emissions + risk)	88%
	$0.040	PV of avoided cost of energy (T&D losses)	6%
$ 300.00	$ 0.034	PV of avoided cost of generation capacity	5%
$ 73.31	$ 0.008	PV of avoided cost of T&D capacity	1%
	$0.699		100%

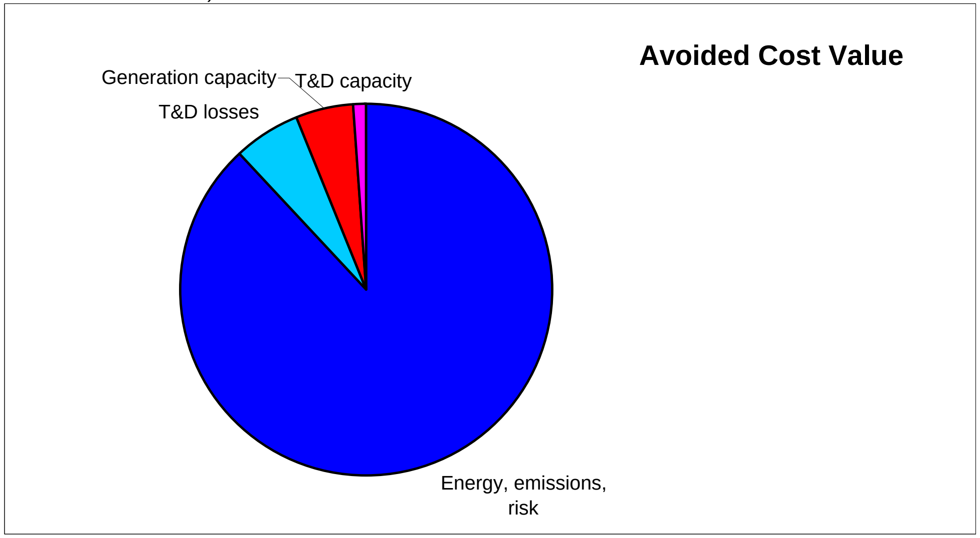
94% Total energy
6% Total capacity

$0.0639 Levelized cost/kWh of four energy components of AC
$0.0042 Levelized cost/kWh of two capacity components of AC

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
20	Measure life
351.000	Annual kWh savings per unit
0.0114%	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)

$216.24	PV of avoided cost of energy (energy + emissions + risk)
$14.06	PV of avoided cost of energy (T&D losses)
$12.02	PV of avoided cost of generation capacity
$2.94	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$245.25	Total Resource Cost test benefits
$65.44	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$65.44	Total Resource Cost test costs
$179.81	Net TRC $ amount
3.75	**TRC benefit / cost ratio**

Exit sign replacement (LED)



Light colored roof (from .8 to .45 absorptivity)

Summarization of AC benefits and comparison to TRC costs

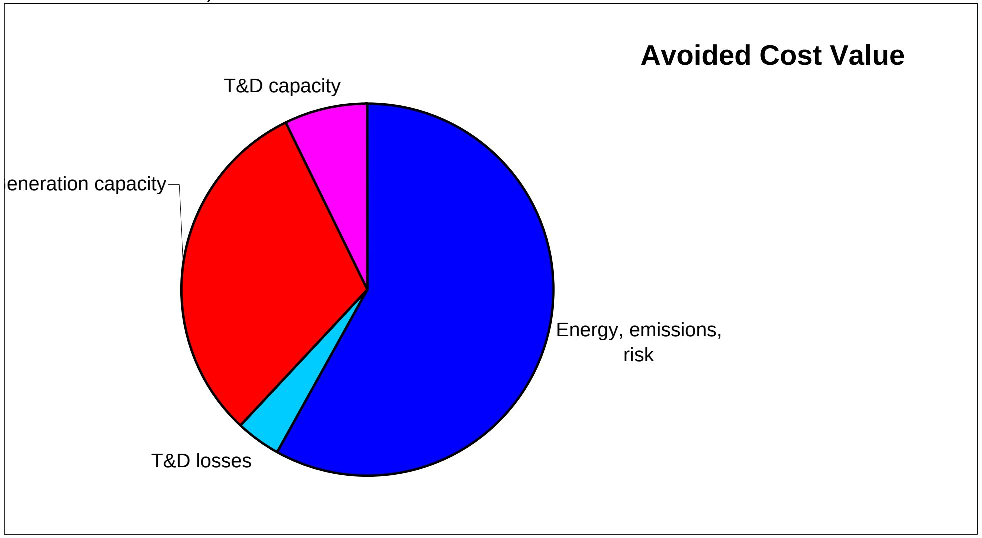
Per first year kW	Per first year kWh		% of total value
	$0.360	PV of avoided cost of energy (energy + emissions + risk)	58%
	$0.023	PV of avoided cost of energy (T&D losses)	4%
$ 184.47	$ 0.190	PV of avoided cost of generation capacity	31%
$ 44.23	$ 0.046	PV of avoided cost of T&D capacity	7%
	$0.619		100%
			62% Total energy
			38% Total capacity

driver	"driver", "non-driver" or "zero" 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)

$0.0557	Levelized cost/kWh of four energy components of AC
$0.0342	Levelized cost/kWh of two capacity components of AC

$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

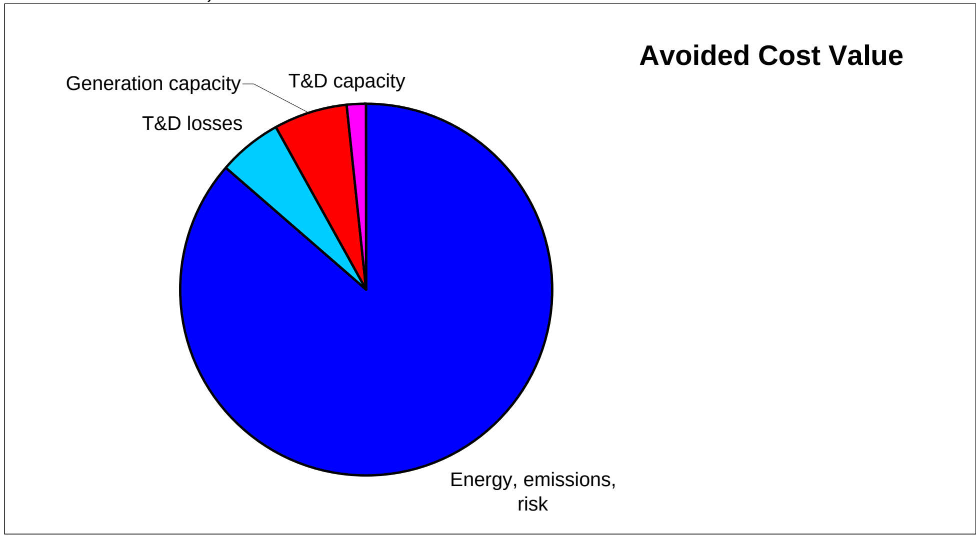
Per first year kW	Per first year kWh		% of total value	
	$0.481	PV of avoided cost of energy (energy + emissions + risk)	86%	
	$0.031	PV of avoided cost of energy (T&D losses)	6%	
$ 237.24	$ 0.036	PV of avoided cost of generation capacity	6%	
$ 57.34	$ 0.009	PV of avoided cost of T&D capacity	2%	
	$0.558		100%	
			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
14	Measure life
1.59	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)

$0.0601	Levelized cost/kWh of four energy components of AC
$0.0053	Levelized cost/kWh of two capacity components of AC

$0.77	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
$0.01	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.89	Total Resource Cost test benefits
$0.58	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.58	Total Resource Cost test costs
$0.31	Net TRC $ amount
1.53	**TRC benefit / cost ratio**

Occupancy sensors for lighting



Light fixture reconfiguration

Summarization of AC benefits and comparison to TRC costs

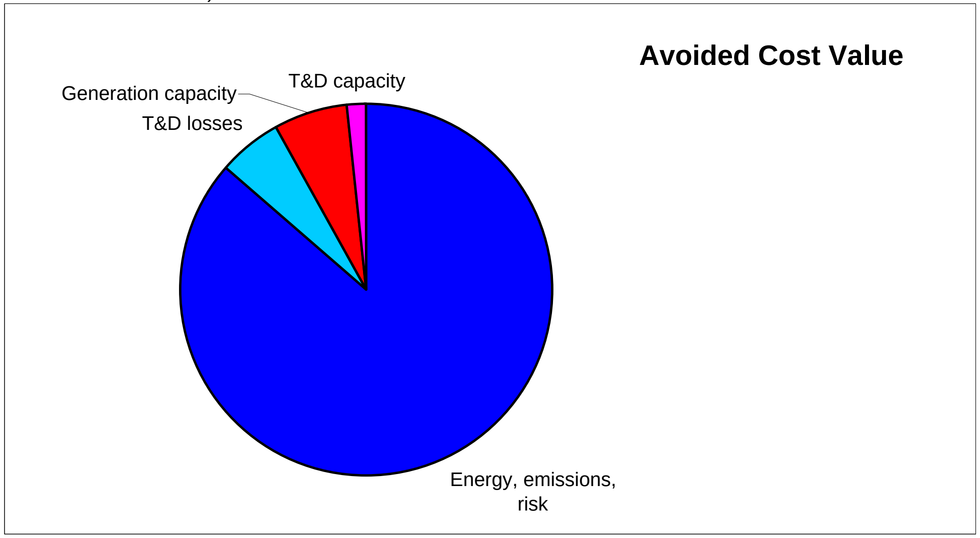
Per first year kW	Per first year kWh		% of total value	
	$0.535	PV of avoided cost of energy (energy + emissions + risk)	86%	
	$0.035	PV of avoided cost of energy (T&D losses)	6%	
$ 260.14	$ 0.040	PV of avoided cost of generation capacity	6%	
$ 63.11	$ 0.010	PV of avoided cost of T&D capacity	2%	
	$0.619		100%	
			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
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)

$0.0620	Levelized cost/kWh of four energy components of AC
$0.0054	Levelized cost/kWh of two capacity components of AC

$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
$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



MH 250 to Pulse Start MH 175, installed

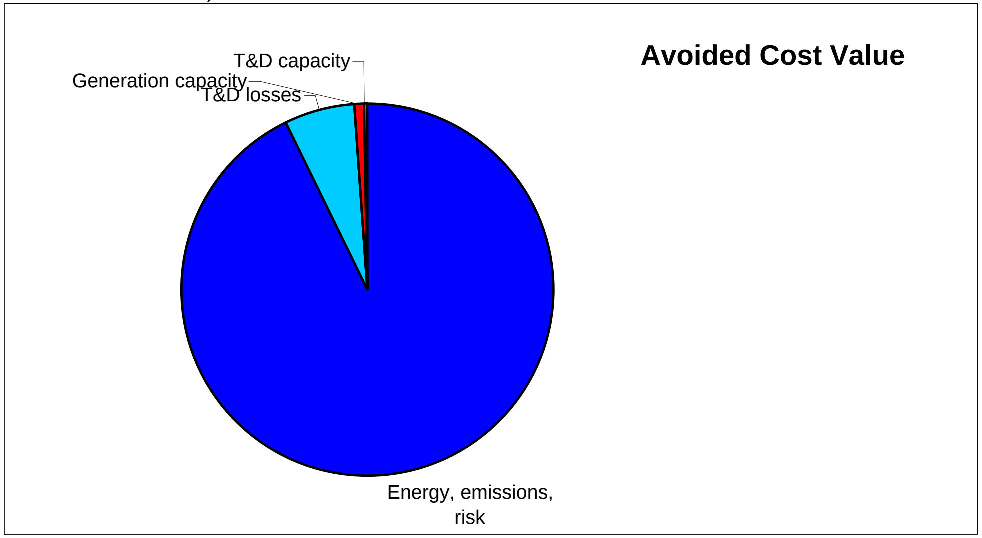
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.501	PV of avoided cost of energy (energy + emissions + risk)	93%	
	$0.033	PV of avoided cost of energy (T&D losses)	6%	
$ 260.14	$ 0.005	PV of avoided cost of generation capacity	1%	
$ 63.11	$ 0.001	PV of avoided cost of T&D capacity	0%	
	$0.540		100%	
			99%	Total energy
			1%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0580	Levelized cost/kWh of four energy components of AC
16	Measure life	$0.0007	Levelized cost/kWh of two capacity components of AC
349.000	Annual kWh savings per unit		
0.0229%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0020%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$174.77	PV of avoided cost of energy (energy + emissions + risk)
$11.36	PV of avoided cost of energy (T&D losses)
$1.82	PV of avoided cost of generation capacity
$0.44	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$188.39	Total Resource Cost test benefits
$196.86	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$196.86	Total Resource Cost test costs
($8.47)	Net TRC $ amount
0.96	**TRC benefit / cost ratio**

MH 250 to Pulse Start MH 175, installed



MH to T5 Flourescents (400W to 4 HO, 3,000 hr)

Summarization of AC benefits and comparison to TRC costs

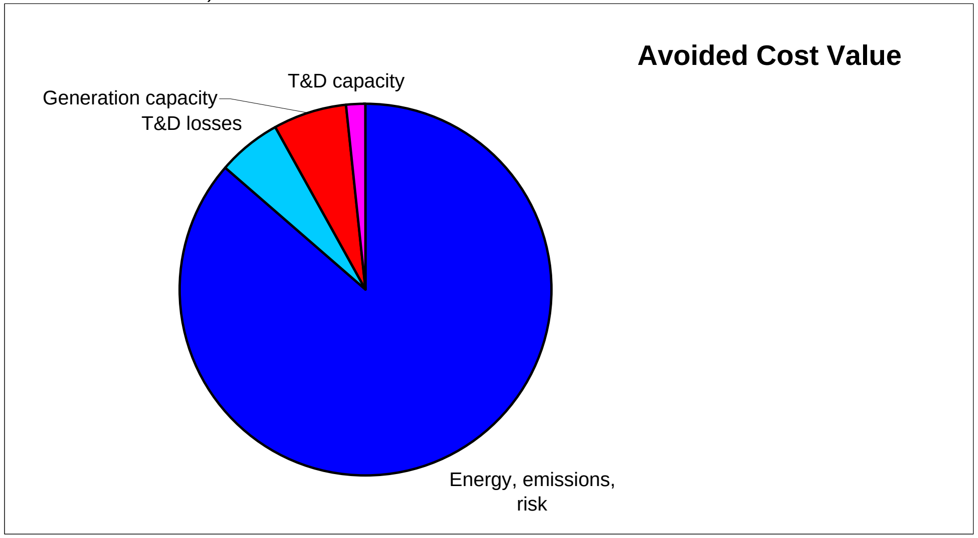
Per first year kW	Per first year kWh		% of total value
	$0.509	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.038	PV of avoided cost of generation capacity	6%
$ 60.28	$ 0.009	PV of avoided cost of T&D capacity	2%
	$0.589		100%

92% Total energy
8% Total capacity

$0.0611 Levelized cost/kWh of four energy components of AC
$0.0053 Levelized cost/kWh of two capacity components of AC

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)
$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
1.58	**TRC benefit / cost ratio**

MH to T5 Flourescents (400W to 4 HO, 3,000 hr)



Occupancy sensors for 1-zone A/C & PTAC (per sq. ft.)

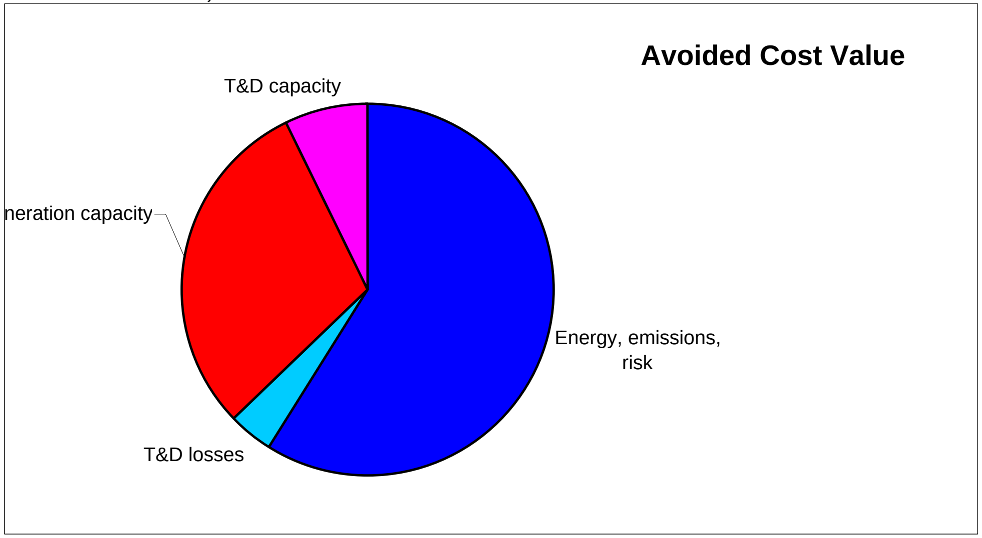
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%	
	$0.033	PV of avoided cost of energy (T&D losses)	4%	
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%	
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%	
	$0.854		100%	
			63%	Total energy
			37%	Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0603	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0359	Levelized cost/kWh of two capacity components of AC
1.694	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)		

$0.85	PV of avoided cost of energy (energy + emissions + risk)
$0.06	PV of avoided cost of energy (T&D losses)
$0.43	PV of avoided cost of generation capacity
$0.11	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$1.45	Total Resource Cost test benefits
$0.20	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.20	Total Resource Cost test costs
$1.25	Net TRC $ amount
7.23	**TRC benefit / cost ratio**

Occupancy sensors for 1-zone A/C & PTAC (per sq. ft.)



Prescriptive sidestream filtration

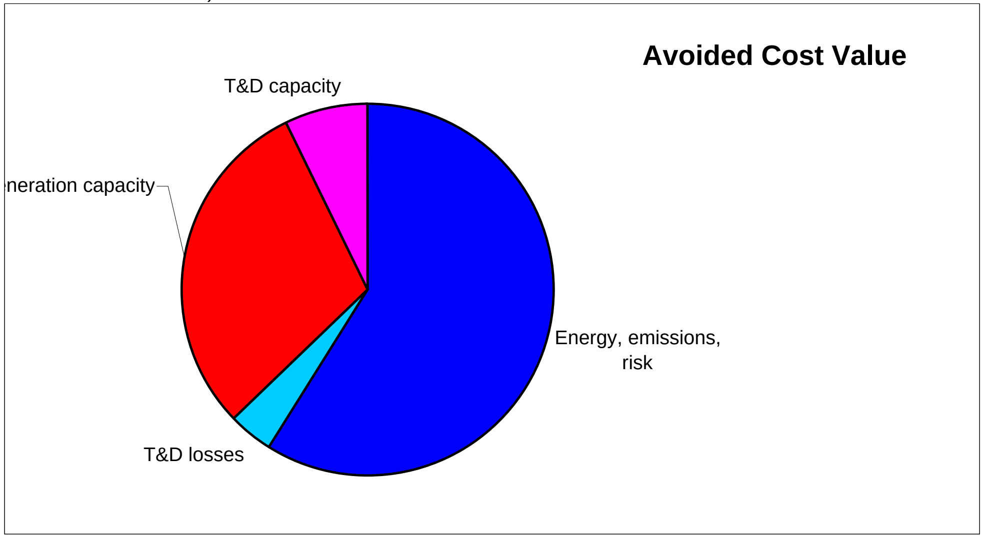
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%
	$0.033	PV of avoided cost of energy (T&D losses)	4%
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%
	$0.854		100%
			63% Total energy
			37% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0603	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0359	Levelized cost/kWh of two capacity components of AC
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**

Prescriptive sidestream filtration



Refrigeration tune-up/commissioning (per sq. ft.)

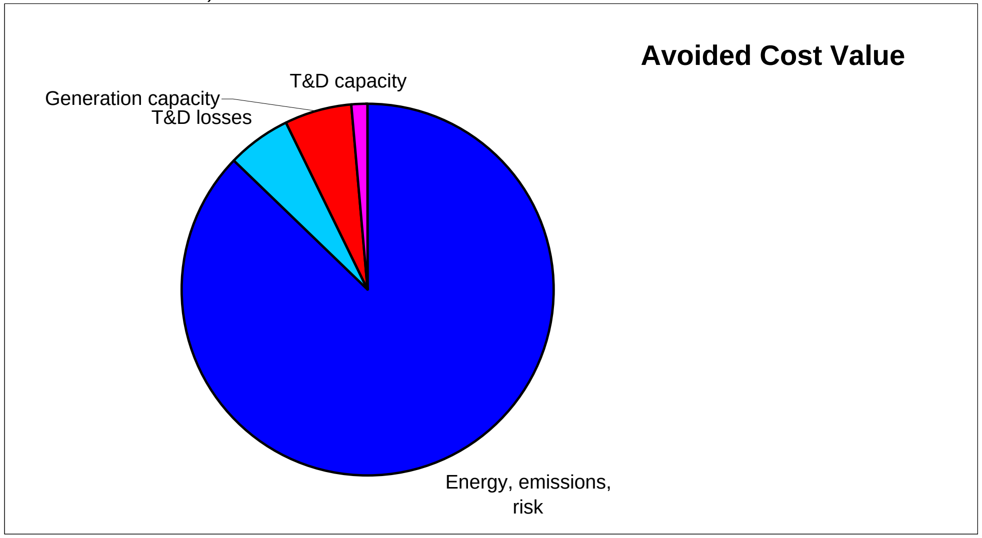
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.135	PV of avoided cost of energy (energy + emissions + risk)	87%	
	$0.009	PV of avoided cost of energy (T&D losses)	6%	
$ 64.65	$ 0.009	PV of avoided cost of generation capacity	6%	
$ 15.26	$ 0.002	PV of avoided cost of T&D capacity	1%	
	$0.154		100%	
			93%	Total energy
			7%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0550	Levelized cost/kWh of four energy components of AC
3	Measure life	$0.0043	Levelized cost/kWh of two capacity components of AC
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)		

$0.16	PV of avoided cost of energy (energy + emissions + risk)
$0.01	PV of avoided cost of energy (T&D losses)
$0.01	PV of avoided cost of generation capacity
$0.00	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$0.19	Total Resource Cost test benefits
$0.06	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.06	Total Resource Cost test costs
$0.13	Net TRC $ amount
3.11	**TRC benefit / cost ratio**

Refrigeration tune-up/commissioning (per sq. ft.)



Rooftop DX maintenance (per sq. ft.)

Summarization of AC benefits and comparison to TRC costs

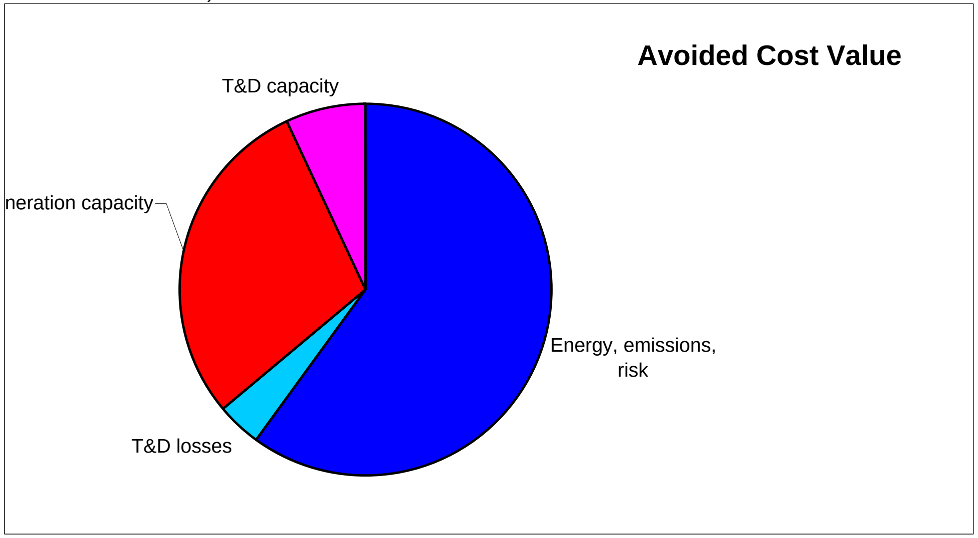
Per first year kW	Per first year kWh		% of total value
	$0.137	PV of avoided cost of energy (energy + emissions + risk)	60%
	$0.009	PV of avoided cost of energy (T&D losses)	4%
$ 64.65	$ 0.067	PV of avoided cost of generation capacity	29%
$ 15.26	$ 0.016	PV of avoided cost of T&D capacity	7%
	$0.228		100%
			64% Total energy
			36% Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
3	Measure life
0.651	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)

$0.0559	Levelized cost/kWh of four energy components of AC
$0.0316	Levelized cost/kWh of two capacity components of AC

$0.09	PV of avoided cost of energy (energy + emissions + risk)
$0.01	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
$0.15	Total Resource Cost test benefits
$0.23	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.23	Total Resource Cost test costs
($0.08)	Net TRC $ amount
0.65	**TRC benefit / cost ratio**

Rooftop DX maintenance (per sq. ft.)



Pre-rinse sprayers

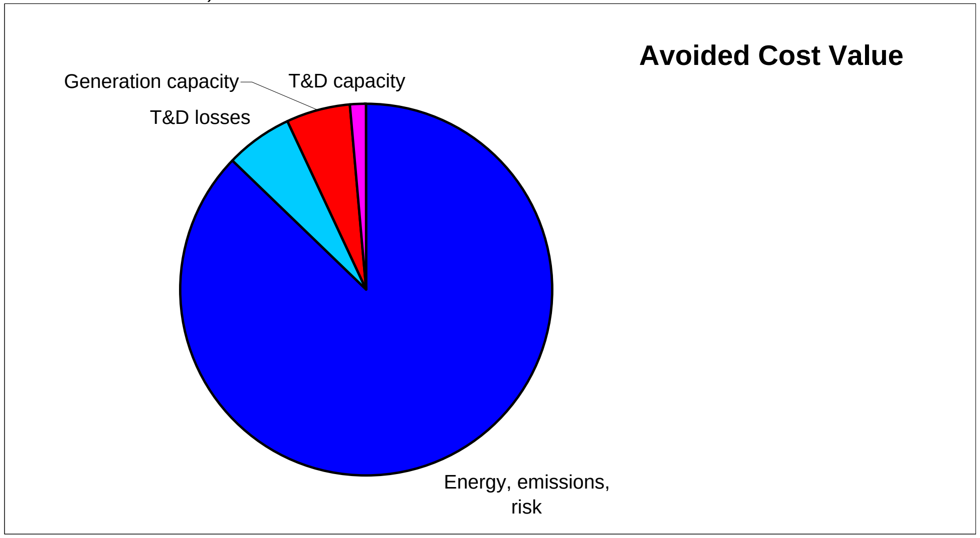
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.208	PV of avoided cost of energy (energy + emissions + risk)	87%	
	$0.014	PV of avoided cost of energy (T&D losses)	6%	
$ 102.97	$ 0.013	PV of avoided cost of generation capacity	6%	
$ 24.42	$ 0.003	PV of avoided cost of T&D capacity	1%	
	$0.239		100%	
			93%	Total energy
			7%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0547	Levelized cost/kWh of four energy components of AC
5	Measure life	$0.0041	Levelized cost/kWh of two capacity components of AC
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)		

$792.01	PV of avoided cost of energy (energy + emissions + risk)
$51.48	PV of avoided cost of energy (T&D losses)
$51.13	PV of avoided cost of generation capacity
$12.13	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$906.74	Total Resource Cost test benefits
$162.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$162.00	Total Resource Cost test costs
$744.74	Net TRC $ amount
5.60	**TRC benefit / cost ratio**

Pre-rinse sprayers



CFL 20W screw-in for incandescent 75W (retrofit)

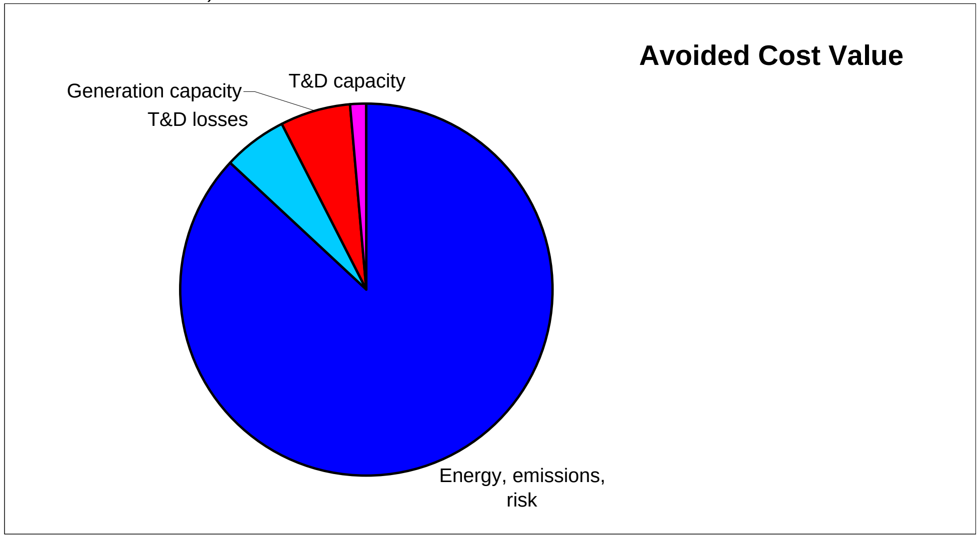
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.096	PV of avoided cost of energy (energy + emissions + risk)	87%	
	$0.006	PV of avoided cost of energy (T&D losses)	6%	
$ 44.10	$ 0.007	PV of avoided cost of generation capacity	6%	
$ 10.39	$ 0.002	PV of avoided cost of T&D capacity	1%	
	$0.111		100%	
			93%	Total energy
			7%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0545	Levelized cost/kWh of four energy components of AC
2.1	Measure life	$0.0044	Levelized cost/kWh of two capacity components of AC
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)		

$25.05	PV of avoided cost of energy (energy + emissions + risk)
$1.63	PV of avoided cost of energy (T&D losses)
$1.75	PV of avoided cost of generation capacity
$0.41	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$28.84	Total Resource Cost test benefits
$10.25	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$10.25	Total Resource Cost test costs
$18.59	Net TRC $ amount
2.81	**TRC benefit / cost ratio**

CFL 20W screw-in for incandescent 75W (retrofit)



Prescriptive sidestream filtration

Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	59%
	$0.033	PV of avoided cost of energy (T&D losses)	4%
$ 248.96	$ 0.257	PV of avoided cost of generation capacity	30%
$ 60.28	$ 0.062	PV of avoided cost of T&D capacity	7%
	$0.854		100%
			63% Total energy
			37% Total capacity

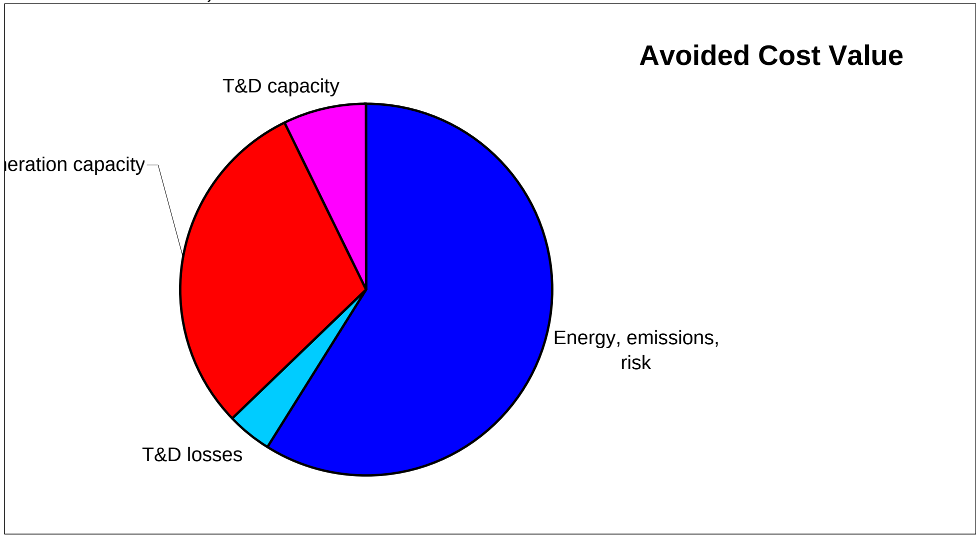
driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
200,000	Annual kWh savings per unit
0.1031%	Percent of annual energy in maximum hour (use for "driver" measures)
0.0547%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)

$0.0603 Levelized cost/kWh of four energy components of AC

$0.0359 Levelized cost/kWh of two capacity components of AC

$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**

Prescriptive sidestream filtration



Signage: incadescent to LED/incadescent to cold cathode

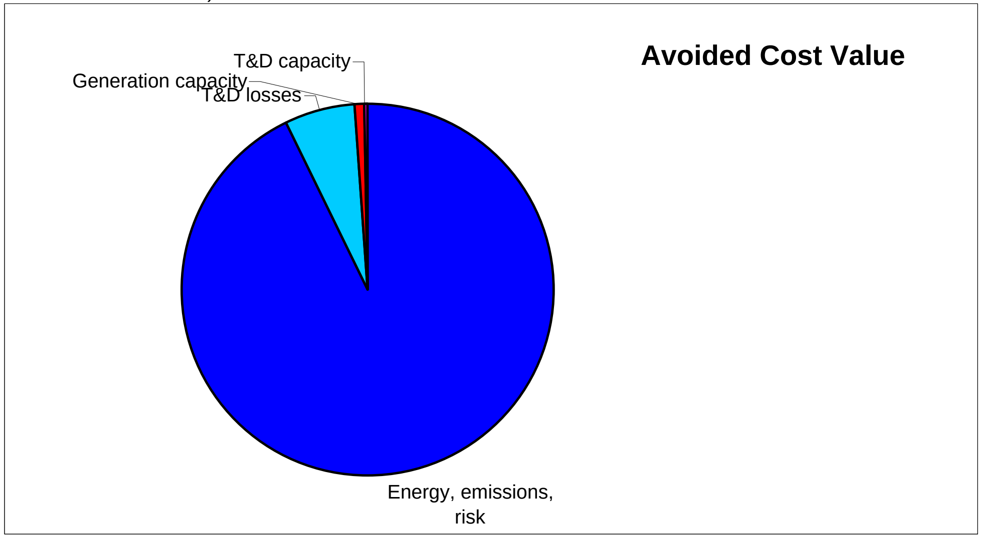
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.194	PV of avoided cost of energy (energy + emissions + risk)	93%	
	$0.013	PV of avoided cost of energy (T&D losses)	6%	
$ 102.97	$ 0.002	PV of avoided cost of generation capacity	1%	
$ 24.42	$ 0.000	PV of avoided cost of T&D capacity	0%	
	$0.209		100%	
			99%	Total energy
			1%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0509	Levelized cost/kWh of four energy components of AC
5	Measure life	$0.0006	Levelized cost/kWh of two capacity components of AC
74.000	Annual kWh savings per unit		
0.0229%	Percent of annual energy in maximum hour (use for "driver" measures)		
0.0020%	Percent of annual energy in average hour of designated system peak (use for "non-driver" measures)		

$14.35	PV of avoided cost of energy (energy + emissions + risk)
$0.93	PV of avoided cost of energy (T&D losses)
$0.15	PV of avoided cost of generation capacity
$0.04	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$15.47	Total Resource Cost test benefits
$15.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$15.00	Total Resource Cost test costs
$0.47	Net TRC $ amount
1.03	**TRC benefit / cost ratio**

Signage: incadescent to LED/incadescent to cold cathode



Smart programmable thermostat (per sq. ft.)

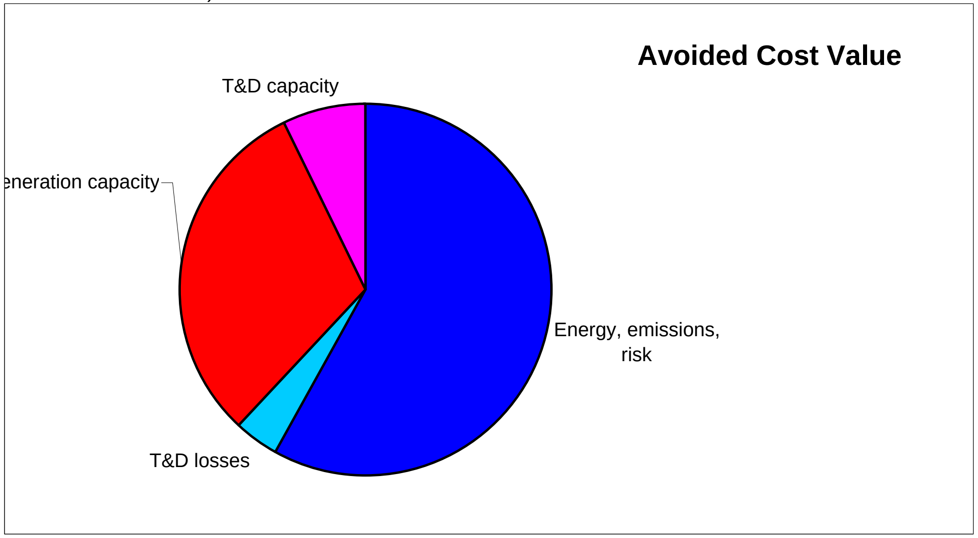
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value	
	$0.360	PV of avoided cost of energy (energy + emissions + risk)	58%	
	$0.023	PV of avoided cost of energy (T&D losses)	4%	
$ 184.47	$ 0.190	PV of avoided cost of generation capacity	31%	
$ 44.23	$ 0.046	PV of avoided cost of T&D capacity	7%	
	$0.619		100%	
			62%	Total energy
			38%	Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0557	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0342	Levelized cost/kWh of two capacity components of AC
0.279	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)		

$0.10	PV of avoided cost of energy (energy + emissions + risk)
$0.01	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
$0.17	Total Resource Cost test benefits
$0.15	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.15	Total Resource Cost test costs
$0.02	Net TRC $ amount
1.15	**TRC benefit / cost ratio**

Smart programmable thermostat (per sq. ft.)



Solar water heating

Summarization of AC benefits and comparison to TRC costs

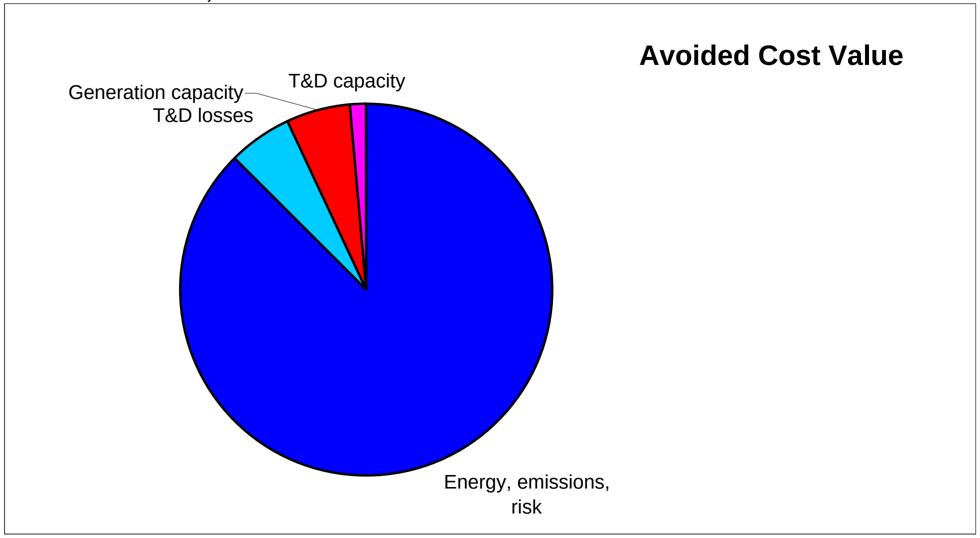
Per first year kW	Per first year kWh		% of total value	
	$0.509	PV of avoided cost of energy (energy + emissions + risk)	87%	
	$0.033	PV of avoided cost of energy (T&D losses)	6%	
$ 248.96	$ 0.033	PV of avoided cost of generation capacity	6%	
$ 60.28	$ 0.008	PV of avoided cost of T&D capacity	1%	
	$0.582		100%	
			93%	Total energy
			7%	Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
15	Measure life
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)

$0.0610	Levelized cost/kWh of four energy components of AC
$0.0046	Levelized cost/kWh of two capacity components of AC

$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**

Solar water heating



T12 EEmag to Super T8 Flourescents (retrofit)

Summarization of AC benefits and comparison to TRC costs

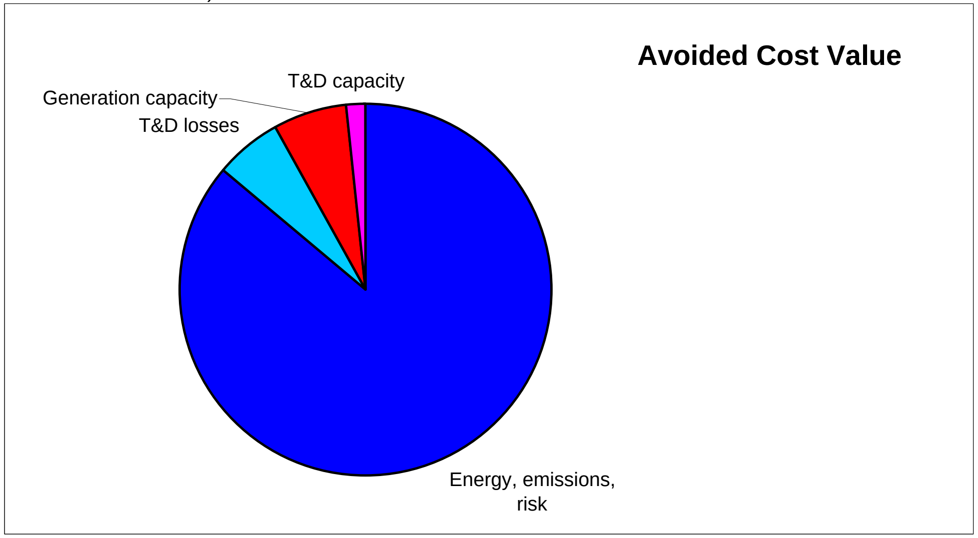
Per first year kW	Per first year kWh		% of total value
	$0.396	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.026	PV of avoided cost of energy (T&D losses)	6%
$ 198.60	$ 0.030	PV of avoided cost of generation capacity	7%
$ 47.71	$ 0.007	PV of avoided cost of T&D capacity	2%
	$0.459		100%
			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
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)

$0.0573	Levelized cost/kWh of four energy components of AC
$0.0051	Levelized cost/kWh of two capacity components of AC

$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
1.80	**TRC benefit / cost ratio**

T12 EEmag to Super T8 Flourescents (retrofit)



Commissioning/retro-commissioning

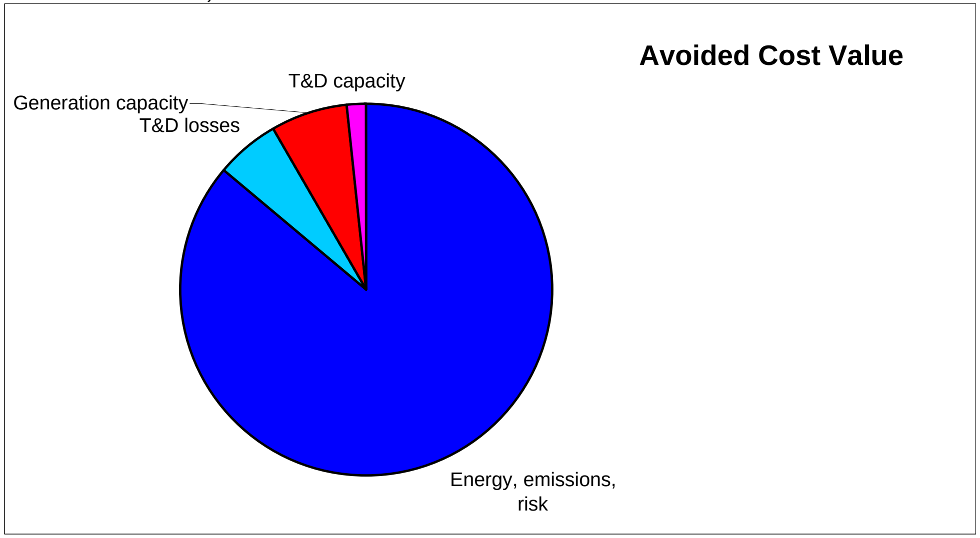
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.363	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.024	PV of avoided cost of energy (T&D losses)	6%
$ 184.47	$ 0.028	PV of avoided cost of generation capacity	7%
$ 44.23	$ 0.007	PV of avoided cost of T&D capacity	2%
	$0.422		100%
			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	$0.0561	Levelized cost/kWh of four energy components of AC
10	Measure life	$0.0051	Levelized cost/kWh of two capacity components of AC
1,612.000	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)		

$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
$680.57	Total Resource Cost test benefits
$215.50	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$215.50	Total Resource Cost test costs
$465.07	Net TRC $ amount
3.16	**TRC benefit / cost ratio**

Commissioning/retro-commissioning vm



VF Drives for HVAC

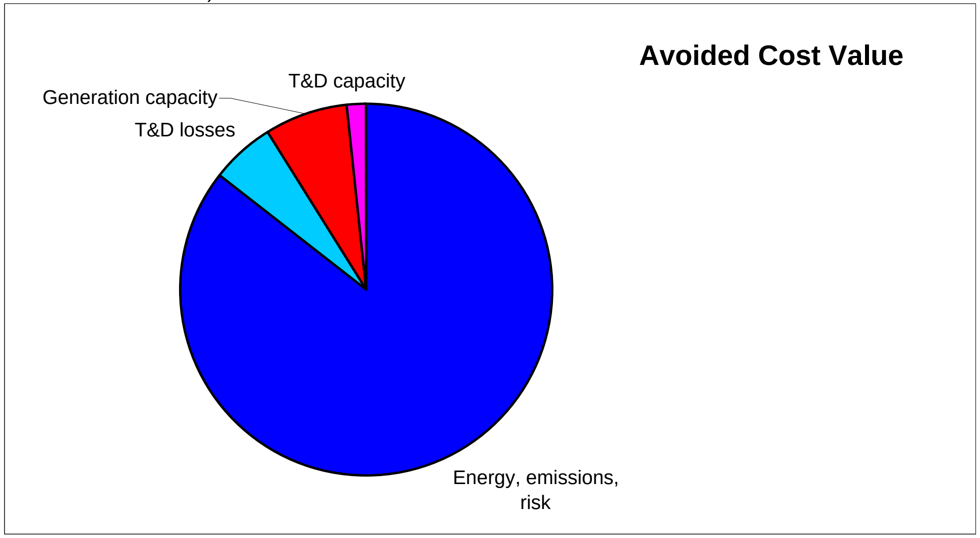
Summarization of AC benefits and comparison to TRC costs

Per first year kW	Per first year kWh		% of total value
	$0.503	PV of avoided cost of energy (energy + emissions + risk)	86%
	$0.033	PV of avoided cost of energy (T&D losses)	6%
$ 248.96	$ 0.042	PV of avoided cost of generation capacity	7%
$ 60.28	$ 0.010	PV of avoided cost of T&D capacity	2%
	$0.588		100%
			91% Total energy
			9% Total capacity

non-driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)		
7.41%	Discount rate	$0.0604	Levelized cost/kWh of four energy components of AC
15	Measure life	$0.0059	Levelized cost/kWh of two capacity components of AC
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)		

$0.34	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
$0.40	Total Resource Cost test benefits
$0.21	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$0.21	Total Resource Cost test costs
$0.19	Net TRC $ amount
1.89	**TRC benefit / cost ratio**

VF Drives for HVAC



Window films

Summarization of AC benefits and comparison to TRC costs

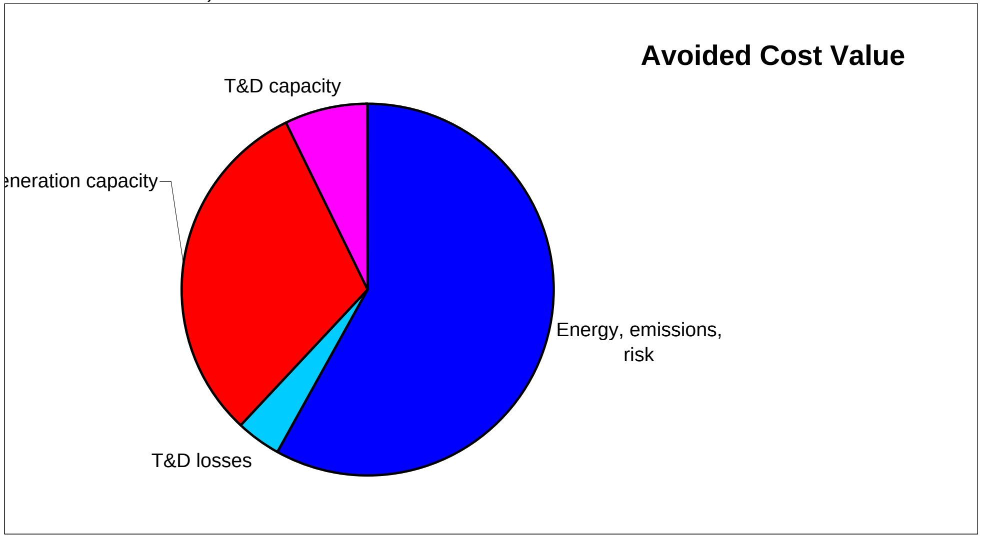
Per first year kW	Per first year kWh		% of total value	
	$0.360	PV of avoided cost of energy (energy + emissions + risk)	58%	
	$0.023	PV of avoided cost of energy (T&D losses)	4%	
$ 184.47	$ 0.190	PV of avoided cost of generation capacity	31%	
$ 44.23	$ 0.046	PV of avoided cost of T&D capacity	7%	
	$0.619		100%	
			62%	Total energy
			38%	Total capacity

driver	"driver", "non-driver" or "zero" measure type (based upon coincidence with managed system peak period)
7.41%	Discount rate
10	Measure life
50.000	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)

$0.0557	Levelized cost/kWh of four energy components of AC
$0.0342	Levelized cost/kWh of two capacity components of AC

$18.01	PV of avoided cost of energy (energy + emissions + risk)
$1.17	PV of avoided cost of energy (T&D losses)
$9.51	PV of avoided cost of generation capacity
$2.28	PV of avoided cost of T&D capacity
$0.00	PV of avoided cost of natural gas
$0.00	PV of non-energy benefits
$30.97	Total Resource Cost test benefits
$100.00	Incremental customer cost
$0.00	Incremental non-incentive utility cost
$100.00	Total Resource Cost test costs
($69.03)	Net TRC $ amount
0.31	**TRC benefit / cost ratio**

Window films



Estimated Resource Integration Costs

March 26, 2007

R. Gnaedinger
S. Koeff
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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 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

<u>Annual O&M $400k</u>

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

<u>Annual O&M $24k</u>

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 reconductored 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 reconductored 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 115kV line from Garden Springs to Sunset would need to be reconductored 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

<u>Annual O&M $14k</u>

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 reconductored 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

<u>Annual O&M $200k</u>

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

<u>Annual O&M $10k</u>

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 reconductored. 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

<u>Annual O&M $100k</u>

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

<u>Annual O&M $10k</u>

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

<u>Annual O&M $10k</u>

Total $1.5 million